Powercor Regulatory Proposal 2016–2020

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Executive summary 1

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1. Executive summary

We are seeking to invest in priorities that strike the right balance between safety, reliability, growth and affordability so that we meet the expectations of our customers today and into the future.

As a result of our efficient approach to investment, our customers will see a $43 reduction in the average residential customer's annual electricity bill in 2016, adjusted for inflation. Network charges will remain stable for the remainder of the five-year period.

Our forecast expenditure over the next regulatory control period is predominantly driven by:

- reducing bushfire risk (protecting our customers and our network);
- network asset replacement (maintain cost-effective reliability;
- network growth (growing with Victoria);
- building the network for the future; and
- making it easier for our customers.

1.1 Our business

We are the most efficient and reliable rural electricity network in Australia. We are one of Victoria's five privately owned electricity distributors. We own and manage assets that deliver electricity to more than 765,241 homes and businesses across Melbourne's outer western suburbs and central and western Victoria.

Our electricity distribution network is vast and complex, covering more than 145,000 square kilometres and traversing some of the most difficult and remote terrain.

1.2 A changing energy future

Our Regulatory Proposal has been prepared in an environment where customers are changing how and when they use energy.

The changing energy landscape presents both challenges and opportunities for us. Our customers expect us to better enable their energy choices through connecting solar panels and giving them greater access to information about their electricity usage.

These customer choices require us to design and build our electricity network to meet changing energy usage patterns, as customers become more proactive in managing their energy needs.

1.3 Our track record

We are proud of our strong performance and reputation for safety, efficient operations and reliability that has provided our customers with outstanding value for money.

Never compromising safety

Safety is our number one priority. We are committed to achieving the highest standards of safety for our customers, employees, contractors and the community. The overall health and condition of our assets is an important contributor and we have robust preventative maintenance and replacement policies to minimise risks arising from operation of our assets. We have, and will continue, to work collaboratively with the Victorian Government and Energy Safe Victoria (**ESV**) to reduce safety risks.

Reliability

Consistent with customer expectations, we have maintained our commitment to reliability over the current regulatory control period. Our performance is a testament to our robust and disciplined approach to asset management.

Our customers enjoy the best network availability of all Australian rural distributors at 99.96 per cent network availability. Our reliability performance also compares favourably with other Australian electricity distributors despite our customers being spread across our extensive network with less than 11.4 customers per kilometre of line and less than 12 per cent of our assets being located underground.

Efficient network management

Our safety and reliability performance has been achieved without compromising our record as being one of the most cost efficient distributors of electricity in the National Electricity Market (**NEM**). This has been demonstrated by the Australian Energy Regulator's (**AER**) own independent benchmarking analysis.

Affordable pricing outcomes

We aim to ensure value for money. Research conducted by Oakley Greenwood[1] found that between 1995 and 2014, our average residential network charges decreased by $150 in real terms.

1.4 Engaging better with our customers

To ensure we had a robust foundation for our detailed plans and submissions for the 2016-2020 regulatory control period, we undertook a comprehensive stakeholder engagement program which started more than 18 months ago to better understand what was important to our customers.

Through our engagement program, customers and stakeholders told us what they want from us during the upcoming regulatory control period. This feedback has informed our plans and as a result, we are confident that our Regulatory Proposal delivers on the expectations of our customers.

1.5 Highlights of our proposal

Reducing bushfire risk

Our operating environment is challenging – our network is located in some of the most difficult, diverse and remote terrain in the State. A key consideration is the community safety risks posed by the environment in which our assets are located, particularly in bushfire risk areas.

The Victorian Bushfires Royal Commission (**VBRC**) was established to conduct an extensive investigation into the causes and impact of the Victorian bushfires in 2009.

The VBRC made 67 recommendations, eight of which proposed major changes to the State's electricity distribution infrastructure and operation management. Our proposed expenditure would enable us to continue to implement the recommendations of the VBRC in accordance with obligations imposed, or anticipated to be imposed, on us by ESV or the Victorian Government.

[1] Oakley Greenwood, Powercor pricing comparisons, 1995 to 2014.

The obligations relate to a number of activities including:

- installation of armour rods and vibration dampers to reduce the safety risk from vibration caused by the wind;
- installation of new generation automatic circuit reclosers (**ACRs**) to single earth wire return (**SWER**) lines to instantaneously detect and turn off power at a fault on high risk fire days; and
- installation of earth-fault limiting equipment to trial the technology for its ability to mitigate bushfires. This technology seeks to detect and turn off power at a fault almost instantaneously at zone substations.

Network asset replacement

Our proposed replacement expenditure will enable us to continue to maintain the safety, security and reliability of the network, whilst minimising outages for customers. That is, the expenditure will allow us to 'keep the lights on'.

We monitor our assets and take a risk based approach when assessing their condition, only replacing them when it is needed to maintain reliability and security of supply. This internationally recognised risk based approach involves monitoring the 'Health Indices (**HI**)' of our strategic major plant items, such as transformers and high voltage circuit breakers, ensuring that the risk profile of this equipment is maintained during the upcoming regulatory control period. This investment includes plans proposing to replace transformers at the Warrnambool, Winchelsea, Terang, Echuca, Geelong East, Robinvale and Charlton zone substations.

Our asset inspection program for poles and the cross arms, that support power lines, has identified the need for increases in replacement volumes and this trend is expected to continue over the next regulatory control period.

Network growth

Our network covers some of the fastest growing regions in Australia, including the western suburbs of Melbourne, and the agricultural regions along the Murray River and southwest Victoria. Despite the decline in the manufacturing sector, growth in the Geelong region is amongst the highest in our network distribution area, fuelled predominately by strong residential and commercial development.

We are also proposing significant investment to enable customers to connect to our network over the next regulatory control period. A large portion of this expenditure will however be directly recovered from the connecting customers. Included in our connection forecasts are those relating to the Victorian Government's bushfire related initiatives such as the Powerline Replacement Fund projects. Connection expenditure is also being driven by a number of large connections, including connections in the dairy sector to support expansion into Asian markets and a number of renewable wind farm connections.

Building the network for the future

We will continue to invest in technologies and solutions that help us build a smarter network that can accommodate both the production and consumption of electricity and information, particularly as energy flows and quality of supply issues become more complex.

Over the 2016-2020 regulatory control period we are planning investments that can maintain voltage quality to facilitate an expected increase of more embedded generation connections such as solar panels. We will invest in better network control, better data analytics and innovative ways to manage and optimise our network to reduce costs and improve value to our customers.

Making it easier for our customers

Access to usage data from smart meters was a common theme in customer and stakeholder feedback throughout our stakeholder engagement activities. One of the key matters that we are planning to address is to implement systems to better engage with our customers, understand their individual preferences and provide access to their data through an automated customer portal. Coupled with investment in a customer relationship management system, we will be better able to respond to customer requests, work with them and their electricity retailers to reduce power bills further, as well as give easier access to new tariffs that incentivise customers to help us minimise overloads on high demand days.

Table 1.1 Distribution charge impact for typical customers (including metering) (per cent, real)

Typical annual bill	2016	2017	2018	2019	2020	Average % p.a.
Residential	-8.2	-1.2	-0.7	-0.9	-0.5	-2.3
Small commercial	-6.1	0.6	1.3	1.1	1.5	-0.3
Large	-4.5	1.9	1.9	1.6	2.1	0.6

Source: Powercor

Table 1.2 Revenue requirement for standard control and metering services ($m, real)

	2016	2017	2018	2019	2020	Total
Annual revenue requirement	694	707	744	771	801	3,716

Source: Powercor

Table 1.3 Proposed forecast expenditure for standard control and metering services ($m, real)

	2016	2017	2018	2019	2020	Total
Forecast net capital expenditure	418.9	408.8	412.1	403.4	417.8	2,061.0
Forecast operating expenditure	263.4	271.2	283.3	292.6	301.8	1,412.3

Source: Powercor

Introduction 2

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2. Introduction

This document, appendices and its attachments comprise our Regulatory Proposal to the Australian Energy Regulator (**AER**) for the regulatory control period 2016–2020. It sets out the revenue, we believe, is required to manage the network in a safe, reliable and efficient manner for our customers and the community in general.

The Regulatory Proposal is supported by the following accompanying documents:

- an Overview Paper that has been prepared in line with clause 6.2.2(C1) of the *National Electricity Rules* (**Rules**);[2] and
- copies of our documentation supporting the Regulatory Proposal and appendices and attachments (including the information required by the Expenditure Forecast Assessment Guideline and the *Price Reset Regulatory Information Notice* (**Reset RIN**)).

This Regulatory Proposal and its appendices and attachments were prepared in accordance with the Rules and Reset RIN requirements, as set out in the attached, *NER Cross Reference Matrix* and *Reset RIN Cross Reference Matrix*.

2.1 Our vision and values

Our vision is connecting for a bright future. To realise this vision, we are focused on:

- continually improving how we engage with customers and key stakeholders on what matters to them to ensure we meet the energy needs of Victorians today and into the future;
- providing customers with outstanding value for money by maximising the efficiency of our operations, with a focus on safety and reliability;
- maintaining appropriate levels of investment in our network to support growth in Victoria; and
- understanding emerging technologies and alternative sources of energy, and changing consumer patterns to ensure effective and cost efficient reinforcement of our network.

Our values underpin everything we do, every day. Together they give us greater focus on understanding and supporting customers, doing what is right and helping employees and the Business strive for excellence in everything we do. Our values are to:

- live safely;
- make it easy for your customer;
- succeed together;
- be community minded;
- be the best you can be; and
- drive and embrace change.

2 Clause 11.60.3(a) relevantly provides that 'current Chapter 6' applies in respect of the making of a distribution determination for an 'affected DNSP' for the next regulatory control period (being the regulatory control period that immediately follows the period ending 31 December 2015). Clause 11.65.2 relevantly provides that references in rule 11.60 to 'current Chapter 6' are to be read as Chapter 6 of the Rules as in force immediately after the National Electricity Amendment (Network Service Provider Expenditure Objectives Rule 2013) came into force. That rule came into force on 26 September 2013 contemporaneously with version 58 of the Rules. Furthermore, clause 11.65.2 states that references to 'current Chapter 6' in clause 11.60 are to be read in this way despite clause 11.60.2. Accordingly, except where otherwise stated, references to Chapter 6 of the Rules in this document are to Chapter 6 in version 58 of the Rules.

2.2 Regulatory context

As a monopoly service provider, we are subject to a comprehensive set of regulatory obligations designed to ensure appropriate outcomes for customers, the community and investors. We require a fair commercial return to enable us to deliver an appropriate level of network reliability, safety and customer service in an efficient and sustainable manner.

The AER is responsible for the economic regulation of our business. In undertaking this economic regulation role, the AER is required to do so in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (**NEO**) as stated in section 7 of the *National Electricity Law* (**NEL**).

The objective of the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The Victorian Government retains responsibility for setting service levels, while Energy Safe Victoria (**ESV**) is responsible for safety and technical regulation in Victoria.

The AER has decided to apply a revenue cap form of control to our standard control services in the 2016–2020 regulatory control period and has put in place incentive arrangements to encourage us to pursue efficiency gains, further investigate demand management opportunities, and improve service performance to customers over the regulatory control period.

The AER is required to ensure that pricing outcomes, and the revenues on which they are predicated, are sufficient to enable us to undertake the capital and operating work programs required to deliver the service levels as defined by the *Victorian Electricity Distribution Code* (**Code**), comply with all applicable regulatory obligations and requirements and maintain the safety of the distribution system. The allowed pricing outcomes must also provide for a fair commercial return to our shareholders. We have developed our capital expenditure program and forecasts taking into account the requirements of the Code and consider that the proposed capital expenditure programs are sufficient to ensure that we comply with that Code.

Since the 2011–2015 regulatory determination, there has been significant regulatory change. This is discussed further in chapter 4.

In addition, at the time of preparing this Regulatory Proposal, a number of important consultations or decisions remain in progress, including Rule changes aimed at expanding competition in metering and related services and whether Victoria joins the National Energy Customer Framework (**NECF**). This Regulatory Proposal reflects our best assessment of the impact of open Rule change processes and other deliberations. However, changes to regulatory arrangements that are determined subsequent to the submission of this Regulatory Proposal may require further consideration during the AER's determination process.

In October 2014, the AER released its *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A**)[3]. The F&A paper, amongst other things, defines the revenue control mechanism to apply in the 2016–2020 regulatory control period, the AER's proposed approach to the classification of distribution services and the specific application of regulatory incentive schemes in the 2016–2020 regulatory control period.

[3] AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, 24 October 2014

We accept the conclusions advanced in the F&A paper. As a consequence, this Regulatory Proposal is based on the application of a revenue control mechanism and the service classification outlined in the F&A paper.

For the purposes of 6.3.2(a) and S6.1.3(13) of the Rules, we are proposing our next regulatory control period commence on 1 January 2016 and operate for a period of five years concluding on 31 December 2020.

Further information on the F&A Paper can be found at **aer.gov.au**.

2.3 Structure of this Regulatory Proposal

In addition to this Regulatory Proposal, we have prepared a plain English overview document which provides a summary of this Regulatory Proposal. It is available on our website talkingelectricity.com.au.

Table 2.1 Chapters of the Regulatory Proposal

Chapter	Title	Description
1	Executive summary	An overview of the Regulatory Proposal, its objectives and conclusions.
2	Introduction	Contextual information.
3	Our track record	A description of our business in terms of its role, the network, our customers and a summary of our achievements in terms of safety, reliability, affordability and service.
4	Our operating environment	Current operating challenges and new operating challenges emerging.
5	Benchmarking	Assessment of our efficiency performance.
6	Our customer engagement	An overview of our engagement with customers and our findings.
7	Real price growth	Provides our forecast of labour, material and contract escalation in the 2016-2020 regulatory control period.
8	Demand, energy and customer forecasts	Presents our demand, energy and customer number forecasts for the 2016–2020 regulatory control period.
9	Capital expenditure	Details the capital expenditure forecast for the 2016-2020 regulatory control period.
10	Operating expenditure	Details the operating expenditure forecast for the 2016-2020 regulatory control period.
11	Incentive schemes	An explanation of the incentive schemes that will apply in the 2016-2020 regulatory control period.
12	Rate of return	Sets out the rate of return we consider should be applied to our determination.
13	Revenue and pricing	Summarises the total revenues that will be recovered through our tariffs.
14	Managing uncertainty	An explanation of proposed pass through and contingent project events and triggers.

Chapter	Title	Description
15	Metering	The total revenues that will be recovered for metering services in the 2016-2020 regulatory control period.
16	Non-standard control	Our proposed charges and terms for alternative control, public lighting and negotiated services for the 2016-2020 regulatory control period.
17	Glossary	Description of the defined terms within the Regulatory Proposal.
18	Appendices	Lists the appendices attached to this Regulatory Proposal.
19	Attachments	Lists the attachments to this Regulatory Proposal.
20	Models	Lists the models attached to this Regulatory Proposal.
21	Regulatory information notice	Lists the attachments to the reset RIN.

Source: Powercor

2.4 Determination timeframes and feedback opportunities

This Regulatory Proposal presents our proposed expenditure, regulatory arrangements, rate of return and distribution revenue for the 2016–2020 regulatory control period.

Following an assessment of this Regulatory Proposal and submissions received from interested parties, the AER will make a preliminary distribution determination by 31 October 2015.

Transitional arrangements are currently in place as a consequence of Rule changes in 2012 which extend the usual determination timeframes. Thus, although our next regulatory control period will still commence on 1 January 2016, the AER will continue its determination process into 2016 as required by clause 11.60.4 of the Rules.

Interested parties will have the opportunity to make further submissions on the AER's preliminary distribution determination until 45 business days post the determination. Subsequently the AER will publish a substitute distribution determination on 30 April 2016 that will take effect from 1 January 2017.

Any differences between the preliminary distribution determination and the substitute distribution determination that impact allowed revenues in the 2016 regulatory year will be addressed by means of a revenue 'true up' at 1 January 2017.

Further information on our determination process can be found at the AER website: **http://www.aer.gov.au/node/27890**.

Our track record 3

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3. Our track record

Over the current, and previous, regulatory control periods, we have properly and determinedly responded to the incentives under the regulatory framework to maintain downward pressure on costs and innovate to the benefit of all our customers. This is evidenced in the 29 per cent reduction in distribution use of system charges since 1995. At the same time, we have operated our network in a reliable and safe manner that has delivered strong service improvements for our customers.

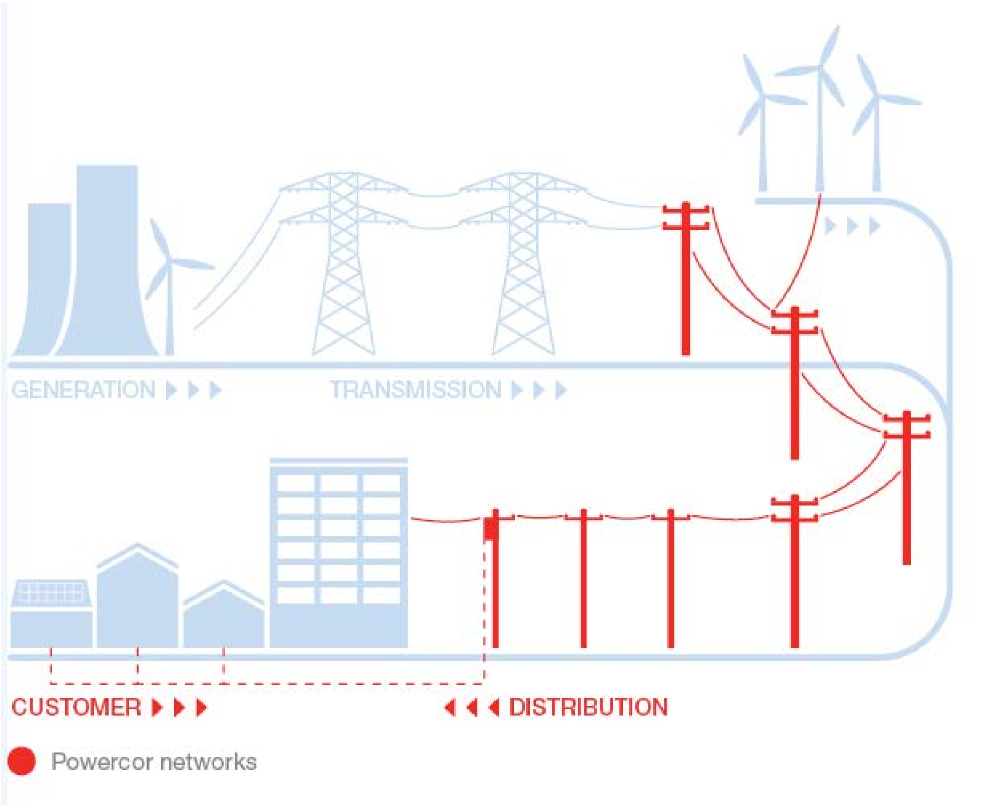
Today our distribution charges represent less than 25 per cent of the average residential electricity bill whilst our network charges are amongst the lowest in the National Electricity Market (**NEM**). Further, based on the Australian Energy Regulator (**AER's**) rankings, we are the most reliable regional distributor in Australia.

3.1 Our role

In the NEM, generators (either fossil fuelled or renewable) produce electricity, which is transported at extra high voltage across the transmission network (operated by AusNet Services in Victoria), to transmission network 'exit points' in or near urban and rural centres.

We then deliver electricity from the transmission system exit points to customers across western and northern Victoria including the growth corridors of northern and western Melbourne to Victoria's major provincial cities of Geelong, Ballarat, Bendigo and Shepparton. In between the network covers some of the most sparsely populated remote and rural areas in Australia. Retailers sell electricity to customers, having purchased it from the NEM wholesale market. They pay us for use of the network that transports electricity to customers.

Figure 3.1 Distribution in the electricity supply chain



Source: Powercor

We are a key part of Victoria's economy and community. As the local distributor throughout western and northern Victoria, we have primary responsibility for planning, building, operating and maintaining the 'poles and wires' — a strategic community asset and core component of Victoria's energy infrastructure. We do this in a safe, reliable, efficient and prudent manner.

We connect residential and business customers to a safe and reliable electricity supply. Our key distribution activities include:

- maintaining network safety and reliability to meet the current power supply needs of our customers;
- extending and upgrading the network so that the future power supply needs of customers are met when required;
- operating the network on a day to day basis;
- connecting new customers to the network;
- maintaining the public lighting system;
- reading electricity meters; and
- providing meter data to retailers.

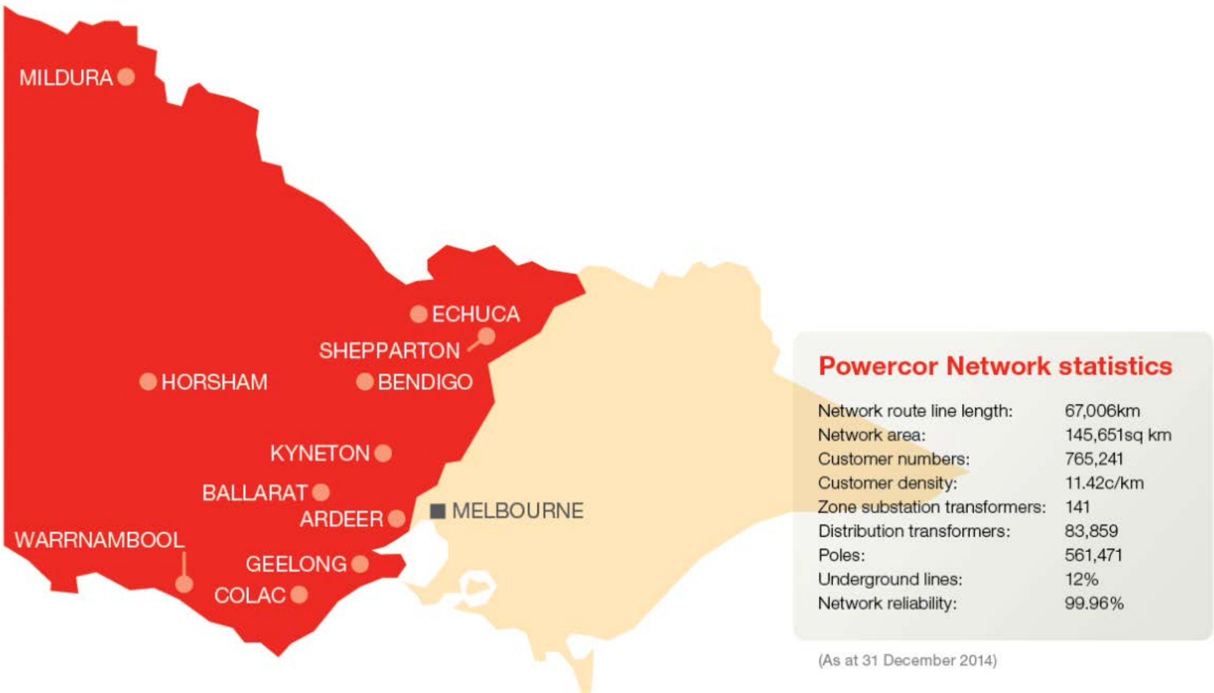
With the rapid take-up of new technologies, such as solar photovoltaic (**PV**) by residential and commercial customers, we are increasingly facilitating the integration of small scale generation into the network, essentially providing a means for small customers to participate in the market. This role is expected to continue to grow in coming years as customers adopt a wider range of 'distributed energy resources' eg: battery storage, electric vehicles.

Our electricity distribution network is vast and complex, covering more than 145,000 square kilometres. The network extends across difficult and remote terrain and operates in demanding conditions and stretches for more than 67,000 km, and includes 141 zone substations, 83,859 street transformers, and more than 561,471 poles. Other assets include circuit breakers, switches, meters, and a multitude of ancillary systems as well as fleet and depot facilities spread across the network.

The network has one of the lowest customer densities in the NEM at 11.4 customers per route line length kilometre.

The network supplies electricity to more than 765,000 customers ranging from isolated farms in rural areas to industry precincts, regional and metropolitan residential homes, businesses and city centres.

Figure 3.2 **Powercor network statistics**



Source: Powercor

3.2 Our ownership, organisational structure and governance

We are a limited liability company owned by Victoria Power Networks (**VPN**). VPN is ultimately 51 per cent owned by Cheung Kong Infrastructure Holdings Limited and Power Assets Holdings Limited, which form part of the Cheung Kong Group of companies based in Hong Kong. The remaining 49 per cent of the company is ultimately owned by Spark Infrastructure Group, a publicly listed infrastructure fund.

VPN is the principal entity and owner of investments in Powercor, CitiPower, CHED Services and Powercor Network Services (**PNS**) and has responsibility for the overall direction of these companies. The corporate functions of Powercor and CitiPower (another Victorian distributor) have been integrated and are supplied by CHED Services. Field services for both Powercor and CitiPower are provided by PNS.

The Board has overall responsibility for our corporate governance including the critical responsibilities of strategy setting, policy definition and compliance and monitoring of business performance. The Board has established the following committees to assist in the execution of its duties: Audit, Risk Management and Compliance and Remuneration. In addition, all investment decisions above $1.5 million are subject to the Capital Investment Committee (**CIC**) which includes the Chief Executive Officer and the Chief Financial Officer.

All investment cases must provide adequate information about how the investment contributes towards our longer term strategic direction. Secondly, business cases require approvals from the Network Planning Committee (**NPC**) or the IT Project Governance Committee (**IT PGC**) and the CIC. This ensures that our network planning and management objectives align with our corporate strategic objectives. During 2014 we also began trialling a new portfolio and project control framework which is designed to result in more efficient investments through a stronger investment framework and stronger capital controls. It is anticipated the new framework will be fully introduced in 2015.

All of our proposed capital investments are appraised and approved through a single process. This ensures that a consistent investment appraisal criterion is applied to all investment decisions. The approval process delegates approval responsibility appropriately to the NPC (>$300k), the CIC (>$1.5M), Chief Executive Officer (<$5M), Chief Executive Officer and Chairman jointly (<$10M) and the Board (>$10m). Further, the capital investment process is subject to periodic review and audit.

It is a fundamental requirement that all capital investments must either enhance or protect existing customer and shareholder value or is incurred to satisfy a non-financial requirement such as a customer service, regulatory, quality, legal, environmental or health and safety compliance obligation.

Our investment governance framework evaluation process is set out in the following documents, the *Expenditure Approval Manual*[4]*, Purchasing and Procurement Policy Manual*[5] and *Post Investment Review Policy*[6] .

3.3 Never compromising safety

Keeping our customers, communities and employees safe has always been, and remains, our number one priority. We will never compromise safety. It is embedded in our culture and values.

We have well established network development, replacement and maintenance programs in place to reduce the probability of network assets creating a safety hazard or starting a fire. These programs amongst other things address:

- overhead conductor failure, complete or partial separation of electric wires;
- pole failure; and
- cross arm failure.

[4] CitiPower and Powercor, Expenditure Approval Manual, 7 August 2013
[5] CitiPower and Powercor, Purchasing and Procurement Policy Manual, 7 August 2013
[6] CitiPower and Powercor, Post Implementation Review Policy, 9 March 2012

Electrical safety in Victoria

In Victoria, responsibility for electricity safety rests with the independent technical regulator Energy Safe Victoria (**ESV**). ESV is a Victorian Government statutory authority.

Victoria's safety regulatory regime requires us to provide ESV with documentation for review that details the safety systems that we have in place to reduce the risk of our network starting fires or posing other safety risks to the community and our employees. An Electricity Safety Management Scheme (**ESMS**) and a Bushfire Mitigation Plan (**BMP**) must be submitted to ESV every five years, whilst we are also required to submit Electric Line Clearance Management Plans (**ELCMPs**) annually.

As part of its role, ESV also annually reviews our safety performance. Their reviews focus on the key safety indicators, as well as the operation of the ESMS, which became a mandatory requirement on our business following the 2009 Victorian Bushfires Royal Commission.

The primary responsibility for ensuring network safety rests with us and ESV holds us accountable by requiring us to participate in targeted annual audits to confirm compliance with our safety systems.

ESV also provides comments and input to the safety programs included in our Regulatory Proposal, both to us and the AER.

The reliability and safety performance of electricity networks, including their potential to start fires, is ultimately a function of environmental factors as well as how well the networks are planned, designed, maintained and operated. This is in turn a reflection on the design and effectiveness of both economic and safety regulatory regimes.

Rural Victoria is one of the most bushfire prone places in the world requiring us to remain focussed on the safety of the community at all times. Bushfire risk is managed through:

- ongoing vegetation management;
- continuous asset inspection and maintenance programs;
- making adjustment to the electricity network operations control systems during high risk periods;
- preparing crews across the network for fire season; and
- more frequent inspections of overhead lines in high bushfire risk areas.

In addition to our planning, policies and procedures, a number of new investments have been made over the current regulatory control period aimed at bushfire prevention. These include:

- the installation of armour rods and vibration dampers on more than 170,000 spans of high voltage line in high bushfire risk areas;
- a survey of more than 10,000 spans of multi circuit powerlines in high bushfire risk areas using state of the art laser measuring equipment to identify any instances of potential for clashing and where identified, the fitting of spreaders;
- reducing the time between inspection for poles in high bushfire risk areas from 60 to 37 months; and
- installation of 179 new generation automatic circuit reclosers (**ACR**s) on rural single wire earth return (**SWER**) lines.

We are continuing to work with the Victorian Government through the Powerline Replacement Fund to underground critical powerlines. Undergrounding efforts over the current regulatory control period have centred on the Otway Ranges to help create a safer environment for those communities as well as coastal areas south and east extending beyond Anglesea.

Workplace safety

Victoria's Occupational Health & Safety Act 2004 provides a broad framework for achieving health and safety standards in the workplace. It consists of objectives and general duties that apply to all businesses including us. The objectives of the Act are to:

- secure the health, safety and welfare of employees and other persons at work;
- eliminate at the source risk to health, safety or welfare of employees and other persons at work;
- ensure the health and safety of members of the public is not placed at risk by the conduct of employees and self-employed persons; and
- provide for the involvement of employees, employers and organisations representing those persons in the formulation and implementation of health, safety and welfare standards.

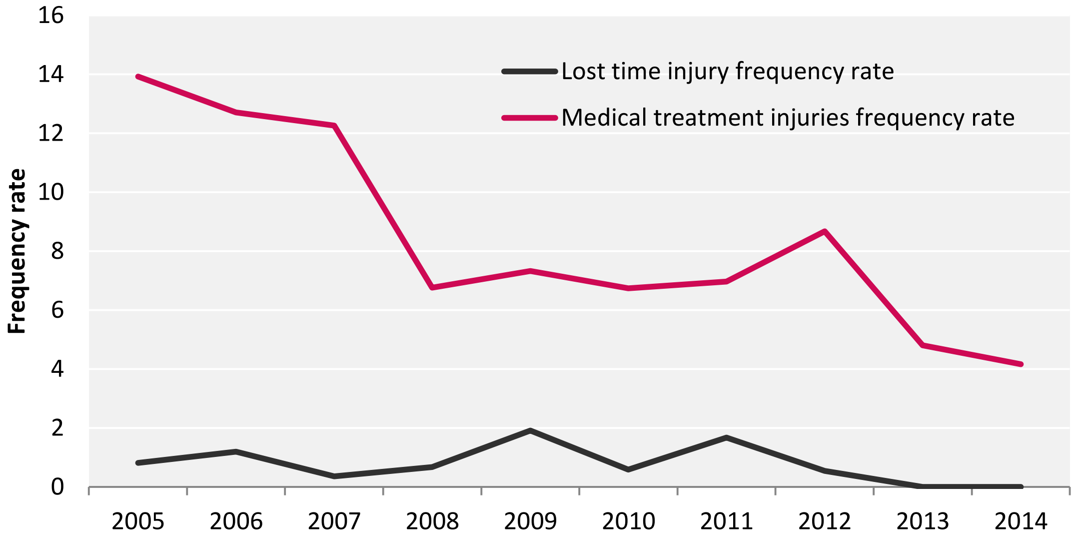
Complying with the occupational health and safety legislation is an essential aspect of doing business in Victoria and as a business, we are fully committed to ensuring compliance.

In 2014 we achieved a 60 per cent reduction in significant incidents, which are incidents that have the potential for a fatality or permanent disability. Also over 2014, we have improved our identification of hazards through emphasising the importance of reporting risks.

In the spirit of promoting our safety culture, we have for 2015 tightened our internal safety targets further, placing us in the best position to realise zero significant incidents in the future. Also in 2015, we are introducing a safety leadership and engagement program for our senior management to ensure that everyone in our business has safety top of mind every day.

Our employee safety performance continues to lead the industry and is reflected in figure 3.3, which demonstrates excellent and improving outcomes in terms of the Lost Time Injury Frequency Rate (**LTIFR**) and Medical Treatment Injuries Frequency Rate (**MTIFR**).

Figure 3.3 **Lost time injury frequency rate and medical treatment injuries frequency rate**



Source: Powercor

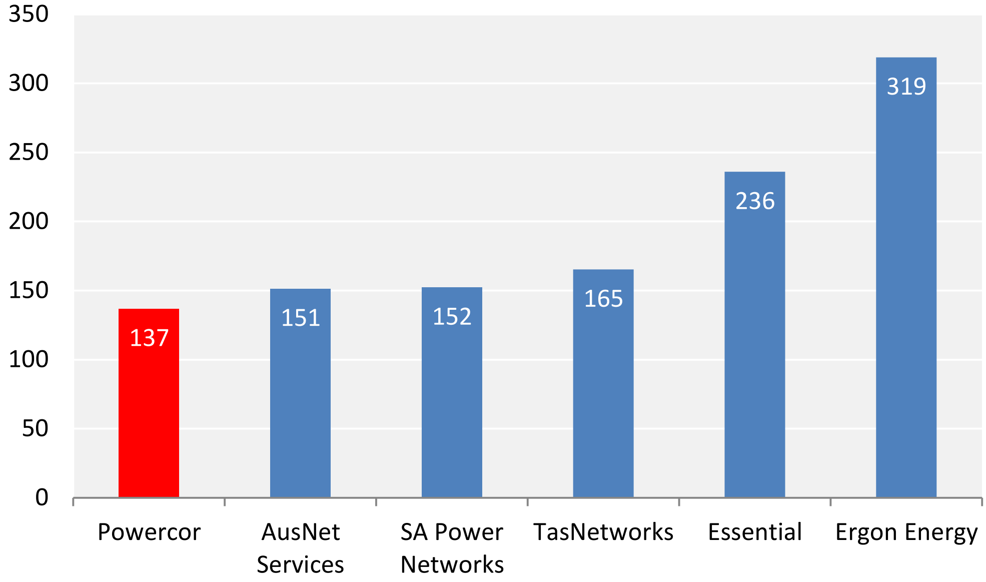
3.4 Australia's most reliable rural network

Our customers enjoy the best network availability of all Australian rural distributors at 99.96 per cent network availability.

Our reliability performance is testament to the robust asset management programs in place across the network, particularly given the often challenging conditions in which we operate, which can adversely impact supply reliability.

We have continued to perform favourably against other Australian distributors over the current regulatory control period. Despite having less than 11.4 customers per route line length kilometre and less than 12 per cent of our assets underground, we are one of the most reliable rural networks in Australia based on average minutes off supply experienced per customer.

Figure 3.4 **Unplanned number of minutes off supply per customer (average 2006-2013)**[7]



Source: AER, Electricity distribution network service providers, Annual benchmarking report, November 2014, Figure 6

Over the current regulatory control period, we have continued to target supply reliability including:

- continuation of existing asset management programs to maintain system average unplanned/planned reliability performance;
- investment in areas where localised reliability issues exist;
- improved identification and rectification of supply quality issues; and
- improved ability to detect outages through automated fault indicators.

The developments related to the bottom two points have been greatly enhanced by the completion of the smart meter program and its integration into network management systems.

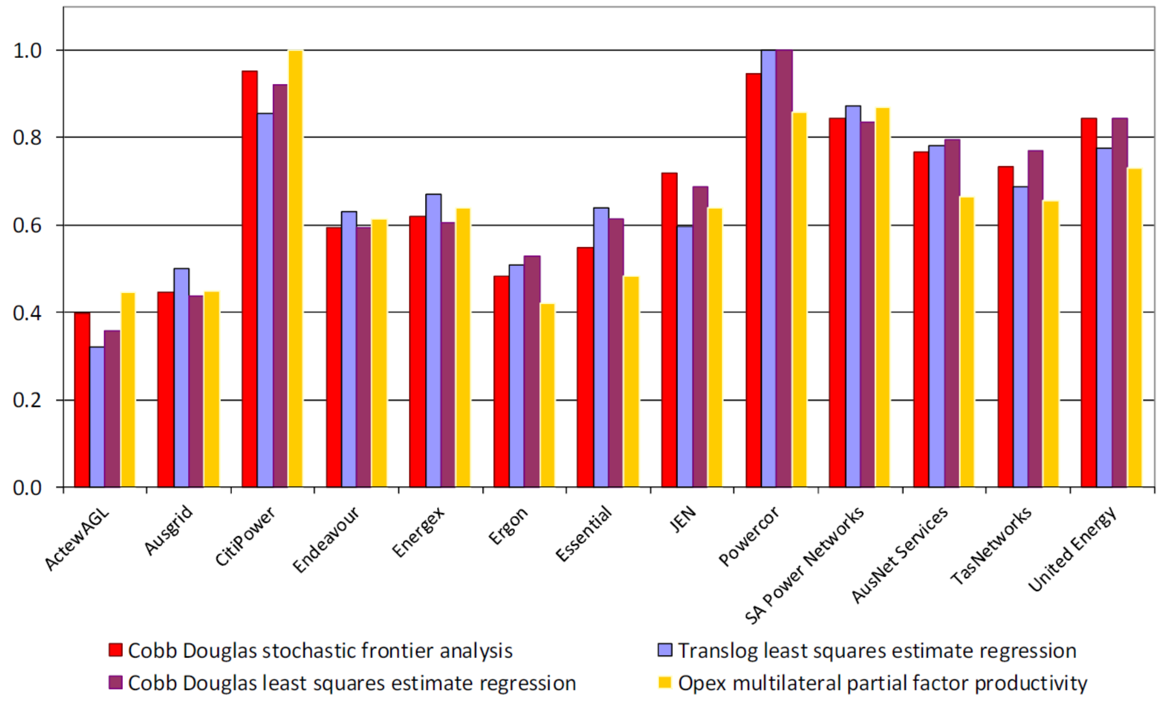
3.5 Affordability of distribution services

We take pride in our strong efficiency performance that has allowed us to deliver balanced outcomes in terms of price and quality of service for our customers. Based on the AER analysis, we have consistently been a top performer over the period 2006 to 2013.

Whilst the AER's own analysis demonstrates we are performing strongly, it should be noted this performance has been achieved despite a number of new regulatory obligations imposing additional costs, particularly in relation to vegetation management, bushfire mitigation and regulatory information notice activities (discussed further in chapter 5).

[7] The effects of major events have been excluded from the minutes off supply reported in this figure consistent with the AER's Service Target Performance Incentive Scheme Guideline

Figure 3.5 **Relative operating expenditure efficiency measures**[8]



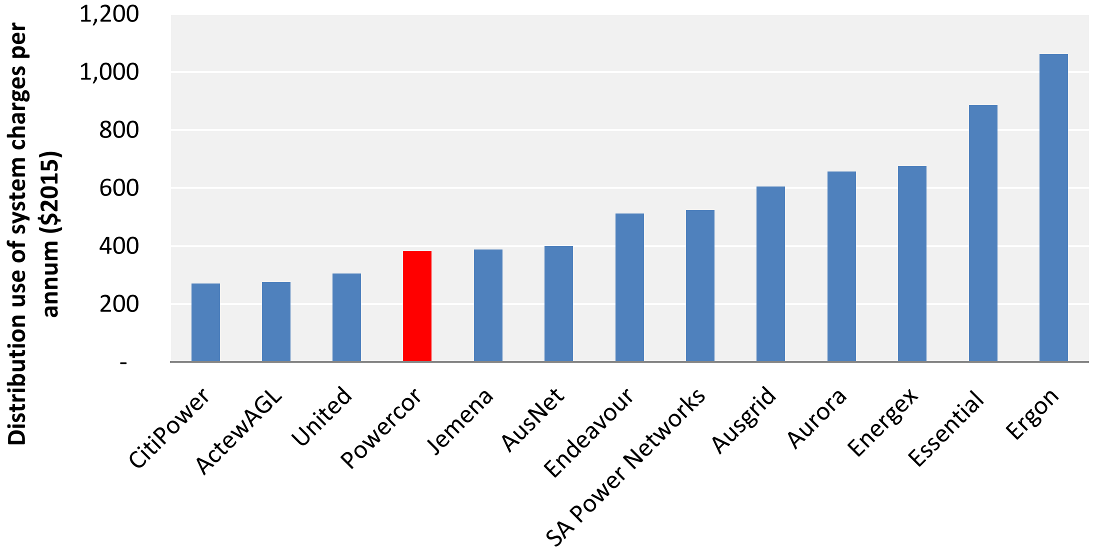
Source: AER, *Benchmarking Fact Sheet*, published 27 November 2014, p. 2.
Note a high score represents greater operating expenditure efficiency.

Strong efficiency performance has enabled our customers to benefit from some of the lowest network charges in the NEM. Independent research conducted by energy sector experts Oakley Greenwood concluded that for our customers, distribution-related costs (excluding government policy-related smart meter charges and feed in tariffs) comprise less than 25 per cent of the average household electricity bill, compared to a range of 45–50 per cent in other states and territories.[9]

Our customers also benefit from some of the lowest distribution use of system (**DUoS**) tariffs in Australia. Based on our 2015 published DUoS tariffs (ex GST and annual consumption of 4,300 kWh), our average residential customers on a single rate tariff pay $382 per annum compared to higher DUoS charges in other states, particularly when compared against other predominantly rural based distributors.

8 AER, Draft decision, Essential Energy distribution determination 2015-16 to 2018-19 Overview, November 2014, p. 53.
9 Oakley Greenwood, Powercor Pricing Comparisons, 1995 to 2009, 29 December 2014, p. 4.

Figure 3.6 Distribution use of system charges per annum ($2015)[10]



Source: Powercor

3.6 Putting customers first

Excellence in customer service and making it easy for customers is an integral component of our vision. We are committed to providing outstanding service to our customers at all times. This commitment was reflected in the Customer Service Institute of Australia presenting us the Australian Service Excellence Awards Best of the Best award in 2012.

Our Powerful Customer Service program, in place since 2011, is focused on listening to our customers and taking responsibility for their satisfaction by meeting commitments and ensuring our people follow through on the resolution of customer complaints. The success of the program over the current regulatory control period is reflected by us having:

- average complaints per 1,000 customer being consistently below the industry average since 2003;
- since 2011-2012 financial year, a significant decline in complaints escalated to the Energy and Water Ombudsman (**EWOV**), a trend welcomed by EWOV[11];
- consistently high satisfaction ratings across residential customers (85 per cent) and major customers (87 per cent).

We do however recognise there remain areas for improvement, with complaints most commonly relating to connections, meter exchanges, unplanned outages, voltage variations and disconnections. In preparing this Regulatory Proposal we have closely examined the issues underlying these complaints and, where possible, sought to implement network and service improvements.

10 All bills are ex GST and based on published 2014/15 prices. Assumes annual consumption of 4,300kWh. Assumes a flat profile and the most basic residential tariff (no electric hot water).

11 EWOV, Re: CitiPower and Powercor Australia Directions and Priorities Consultation Paper, 24 October 2014.

We have also consistently delivered high levels of appointments and connections met by the agreed date with our customers. Over the current regulatory control period, less than 0.03 per cent of connections have not been met by the agreed date.

We have also continued to meet our obligations with respect to repair of faulty street lights, repairing the overwhelming majority within five business days of the fault being reported. Over the current regulatory control period, on average, less than 2.3 per cent of fault street lights were not repaired within five business days.

At the forefront of our mind in developing this Regulatory Proposal is delivering outcomes that are consistent with the long term interests of customers. As a business, we are committed to being a 'customer centric' organisation.

We have undertaken a comprehensive customer engagement program entitled 'Talking Electricity', which aligns with the requirements of the AER's Consumer Engagement Guideline[12]. The 'Talking Electricity' program is described in greater detail in chapter 5.

In summary what we have heard from customers is that they want us to:

- run a safe electricity distribution network, particularly in respect to bushfire mitigation activities;
- focus on cost effective management of our assets and investments to maintain reliability levels, manage risk and support growth;
- get more from emerging technologies to build a more resilient network that can meet customer needs in the future;
- help facilitate customers' energy choices, educating them about new technologies and industry changes to help increase their satisfaction;
- provide improved access to data and information about energy consumption; and
- maximise opportunities to improve the service experience.

3.7 A culture of continuous improvement

Over the current regulatory control period, we have continued to find new and exciting ways to innovate and drive business and service improvements. The completion of the smart meter program in 2013 within budget and on time is already delivering significant benefits for our customers including:

- remote reading 30 minute interval data of virtually all meters across the network eliminating the costs associated with manual quarterly meter visits and special meter reads;
- remote reconnect and disconnect of a customers' premise (depending on the customers' retailer) to avoid costly and untimely truck calls when customers move in or move out;
- implementation of the Meter Outage Notification (**MON**) system which brings benefits to our customers through early identification of localised faults, pinpoints their exact location, identifies the exact time of restoration and reduces the need for field crews to undertake outage investigations. The MON system was the winner of the Innovation award at the prestigious Australian Business Awards 2014;
- accessing of voltage data to support investigation of voltage complaints in lieu of dispatching specialist crews and voltage recording equipment;

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12 AER, Consumer Engagement Guideline for Network Service Providers, November 2013

- supply status test which enables us to verify on contact from a customer whether a supply complaint is on the customer or network side of the meter avoiding a potentially costly service truck visit; and
- improved monitoring and reporting of short duration momentary outages in rural areas.

Combined these initiatives delivered more than $15.4 million in benefits to our customers in 2014.

We are also further developing the network 'smarts' that will enable enhanced load performance management (allows more efficient operation of the network), demand management technology to interface with in-home appliances (can allow more efficient capital expenditure decisions), supply capacity control (to manage and reduce the impacts of severe customer load shedding during large scale emergencies on the Victoria wide electricity grid) and tamper alarms (reducing theft and network losses).

In the field we have also sought to actively innovate over the current regulatory control period including revision of design and construction standards, purchase of new fleet, introduction of revised line practices and the rollout of workforce mobility devices to improve efficiency in the field.

We have also sought to adapt our service to meet changing customer needs, particularly in relation to transparency and more information and education. While the preferred method of contact remains the telephone, we have greatly enhanced the use of internet, SMS alerts, email and other advancing digital technologies such as our release of Australia's first outage application, meaning customers can increasingly communicate with us using the channel of their choice. Over the last two years we have invested more than $9 million in new telephony systems, and responded to requests for better access to information – we are the only distributor in Australia able to provide customers with specific information via an automated service about their property, rather than suburb, when they are calling about a power outage.

Over the next regulatory control period, we will look to further advance many of these initiatives and develop new ones to the ultimate benefit of our customers. These are discussed more fully in chapter 9 of this Regulatory Proposal and the following provides a window into some of our planned innovation initiatives.

Innovative expenditure

We are committed to undertaking a range of innovative investments to manage the network, rather than rely on traditional 'network solutions' to add new capacity or replace assets.

These innovative investments draw upon recent technological advancements to enable us to better interact with, and provide improved service to, our customers. The innovations include:

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

Our network operations centre will therefore become better informed about energy consumption and enable more efficient management of our assets. Our customers will also be better informed about how they use energy, which may lead to a change in energy consumption behaviour and thus more efficient investment decisions.

4 Our operating environment

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4. Our operating environment

4.1 Overview

In preparing our proposal, we have been cognisant of the environment in which we operate and how that may change over the next regulatory control period. Many of the unique characteristics that distinguish our operating environment from other Australian distributors are permanent, such as network structure. Other elements of our operating environment are more generic to the distribution sector and will be challenging for all distributors.

The purpose of this chapter is to bring attention to the key factors in our operating environment that have influenced the preparation of this proposal, and how they have been considered. These factors include:

- rapid change in energy markets – the distribution sector is going through a period of unprecedented change driven by smart meter technology, automation of the network and rapid growth in distributed energy resources. Keeping up with these changes requires prudent investment in information technology and supervisory control and data acquisition (**SCADA**) systems;
- customer behaviour – our customers are seeking to be better informed to enable them to exercise greater choice over how their energy needs are met. They are seeking access to this information through multiple channels. At the same time our customers are increasingly exercising their choices resulting in fundamental changes in the way energy is consumed. These changes have wide ranging impacts on our business from the contact centre through to network planning;
- a changing regulatory environment – over the past five years the regulatory framework under which we operate has undergone major transformation. Regulatory changes may impact on the incentives we face and our expenditure program into the future;
- long and 'radial' network structures – compared to other distribution networks in Australia, we operate a relatively long network, reflecting the wide geographical area serviced by our network. This is mirrored in an average of only 11.4 customers per kilometre of route line length representing the most sparsely populated network in Victoria, and one of the least populated in Australia. The long and radial nature of our network has implications for our expenditure plans in comparison with other distributors;
- ageing infrastructure - our network is growing older, as noted by Energy Safe Victoria (**ESV**)[13.]. As assets age, they may become more susceptible to faults and require greater maintenance. Increasingly it becomes more cost effective to replace these assets to manage reliability levels rather than continue repairs. This will impact replacement expenditure over the next regulatory control period; and
- bushfire threat – our network territory covers some of the most fire prone country in the world. Following the 2009 Victorian bushfires, significant changes have been made to network standards in fire prone areas that have impacted both our operating and capital expenditure plans in the next regulatory control period.

Combined, these features create a network requiring unique and relatively specialised expenditure solutions. These features also create an environment with greater susceptibility to supply interruptions and faults. Despite these challenges, we have delivered, and will continue over the next regulatory control period to deliver, strong safety, reliability and financial performance for our customers and shareholders.

The remaining sections of this chapter describe the factors above further.

[13] For example see p. 7, Energy Safe Victoria, Safety Performance Report on Victorian Electricity Networks 2013, June 2014,

4.2 Changes in the energy landscape

The landscape in which we operate is changing at an unprecedented pace. Market forces and technology are shifting the traditional linear energy supply chain to a more contemporary model where consumers become producers ('prosumers') and distributors become enablers of energy solutions.

Globally, the electricity sector is focusing efforts on 'smarter grids' as a way to make valuable infrastructure improvements, increase customer options and improve efficiency. This is in response to customers, regulators and governments[14] seeking networks that are safer, more reliable and environmentally cleaner.

Smarter grids

Smart grids can mean different things to different people. We have adopted the definition outlined by the United States Department of Energy which has identified seven traits that constitute a smarter grid:

- optimise asset utilisation and operating efficiency;
- accommodate all generation and storage options;
- provide power quality for the range of needs in the digital economy;
- anticipate and respond to system disturbances in a self-healing manner;
- operate resiliently against physical and cyber-attacks and natural disasters;
- enable active participation by customers; and
- enable new products, services and markets.

A core foundation of the move to a smarter grid has been the completion of the smart meter roll out across our network which was importantly completed on time and on budget.

Smart meters provide a view of the network never seen before, providing the ability to better manage capacity versus demand, react to changes in the network, provide greater safety margins, faster restoration time, optimised plant life and foresee critical networks events before they occur.

Already smart meters are offering customers immediate benefits including reduced costs associated with manual meter reading, remote reconnection and disconnection and automatic fault detection.

[14] For example, see Energy Market Reform Working Group, New Products and Services in the Electricity Market, Consultation on regulatory implications, December 2014

Table 4.1 describes some of the other smart meter leveraged benefits already being realised over the current regulatory control period.

Table 4.1 Smart meter leveraged initiatives overview 2011-2015

Program	Description	Benefit
Meter outage notification	Use outage data provided by smart meters in an intelligent process to generate notifications to systems that are used to co-ordinate response to outages	Greater outage clarity on the network leading to more informed outage profiling Improved outage data to use in quality related reporting
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	Supply quality monitoring Reduced operational costs Faster response to faults
Power flow analysis	Create reports in the data warehouse that can export interval data in a format suitable for existing power flow tools	More accurate network reporting Streamlined planning Capital deferment
Proactive voltage monitoring	Voltage polling tool used to investigate voltage anomalies remotely	Avoided costs associated with operational impact of solar installations Reduction in customer damaged electrical appliances
Smart meter safety reporting	Utilise smart meter data to identify safety concerns in the network	Improved safety outcomes for customers and employees Foundation established for additional smart meter reporting capabilities
Home area networks	Trial in 1,000 homes installing in-home display units bound to the smart meter via the establishment of an authorised home area network	Customers are more informed about their energy usage

Source: Powercor

In addition to smart meters, we have completed over the current regulatory control period, the first stage of our Distribution Management System (**DMS**) implementation. Already this has resulted in a single SCADA system and the associated reduction in support costs. Stage 2 of the DMS will unlock further benefits including faster fault detection, isolation and restoration, enhanced voltage control and integration of DMS with the outage management system enabling system controllers' real time network information spanning the sub transmission system through to the low voltage network.

Over the next regulatory control period we will continue to invest in new technologies that will reduce distribution costs and improve the quality of our services and provide customers with easily assessable information and encourage active participation in the energy value chain. These investments are grouped into three categories, network management optimisation, smart analytics and network innovation. When completed, these programs will deliver further benefits including:

- improved management of quality of supply compliance: improved service quality ensuring no impact on customer load side equipment;

- containing operational costs: improved operational efficiency translating over time to reduce the cost of distribution services;
- reliability: reduce current levels of supply interruptions from both planned and unplanned outages;
- capital deferment: deferment of capital expenditure associated with refurbishment or replacement of assets;
- customer engagement and service: improved customer engagement and participation resulting in increased customer satisfaction; and
- improved safety: avoidance of internal or community safety incidents resulting in avoided injuries.

Realisation of further network benefits necessarily requires investment over the next regulatory control, particularly in information technology. In proposing this investment, we have been mindful that the benefits afforded must be tangible and need to be supported by a rigorous cost benefit analysis. Further discussion of the evolution to a smart grid and its benefits are discussed in chapter 9.

4.3 Customer expectations

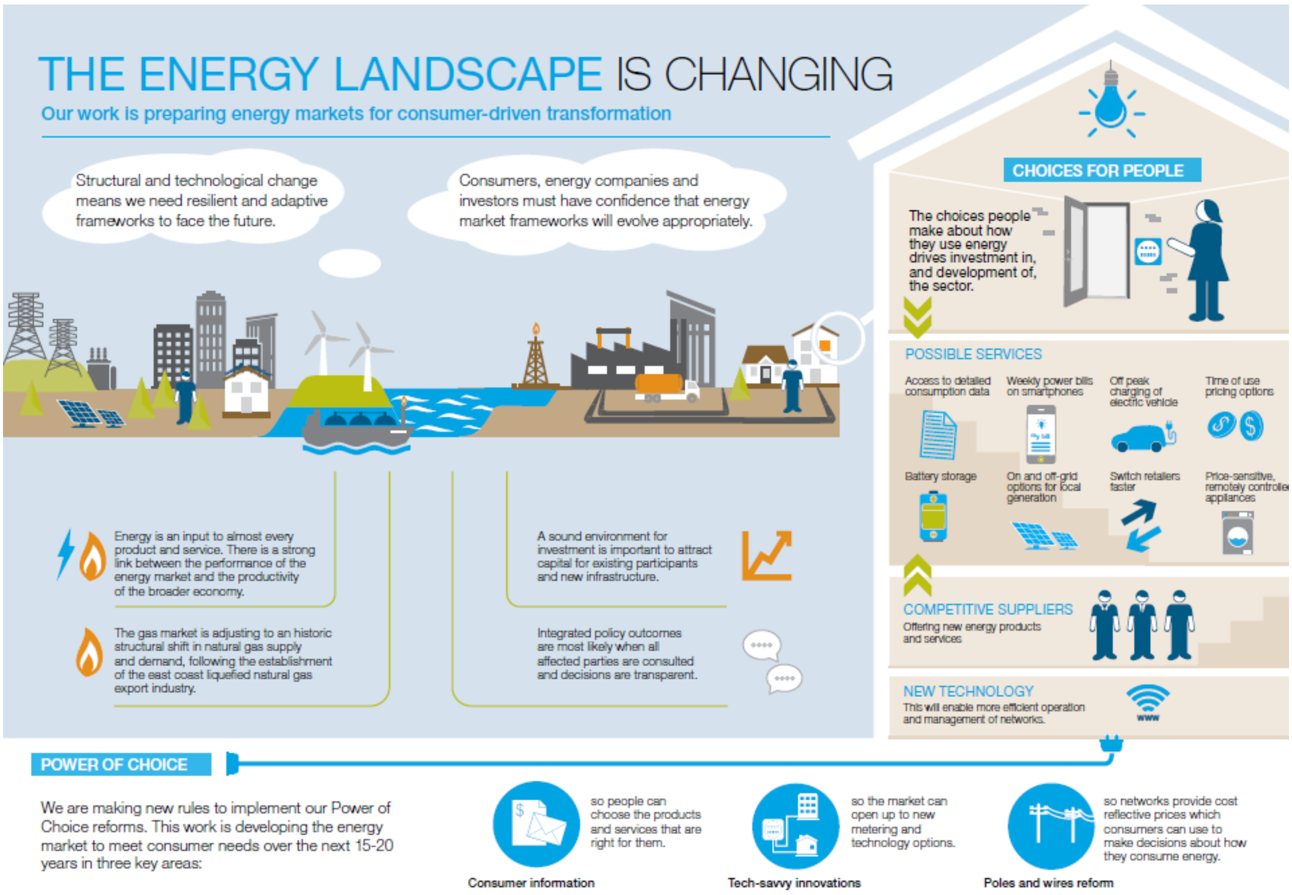
Changing customer behaviour and expectations around how they use energy and the range and levels of services they expect are changing the way we need to invest in our network over the next regulatory control period.

Our customers, due to advances in communication technology, are increasingly able to access high quality information for a range of their daily needs with few limitations on location or time due to advances in communication technology. This has raised expectations for accurate and timely information via a wide range of channels including smart phone applications and social networking sites.

Customers are also increasingly accustomed to controlling what information they receive and how they receive it using preferences, portals and dashboards, which they expect to be easy to configure themselves. Their rising expectations regarding availability, timeliness, accuracy and relevance of information will need to be met to allow us to continue to meet those expectations.

These behavioural changes are manifesting themselves in many aspects of energy markets, as noted by the Australian Energy Markets Commission (**AEMC**) in figure 4.1. These changes include our customers seeking greater choice as to how they use energy and the services they seek to use.

Figure 4.1 The changing energy landscape



Source: AEMC

As our customers' needs evolve from simple connection and fault rectification requests to more sophisticated energy management services and support queries, we will need to be ready to address the changed circumstances. For example, the take up of distributed generation such as solar photovoltaic (**PV**) and more generally, demand side management has far reaching implications for all parts of our business from the role of our contact centre and customer facing systems right through to how we plan, build, operate and maintain our network.

Our customers' changing expectations are not limited solely to the services they require but also to how their energy needs will be met in the future. These changing expectations were noted by Oakley Greenwood and the Institute for Sustainable Futures[15] who observed:

> *The electricity supply industry is undergoing a period of significant change which has the potential for major implications on Victoria Power Network's (**VPN**) business model. This has arisen due to a combination of factors including:*
>
> - *the impact of energy efficiency programs and environmental awareness and policy;*

15 Oakley Greenwood and Institute for Sustainable Futures, Scenario Development prepared for CitiPower Pty and Powercor Australia Limited, May 2014, p. 8.

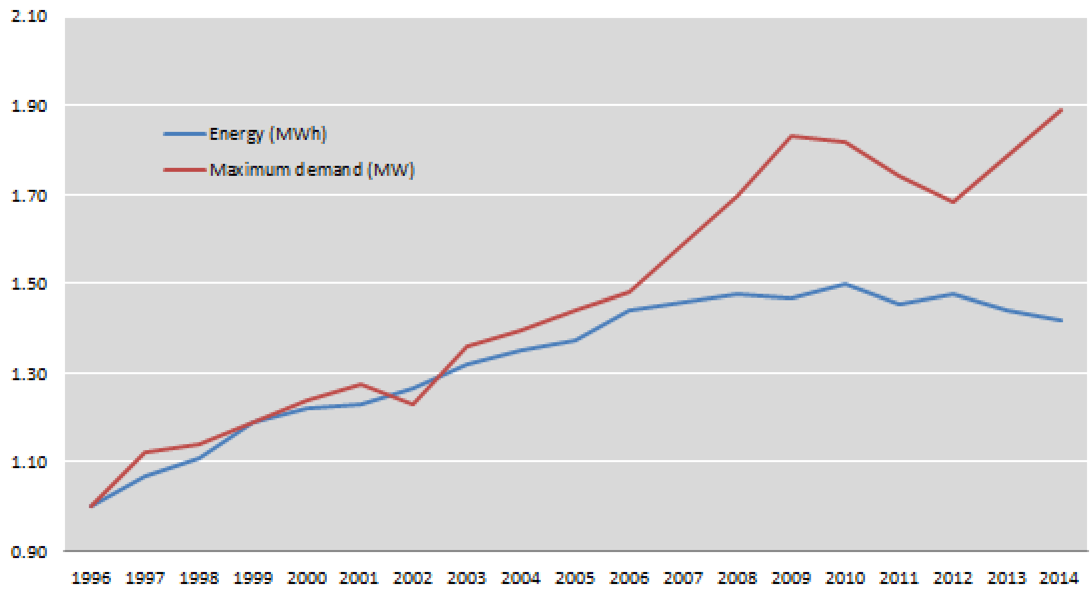
- *the rapid rise of small scale distributed generation, and in particular, solar PV at a residential level, in no small measure as a result of environmental awareness and policy;*
- *the impact and role of technological changes;*
- *the impact of the GFC on energy usage; and*
- *shifting customer and usage responses to either or both price increases and changing price signals.*

  These impacts are projected to continue into the future and potentially accelerate as new technologies become competitive and consumers become more engaged and informed with respect to energy usage, and more capable through technology, of responding to price signals. Coupled with this, the business faces a changing and potentially more demanding regulatory environment.

Already growth in solar PV is having a profound impact on when, and where, the network is utilised. It is also resulting in different customers placing different demands on the network at different times of the day.

More generally, promotion of government energy efficiency initiatives and incentives and customer concern with rising energy prices has had a strong dampening effect on energy consumption. The decline in energy consumption has not however been matched by maximum demand, which despite a decline in the period 2010–2013, set a network record in 2014.

Figure 4.2 Normalised energy and maximum demand 1996-2014



Source: Powercor

We have sought to innovatively manage the increasing divide between energy consumption and maximum demand through load management however, over the next regulatory control period, without augmentation, customers would likely face more frequent and lengthy outages. Solar PV has only marginally impacted peak demand as it typically does not operate during network peak demand.

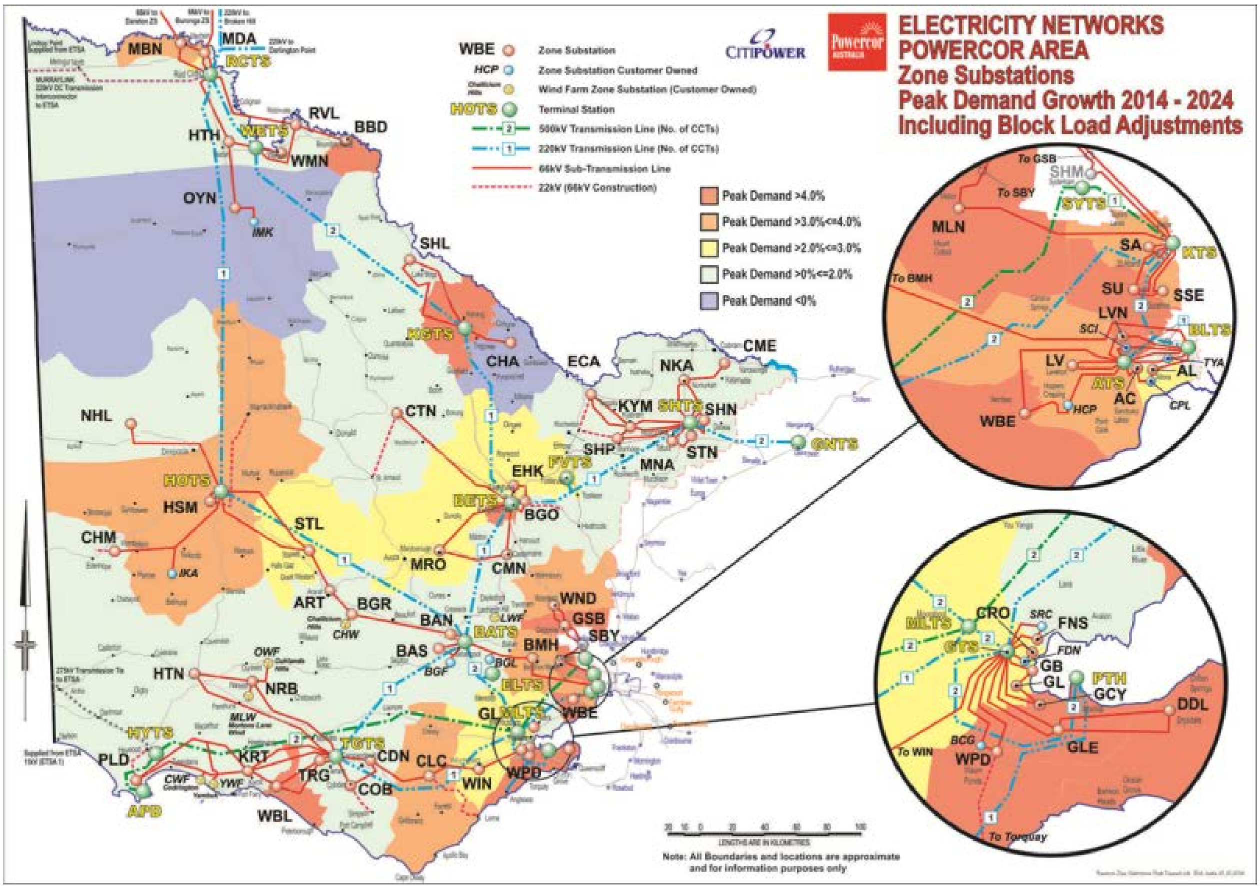
It is important to note the changes in energy consumption patterns and behaviour not only impact upon reliability but also power quality. The rapid growth of solar PV in particular, has created voltage issues in a number of areas across the network that has created physical constraints. Managing these constraints will require additional expenditure over the next regulatory control period.

Observed demand growth is also increasingly regional in nature, with strong pockets of growth across sections of our service area. Our observation of this demand growth is also supported by independent analysis undertaken by the Centre for International Economics (**CIE**), (*Forecasting Connection projects for CitiPower and Powercor*).

Demand growth is focused in strong population growth corridors around Geelong and the Surf Coast[16] and the outer north western suburbs of Melbourne. High energy use and demand from the horticultural and dry land agricultural sectors continue to grow strongly in the north west of Victoria in addition to growth in solar and biomass generation[17]. In the south west, dairy is growing strongly driven by demand in Asian markets for powdered milk products.

The diagram below sets out the growth projections for the period 2016-2020 by zone substation. It shows that demand growth in excess of 4 per cent per annum is expected across a number of zone substations including Boundary Bend, Warrnambool, Swan Hill, Waurn Ponds, Geelong East, Drysdale, Sunshine, Laverton, Werribee and Melton North. In contrast many areas across the north and west of the State are expected to have demand growth of less than 2 per cent per annum.

Figure 4.3 Zone substation spatial peak demand forecasts



Source: Powercor

16 For example see Enterprise Geelong, CitiPower & Powercor Australia Directions and Priorities Consultation Paper, 3 November 2014.

17 Mildura Development Corporation, Submission – CitiPower and Powercor Australia Directions and Priorities Consultation Paper, 3 November 2014, p. 5.

Finally, the Australian Energy Market Operator (**AEMO**) recently reviewed what customers, including our customers, are willing to pay for reliability. We are obliged to use the value of customer reliability (**VCR**) that AEMO determines from its review in assessing our proposed network investments. As a result of new VCR values, which are considerably lower than previous values, we have deferred some augmentation projects that were previously earmarked for the 2016-2020 regulatory control period. The lower VCR will also impact on reliability over the 2016-2020 regulatory control period.

4.4 A changing regulatory environment

There has been considerable change over the current regulatory control period in terms of economic and technical regulation that has, and will, impact how we operate our business.

In terms of economic regulation, we have seen the expansion of the Regulatory Information Notice (**RIN**) requirements. Whilst the Australian Energy Regulator (**AER**) has made the case that the expansion of the RIN will allow for better regulatory decision making, the incremental costs of providing the requested information is not inconsequential.

Today the majority of data provided by us is based on estimates, which are generated based on manual processes and judgement. It is understood going forward estimated data will not be acceptable to the AER beyond the 2016 reporting period. As a consequence we will require significant data, systems and most importantly, work practice changes to record and report the requisite actual data.

Other substantive economic regulatory changes have included:

- the ‘Better Regulation’ project which amongst the many Rule and Guideline changes, requires us to demonstrate our consumer engagement and focus on the long term interests of customers;
- ‘Power of Choice’ initiatives which to date have included fundamental reform of network tariff setting framework. Further change is expected to include changes to facilitate demand side response by customers; and
- introduction of meter contestability from July 2017.

There have also been a number of technical regulation changes. Most significant have been the changes associated with vegetation management clearance space requirements in high and low bushfire risk areas. Other changes have included:

- shortening of pole inspection cycles in high bushfire risk areas to 37 months;
- directions to rollout armour rods and vibration dampers in high and low bushfire risk areas;
- directions requiring us to survey, and where appropriate fit spreaders to conductors in hazardous bushfire risk areas; and
- direction to install 179 new generation automatic circuit reclosers (**ACR**s) on rural Single Wire Earth Return (**SWER**) lines.

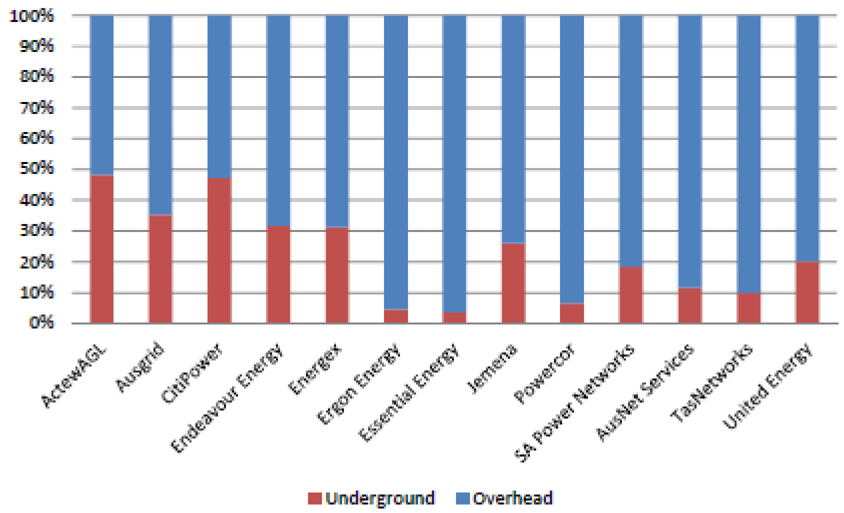
The impact of some regulatory changes are often not transparent in forecast expenditure as they are captured in larger capital expenditure projects or programs. Others however are more readily identifiable through operating expenditure step changes as identified in chapter 10.

4.5 Long and radial network structures

We deliver electricity to over 765,000 customers in a 145,651 square kilometre area, with a customer density of around 11.4 customers per kilometre of route line length.

Our network comprises a sub-transmission network and a distribution network. The sub-transmission network, which consists of predominately overhead lines, operates at 66 kV. The distribution network, again most of which is overhead, generally operates at 22kV. There is also some distribution network in Melbourne's western suburbs operating at a voltage of 11 kV. Overall approximately 88 per cent of the network is overhead, making our network one of the largest overhead networks in the National Electricity Market (**NEM**).

Figure 4.4 Proportional composition of overhead and underground circuits



Source: AER, Electricity Distribution network service providers, 2011-13 Performance report, November 2014, p. 21

The sub-transmission network is supplied from a number of terminal stations which typically operate at 220kV or greater.

The sub-transmission network nominally operates at 66 kV and is generally configured in loops to maximise reliability. However, some remote rural locations are supplied by radial 66 kV lines. The sub-transmission network supplies electricity to zone substations which then transform (step down) the voltage suitable for the distribution to the surrounding area.

The distribution network consists of both overhead and underground lines connected to substations, switchgear, and other equipment to provide effective protection and control.

Whilst the majority of the high voltage distribution system nominally operates at 22kV, there are notable exceptions:

- in remote and sparsely settled rural areas there is a substantial volume of SWER lines which operates at a nominal voltage of 12.7kV;
- in the western suburbs of Melbourne, there are three smaller areas where the high voltage distribution system operates at a nominal voltage of 11kV; and
- in the far south west of the state, there is a small SWER system supplied from the South Australian network. This system operates at 19kV.

Distribution feeders are generally operated in a radial mode from their respective zone substation supply points. In urban areas, distribution feeders generally have inter-feeder tie points which can be reconfigured to provide for load transfers and other operational contingencies.

The final supply to small consumers is provided through the low voltage distribution systems that nominally operate at 230 or 400 volts. These voltages are derived from 'distribution substations' which are located throughout the distribution network and typically range in size from 5kVA to 2,000kVA. Both overhead and underground low voltage reticulation, including service arrangements, complete the final connections to the low voltage consumer points of supply.

The long radial nature of our network has implications for the costs associated with augmenting, replacing and maintaining assets across our network. This is particularly the case when comparing our business against other more urbanised distributors.

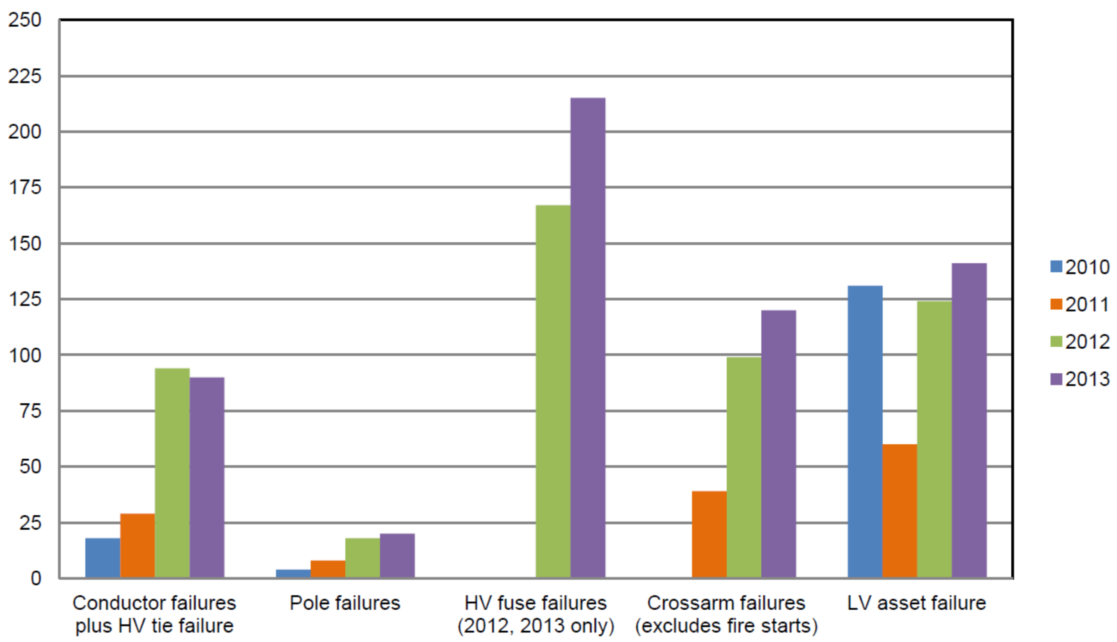
4.6 An ageing network

Our network is ageing. Many of our assets were installed during the 1950s and 1960s and are now reaching the end of their engineering life. As assets age, the number of faults observed tends to increase, often despite increased inspection and maintenance activities. This observation is noted by ESV who state:

> *some distribution MECs may be approaching the limit of risk-based or condition-based management of aging assets, and recognises the challenge in applying traditional inspection regimes to determine end-of-life for individual assets*[18]

For our network, increased failure rates have been observed across a number of asset categories as shown in figure 4.5.

Figure 4.5 **Powercor line failure and maintenance (2010-2013)**



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

[18] ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014, p.7.

We are committed to taking a targeted and cost effective approach to the replacement and refurbishment of our assets. That is why we replace assets only when its condition deteriorates to a level outside our asset management policies, rather than based entirely on age. Our approach is based on monitoring assets, and taking a risk based approach when assessing their condition, replacing or repairing an asset when it is needed to maintain reliability and/or security of supply.

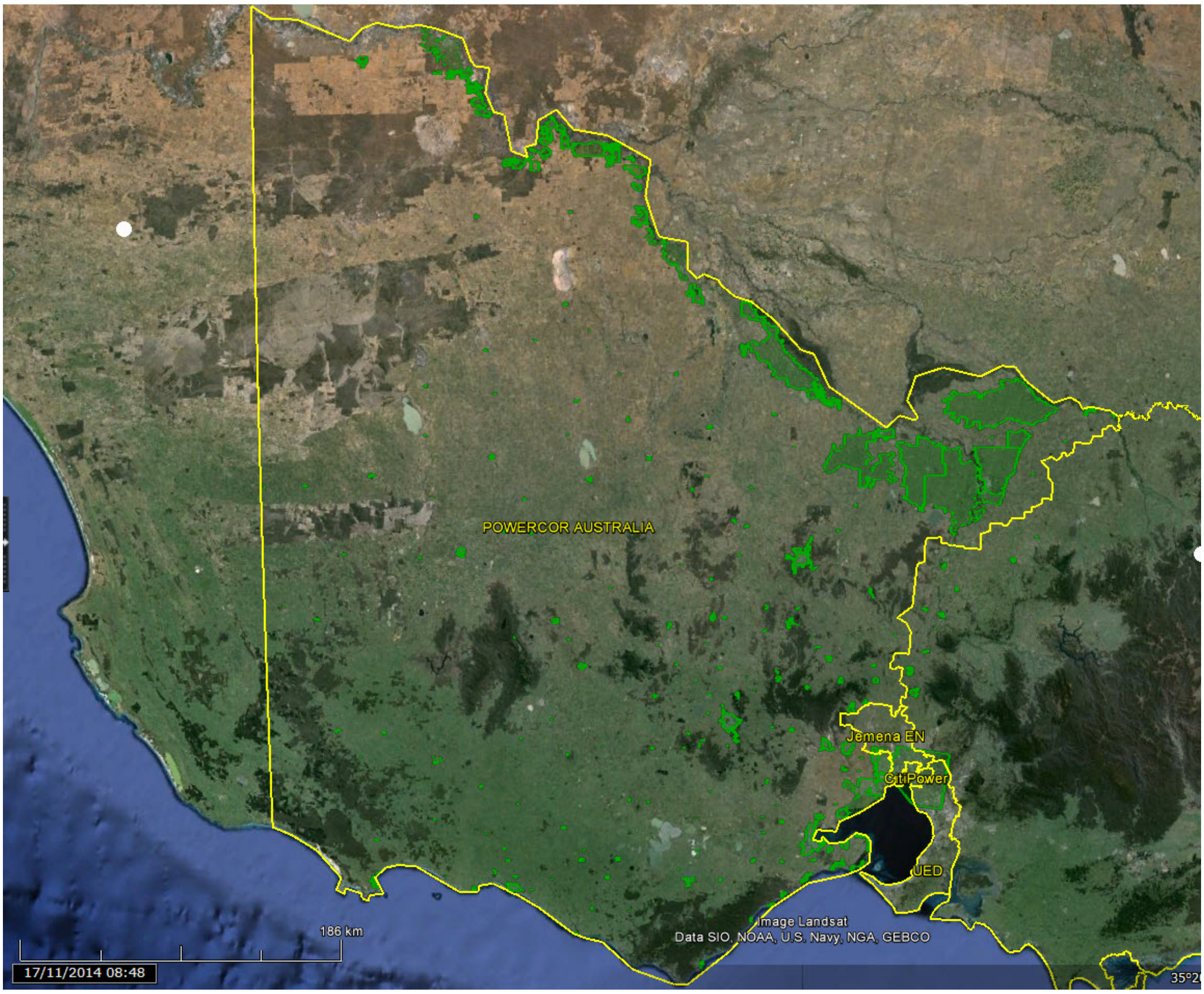
Over the current regulatory control period, we have increased our replacement and refurbishment program to manage observed fault levels. This investment will need to continue into the next regulatory control period, particularly in the areas of pole and cross arm replacement, to contain faults rates and maintain the safety of the network for the community, our customers and our employees.

4.7 Extreme bushfire threat

Victoria's unique climate and environment makes it particularly conducive to the ignition and spread of bushfire. The risk of fire start is highest over the hot and dry summer and autumn seasons. The timing and extent of annual rainfall, together with the frequency of days of extreme temperature and wind, have a major influence on the severity of Victoria's fire season.

Approximately 54 per cent of our assets, based on pole population, are located in hazardous bushfire risk areas (**HBRA**). A HBRA is defined as an area that the Country Fire Authority has assigned a fire hazard rating of 'high' under section 80 of the *Electricity Safety Act 1998*. Figure 4.6 identifies the HBRA and low bushfire risk area (**LBRA**) designations in our territory. The areas highlighted in green are low bushfire risk areas. The remainder of the service territory is designated high bushfire risk.

Figure 4.6 Identification of HBRA and LBRA areas



Source: Powercor

We take bushfire risk very seriously. We are committed to effectively, and efficiently, managing the bushfire risk our electrical assets present. In managing the risk, we work closely with a variety of parties including the Victorian Government, Country Fire Authority, Emergency Management Victoria and ESV.

Section 113A(1) of the *Electricity Safety Act 1998* requires us to submit a plan for mitigation of bushfires in relation to our distribution network. We manage bushfire risk through:

- ongoing vegetation management planning;
- continuous asset inspection and maintenance programs;
- making adjustments to the electricity network operations control systems during high risk periods;
- preparing crews across the network for the fire season; and
- more frequent inspections of overhead powerlines in HBRA.

In addition to these activities, we have installed over the current regulatory control period vibration dampers and armour rods across the majority of lines in HBRA, installed 179 new generation ACRs, increased pole inspection cycles in HBRA to two and a half years and undertaken an extensive survey of line clearances across HBRAs and where necessary, installed spreaders. Work has also commenced undergrounding identified high risk lines in the Otway Ranges.

Bushfire mitigation works are a significant component of both our operating and capital expenditure plans. We will continue to prudently manage bushfire risk over the next regulatory control period. Further detail is provided in chapter 9.

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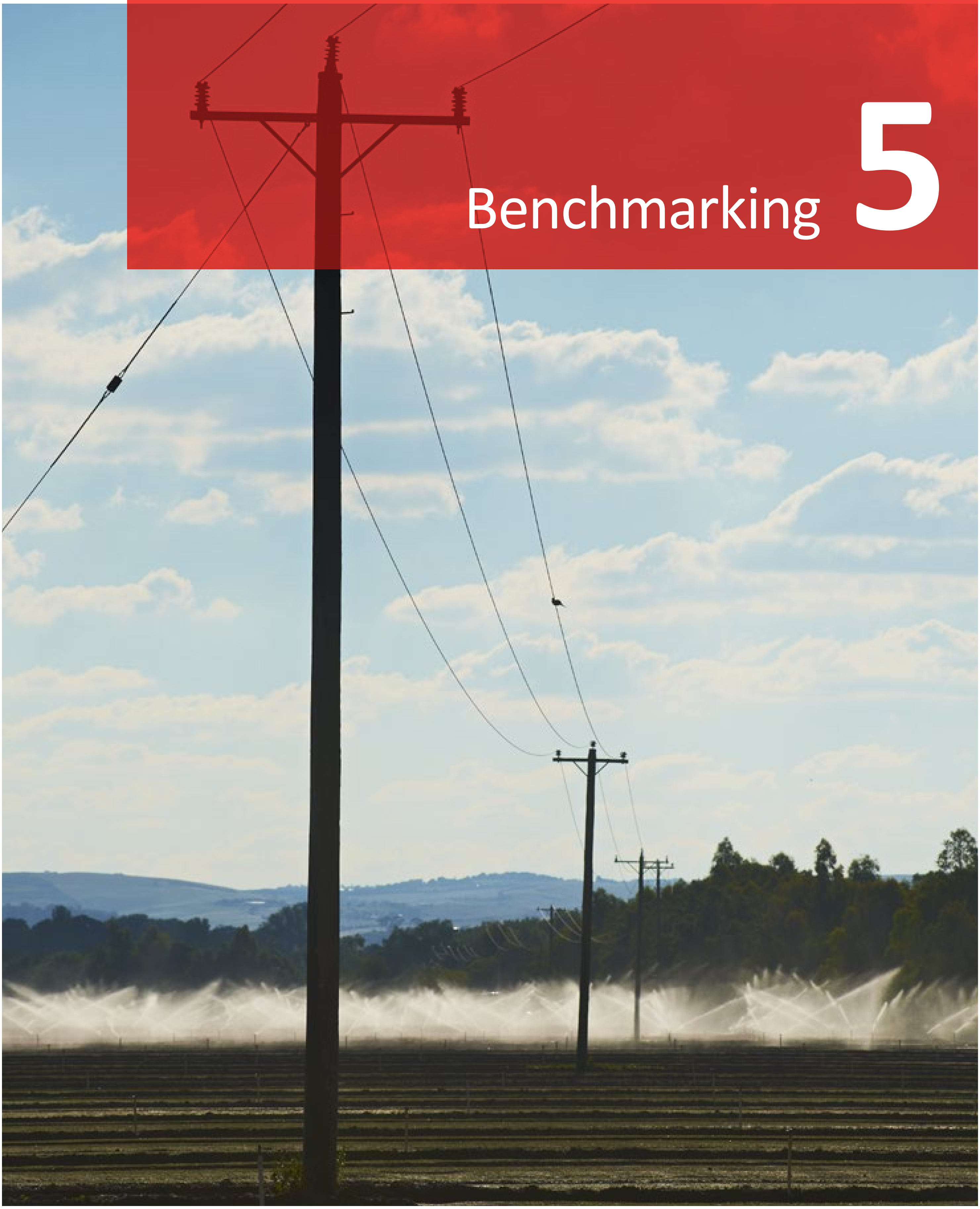
5 Benchmarking



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5. Benchmarking

We are one of the most efficient distribution networks in Australia as demonstrated by a range of benchmarking analyses.

Such an outcome is not a surprise given our track record in seeking efficiency improvements and responding to the Australian Energy Regulator's (**AER's**) incentive framework.

We have sought and achieved efficiency improvements while maintaining a strong safety and reliability record.

Our strong benchmarking performance supports the efficiency of our historical operating and capital expenditure.

We consider top-down benchmarking models provide a useful starting point for the AER to begin to understand differences in the relative performance of distributors.

Top-down benchmarking is more useful than bottom-up category level benchmarks due to its aggregated nature which is less prone to data inconsistencies.

5.1 Our performance

The AER published its first annual benchmarking report on 26 November 2014[19] and subsequently released on 27 November 2014 a benchmarking report it commissioned from Economic Insights.[20] These two reports demonstrate that we benchmark well across a range of expenditure categories and a range of benchmarking models.

Our strong benchmarking performance supports the efficiency of our historical operating and capital expenditure. We have sought and achieved efficiency improvements while maintaining a strong safety and reliability record.

5.1.1 Operating expenditure

Economic Insights analysis demonstrates our operating expenditure is efficient relative to other distributors in the National Electricity Market (**NEM**), shown in figure 5.1. This provides support to the efficiency of our historical operating expenditure for the 2016–2020 regulatory control period.

Importantly, the benchmarking analysis demonstrates that we have been responding to the Efficiency Benefit Sharing Scheme (**EBSS**) by seeking to minimise our operating expenditure continuously through the regulatory control period. Our performance under the EBSS is discussed in chapter 13.

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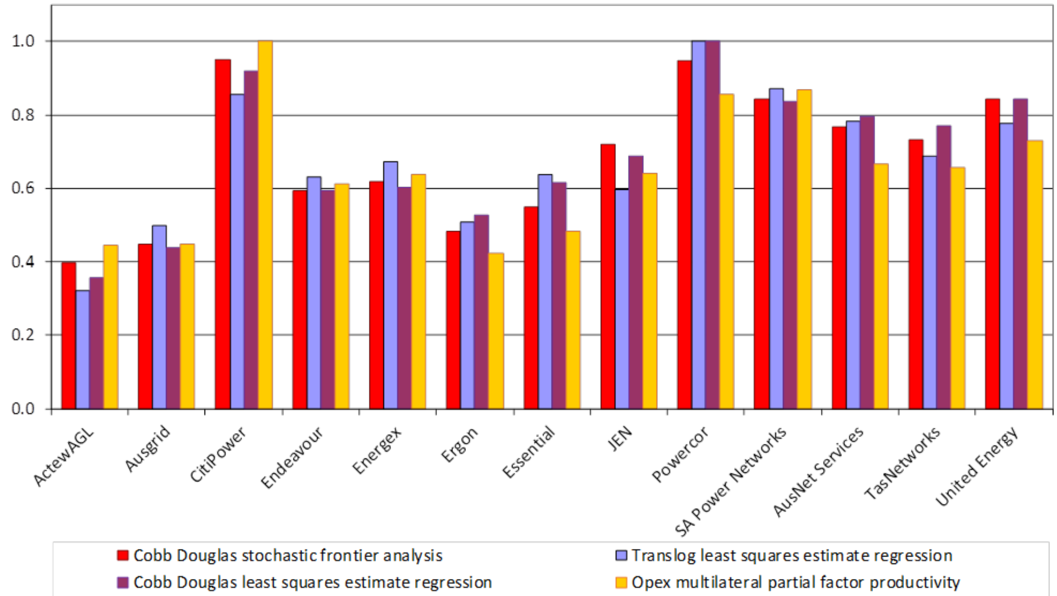
19 AER, Annual Benchmarking Report, November 2014.

20 Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, Report prepared for the Australian Energy Regulator, November 2014.

Figure 5.1 Operating expenditure efficiency scores, average 2006 to 2013



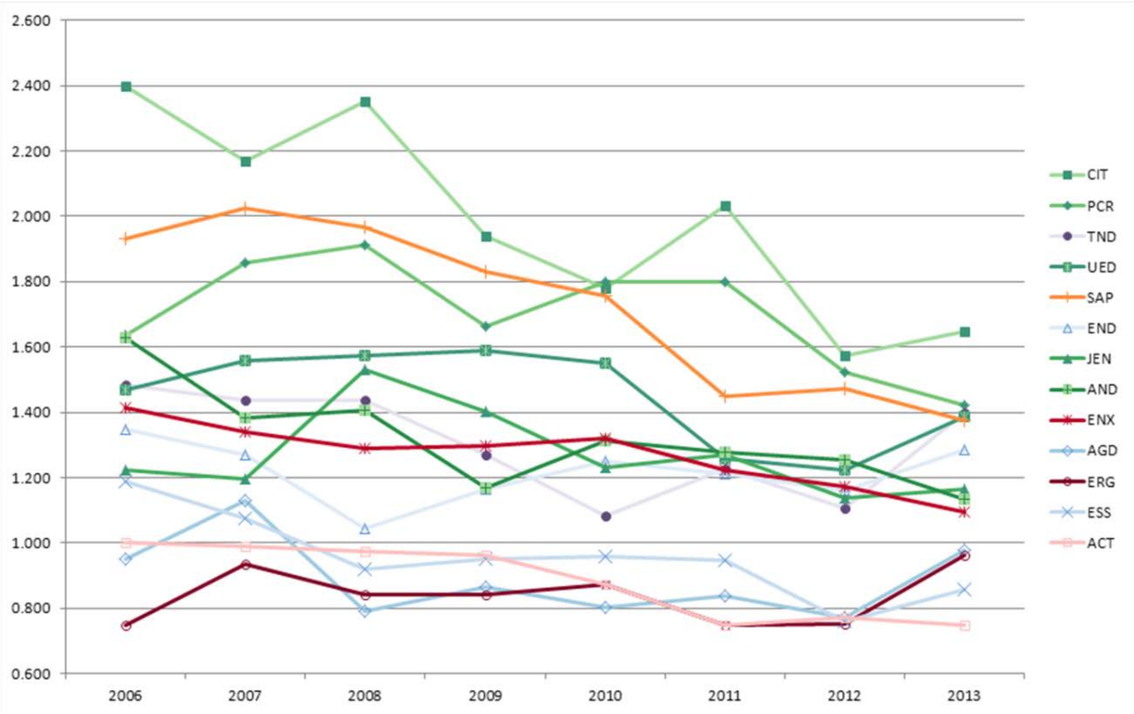
Source: AER, Benchmarking Fact Sheet, published 27 November 2014, p. 2.
Note a high score represents greater operating expenditure efficiency.

Figure 5.1 demonstrates that we have remained one of the most efficient distributors throughout the 2006–2013 period. While there has been a decreasing trend in operating expenditure productivity across all distributors, as shown in figure 5.2, this is considered to be a reflection of the increasing compliance costs required to meet regulatory obligations to achieve the operating expenditure objectives in the Rules, for example changes in vegetation management and bushfire mitigation activities as a result of the Victorian Bushfires Royal Commission findings.[21] The decreasing trend in operating expenditure productivity should not be misinterpreted as declining operating efficiency. It simply reflects cost drivers that are not captured in the model.

The benchmarking analysis demonstrates that our actual 2014 operating expenditure is an appropriate starting point for forecasting efficient operating expenditure required to meet the operating expenditure objectives for the 2016–2020 regulatory control period. As discussed in chapter 10, we have applied our actual 2014 recurrent operating expenditure as the base level of expenditure for forecasting our 2016–2020 operating expenditure requirements. Using an efficient base level of expenditure ensures that the 2016–2020 forecasts are also efficient.

21 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010.

Figure 5.2 **Operating expenditure multilateral partial factor productivity 2006 to 2013**



Source: AER, *Annual Benchmarking Report*, November 2014, figure 13.
Note: Powercor is represented as 'PCR'. A high score represents greater operating expenditure efficiency.

5.1.2 Capital expenditure

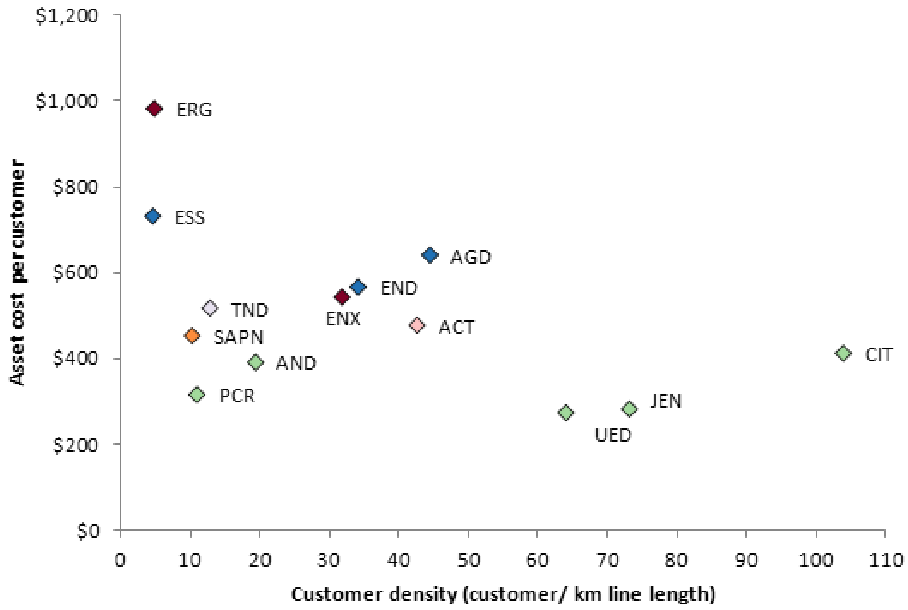
The profile of total capital expenditure is highly dependent on network conditions and customer characteristics prevailing at the time. Unlike operating expenditure, capital expenditure is not re-occurring and therefore cannot be directly compared across distributors at a point in time. For these reasons capital expenditure is more difficult to benchmark and is generally better assessed at the project and aggregated category level.

Nonetheless, the benchmarking analysis presented in the AER's 2014 annual benchmarking report indicates that our asset cost[22] per customer is one of the lowest in the NEM, refer figure 5.3. This indicates that our historical capital expenditure decisions have been efficient. Our forecast capital expenditure for the 2016–2020 period also ensures that we remain one of the most cost efficient networks in Australia.

Our performance relative to the AER's capital expenditure category models for aggregated replacement and augmentation expenditure categories is discussed in the capital expenditure chapter 9.

22 The AER calculated the annual asset cost as depreciation plus the average return on capital.

Figure 5.3 Asset cost per customer, average 2006 to 2013



Source: AER Annual Benchmarking Report, published 26 November 2014.
Note Powercor is represented as 'PCR'. A lower asset cost per customer is indicative of more efficient capital expenditure.

5.2 Role of benchmarking in regulatory determinations

Benchmarking analysis provides high level information which is a useful guide and starting point for assessing the efficiency of distributors' current and forecast expenditure. Notwithstanding the potential usefulness of top-down benchmarking, a distributor's Regulatory Proposal should remain the starting point for the AER's assessment process and benchmarking models should not be applied as a direct substitute for a distributor's forecast.

Chapter 4 discussed some of the key characteristics of our network which are important when considering our expenditure requirements and which, if not adequately taken into account, can potentially result in misleading benchmarking analysis.

The development of robust benchmarking analysis, suitable for use in regulatory assessment processes, is a long journey which requires a long term commitment from industry and the regulator to collaborate to ensure that the data is of high quality, the models are robust and uncontrollable exogenous differences between distributors are properly understood by all parties and are appropriately accounted for. The AER has only recently commenced this journey; accordingly there is still a way to go before direct reliance should be placed on the results.

At this stage, we consider top-down benchmarking models can be used as a useful starting point for the AER to begin to understand differences in the relative performance of distributors. Given current data availability and quality, top-down benchmarking is a more useful tool for assessing distributors' Regulatory Proposals than bottom-up category level benchmarking. This is because top-down benchmarking, due to its aggregated nature, is generally less prone to distortions resulting from data reporting inconsistencies and errors than bottom-up category level benchmarks. Top-down benchmarking models therefore could be used by the AER as one of a number of tools for assessing distributors' Regulatory Proposals.

In summary, we recognise that benchmarking is an important part of the regulatory framework that, when combined with other expenditure assessment methods, is a useful tool for assessing the efficiency of distributors' historical and forecast expenditure required to meet the operating expenditure and capital expenditure objectives in the Rules.

5.3 Category level unit rate benchmarking

We have reservations regarding the accuracy of the detailed level category information that is intended to be used by the AER for unit costs analysis. We also have reservations regarding whether network specific operating environment conditions impacting on unit costs can be adequately taken into consideration in category level unit costs analysis.

The following three principles should be met before comparisons of unit rates across distributors could be considered sufficiently reliable for regulatory assessment purposes:

- accurate and consistent reporting of data across distributors;
- a sufficient number of comparable projects are available to obtain a representative sample; and
- account is taken of exogenous differences in operating environment.

If the above principles are not met then differences in unit rates between distributors cannot be attributed to inefficiency with any level of certainty. This is because differences in unit rates may be a function of data inaccuracies, unrepresentative samples or exogenous differences. If these factors exist then it is impossible to isolate the difference in unit rates attributable to management inefficiency.

As discussed in the sections below, our review of the category analysis RIN data and basis of preparation documents strongly indicates that, at this stage, none of the above principles are met. We therefore consider that, at this stage, the category level benchmarking analysis should be used cautiously and the AER should give thorough consideration to the serious limitations of the data and the analysis. Until such time as the above principles can be met with confidence, we do not consider it appropriate for inferences to be made regarding efficient unit rates.

5.3.1 Accurate and consistent reporting

Unit rate calculations are very sensitive to the accuracy of the data reported by distributors. Unit rates are a function of both the reported expenditure and the reported activity volumes. Error in one or both of these can lead to significant mis-representation of the true unit costs of undertaking an activity.

At the time the AER requested the category level data from distributors, internal business systems were not in place to either collect the required data in the field or to store or report the data in the form required. This is because the type of data requested has not previously been required for business operations. In our case, our business systems do not report the information required in the form requested and consequently there is a significant level of estimation and assumption in the reported data. For example, we do not capture unit costs in performing individual tasks in the field. This is because, for efficiency reasons, field crew undertake multiple tasks in one site visit. It has not previously been necessary for every task undertaken in the field to be individually itemised, costed, time confirmed and reported. We understand that this is also the case for the other Australian distributors. Consequently the data provided by distributors in the category analysis RIN responses cannot be an accurate reflection of that requested by the AER and will not be so until business systems both in the field and back-office of every distributor are implemented to enable accurate data collection and reporting.

Additionally, as a consequence of the significant level of estimation in the category level data reported by distributors to date, differences in the estimation methods and assumptions applied by distributors to populate the data requested will also lead to comparability issues.

At this stage, our observation from reviewing the category analysis RIN data and basis of preparation documents is that data inaccuracies and differences in estimation methods are very likely to account for a large majority of the differences in distributor's unit rates calculated from the category analysis RIN data.

5.3.2 Representative sample

For unit rates to be comparable across projects and across distributors it is necessary for the sample of projects to be representative of a typical project undertaken in the industry. This requires a sufficiently large sample of similar sized projects be included in the unit rate calculations. The sample should cover a sufficient number of projects for each distributor to ensure the average unit rate is reflective of the industry.

Where there is a small sample size, the unit rates are unlikely to be representative of a typical project for the industry because:

- unusual projects can receive too much weight in the unit rate calculation; and
- projects of a particular distributor may receive too much weight in the calculation, resulting in a unit rate which is overly representative of a distributor's specific network characteristics.

Our observation from reviewing the category analysis RIN data is that in many cases, there is an insufficient sample of similar projects for the derived unit rates to be representative of a typical project that could be undertaken by any distributor in the NEM.

5.3.3 Accounting for exogenous differences

Differences in unit rates between distributors may also be due to exogenous differences in network operating environments. The AER acknowledges that differences in costs can arise from network operating environments, for example differences in network density and location:

> *'We consider a key driver of the cost of replacing an asset is its location on the network. We would anticipate that assets in geographically remote segments of the network would encounter extended travel costs to service its assets. Conversely a NSP with a highly dense network would have higher traffic management or other civil costs.'*[23]

We are in a unique position to demonstrate the likely magnitude of the contribution that differences in network operating environments can make to differences in unit costs. The Powercor and CitiPower networks are operated under the same management team, with the same business systems and processes. Powercor's network has relatively low customer density on average and very low density is specific parts of the network, for example the Mallee and the Wimmera in north-west Victoria. Conversely, CitiPower's network is concentrated in Melbourne's Central Business District and has the highest customer density of the distributors in the NEM.

Due to the joint management of these two networks, differences between CitiPower and Powercor's unit rates are not attributable to differences in data collection or reporting. Differences in the unit rates are therefore primarily attributable to differences in external operating environment factors.

As demonstrated in chapter 4, the contribution of operating environment conditions to differences in unit rates between distributors is potentially very large. Consequently, we do not consider that, at this stage, sufficient normalisation of data is undertaken to enable inferences to be made about the extent that inefficiency is a contributing factor to the differences in unit rates between distributors.

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[23] AER, *Better regulation, Explanatory statement, Final regulatory information notices to collect information for category analysis*, March 2014, p.57.

Our customer engagement 6

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6. Our customer engagement

We take very seriously our responsibility to deliver electricity to all customers safely, reliably and efficiently. We also have a responsibility to work with our customers and diverse stakeholders to understand their requirements to ensure that we continue to deliver services that meet their needs now and in the future.

We have a proud history of customer engagement and for building, maintaining and enhancing effective relationships and dialogues with our customers. Our customer engagement includes a number of activities such as our:

- active customer consultative committee;
- Regional Business Managers (formerly referred to as Regional Asset Managers) who are responsible for developing and maintaining relationships with our major customers throughout our distribution network; and
- routine monitoring of customers’ satisfaction, in particular we undertook significant community engagement activities to support the successful rollout of smart meters to over 99 per cent of our customers.

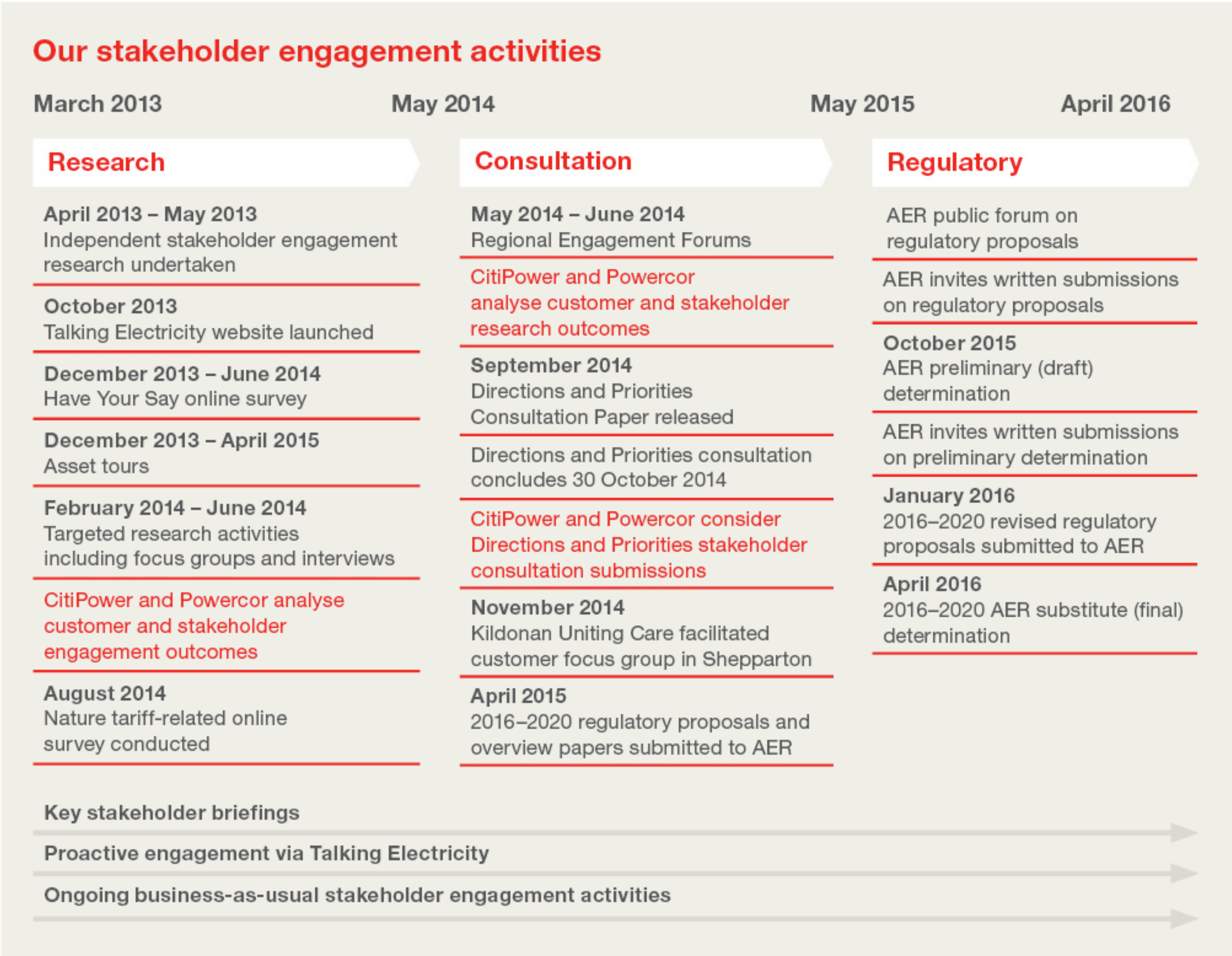
A comprehensive review of the effectiveness of our business as usual engagement activities was undertaken during early 2013 and this review, combined with recent stakeholder engagement experience from utility businesses both in the United Kingdom of Great Britain (**UK**) and in Australia, was incorporated into the development of our Price Reset Stakeholder Engagement Program. In parallel, we provided input to the Australian Energy Regulator (**AER**) as they developed the *Consumer Engagement Guideline for Network Service Providers* (**Consumer Engagement Guideline**).

The cornerstone of our Price Reset Stakeholder Engagement Program was the importance of commencing our engagement activities early enough to enable plenty of time for effective engagement as well as enough time to consider customer feedback and factor the feedback into the development of our Regulatory Proposal for the 2016-2020 regulatory control period.

6.1 Overview of our engagement program

To guide the development of our Regulatory Proposal, we designed and implemented our comprehensive Price Reset Stakeholder Engagement Program (**engagement program**), the objective of which was to engage with our customers and stakeholders in order to understand their current and future needs, concerns and preferences. An overview of our engagement program is provided in figure 6.1.

Figure 6.1 **Our price reset stakeholder engagement program**



Source: Powercor

Objectives

Our objectives for the engagement program were to:

- help our customers and stakeholders gain a better understanding of the electricity industry and raise their awareness of our role;
- successfully communicate our price reset-related plans to all customers and stakeholders via open and clear channels with a view to those customers and stakeholders becoming informed participants in the price reset (also referred to as regulatory determination) process;
- ensure we were positioned to listen early to our customers' and stakeholders' concerns;
- better understand the views and preferences of our customers and stakeholders;
- assess the concerns and issues raised and our potential to address them;
- provide prompt and clear feedback to our customers and stakeholders on our assessment and how we are planning to incorporate the feedback into our future plans;

- use the feedback we received from customers and stakeholders to help shape our Regulatory Proposal;
- be inclusive and clearly outline what our customers and stakeholders could expect from us via our engagement activities;
- demonstrate an evidence based process;
- implement good engagement practices and share our learnings with other distributors;
- comply with regulatory guidelines, including the AER's consumer engagement guideline for network service providers; and
- provide an ongoing platform for future engagement activities.

Our engagement program was managed and co-ordinated by stakeholder engagement experts from within our business and was supported by market research organisations including one of Australia's leading market research organisations, Colmar Brunton.

Colmar Brunton designed and hosted our price reset online survey, designed and facilitated the residential customer focus groups and conducted interviews with our small/medium enterprise and large business customers. This ensured independence of our quantitative and qualitative market research activities, the objective of which was to provide confidence that our customers' views were obtained in a robust and credible manner. The research approach and results were formally documented by Colmar Brunton and have been published on our Talking Electricity website.

During the second half of 2014, Nature (quantitative market researchers) were engaged to design and host an online survey to understand our customer's views on peak rebates and maximum demand tariffs, the results of which can also be found on our Talking Electricity website.

The AER's Consumer Engagement Guideline, issued in November 2013, provides a high level framework based on best practice principles drawn from the Stakeholder Engagement Standard (AA1000SES) and the International Association of Public Participation (**IAP2**) framework. Drawing on AA1000SES and IAP2, the guideline outlines four best practice principles that should guide all aspects of Network Service Providers' customer engagement. The principles require all components of engagement to be:

- clear, accurate, relevant and timely;
- accessible and inclusive;
- transparent; and
- measurable.

Our engagement program was designed to comply with these principles and, in addition, we adopted a best practice approach to stakeholder engagement based on an adaption of the highly respected IAP2 spectrum.

The IAP2 spectrum is an internationally recognised, best practice framework designed to assist organisations select the appropriate level of engagement for different stakeholder groups. Recognising that there is no 'one right' approach to stakeholder engagement, the spectrum provides us with a flexible framework for successful stakeholder engagement.

The spectrum provides five engagement levels – inform, consult, involve, collaborate and empower – and depending on the current involvement or activity with each stakeholder group, their level of influence on us and their level of dependency on our success, they can be organised and prioritised for different levels of engagement. Depending on the involvement stakeholders currently have with us and our goals, some stakeholders will require higher levels of engagement than others, and some will need to be taken on a journey over a longer period of time. As part of the planning of our engagement activities, an IAP2 assessment was undertaken to confirm the desired engagement level of each activity.

Our engagement program has utilised a variety of channels and engagement tools to effectively engage with our diverse stakeholders to obtain feedback from our customers about our current and future services. This feedback has been considered in the development of our future business plans and our expenditure forecasts for the 2016-2020 regulatory control period. Table 6.1 summarises our assessment of our engagement program against key performance benchmarks based on the AER's consumer engagement guideline.

Table 6.1 Our engagement program alignment with key performance benchmarks

Performance benchmarks	Alignment
Clear, accurate, relevant and timely	✓
Accessible and inclusive	✓
Transparent	✓
Measurable	✓

Source: Powercor

We are proud of our comprehensive price reset engagement program and believe that it meets the requirements for effective customer engagement as outlined in the AER's consumer engagement guideline and aligns with the IAP2 framework.

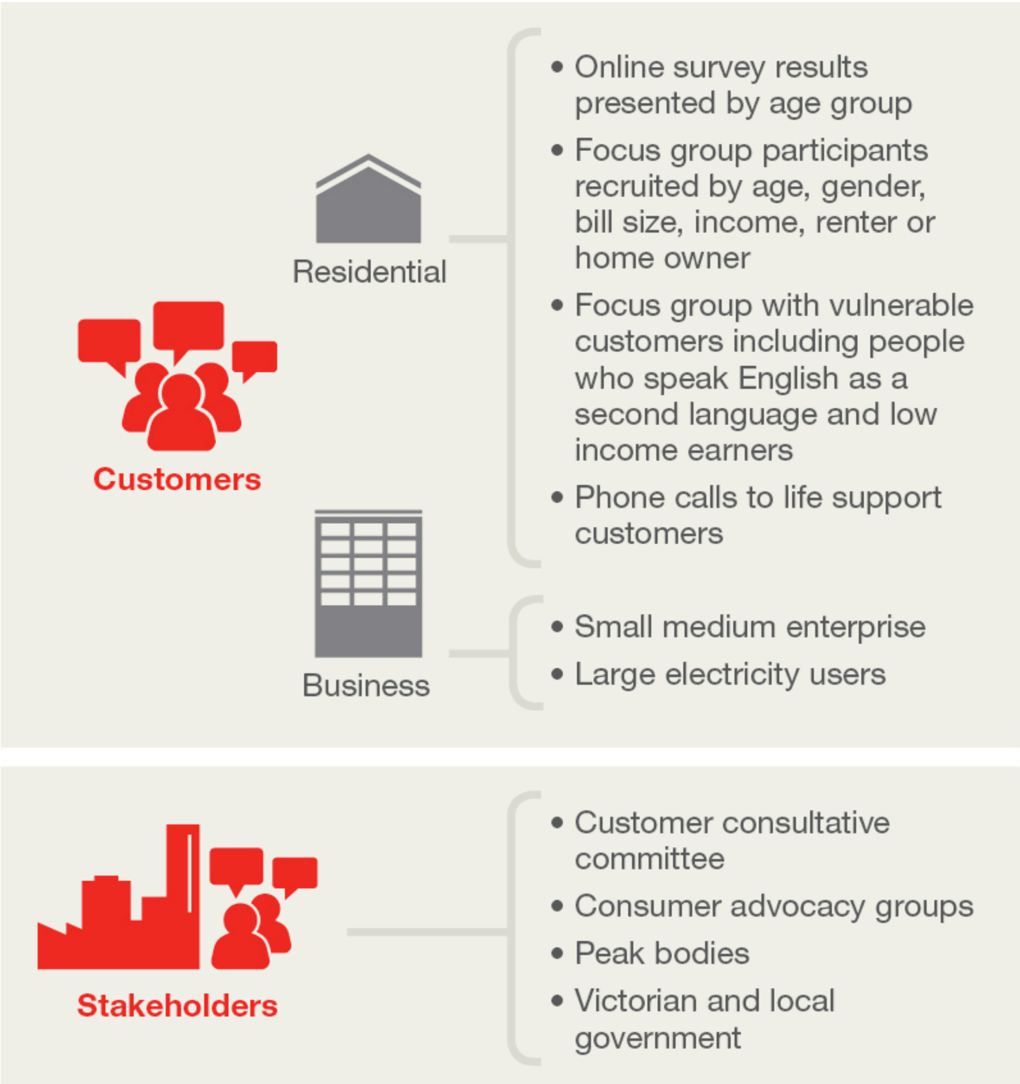
TalkingElectricity.com.au website and appendix A provides details of our approach, background information, research findings and all outputs from our engagement program.

6.2 Our customers and stakeholders

We have over 750,000 customers, 86 per cent of which are residential customers and 14 per cent are business customers.

As part of our engagement program planning, we identified different customers, customer cohorts and stakeholders to be engaged through a variety of engagement activities. Figure 6.2 summarises our customers and stakeholders.

Figure 6.2 Our customers and stakeholders



Source: Powercor

6.3 Our engagement approach

6.3.1 Overview

As outlined in figure 6.3, our engagement program encompasses three phases.

Research phase

Our research phase focussed primarily on informing our customers and stakeholders about who we are, our role in the supply of electricity and the services that we provide, engaging with our customers and listening to what our customer and stakeholders think about our current services, our performance and their future needs.

Market research undertaken during April 2013 as part of the review of our business as usual stakeholder engagement activities highlighted the fact that over half our customers surveyed, particularly residential customers, did not know who we were, our role in the supply of electricity and the services that we provide[24].

Consultation phase

Our consultation phase focused on involving our customers and stakeholders and was designed to progress and integrate customer expectations and concerns into our planning for the 2016–2020 regulatory control period. Key elements of this phase included our regional engagement forums and our 'Directions and Priorities' consultation, together with a targeted focus group. This phase will culminate in the submission of our Regulatory Proposal to the AER on 30 April 2015.

Regulatory phase

The regulatory phase is focused on the AER's evaluation of our Regulatory Proposal. This phase includes opportunities for our customers and stakeholders to provide feedback to the AER on our proposed expenditure plans and our required revenue for the 2016-2020 regulatory control period as part of the AER's consultation activities.

6.3.2 Our engagement activities

The engagement activities covered all customer segments and key stakeholder groups across our electricity distribution area. Opportunities to participate were widely promoted; we made use of independent market research experts, involved senior management and subject matter experts and aimed to reach different customer segments in a variety of ways. Refer to figures 6.3 to 6.5.

Appendix A provides more details on our engagement activities.

Figure 6.3 Engagement activities timeline

Source: Powercor

[24] UMR Research, CitiPower-Powercor Consumer survey May 2013 Final: '41% can name Powercor as their distributor'

Figure 6.4 Research phase activities overview

Source: Powercor

Figure 6.5 Consultation phase activities overview

Source: Powercor

6.4 What our customers and stakeholders have told us

6.4.1 Customer expectations

Through our engagement program, our customers and stakeholders told us what they want from Powercor during the upcoming five year regulatory control period. This feedback has informed our plans and, as a result, we are confident that our Regulatory Proposal delivers on the expectations of our customers.

Customer expectations have been summarised into six key insights:

- customers want reliable supply for a reasonable price;
- they want efficient and targeted investment across our networks;
- customers want us to pay close attention to safety and maintenance and they support additional investment in activities that reduce risk of fire danger;
- they expect forward and proactive planning to ensure the integrity, capacity and capability of the network;
- future needs are best met by a smart grid to enable choice and flexibility, taking pressure off the existing network and facilitating the connection of renewable energy sources; and
- customers want greater access to readily understand information about their electricity usage.

6.4.2 How we are responding

The integration of customer expectations and concerns into our planning is an important part of developing our Regulatory Proposal. Table 6.2 illustrates how the engagement outcomes have been factored into our Regulatory Proposal and long-term business plans.

Table 6.2 Our response to your feedback

What you said	What we will do
You want a safe, reliable electricity supply at a reasonable price. Most people (83 per cent of survey participants) are satisfied with the current reliability of their electricity supply and do not want to pay any more to improve it. Some regional customers say we could do more to improve reliability in regional and rural areas. Larger business customers stressed the critical importance of continuous, uninterrupted, reliable supply of electricity to their organisation, with the implications of any interruption in supply of electricity representing a major cost to business.	We will take a cost efficient approach to all our investment decisions so we deliver the best long term outcomes – this is about balancing cost savings with the need to maintain a safe, reliable electricity supply. Through the ongoing assessment of the condition of our assets, we have identified a number of areas which require upgrades and we plan to replace more of our ageing infrastructure.
Dairy farmers want a greater level of reliability in rural areas.	We are planning targeted investment to replace some of our older infrastructure in regional and rural areas and will fund a continuing program to upgrade overhead lines.
Absolutely no risks to be taken when it comes to fire related safety and take all reasonable measures to protect the safety of customers and their communities. Survey participants were happy to accept a small price increase that contributed to reduced risk of fire danger.	Safety is our number one priority. We will continue to undertake all reasonable steps to ensure ongoing community safety including the ongoing maintenance of our electricity assets. We will continue to invest in bushfire mitigation activities and prudently and efficiently implement measures to mitigate fire risk. Under the Victorian Government's Powerline Replacement

What you said	What we will do
	Fund, we will underground powerlines in high risk areas.
A clear preference for the development of a wider safety campaign targeted at all of those that come into contact with the electricity network (as opposed to specific messages targeted at specific groups).	We will work with Energy Safe Victoria to promote community safety.
Targeted investment to support growing areas of the State.	We have identified areas that are growing and will invest to support residential, commercial and industrial growth in these regions.
Large energy users expressed a desire for stronger partnering in the form of Powercor taking a lead role in infrastructure investment, and in one case, investing in infrastructure to attract more business to the Mildura region.	We are committed to partnering with local government and businesses to identify areas of growth and ensure appropriate targeted investment occurs. Under the current regulatory framework, we cannot build infrastructure without clear drivers for growth.
Undergrounding was seen as a necessity (but dependent on a cost-benefit analysis); with general consensus that new developments and fire prone areas should include undergrounding and that outdated poles/wires should be replaced with an underground equivalent. Infrastructure for new suburbs to be forward thinking and well considered, and to include undergrounding.	Developers of new subdivisions are generally required to underground electricity cables. Undergrounding existing power lines is expensive and would impact on customers' bills. Some undergrounding can take place if customers directly benefiting from the work are prepared to pay or work with their local council to secure funding. We will continue to work with local authorities and customers who commission projects to put lines underground.
Most are happy with our current vegetation management practices but some would like less pruning of older trees in town centres. There was minimal interest in trees being trimmed lightly and regularly (57% of survey participants were not willing to pay a small increase in return for trimming vegetation more frequently and less severely). The preference was either to trim them heavily or remove them.	We will maintain our commitment to vegetation management practices that balance safety with affordability. We will continue to work with local government to ensure local interests are taken into consideration.
Residential customers are generally happy with our connection processes but remotely based customers feel connection costs are excessive. Commercial customers expect Powercor to be transparent and work to exact timelines.	We will automate our standard connections processes to make it easier, faster and cheaper for customers. We will continuously explore ways to improve timeliness and quality of service to connect large customers. We will effectively communicate the time needed to develop the right solutions for complex connections.
Enable the connection of more renewable energy generation, particularly in solar and wind technology – this is a key regional priority. Some customers have not been able to connect larger solar photovoltaic systems because of network limitations. Regional development associations see the connection of wind and solar energy as a priority for their areas and want us to be proactive in enabling these connections.	We are enabling the connection of several large wind farms in western Victoria during the upcoming five year regulatory control period. In addition, we are investing in technology to better control voltage levels so we can connect more rooftop solar panels.
Install more energy-efficient street lighting.	We are working with local councils to introduce new types of

What you said	What we will do
	energy-efficient street lights and will continue to be directly involved in the 'Lighting the Regions' project involving multiple councils across Victoria.
Greater access to smart meter data, via an online portal, would give you greater ability to manage electricity use and power bills. You wanted easy-to-access, easy to understand information.	We are planning to invest in a customer relationship management system and online customer portal so customers can access their electricity usage data and manage their electricity bills.
A smart grid is a necessary initiative worthy of investment. It was generally felt that future needs would be best met with a smart grid to enable choices and flexibility, and take pressure off the existing network and traditional sources of power. Powercor needs to be forward thinking rather than just upgrade infrastructure.	We will invest in the development of a smarter network by using advanced technologies that create efficiencies and improve reliability and safety. We will investigate demand-side solutions to meet localised energy requirements during peak periods, and the application of new technologies such as batteries, cold storage and off-grid solutions.
Speed of responsiveness is expected when issues occur, particularly issues relating to motor vehicle accidents and wind/weather related outages.	Our call centre and website provide channels for our customers to contact us. In addition, we currently provide outage information through our website and apps, and SMS notifications straight to customers' phones. We will continue to look at ways of improving our communications on an ongoing basis.
Engage with us more effectively – you welcomed the opportunity to participate but want more information about issues.	We are extending our engagement program by consulting on our future tariff structures as well as issues affecting customers' electricity supply and energy choices.
You want flexibility and don't want to be disadvantaged by any changes to tariff structures. Different types of tariffs are confusing. There are concerns that locational tariffs may disadvantage some customers and there are conflicting views on maximum demand tariffs.	We are extending our engagement program by consulting on our future tariff structures for the 2016-2020 regulatory control period. We are currently considering a number of options, including rebates for lower energy use as well as tariffs for peak demand periods.

Source: Powercor

6.5 Conclusion and next steps

We are proud of our price reset stakeholder engagement program and believe that it has been 'fit for purpose' given the nature of our business and our customers' level of knowledge of our role and services, as well as the regulatory determination process.

Our Talking Electricity website and electronic newsletters will contain information about the AER's consultation process and any upcoming public forums on our Regulatory Proposal.

Learnings from the Price Reset Stakeholder Engagement program will help refine the business wide stakeholder engagement approach which is being refreshed in 2015 to ensure that it remains aligned with our current and future priorities.

In early 2015, our Customer Consultative Committee was refreshed and membership increased to capture a broader range of views. The refresh incorporated feedback obtained during consultation activities during 2013 and 2014 as well as leveraging 'best of breed' approaches to consultative committees from utility peers worldwide.

It takes time to develop, maintain and enhance longer term relationships with our customers, our stakeholders and their advocates. Through our price reset engagement activities, we have strengthened existing relationships and developed new relationships that we will maintain and enhance on an ongoing basis.

We are continuing to evolve our engagement approach across all our business activities to ensure that our business focus and our strategic priorities remain firmly focused on the long term interests of our customers.

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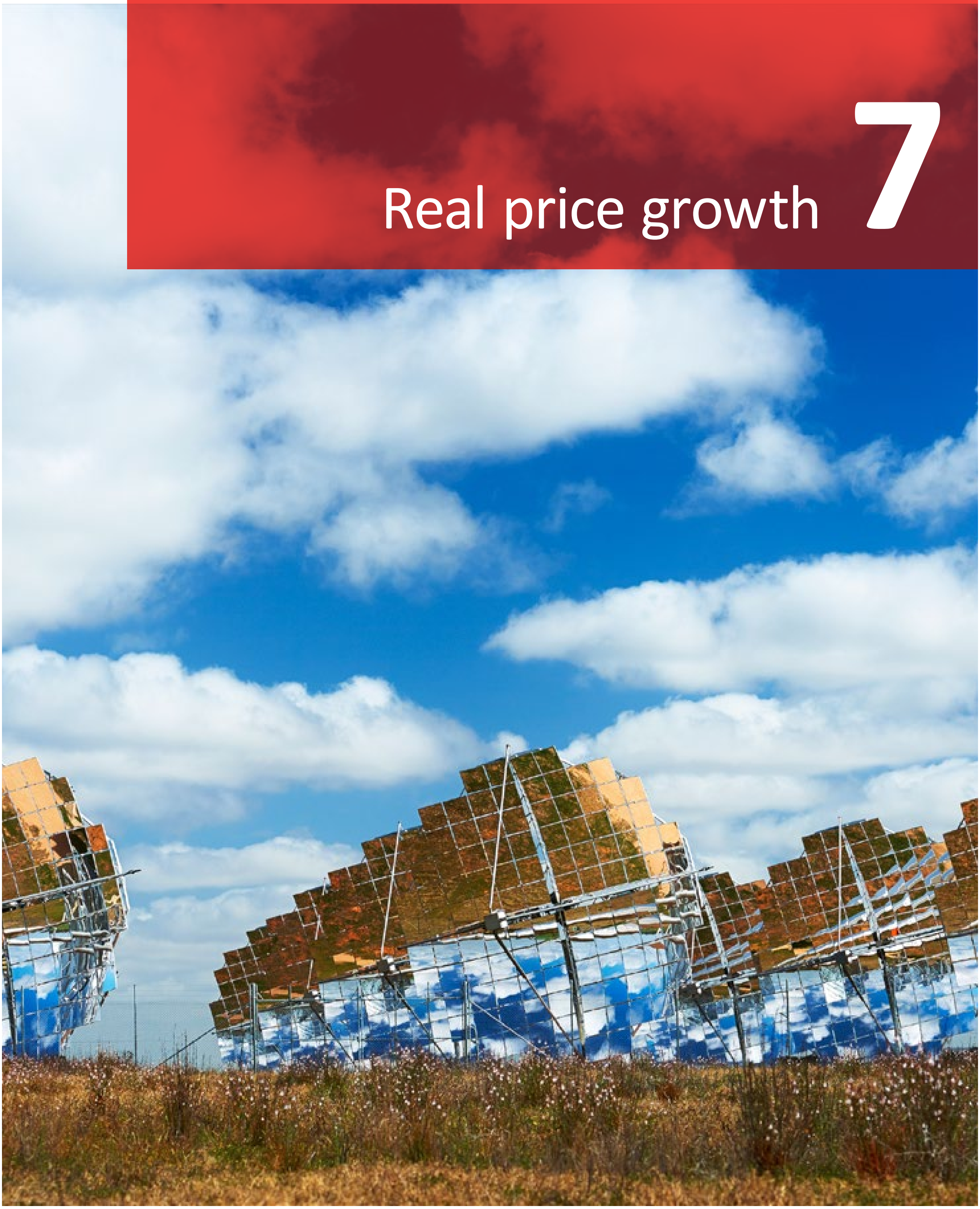
Real price growth 7



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7. Real price growth

Our Enterprise Bargaining Agreements (**EBAs**) reflect efficient market outcomes. We negotiate strongly but in good faith to ensure we attract and retain the highly-skilled labour required to operate an electricity distribution network while minimising costs.

We achieve operating efficiency by ensuring we optimise the utilisation of our labour resources. Our labour costs therefore reflect the efficient costs required to deliver a reliable electricity supply to our customers.

EBA wage growth rates directly reflect the growth in labour prices paid by electricity distributors. Wage growth rates forecast for the broader Electricity, Gas, Water and Waste services (**EGWW**) sector do not sufficiently reflect the skills required in the electricity distribution industry.

We therefore consider that EBA wage growth rates provide the most realistic forecast of our wage growth rates over the 2016-2020 regulatory control period.

We have examined the expected growth in prices over the 2016-2020 regulatory control period for key inputs we use to deliver standard control services, including prices for labour, materials and contracts.

We found that over the 2016–2020 regulatory control period input prices for labour and contracts are forecast to growth at a faster rate than the Consumer Price Index (**CPI**). We therefore include real price escalators in the labour and contracts components of our operating and capital expenditure forecasts for the 2016-2020 regulatory control period.

We use a range of electricity distribution equipment such as transformers, circuit breakers, conductors and poles. In aggregate, we expect our materials input prices to grow at approximately the same rate as the CPI. We therefore do not include real price escalation in the materials component of our operating and capital expenditure forecasts for the 2016-2020 regulatory control period.[25]

Our real price growth forecasts for labour and contracts are set out below.

7.1 Labour price growth

Our internal labour price growth is driven by the outcomes of EBAs. The electricity distribution industry, like most industrial sectors in Australia, has a highly unionised workforce and we are required to negotiate wage growth rates, and other terms and conditions of employment, with our unionised employees through EBA's in accordance with our legal obligations under the Fair Work Act 2009 (**FW Act**).

Given that EBAs are the primary means of determining labour price growth in the electricity distribution industry, we consider that applying EBA wage growth rates to forecast labour price growth provides the most realistic expectation of labour input costs required to achieve the operating and capital expenditure objectives in the National Electricity Rules (**Rules**).

In this section we:

- explain our proposed labour price growth forecasts for the 2016–2020 regulatory control period, refer section 7.1.1;
- demonstrate that our EBAs reflect efficient market outcomes, refer section 7.1.2;
- demonstrate that the EGWW Wage Price Index (**WPI**) is not representative of labour price growth rates for the electricity distribution sector, refer section 7.1.3; and

[25] Reset RIN requirement 18.2(c) requests evidence that our method for forecasting material price escalation explains the price of materials previously purchased. Our reporting systems do not capture data in the form required to provide the requested information.

- explain that it is not appropriate to make productivity adjustments to the labour price growth forecasts, refer section 7.1.4.

7.1.1 Our proposed labour price growth forecasts

Actual EBA growth rates for period up to expiry

For the period up until expiry of our EBA's, our proposed labour price escalation rates are based on our actual annualised EBA wage growth rates, weighted for the proportion of EBA employees on each EBA.[26]

We have two existing EBAs. The first covers employees that are members of the Australian Services Union (**ASU**), the Association of Professional Engineers, Scientists and Managers Australia (**APESMA**)[27] or the National Union of Workers (**NUW**) and was agreed in 2013. The second covers employees that are members of the Electrical Trades Division of the Communications Electrical Plumbing Union (**CEPU**) and was agreed in 2014. Both these EBAs are attached.

Our existing EBAs set out the wage growth rates for the period to:

- 31 December 2016 - agreement with CEPU; and
- 30 June 2017 - agreement with ASU, APESMA and NUW.

As explained in section 7.1.2, our EBA wage growth rates reflect efficient market outcomes. Using our actual EBA wage growth rates up until expiry ensures the forecasts reflect a realistic expectation of our labour costs required to achieve the operating and capital expenditure objectives.

Applying any labour price growth rate less than our actual EBA wage growth rates would result in the business systematically recovering less than the efficient costs required to achieve the operating and capital expenditure objectives. As discussed in section 7.1.3, the EGWW WPI is not representative of labour price growth rates for the electricity distribution sector and is not a suitable substitute for our actual EBA wage growth rates which reflect our actual costs. Applying the actual EBA rates up to the date of expiry is also consistent with Australian Competition Tribunal 2010 judgement on Ergon Energy's appeal[28] and the AER's approach in subsequent regulatory determinations for the AusNet Services and ElectraNet electricity transmission networks.[29]

Historical industry average EBA growth rates for period after actual EBA's expire

For the period following the expiry of each of our EBAs, we apply the five year historical average EBA growth rate for all privately owned electricity networks, calculated by Frontier Economics.[30]

EBA wage growth rates across the electricity network industry have been relatively consistent over the past ten years, as demonstrated in figure 7.1. This reflects the nature of the industry which is in a steady state, with steady network growth and consequently steady labour demand and supply conditions. The low variation in EBA wage growth rates over time is further supported by the low intra-year standard deviation in the average private

[26] Employees currently engaged under individual employment agreements and are technically covered by the terms and conditions of an EBA, are entitled to revert back to those EBA conditions at any time. Consequently, there is no systematic wage growth differential between EBA and non-EBA employees. We have therefore applied the weighted average EBA rate to all internal labour.

[27] Renamed 'Professionals Australia' in 2013.

[28] Australian Competition Tribunal, Application by Ergon Energy Corporation Limited (Labour Cost Escalators)(No3)[2010] ACompT 11, paragraphs 58 to 60.

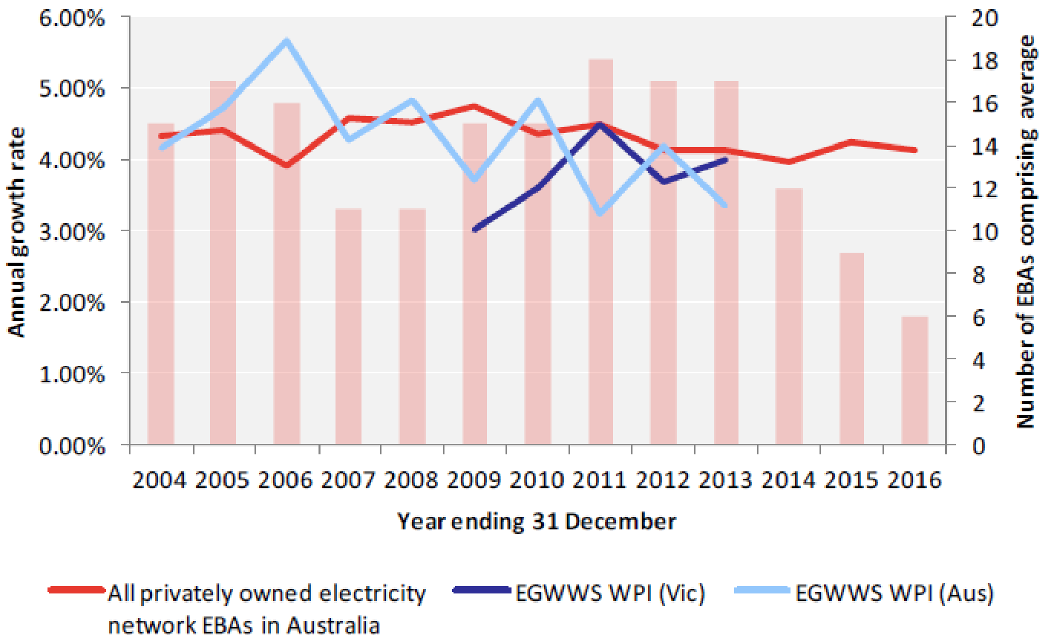
[29] AER, Final Decision, SP AusNet Transmission Determination 2014-15 to 2016-17, January 2014, page 68. AER, Final decision, ElectraNet Transmission determination, 2013-14 to 2017-18, April 2013, page 55.

[30] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, page vi.

sector EBA wage growth rates of only 0.21 per cent around a mean of 4.40 per cent.[31] It is therefore reasonable to expect that wage growth rates over the forecast period will continue to reflect historical industry averages.

Figure 7.1 also demonstrates the difference between EGWW WPI and the average EBA wage growth rates for privately owned electricity networks over the past ten years. The data clearly shows that the EGWW WPI is not representative of actual labour price growth for the electricity distribution sector, particularly in Victoria. Section 7.1.4 explains why the EGWW WPI is not representative of the labour price growth for the electricity distribution industry.

Figure 7.1 Comparison of historical EBA rates compared to the EGWW WPI



Source: Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, p. 15.

The private sector industry average EBA wage growth rate provides a realistic forecast of our EBA wage growth rates for the 2017 to 2020 period. Our current employee weighted average EBA wage growth rate is within one standard deviation of both the private sector industry long term average (2004 to 2014) and short term average (2010 to 2014). Additionally, our long term average EBA wage growth rate (over the period 2004 to 2014) is also within one standard deviation of both the private sector industry long and short term averages.

The low variability in EBA growth rates both across time and across networks is reflective of the essential services nature of the industry with relatively constant demand and the persistent shortages in specialised electrical tradespeople. These two factors contribute to the labour market for electricity distribution labour being relatively unaffected by broader macro-economic conditions. There is no reason to expect that these conditions will materially change during the 2016–2020 regulatory control period.

For the reasons noted above, the historical private sector industry average growth rate therefore reflects the prudent and efficient costs that we require to meet the operating expenditure objectives in clause 6.5.6 of the Rules.

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31 Calculations taken over the period 2004 to 2014.

Using a historical industry average EBA wage growth rate also provides us with strong incentives to seek to outperform the industry benchmark and retain the benefits for five years in accordance with the Efficiency Benefit Sharing Scheme (**EBSS**). Applying an industry average EBA wage growth rate is therefore consistent with the revenue and pricing principles in the NEL which states that '*A regulated network service provider should be provided with effective incentives in order to promote economic efficiency…*' clause 7A(3).

Additionally, applying an industry benchmark would promote dynamic efficiency as it is reasonable to expect that the private sector industry average EBA wage rate may decline as some distributors seek to outperform the benchmark.

Our proposed labour price growth rates are presented in table 7.1. The calculation is provided in the attached model, *PAL Labour Escalation*.

Table 7.1 Labour price growth forecasts (per cent)

Labour escalation	2015	2016	2017	2018	2018	2020	Average 2016-2020
Nominal	4.52	4.52	4.33	4.33	4.33	4.33	4.37
Real	2.16	1.87	1.68	1.68	1.68	1.68	1.72

Source: Powercor

7.1.2 Our EBA negotiations reflect efficient market outcomes

Framework for negotiation

As noted above, our internal labour price growth is driven by the outcomes of EBAs. Under the FW Act, we are required to negotiate wage growth rates, and other terms and conditions of employment, with our unionised employees through EBAs. The FW Act prescribes a range of rights and obligations on parties to EBA negotiations which are intended to allow market forces to drive the negotiation outcome. Attachment, *DLA Piper*, *Legal Advice, Enterprise Bargaining Agreements*, provides more details on the rights and obligations.

With limited exceptions, the FW Act allows bargaining to continue indefinitely until an agreement is reached. During this bargaining period the employee parties (unions and their member employees) are able to utilise industrial action in pursuit of their claims. Employers have limited options to respond to any such industrial action, other than agreeing to the employee/union demands or locking out their workforce which, given that we are a provider of essential services, is not an effective or efficient outcome for any party. Prolonged industrial action or lock-outs could lead to network outages not being rectified and consequently result in electricity supply and safety impacts. Our options for engaging alternative labour in such circumstances are also very limited due to high proportion of union membership among people holding the required technical qualifications, including those in the contractor sector.

Additionally, the market for the specialised labour skills required to operate an electricity distribution network is shallow due to the specialised skills and training required. An historical shortage in training new apprentices has also affected the availability of skilled resources today. The skills required are specialised and cannot easily be sourced or transferred from other industries. Lines persons in particular require specific training to operate on network assets. Further, electrical work requires a high level of industry-specific health and safety training which is not provided in other industries. The industry therefore must continue to invest in succession planning to make up for historical shortages and to prevent future shortages. Attachment, *VESI Skills & Training Reference Committee*, provides a matrix of our minimum training requirements for all internal employees or contractors that work on the network.

The persistently tight labour market conditions for trained, highly skilled, lines persons, electrical technicians and engineering experts is reflected in the consistently strong wage growth rate observed in the electricity distribution sector.

Our objectives

In negotiating our EBA wage growth rates, we balance multiple objectives, including:

- ensuring our labour prices are constrained to reflect efficient market outcomes. As a privately owned business we have strong incentives to negotiate competitive EBA wage growth rates;
- ensuring we attract and retain the necessary labour skills to continue providing a secure and reliable electricity supply. Due to the extensive level of training required and the costs associated with this training, it is important that we offer competitive labour rates to retain trained labour and avoid the risk of losing highly skilled personnel to other network services providers or other electrical or engineering trades. The time and cost of training new personnel are significant and this must be taken into consideration when negotiating wage growth rates that provide efficient outcomes over the longer term. Further, we must invest in succession planning and ensure that wage rates offered are sufficiently attractive to persons new to the labour market that may be still deciding which sectors or industries they want to pursue a career in; and
- ensuring that our operational practices can continue to evolve and new processes, methods and technologies can be adopted in a timely manner to support continual productivity improvements. We renegotiate our EBAs approximately every three years. The timeframe provides for a reasonable period of wage rate certainty while also enabling sufficient flexibility to review business processes and practices which may be captured in the next round of EBA negotiations. For example, in our most recent EBA negotiations with the CEPU we pursued a claim to change the terms of the Consultation and Introduction of Change clause. This clause required us to consult and agree with the CEPU and employees before introducing any change in production, program, organisation or technology which are likely to have effects on employees. Following extensive negotiations we were able to achieve a change in the wording of this clause including that the clause only applies where the change is a ‘major’ change and only where it has a ‘significant’ effect on employees, which allows the businesses more flexibility to introduce changes.

Importantly, while the EBA wage growth rate is an input into overall labour costs, it is not the main determinate of operational efficiency and productivity. The most significant factor for labour cost efficiency is the utilisation of labour, that is the way in which work is performed and how labour resources are planned, organised and deployed. Appendix B explains how we ensure the optimal utilisation of our labour to efficiently manage periods of increased and decreased labour requirements and minimise the risk of inefficiencies associated with stranded or under-utilised labour.

Our negotiations

Notwithstanding the legislative and market constraints discussed above, our EBAs are the result of intense negotiations which are clearly undertaken at arms-length from the unions. For example, we are able to demonstrate in detail the process that was followed and the extent of resistance against claims being pursued by the CEPU in our most recent EBA negotiations. We committed management time attending strategy, preparation and negotiation meetings over ten months, responding to the CEPU log of 120 claims. Attachment, *CEPU log of claims*, provides more details on the negotiation process.

The CEPU’s initial starting point, in relation to the headline wage increase, was a minimum eight per cent per annum. The final EBA wage growth rate agreed is 2.25 per cent per half year (equivalent to 4.55 per cent per annum).

The CEPU also requested numerous changes to non-wage employment terms and conditions which we did not concede, including for example:

- a reduction in weekly hours worked from 36 to 32 hours;
- an increase in annual leave from 4 to 6 weeks for all employees; and
- specification of redundancy payments to include four weeks per years of service, ex gratia payments for every five years of service and payment of accumulated sick leave. There is no specification of redundancy payments in our EBAs.

Some changes requested by the CEPU were agreed as we considered these were appropriate or beneficial over the long term, for example in relation to the provision of thermal clothing in certain circumstances.

At the same time, we pursued specific changes to EBA clauses which limited our ability to drive productivity improvements in our operations, some of which were agreed with the CEPU, including:

- to enable shift work for employees, by negotiation and agreement. Previously there was no provision for employees to undertake shift work; and
- a revision to remove the need for extensive consultation for non-major workplace changes (as noted above) and also providing for disagreements about major changes to employment conditions that significantly affect an employee to be referred to the Fair Work Commission for conciliation. This enables the Fair Work Commission to use its influence and mediation skills to facilitate the achievement of major changes. In the previous enterprise agreement consultation and introduction of change clauses, a change to an employee's employment conditions (even if it was not a major) could only occur with employee and union consent and there was no process for conciliation with the Commission.

These changes provide us with more flexibility in the management of our labour force which is the key contributing factor in ensuring efficiency in our overall labour costs. These changes are evidenced in our final EBA with the CEPU.

In reaching these outcomes, we faced a range of work bans and other forms of industrial action across our network over a period of four months, which had material impact on our commercial performance and ability to schedule and efficiently perform planned work on our network. Attached is a set of industrial action notices received from the CEPU.[32] In an attempt to challenge the work bans and progress negotiations we sought the assistance of the Fair Work Commission, which facilitated numerous negotiation meetings before a member of the Commission. We communicated extensively with our workforce during the negotiations in an effort to convey the reasonableness of the company position and demonstrate good faith bargaining. The conduct of the negotiation process and the impact of the EBA outcomes on the business were taken very seriously.

Achievement of the long term efficient outcomes through the EBA negotiation requires balancing the long term benefits of achieving future productivity changes and resisting union claims against the short term costs of industrial action and conceding on some union claims. The EBA outcome which promotes the long term benefits of consumers therefore may require accommodating, to some degree, one or more of the union claims, whether that be in relation to wage growth or other terms and conditions of employment.

Our resulting EBA rates are prudent and efficient

The above clearly demonstrates that our EBAs are negotiated at arms-length from the unions and that we take a strong position in our negotiations, despite the consequence of prolonged industrial action. Our EBA wage growth rates therefore reflect the most prudent and efficient outcome for the business given the circumstances.

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[32] Fair Work Act 2009, Notice by Bargaining Representative of Employees of Intention to take Employee Claim Action (s.414).

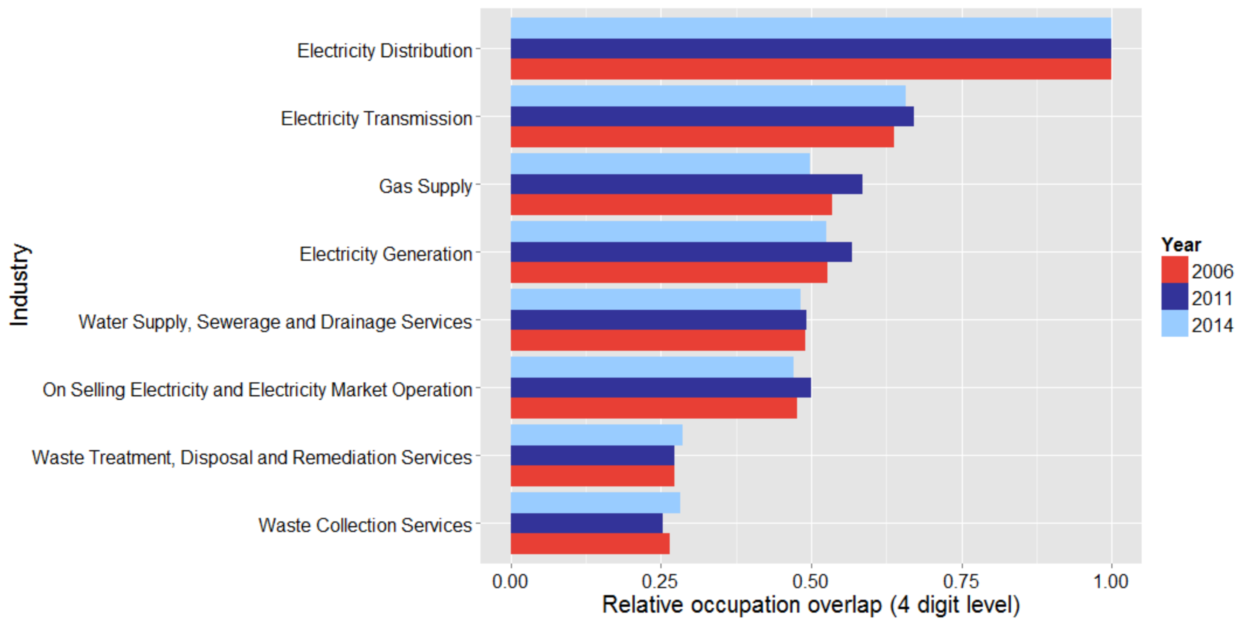
Our negotiation process ensures that our resulting EBA wage growth rates represent the efficient and prudent costs required to achieve the operating expenditure objectives in the Rules. It would be inconsistent with the Rules for the AER to ignore our EBA outcomes as the EBA wage growth rates reflect the growth in the efficient costs required to deliver standard control services in accordance with the operating expenditure objectives.

Additionally, as noted above, our negotiations focus on promoting the long term benefits of electricity users. The resulting EBA wage growth rates are therefore consistent with the National Electricity Objective.

7.1.3 The EGWW WPI is not representative of electricity distributors' labour price growth

Applying EBA wage growth rates for the forecast period provides a more realistic cost forecast than a forecast of the EGWW WPI. This is primarily because the EGWW WPI is made up of sectors and sub-sectors which have materiality different labour skill requirements to electricity distribution. This is demonstrated in figure 7.2 which shows the extent of overlap in the labour skill requirements between the electricity distribution sector and other sectors captured in the EGWW WPI. Attachment, *Labour cost escalation forecasts using Enterprise Bargaining Agreements*, provides further detailed analysis of differences in labour skills requirements between sectors and sub-sectors captured in the EGWW WPI.[33]

Figure 7.2 Labour skill overlap in EGWW 2006, 2011 and 2014



Source: Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, p.12.

Further, using EBA wage growth rates as the basis for forecasting labour price growth is also more consistent with the AER's principles for the assessment of expenditure proposals than forecasts of the EGWW WPI. As discussed by Frontier Economics[34], this is primarily because:

- EBA wage growth rates are transparent and can be calculated from publicly available data. Conversely, consultants' forecasts of the EGWW WPI are not transparent due to the proprietary nature of the models;

[33] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.3 and appendix B.
[34] Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.5.2.

- calculating EBA wage growth rates is a simple method for forecasting labour price growth. Conversely, consultants' methods for calculating the EGWW WPI cannot be assessed against this principle as they are not disclosed; and
- EGWW WPI forecasts have not proven accurate or reliable. Consultants' EGWW WPI forecasts have tended to be lower than the industry average EBA rates and there are large differences in forecasts between consultants.[35] This is likely because, as discussed above, the EGWW WPI is not representative of the labour skill requirements of the electricity distribution industry. Conversely, EBA rates have been relatively consistent through time and provide a direct representation of the labour growth rates in the electricity distribution industry.

In conclusion, the above analysis demonstrates that using EBA growth rates as the forecast of labour price growth provides a more realistic forecast than the EGWW WPI because it:

- is a low cost and transparent mechanism which provides a directly representative forecast of labour price growth rates paid in the electricity distribution industry; and
- provides the most realistic expectation of our labour price growth for the forecast period and is therefore consistent with clause 6.5.6(3)(c) of the Rules which requires the AER to accept a proposal that reasonably reflects a realistic expectation of cost inputs required to achieve the operating expenditure objectives.

7.1.4 Labour productivity

We have not applied productivity adjustments to the labour price escalators set out in table 7.1 because:

- we do not support the application of pre-emptive labour productivity adjustments which are inconsistent with the intent of the EBSS and are likely to lead to less than a reasonable opportunity to recover the efficient costs of providing direct control services; and
- our current quantity of labour is efficient and we do not expect net reductions in labour costs to arise due to foreseeable productivity changes over the regulatory control period. Our actual labour costs in 2014 are therefore the appropriate base for escalating for real growth in the per unit price of labour. Refer to appendix B which explains why our labour costs are efficient.

Further, we note that in its draft decision on the NSW/ACT distributors the AER rejected the use of EBAs on the basis that EBAs may contain a trade-off between wages and productivity.[36] As noted by Frontier Economics, there are two problems with the AER's position:[37]

- first labour and productivity are not separable concepts. Economic theory implies that as labour productivity increases, all else being equal, labour prices should increase and therefore it is artificial to treat labour price and labour productivity separately; and
- second the use of the EGWW WPI captures labour productivity of both electricity distribution and non-electricity distribution sectors of the economy, such as water services, waste services and electricity generation and retail services. As discussed in section 7.1.3 and in detail in Frontier Economics' report[38], the labour skills required for electricity distribution services are significantly different to those required in other sectors captured in the EGWW WPI. It is therefore unreasonable to assume that labour productivity in the electricity distribution sector reflects that of the broader range of sectors included in the EGWW WPI.

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35 For example refer to tables 3.9 and 3.10 of attachment, CIE, *Labour price projections*, December 2014, p. 27.
36 AER, Draft decision, AusGrid distribution determination 2014-19, Attachment 7: Operating expenditure, November 2014, p. 7-151.
37 Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.2.
38 Frontier Economics, Labour cost escalation forecasts using Enterprise Bargaining Agreements, February 2015, section 2.3 and appendix B.

7.2 Contracts

We use external contractors to deliver specialised services, for example vegetation management, asset inspection, electrical construction, civil works and traffic management.

The primary nature of these contracts is for labour-based services. The Australian Bureau of Statistics' WPI for the construction sector most closely reflect the types of labour skills required to deliver these services.

We engaged the Centre for International Economics (**CIE**) to develop forecasts of the construction sector WPI for Victoria. CIE's report, *Labour price projections,* is attached.

Our contracts price escalator is based on the CIE's construction sector WPI forecasts. The resulting growth rates provide a realistic expectation of our expected contract cost increases over the forecast period. We have therefore applied these forecasts to the contracts component of our operating and capital expenditure forecasts.[39]

Our contracts price escalators for 2016-2020 are provided in table 7.2. The calculation is provided in the attached model, *PAL Contracts Escalation*.

Table 7.2 Contracts input price growth (per cent)

Contracts escalation rates	2015	2016	2017	2018	2019	2020	Average 2016-2020
Nominal	3.56	3.59	4.81	4.38	4.36	4.39	4.31
Real	1.22	0.96	2.15	1.73	1.72	1.74	1.66

Source: CIE, *Labour price forecasts*, December 2014, p. 7.

7.3 Proportion of labour, materials and contract costs

Table 7.3 demonstrates the proportion of our operating expenditure and capital expenditure attributable to each of labour, materials and contracts costs based on our actual expenditure in 2014 for standard control services.

Due to the nature of operating an electricity distribution network, there is limited opportunity to substitute labour-based services for materials or vice versa.

We acknowledge however that there is a degree of opportunity to substitute the use of internal labour relative to labour-based contractor services. The optimal mix of internal relative to contracted labour-based services at any point in time is subject to prevailing market conditions as well as legal and contractual obligations. We continuously review the optimal mix of internal labour relative to contracted labour services and seek to implement the most efficient strategy at every opportunity.

[39] Reset RIN requirement 18.2(c) requests evidence that our method for forecasting input price escalation explains the price of purchased inputs. Our reporting systems do not capture data in the form required to provide the requested information for contracts.

Table 7.3 Proportion of labour, materials and contracts (per cent)

Expenditure type	Labour	Materials	Contracts
Operating expenditure	44.6	5.7	49.7
Capital expenditure	49.2	23.5	27.4

Source: Powercor

We note that the AER's draft decision on the NSW and ACT distributors assumes that material costs contribute to 38 per cent of operating expenditure. We have examined the category analysis RIN data reported by all distributors.[40] Based on this data, the weighted average contribution of materials costs to standard control services operating expenditure in 2013 across the industry is five per cent. The AER's assumption of 40 per cent is clearly not an appropriate benchmark for either Powercor or the industry more generally.

We have therefore applied real price escalators to our forecast expenditure based on our forecast of labour, materials and contracts costs for each of operating and capital expenditure which is based on our actual proportions in 2014 as shown in table 7.3.

7.4 Overall real price growth

Table 7.4 and table 7.5 show the overall value of real input price growth rates applied to each of the operating and capital expenditure forecasts.

Table 7.4 Operating expenditure real price growth ($m, real)

Operating expenditure	2015	2016	2017	2018	2019	2020
Labour	1.6	4.0	5.8	7.8	9.9	12.0
Materials	-	-	-	-	-	-
Contracts	1.1	2.5	5.1	7.5	9.8	12.3
Total value of real price growth	**2.7**	**6.5**	**11.0**	**15.3**	**19.7**	**24.3**

Source: Powercor

40 Jemena's data is excluded because it is not provided in either the public or confidential versions of Jemena's category analysis RIN as provided by the AER.

Table 7.5 Capital expenditure real price growth ($m, real)

Capital expenditure	2016	2017	2018	2019	2020
Labour	3.5	7.1	10.2	13.4	17.3
Materials	-	-	-	-	-
Contracts	1.1	3.6	5.2	6.8	8.6
Total value of real price growth	**4.7**	**10.7**	**15.4**	**20.2**	**25.8**

Source: Powercor

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Demand, energy and customer forecasts 8

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8. Demand, energy and customer forecasts

Demand for electricity usually increases on hot summer days, when most of our customers turn on their air-conditioners. This drives a spike in demand.

When we forecast that the peak in demand will be greater than the capacity of our network in that area, then we must ensure that we can continue to meet the demand required by our customers by investing in the network or implementing economic demand management solutions.

Our forecasts indicate that peak demand is increasing, even though the average demand (or energy throughput) has not been increasing at a rapid rate. It is peak demand, however, that drives investment.

Our demand forecasts have been prepared using a robust process that combines our own detailed local knowledge with independent economic analysis.

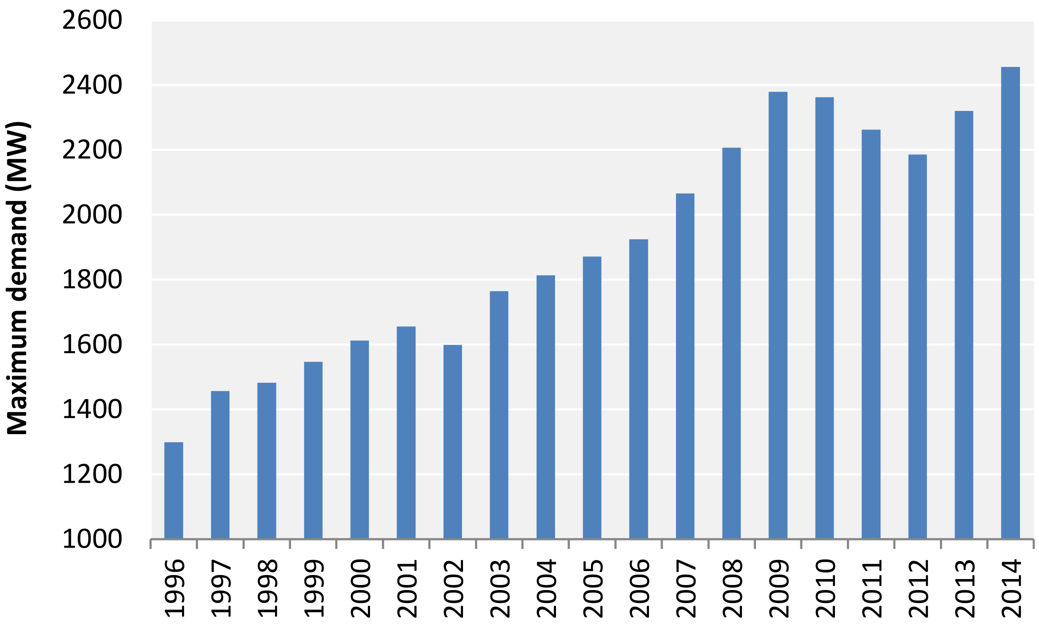
Our peak demand, energy and customer forecasts are described in more detail in appendix C.

8.1 Peak demand forecasts

We experienced our highest ever peak of demand on our network on Tuesday 14 January 2014, during a four day period where temperatures exceeded 41 degrees Celsius each day. The network peak of 2,432MW was reached at 5.00pm, even though this period fell inside the holiday season, when some industry sectors had not returned to full capacity.

The upward trend in 'raw' peak demand (i.e. data that is not temperature corrected) is shown in figure 8.1.

Figure 8.1 Increasing 'raw' level of peak demand (coincident demand at terminal station level)



Source: Powercor

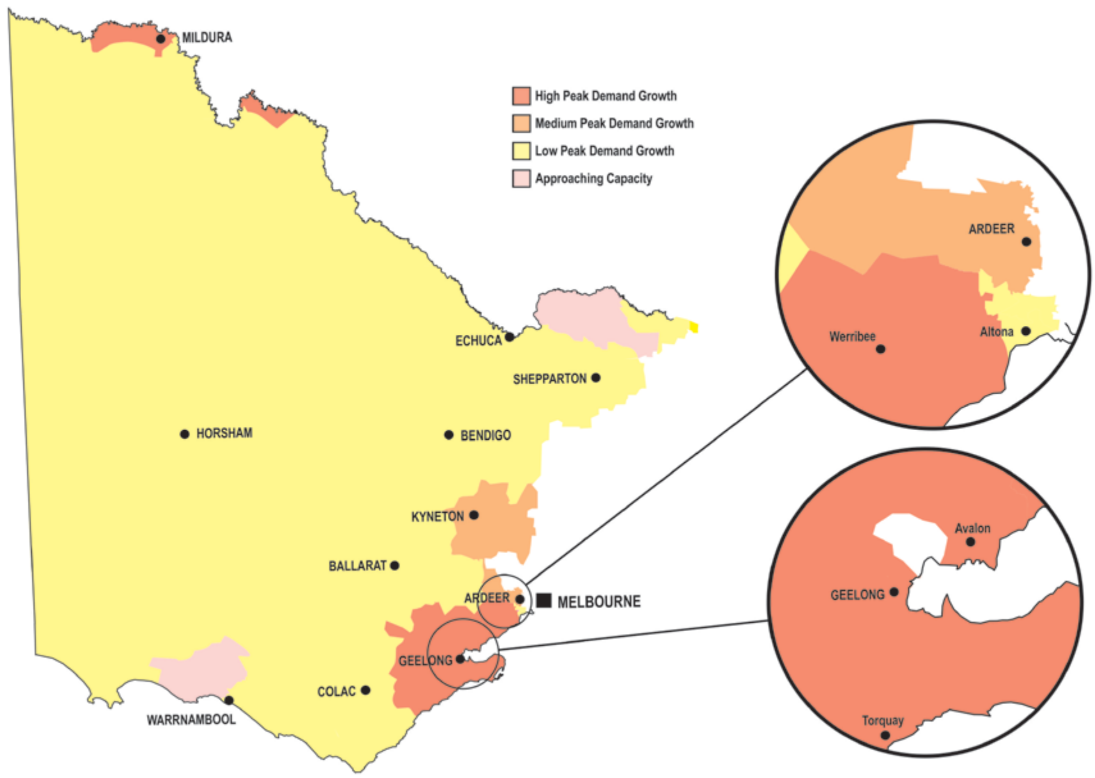
The use of air-conditioners by commercial and residential households was a key driver of the network peak, as the community sought respite from the prolonged heat. Increases in the frequency and duration of heatwaves[41] will be a significant contributor to a new network record peak being recorded in the future.

Over the 2016–2020 regulatory control period, we expect peak demand to increase in specific areas of our network. In addition to the impact of temperature, the increase in peak demand will be driven by:

- population growth in the western suburbs of Melbourne and the Greater Geelong region; and
- expansion and additional capacity required in the agricultural sector, particularly in the Warrnambool and Murray River regions.

Figure 8.2 provides a map of the areas of higher peak demand growth in the network together with areas approaching capacity.

Figure 8.2 Powercor peak demand forecasts



Source: Powercor

The areas that we have identified for the continued growth in peak demand is supported by a range of evidence from government and sectorial information that is publicly available.

The Victorian Government's projections for annual population growth reinforce our expectations of strong population growth in the western corridor of Melbourne, as well as the greater Geelong region. The City of Greater Geelong also commented in its response to our Directions and Priorities paper that:[42]

[41] Climate Council, *Heatwaves: Hotter, Longer, More Often*, 2014. Available from: http://www.climatecouncil.org.au/uploads/9901f6614a2cac7b2b888f55b4dff9cc.pdf

Areas to the City's south are also anticipating strong growth such as Waurn Ponds, Wandana Heights and particularly Armstrong Creek a major new suburb currently underway and which will see 22,000 homes upon completion.

The Mildura Development Corporation (**MDC**) also noted the local growth in horticultural and dryland agricultural sectors, as well as solar developments and implored us to further invest in the region:[43]

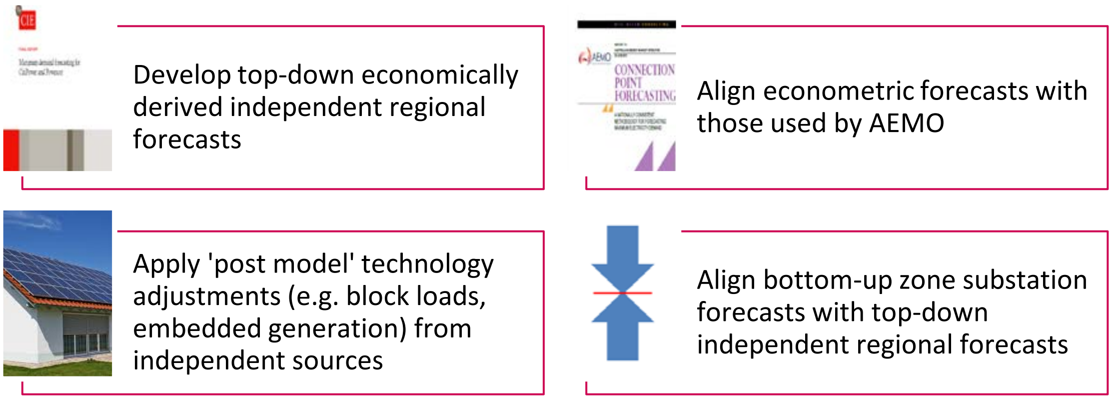
MDC… calls for further support for an even more significant expansion in local power network capacity, not only recognising the many food processors and solar energy plants with high energy demands establishing themselves in the region, but also recognising the needs of those companies considering establishing themselves in the region ….

8.1.1 Our demand forecasts

Our peak demand forecasts have been prepared using a robust process that draws upon independent analysis of economic and environmental factors. A key objective of our demand forecasting process was to align our econometric modelling methodology with that used by the Australian Energy Market Operator (**AEMO**).

The key elements in our process are shown in figure 8.3.

Figure 8.3 Key elements of our forecasting process



Source: Powercor

We engaged the Centre for International Economics (**CIE**) to undertake a top-down forecast of maximum electricity demand at the terminal station level, underpinned by the same economic drivers that are used by AEMO.[44] The forecasts took into account average demand as well as maximum demand at each terminal station.

CIE's forecasts for average demand growth took into account the following demand drivers:

- price: electricity prices are projected using forecasts of the real electricity residential price index, including assumptions about use of time of use tariffs;
- income: projections based on the growth rate in Gross State Product per capita in each quarter;

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[42] Email from City of Greater Geelong to Powercor, *Response to Directions and Priorities Consultation Paper*, 4 November 2014.
[43] Mildura Development Corporation, Submission – CitiPower and Powercor Australia Directions and Priorities Consultation Paper, 3 November 2014, p. 6.
[44] CIE, Maximum demand forecasting for CitiPower and Powercor, Final report, July 2014.

- population: annual forecasts of population in local government areas; and
- weather: the effect of temperature on demand largely due to air-conditioner and heater usage.

CIE also used an econometric model to forecast summer, winter and annual maximum demand. The modelling took into account relationships between the ambient temperature effects using weather station data from the Bureau of Meteorology aligned to each terminal station, as well as calendar effects reflecting the dependency of maximum demand on the day of the week and time of summer etc.

They then combined the results of the economic simulation with the forecasts of average quarterly electricity demand to obtain a distribution of maximum demand at each terminal station for each year of the forecast period.

The process undertaken by CIE was broadly consistent with the two step modelling approach used by AEMO to deliver its forecasts in 2013.

Post-model adjustments were made by CIE for:

- known changes in block loads, such as negative adjustments for industry shutdowns or positive adjustments for load increases such as major new connections; and
- demand from major embedded generators, notably wind farms and solar photovoltaic (**PV**) based on a report from Oakley Greenwood on the impact of technology changes on terminal station demand.[45]

As energy efficiency policies and outcomes are already reflected in the historical data, post model adjustments were not included for energy efficiency. CIE forecasts assume that growth in energy efficiency policy and outcomes will continue to occur at the historical rate.

CIE's forecasts for the annual change in coincident maximum demand at the network level, in MW, are shown in table 8.1.

Table 8.1 Coincident annual maximum demand at terminal stations annual growth rate (per cent)

	2016	2017	2018	2019	2020
50%PoE	4.5	3.2	1.3	3.7	2.2
10%PoE	4.7	5.5	2.2	2.6	2.4

Data source: CIE, *Maximum demand forecasting for CitiPower and Powercor*, Final report, July 2014, p. 130.

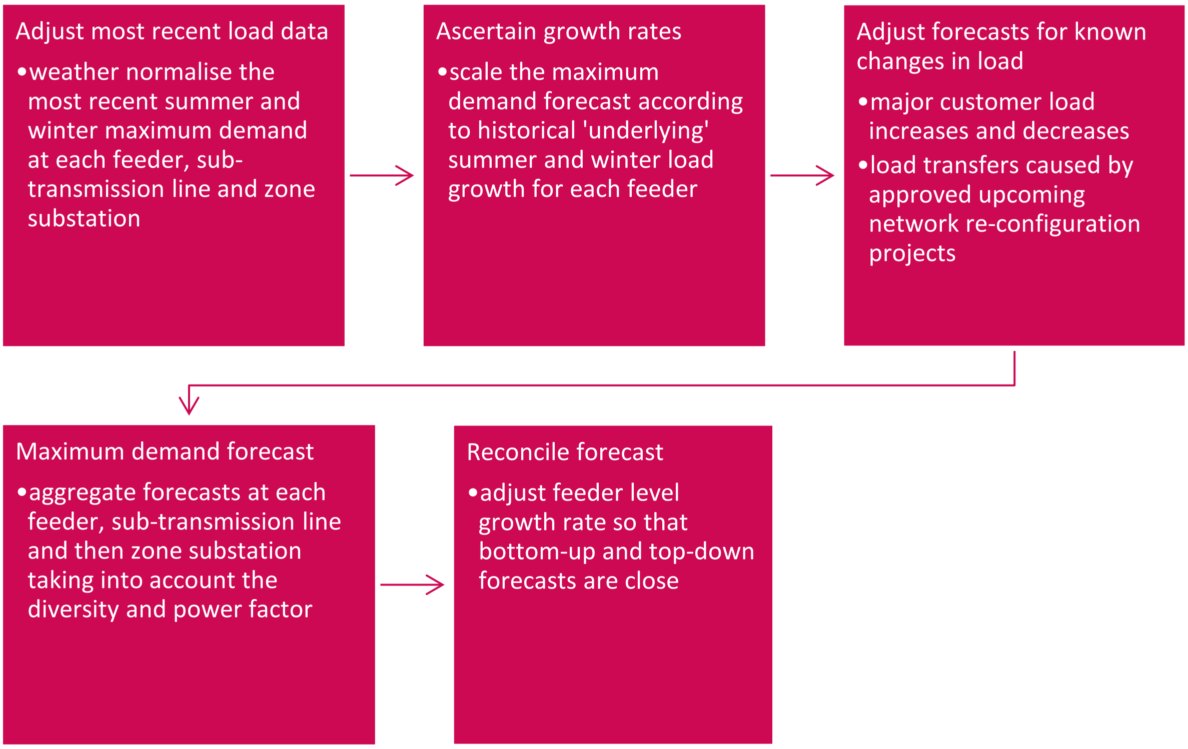
We adjusted down the CIE top-down forecasts in cases where the baseline forecasts were inconsistent with the judgement of expert planners with strong local area knowledge. This forecasting adjustment is consistent with industry 'best practice' outlined in the ACIL Allen report for AEMO entitled *Connection Point Forecasting*.[46]

We reconciled the top-down forecasts with our own bottom-up forecasts for demand. This is because top-down forecasts generally lack local detail, which is a key strength of bottom-up forecasts as they capture the underlying characteristics of the areas serviced by local zone substations. In contrast, bottom-up forecasts cannot take account of changing economic outlook and other longer term factors.

Our bottom-up forecasts were prepared using the following process.

45 Oakley Greenwood, Summary and documentation of the terminal station impacts of five technology trends, May 2014.
46 ACIL Allen Consulting, Connection point forecasting – a nationally consistent methodology for forecasting maximum electricity demand, Report to Australian Energy Market Operator, 26 June 2013.

Figure 8.4 Bottom-up forecasting process



Source: Powercor

Our reconciliation process was reviewed by ACIL Allen and found to be appropriate, although they identified some minor areas for improvement, mostly related to the weather corrected forecasts at the 10 per cent probability of exceedance level (10 per cent PoE) for extremely hot summer days.[47]

Our demand forecasts by zone substation are shown in figure 8.5.

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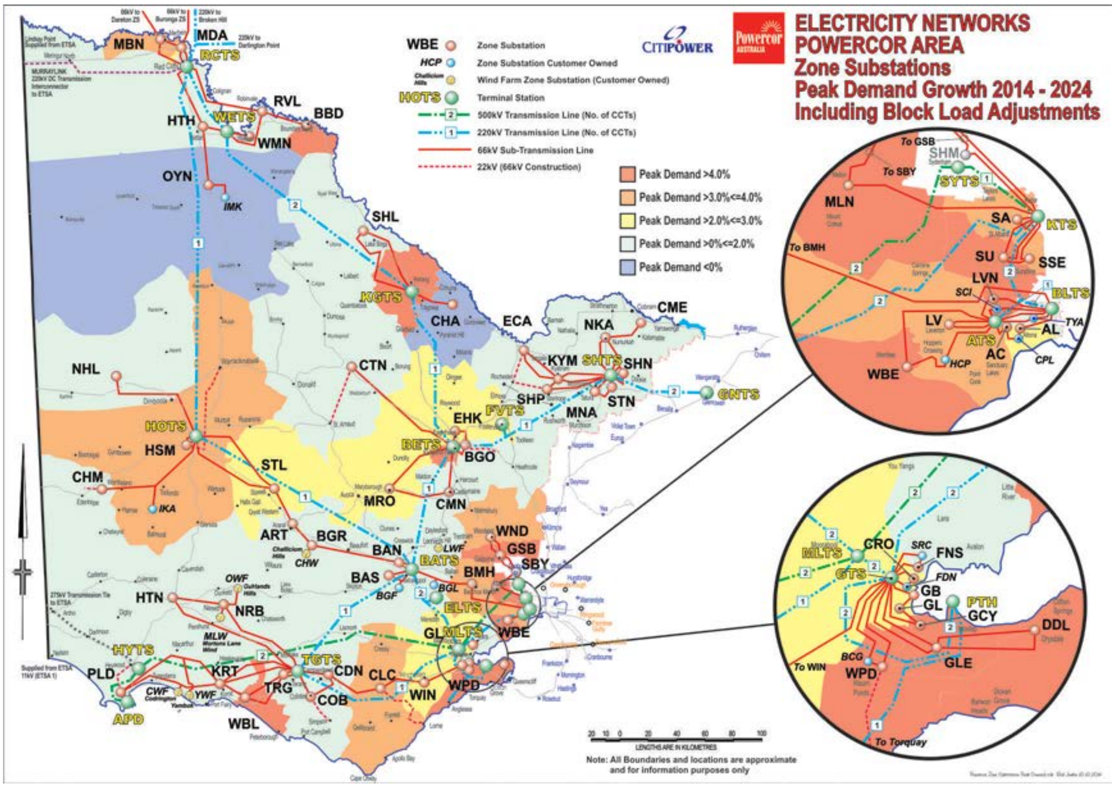
[47] ACIL Allen, Demand forecasts – reconciliation review, 27 January 2015.

Figure 8.5 Peak demand forecasts by zone substation



Source: Powercor

8.1.2 AEMO forecasts

AEMO has produced two sets of forecasts in Victoria: Victorian system level forecasts and forecasts at each transmission connection point.

We have worked with AEMO to discuss their methodology, as well as providing historical data and our demand forecasts. However, as discussed below, AEMO has assumed aggressive assumptions associated with solar PV penetration and energy efficiency that we have been unable to verify, and as a result we have been unable to align our forecasts with those of AEMO at the transmission connection point level.

We will continue to work with AEMO as they continue to develop and refine their forecasts. However, given our concerns with AEMO's forecasts, we consider it appropriate that the Australian Energy Regulator (**AER**) relies upon our own demand forecasts rather than those of AEMO. This would be consistent with the AER's draft decision in NSW where it accepted the distributors' forecasts over those produced by AEMO.

System level forecasts

AEMO produces Victorian system level forecasts of peak demand in its National Electricity Forecast Report (**NEFR**). Since the first NEFR report in 2012, AEMO has reduced its summer 10 per cent PoE forecasts for Victoria for the period to 2018/19 by 25 per cent, with the ten year growth rate falling from 1.6 per cent to 0.1 per cent per annum.[48] The change in forecast is shown in figure 8.6.

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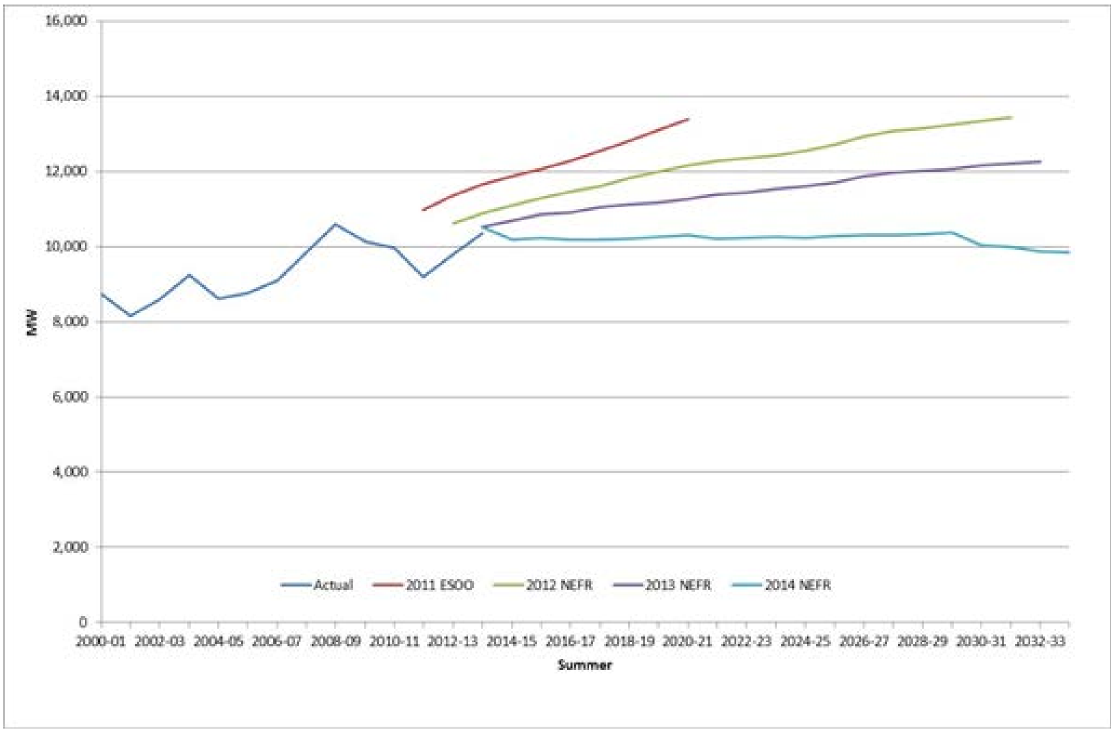
48 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 12.

Figure 8.6 **Victorian summer 10% PoE peak demand forecasts**



Source: GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 12.

According to GHD, the reductions in long term growth rates appear to reflect methodological changes to the core model, as well as other elements of the forecasts outside of the core model such as increasing estimates of future rooftop PV generation.

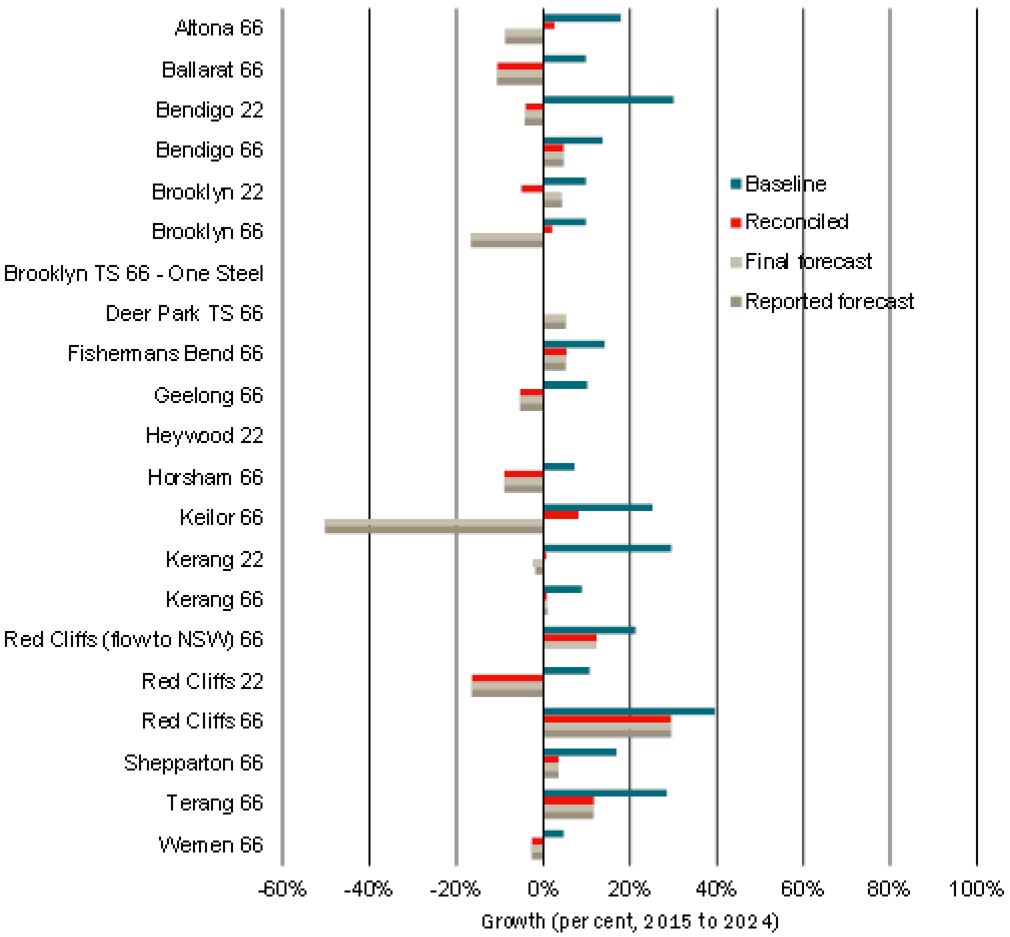
Transmission connection point forecasts

In September 2014, AEMO produced its first electricity demand forecasting report of maximum demand at the transmission connection point level for Victoria, i.e. each terminal station. We understand that these terminal station maximum demand forecasts consist of four different forecasts:

- baseline forecast which are extrapolated from historical trend;
- reconciled forecasts which are the baseline forecasts adjusted for solar PV and energy efficiency to then reconciled to the state-wide forecasts;
- final forecast which is further adjusted by block loads and known transfers; and
- report forecast which is made publicly available.

There are substantial reductions in the growth rates for Powercor as a result of moving from baseline to reconciled forecasts, as shown in figure 8.7.

Figure 8.7 **AEMO changing forecasts for terminal stations**



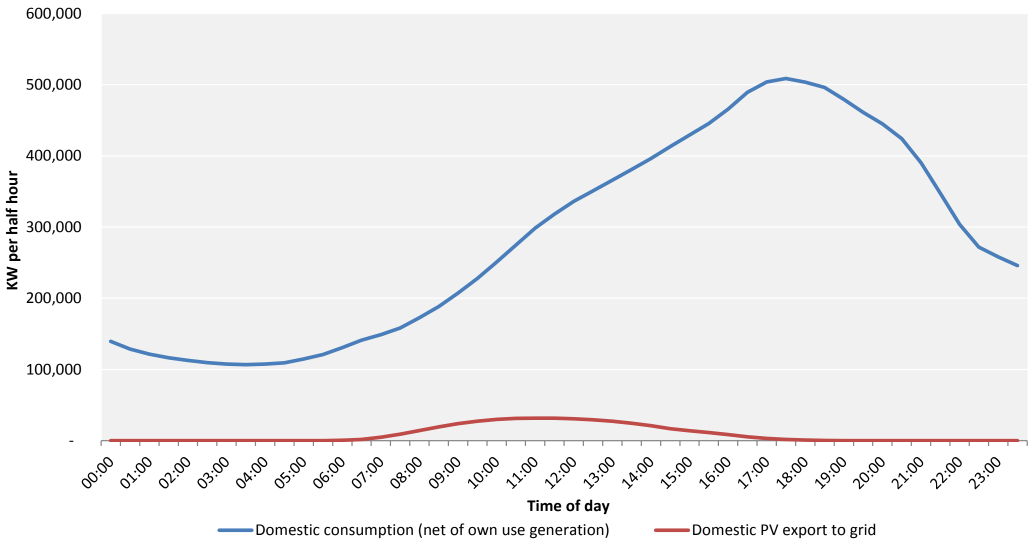
Source: CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, p. 5.

As shown above, the reconciliation process to take baseline peak demand forecasts for each terminal station and reconcile this to Victoria-wide demand has been an important component of AEMO's forecasting approach. Two key aspects of the reconciliation process are:

- contributions of solar PV to reductions in peak demand; and
- energy efficiency assumptions.

AEMO has forecast a significant contribution from rooftop solar PV to peak demand. Our own experience is that solar PV makes a very small contribution, if any, to peak demand. For example, when our network reached its peak demand for residential customers at 5.30pm on 14 January 2014, solar PV contributed around 0.46 per cent of that peak demand. This is shown in figure 8.8.

Figure 8.8 Domestic consumption of electricity on 14 January 2014



Source: Powercor

AEMO's own analysis from the Victorian heatwave of January 2014 showed that at the state wide system peak recorded at 4.30pm on 16 January 2014, embedded solar generation contributed 1.04 per cent to the peak operational demand.[49]

In terms of AEMO's forecasting process relating to contributions from solar PV, CIE and Oakley Greenwood identified four material assumptions that place downward pressure on the installation forecasts:[50]

- assuming that 50 per cent of all energy that is produced will be exported is too high unless large increases in the penetration of solar PV on commercial rooftops is assumed (which it does not appear to given comments in the NEFR);
- methodology makes no allowance for the possibility that tariff structures (as opposed to tariff levels) will adjust in response to Rule changes requiring a move to cost-reflective tariffs and competitive pressure placed on distributors;
- methodology makes no allowance for the required payback period for future customers to be shorter than for those who already have installed solar PV systems given the increased maturity of the technology; and
- forecasts do not appear to have taken into account the downward risk that current incentives for purchases of solar PV will decline in the future.

Secondly, in relation to energy efficiency the CIE and Oakley Greenwood found that the forecasts were partly based on unpublished reports, were not appropriately disaggregated to take into account the energy savings of different appliances and customer classes, and that AEMO made the unreasonable assumption that energy efficiency programs will be implemented by industry irrespective of the fact that the Federal Government has scrapped the funding.

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49 AEMO, *Heatwave 13-17 January 2014*, 26 January 2014, page 6, which is available from: http://www.aemo.com.au/News-and-Events/News/2014-Media-Releases/Heatwave-13-to-17-January-2014.

50 CIE and Oakley Greenwood, *Review of AEMO Transmission Connection Point Forecasts*, 16 January 2015, pp. 21–22.

A further review of the connection point forecasting process used by the AEMO was undertaken by GHD. Separately, GHD identified similar material forecast issues as identified by the CIE/Oakley Greenwood report, including:

- solar PV generation forecasts 'could reflect over-optimistic assumptions about generation from a given installed capacity by AEMO';[51]
- forecasts may have double-counted the level of energy efficiency adjustment that applies to the most recent demand observation, such that the adjustments are at the high end of a wide range of uncertainty;[52]
- concerns with the reconciliation process between the state-wide forecast and the connection point forecasts; and
- the alignment between AEMO energy and peak demand models.

AEMO has stated that as this is the first time they have undertaken Victorian connection point forecasts, they identified an improvement action plan for future connection point forecasts. We are working with AEMO in providing feedback and suggestions for improvements to their forecasting process.

Given the range of shortcomings in AEMO's forecasting process, we consider it appropriate that the AER relies upon our own demand forecasts which take into account independent economic analysis together with our detailed local knowledge and utilisation of a robust methodology that has been independently verified. This would be consistent with the AER's draft decision in NSW where it accepted the distributors' forecasts over those produced by AEMO.

8.2 Energy forecasts

We engaged CIE to develop our energy volume forecasts for the 2016–2020 regulatory control period. CIE forecast growth rates in energy volumes for residential, commercial and industrial customers, taking into consideration factors that drive demand for a particular tariff class and factors that contribute to network-wide demand growth, including:

- historical trends in energy usage;
- projections of customer numbers by tariff class;
- block-load forecasts; and
- economic conditions such as incomes and electricity prices.

Table 8.2 sets out our forecast growth in energy volumes for the 2016–2020 regulatory control period.

Table 8.2 Energy volume growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Energy growth rates	2.1	1.3	1.0	1.3	1.3	1.2

Source: CIE, *Tariff volume forecasts*, February 2015, p. 16.

51 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 20.
52 GHD, Review of AEMO Demand Forecasting Methodology, January 2015, p. 17.

8.3 Customer forecasts

We engaged CIE to develop our customer number forecasts for the 2016-2020 regulatory control period. CIE forecast the growth rate in customer numbers for residential, commercial and industrial customers as follows:

- residential customers – based on the forecast growth in dwelling numbers by Local Government Area (**LGA**) produced by the Victorian Government Department of Transport, Planning and Local Infrastructure. CIE mapped the relevant LGAs to our network area;
- commercial customers – based on a time trend from the most recent data point (2013); and
- industrial customers – assumed zero growth from the most recent data point (2013).

Table 8.3 sets out our forecast growth in customer numbers for the 2016-2020 regulatory control period.

Table 8.3 Customer number growth rates (per cent)

	2015	2016	2017	2018	2019	2020
Customer number rates	1.7	1.7	1.8	1.8	1.8	1.8

Source: CIE, *Tariff volume forecasts*, February 2015, p. 7.

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9 Capital expenditure

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9. Capital expenditure

We need to invest around **$2.015 billion** of capital expenditure into our network in the next regulatory control period to continue to meet expected demand and connect new customers while safely delivering a quality and reliable electricity supply to our consumers. We must also undertake the required activities to mitigate the risk of our assets contributing to starting a fire.

As demonstrated in chapter 5, we are one of the most efficient distributors in Australia. Our rigorous cost controls and condition-based approach to maintaining and replacing assets has resulted in a reliable electricity supply at low cost.

We have asked our stakeholders their views on our business, to better understand their priorities and concerns. The majority of our customers are satisfied or very satisfied with the current level of reliability.[53] Regional stakeholders supported local investment to increase capacity for businesses and households or to address particular reliability concerns. Also, the majority of customers indicated that they would accept small price increases to reduce the risk of fire danger arising from our network.

Customers are supportive of creating a smarter grid that facilitates new technologies and further utilises data from smart meters to enable us to better manage and react to changes in the network. Customers seek to better understand their energy consumption data to be more informed about their usage and consumption choices.

We have taken our stakeholder views and expectations into account in developing our expenditure forecasts for the 2016–2020 regulatory control period.

The capital expenditure has been properly allocated to standard control services in accordance with the principles and the policies in the Cost Allocation Method (**CAM**).[54]

This section should be read in conjunction with appendix E to gain a full appreciation of our proposal.

9.1 Overview of capital expenditure

Table 9.1 summarises our forecast capital expenditure, by category, for the 2016-2020 regulatory control period.

Table 9.1 Total capital expenditure ($m, real)

	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

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

54 This includes allocated costs between distribution services, allocated directly attributable costs, allocated shared costs between the relevant categories of distribution services and allocated directly attributable costs and shared costs.

	2016	2017	2018	2019	2020	Total
Gross direct capital expenditure	**433.4**	**436.5**	**425.2**	**411.4**	**422.7**	**2,129.1**
Add 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

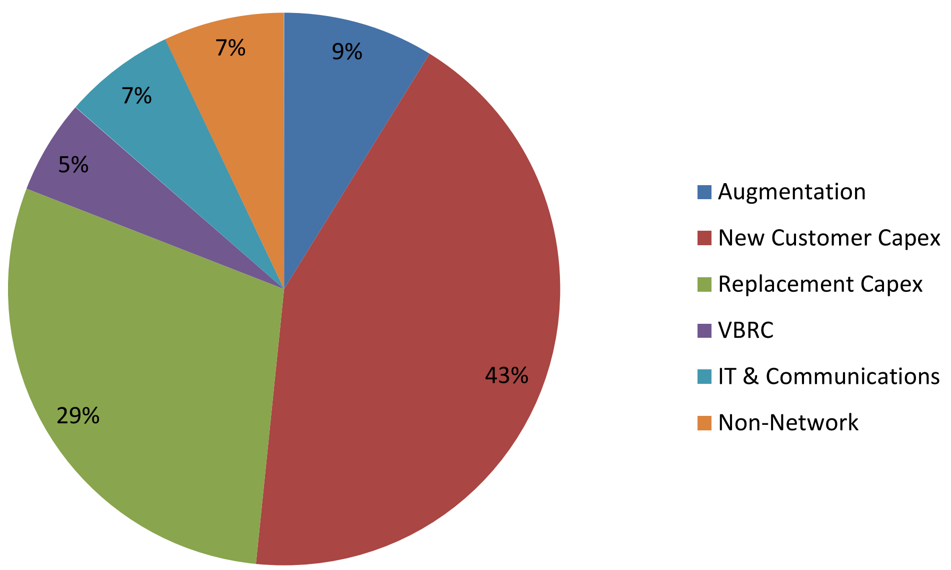
9.1.1 What we have delivered

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

The largest proportion of our gross capital expenditure was spent on new connections, as shown in figure 9.1. We had around 47,000 net additional customers connect to our network over the period 2011-2014. This includes the connection of several large wind farms in western Victoria, as well as a number of large industrial customers.

Replacement expenditure to maintain the reliability of the network was the second largest expenditure category, where we have continued to provide a network that is available over 99.96 per cent of the time.

Figure 9.1 Capital expenditure by category in the current regulatory control period



Source: Powercor

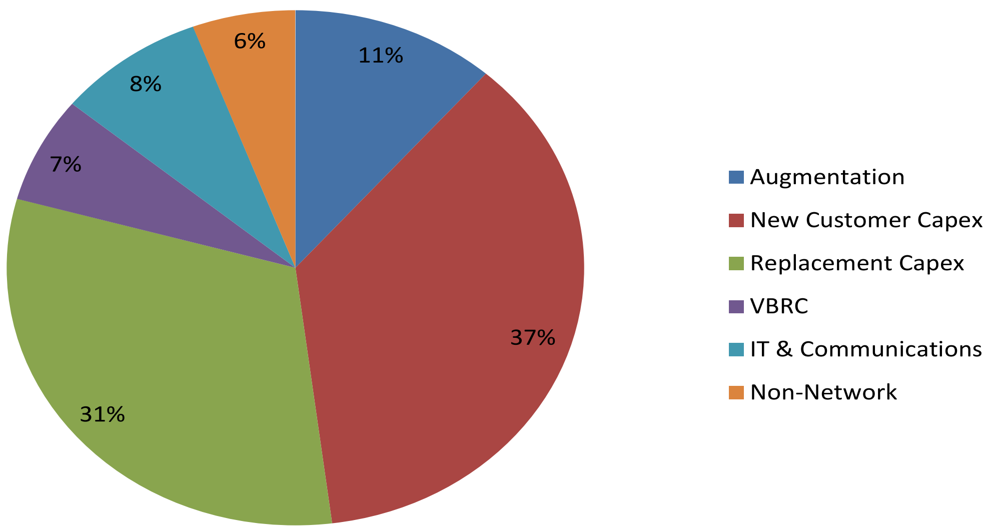
We constructed a new zone substation in Gisborne as well as installing new assets to meet increasing demand or to increase capacity to address reliability and quality of supply of the network. Augmentation expenditure comprised only nine per cent of total expenditure.

We also incurred expenditure related to the Victorian Bushfire Royal Commission (**VBRC**) recommendations for specific activities that we were obligated to undertake during the period. These activities were funded through an additional allowance provided by the AER in 2012, as the obligations were not known at the time of the 2010 regulatory determination.

9.1.2 What we plan to deliver

We have determined the amount of capital expenditure that we need to spend during the 2016-2020 regulatory control period to ensure that we continue to provide a safe and reliable electricity supply to our consumers, while also meeting our regulatory obligations. The breakdown by capital expenditure category is shown in figure 9.2.

Figure 9.2 Forecast capital expenditure by category (excluding equity raising costs)



Source: Powercor

The largest category of capital expenditure is expected to be new customer connections. Replacement expenditure is expected to be the second largest category, accounting for around 31 per cent of capital expenditure.

Our planned network capital expenditure is primarily driven by the following factors:

- large and specific connection projects as a result of expansion of the dairy industry, new wind farm 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;
- mitigating the potential for an increased failure rate on aging lines and poles by stepping up the rate of replacements; and

- mitigation of the risk of powerlines starting bushfires in response to the Victorian Bushfire Royal Commission.

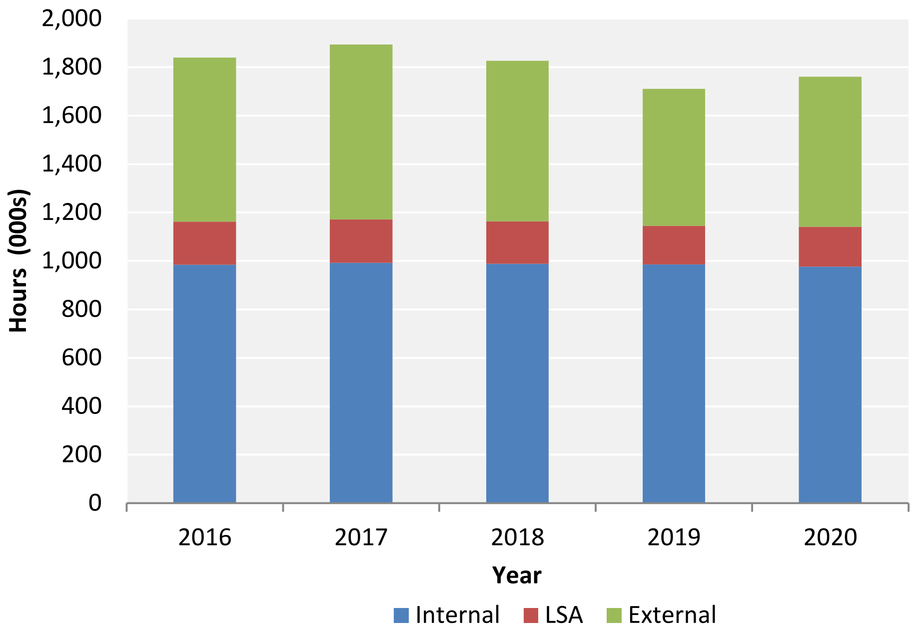
We have developed a deliverability plan to ensure that we are able to provide the necessary works over the 2016—2020 regulatory control period. Our deliverability plan will utilise internal labour resources which will be supplemented, as required, by use of external subcontractors. We have established a number of arrangements to ensure that we 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 area; and
- access to agency and limited tenure personnel.

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. Refer to appendix B which discusses the efficiency of labour costs and provides a detailed explanation of our resource arrangements.

Our proposed deliverability plan for network-related works, by work hours, is shown in figure 9.3.

Figure 9.3 Deliverability plan by internal and external labour capability



Source: Powercor

LSAs and panel contractors provide us with a degree of flexibility in allocating resources to meet varying annual workload levels. These flexible arrangements enable us to minimise the costs of engaging external resources to assist it in delivering services required by our customers.

9.2 Replacement expenditure

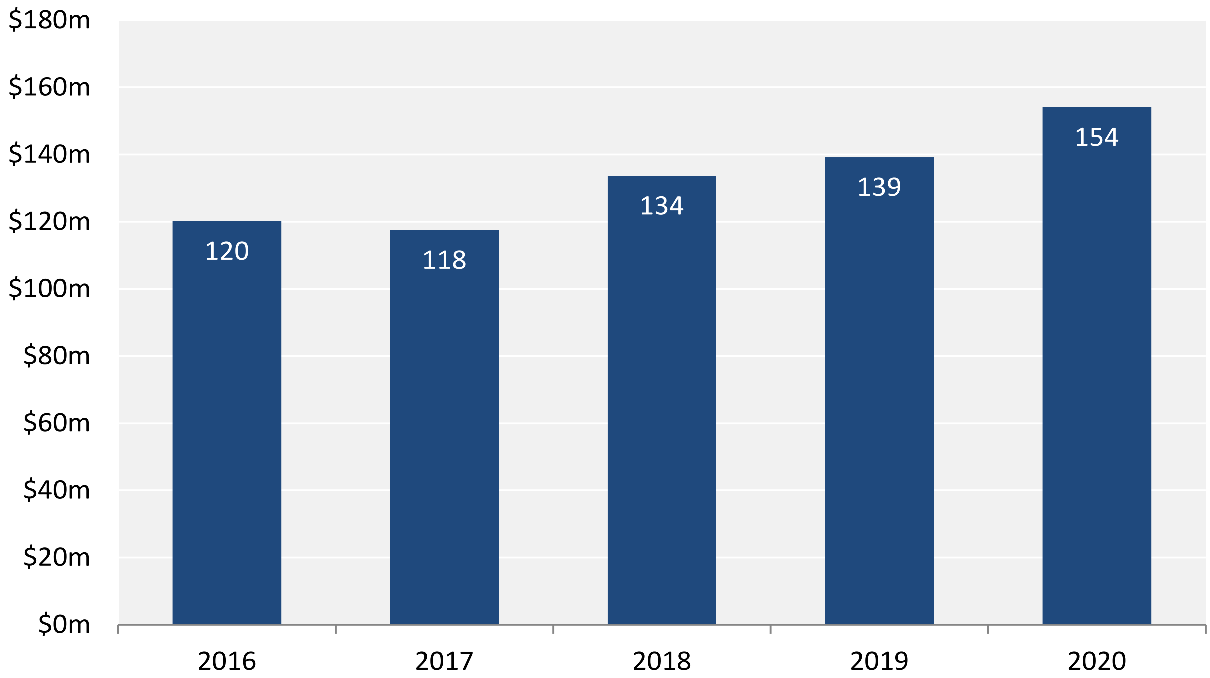
We are committed to taking a targeted and cost effective approach to the replacement and refurbishment of our assets.

Our proposed capital expenditure will enable us to continue to maintain the safety, security and reliability of the network, while minimising outages for our customers. That is, the expenditure will allow us to 'keep the lights on'.

This section explains why our forecast capital expenditure for replacement is required in order to continue to deliver a safe and reliable electricity supply to our customers.

The profile of our forecast replacement expenditure is shown in figure 9.4.

Figure 9.4 Forecast direct replacement expenditure including real escalation ($m, real)



Source: Powercor

9.2.1 What we have delivered

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

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

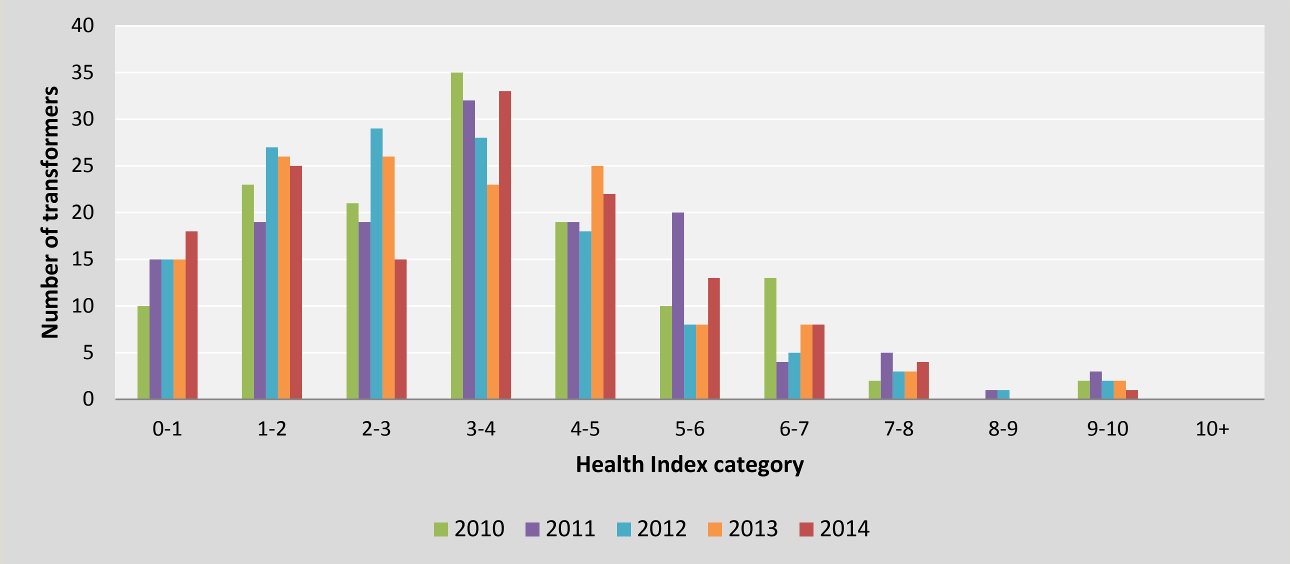
- replaced over 4,000 poles;
- replaced over 40 kilometres of underground cables and 136 kilometres of overhead cables;
- replaced seven transformers in zone substations— the three transformers in the Castlemaine zone substation that had all been installed prior to 1950 were replaced with a single larger standard unit;

- replaced ten 66kV circuit breakers and 17 HV circuit breakers; and
- replaced control and protection equipment at 19 zone substations.

Maintaining the HI

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

Figure 9.2.1 Maintaining the HI over the current regulatory control period



Source: Powercor

This demonstrates that our expenditure during the 2011–2015 regulatory control period was appropriate.

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

In addition, we received a direction in 2012 from Energy Safe Victoria (**ESV**) to install new generation automatic circuit reclosers (**ACRs**) on Single Wire Earth Return (**SWER**) lines in specific high risk areas in the High Bushfire Risk Areas (**HBRA**). We installed 178 new electronic SWER ACRs, controlling 179 SWER lines in the highest risk bushfire areas in 2012/13.

9.2.2 How we prepared our forecasts

We apply the following condition-based asset management methodologies to our 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 our asset management procedures and 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 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 methodologies 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 and wires. It involves regular physical inspections of the assets, where defects are identified.

The RCM methodology 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 for the asset is developed which considers the type of defects, the possible impacts and the viable inspection and maintenance tasks.

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 interim measures to prolong the life of the asset, such as pole staking.

The performance of assets is monitored to identify where the developed maintenance plan is not achieving the outcomes intended by the strategy. This provides a feedback mechanism for the routine review of each policy, to ensure that it remains appropriate and efficient, also taking into account cost, industry developments, and changed environmental conditions. As a result, the policies continue to evolve and improve through this rigorous process.

In forecasting the expenditure for poles and wires, we have used the following process:

Figure 9.5 Process for forecasting expenditure for poles and wires

Step 1 • Estimate number of assets inspected each year

Step2 • Calculate historical defect rate

Step 3 • Forecast number of defects (step 1 x step 2)

Step 4 • Calculate expenditure to remedy defects (step 3 x unit cost)

Step 5 • Calculate supplementary cost of replacement

Step 6 • Total replacement expenditure (step 4 plus step 5)

Source: Powercor

Our replacement costs have been based on the average rate over the period from 2011 to 2014 for each asset category. Because it is more efficient completing several jobs on multiple assets when dispatching a work crew to the field, rather than completing an individual asset job and returning to the depot, we capture total costs for a program of work, and then allocate the costs to the asset categories. As a result the averages accurately reflect the cost of delivering the total program of works but are less reliable at an individual asset category level. The asset categories align with our internal reporting systems.

Transformers and switchgear

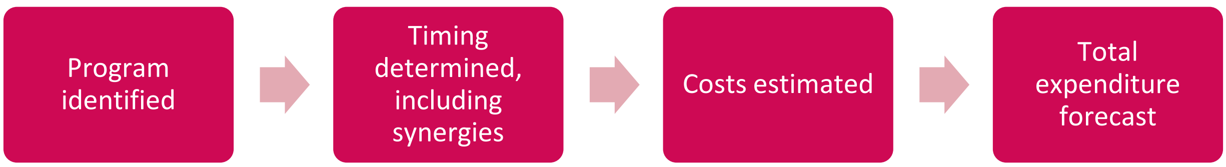
The CBRM methodology provides for a systematic framework to determine the replacement of major plant and equipment including, for example, transformers and circuit breakers. The variables include the following:

- asset condition – this is based on a HI which is a numeric representation of the condition of the asset;
- asset performance – this identifies the Probability of Failure (**PoF**) of an asset; and
- risk – this assesses the combination of PoF and the Consequence of Failure (**CoF**) for individual assets.

Under this methodology, a calculation is made for each individual item of plant and equipment in order to determine the year in which it will reach or exceed a threshold HI value. The methodology identifies a proposed year for the replacement of the asset. This 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 process to forecast assets using the CBRM methodology is set out below.

Figure 9.6 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 our 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 probability of failure, or in conjunction with other asset projects such as a planned augmentation or customer connection.

We have obtained cost estimates from a supplier for each of our large replacement projects. For smaller projects, our cost estimates have been derived from historical project costs for similar projects.

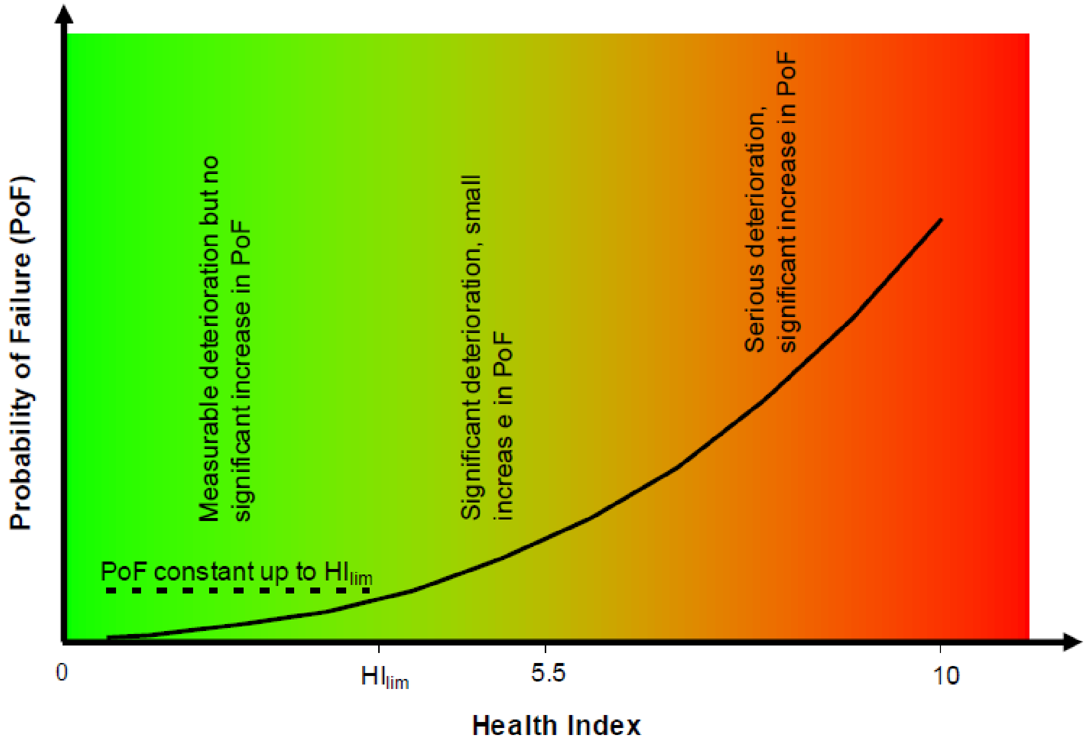
Approach to checking the reasonableness of expenditure forecasts using top-down measures

In order to check that our expenditure forecasts are reasonable, sustainable and enable us to prudently and efficiently manage our 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 HI profile is used as a visual tool to understand at a high level the current condition of our major plant assets. The HI of an asset combines information relating to age, environment, duty, and specific condition and performance information. The HI is presented in a range from 0 to 10, where 0 is a new asset and 10 represents end of life.

An asset can accommodate significant degradation with very little effect on the risk of failure. However, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The relationship between the condition of the asset and hence the HI, and the risk of failure is shown in figure 9.7.

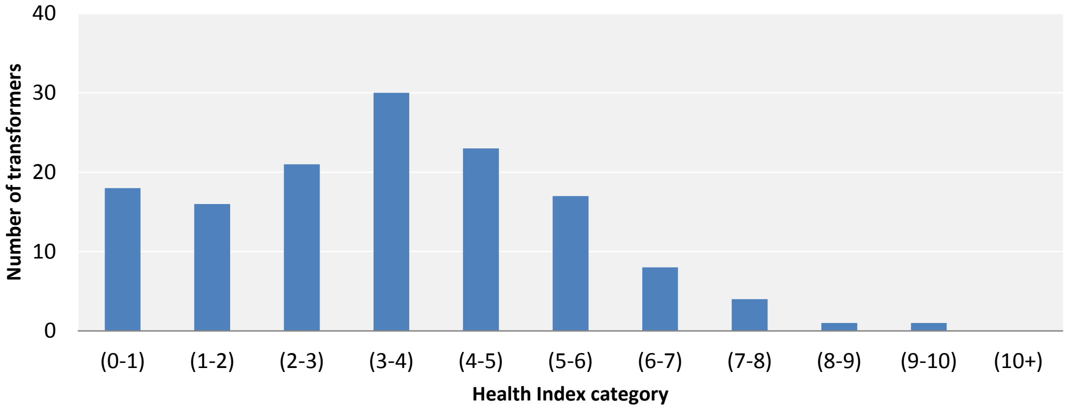
Figure 9.7 Relationship between HI and Probability of Failure



Source: Powercor

We focus on those assets with a HI of seven or above. An HI of seven 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. For our transformers in our zone substations, the HI at the start of the 2016–2020 regulatory control period is shown in figure 9.8.

Figure 9.8 HI of transformers at zone substations at the start of 2016



Source: Powercor analysis

We can use the CBRM models to generate HI profile predictions for future years to check the appropriateness of our expenditure forecasts. 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. This is particularly applied to that portion of the profile that is greater than or equal to seven, as from that point the rate of change of the probability of failure significantly escalates.

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 would suggest that a step up in expenditure is required.

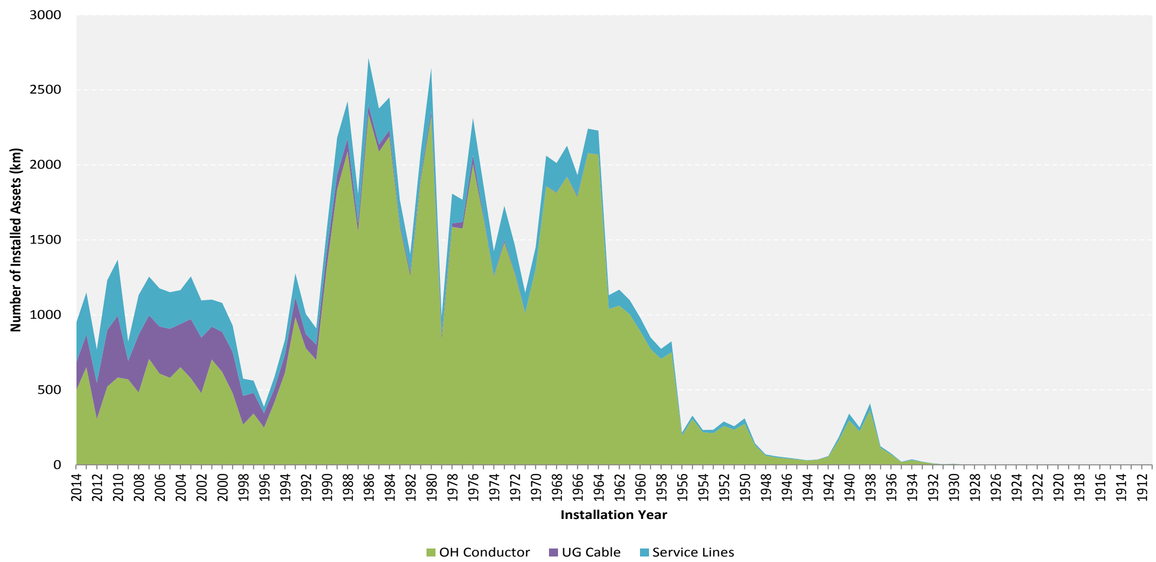
9.2.3 Drivers of expenditure

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.

We have an ageing network, with the majority of our current assets installed during the 1960s, 1970s and 1980s. This is shown in figure 9.9 containing the number of line assets installed (by kilometre) each year.

Figure 9.9 Powercor lines asset age profile



Source: Powercor

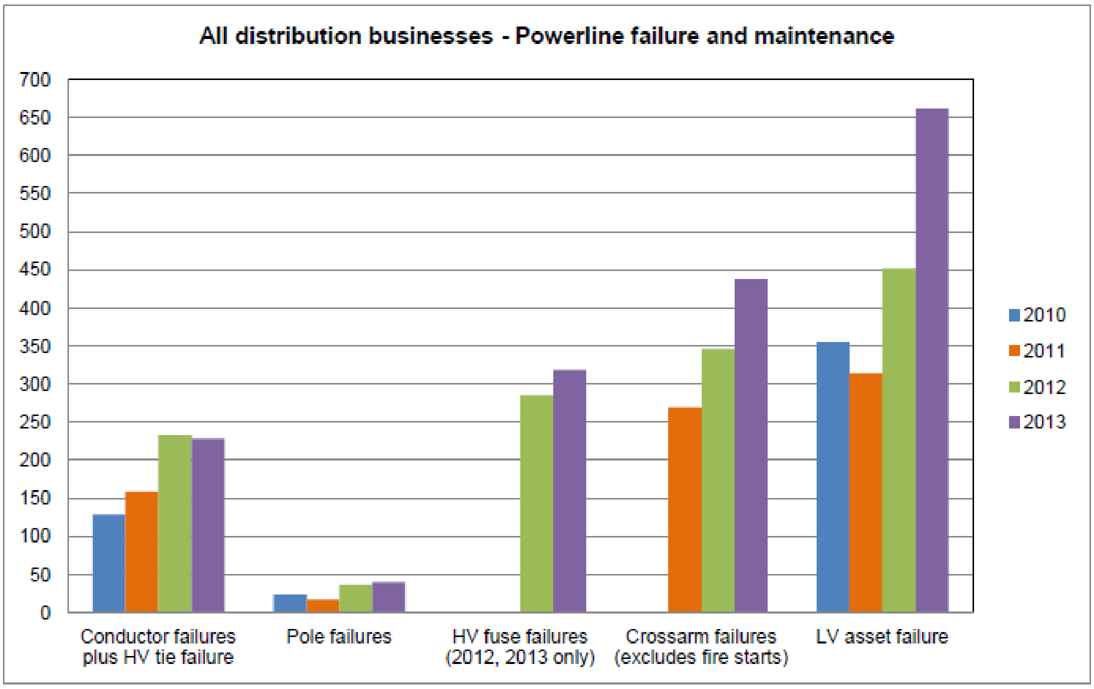
ESV has recently commented on the increasing failure rate across pole and wire assets, noting that:[55]

> *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.*

ESV has identified that we have an increasing failure rate for poles and conductors. [56] This is not inconsistent with the failure rates being observed by ESV across all of the Victorian distributors. Figure 9.10 shows the increasing failure rate across all Victorian distributors.

55 ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014, p. 61.
56 ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014, p. 64.

Figure 9.10 Powerline failure and maintenance across all Victorian distributors



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

ESV has also noted:[57]

> *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.*

The increasing failure rate of our 'poles and wires' assets is a key driver of our replacement expenditure.

9.2.4 Forecast expenditure

Our expenditure forecast is driven by the planned delivery of:

- increased replacement of poles and cross-arms to mitigate the increasing failure rate;
- the re-commencement of the replacement of high-voltage overhead conductor program following expected certainty from the Victorian Government's Powerline Bushfire Safety Taskforce (**PBST**) of its initiatives to address bushfire safety; 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.

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

Replacements of poles and wires

Replacement of poles, cross-arms and conductors is our largest area of forecast replacement expenditure. These assets are ageing, with the majority installed during the 1960s, 1970s and 1980s.

As the assets are maintained using the RCM process, we have forecast expenditure using the observed historical defect rate. As noted above, we experienced an increase in the failure rates on poles and cross-arms during the 2011–2015 regulatory control period. This increase in asset failures was noted by the ESV in its *2013 Safety Performance Report on Victorian Electricity Networks*.[58]

We need to continue to invest to replace these assets so that the reliability of the network does not deteriorate. In addition, the investment is needed to ensure the safety of these assets in the community.

Conductor replacement program

We intended to undertake a program to pro-actively replace overhead conductors during the current regulatory control period. This was to ensure the reliability of the conductors was maintained in light of continued ageing and deterioration of these assets especially in rural areas where lines were not being augmented as a result of demand increases.

However, following the recommendations of the VBRC to progressive replace all SWER line and 22kV feeders in Victoria,[59] the PBST recommended the targeted replacement of powerlines with underground or insulated cable in the highest fire loss consequence areas.[60]

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

The program was recommenced in 2014 after the areas targeted by the PBST recommendations were identified. This program is expected to continue over the 2016-2020 regulatory control period and beyond, focused on the rural areas of the network. The proactive program is necessary given the large volume of conductor approaching end of life and the potential risk they may pose to public safety.

Replacement of transformers and switchgear

To maintain the HI profile of transformers at zone substations, we need 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.

We also need to address the high HI associated with circuit breakers in around eight of our zone substations. Our 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 our intervention program includes both replacement and refurbishment strategies to address the advancing HI profile. We intend to replace the switchgear in five zone substations and refurbish in ten zone substations.

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58 ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014.
59 2009 Victorian Bushfires Royal Commission, Final Report, July 2010.
60 PBST, Final Report, 30 September 2011, p. 6.

Checking the reasonableness of our forecasts

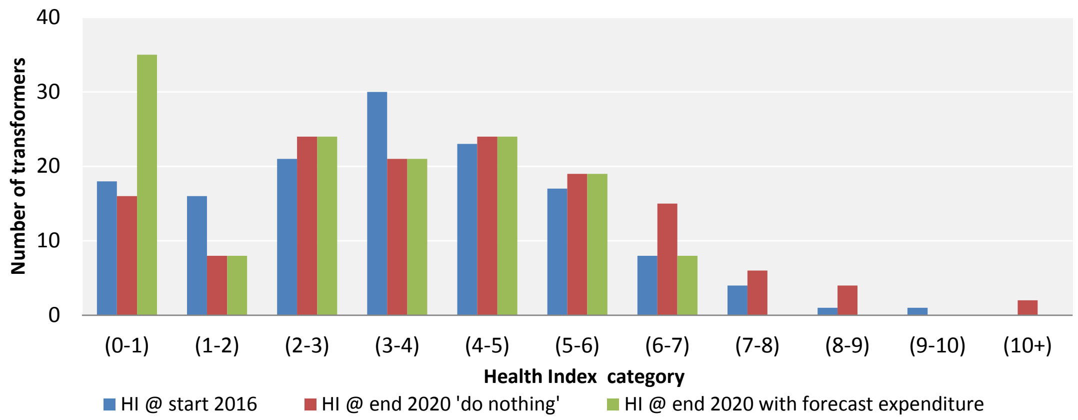
As noted above, we are able to undertake a top-down check that our expenditure forecasts are reasonable, sustainable and will enable us to prudently and efficiently manage our ageing and deteriorating large assets using current strategies, maintenance policies and operating practices by using the HI profile predictions for future years.

We have created the HI profile at the end of the current regulatory period and compared that to:

- the profile that would occur if we 'do nothing' over the 2016–2020 regulatory control period; and
- the profile that would occur if we undertake the investments set out in this Regulatory Proposal.

Using transformers in zone substations as an example, figure 9.11 shows that our forecast expenditure is reasonable as we are able to appropriately maintain the number of transformers with a HI of seven or above, as well as maintain the overall HI profile. If we did not undertake any investment over the 2016–2020 regulatory control period, then the number of zone substations with transformers with HI of seven or above would rise from six to 12.

Figure 9.11 HI profiles of transformers in zone substations



Source: Powercor analysis

The HI profile forecast graphs for 66kV circuit breakers and 22/11kV circuit breakers show a similar trend.

9.2.5 Replacement (repex) model

In the Forecast Assessment Expenditure Guidelines, the Australian Energy Regulator (**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.[61] The AER used this model in our 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:

- operational history;
- environmental condition (e.g. damp or dry, or coastal or inland); and

[61] AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, Explanatory Statement, November 2013, p. 185.

- quality of its design and installation (including early-life failures of assets).[62]

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.[63] As a result, 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.

Repex model output

The AER's repex model simplistically predicts the volume of replacement based on the age of system assets on a distributor's network by asset category.

The AER's model indicates that the largest category of replacement costs will be for poles, which is consistent with our 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, noting:[64]

> *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*

[62] AER, Electricity network service providers Replacement expenditure model handbook, November 2013, p. 9.
[63] AER, Electricity network service providers Replacement expenditure model handbook, November 2013, p. 9.
[64] Parsons Brinckerhoff, *Repex model review CitiPower – Powercor*, July 2010, p. vi.

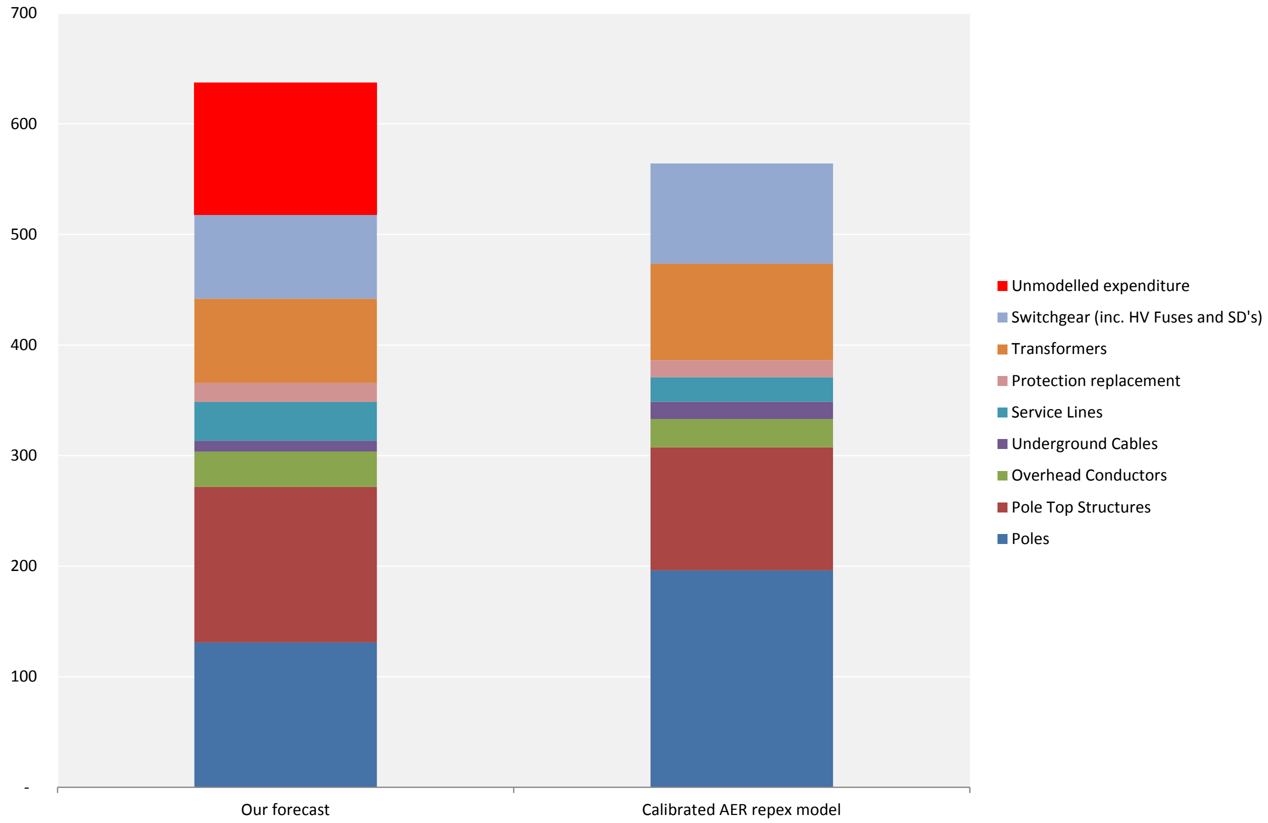
significant adjustment applied by Nuttall's for this activity code, PB considers that the use of a calibrated life that is well beyond normal industry expectations, may significantly understate the reasonable level of total replacement capex required over the next regulatory control period.

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

Reconciliation of the repex model

The repex model forecasts around the same level of overall expenditure for replacement related works compared to our own forecasts. For the elements of replacement expenditure where the cost drivers are covered by the repex model for standard control services, our forecasts are lower than the forecasts from the repex model. This is shown in figure 9.13.

Figure 9.13 Comparison of our forecast to repex model forecast output ($m, real)



Source: Powercor
Note: excludes labour escalation

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'.[65]

We calculate that the repex model drivers cover 81 per cent of our replacement expenditure.

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

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.

The AER's repex model does not capture our proactive program to replace overhead conductors. Nor does it include costs such as property refurbishments, for example 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 AER's repex model. A specific example is that the repex model does not include building civil replacement costs associated with the Sunshine zone substation.

The AER's repex model also does not capture expenditure associated with management of environmental matters, for example, the reduction of noise to ensure compliance with Environmental Protection Authority (**EPA**) standards, or the replacement of line coverings preventing bird interference.

9.3 Augmentation expenditure

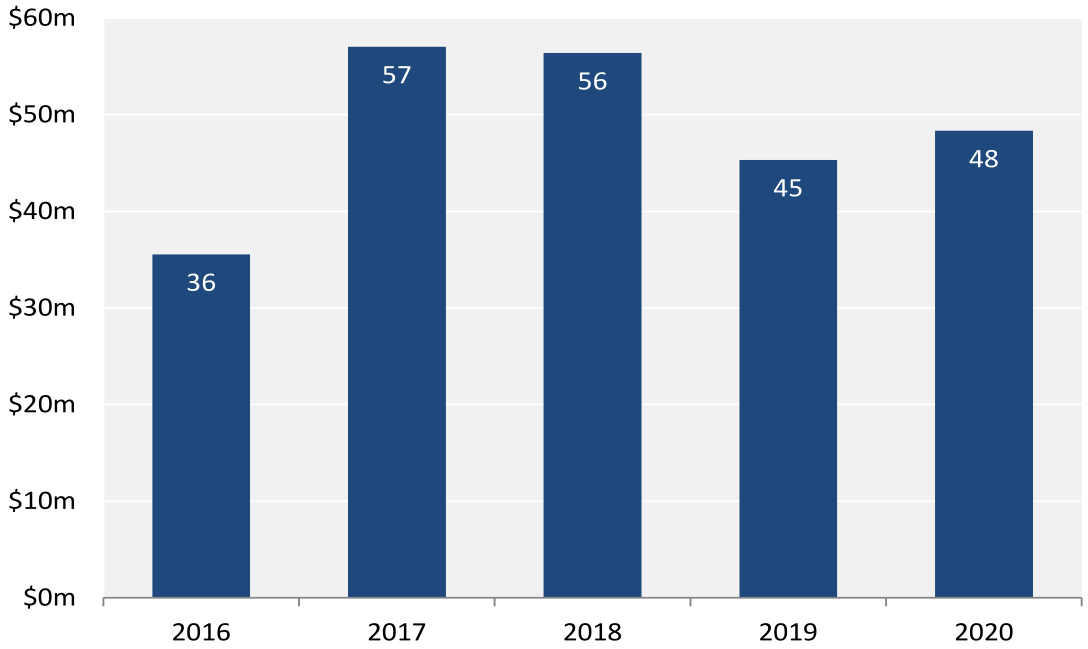
To ensure we continue to support the growth and development of our communities, we need to target our investment in high growth areas to meet future demand.

Our proposed capital expenditure will also allow us to undertake augmentation to maintain the security, reliability and quality of supply of the network.

This section explains why our forecast expenditure for augmentation is required in order to meet or manage the expected demand over the 2016-2020 regulatory control period.

The profile of our forecast augmentation expenditure is shown in figure 9.14.

Figure 9.14 **Augmentation direct capital expenditure including real escalation ($m, real)**



Source: Powercor

Augmentation capital expenditure comprises:

- demand driven expenditure to upgrade the capacity of the existing distribution network, in response to local or regional 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.

9.3.1 What we have delivered

We have delivered a range of projects to increase the capacity of the network over the 2011–2015 regulatory control period, including:

- construction of a new zone substation at Gisborne (**GSB**) together with new 22kV feeders to serve the residential customer growth;
- installation of five new transformers at zone substations as well as new capacitor banks at three zone substations;
- construction of two new sub-transmissions lines to 66kV standard, although they are operating at 22kV until the network is further augmented;
- uprated a number of sub-transmission lines in the greater Geelong the Bellarine Peninsula area, another from Ballarat to Bacchus March and commenced the uprate of the line from Bendigo to Charlton;
- construction of seven new feeders; and
- commissioned upgrades to the supply from three terminal stations, including the Keilor terminal station (**KTS**) to manage risk until Deer Park terminal station (**DPTS**) is built.

Use of demand management

We have used demand management initiatives in the current regulatory period to defer network augmentation. For example, we are installing a battery south of Ballarat in a trial to manage maximum loads to a constrained rural long 22kV feeder.

We are using a Lithium Ion battery that is housed in two 40ft shipping containers. The battery will store energy from the grid, and be utilised to:

- defer augmentation of the 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.

9.3.2 How we prepared our forecasts

Our forecasting methodology for augmentation expenditure differs depending on whether the network constraint is demand or non-demand driven.

Demand driven

For augmentations that are driven by increasing demand on the distribution network, we have undertaken the steps outlined in figure 9.15 to forecast expenditure. This process is consistent with the methodology that is set out in the Distribution Annual Planning Report (**DAPR**).

Figure 9.15 Process to forecast augmentation capital expenditure

Source: Powercor

The forecasts for peak demand across our network assets have been determined using the following process, which is described in more detail in chapter 8:

- top–down independent econometric forecasts at the terminal station and across our network have been undertaken by the CIE, an independent economic forecaster;
- 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 forecasts;
- the reconciled zone substation forecasts have been used to model forecasts of maximum demand on each sub-transmission line and zone substation.

The forecasts do not apply a growth rate to large industrial loads. These are only adjusted upon advice from the customer regarding an increase in load or by applying local knowledge in respect to a known closure of a plant or industrial type load.

Given the demand forecasts, using the probabilistic planning approach we assess and value the amount of load and energy that would not be supplied on our network assets if an element of the network is out of service. For example, we calculate the amount of unserved energy at a zone substation if one of the transformers fails.

The energy at risk is assessed against our internal policies to determine whether it is sufficient to trigger a review of the network constraint. Where it is sufficient, we assess a range of options to address that network constraint, including non-network options.

For large augmentation projects over $5 million that are subject to a distribution Regulatory Information Test (**RIT-D**), then we undertake a detailed assessment process to determine the value of supply reliability from the customer's perspective, using the latest values of customer reliability (**VCR**) as calculated by the Australian Energy Market Operator (**AEMO**). This is then compared to the costs of the different options, including non-network solutions, to determine the preferred option, which is the credible option with the highest net economic benefit.

The large reduction in the AEMO VCR values between 2013 and 2014 resulted in the deferral of some projects that were intended to be undertaken in the 2016–2020 regulatory control period.

The change in VCRs impacts the reliability targets for the Service Performance Target Incentive Scheme (**STPIS**), and will result in lower reliability for our customers going forward.

For smaller augmentation projects, we conduct a detailed investigation into possible network and non-network solutions to address the network constraint, and the most cost effective solution is chosen as the preferred option.

We have obtained cost estimates from a supplier for each of our large augmentation projects. For smaller projects, our cost estimates have been derived from historical project costs for similar projects.

Approach to checking the reasonableness of our forecasts using top-down measures

We use load indices to provide a high level indication of demand-related network risk and performance of assets on our network. In addition, it can be used to check the appropriateness of our bottom up augmentation expenditure forecasts.

The load index measures applied in the United Kingdom (**UK**) have been adapted to accommodate the greater spread of load conditions on our network, reflecting the use of probabilistic planning standards rather than deterministic standards.

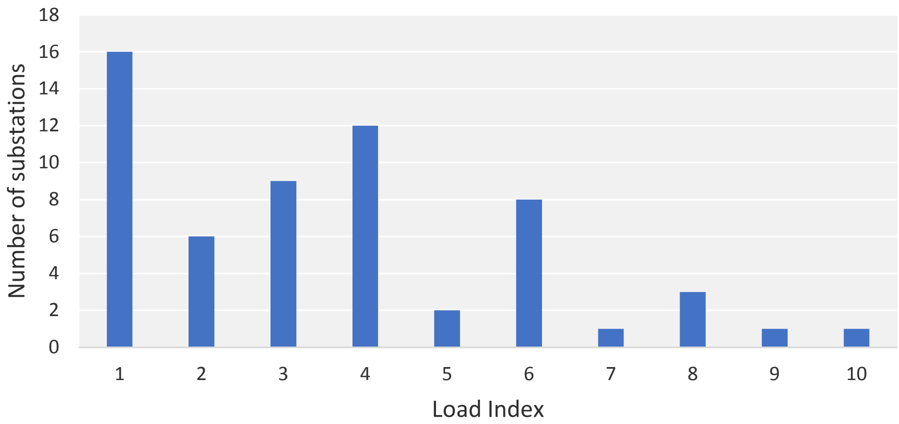
The load index is generated from two factors;

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

The load index is placed on scale from one to ten, with an index of one indicating that there is no load at risk under peak load conditions, and an index of ten indicating that load shedding is likely to occur, resulting in significant loss of supply and/or time required to restore supply, as the peak load is forecast to exceed the N-1 capacity of the zone substation.

Our expected load index profile at the start of the 2016-2020 regulatory control period is shown in figure 9.16.

Figure 9.16 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 we have several zone substations that have more than 500 hours at risk in the event of an outage of a transformer at the zone substation (represented as a load index of seven or eight). This includes all single transformer zone substations. Additionally, we have a zone substation that is approaching its normal capacity at times of peak demand (represented as load index of nine), and one that is forecast to exceed its normal capacity at times of peak demand leading to load shedding (a load index of ten). Given the load indices, we need to augment the network.

We can use the demand forecasts generate load index profile predictions for future years to check the appropriateness of our 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. This is particularly applied to that portion of the profile that is greater than or equal to seven.

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.

Non network alternatives

There are a range of non-network solutions that can be used by electricity networks to defer demand-driven network augmentations, 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);

- converting the appliance energy source from electricity to an alternative (eg: switching from electric to gas heating);
- 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 and renewable fuel sources;
- use of stand-by generators to enable load transfer; 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.

Non-demand driven

As noted previously, augmentation expenditure may also be driven by non-demand factors such as ensuring the security, reliability and quality of supply of the network.

Quality of supply issues in the network are identified during the process to identify possible demand-driven constraints. That is, we consider whether the forecast changes in demand, both changes in load growth and embedded generation (e.g. solar PV growth), may result in the prospective fault current or voltage levels being outside the allowable limits.

Security of supply is often considered alongside a demand-driven augmentation project. We would consider improving the security of supply particularly where there is:

- a single transformer at a zone substation;
- radial sub-transmission lines; and
- in our oldest zone substations, banked configuration of the transformers.

For example, if a major demand-driven augmentation is planned at a zone substation, then we would consider the incremental costs of upgrading the banked switching configuration of the transformers to the current standard of being fully switched. This would enable supply to be maintained without any intermittent loss of supply in the event of a transformer outage.

If no demand-driven augmentation is planned that will address the network constraint, then we will consider options to address the issue.

Cost estimates for each large augmentation project have been individually estimated. For smaller projects, our cost estimates have been derived from historical project costs for similar projects.

9.3.3 What we plan to deliver

Our expenditure forecast is underpinned by the following key drivers:

- localised demand growth from growth in population, particularly in the western suburbs of Melbourne and the greater Geelong 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 which is discussed in the box below;
- installation of voltage regulators to ensure the voltage levels do not exceed the thresholds required by the regulations or equipment.

These are discussed below.

Demand driven

Chapter 8 discusses the forecasts for peak demand across our network. Some of the larger augmentation projects that we intend to undertake to address the localised increase in demand include:

- construction of the Truganina (**TNA**) zone substation to address demand growth in the western suburbs of Melbourne, which is associated with the works to address the constraint at the Keilor Terminal Station;
- construction of a new zone substation in Torquay (**TQY**) and two sub-transmission lines to serve TQY from the Waurn Ponds (**WPD**) zone substation, which was a project that was efficiently deferred from the current regulatory period;
- installation of two larger transformers at the Geelong East (**GLE**) zone substation to also support growth in the Greater Geelong region; and
- installation of a new transformer in the Merbein (**MBN**) zone substation to support irrigation needs in the greater Mildura area.

The first two projects are discussed below.

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.

Augmentation expenditure is not a large part of our overall capital expenditure. In the current regulatory period, only 9 per cent of total capital expenditure relates to augmentation works. For the 2016–2020 regulatory control period, we expect to spend only 11 per cent of capital expenditure on augmentation works.

<u>New Truganina zone substation</u>

We will commence works associated with the DPTS, including the TNA zone substation, in 2015.

We undertook a joint Regulatory Test with Jemena Electricity Networks and AEMO to address a system limitation at the KTS**.** This is one of the points where Powercor and Jemena connect to the transmission network.

System limitations were also identified on the sub-transmission lines from KTS that serve Melton (**MLN**), Sunbury (**SBY**) and Sydenham (**SHM**) zone substations. SBY and SHM are zone substations for Jemena.

The final report, published on 24 April 2012, recommended the construction of a new terminal station at Deer Park. The regulatory test demonstrated 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 included:

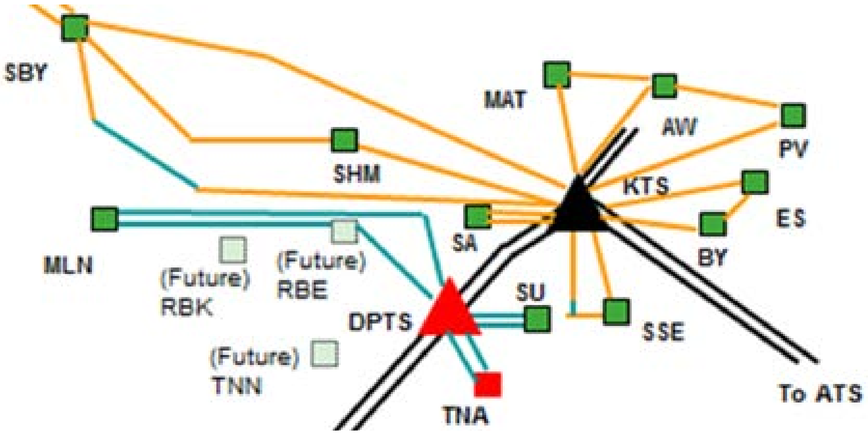
- construction of 66kV sub-transmission lines from DPTS to a new Powercor zone substation at Truganina;
- construction of 66kV sub-transmission lines to transfer the existing MLN zone substation to DPTS, relieving constraints at KTS. As part of this work, the existing KTS to MLN and MLN to SBY 66kV sub-transmission 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 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 9.17.

Figure 9.17 Schematic of the Deer Park terminal station and associated works



New Torquay zone substation

The construction of TQY is needed to address the forecast increases in demand as well as voltages on the 22 kV feeders from the WPD.

Peak demand at WPD 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.

We constructed new 22 kV 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 we also plan to install equipment 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 regulated standards.

The construction of TQY was initially planned for the current regulatory control period, however we were able to efficiently defer the project due to the later than forecast start of large residential developments in the Geelong area, such as the Armstrong Creek subdivision.

Delay at Armstrong Creek

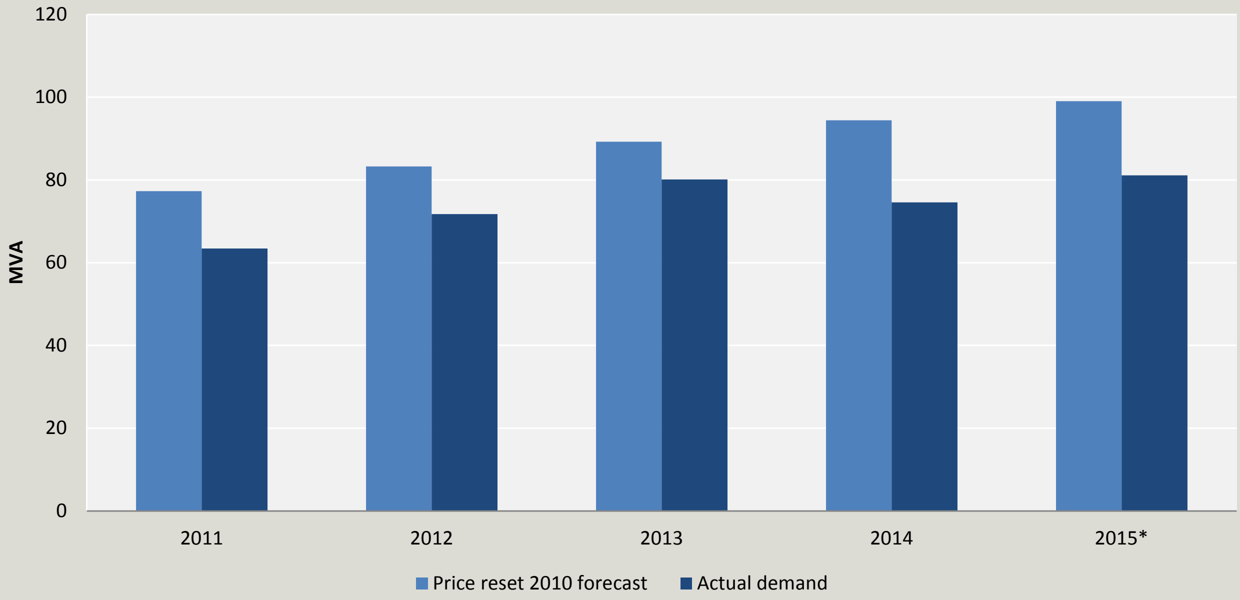
The Armstrong Creek growth area consists of 2,500 hectares of contiguous land and will provide housing for between 55,000 and 65,000 people. It will comprise of approximately 22,000 residential homes.[66]

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 WPD zone substation. Our forecast of peak demand in 2010 is shown in figure 9.18, together with the actual peak demand that has materialised.

Figure 9.18 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 our 2010 DAPR, we forecast that by 2014, the annual hours at risk at WPD would be 215 hours if we did not undertake an augmentation. However, in our 2013 DAPR, we expected there to be only 80 hours at risk in 2014. The reduction in the annual hours at risk allowed us to efficiently defer the commencement of the augmentation at WPD.

The Armstrong Creek development has now commenced.

[66] 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

Checking the reasonableness of our expenditure forecasts

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

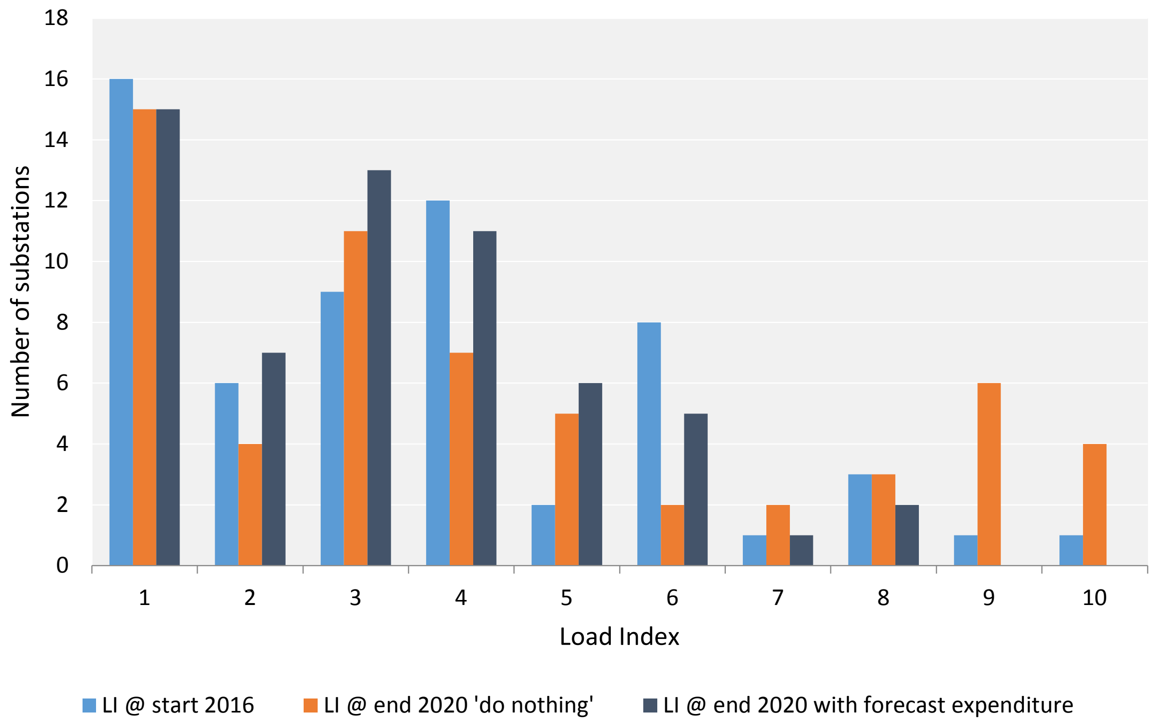
We have created the load index profile at the end of the current regulatory period and compared that to:

- the profile that would occur if we 'do nothing' over the 2016-2020 regulatory control period; and
- the profile that would occur if we undertake the investments set out in this Regulatory Proposal.

The comparison of these profiles allows us 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.

Figure 9.19 shows that our forecast expenditure is reasonable as we are able to appropriately maintain the number of zone substations with a load index of seven or above, as well as maintain the overall load index profile. If we did not undertake any investment over the 2016-2020 regulatory control period, then the risk on our network will increase substantially.

Figure 9.19 Load index profile of transformers in zone substations



Source: Powercor

In fact, around ten 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.

Non-demand driven

We must maintain our 22kV high voltage network within the specified thresholds for voltage, in accordance with the Victorian Electricity Distribution Code and the Rules.

The long distance between the customer and the voltage regulating equipment (e.g. transformers and regulators) means that lower voltage levels can result on our network if not carefully managed.

Voltage levels are important for the operation of 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.

Voltage levels are affected by a number of factors including:

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

As a result, we need to upgrade the 22kV lines, such as adding transformers to provide extra capacity and thereby address the voltage issues.

9.3.4 Augmentation (augex) model

In assessing augmentation expenditure forecasts, the AER indicates in its *Expenditure Forecast Assessment Guidelines* that the 'augex model' will be one of several tools used to review our forecasts.[67]

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 together with the forecast demand growth. When the peak demand of the asset reaches a certain proportion of its capacity, then it triggers augmentation.

Distributors usually use a complex range of forecasting methods to predict augmentation expenditure. However, the augex model attempts to simplify this process by essentially assuming a distribution network with rigid, deterministic planning criteria, and predicable augmentation methods. This results in the following model 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.

The simplifications in the augex model necessarily lead to a reduction in accuracy of the planning outcomes that would be expected from a distributor.

It is noted that 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.

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

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.[68] However, the AER decided not to rely upon that tool in the 2010 final determination on the basis that the model required further testing to ensure that the model could reliably forecast the augmentation capital expenditure that would reasonably reflect the capital expenditure criteria over the 2016-2020 regulatory control period.

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:

- the consultant who developed the augex model noted that it is a regulatory tool, and not a planning/management tool;[69]
- the AER indicated that in the Expenditure Forecast Assessment Guidelines that it may use the model in a deterministic manner;[70]
- 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 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.

We are therefore concerned about the use of the augex model by the AER to forecast the capital expenditure but the AER not considering the augex model appropriate to be used as a planning tool to address expected demand.

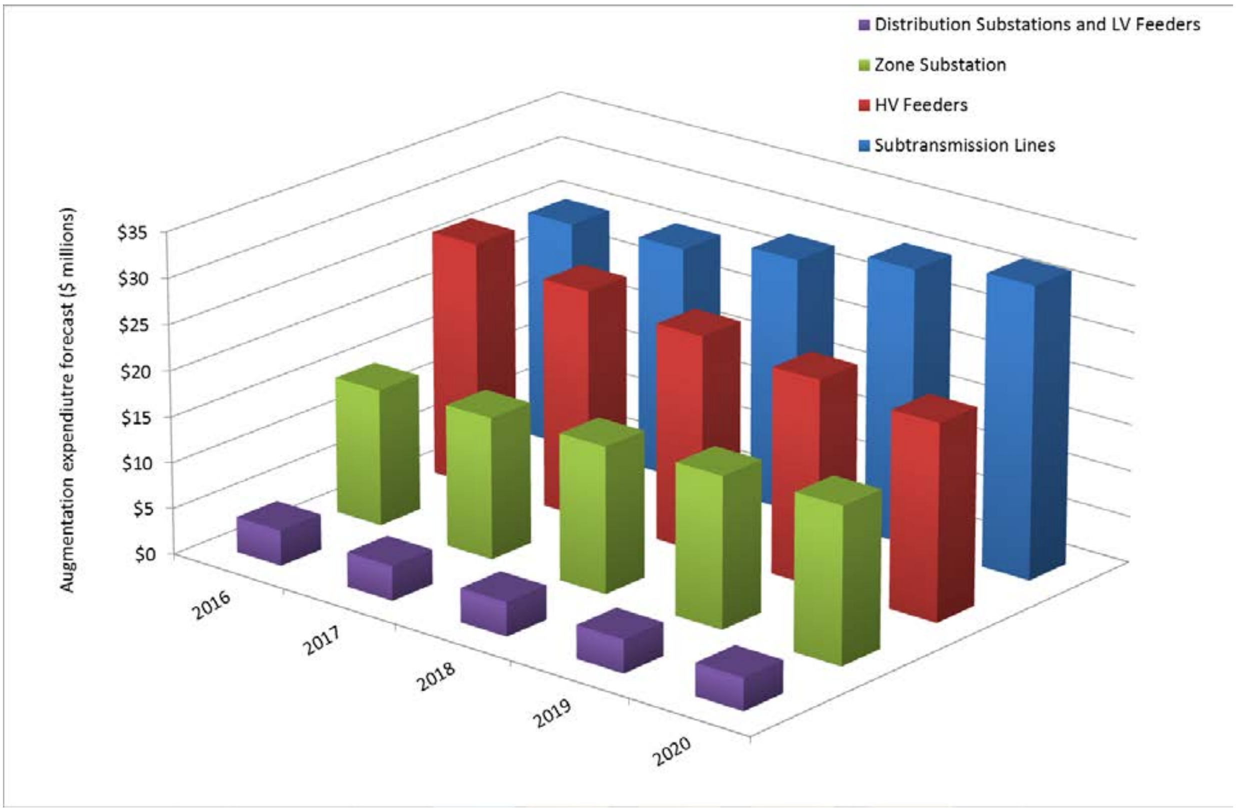
Furthermore, we note that the AER did not rely on the augex model in its draft decision in NSW, rather it only took into account trends in utilisation rates in a qualitative sense.[71]

Augex model output

We used a consultant, Jacobs, to assist us in populating the augex model. Jacobs have prepared a report which outlines the steps that were undertaken in the model population, including how it determined the input parameters.[72] The model is sensitive to small changes in the input parameters. The outputs of the model are shown in figure 9.20.

68 AER, Victorian electricity distribution network service providers distribution determination 2011-2015, draft decision, June 2010, p. 316.
69 AER, AER expenditure workshop no.4 slides – DNSP replacement and augmentation capex – 8 March 2013, available from https://www.aer.gov.au/node/19508.
70 AER, Expenditure Forecast Assessment Guideline for Electricity Distribution, Explanatory Statement, November 2013, p. 169.
71 For example, see AER, Draft decision Ausgrid distribution determination 2015–16 to 2018–19, Attachment 6: capital expenditure, November 2014, p. 6-35.
72 Jacobs, Powercor AER augex modelling assistance, 25 November 2014.

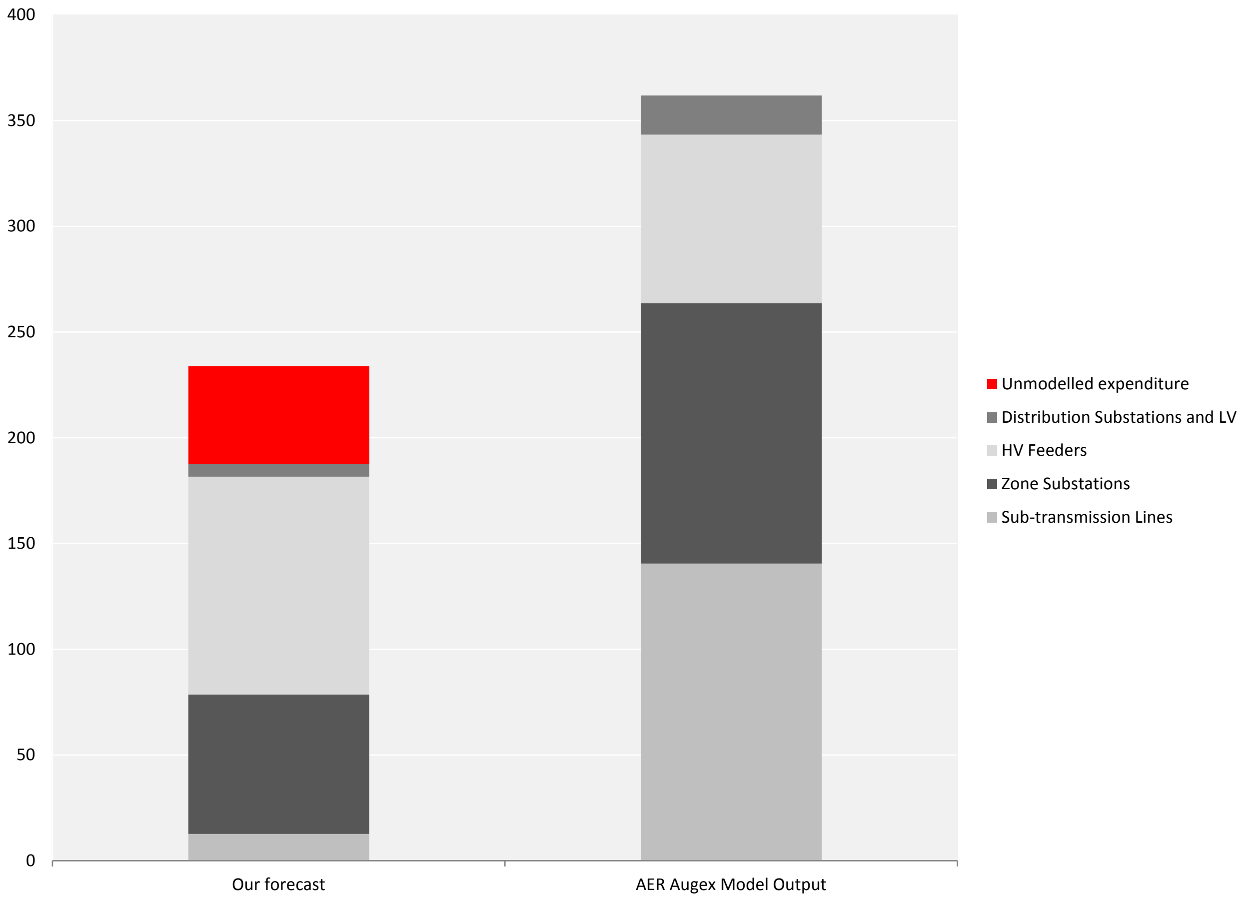
Figure 9.20 Augex model forecast output summary – annual expenditure



Source: Jacobs

The augex model forecasts a higher level of expenditure required for augmentation related works compared to our own forecasts, as shown in figure 9.21.

Figure 9.21 **Comparison of our forecast to augex model forecast output ($m, real)**



Source: Powercor
Note: direct costs excluding labour escalation

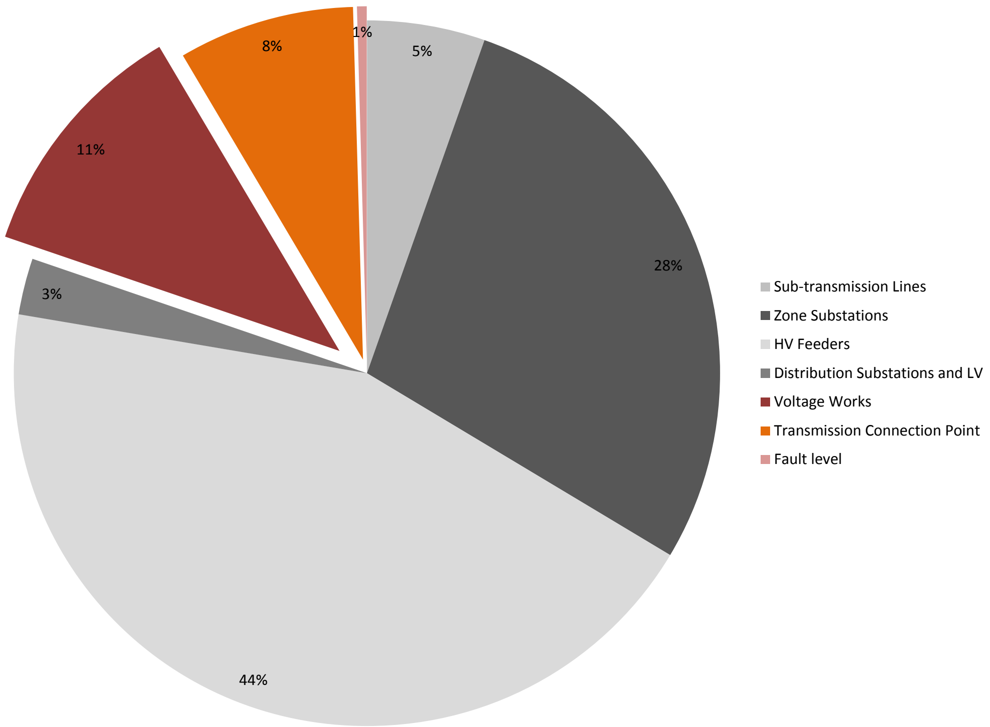
We estimate that the drivers of 80 per cent of our augmentation expenditure are covered by the AER's augex model.

The remaining 20 per cent of augmentation expenditure that is not covered by the augex model relates to:

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

This is shown in figure 9.22.

Figure 9.22 Powercor augmentation expenditure not captured by augex model



Source: Powercor

As we have previously discussed, DPTS is being constructed to address the transmission-level network constraint at the KTS. We are rearranging our existing sub-transmission lines so that the MLN and SU zone substations are served by DPTS rather than KTS.

We note that the augex model captures the works associated with the new TNA zone substation, as this is a demand-driven project that addresses constraints on the distribution network.

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

9.3.5 Synergies between augmentation and replacement

We are 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 matrix (figure 9.23) shows the Load and Health Indices for each zone substation that we expect at the start of the 2016-2020 regulatory control period. This takes into account expected works during the 2015 calendar year.

Figure 9.23 Load and health indices at zone substations at start of 2016

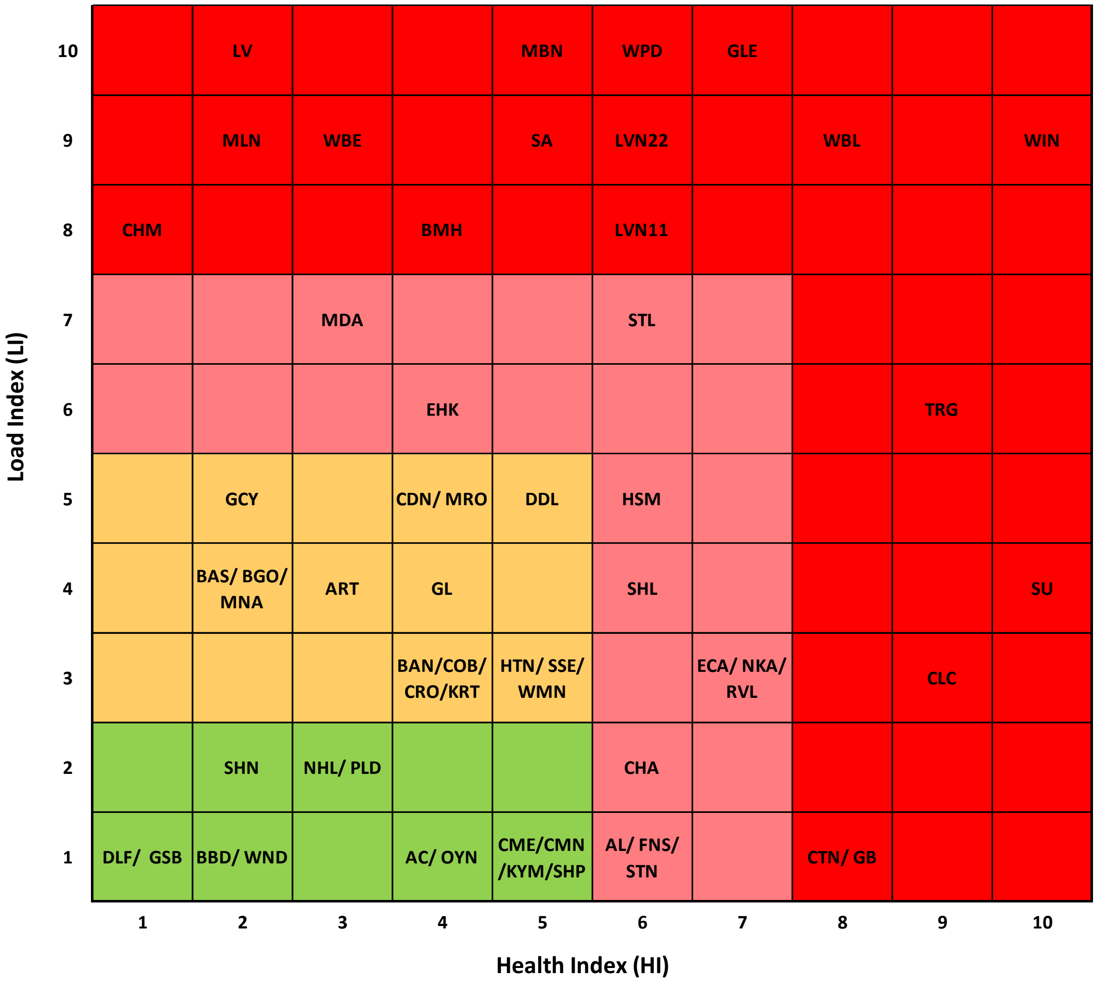
Load Index (LI) \ Health Index (HI)	1	2	3	4	5	6	7	8	9	10
10						GLE				
9					WPD					
8	CHM			KRT	LVN11					
7					MBN					
6		MLN	EHK/ MDA	BMH	LVN22		WBL	TRG	WIN	
5				MRO	STL					
4		BAS/BGO/ GCY/LV/M NA	ART/ GL/ WBE	CDN/ DDL	HSM/ SA					
3				CME/ COB/ WMN	CHA	ECA/NKA/ RVL/SHL				SU
2		SHN	BAN	CRO/SSE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

Source: Powercor

As can be seen, we have high load index at GLE, 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. We also have 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 we do not invest in augmentation and replacement works over the 2016-2020 regulatory control period, ie: 'do nothing', then an increasing number of zone substations will have Load and Health Indices as shown in the matrix in figure 9.24.

Figure 9.24 Load and health indices at zone substations at the end of 2020 in the 'do nothing' scenario

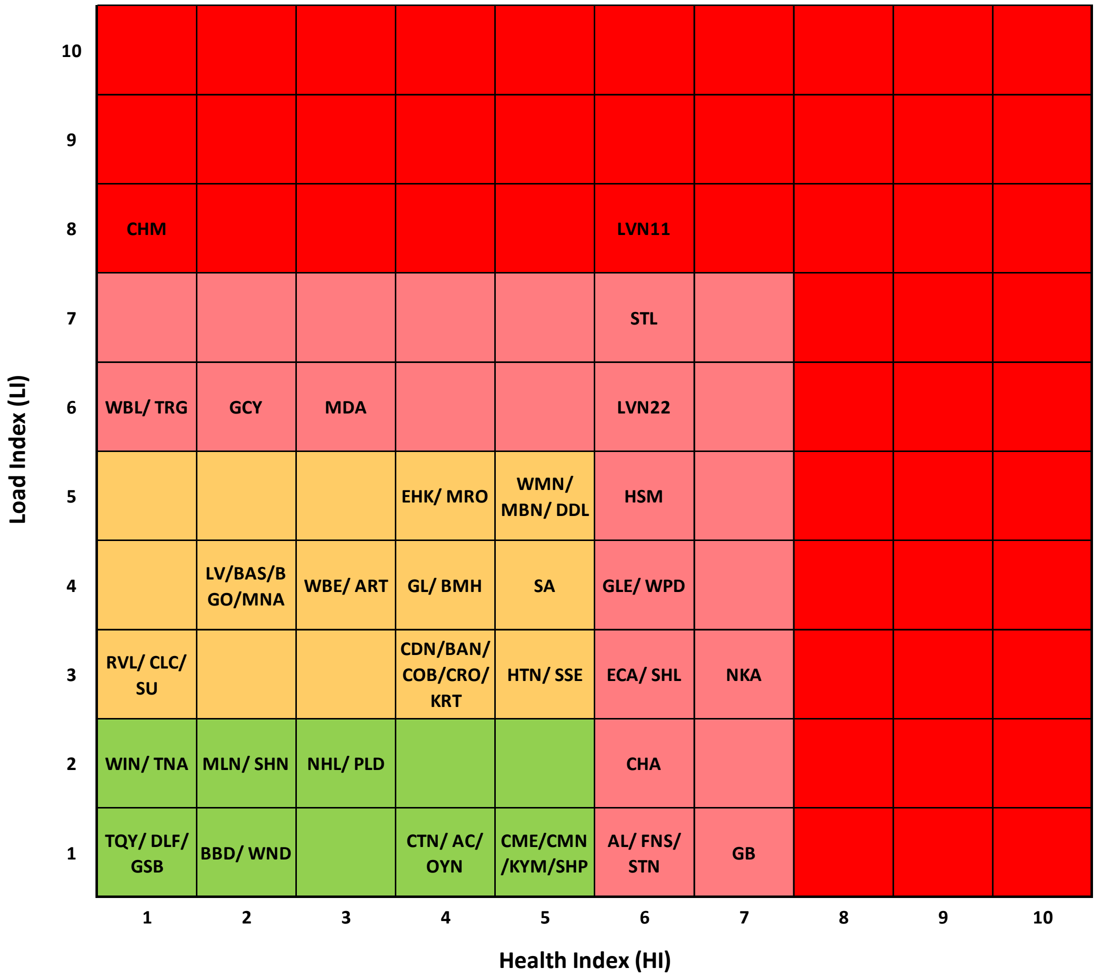


Source: Powercor

If we do nothing, 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 we do not invest, then our customers would experience a vast increase in the number of outages as our assets become overloaded and/or fail due to poor condition.

The matrix in figure 9.25 shows the load and health indices for the zone substations post the expenditure contained with this Regulatory Proposal.

Figure 9.25 Load and health indices at zone substations at the end of 2020 with proposed expenditure



Source: Powercor

This matrix demonstrates that our proposed expenditure will address zone substations with high load and/or health indices. For example, the construction of the TNA zone substation will address the forecast load-related concerns at the zone substations in the western suburbs of Melbourne, and the construction of TQY zone substation will alleviate the load at risk at WPD. In addition, the completion of the SU zone substation redevelopment will address the poor condition of those assets.

9.4 Connection expenditure

When customers seek to connect to our network, or change their existing connection, then we need to meet our customers' requirements.

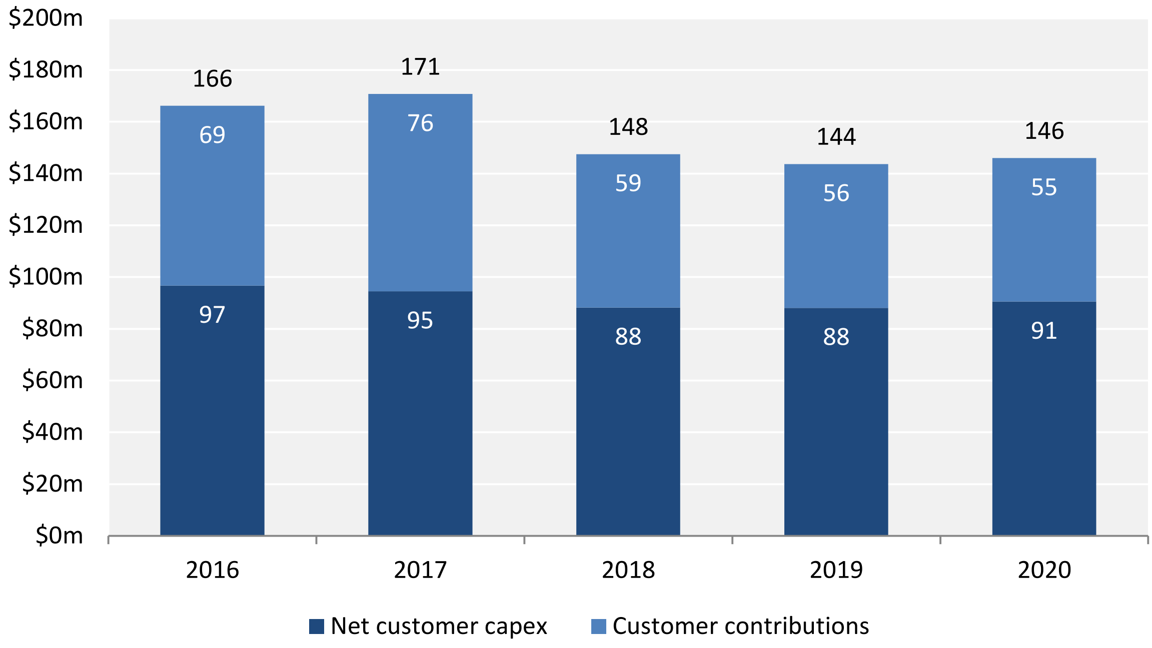
Our forecast expenditure will enable us to connect customers to our network, including to supply new residential customers, assist industrial customers in expanding their operations, and to support connection of renewable energy generators.

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

This section explains why our forecast capital expenditure for connections and customer-driven works is necessary to connect residential, commercial and industrial customers to the distribution network, as well as connections for embedded generators and customer requested relocations (i.e. recoverable works).

The profile of our forecast gross and net customer connection expenditure is shown in figure 9.26.

Figure 9.26 Forecast customer connection expenditure including real escalation ($m, real)



Source: Powercor

The difference between the gross and net customer contribution figures is as a result of customer contributions. We will receive funding directly from some customers toward their connection.

This category of expenditure is driven by customers, rather than being initiated by us. It is influenced by economic conditions and development demographics, including major projects arising from government initiatives, generation and embedded generation, changes in industrial and agricultural sectors and housing developments.

9.4.1 What we have delivered

We connected around 47,000 additional customers to our network in the 2011–2015 regulatory control period. The majority of these connections were smaller residential, industrial and commercial connections.

We also completed some large customer connection projects and customer-driven works during that time including:

- connection of the Oakland Hills, Mortons Lane and Leonard’s Hill windfarms;
- 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; and
- connection to the high-voltage network of a new processing plant for an agribusiness near Mildura.

9.4.2 How we prepared our forecasts

We have 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.

Low volume activity

We have undertaken a bottom-up build of the expenditure for the following categories of connections where there are typically low volumes, namely:

- commercial/ industrial connections connected at High Voltage (**HV**);
- embedded generation; and
- recoverable works (reported as quoted services).

For projects that cost $2.5 million or more, we have identified projects where the customer has made initial enquiries with us, or requested options for connections or a connection offer. Based upon correspondence with the customer, we have assessed that the project is highly likely to proceed and have included the connection in the forecast. The expenditure is based upon cost estimates from a supplier.

For the large number of smaller projects that cost less than $2.5 million, we have forecast the amount of expenditure for connections based on the average expenditure for non-major projects for the 2011 to 2014 period.

Customer contributions

Our process for connecting customers is set out in Powercor's customer guideline for making an electricity supply available.[73]

The majority of residential connections are routine connections where we can remotely connect the customer at the request of a retailer. However, 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 us, which sets out the location of the premises and an estimate of the amount of electricity required.

In response, we 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 Guidelines 14 – Provision of Services by Electricity Distributors (***Guideline 14**).

[73] 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;

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 we will incur in making the supply available to the nominated point of supply. The IC excludes the Connection Service Fees and transmission costs.

If the applicant chooses to run their own tender and use another Recognised Contractor to complete any Contestable Services, the applicant is required to provide us with evidence detailing the total cost of these tasks. We will compare those costs against the average cost for equivalent work completed on our lines, when calculating any IC.

Incremental Revenue (IR) is the revenue that we 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 us and returned with interest, should the applicant achieve the agreed electrical revenue consumption targets.

If the customer seeking to connect an embedded generator to the grid, then we have 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.

We are supportive of small solar generation that can be interconnected with our network. However, the pre-approval process allows us to identify concentrations of solar PV systems on the low voltage network which can lead to power quality issues such as overvoltage and voltage unbalance.

The customer may be liable to pay a customer contribution towards the connection involving embedded generation, where the contribution is calculated in accordance with Guideline 15. Under the 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.[74]

Our customer contribution forecasts were calculated by multiplying a calculated contribution rate by the gross connection capital expenditure for each of our internal reporting categories for connections. The contribution rates were calculated by first selecting a representative sample of 2013 customer projects for each connection category, and then updating the contribution rate to reflect changes in input parameters, such as our proposed Weighted Average Cost of Capital (**WACC**) and X factors, as well as changes in cost.

It is noted that while customer contributions have been calculated in accordance with Guidelines 14 and 15, the forecasts would change in the event that the Chapter 5A of the NER is implemented in Victoria. The introduction of Chapter 5A would involve the transfer of Victorian responsibilities to a new national regulatory regime. One of the largest implications would be that Guidelines 14 and 15 fall away, and Chapter 5A of the Rules will apply in Victoria.

High volume activity

We have used economic forecasts for the following categories of connections which typically are associated with high volumes of activity:

- residential complex connection at Low Voltage (**LV**);
- residential complex HV works connected at LV;
- commercial/ industrial HV works connected at LV; and
- subdivision.

We engaged the Centre of International Economics (**CIE**) to prepare forecasts of customer project connections for the 2015 to 2020 period. CIE established historical relationships between the historical data and economic and demographic variables for the connection categories. 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: [75]

- for gross state product (**GSP**), CIE used the forecast by 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.

The connection job forecasts produced by CIE were mapped to our internal reporting categories, known as function codes. These volumes were then multiplied by the unit rate in each function code to prepare the connection expenditure forecasts. 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.

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

75 The CIE, Forecasting connection projects for CitiPower and Powercor, November 2014.

Customer contributions

Customer contributions may also arise for connections in the high volume categories. The process for calculating the contributions is the same as that set out above for low volume connections.

Gifted assets

Guideline 14 currently regulates connection services. In particular, it makes connection and augmentation works contestable in accordance with our licence conditions – we are 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 us that a tender is not required.[76] This means that customers can elect to use a third party Approved Contractor,[77] 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 we may acquire the asset as a 'gifted asset' once it is connected to the distribution network. We may then pay a rebate to the customer or developer for the asset, applying the principle that our contribution to the project is the same that we would have made if we had constructed the connection. This ensures competitive neutrality between us and third party providers.

The costs of the rebate are included within the proposed capital expenditure for this category. The forecasts for rebates have been calculated as the average of the actual rebates in the 2011 to 2014 period, by function code.

The gifted asset is included in the Regulatory Asset Base (**RAB**) at zero value. The asset is then maintained in accordance with our asset management policies.

9.4.3 What we plan to deliver

Our 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 Victorians' Government's Powerline Replacement Fund to replace bare wire powerlines with insulated overhead powerline, underground powerlines or new conductor technologies;
- increase in supply of services to industrial customers at HV, reflecting the expansion of our 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 large customer connection projects, in the categories of recoverable works, commercial and industrial connections at HV and embedded generation. Some of these larger customer connection projects are discussed below.

Powerline Replacement Fund

Following the 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.[78]

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76 Powercor also provides the customer the option of conducting the tender process themselves.
77 Eligible Approved Contracts are accredited by Powercor. Customers are required to select an accredited Approved Contractor.
78 PBST, Final Report, 30 September 2011.

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:[79]

> *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 October 2014, Murray Goulburn announced plans for new infrastructure to meet growing international demand for Australian made dairy foods.

To provide the customer's required amount of electricity, we will need to establish a new sub-transmission line from the nearest terminal station to the customer connection point near Cobram.

Berrimal Wind Farm

The Berrimal Wind Farm is proposed to generate up to 72MW of electricity at a site 16km west of Wedderburn in north western Victoria.

To connect the windfarm to the Powercor network, we will need to construct a new sub-transmission line and establish a new switching station for the customer.

Project Harvest

Balfour-Beattie Investments is planning the construction of a 35MW biomass power station at Carwarp, near Mildura. The plant will burn almond hulls and shells, grape waste from local wineries and cereal straw from grain farms in the region.

To connect to the local network, we will need to construct a new sub-transmission lines, as well as associated infrastructure.

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. To connect the wind farm to our network, we will need to extend the existing Winchelsea to Colac sub-transmission line.

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[79] 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.

9.5 Victorian Bushfires Royal Commission

The catastrophic 'Black Saturday' bushfires on 7 February 2009 were one of Australia's worst ever natural disasters.

The 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.[80]

Our proposed expenditure is to continue to implement the recommendations of the VBRC, in accordance with obligations imposed, or anticipated to be imposed, on us by the safety regulator, ESV.

This section explains our forecast capital expenditure for obligations imposed on us arising from 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 we started to implement during the current regulatory control period and will continue into the 2016-2020 regulatory control period.

> *“Anything to do with safety, they should know what to do and just do it.”*

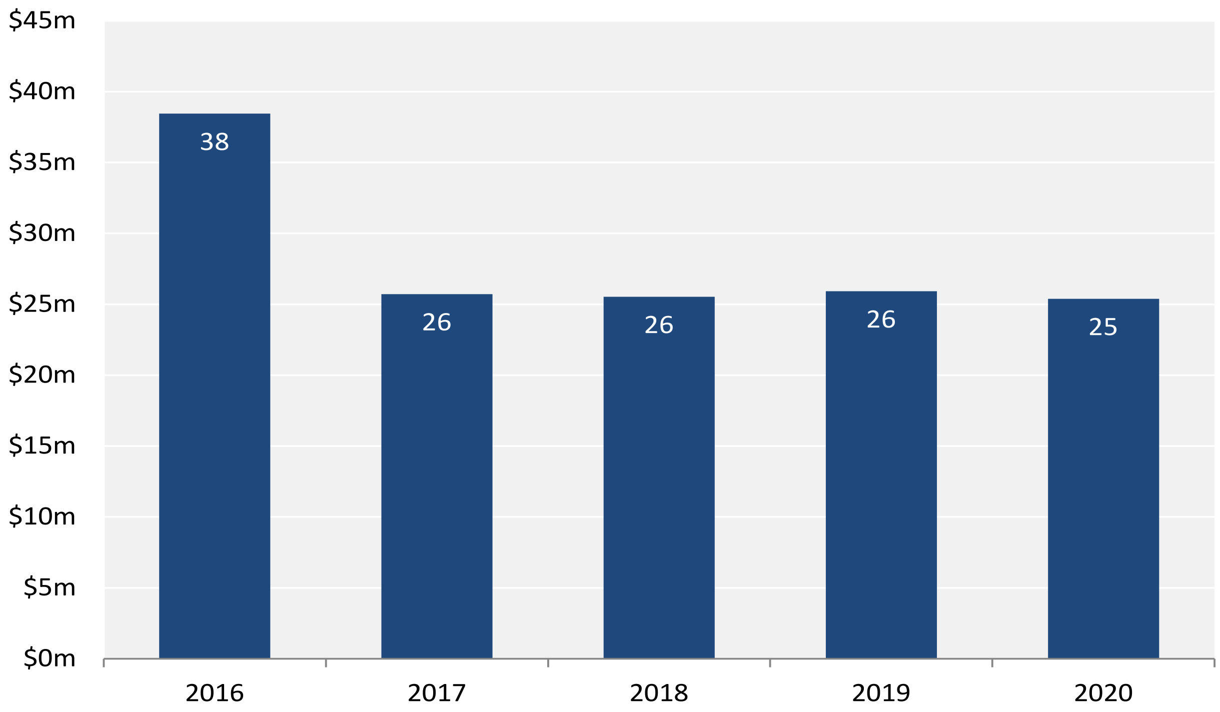
> *“It's a no brainer, they have to get the safety side of things right. That's a top priority.”*

Our stakeholders strongly support our expenditure to minimise any potential fire or safety related risk. This view has been expressed by all of stakeholders, whether residential, small to medium enterprises or large industrial customers through a range of interfaces, including online surveys, one-on-one interviews and attendees at our public forums.

[80] 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

The profile of our forecast VBRC expenditure is shown in figure 9.27.

Figure 9.27 Forecast direct VBRC expenditure including real escalation ($m, real)



Source: Powercor

VBRC expenditure is driven by specific obligations that have been imposed, or are anticipated to be imposed, on us by ESV. The obligations relate to the installation of:

- armour rods and vibration dampers to specific conductors which is intended to reduce wear on conductors and the effects of wind-induced vibration on powerlines, in accordance with our Electricity Safety Management Scheme (**ESMS**);
- new generation Automatic Circuit Reclosers (**ACRs**) to SWER lines to instantaneously detect and turn off power at a fault on high risk fire days, in accordance with our Bushfire Mitigation Strategy Plan (**BMP**);
- earth-fault limiting equipment to trial the technology for its ability to mitigate bushfires caused by detecting and turning off power at a fault almost instantaneously, in anticipation of a requirement from ESV to install such equipment;
- conduct a survey of multi-circuit lines to assess whether the conductor clearance is sufficient, in accordance with our ESMS; and
- spacers in aerial lines to maintain conductor clearances and stop conductor clashing in windy conditions, in accordance with our ESMS.

Working with ESV and the Victorian Government

We are an active participant in discussions with the safety regulator, ESV, and the Victorian Government, in developing regulation and safety systems to reduce the risk of our infrastructure starting fires. For example, we are on Powerline Bushfire Safety Program – Distribution Business Reference Group, in addition to the REFCL Technical Working Group and the REFCL Deployment Working Group.

We have 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, we propose to categorise the following projects as contingent projects, as set out in table 9.2.

Table 9.2 VBRC related proposed contingent projects

Event	Value ($2015, real)	Trigger
Installation of equipment to achieve earth faults standard	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

The contingent projects are discussed in more detail in chapter 14.

9.5.2 What we have delivered

In accordance with a Direction from ESV in January 2011, we updated our ESMS to include a program to install armour rods and vibration dampers to specified conductors in high bushfire risk areas (**HBRA**).

We commenced the program in 2012. At the end of 2014, we had installed vibration dampers and armour rods on around 128,000 of the 193,300 spans identified in the HBRA. The expenditure to undertake these works was approved by the AER as a pass through event in 2012.

Other bushfire mitigation activities that we have delivered in the current regulatory period include:

- installation of new generation ACRs on SWER lines in specific high risk areas in the HBRA (categorised as replacement expenditure); and
- undergrounding of powerlines in the Otway ranges, which was funded by the Victorian Government's Powerline Replacement Fund (categorised as recoverable works in customer connection expenditure).

"Generally the BMFPs [Bushfire Mitigation Plans] were clear, well presented and defined the basis for each MECs [major electricity businesses] BFM [bushfire mitigation] activities. They were supported by a comprehensive set of mature policies and procedures that were regularly updated. ESV was pleased to find there was a strong connection between the BFMPs and the activity in the field."

Source: ESV, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014, p. 12.

9.5.3 How we prepared our forecasts

The VBRC expenditure forecast is project-based, using a bottom-up build. Where we have undertaken projects in 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 9.3 sets out the forecasting methodology for each VBRC project.

Table 9.3 VBRC forecasting methodology

Project	Volume estimates	Cost estimates
Armour rods and vibration dampers	Based on detailed assessment of each span using our Geographic Information System (**GIS**)	Based upon HBRA project cost information for 22kV lines, and bottom-up build for 66kV sub-transmission lines
ACRs on SWER lines	Set in Bushfire Mitigation Plan (**BMP**)	Based upon HBRA project cost information
Trial of earth-fault limiting equipment	Trial proposed in two zone substations	Based upon our detailed scope and design for a zone substation
Survey of multi-circuit lines	GIS data	Based upon HBRA project cost information
Installation of spacers in multi-circuit lines	Based on outcomes from HBRA survey	Based upon HBRA project cost information
Rebuild of spans	Based on outcomes from HBRA survey	Bottom-up build based on historical costs for similar projects

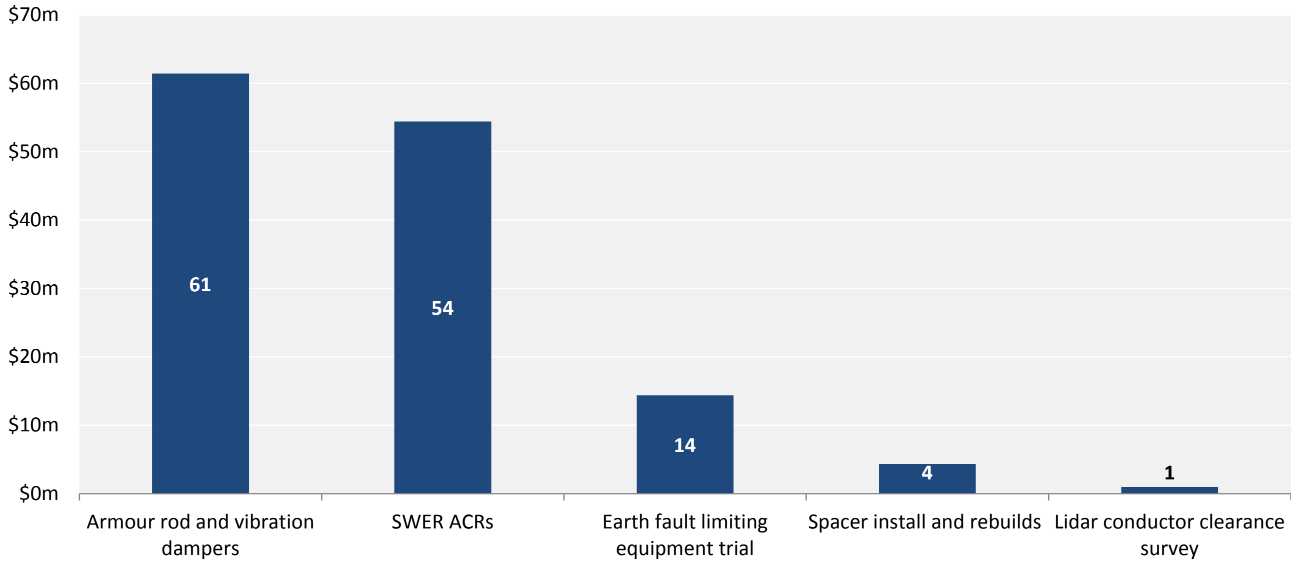
Source: Powercor

9.5.4 What we plan to deliver

Our forecast expenditure for VBRC relates to specific projects that we are obligated to undertake, or anticipate that we will be obligated to undertake, during the 2016 – 2020 regulatory control period.

An overview of the expenditure, by project, is shown in figure 9.28.

Figure 9.28 VBRC direct capital expenditure by program ($m, real)



Source: Powercor

Each obligation is discussed in turn below.

Armour rods and vibration dampers

We are required to install armour rods and vibration dampers in low bushfire risk areas by 1 November 2020.

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.

The obligation arises from Recommendation 33 of the VBRC which proposed that:[81]

> *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 the *Electricity Safety Act 1998*, which required us to update our ESMS to include a program to fit armour rods and vibration dampers to certain conductors, and that the program be completed:[82]

- in hazardous bushfire risk areas — before 1 November 2015; and
- in all other areas — before 1 November 2020.

We subsequently updated our ESMS to include the requirements of the Direction. We must comply with the revised scheme or plan as compliance is enforceable by ESV.

81 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 30.

82 ESV, Direction under section 141(2)(d) of the Electricity Safety Act 1998, Fitting of armour rods and vibration dampers, 4 January 2011.

'The ESMSs were found to be well developed and supported by procedures and the implementation of a comprehensive library of system records to support each of the businesses. Illustrating these good practices were the improvements that had been made to the ESMSs including new software applications for managing assets, predictive tools for assessing remaining asset life, new management system certification programs, and revisions to the Asset Inspector's Manual.

Senior management personnel were represented at each of the audits, demonstrating a strong interest and commitment to their ESMSs. A range of personnel, employees and subcontractors were interviewed and found to be cooperative and well prepared for the audit'.

Source: ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014 p. 24.

There are approximately 112,800 of spans in LBRA where armour rods and vibration dampers are required to be installed during the 2016–2020 regulatory control period. The figure is based on a detailed analysis of the characteristics of each span in the network using our GIS system.

The cost to install each armour rod and vibration damper is based on the historic average cost per span, plus design and project related costs.

We have also been in discussions with ESV relating to our HBRA program. The program is slightly behind schedule and the final 9 per cent of the total spans will now be completed in 2016. The remaining spans include all 66kV sub-transmission lines as well as 22kV feeders where we had access restrictions and/or difficulties. The costs for the 66kV sub-transmission lines is based on contractual labour rates and field operating costs, and the 22kV rates are based on historical unit rates taking into account the challenges for these particular feeders.

ACRs on SWER lines

We are required to install 1,088 ACRs on SWER lines during the 2016–2020 regulatory control period.

The obligation arises from Recommendation 27 of the VBRC which proposed that:[83]

> *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.*

PBST was established to undertake further analysis of two of the complex VBRC recommendations, including recommendation 27. Their final report recommended widespread deployment of new protection network technologies, in particular the installation of rapid earth fault current limiters (**REFCLs**) and new generation SWER ACRs, together with the targeted replacement of powerlines with underground or insulated cable in the highest fire loss consequence areas.[84]

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83 2009 Victorian Bushfires Royal Commission, *Final Report*, July 2010. p. 29.

84 Powerline Bushfire Safety Taskforce, *Final Report*, 30 September 2011.

ESV issued a Direction to Powercor on 5 April 2012 under 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 us to update the BMP to include a program to ensure the protection settings and reclose functions on SWER ACRs, and SWER fuses that are downstream of the isolating transfer (excluding on distribution substation fuses) can be remotely controlled by our Supervisory Control and Data Acquisition (**SCADA**) system.

In 2012/13, we replaced 179 SWER ACRs located in the highest 80 per cent consequence areas. We also updated our BMP with 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 program will commence in 2016 and be completed in 2020.

The cost to install SWER ACRs is based on average project cost information obtained from the current regulatory control period when we installed the equipment in the highest 80 per cent consequence areas in HBRA.

Earth fault limiting equipment trial

We do not currently have an obligation to install earth fault limiting equipment in our network. However, it is anticipated that an obligation will be imposed during the 2016–2020 regulatory control period.

The obligation is likely to arise from Recommendation 27 of the VBRC, noted above, that proposes the progressive replacement of all SWER powerlines and 22kV distribution feeders with aerial bundled cable, underground cabling <u>or other technology</u> that delivers greatly reduced bushfire risk.

In its final report, the PBST identified 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.[85]

In response to the PBST report which identified the use of REFCLs and SWER ACRs to reduce the likelihood of powerlines, the Victorian Government indicated that it would require us to install these devices in our network.

The use of REFCLs to reduce the possibility of a bushfire starting has not yet been demonstrated in Australia. Trials of the technology are ongoing, including:

- installation 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 we are participating in the program.

We wish to understand the benefits and challenges of installing a REFCL on our network, particularly given 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.

[85] Powerline Bushfire Safety Taskforce, Final Report, 30 September 2011.

The trial would enable us to be in a position to design, install and operate REFCLs, should the technology demonstrate that it is able to reduce the possibility of a bushfire starting.

We are proposing to trial the REFCL in our WND and GSB zone substations in 2016. This trial would allow us 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.

The cost of installing the REFCL has been based on a detailed scope and preliminary design undertaken for the installation of a REFCL in a zone substation, which was informed by our involvement with AusNet Services on REFCL technology trials.

Survey of aerial lines and installation of spacers on multi-circuit lines

We are required to survey our lines to assess whether the conductor clearances meet the minimum separation requirements set out in industry guidelines, and where they are found not to meet that level, to either reconstruct the line or install aerial spacers into the line.

The obligation arises from Recommendation 33 of the VBRC which proposed that we fit spreaders to any lines with a history of clashing or the potential to do so.

ESV issued a Direction to Powercor on 4 January 2011 under the *Electricity Safety Act 1998* which required us to update our ESMS to:

- develop a program to identify all spans that do not comply with the minimum separation requirements set out in industry guidelines; and
- for all spans that do not comply with the minimum separation requirements, construct the spans so that they do comply or fit an aerial spacer by 1 November 2015 in HBRA and in all other areas by 1 November 2020.

We updated our ESMS with a plan to undertake a survey of spans in LBRA by July 2019, and to complete any identified works to install spacers or reconstruct the span to comply with the separation requirements by 1 November 2020. We must comply with the updated ESMS as compliance is enforceable by ESV.

We estimate that 550km of lines will need to be surveyed in 2016. The length of line has been assessed using our GIS system. The cost of the survey has been based on the contract rates from the HBRA survey undertaken in the current regulatory period, plus our design costs.

Additionally, we estimate that 900 spans will not comply with the minimum separation requirements in LBRA. This is based on information from the HBRA surveys assessing the compliance of the spans. The costs to install spacers on 22kV feeders have been based on the average costs per span incurred in the current regulatory period in HBRA.

Spans involving a 66kV sub-transmission line that do not comply with the minimum separation requirements must be rebuilt, as there is currently no spacer that can be used on such lines. The cost of rebuilding spans has been conservatively based upon the historical unit cost of replacing the cross-arm associated with the 66kV sub-transmission lines on a multi-circuit span, plus design costs. The assumption is considered conservative as a more costly pole replacement may be required.

We have also been in discussions with ESV relating to our HBRA program. Unfortunately, the program is behind schedule as we have not undertaken the rebuilds for multi-circuit lines that involved 66kV sub-transmission lines. These will be completed in 2016 and 2017 after the design works are finalised. The costs for these rebuilds have been calculated on the same basis as those in LBRA.

9.6 Information technology and communications

As we move towards embracing a network of the future, information technology (**IT**) provides critical support to enable integrated digitalisation across all aspects of our operations and network.

By prudently and efficiently investing in, and managing our IT systems and infrastructure we are able to provide safe and reliable services that supply energy to our customers.

Through partnerships with our internal stakeholder we support critical business direction across our company, focusing on providing solutions that deliver innovative customer services through the pragmatic use of technology.

We recognise consumers' need for access to energy consumption information that allows them to self-determine their energy usage practices and demand. Our aim is to provide customer services that make it easier for our customers to make informed choices through access to real time information across multiple platforms.

Our expenditure forecasts for IT and Communications support the directions and strategies of our business. We provide critical energy, metering and information services that enable the efficient and reliable delivery of energy to customers. Underpinning these services are Network, Asset Management, Works Management, Metering and Corporate IT services that provide the essential information to successfully operate our network.

Supporting these service levels requires a continuous investment in IT infrastructure and devices that must be proactively, prudently and efficiently managed throughout their lifecycle.

A key focus is on facilitating 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.

Our IT service delivery is enabled through the IT Infrastructure Library (**ITIL**) best practice processes, which have been used to form the development of the investment priorities over the 2016-2020 regulatory control period. Robust planning has been undertaken to determine our capital investment and the supporting operating expenditure profiles for maintenance of existing service levels and the delivery of new business and industry requirements.

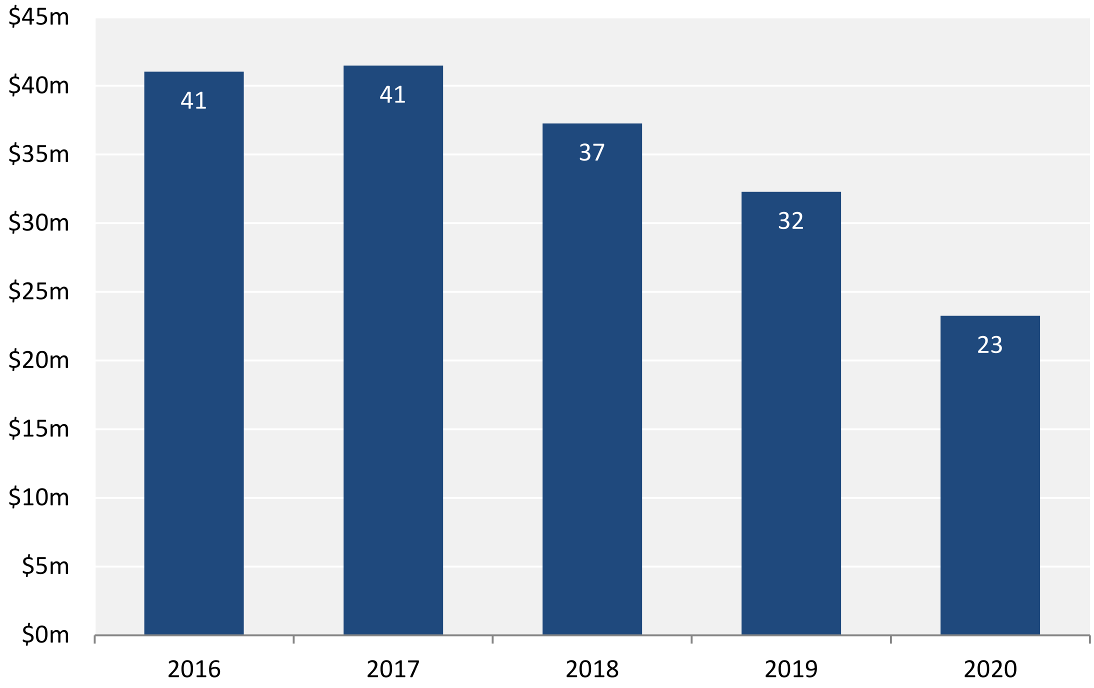
Long term IT planning is inherently challenging due the rapid changes in available technological solutions – hence planning in infrastructure, currency and capacity, compliance, device replacement, smarter networks, customer engagement and security have been undertaken to break the planning process into smaller streams.

Our expenditure forecasts are driven by:

- maintaining the increasing number of IT systems to the levels required by the vendor and/or industry to ensure continued operation, support and compatibility;
- continuing the journey to build a smarter network to enable greater consumer choice, through use of new and existing technologies that provide a more innovative and integrated self-healing network, where by notifications are automatically generated and work dispatched when a fault is detected;
- introduction of a customer relationship management (**CRM**) system and replacement of the ageing billing platform to enable the implementation of the Power of Choice reforms focused on distributors empowering consumers; and
- improved security of the IT systems that support the network due to the ever increasing complexity of the converging information and operational technologies required to support our distribution network.

The profile of our forecast IT and communications expenditure is shown in figure 9.29.

Figure 9.29 Forecast IT and communications expenditure including real escalation ($m, real)



Source: Powercor

A feature of our successful IT and communications program has been a strong focus on innovation that enhances the operation of our business by empowering users and customers through seamlessly integrating digital tools, content and technology into all aspects of their day-to-day work.

The alignment between business objectives and customer engagement is required to ensure that innovative digital solutions focused on delivering value to the customer and organisation, and by working in partnership with the user community we deliver technological solutions that meet the intended need.

A key strategic focus of our IT program is to take advantage of new technologies to improve customer service, further improve network safety, innovate and optimise the use of the increasingly complex network. Through engagement, communication and feedback we continue to review, learn and adapt our priorities and directions.

We have delivered a range of innovative IT projects that have built upon the foundation of smart meter technology over the current regulatory period, and we intend to continue innovative responses to customer and business needs. An overview of our past and planned innovation is shown in figure 9.30.

Figure 9.30 Past and future IT innovation

Past innovation

- Meter outage notification (**MON**): an automated system process to make intelligent use of the outage data provided by smart meters to notify our systems used to coordinate our network response to the identified outages.
- Distribution Transformer Monitoring: providing access to Distribution Transformer interval data and customer interval data linked to a specific asset to support asset management and protection against theft.
- Remote Energisation: automated system capability that utilises the remote functionality inherent ino our smart meters to schedule and action remote energisation and de-energisation requests.

Future innovation

- Customer relationship management: capability to manage the increasing complexity of customer information provision and enable new market participants.
- Digital enablement: delivering mobile apps solutions to our user community that deliver real time information, using rapid pace design and delivery methods to meet ‘here and now’ consumer requirements.
- Network management optimisation: bringing together the multiple existing IT and Operating Technology (OT) systems into an integrated Smart Grid solution that will deliver flexible energy choices to our customer.

Source: Powercor

9.6.1 What we have delivered

During the 2011–2015 regulatory control period we have placed a strong focus on developing the inherent capabilities of smart meters and continued a prudent investment approach into existing IT systems, applications and infrastructure. This program includes:

- data warehouse and analytics: providing a technical platform that handles high volumes of data, such as the mandated interval read volumes, in an efficient way that supports business data analysis and reporting functions. This analysis and reporting allows us to:
  - undertake better network planning by understanding network activities which assist in operational efficiencies, and through reliable information reduce field visits; and
  - enables rapid modelling and analysis of tariffs to improve customer offerings.
- meter outage notification: allows for identification of customers off supply in real time, allowing us to proactively dispatch field crews to affected customers, leading to earlier outage rectification times;
- proactive voltage complaint analysis: utilises the smart meters’ quality of supply (**QoS**) recording to allow improved analysis, network management and customer service. By better understanding QoS data we are able to target key areas for QoS improvement, increase the effectiveness of voltage complaint response processes and identify customers whose usage patterns affect the quality of service of their neighbourhood;

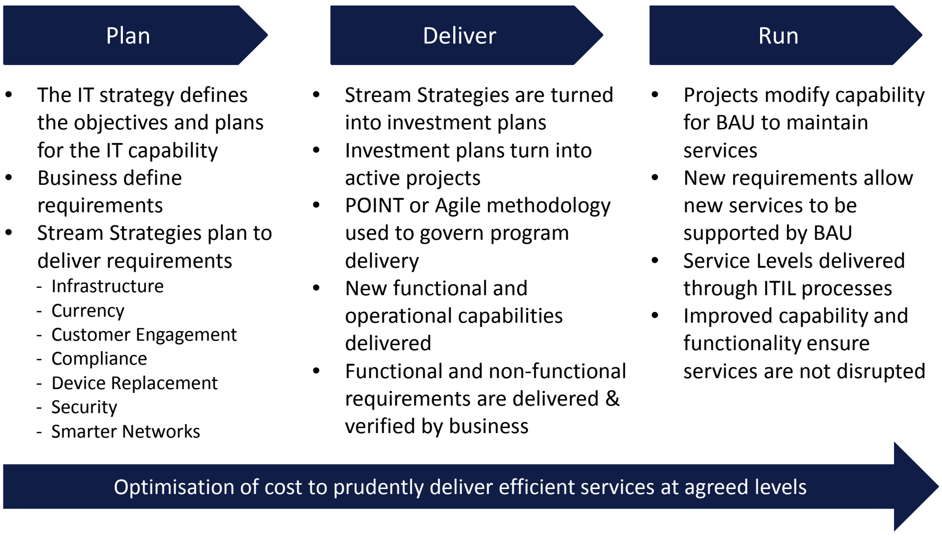
- REConnect: delivering a web-based platform to increase the efficiency of planned works, such as new connection and meter additions and alterations. The REConnect portal provides Registered Electrical contractors (**RECs**) and Retailers with the functionality to lodge requests within our network, and the ability to upload the appropriate associated documentation (i.e. Certificate of Electrical Safety or Solar Photovoltaic forms and any other associated documentation). The platform also allows for automation of backend support processes and provides 24 hour visibility to users on the associated jobs status and provides notifications via SMS and/or email at defined process milestones;
- remote energisation: automated functionality that provides remote energisation and de-energisation services to customers by leveraging smart meter infrastructure to deliver remote capability to Retailers and their customers. Automated system functionality was developed to schedule and action remote requests in line with regulatory timeframes and customer expectations, as well as ensuring work is completed within industry and business safety standards; and
- home area networks/ in home displays: delivered trial smart meter capabilities that allow customers to bind an in-home display unit to our smart meters via the establishment of an authorised Home Area Network (**HAN**).

9.6.2 How we prepared our forecasts

To maintain service levels and deliver future business requirements, a disciplined investment prioritisation process was used to identify core planning streams to ensure all aspects of our service composition were considered.

The IT Service Delivery Model turns strategies and plans to programs of work to prudently ensure business-as - usual (**BAU**) service levels can be maintained in the future at an efficient cost. These IT services are directly related to delivering energy, meeting regulatory compliance obligations and performance service levels expected by our customers.

Figure 9.31 IT strategic planning framework



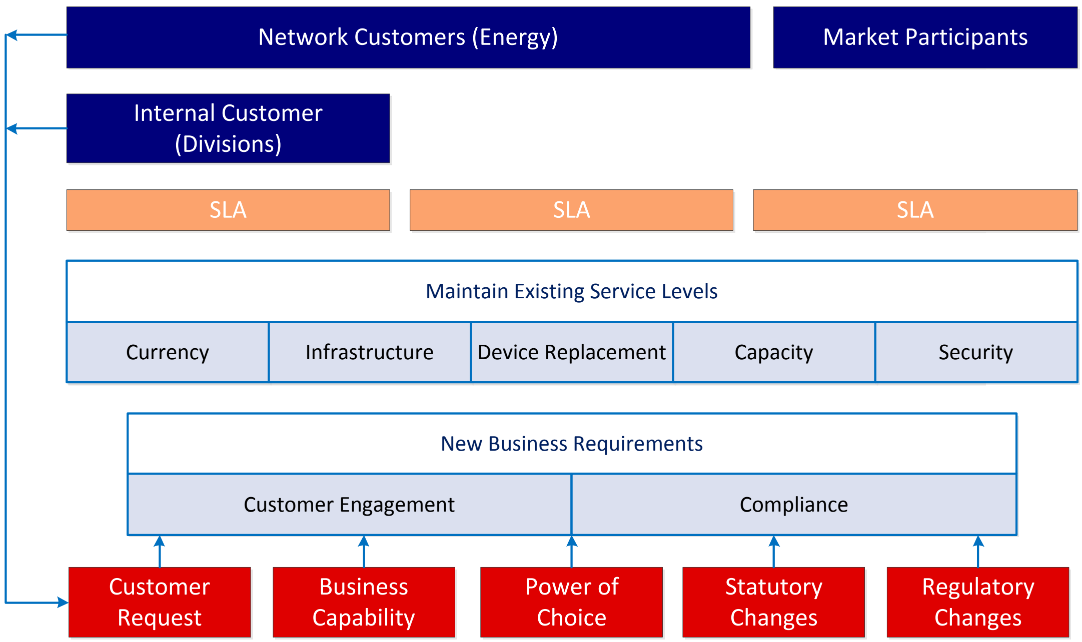
Source: Powercor

In this planning process, new business requirements are requested as a result of external or internal needs, and adjustments are made to the investment plan to cater for new requirements whilst ensuring the BAU service levels can be maintained.

The strategic planning process identified a number of requirements that drive increased IT capital expenditure in the next regulatory period including:

- currency and capacity requirements to cater for the increased storage of interval meter data and subsequent back-up requirements;
- security requirements to monitor, manage and mitigate cyber-security threats for critical infrastructure in an increasingly hostile cyber-security environment;
- improved technology and enabling systems to enable smarter network innovative solutions to maintain customer reliability and service standards;
- systems changes required to meet regulatory, legal and market compliance and the provision of actual data in response to the Request for Information Notices (**RIN**) obligations;
- customer relationship management and billing requirements driven by Power of Choice NER changes and the implementation of time of use tariffs; and
- increasing complexity of the operating environment including multiple Financially Responsible Market Participants (**FRMPS**), Power of Choice, metering contestability and the entry of new market participants requiring the exchange of customer and network data for provision of services.

Figure 9.32 **Investment stream planning supports internal and external customers**



Source: Powercor

We have undertaken a robust bottom-up build of all forecast IT costs based on individual projects or programs. The projects/programs have been identified through an iterative process which involved:

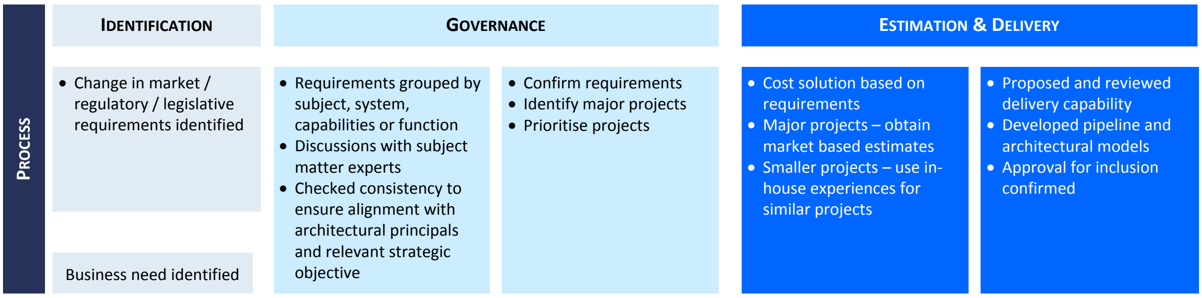
- gathering information on 2016-2020 directions and strategies from within the business, identifying projects that address these needs and requirements;

- analysing IT and energy industry trends and forecasts to assist with identifying possible business needs, this includes varying internal and external support models, cloud and purchase models;
- understanding and anticipating Regulatory and Legislative changes;
- evaluating proposals and ideas to ensure they:
  - align with business and IT strategic directions;
  - are prudent and efficient ;
  - the business and IT have the capability and delivery models in place to effectively resource the delivery and implementation of the required project/program; and
  - align to a high level assessment of technology/product maturity/market readiness.

Robust cost estimates have been sourced from:

- 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.

Figure 9.33 Requirements identification and costing process



Source: Powercor

9.6.3 What we plan to deliver

Through our review of strategic planning process, we identified a number of requirements that we must undertake during the 2016-2020 regulatory control period. Each of these requirements is discussed below.

Currency and capacity

The currency and capacity stream objective is to ensure agreed service levels are maintained via contractual support agreements, current software versions and proactive capacity planning. The programs in this stream aim to have solutions and core software within vendor support and within acceptable and consistent versions whilst maintaining adequate capacity to meet current and future business requirements.

The capacity management process proactively ensures that business needs and service definitions are fulfilled using a minimum of computing resources. To determine the capacity plan, planning activities relating to resource utilisation, demand management, infrastructure performance, application sizing and storage capacity were undertaken. From these planning processes, significant infrastructure capacity projects were allocated to the infrastructure steam with remaining projects allocated to this stream to progress.

The currency program reviewed software assets to ensure fully supported systems deliver agreed service levels and new business requirements for the investment period. To develop the currency program, activities were undertaken including a software asset register review, vendor roadmap review, options analysis, business scan of future requirements. A prioritisation process was then undertaken to determine the timing and priority of currency programs peer reviewed and costs estimated.

The currency and capacity program includes the following investment drivers:

- upgrade: upgrade software to current version via manufacturers recommended upgrade path;
- refresh: re-implement solution with identical, upgrades or alternative software to provide continuing business functionality;
- enhance: provide enhancement to solution software to ensure existing systems meet current business requirements;
- replace: replace solution software with alternative solution to provide business functionality on current platform; and
- growth: provide additional capacity to ensure service levels are not jeopardised.

Program timing is then allocated to ensure no service interruption is incurred outside of agreed service levels.

Compliance

The compliance stream objective is to ensure financial, regulatory, statutory, market and legal compliance are maintained via implementation of new capability in a timely manner. The ability to meet compliance obligations is directly impacted by the capability of our systems, processes and analytics to deliver services and information when required by the relevant law or regulation change.

The scope of this stream includes meeting compliance obligations in a timely manner taking into consideration development and implementation timelines for each of the obligations. The core components of the compliance 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 systems, data models, reporting and analytics to ensure compliance with regulatory reporting obligations and 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 safety, payroll to ensure compliance with National, State and local obligations; and
- 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.

This undertaking will take time and require manual transitional solutions in the interim. In addition to annual performance and F factor reporting and price reset data provision, a change in compliance requirements in this period is the annual Economic Benchmarking and Category Analysis RIN reporting requirement. This obligation focuses on relative efficiency in providing service for previous 12 months and assesses benchmark operating and capital expenditure that would be in incurred by an efficient distributor. A challenge being worked though is the provision of actuals data rather than estimates within all RIN reporting, company-wide.

Based on historical experience, the legal and statutory changes that occur in the external environment require an ongoing compliance readiness investment to ensure changes are in place when legally required. This ongoing program of work is required to ensure best endeavour attempt is made to implement solutions to meet compliance obligations or implement workarounds in the interim.

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. Investment in refreshing the end user devices maintains employee and workforce productivity and performance as the gateway to all corporate systems.

The scope of the device replacement stream includes all end user devices (**EUDs**) and Human Machine Interfaces (**HMI**), 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).

Principles used to guide investment decisions in this stream include:

- replacement decisions will be made on the long term business needs of the organisation rather than individual needs;
- overall business considerations will be considered alongside technology considerations;
- enterprise purchasing will be leveraged to maximise bulk purchasing discounts; and
- best practice will be adopted such as standard image, standard device, support and maintenance.

Smarter networks

The smarter networks stream will continue to enable 'Networks for the Future' through targeted investment in technologies that maintain and improve customer service standards and enable new services.

Capgemini has prepared a roadmap to help us move to a smarter grid to integrate and control every aspect of the network.[86] The roadmap sets out the required investment in energy network related systems to enable

[86] Capgemini, Networks for the future – ICT roadmap, December 2014.

improved network management and delivery of new services to customers. This leverages from the investments that we have made to date and builds smart network capabilities in three areas:

- network management optimisation: the aim of this initiative is to optimise the current multiple existing 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 our 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.

Building a 'Networks for the Future' is a key strategic business objective in empowering customer choice. The smarter grid will change the way that the business generates data, presents information, makes decisions, executes work and relates to customers. Amongst a number of factors continuing to impact the energy sector shifting energy production and consumption, one of the strongest drivers is customer choice. 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.

Customer engagement

The customer engagement stream will implement a new 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.

A CRM and a flexible billing system are required to manage the increasing complexity of the direct customer relationship and emerging customer billing requirements. The scope of this stream includes system integration, reporting capability and data migration.

Anticipated industry and regulatory change are expected to have significant implications for billing and customer management functions[87].

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. The current billing system cannot meet emerging market requirements and will require significant modification on a high risk outdated platform.

As a result of ongoing engagement with our internal stakeholders we have identified the following drivers to meet their needs:

- 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;
- enable customer access to energy data and encourage informed consumer choice and participation;

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[87] Deloitte Access Economics, CitiPower and Powercor-Investing in a new billing and customer relationship management system, December 2014, p. 10.

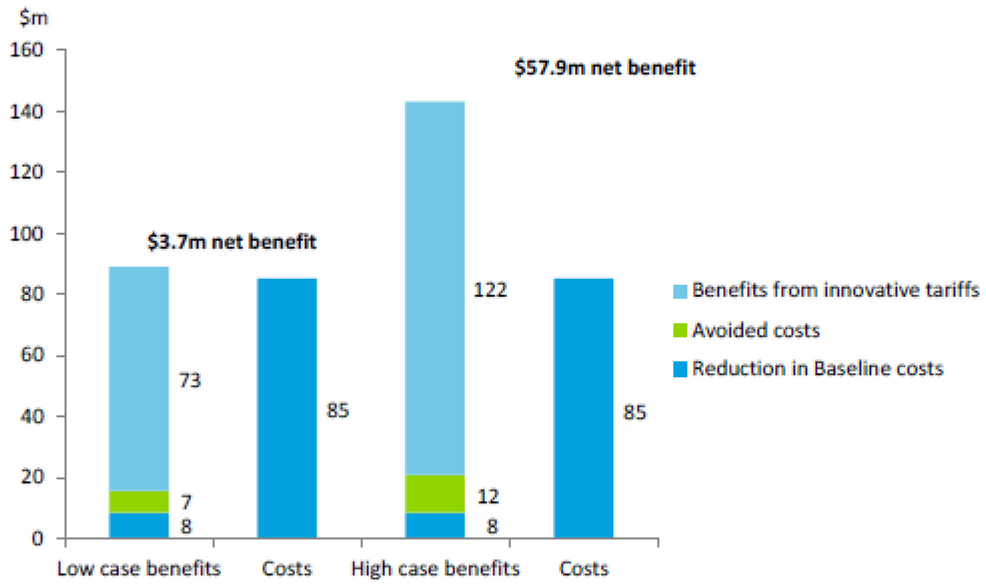
- customer enablement initiatives: develop a suite of customer enablement capabilities that leverage off the information and functionality that are provided through the implementation of a CRM and flexible billing solution;
- the complexity of customer interactions as the market evolves will become increasingly challenging, driving the need to move from National Meter Identifier (**NMI**) centric engagement to full understanding of who our customer is; and
- the business is carrying a significant obsolescence risk in the current billing system solution that is increasing over time as the changing market demands more of it.

We engaged Capgemini to undertake a scan of the CRM and billing systems in the market that would meet our internal customer requirements, as well as the anticipated future regulatory and market changes.[88]

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 our 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 reduce network investment;
- costs that we would avoid from upgrading the existing system; and
- reducing the costs to operate the existing system.

Figure 9.34 Net economic benefit 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 we invest in a new CRM and billing system.

[88] Capgemini, CRM and Billing Market Scan – Final Report, 27 June 2014.

Security

Energy distribution is critical infrastructure that is at high risk of attack. Therefore prudent investment in security measures is deemed essential. To ensure that the availability of our distribution network is assured and that our customers continue to receive a reliable distribution of controlled power, cyber-security threats need to be monitored, managed and mitigated.[89]

Ernst & Young undertook an audit to examine the adequacy of key policies, procedures and processes governing the SCADA IT operations. Weaknesses in our security were identified and an action plan established to address the findings.

In addition, CSC were engaged to conduct an Enterprise Security Roadmap assessment of our information security practices using the International Standard Organisation (**ISO**) standard. They identified a significant number of security improvement projects across all of our IT systems.

Key decisions in the security stream have been based on robust analysis and independent opinion on areas of focus in each of the security work stream areas to address:

- increased focus on external threats based on international trends;
- heightened alert based on increasing cyber terrorism to critical infrastructure over the past decade;
- continued focus on financial fraud attempts to maintain diligence;
- focus on developing internal centre of excellence on security to minimise risk;
- cover all security domains as a part of investment spread; and
- up front focus on 'Protect' and 'Detect' within the period.

Deloitte has, on our behalf, developed a program of IT security initiatives 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.

[89] CitiPower and Powercor, Information Security Business Case, January 2015, p. 4.

Figure 9.35 IT security capability lifecycle

Source: 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 our energy networks. Investment in the toolsets and processes to effectively govern information security ensures robust and best practice processes are in place.

Infrastructure

The infrastructure stream objective is to prudently optimise asset lifecycles of physical infrastructure assets to ensure agreed service levels are maintained at the lowest cost. The scope of the stream includes servers, storage, data centre infrastructure, Local and Wide Area Network infrastructure (**LAN/WAN**) and backup facilities as follows:

- servers: manage the lifecycle of both SCADA and Corporate servers including both Windows and UNIX, including hardware and associated server software;
- storage: manage the lifecycle of Storage Area Network infrastructure, including switch, array and associated infrastructure. This component also includes storage capacity for growth;
- data centre infrastructure: manage to the lifecycle of data centre infrastructure, including data warehouse hardware and associated equipment;
- LAN/WAN: manage the lifecycle of Local Area Networks and Wide Area Network infrastructure including switch, router and associated equipment; and
- backup: manage the lifecycle of backup infrastructure including replacement, refresh and growth.

Strategies and investment plans are developed using experience, vendor recommendations, historical performance data, support costs, competitive replacement pricing, future vendor roadmaps and alternative service options.

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.

9.7 Non-network expenditure

Non-network expenditure is necessary to support our network operations, such as having the Elevated Work Platforms or 'cherry-pickers' available and in good working order so that our crews are able to use them to help restore service to our customers quickly in the event of an outage.

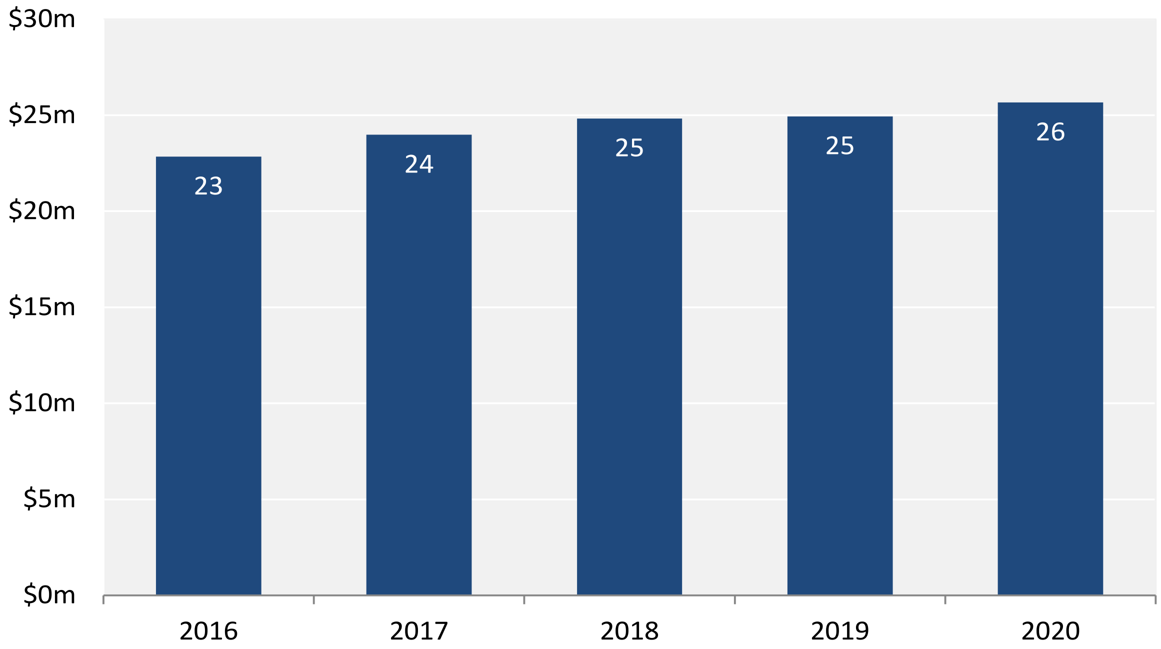
This section explains our forecasts for non-network capital expenditure, which is required to support our network operations.

Non-network capital expenditure includes the following cost categories:

- motor vehicles: relates to the purchase, replacement or rebuild costs associated with our light and heavy fleet of vehicles;
- property: relates to the provision of office and depot accommodation, buildings and property;
- 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; and
- other: includes equity raising costs, general equipment such as miscellaneous tools and equipment.

The profile of our forecast non-network expenditure is shown in figure 9.36.

Figure 9.36 Forecast non-network capital expenditure including real escalation, excluding equity raising costs ($m, real)[90]



Source: Powercor

9.7.1 What we have delivered

In the 2011–2015 regulatory control period, we have undertaken a range of activities including:

- replacement of motor vehicles in accordance with our replacement cycle as well as the purchase of new fleet where necessary to support our operational requirements;
- upgrade of our fleet to address changes in safety and compliance as required by Australian Standards or Australian Design Rules;
- commencement of the migration of switch control for ACRs away from legacy technology and onto the SCADA distributed network protocol so that we are 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 our strategy to replace unsupported communications technologies in our SCADA network;
- further deployment of fibre infrastructure across our 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 and Market Street head office as well as starting the construction of a new depot in Mildura.

9.7.2 How we prepared our forecasts

This section explains the drivers and forecasting methodology for each non-network expenditure category.

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90 2011 to 2014 are actual costs, 2015 to 2020 are forecast costs.

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. Our 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.

We have used the average expenditure from 2011 to 2014 to forecast our requirements for fleet in the 2016–2020 regulatory control period.

We consider this to be an appropriate methodology for forecasting this expenditure category. 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

To continue to 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 connect these devices with the control room.

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.

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 are captured in the augmentation or replacement categories.

Consistent with motor vehicles, we have used the average expenditure from 2011 to 2014 to forecast our requirements for fleet in the 2016–2020 regulatory control period.

Other

These costs relate to the costs of raising equity financing, and other non-network capital expenditure such as general equipment. We have used the average expenditure from 2011 to 2014 to forecast our requirements in the 2016–2020 regulatory control period with the exception of equity raising costs, which have been forecast using the methodology set out in the AER's Post Tax Revenue Model (**PTRM**).

9.7.3 What we plan to deliver

Our forecasts for motor vehicles, SCADA and property are discussed below.

Motor vehicles

We purchase, rather than lease, motor vehicles. We have determined this to be most efficient method of sourcing vehicles following an internal review of our procurement strategy.

We forecast motor vehicle costs to be the largest category of non-network expenditure. Our 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 us to acquire, replace or rebuild our light and heavy fleet of vehicles and comply with the changes in safety and compliance obligations.

SCADA

SCADA is forecast to be our second largest category of non-network expenditure. Our forecasts have been informed by our strategy to develop our network communications over the longer term, including a specific project to enable further embedded generation into our network, and therefore an increase in expenditure is required compared to our expenditure during the 2011 – 2015 regulatory control period.

UXC Consulting undertook a review of the methods and processes that we used 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 we currently use a significant amount of older communications technology, and that some elements within the communications network will need to be upgraded to enable support of SCADA Distributed Network Protocol (Level 3) (**DNP3.0**).[91]

As a result, our 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. This will also assist in our move towards a 'smarter grid' with two-way, real-time communications to optimise the management of the increasingly complex network mix of consumption/ generation, to improve our service to customers.

The strategy report also identified that over the next ten years, we 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 implement voltage and Volt-ampere reactive (Var) control.

Distribution Automation refers to the introduction of smart monitoring and control devices in the distribution network to allow our operational and planning teams to better manage energy flows and voltage levels in the network.

In terms of voltage and Var control, we 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 scenarios of PV penetration using historical loading data to determine the extent to which voltage regulation facilities need to be improved. Based on this analysis, Aecom recommended that:[92]

- due to the occurrence of reverse power, the distribution regulators are to be upgraded to bi-directional, mostly at rural long feeders; and
- where solar penetration is greater than 15 per cent, bi-directional regulators are required at zone substations with a mix of rural long and other feeders and to sectionalise rural long feeders.

[91] UXC Consulting, Distribution Network Communications Strategy CitiPower– Powercor, December 2012.

[92] Aecom, Solar PV impact study – strategy recommendations, 15 October 2014, p. i.

The implementation of 89 bi-directional regulators to manage reverse power flow arising from solar PV will enable greater embedded generation onto our 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 limits and this would prevent us from allowing additional customers to connect embedded generation to the network. The bi-directional 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.

Property

Our property forecast for each year in the 2016–2020 regulatory control period reflect the average of costs incurred from 2011 to 2014. Our planned projects include:

- completion of the build of a new depot in Mildura, as the current depot site does not meet the current operational 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.

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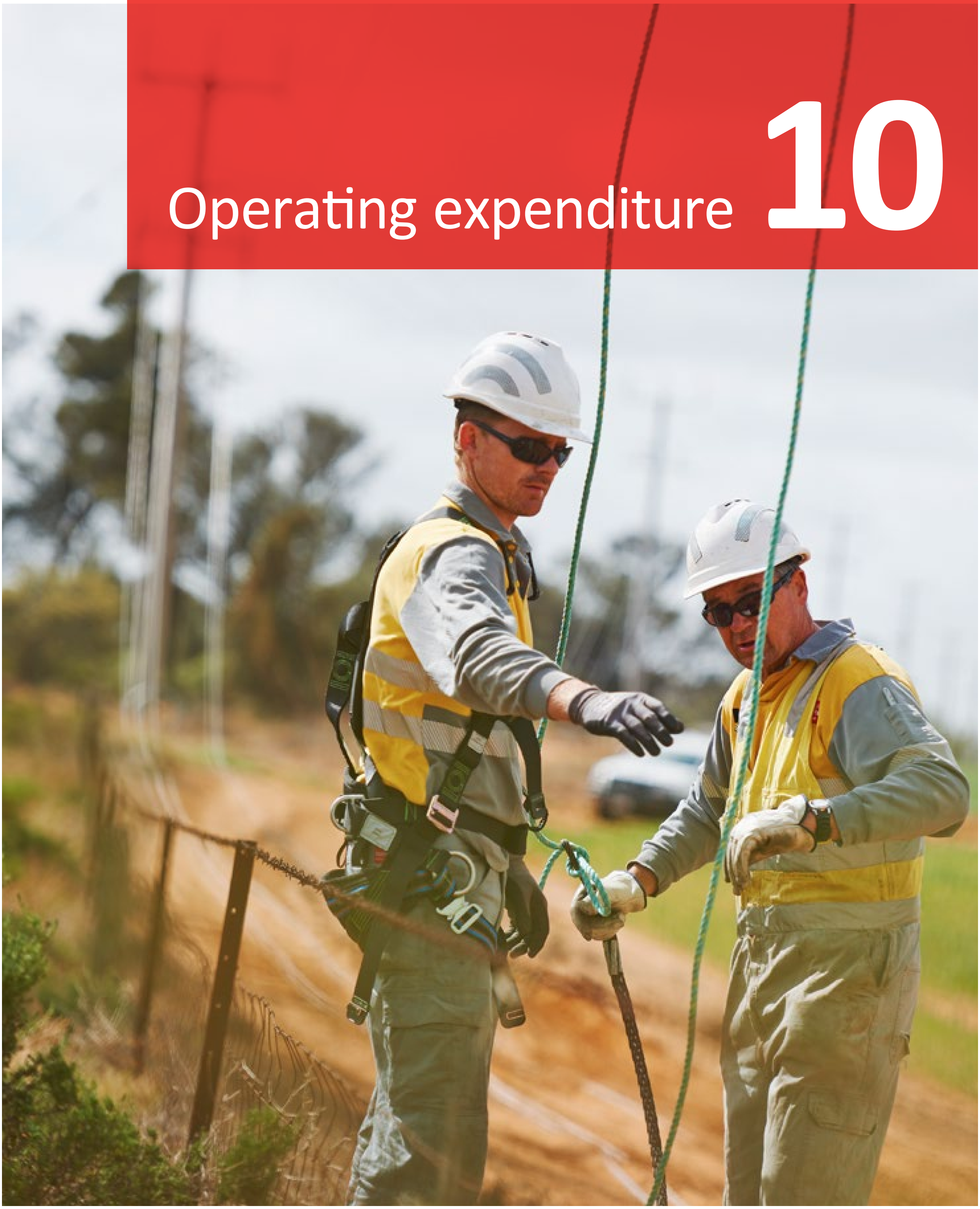
Operating expenditure 10



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10. Operating expenditure

This chapter outlines our operating expenditure forecast for standard control services for the 2016–2020 regulatory control period.

Our operating expenditure forecast reflects the amount we require to meet the operating expenditure objectives, as set out in the Rules.[93] This includes expenditure to meet and manage the expected demand for standard control services over the 2016–2020 regulatory control period; comply with all applicable regulatory obligations; and ensure our distribution system, and network, connection and metering services, meet relevant quality, reliability, safety and security of supply standards.

The key points of our proposed operating expenditure forecast are set out below.

We are one of the most efficient distributors in Australia

Benchmarking studies show we are one of the most efficient rural distribution networks in Australia. This includes benchmarking at a total operating expenditure level, as well as in disaggregated categories such as vegetation management and non-network services.

Our performance relative to other Australian electricity distribution networks is discussed in chapter 5.

We continually aim to deliver efficiency improvements both to our shareholders and customers

The regulatory framework, including the range of incentive schemes applied by the Australian Energy Regulator (**AER**), provides continuous incentives to seek efficiency improvements while maintaining service standards. We also have obligations as a private company to deliver efficiency improvements to our shareholders. As one of the lowest cost distributors in Australia, we have demonstrated a positive response to these incentives.

We operate in an ever changing environment

The economic and network conditions in the 2016–2020 regulatory control period are expected to differ from the economic and network conditions experienced in the 2011–2015 regulatory control period. Our operating expenditure forecast, therefore, reflects expected changes in input prices, as well as the impact of our evolving network.

We need to keep our network safe and reliable, and comply with our obligations

Safety and reliability are critical to the operation of our network. Our operating expenditure forecast reflects the need to comply with our regulatory and legislative obligations in a prudent and efficient manner. This includes responding to changes in our operating environment that are beyond our control.

We are responsive to customer needs through our ongoing customer engagement program

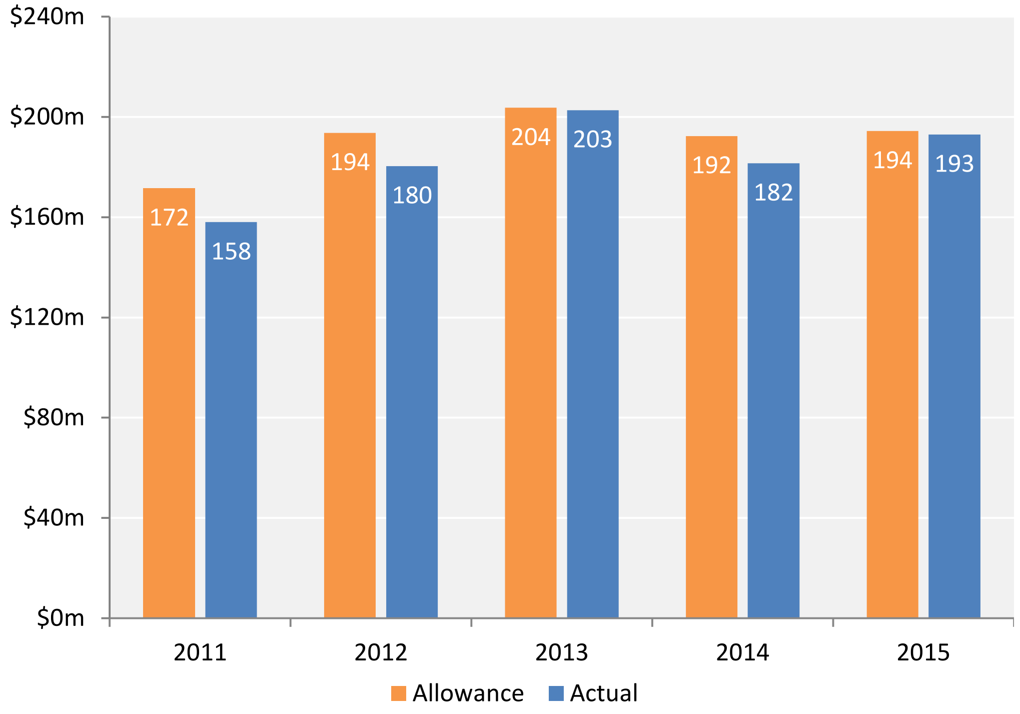
Ongoing stakeholder engagement allows our network to more effectively service the diverse needs of our customer base. The feedback received through our customer engagement programs has been important in the development of our operating expenditure forecasts. This includes, for example, enabling better access to customer data through our proposed billing and customer relationship management system.

93 NER, cl. 6.5.6(c).

10.1 Our current operating expenditure

Our actual operating expenditure in the current regulatory control period is $916 million.[94] As shown in figure 10.1, this represents an underspend of $40 million on our operating expenditure allowance.

Figure 10.1 Actual operating expenditure versus allowance for 2011–2015 ($m, real)



Source: Powercor
Notes: 2015 'actual' spend is a forecast.

As discussed in section 10.2, our underspend on operating expenditure demonstrates a positive response to the incentives in the regulatory framework. This reflects our commitment to continually deliver efficiency improvements to our customers and shareholders, while maintaining service standards.

10.2 Our forecast operating expenditure

Our forecast operating expenditure for the 2016–2020 regulatory control period is $1,333.7 million ($2015). The profile of this expenditure is shown in table 10.1.

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[94] This expenditure includes a forecast for 2015, as actual data is not currently available. Further, included in the attached model, *PAL Opex Consolidation*, is our operating expenditure for each of the 2006–2015 regulatory years, and the operating expenditure for 2015, categorised in the same way as our operating expenditure forecast for the 2016–2020 regulatory control period.

Table 10.1 Forecast annual operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020	Total
Actual operating expenditure (2014)	181.5	181.5	181.5	181.5	181.5	907.6
Net base year adjustments	5.9	5.9	6.9	7.3	7.3	33.4
Change in capitalisation policy	34.7	34.7	34.7	34.7	34.7	173.4
Service reclassification	8.7	8.7	8.7	8.7	8.7	43.3
Step changes	2.3	1.5	4.1	3.8	4.7	16.5
Rate of change	14.5	23.4	31.8	40.8	48.9	159.6
Total	**247.5**	**255.8**	**267.7**	**276.8**	**285.9**	**1,333.7**

Source: Powercor

We have developed our operating expenditure forecast for the 2016–2020 regulatory control period using a 'base–step–trend' approach. This approach is consistent with the AER's preferred model, as set out in its Expenditure Forecast Assessment Guideline.[95]

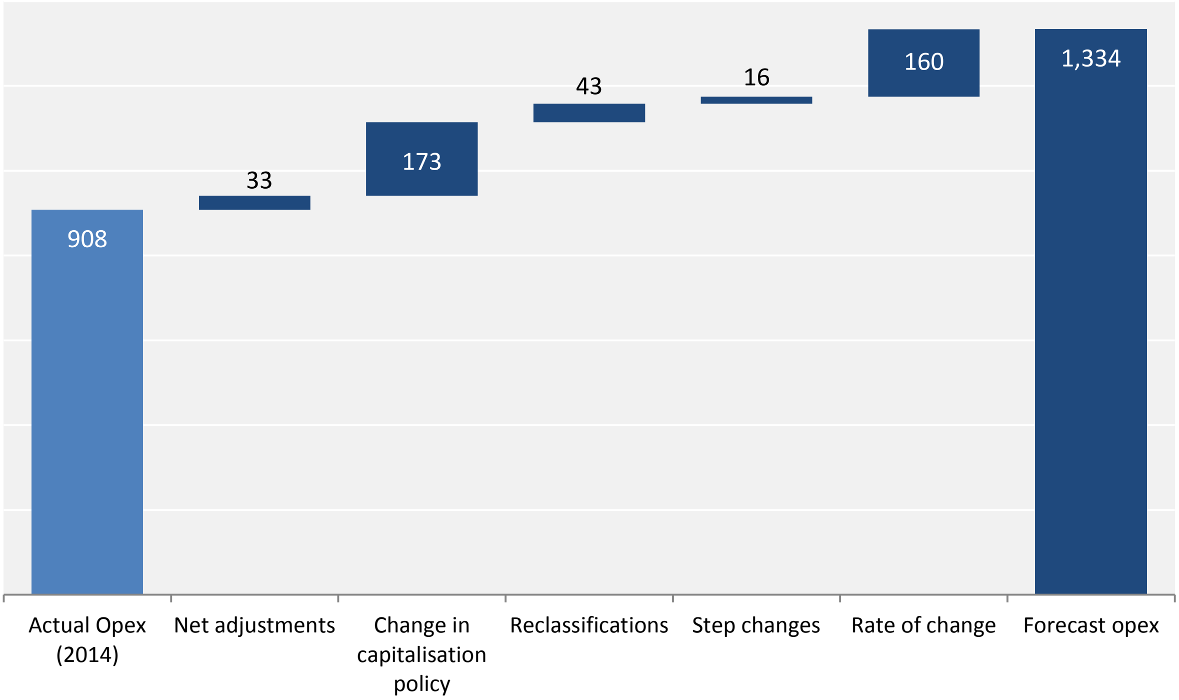
Specifically, we have developed our operating expenditure forecasts for the 2016–2020 regulatory control period as follows:

- nominated 2014 as the efficient revealed base year;
- adjusted our base year expenditure to include an efficient forecast for activities for which the base year expenditure did not reflect expenditure going forward (including a review for any non-recurrent costs);
- adjusted the base year to present the forecast operating expenditure consistent with the approved cost allocation methodology (**CAM**);
- adjusted the base year to include an efficient forecast for services reclassified as standard control services;
- added to the base year the efficient level of forecast step changes for the 2016–2020 regulatory control period; and
- added to the base year the efficient level of operating expenditure determined by applying a rate of change formula, including the rate of change in real prices, output growth and productivity.

A build-up of our forecast operating expenditure for the 2016–2020 regulatory control period, using the base–step–trend approach, is set out in figure 10.2. A split of our operating expenditure forecast into different expenditure categories is also provided in regulatory templates 2.16 and 3.2.

95 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 32.

Figure 10.2 Operating expenditure forecasting approach 2016–2020 ($m, real)



Source: Powercor

10.3 Efficiency of the base year

We nominate the fourth year of the 2011–2015 regulatory control period, being 2014, as the efficient year on which we have based our operating expenditure forecast for the 2016-2020 regulatory control period. We consider our base year expenditure is efficient for the following reasons:

- our base year data is current and robust;
- we are subject to an incentive framework, and have responded to these incentives;
- our ownership structure promotes efficient expenditure; and
- benchmarking analysis supports the efficiency of our operating expenditure.

These reasons are discussed in detail below. The AER, therefore, should accept our base year expenditure (subject only to the adjustments set out in section 10.3.6) when reviewing our total forecast operating expenditure.

10.3.1 Current and robust base year data

We have used 2014 as the base year as it represents the most recent actual audited reported performance that will be available before the AER is required to make its Draft Decision. The currency of this data (relative to earlier years) ensures our forecasts are based on up-to-date data. That the data is audited ensures the starting point for our forecasts are robust.

10.3.2 Incentive framework

The regulatory framework in which we operate is an incentive based regime. This is embedded in the National Electricity Law (**NEL**), which requires a regulated network service provider be provided with effective incentives in order to promote economic efficiency with respect to the direct control network services the operator provides.[96]

This incentive framework is predicated on profit being a motivating factor, and therefore a driver for business is to seek efficiencies by reducing costs. In its inquiry into the regulatory framework for electricity networks, the Productivity Commission stated the following:[97]

> *Incentive regulations are built on a simple premise. Where the regulatory rewards to the business are (at least significantly) separated from their actual costs, profit-motivated businesses face strong incentives to cost minimise in any given period.*

To ensure the incentive to minimise costs exists throughout a given period, such as a regulatory control period, the AER employs an efficiency benefit sharing scheme (**EBSS**). As discussed in chapter 11, the EBSS allows distributors to retain an incremental efficiency gain or loss for five years, regardless of the year in which the gain or loss is made. The EBSS is also applied symmetrically—that is, equally to efficiency gains and losses—such that the penalty for an overspend is the same as the benefit for an equivalent underspend.

In previous price reviews the AER has noted that, because of the incentive regime, it is able to rely on revealed costs to set the efficient base year:[98]

> *The AER considers that given the incentives to minimise costs in the regulatory regime, the revealed costs of a DNSP are likely to be a reasonable approximation of efficient costs in the circumstances of that DNSP for the scope of work undertaken.*

Our total operating expenditure has been subject to an EBSS throughout the 2011–2015 regulatory control period. Consistent with the reasons previously set out by the Productivity Commission and the AER, therefore, our actual operating expenditure in our base year should be considered efficient.

10.3.3 Ownership structure

In addition to the incentive framework, our ownership structure provides further reason to accept our base year total operating expenditure, without adjustment, as being efficient. That is, as a privately owned business we have an obligation to maximise returns to shareholders. This contrasts with publically owned utilities that may face competing, non-commercial incentives that limit their responsiveness to profit based incentives.[99]

As a privately owned business, we also face scrutiny on our financial performance, beyond that of the regulator. For example, we raise financing from multiple parties (as opposed to a single Treasury). These multiple parties each continually monitor our performance, and the consequences of poor management can impact the capacity of the business to raise further capital. This provides additional discipline on us to maintain an efficient expenditure profile.

Our corporate governance framework further supports the efficiency of our actual total operating expenditure. This framework is discussed in section 3.3. In particular, our internal governance measures include structured and rigorous cost controls over all expenditure. It also includes policies that establish principles and practices

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96 NEL, cl. 7A(3).

97 Productivity Commission, *Inquiry report volume 1, Electricity network regulatory frameworks*, 9 April 2013, p. 267.

98 AER, *Final decision, Victorian electricity distribution network providers, Distribution determination 2011–2015*, October 2010, p. 316.

99 See, for example: Productivity Commission, *Inquiry report volume 1, Electricity network regulatory frameworks*, 9 April 2013, pp. 270–279.

that govern purchasing and procurement activities for all goods, materials, services and intellectual property assets.

10.3.4 Benchmarking analysis

Our responsiveness to the incentive framework, and the effectiveness of our ownership and governance structures, are further supported by the performance of our business relative to other, comparable networks. Notably, the AER's Annual Benchmarking Report for 2014 shows that we have performed well on most metrics, including at a total operating expenditure level.[100]

We provide a more detailed discussion on benchmarking in chapter 5. In summary, we consider benchmarking is an important part of the regulatory framework. When combined with other expenditure assessment methods, it is a useful tool for assessing the efficiency of a distributors' historical and forecast expenditure required to meet the operating expenditure objectives in the Rules.

10.3.5 The impact of transitioning to a new cost allocation methodology

On 3 October 2014, the AER approved our CAM.[101] Our operating expenditure forecast for the 2016–2020 regulatory control period has been properly allocated to standard control services in accordance with the principles and the policies in the CAM.[102] In allocating our directly attributable costs or shared costs, we have ensured that no costs have been double counted. We have engaged an external auditor to assure us that our historical costs have been properly allocated in accordance with our approved CAM.

The transition to the approved CAM accounts for $173.4 million of our total forecast increase in operating expenditure. The primary difference in our approved CAM, relative to the previously approved CAM, is that indirect corporate overheads will now be expensed. This represents a reallocation of costs (rather than any new costs)—that is, the implementation of our approved CAM has not changed the combined total of our capital and operating expenditure forecasts for standard control services.

10.3.6 Expenditure removed from base year and base year adjustments

We have reviewed our base year operating expenditure for any non-recurrent expenditure. Although no non-recurrent operating expenditure was discovered, we identified several activities for which the 2014 base year does not reflect the expenditure for these activities going forward. A summary of these activities, and the net adjustments to our 2014 base year operating expenditure, are set out in table 10.2.

[100] AER, *Annual Benchmarking Report*, November 2014.
[101] See our approved CAM, attached: *Cost Allocation Method*.
[102] This includes allocated costs between distribution services, allocated directly attributable costs, allocated shared costs between the relevant categories of distribution services and allocated directly attributable costs and shared costs.

Table 10.2 Net base year adjustments ($m, real)

Expenditure removed from base year	2016	2017	2018	2019	2020	Total
Less: base year regulatory reset costs	-1.1	-1.1	-1.1	-1.1	-1.1	-5.7
Add: forecast regulatory reset costs	-	-	0.9	1.3	1.4	3.6
Less: base year GSL payments	-2.2	-2.2	-2.2	-2.2	-2.2	-11.0
Add: forecast GSL payments	2.2	2.3	2.3	2.4	2.4	11.6
Less: base year superannuation (defined benefit contributions)	-4.3	-4.3	-4.3	-4.3	-4.3	-21.6
Add: forecast superannuation (defined benefit contributions)	7.2	6.9	6.7	6.4	6.0	33.2
Less: base year DMIA	-0.2	-0.2	-0.2	-0.2	-0.2	-1.2
Add: forecast DMIA	0.6	0.6	0.6	0.6	0.6	3.0
Less: base year debt raising costs	-0.2	-0.2	-0.2	-0.2	-0.2	-1.2
Add: forecast debt raising costs	4.0	4.2	4.5	4.8	5.0	22.5
Total	**5.9**	**5.9**	**6.9**	**7.3**	**7.3**	**33.4**

Source: Powercor

Appendix F provides additional information on these adjustments to our base year operating expenditure, as well as our approach for forecasting this expenditure for the 2016–2020 regulatory control period. This includes an outline of our approach to forecasting debt raising costs, which differs from that previously adopted by the AER.

10.3.7 Service classification

In addition to discussing the adjustments to our base year operating expenditure, appendix F also outlines expenditure related to the reclassification of services (for which the impact on customers is net present value neutral). A summary of these adjustments is set out in table 10.3.

Table 10.3 Service reclassification ($m, real)

Base year adjustments	2016	2017	2018	2019	2020	Total
Supply abolishment	0.6	0.6	0.6	0.6	0.6	3.0
Category RIN alignment	3.1	3.1	3.1	3.1	3.1	15.6
Reclassification of IT metering expenditure	4.9	4.9	4.9	4.9	4.9	24.6
Total	**8.7**	**8.7**	**8.7**	**8.7**	**8.7**	**43.3**

Source: Powercor

10.4 Rate of change

Actual operating expenditure in the base year reflects the economic and network conditions that prevailed during the 2014 year. Over the 2016–2020 regulatory control period it is reasonable to expect that these economic and network conditions will change and therefore the operating expenditure forecasts must take these changes into account.

The AER's Expenditure Assessment Forecast Guideline sets out the following reasons why efficient operating expenditure in the forecast period may differ from the base level of expenditure:[103]

- real price growth—this is changes in the prices that we pay for key inputs used in our operations including, labour, materials and contractors. Real price growth is the growth rate in prices relative to growth in the Consumer Price index. As real input prices change our efficient level of expenditure will change;
- output growth—this is the change in the scale of the network that reflects changes in demand for network services. It is reasonable that as the scale of operations increases our efficient costs will increase; and
- productivity growth—this is changes in the level of expenditure required to deliver the same level of services to customers. Productivity growth may arise during the regulatory control period as a result of economies of scale, technical changes or efficiency improvements.

We have developed forecasts of each of the above components and applied these to develop our operating expenditure forecasts. Our approach to real price growth is discussed in chapter 7. Therefore only our approaches to forecasting output growth and productivity growth are explained in this chapter.

10.4.1 Output growth escalation

Output growth escalation is required to capture increases in operating expenditure which are driven by changes in the size of the network and the quantity of services we will supply over the 2016–2020 regulatory control period.

Key categories of operating expenditure and the extent to which these vary with changes in network size are set out in table 10.4.

103 AER, *Expenditure forecast assessment guideline for electricity distribution*, November 2013, p. 34.

Table 10.4 Extent of variable expenditure by key operating expenditure category

Category	Distribution services	Extent variable costs
Direct maintenance	Includes costs relating to, for example, maintenance (routine and condition based), vegetation management, emergency response and Supervisory Control and Data Acquisition (**SCADA**).	Highly variable with physical size of network. As network scale increases the scale of maintenance activity increases.
Operating	Includes cost relating to network and corporate overheads. For example, network control room, network planning, network management, GSL payments, network licence fees, levies, fleet and property overheads, land taxes, billing and revenue collection, customer services, advertising and marketing, insurance and debt raising costs, back-office and IT support.	Network operating costs that relate to network planning and management vary with workloads, which generally vary with network size. Land taxes, fleet and property vary to a degree with network size. There are some components of network operating costs that are relatively fixed (e.g. licence fees). Customer related costs vary with number of customers. Insurance and debt raising costs vary with the value of the network which is related to the size of the network. Back-office support costs vary with workload which varies to a degree with network size.

Source: Powercor

As noted in section 10.2 we have prepared our operating expenditure forecasts at the aggregate level using a revealed cost approach. We have therefore undertaken the quantitative analysis of the variation in operating expenditure resulting from changes in the network size at the aggregate level, rather than by operating expenditure category.

We have used econometric models to quantify the relationship between growth in operating expenditure and growth in key cost drivers that affect the size of the network. Three of the econometric models were developed by expert econometricians, Frontier Economics, and the fourth model was developed by Economic Insights and applied by the AER's in its Draft Decision for NSW and ACT distributors.[104] To develop our output growth escalator we have combined the results of the four econometric models.

We consider that taking an average of the results of multiple econometric models:

- enables the impact of a broader range of operating expenditure cost drivers to be captured in the output growth escalator;
- addresses the statistical limitations associated with a small sample size and high correlations between cost drivers; and
- will likely produce a more accurate forecast than using a single model.

[104] Economic Insights, *Economic Benchmarking Assessment of Operating Expenditure for NSW and ACT Electricity DNSPs*, November 2014, p. 33.

Frontier Economics note that:[105]

> *It has long been recognised in the statistics literature that when multiple forecasts of the same variable are available, combining the forecasts from different sources generally results in more accurate forecasts than if a single source were used. In order for this to be effective, each source, even if not completely free from error, must contribute some useful information.*

Frontier Economics developed its econometric models using eight years of data for the 13 National Electricity Market (**NEM**) distributors over the 2006–2013 period. This data was sourced from the distributors' responses to the AER's Economic Benchmarking RIN. Frontier Economics' report is provided in attachment, *Opex scale escalation econometric model*. Frontier Economics econometric model results are presented in table 10.5.

Table 10.5 Frontier Economics output growth econometric models

Log operating expenditure	Model 1	Model 2	Model 3
Log Customer numbers	0.380*		
Log Total zone substation transformer capacity	0.345***		
Log Ratcheted maximum demand		0.737***	
Log Composite Scale Variable			0.665***
Log Service area	0.116***		0.170***
Log Customer per route length		-0.596***	
Urban dummy		0.813*	1.077***
2007.year	-0.003	0.010	0.013
2008.year	0.079	0.084	0.100*
2009.year	0.058	0.052	0.081
2010.year	0.113*	0.110*	0.143**
2011.year	0.156***	0.173***	0.198***
2012.year	0.246***	0.272***	0.295***
2013.year	0.217**	0.261***	0.275***
Constant	2.725	7.599***	2.645***
Number of observations	104	104	104
Within R2	0.648	0.606	0.648
Between R2	0.957	0.923	0.974
Overall R2	0.946	0.911	0.962
σu	0.177	0.264	0.149

105 Frontier Economics, *Operating expenditure scale escalation econometric model*, January 2015, p. 27.

Log operating expenditure	Model 1	Model 2	Model 3
σe	0.096	0.098	0.098

Source: Frontier Economics, *Operating Expenditure Scale Escalation Model*, January 2015.
Notes: 1. The dependent variable is log (opex). All driver variables, except the year and urban dummy variables, are in logarithms
2. Estimated coefficients for each variable are shown on the first row; p-values are indicated by the number of stars next to each coefficient: *** for p-value < 0.001, ** for p-value < 0.01, * for p-value < 0.05
3. The composite scale variable includes the following output variables and weightings, route line length – 50%, customer numbers – 25% and maximum demand – 25%.
4. The urban dummy takes the value 1 if the distributor is considered urban and 0 if the distributor is considered rural.

We note that there are numerous other cost drivers that are not captured in the econometric models due to data limitations and statistical constraints. Notwithstanding, we consider that the using an average of multiple models adequately captures the impact of growth in the core cost drivers on operating expenditure.

Output variable forecasts

To populate the econometric models and develop our output growth escalator, we require forecasts of the growth in the output variables. We forecast the growth in the output variables as set out in table 10.6.

Table 10.6 Method for forecasting output variables

Output	Forecast method	Reset RIN location	Applicable models
Customer numbers	Sourced from independent experts the Centre for International Economics (CIE), refer to chapter 8.	Reset RIN and 2014 Benchmarking RIN, Template 3.4 Operational data	AER model Frontier model 1 Frontier model 3
Zone substation transformer capacity	Developed using a bottom up forecasting methodology taking into account current, committed and planned projects for completion during the 2016–2020 regulatory control period. The combination of forecasting methods ensures the forecasts are reasonable given our capital expenditure program.	Reset RIN and 2014 Benchmarking RIN, Template 3.5 Physical Assets	Frontier model 1
Ratcheted maximum demand	Based on aggregate maximum demand forecasts at terminal station, 50% POE. Forecasts are developed by CIE at the terminal station using a top down econometric approach. The top down forecasts are then reconciled to the bottom up forecasts. The forecasting process is discussed in detail in chapter 8.	Reset RIN and 2014 Benchmarking RIN, Template 3.4 Operational data	AER model Frontier model 2 Frontier model 3
Route line length	Developed based on historical trends over the period 2009 to 2014.	Reset RIN and 2014 Benchmarking RIN, and Template 3.7 Operating environment	Frontier model 3

Output	Forecast method	Reset RIN location	Applicable models
Circuit length	Developed by voltage level for each of overhead and underground circuits. Our forecasting method is a combination of historical trends which is applied primarily for lower voltage categories and bottom up analysis for higher voltage lines (66kv) based on known projects. Negative growth is forecast for overhead SWER which is being replaced with underground SWER. Forecasting at voltage level and taking account of historical trends and known projects ensures our forecasts are reasonable. Total circuit length is the sum of the length of circuit for each voltage category, including overhead and underground circuits.	Reset RIN and 2014 Benchmarking RIN, Template 3.5 Physical Assets	AER model

Source: Attached *Powercor 2016 – 2020 Reset RIN* and *2014 Benchmarking RIN*

Table 10.7 provides our forecast growth rates for each of the output variables.

Table 10.7 Forecast growth rates in output variables (per cent)

Annual growth rate	2015	2016	2017	2018	2019	2020
Customer numbers	1.75	1.75	1.81	1.82	1.82	1.82
Zone substation transformer capacity	-0.07	1.42	4.07	0.93	0.93	0.00
Maximum demand	2.56	3.23	2.23	2.62	3.10	2.07
Route line length	0.31	0.31	0.31	0.31	0.31	0.31
Circuit length	0.40	0.41	0.44	0.43	0.50	0.50

Source: Powercor

Combined output growth escalator

We have removed economies of scale from the output growth component of the rate of change. Removing economies of scale from the output growth component is consistent with the AER's rate of change formula set out in the Expenditure Forecast Assessment Guideline and the AER's Draft Decision for the NSW and ACT distributors.[106] This approach means that economies of scale are considered as part of the assessment of total productivity change and avoids the potential for double counting the impact of economies of scale.

For each of the four models we have removed the economies of scale by scaling the coefficients to add to one. For each model, we then multiply the scaled coefficients by the forecast growth in the respective output variables. This provides an output growth rate for each of the four models. We then take a simple average of the implied output growth rates from the four models. This process is demonstrated in attached model, *PAL Output Growth*.

Our combined output growth escalators are provided in table 10.8.

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106 AER, Better Regulation, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, p. 34; AER, *Draft Decision, Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, November 2014, p. 205.

Table 10.8 Combined output growth escalator (per cent)

	2015	2016	2017	2018	2019	2020
Model 1—Frontier Economics	0.88	1.59	2.89	1.40	1.39	0.96
Model 2—Frontier Economics	2.56	3.23	2.23	2.62	3.10	2.07
Model 3—Frontier Economics	1.23	1.40	1.17	1.26	1.38	1.13
Model 4—Economic Insights	1.78	1.93	1.76	1.84	1.96	1.73
Combined	**1.61**	**2.04**	**2.01**	**1.78**	**1.96**	**1.47**

Source: Powercor

Importantly, our proposed output growth escalators do not capture the forecast increase in operating expenditure associated with our proposed step changes. This is because our proposed operating expenditure step changes are not driven by increases in the size of the network.

10.4.2 Productivity change

Productivity change can result from technical change, efficiency improvements and economies of scale. The AER's Expenditure Forecast Assessment Guideline and its recent approach to assessing productivity in its Draft Decision for NSW and ACT distributors indicates its preference to consider productivity as a whole.[107]

In principle, we do not consider it appropriate to pre-emptively reduce operating expenditure forecasts for potential productivity benefits that may or may not occur in future due to technical change or efficiency improvements. Applying pre-emptive productivity adjustments to expenditure forecasts is not appropriate because:

- it is inconsistent with the EBSS and incentive-based regulation. The EBSS is designed to provide incentives for distributors to seek and implement opportunities to make productivity and efficiency savings in a timely manner, the benefits of which are shared between distributors and customers. Further, reducing future operating expenditure allowances to reflect historical productivity change could inadvertently reduce incentives to seek productivity gains between regulatory control periods;
- there is no basis upon which the AER can derive a realistic expectation of future productivity change with any level of accuracy. Historical productivity changes provide little information on the likely benefits of future productivity change as future innovations are unknown and there are likely diminishing returns over time from technical changes that have already occurred; and
- it is inconsistent with the Rules because there is a very high likelihood of forecasting error and consequently a high likelihood that distributors would have an ex ante expectation of recovering less than efficient costs of operating the network to achieve the operating expenditure objectives.

Notwithstanding the above, the AER's benchmarking analysis does not provide any evidence of productivity growth in the distribution industry, or for our business, over the past eight years. The AER's benchmarking analysis instead suggests that the distribution industry has exhibited declining operating expenditure productivity over the last eight years.[108] This trend is consistent with the Productivity Commission's analysis of

[107] AER, *Better Regulation, Expenditure Forecast Assessment Guideline for Electricity Distribution*, November 2013, pp. 34-35. AER, *Draft Decision Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, pp. 206-207.

[108] AER, *Electricity distribution network service providers, Annual Benchmarking Report*, November 2014, p. 34. Economic Insights, *Economic benchmarking of Operating Expenditure for NSW and ACT Electricity DNSP, November 2013,* p. 33.

productivity trends in the electricity, gas, water and waste sector, and is also consistent with trends observed in other jurisdictions, for example New Zealand.[109] As noted by Economic Insights 2014:[110]

> *…the civil construction–oriented nature of distribution capital means the industry has gained less from computerisation cost savings than have industries which use a higher proportion of machinery and equipment instead of structures.*

Factors contributing to declining productivity include:

- increases in operating costs that are driven by factors independent of the quantity of outputs produced or services provided, for example changes in regulatory obligations such as increased compliance reporting, increased requirements relating to vegetation management as a result of increased clearance requirements from Energy Safe Victoria and increased asset inspection as a result of the Victorian Bushfires Royal Commission findings. Due to data limitations it is extremely difficult to isolate the exact impact of each regulatory change on operating expenditure productivity;
- slow output growth which is being observed universally in advanced western economies and is beyond the control of distributors. In particular, energy throughput has been declining for the industry in aggregate since 2010. Reductions in system-wide energy throughput do not lead to reductions in distributors' costs. Distributors must provide and maintain the necessary capacity to meet peak demand location by location on the network rather than average demand; and
- changes in asset health and condition over time can require increased maintenance expenditure with no change in the physical measure of the capital stock and no change in the quantity of measured outputs.

Importantly, declining productivity trends do not necessarily provide evidence of declining industry efficiency. Observing declining productivity can be a reflection of a number of factors as indicated above.

In conclusion, we do not consider it appropriate to apply pre-emptive productivity adjustments to our operating expenditure forecasts. Further, there is no evidence to justify making pre-emptive productivity adjustments to our operating expenditure forecasts.

We have therefore applied a zero productivity adjustment in our rate of change forecasts. We will however continue to respond to the EBSS incentives during the 2016–2020 regulatory control period and seek to implement opportunities to make productivity improvements and efficiency savings, the benefits of which will be shared with customers through the EBSS arrangements.

10.4.3 Relationship between productivity growth and step changes

The AER's Expenditure Forecast Assessment Guideline states that the increased costs of step changes occurring in the 2016-2020 regulatory control period may be accounted for in the productivity adjustment in the rate of change formula.

As noted above, we do not consider it appropriate to apply pre-emptive productivity adjustments and have therefore applied a zero productivity adjustment. Consequently, the negative impact on measured operating expenditure productivity resulting either from past or future step changes is not captured in the productivity component of our rate of change forecasts.

To ensure that our operating expenditure forecasts are sufficient to achieve the operating expenditure objectives in the Rules, the impact of future step changes must be added to our operating expenditure forecasts as a separate item. Our step change proposals are discussed in section 10.5.

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[109] Productivity Commission, *Productivity Update*, April 2014.
[110] Economic Insights, *Electricity Distribution Industry Analysis*, 1996-2013, June 2014, p. v.

10.4.4 Overall rate of change

Table 10.9 shows the overall rate of change applied to our operating expenditure forecasts. The rate of change is one of two factors that explain the significant variation in forecast operating expenditure from our historical operating expenditure.

Table 10.9 Rate of change in operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020	Total
Real price growth	6.5	11.0	15.3	19.6	24.3	76.7
Output growth	8.0	12.5	16.6	21.1	24.6	82.8
Productivity	-	-	-	-	-	-
Total value of rate of change	14.5	23.5	31.8	40.8	49.0	159.6

Source: Powercor

10.5 Step changes

This section discusses the framework and role of step changes in our total operating expenditure forecasts, as well as our approach to identifying and justifying individual step changes. The step changes are one of two factors that explain the significant variation in forecast operating expenditure from our historical operating expenditure. A summary of our proposed step changes is included, with further detail on the individual step changes provided in appendix G.

10.5.1 Rules framework

The Rules state that our total forecast operating expenditure for the 2016–2020 regulatory control period must include the amount required to achieve each of the operating expenditure objectives. The operating expenditure objectives, as set out in clause 6.5.6(a) of the Rules, are to:

(1) meet or manage the expected demand for standard control services over the regulatory control period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

  (i) the quality, reliability or security of supply of standard control services; or

  (ii) the reliability or security of the distribution system through the supply of standard control services,

  to the relevant extent:

  (iii) maintain the quality, reliability and security of supply of standard control services; and

  (iv) maintain the reliability and security of the distribution system through the supply of standard control services.

(4) maintain the safety of the distribution system through the supply of standard control services.

The Rules further state that the AER must accept our forecast operating expenditure where it is satisfied the forecast operating expenditure for the regulatory control period reasonably reflects the operating expenditure criteria. The operating expenditure criteria in clause 6.5.6(c) of the Rules are:

(1) the efficient costs of achieving the operating expenditure objectives in clause 6.5.6(a) of the Rules;

(2) the costs that a prudent operator would require to achieve the operating expenditure objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

As discussed in section 10.3, our total operating expenditure in 2014 reflects the efficient costs a prudent operator in our circumstances would require to meet the operating expenditure objectives. This is based on our current operating environment, and having regard to our current service targets, regulatory obligations and other prevailing environmental circumstances. To meet the operating expenditure objectives in the 2016-2020 regulatory control period a prudent operator in our circumstances will be required to undertake new or increased activities, and to incur new or increased costs associated with the following:

- a change in a regulatory obligation or requirement;
- a change in the expected demand for standard control services which is not otherwise provided for in the rate of change;
- where base year operating expenditure is not sufficient to maintain:
  - the quality, reliability and security of supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); or
  - the safety, reliability and security of the distribution system through the supply of standard control services (to the extent that there is no applicable regulatory obligation or requirement in relation to that quality, reliability and security); and
- a change in expenditure that is in the long term interests of consumers, but is of limited benefit to the business.

Our operating expenditure forecasts therefore include the impact of step changes over the 2016–2020 regulatory control period for new or increased activities and new or increased costs. These step changes reflect the changing environment in which we operate.

Our approach to forecasting step changes is largely consistent with that proposed by the AER in its forecast expenditure assessment guideline and its Draft Decision for the NSW and ACT electricity distribution businesses. In particular, the AER stated that step changes should generally relate to a new obligation or some change in the service provider's operating environment beyond its control.[111]

As set out above, we have also included step changes for where base year operating expenditure is not sufficient to maintain the quality, reliability and security of supply of standard control services, or the safety, reliability and security of the distribution system. Similarly, we have included step changes where the additional operating expenditure will result in cost savings to consumers, but are of limited benefit to our business. Our reasons for including these step changes are set out below:

[111] AER, *Draft Decision, Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, November 2014, p. 7-161.

- The scope of operating expenditure step changes must be determined by reference to the statutory test for the AER's acceptance of our proposed operating expenditure forecast. That is, the nature of forecast changes to our operating expenditure (relative to base year operating expenditure) that may constitute a step change depends upon the content of the operating expenditure objectives in clause 6.5.6(a) of the Rules. For example, the Rules do not confine step changes to operating expenditure changes arising from changes in regulatory obligations and requirements, or operating and capital expenditure trade-offs.
- In its draft decision for the NSW and ACT electricity distributors, the AER stated that separately forecasting operating expenditure for activities that may change at a different rate to operating expenditure (more generally) may lead to forecasting bias.[112] In effect, the AER is concerned that distributors will separately forecast activities that increase at a higher rate than total operating expenditure, but fail to separately forecast activities that increase at a lower rate.

  The AER’s position may be appropriate in regard to small changes in costs, such that the impact of variations would not limit or overstate the capacity for our forecast operating expenditure to achieve the operating expenditure objectives. Our forecast step changes, however, represent material changes to our expenditure. That is, without these changes our forecast operating expenditure may not be sufficient to maintain the quality, reliability and security of supply of standard control services, of the safety, reliability and security of the distribution system.[113] This is supported by our current level of efficiency—as shown in the AER’s benchmarking analysis—and this efficiency has been achieved using an approach that included material step changes (for the circumstances outlined previously).

  Moreover, we have separately forecast activities that increase at a lower rate, or may otherwise lead to an operating expenditure forecast that does not meet the operating expenditure criteria. For example, we have removed from our operating expenditure forecasts the impact of higher regulatory reset costs in our base year. The removal of our actual DMIA expenditure from the base year, and replacing it with a forecast based on the expected allowance follows a similar premise. We also remove actual GSL payments, to ensure our forecast operating expenditure is not overstated due to anomalous GSL payments in our base year.
- Similarly, the AER should not assume that base year expenditure is sufficient to provide all forecast costs necessary to maintain network security, in particular for IT security expenditure. Environmental changes in the IT security space are rapid and continual. The advance of technology means that what may have been prudent in 2014 is not necessarily sufficient to manage risk in 2016 and beyond.

  The regulatory framework is also important in the timing of IT security expenditure. IT security expenditure is not self-financing. That is, it is typically driven by avoiding the potential for future costs, as opposed to productivity or efficiency gains that our business will benefit from. As a commercial entity, we would not undertake this expenditure unless it was explicitly included in our operating expenditure allowance, notwithstanding it being in the long term interests of consumers. The AER acknowledged these circumstances in its Final Decision for Envestra’s gas network in Victoria:[114]

  > *In some limited circumstances the benefits of a discretionary project may not be productivity gains, but the project is expected to lead to lower prices to customers. If there are few benefits to the gas service provider, the benefits of undertaking the project to the gas service provider may not outweigh the cost of the project. Therefore it may not undertake the project without an increase in opex. A step change in opex may be necessary so that customers benefit in the long term.*

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112 See, for example: AER, *Draft Decision, Ausgrid distribution determination 2014-19, Attachment 7: Operating expenditure*, November 2014, p. 7-173.

113 See, for example: NER, cl. 6.5.6(a).

114 AER, *Access arrangement final decision, Envestra Ltd 2013–17, Part 2: Attachments*, March 2013, p. 171.

It is also notable that IT security requirements may not be linked to specific regulatory obligations. This does not mean, however, that IT security expenditure is not prudent and efficient. Instead, prescriptive regulations that require particular IT security solutions would almost certainly become redundant as technology evolves.

10.5.2 Identifying and justifying step changes

Based on the above, we undertook a series of internal workshops. These workshops identified events that are foreseeable, and forecast their impact by relying on the best information available. For an identified step change to be proposed, it was required to demonstrate the following:

- there is an uncontrollable change in the environment that affects our efficient forecast expenditure;
- when this change event occurs and when it is efficient to incur expenditure to address the change in the environment;
- the options considered to meet the change and the selected efficient option—that is, we took appropriate steps to minimise its cost from the time the event was foreseeable;
- when we expect to make the changes to meet the changed environmental event;
- the efficient costs associated with making the step change; and
- the costs cannot be met from existing regulatory allowances or from other elements of the expenditure forecasts.

In regard to the latter—that costs cannot be met from our existing regulatory allowance—careful attention has been taken to ensure no output growth is incorporated into the step changes in scope. For example, only the incremental costs above our base year and output growth have been included for step changes where an existing level of costs is reflected in our base year. Our scope changes, therefore, reflect new requirements or activities and do not in any way constitute 'more of the same'.

Similarly, our proposed step changes are not accounted for in forecast productivity growth. As discussed in section 9.4, we have not applied a productivity growth adjustment in developing our operating expenditure forecasts. This reflects our concerns as to the robustness of any such adjustments. In any event, our analysis indicates that applying a productivity adjustment would result in an increase to our forecast operating expenditure for the 2016-2020 regulatory control period. Instead, we have applied a zero productivity growth rate and included forecast step changes.

To the extent that further unforeseen or uncontrollable events occur, we propose to rely on the uncertainty provisions discussed in chapter 14. However, unless relevant materiality thresholds are met, such events may result in expenditure being incurred that is not provided for through our regulatory allowance. That is, the proposed step changes are required to allow us a reasonable opportunity to recover our prudent and efficient costs.[115]

[115] NER, cl. 6.5.6(c).

10.5.3 Forecast step changes

Our proposed list of step changes, consistent with the framework above, is shown in table 10.10.

Table 10.10 Operating expenditure step changes for 2016–2020 ($m, real)

Step change	Total
Customer charter	0.5
Superannuation (accumulation members)	4.6
Monitoring IT security	2.0
Mobile devices	4.1
CIS and CRM	5.2
Total	**16.5**

Source: Powercor
Notes: Total does not add due to rounding.

A summary of these step changes is provided below. The full justification for each step change is set out in appendix G.

Customer charter

Under clause 9.1.2(b) of the Electricity Distribution Code, we are required to provide a customer charter to each customer at least once every five years. The charter must summarise all current rights, entitlements and obligations of distributors and customers relating to the supply of electricity, including:[116]

- the identity of the distributor;
- the distributor's guaranteed service levels; and
- other aspects of the customer's relationship under the Electricity Distribution Code and other applicable laws and codes.

We last provided a customer charter to all our customers in 2011. Therefore, we will next need to provide a customer charter in 2016. This step change reflects the costs of developing, producing and circulating our customer charter.

The forecast impact of this change is set out in table 10.11. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[117]

Table 10.11 Customer charter ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Customer charter	0.5	–	–	–	–	0.5

Source: Powercor

[116] Clause 9.1.3 of the Electricity Distribution Code.
[117] NER, cl. 6.5.6(a)(2).

Superannuation (accumulation members)

Our proposed superannuation (accumulation members) step change comprises two separate components—an increase in our accumulation member superannuation contributions for replacement staff; and an increase due to the superannuation guarantee levy.

Superannuation payments for 'replacement' employees

On an annual basis, we engage the actuary of our superannuation fund, Mercer, to calculate the defined benefit superannuation scheme costs we recognise in our statutory accounts. For the purpose of developing our Regulatory Proposal, Mercer also forecast these defined benefit costs for each year of the 2016–2020 regulatory control period.

Mercer's forecast of our defined benefit superannuation scheme costs factors in an expected decline in the number of defined benefit superannuation scheme members within our organisation over the 2016–2020 regulatory control period. This decline in defined benefit superannuation members will be offset by 'replacement' employees who must be members of an accumulation fund. However, as we use Mercer's forecast to adjust our base year operating expenditure (as set out in appendix F), the superannuation contribution for these 'replacement' employees is not reflected in our base year. As these 'replacement' employees are not due to additional scale, our contributions for these replacement employees will also not be captured elsewhere in the rate of change formula.

Superannuation guarantee levy

Our superannuation expenditure will increase due to the 25 basis point increment to the superannuation guarantee levy.[118] We have forecast this expenditure based on a half year contribution, as this increase became effective from 1 July 2014.

The forecast total impact of our superannuation step change is set out in table 10.12. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services, and to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services.[119]

Table 10.12 Superannuation ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Superannuation (accumulation members)	0.4	0.7	0.9	1.2	1.4	4.6

Source: Powercor

Monitoring IT security

The IT security environment is constantly evolving, and system breaches have become a growing threat. These threats have become particularly pronounced as our operating and IT landscapes continue to converge. For example, we now access our SCADA system through our general IT framework, whereas it was previously accessible only through a direct, isolated network.

Our current IT systems raise alerts for various security threats. These alerts require human intervention to determine the appropriate response, including escalating the alert where appropriate. Active monitoring of these alerts, however, only occurs during business hours. As technology has matured, and the risk and our exposure to IT breaches have increased, this approach is no longer sustainable.

118 See section 19 of the Superannuation Guarantee (Administration) Act 1992, No. 111.
119 NER, cl. 6.5.6(a).

Given the above, we are in the process of engaging an external service provider to monitor our IT security systems on a 24 hour basis.[120] An external service provider is a lower cost option, and is expected to be more effective at identifying and responding to threats (compared to increasing our internal capacity). This service is expected to commence by June 2015.

Consistent with the Rules, this expenditure will form part of a total operating expenditure forecast required to maintain the quality, reliability and security of supply of standard control services, and the safety of the safety, reliability and security of the distribution system.[121]

Table 10.13 Monitoring IT security ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Monitoring IT security	0.4	0.4	0.4	0.4	0.4	2.0

Source: Powercor

Mobile devices

Mobile devices have become an essential component of our business. For example, these devices facilitate in-situ real time data capture and access, as well as accurate and timely hazard and incident reporting. These benefits have led to productivity and efficiency gains that are reflected in our 2014 base year.

Our existing approach for accounting for these devices 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. This is shown in the modelling provided in attached, *Office and field force mobility model*. This step change, therefore, reflects the efficient substitution of capital expenditure for an operating expenditure solution.

The forecast impact of this change is set out in table 10.14. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[122]

Table 10.14 Mobile devices ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Mobile devices	1.0	0.4	1.1	0.5	1.2	4.1

Source: Powercor
Notes: Total does not add due to rounding.

Customer relationship management

Our capital expenditure forecast for the 2016–2020 regulatory control period includes a material project to implement a customer relationship management (**CRM**) system and to replace the existing billing system. The justification for this project is set out in chapter 9.

The business case for the CIS and CRM project incorporates an operating expenditure component of $5.2 million over the 2016–2020 regulatory control period. Specifically, the operating expenditure component comprises the incremental costs for maintaining software licences and support for the new billing system (above the costs of our existing system), and cloud based subscription fees for the CRM system.

[120] Dimension Data, Monitoring IT security price estimate, 2014.
[121] NER, cl. 6.5.6(a).
[122] NER, cl. 6.5.6(a).

The forecast impact of this change is set out in table 10.15. Consistent with the Rules, this expenditure is part of a total operating expenditure forecast required to meet or manage the expected demand for standard control services.[123]

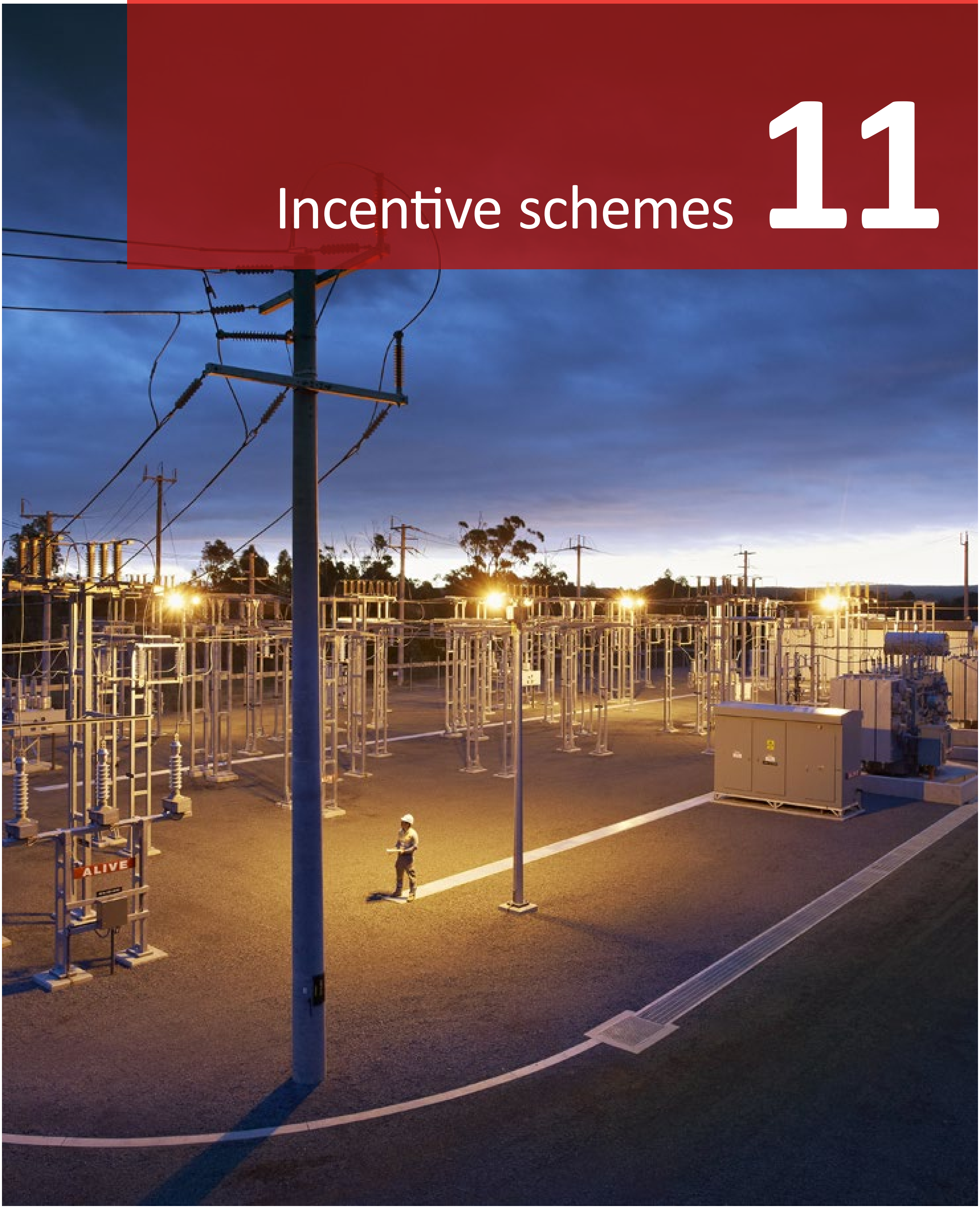
Table 10.15 Customer relationship management ($m, real)

Step change	2016	2017	2018	2019	2020	Total
Customer relationship management	-	-	1.7	1.7	1.7	5.2

Source: Powercor
Notes: Total does not add due to rounding.

[123] NER, cl. 6.5.6(a).

Incentive schemes 11



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11. Incentive schemes

We have a strong history of responding to incentive schemes and we are a firm believer of the incentive framework.

For the 2016–2020 regulatory control period:

- we support the application of the Capital Expenditure Sharing Scheme (**CESS**) and Efficiency Benefit Sharing Scheme (**EBSS**);
- we propose amendments to the Service Target Performance Incentive Scheme to incorporate the updated Value of Customer Reliability (**VCR**) published by Australian Energy Market Operator (**AEMO**) in 2014;
- we propose an amendment to the Demand Management Incentive Scheme (**DMIS**) whereby we can seek further funding above the cap; and
- we accept the application of the f-factor scheme.

We have a strong history of responding to incentive schemes and we are a firm believer of the incentive framework. The AER has published a number of incentives guidelines and is required to set out its proposed approach in its *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**) as to how it intends to apply these schemes to Powercor in the upcoming regulatory control period.

The Rules require us to set out in our building block proposal a description, including relevant explanatory material, of how we propose the incentive schemes should apply in the 2016-2020 distribution determination.[124]

The sections below set out our proposals in relation to the application of the incentive schemes.

11.1 Capital expenditure sharing scheme and proposed approach to depreciation

The capital expenditure sharing scheme (**CESS**) provides ex ante incentives for distributors to undertake efficient capex during a regulatory control period. The CESS provides for a sharing of the benefits between distributors and customers.

In November 2013, the AER published the *Capital Expenditure Incentive Guideline for Electricity Network Service Providers* (**CESS Guideline**).

A key element of the overall capital expenditure incentive framework is the depreciation approach to use when a distributor's regulated asset base (**RAB**) is updated at the beginning of the next regulatory control period. The AER can decide to use either actual or forecast depreciation. The choice of depreciation affects the power of incentives that apply to capital expenditure.

The F&A Paper proposes to use forecast depreciation to establish the value of the RAB as at 1 January 2021 for Victorian distributors. The AER considers this approach, in combination with the CESS, will provide sufficient incentive for us to achieve capital expenditure efficiency gains over the 2016–2020 regulatory control period.

We propose to apply the CESS Guideline for the 2016–2020 regulatory control period on a net basis, with no amendments. We also support the use of forecast depreciation to establish the opening RAB value as at 1 January 2021.

[124] NER, clauses S6.1.3(3),(3A) and (5A).

Given the CESS did not apply for the 2011–2015 regulatory control period no carry over will apply for the 2016–2020 regulatory control period. Accordingly, we propose no revenue increments or decrements arising from the CESS in our 2016-2020 proposed revenue requirement.

11.2 Efficiency benefits sharing scheme

The efficiency benefit sharing scheme (**EBSS**) provides a continuous incentive for distributors to pursue efficiency improvements in operating expenditure. The EBSS provides for a sharing of the benefits between distributors and customers.

In November 2013, the AER published the Efficiency Benefit Sharing Scheme for Electricity Network Service Providers (**EBSS Guideline**).

We propose to apply the EBSS for the 2016–2020 regulatory control period. We propose that the EBSS exclude a number of categories of operating expenditure, including the following:

- debt raising costs;
- self-insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- the DMIS;
- guaranteed service level (**GSL**) payments; and
- pass-throughs

Further, there should be an adjustment for provisions and any changes in capitalisation policy from the final determination.

We consider the requirements of clause 6.5.8 of the Rules are better achieved by excluding these cost categories of operating expenditure which cannot be forecast using a single year revealed cost approach for the next regulatory control period.

In respect to the benchmark allowance, adjustments should be made for costs for new obligations introduced after the final determination.

We note that in its Draft Decision for NSW/ACT networks, the AER did not apply the EBSS on the basis that it made efficiency adjustments to the operating expenditure base year.[125] As discussed in chapter 10, our historical operating expenditure is efficient and provides an appropriate base for forecasting operating expenditure in 2016–2020 regulatory control period. It is therefore not necessary or appropriate to make efficiency adjustments to our base year operating expenditure. And further, there is no reason for not continuing to apply the EBSS to our business for the 2016–2020 regulatory control period.

In respect to the carry over amounts that arise from applying the EBSS for the 2011–2015 regulatory control period refer to chapter 13.

11.3 Service target performance incentive scheme

In November 2009, the AER published the Electricity distribution network service providers, Service target performance incentive scheme (**STPIS Guideline**).

[125] AER, Draft Decision, Ausgrid distribution determination 2015–16 to 2018–19, Attachment 9: Efficiency benefit sharing scheme, November 2014, pp.10-12.

The F&A Paper proposes to continue to apply the STPIS Guideline to the Victorian distributors in the 2016-2020 regulatory control period. The AER does not propose to apply the GSL component as the Victorian distributors are subject to a jurisdictional GSL scheme.[126] Should the Victorian Government move to amend this before the next regulatory control period commences, the AER intends to adopt the changed requirements.

The AER's NSW Draft Decision deviated from the STPIS Guideline by calculating the reliability incentive rates based on the VCR contained in AEMO's 2014 report[127] rather than the values contained in the STPIS Guideline.

We propose to apply the STPIS for the 2016–2020 regulatory control period. We propose to apply the STPIS in accordance with the Guideline, subject to the following exceptions:

- the incentive rates for the reliability parameters are calculated based on the relevant VCR values from AEMO's 2014 report;
- the reliability targets for unplanned System Average Interruption Duration Index (**SAIDI**), unplanned System Average Interruption Frequency Index (**SAIFI**), for each network segment, are calculated based on the historical five year average performance over the period 2010 to 2014 plus an adjustment to account for the deterioration in network performance that will occur as a result of the significant reduction in the VCR used for network planning purposes and the STPIS incentive rates;
- the Momentary Average Interruption Frequency Index (**MAIFI**) is not included; and
- the major event day threshold is calculated to exclude events that are more than 2.8 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data. The AER approved the use of 2.8 standard deviations for Powercor in the 2011–2015 final determination.

We propose no variations from the STPIS Guideline in relation to calculating the telephone answering target or incentive rates. We propose no additional customer service parameters.

Details on how we propose to apply the STPIS Guideline and reasons for our proposed deviations from the Guideline are set out in appendix H.

Our proposed STPIS targets and incentive rates are set out in table 11.1 and 11.2 respectively. The calculations are provided in the attached models, *PAL STPIS targets* and *PAL STPIS incentive rates*.

We propose no revenue increments and decrements for the STPIS as this is dealt with in the price control formulae. For the 2016–2020 regulatory control period we do not propose any expenditure associated with improving the performance of the network for the purposes of the STPIS.

Table 11.1 STPIS targets

Parameter	Segment	2016-2020
Unplanned SAIDI	Urban	86.51
Unplanned SAIDI	Rural short	116.98
Unplanned SAIDI	Rural long	280.76
Unplanned SAIFI	Urban	1.09
Unplanned SAIFI	Rural short	1.40

126 Electricity Distribution Code (Victoria).

127 AEMO, Value of Customer Reliability Review, September 2014.

Parameter	Segment	2016-2020
Unplanned SAIFI	Rural long	2.43
Telephone answering	Network	70.07

Source: Powercor analysis

Table 11.2 STPIS incentive rates

Parameter	Segment	2016-2020
Unplanned SAIDI	Urban	0.03%
Unplanned SAIDI	Rural short	0.02%
Unplanned SAIDI	Rural long	0.01%
Unplanned SAIFI	Urban	2.79%
Unplanned SAIFI	Rural short	1.66%
Unplanned SAIFI	Rural long	1.52%
Telephone answering	Network	-0.04%

Source: Powercor

11.4 Demand management incentive scheme

The DMIS that applies to our business for the 2011–2015 current regulatory control period comprises two components:[128]

- Part A is a demand management innovation allowance (**DMIA**) which is provided on a 'use-it-or-lose it' basis. The approved amount of the DMIA takes the form of an annual ex-ante allowance provided as additional fixed revenue for each year of the regulatory control period. For the purposes of the 2011–2015 regulatory control period the total amount for Powercor was capped at $3 million over the regulatory control period; and
- Part B is a foregone revenue component. A foregone revenue component allows a distributor to recover foregone revenue as a result of successful, approved demand management initiatives under the DMIA, where these result in lower energy throughput (and hence, lost revenue) for the distributor. This component was designed to interact with certain forms of control under which revenue may vary with energy volumes (for example a weighted average price cap).

For the 2011-2015 regulatory control period we will have fully utilised our DMIA of $3 million under Part A of the scheme and we did not make any applications for recovery of foregone revenue under Part B of the scheme. Accordingly, we propose no revenue increments or decrements arising from the DMIS in our 2016-2020 proposed revenue requirement.

The F&A Paper proposes that Part A of the DMIA will continue to apply for the 2016–2020 regulatory control period and the total amount for Powercor will be capped at $3 million over the regulatory control period.

[128] AER, Victorian electricity distribution network service providers distribution determination 2011-2015, Final Decision, October 2010.

We propose the ex-ante capped allowance, Part A of the scheme, continues to be provided as additional fixed revenue for each year of the regulatory control period.

However, we propose an amendment to the scheme whereby we can seek further funding above the capped amount, on the proviso the AER pre-approves all proposed DMIS initiatives in excess of the capped amount. We consider a capped DMIS constrains the ability of distributors to invest in innovation. Given the rapid rate of technological change, a well-functioning DMIS should facilitate our ability to respond and realise greater benefits for consumers.

Enabling further funding to be provided, following pre-approval by the AER, facilitates exploration of demand management innovations in a timely manner and ensures potential efficiently enhancing innovations are not unduly constrained or deferred due to an arbitrary cap. Innovations in demand management have the potential to replace or defer network augmentation and therefore promote efficient investment in electricity services for the long term interests of consumers of electricity. Our proposal to provide an opportunity for further funding above the ex-ante cap is therefore consistent with the National Electricity Objective.

The F&A Paper also proposes that Part B will not apply because it has determined a revenue cap as the form of control. We agree that Part B of the scheme is not necessary under a revenue cap form of control.

11.5 F-factor scheme

In the 2011–2015 current regulatory control period the f-factor scheme has been administered as a separate charge under Victorian legislation.

On 24 June 2010, the Victorian Parliament passed the *Energy and Resources Legislation Amendment Act 2010.* The Act amended the *National Electricity (Victoria) Act 2005* (**NEVA**) to introduce an 'f-factor scheme'. This scheme is intended to provide incentives for distributors to reduce the risk of fire starts and reduce the risk of loss or damage caused by fire starts.

Under section 16C of the NEVA, the Victorian Government may confer functions and powers, or impose duties, on the AER to make a determination for the purpose of providing incentives for distributors to reduce the risk of fire starts and reduce the risk of loss or damage caused by fire starts.

Subsequent to passing the *Energy and Resources Legislation Amendment Act 2010*, the Victorian Government published an *f-factor scheme order 2011* (**Order**) on 23 June 2011.

The F&A Paper proposes the f-factor scheme continue to be incorporated in the control formula in the next regulatory control period. The AER proposes that it will apply any amendments made to the f-factor scheme by the Victorian Government.

We accept the AER's position to apply the f-factor scheme for the 2016–2020 regulatory control period.

We propose no f-factor revenue increments or decrements as it is included as a pass through item under the price control formula.

11.6 Small-scale incentive scheme

We do not propose that a small-scale incentive scheme apply for the 2016-2020 regulatory control period.

We were not subject to a small-scale incentive scheme for the 2011-15 regulatory control period. Accordingly, we propose no revenue increments or decrements arising from small-scale incentive schemes in our 2016-2020 proposed revenue requirement.

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12 Rate of return

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12. Rate of return

12.1 Introduction

The National Electricity Rules (**Rules**) require the return on capital be estimated by applying a rate of return that is commensurate with the efficient financing costs of a benchmark efficient entity and should be estimated as a weighted average of the return on equity and the return on debt. An efficient rate of return is important because if the rate of return is inflated, network charges will be higher than necessary. Equally, if the rate of return is below a fair market return, the investment capital necessary to keep our network financially healthy and enable us to deliver the service customers expect will be directed elsewhere.

Our proposed approach to estimating the rate of return has regard to a broad range of information. In particular, to estimate the return on equity we take into account the output of all relevant models—the SL-CAPM, the Black CAPM, the Fama French Model, and the Dividend Discount Model. In contrast, the AER's approach set out in its Rate of Return Guideline, and in its recent draft determinations for the NSW and ACT electricity distribution businesses, effectively relies on an incorrect application of only a single SL-CAPM model to estimate the return on equity. Our approach is supported by an extensive range of evidence and expert reports. To estimate the return on debt, we adopt a ten year trailing average using a hybrid transition approach. This transition approach is applied only to the risk free rate component (and not the debt risk premium, as this component cannot be hedged). We do not agree that the Guideline transition approach reflects the efficient financing costs of a benchmark efficient entity as required by the Rules.

Combining the return on debt and the return on equity, the AER's approach provides a rate of return that falls considerably short of the rate of return that an efficient benchmark entity would require to attract sufficient capital to sustain our network into the future. This chapter seeks to explain how such a fundamental difference arises and our proposed approach to the allowed rate of return.

In 2012, the Australian Energy Markets Commission (**AEMC**) commenced a process to change how revenues are set for electricity and gas network businesses under the National Electricity Rules (**Rules**). The new Rules include the requirement for the AER's determination to meet the rate of return objective:

> *The allowed rate of return objective is that the rate of return for a service provider is to be commensurate with the efficient financing costs of a benchmark efficient entity with a similar degree of risk as that which applies to the service provider in respect of the provision of reference services (the allowed rate of return objective).*

The main change to the Rules was removal of the prescriptive provisions concerning how the return on capital should be established, and instead requiring that the AER adopt a broader consideration of all the relevant inputs it employs when undertaking its network economic regulatory functions. The Rules provide for the publication of a Rate of Return Guideline (**Guideline**) in which the AER states its intentions with respect to how it will exercise its powers. The Guideline was published in 2014.

We agree with many parts of the Guideline. However, there are also aspects of the Guideline we consider are inconsistent with the allowed rate of return objective, do not promote the National Electricity Objective (**NEO**), nor enable the recovery of the efficient costs of capital as required by the revenue and pricing principles. For example:

- there is agreement concerning the optimal debt to equity ratio employed by such a benchmark firm;
- with respect to equity, there is agreement over which leading finance models could be used to estimate the cost of equity. However, there are important differences of view concerning which of the models should be employed in the regulatory determination, what role each model should play, the manner in which the models should be implemented, and the values ascribed to key parameters used in the models;

- with respect to debt, there is agreement on the use of a ten year trailing average and that the return on debt should be automatically updated annually. However, there are important differences of view concerning:
  - the relevant benchmark credit rating;
  - the transition applied in the estimation of the return on debt;
  - the nomination of averaging periods for use in the estimation of the return on debt;
  - whether an adjustment should be made to reflect the hedging costs and the new issue premium;
- with respect to gamma, there is a fundamental difference of view concerning how to establish the relevant value.

Since the Guideline was published, the AER has published draft determinations for a number of electricity businesses (New South Wales (**NSW**) electricity distribution, NSW electricity transmission, Tasmanian electricity transmission and NSW gas distribution). These draft determinations are relevant in that the determinations:

- clarify how the AER would use financial models other than the Sharpe-Lintner Capital Asset Pricing Model (**SL-CAPM**), and the other material the AER considers to be relevant, which was not fully explained in the Guideline;
- clarify the AER's understanding of the efficient debt management strategy under the previous Rules, and its requirement for all debt averaging periods to be nominated and agreed prior to the commencement of a regulatory control period;
- provide that the benchmark debt costs will be determined using a simple average of the values published by the two currently available service providers (the Reserve Bank of Australia and Bloomberg) and how the data from the Reserve Bank of Australia and Bloomberg would be extrapolated to reflect a ten year benchmark tenor;
- use updated data to produce a gamma of 0.4 instead of the 0.5 value that appears in the Guideline (although the methodology remains as it was in the Guideline);

This chapter is structured as follows:

- an outline of the changing risk profiles for electricity distribution businesses;
- establishing the allowance for the return on equity;
- establishing the allowance for the return on debt;
- an illustrative calculation establishing a return on debt using data from the 20 day period to 30 January 2015;
- establishing the inflation rate;
- calculation of the return on capital; and
- setting the value for gamma.

12.2 The changing risk profile for electricity distribution businesses

The allowed rate of return objective highlights that risk is an important consideration in setting the allowed rate of return for equity and debt. Electricity network operators compete with other businesses to attract investment capital and investors will only provide investment capital if a competitive return is provided that adequately rewards for the risks of that investment. For consumers, it is important that regulatory decisions do not over-reward businesses for risk (because prices would be higher than they need to be) and equally that these decisions do not under-compensate businesses for risk (because under-capitalised businesses cannot make required investments or meet required service standards to consumers, and they carry excessive risk of financial failure).

For at least a century, the principal characteristics of the distribution system have not changed: the most cost effective way to manage load reliably has been to connect almost everyone to the interconnected network that provides access to centralised thermal generation. Throughout the 20 years that the economic regulation has applied through the NEM, demand has been consistently growing in a way that is less volatile than many other industries and technological change has been slow.

However, the risk faced by distributors has changed dramatically in the recent past. Essentially we are now confronted with two possible future scenarios, one in which we evolve and survive and the other in which we become progressively redundant. The risks we face have changed:

- solar PV have been available since the 1970s but they played almost no part in supplying electricity to the grid-connected mass market in the ensuing 30 years because the technologies used to manufacture them were price prohibitive. In recent times, prices of solar PV units have fallen rapidly. The effect of dramatically lower global solar installation prices is that global businesses are aggressively marketing solar PV in Australia.[129]
- the second development is the introduction of 'smart' technology (smart grids and smart meters) that enable better management and control by the consumer of when and how they consume electricity. To date this has been conceived of as being a technology to improve the performance of the traditional grid connected power industry but many of the same technologies will be able to be used with or without grid connection. Some smart grid projects have been launched in Australia already, and we can only anticipate that more projects will be undertaken in the future.[130] Smart meters have been rolled out comprehensively in Victoria, and consumers can elect to be billed on a 'flexible pricing' basis, which allows consumers to better manage their energy usage and thereby reduce their energy bill.[131]
- the third factor to consider concerns power storage, most notably batteries and super capacitors. Similar to the solar PV market, price reductions of power storage systems are resulting from a race between global manufacturers to improve production technology and scale economies in manufacturing to win large-scale new business opportunities in industrialised countries.

Taken separately, each of the above developments (reduced costs for distributed generation, reduced costs for energy storage and the improved ability for consumers to manage their consumption) pose their own risks for network operators. Further, when these three factors combine it calls into question whether customer disconnections from the grid might be significant enough to risk the viability of the whole regulated price recovery system.

Customers connect to the grid and stay connected for two main reasons—to gain access to cost competitive generation and to have access to a reliable supply of electricity as and when they need electricity. The risk that now looms within the relevant 50 year investment horizon is that a significant number of customers may disconnect from the grid. The NEM's Consumer Advocacy Panel funded the preparation of a report *What Happens When We Un-Plug* that studied whether it might be cost effective for customers in Bendigo, Werribee and Melbourne to disconnect individually or in clusters. It was found that it was already economic for some customers to disconnect and for most others it will become economic to do so before 2020.

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129 Mr T. Werner, CEO of global solar power conglomerate, SunPower recently stated that "the economics of solar work better in Australia than in most places in America", per "SunPower says Australia could be global leader in local generation" REneweconomy, April 2014.

130 See Smart Grid Smart City project, < http://www.smartgridsmartcity.com.au/>

131 See State Government of Victoria, Flexible Pricing, <http://www.smartmeters.vic.gov.au/flexible-pricing>

Investment analysts are already downgrading electricity utility bonds in other countries on this basis:[132]

> *Electric utilities ... are seen by many investors as a sturdy and defensive subset of the investment grade universe. Over the next few years, however, we believe that a confluence of declining cost trends in distributed solar photovoltaic (PV) power generation and residential-scale power storage is likely to disrupt the status quo. Based on our analysis, the cost of solar + storage for residential consumers of electricity is already competitive with the price of utility grid power in Hawaii. Of the other major markets, California could follow in 2017, New York and Arizona in 2018, and many other states soon after...*
>
> *In the 100+ year history of the electric utility industry, there has never before been a truly cost-competitive substitute available for grid power. We believe that solar + storage could reconfigure the organization and regulation of the electric power business over the coming decade. We see near-term risks to credit from regulators and utilities falling behind the solar+ storage adoption curve and long-term risks from a comprehensive re-imagining of the role utilities play in providing electric power.*

Electricity industry commentators often refer to a ‘tipping point’ or a ‘point of inflection’ or even a ‘death spiral’, where the regulated pricing system becomes unsustainable and an endless spiral of disconnections commences. The ‘death spiral’ theory posits that if a significant number of customers find distributed generation and power storage more cost effective than staying connected, the prices for those who remain connected would rise to recover the costs of the infrastructure no longer used for the customers who had disconnected. As the prices are raised, it creates the incentive for another group of customers to disconnect and so on until there is not a sufficient customer base to be able to cover the costs of the whole system.

A particular risk in Victoria arises from the high levels of gas penetration which, at more than 90 per cent, eclipse the rates of every other State or Territory.[133] When a household has gas heating, hot water and cooking, a smaller number of solar PV panels will satisfy the smaller electricity demand compared with a household in which all its major appliances are electrical, and a smaller battery storage capacity would enable disconnection from the grid altogether. Similarly, if there are disconnections from the grid, the regulatory arrangements would seek to recover the stranded cost from the remaining customers and, because most of them have gas connected too, would be asked to carry a high per kW cost, in turn creating inequity and further incentives to disconnect.

There is no doubt that power storage, solar power and smart technology are game-changing technologies that will modify the ways in which households and businesses consume energy. However it is important to read the ‘death spiral’ thesis with some caution. This is because ‘death spiral’ type arguments fixate heavily on the potential impacts of solar power and power storage technologies and give too little credit to the capacity of conventional electricity distributors to update their business model by harnessing new technologies. The rollout of smart meters for example, will enable energy distributors to modify the manner in which energy consumption is charged (delivering more accurate, real-time pricing for consumers, which enables consumers to use energy in more cost-effective ways).[134] Having rolled out smart meters en masse, we are in a strong position to do so. Moreover, the ‘death spiral’ theory is predicated on so many intersecting factors that it is difficult to gauge a time at which these three factors might come together in such a way that a flight from the grid could occur. As Paul Graham, chief economist of the CSIRO Energy Flagship has commented, it is unclear how long it will be before power storage systems can be said to be affordable, and thus game-changing.[135]

What is clear, however, is that the manner in which the AER considers risk in estimating the rate of return is inadequate to account for risks faced by the network service providers under the prevailing market conditions.

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[132] Barclays credit strategy team per Barron’s Income Investing, 2014.
[133] AER 2014, State of the Energy Market, page 110.
[134] Grattan Institute, Fair pricing for power, July 2014.
[135] CSIRO, Change and Choice: The Future Grid Forum’s Analysis of Australia’s potential electricity pathways to 2050, December 2013, p. 30.

Specifically, the AER's draft determinations for the NSW electricity distribution businesses proceed on the basis that a gearing ratio, a 'beta' value within an SL-CAPM model, and a benchmark credit rating can adequately recompense a distributor for the returns required on risky investments.[136] These draft determinations, and the Guideline they apply, are largely based on consideration of an analysis of risk by the AER itself, and a report from Frontier Economics (both undertaken at the time of the Guideline development process).[137] It is simply not the case that an adequate compensation for risk can be provided that way. That is:

- restrictions on asset optimisation and the application of a revenue cap—additional measures the AER suggest insulate the business from risk—may not be effective, particularly if the number of disconnections changes the willingness or ability of the remaining consumers to pay for common and potentially stranded assets that were built solely to service customers who have now disconnected; and
- the analysis undertaken by Frontier Economics fails to acknowledge the new risks arising from the scenarios outlined previously (i.e. risks posed by solar penetration, battery storage and smart meters).

It is incumbent upon the AER to engage with the above material and identify how these risks are accommodated in the overall allowed return on capital.

12.3 Return on equity

According to the new Rules, in determining the allowed rate of return regard must be had to relevant estimation methods, financial models, market data and other evidence. Our proposed approach to estimating the return on equity component of the allowed rate of return contributes to this by:

- identifying the relevant rate of return models, being the SL-CAPM, the Black CAPM, the Fama French Model, and the Dividend Discount Model (which are, in fact, the same as those identified by the AER);
- identifying the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise modelling results as a weighted average of the individual estimates with the weights that avoid double-weighting any of the key conceptual elements of the models.

In contrast, the AER's proposed approach effectively estimates the return on equity using a single model—the SL-CAPM. The AER has always used the SL-CAPM for setting rates of return for electricity distribution businesses, even though a vast array of evidence now shows the significant shortcomings of the SL-CAPM and the superior usefulness of other models. Further, the particular implementation of the SL-CAPM applied by the AER estimates returns on equity that move perfectly in parallel with movements in the risk free rate. The effect is that returns on equity have plummeted as observed yields on Commonwealth Government Securities have fallen.

This section explores these issues in detail as follows:

- section 12.2.1 introduces the models that are relevant in estimating the return on equity;

[136] AER, Ausgrid draft determination, November 2014; AER, Essential draft determination, November 2014; Endeavour draft determination, November 2014; ActewAGL draft determination, November 2014.

[137] Frontier Economics, Assessing risk when determining the appropriate rate of return for regulated energy networks in Australia, July 2013.

- section 12.2.2 identifies the key reasons why the approach in the Guideline is delivering an unacceptably low return on equity and does not comply with the requirements of the Rules;
- section 12.2.3 sets out our proposed approach to the return on equity; and
- section 12.2.4 provides an illustrative calculation using current market data.

12.3.1 Identify and compare the relevant models and any other relevant evidence

In developing the new Rules for estimating the rate of return, the AEMC stated that no single return on equity model is preferable as being free of weaknesses or captures all the strengths of others.[138] Accordingly, the AER's Guideline sets out that the relevant financial models for estimating the return on equity are:

- Sharpe Lintner CAPM (SL-CAPM);
- Black-CAPM;
- Fama French Model;[139] and
- Dividend Discount Model.

The AER also proposed to use other information, such as expert reports prepared in the context of assessing whether corporate takeover offers are 'fair', and surveys of practitioners. To the extent these other sources are of any use, they tend to be useful in illustrating how the above models should be implemented and combined in practice to deliver timely estimates of value or return.

We agree with the 'relevant' set of models outlined in the AER's Guideline. In particular, in a report prepared on behalf of a number of energy network business, Professor Gray considered all four of the return on equity models provide evidence that is relevant for estimating the return on equity because:[140]

- all four models have a sound theoretical basis;
- all four models have the purpose of estimating the required return on equity as part of the estimation of the cost of capital;
- all four models can be implemented in practice; and
- all four models are commonly used in practice.

Along with a number of other energy network businesses, we also commissioned a series of detailed reports from leading experts to explore the strong and weak characteristics of each model. The first set of relevant reports was provided by the Energy Networks Association as part of the consultation process on the Guideline.[141]

138 AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 48.

139 Although the AER found the Fama French Model to be relevant, its Guideline proposes to give it no role, page 13 the Guideline.

140 SFG, The required return on equity for regulated gas and electricity network businesses, June 2014, [9]

141 NERA Economic Consulting, Review of cost of equity models, June 2013, NERA Economic Consulting, Estimates of the [Black CAPM] zero beta premium, June 2013, SFG Consulting, Dividend discount model estimates of the cost of equity, June 2013, SFG Consulting, Evidence on the required return on equity from independent expert reports, June 2013, CEG Consulting, Estimating the return on the market, June 2013, CEG Consulting, Estimating E[Rm] [expected return on the market] in the context of regulatory debate, June 2013, SFG Consulting, Regression-based estimates of risk parameters for the benchmark firm, June 2013, SFG Consulting, The Vasicek adjustment to beta estimates in the Capital Asset Pricing Model, June 2013, CEG Consulting, Information on equity beta from US companies, June 2013, SFG Consulting and Monash University, Comparison of OLS and LAD regression techniques for estimating beta, June 2013, SFG Consulting and Monash University, Assessing the reliability of regression-based estimates of risk', June 2013, Incenta Economic Consulting, Term of the risk free rate for the cost of equity, June 2013, NERA Economic Consulting, The market, size and value premiums, June 2013, NERA Economic Consulting, The Fama-French three-factor model, October 2013, SFG Consulting, Reconciliation of dividend discount model estimates with those

Since the publication of the Guideline, SFG Consulting has prepared a suite of reports, which explore in detail a series of issues raised in the Explanatory Statement that accompanied the Guideline. A report dated 12 May 2014 addresses the issues raised in connection with the equity beta in the context of the SL-CAPM.[142] The next three reports focus on the issues raised in relation to each of the other financial models and a fifth report addresses how to set a single allowed return on equity figure using the above inputs.[143] In February 2015 SFG Consulting has written further reports on each of the above topics in response to the suite of draft determinations that the AER issued in late 2014.[144]

NERA has also prepared reports that provide important insights into the empirical performance of the SL-CAPM, the AER's variation on the SL-CAPM and the Black CAPM and into historical estimates of the market risk premium.[145]

Incenta has provided two reports, one prepared for submission to the AER as part of the first group of decisions to be made under the new Rules released in late 2014 and another in response to those draft decisions.

Grant Samuel has extensive experience undertaking valuations in the context of stock market acquisitions and it has provided its views on the AER's approach.[146]

A summary of the strong and weak characteristics of each model, as set out in these reports, includes:

- empirical studies of the SL CAPM have consistently found the performance of this model to be poor.[147]
- the SL-CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. The extent to which the SL-CAPM underestimates returns to low-beta portfolios is both statistically significant and economically significant.[148]
- further estimation problem arise with the SL CAPM during periods of high or low official interest rates, when this model is implemented in the way the AER has for many years (by using a current Commonwealth Government Bond yield to estimate the risk free rate, in combination with a very long run average of historical excess returns to estimate the MRP). The AER's approach, which is inspired by Ibbotson, behaves as

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compiled by the AER, October 2013, CEG Consulting, AER equity beta issues paper: International comparators, October 2013, SFG Consulting, Letter: Water utility beta estimation, October 2013, SFG Consulting and Monash University, Comparison of OLS and LAD regression techniques for estimating beta, June 2013, SFG Consulting and Monash University, Assessing the reliability of regression-based estimates of risk, June 2013, Incenta Economic Consulting, Term of the risk free rate for the cost of equity, June 2013, NERA Economic Consulting, The market, size and value premiums, June 2013, NERA Economic Consulting, The Fama-French three-factor model, October 2013, SFG Consulting, Reconciliation of dividend discount model estimates with those compiled by the AER, October 2013, CEG Consulting, AER equity beta issues paper: International comparators, October 2013, SFG Consulting, Letter: 'Water utility beta estimation', October 2013.

142 SFG Consulting, Equity beta, May 2014.

143 SFG Consulting, Cost of equity in the Black Capital Asset Pricing Model, May 2014; SFG Consulting, The Fama-French model, May 2014; SFG Consulting, Alternative versions of the dividend discount model and the implied cost of equity, May 2014; SFG Consulting, The required return on equity for the benchmark efficient entity, February 2015.

144 SFG Consulting, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, February 2015; SFG Consulting, Using the Fama-French model to estimate the required return on equity, February 2015; SFG Consulting, Beta and the Black Capital Asset Pricing Model, February 2015.

145 NERA, Empirical Performance of the Sharpe-Lintner and Black CAPM, February 2015; NERA, Historical Estimates of the Market Risk Premium, February 2015; NERA, Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama French Three Factor Model, March 2015.

146 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015

147 SFG, Cost of Equity in the Black Capital Asset Pricing Model, 22 May 2014, page 2; see also SFG Consulting: Equity Beta, May 2014, page 6–7; SFG, The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, March 2015.

148 NERA, Empirical Performance of the Sharpe-Lintner and Black CAPMs, February 2015, page 54.

if investors' expectations move in perfect parallel with yields on the Commonwealth Government Bonds. There is no solid basis for this assumption.

- alternatives to the Ibbotson inspired approach adopted by the AER for establishing the market risk premium (for use in the SL-CAPM)—such as the Wright approach, which assumes that the real return on equity is more stable over different market conditions—are not a panacea for all the flaws in the Ibbotson approach.
- the Black CAPM is a more general application of the SL CAPM, and does not rely on the assumption that all investors can borrow at the risk-free rate of interest. It has been demonstrated to provide a significantly better empirical fit to the data than the SL-CAPM.[149] However, the Guideline has identified that the Black CAPM model's use is limited to informing the foundation model (SL-CAPM) parameter estimates.
- despite the AER's assertions that the Black CAPM is unusable because a zero beta portfolio is allegedly hard to estimate, the Black CAPM (also referred to as 'empirical' or the 'Zero Beta' CAPM) has been used extensively in US regulation cases, particularly when estimating a beta value less than one. For example, as set out table 12.1:

Table 12.1 Application of the Black CAPM in regulatory proceedings

Regulator	Citation
New York Public Service Commission (2009)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service; Petition for Approval, Pursuant to Public Service Law, section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers 2009 N.Y. PUC LEXIS 507
New York Public Service Commission (2007)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service 2007 N.Y. PUC LEXIS 449; 262 P.U.R.4th 233
New York Public Service Commission (2009)	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service; Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service 2006 N.Y. PUC LEXIS 227; 251 P.U.R.4th 20
Oregon Public Utility Commission (2001)	In the Matter of PacifiCorp's Proposal to Restructure and Reprice its Services in Accordance with the Provisions of SB 1149. 2001 Ore. PUC LEXIS 418; 212 P.U.R.4th 379

Source: Powercor

- while empirical studies have consistently found that the Black CAPM performs better than the SL-CAPM, the Black CAPM is known to have a downward bias for value stocks.[150] The same problem, however, arises with the SL-CAPM when current returns on central bank debt are used to estimate of the risk-free rate and this is added to a long run average estimate of MRP.

[149] NERA, Empirical Performance of the Sharpe-Lintner and Black CAPM, February 2015, page [56-57].
[150] SFG, Cost of Equity in the Black Capital Asset Pricing Model, May 2014, page 38.

- the Fama French Model provides separately for an additional return on value stocks, and empirical studies in the US and Australia have confirmed that it provides an unambiguously better fit to the data than the SL CAPM.[151]
- the Fama French Model is newer than the other two CAPM models, but one of the authors of the model has received a Nobel Prize for the body of work for which this model is a part.[152] The Fama French Three Factor model has also appeared in a number of state regulatory proceedings in the United States.[153]
- the Guideline takes the approach that although the Fama French Model is 'relevant', it should play no part whatsoever in the establishment of the allowed rate of return. In our view this is wholly unacceptable. In particular, if the Fama French model is wholly excluded from the analysis, there is no other model that specifically addresses the downward bias for value stocks.
- the Dividend Discount Model (or Dividend Growth Models) approaches the task of estimating the required rate of return in a different way to the CAPM and Fama French Model. It has the advantage of not requiring any assumptions about what factors drive required returns—it simply equates the present value of future dividends to the current stock price.[154]
- the Dividend Discount Model is commonly used in industry and regulatory practice. For example, as the Federal Energy Regulatory Commission of the United States (**FERC**) notes, the model has become the most popular technique of establishing the cost of equity, and it is generally accepted by most commissions. Virtually all cost of capital witnesses used this method, and most of them consider it their primary technique.[155]
- whereas the Guideline materials identify some concerns with the dividend discount approach, the specification adopted by SFG Consulting addresses most of those concerns.[156] This model performs well provided a robust method is used for forecasting future dividends. SFG Consulting has reviewed a range of ways that this model can be implemented, both those generated by or for the AER during the Guideline consultation process and in other publications. The principal issues include how quickly it is assumed that the actual level of dividends reverts to the long run assumed dividend rate of growth, whether that progression is linear or otherwise and how long term dividend growth is assumed to be related to assumptions about over-all economic growth.

12.3.2 Flaws with the AER's approach to estimating the allowed return on equity

The AER's approach to estimating the allowed return on equity has a number of flaws including:

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151 SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 9.

152 Eugene Fama is the 2013 recipient of the Sveriges Riksbank Prize in Economic Science in memory of Alfred Nobel (the Nobel Prize in Economics).

153 Direct testimony of Paul R. Moul, Managing Consultant – P.Moul & Associates, Commonwealth of Massachusetts Department of Telecommunications and Energy, October 2005;Application of Pacific Gas and Electric Company for Authority to establish its Authorized Rate of Return on Common Equity for Electric Utility Generation and Distribution Operations and Gas Distribution for Test Year 2006; Application of Sierra Pacific Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto; Application of Nevada Power Company for authority to increase its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto 2007 WL 2171450 (Nev.P.U.C.); Application of Southern California Edison Company (U338E) for Authorized Cost of Capital for Utility Operations for 2008.

154 SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, 6 June 2014, page 9.

155 United States of America Federal Energy Regulatory Commission, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

156 SFG, Dividend Discount model estimates of cost of equity, June 2013; SFG, Share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network, Feb 2015; SFG Consulting, The Required Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 9.

- the AER brings a skewed perspective to the evaluation of the strengths and weaknesses of the models;
- the AER's extra-legislative criteria distort the evaluation of the merits of the available inputs;
- the Guideline does not give real weight to all the relevant inputs as required;
- the AER has laboured over an improper search for a preeminent model and improper constraints inherent in using a 'foundation' model instead of devoting its efforts to specifying all the available models and giving them the weight they merit;
- even when implementing the foundation model approach, the AER has made a flawed selection of the Ibbotson inspired approach to implementing the SL-CAPM as the foundation model;
- the AER's incorrect selection of parameter values for the AER's Ibbotson inspired SL-CAPM; and
- the AER's flawed use of expert reports.

These flaws are discussed separately below.

A skewed perspective on the strengths and weaknesses of the available models

We are concerned that the assessment by the AER is not being undertaken on an 'even handed basis' and that this could explain how the other flaws discussed below have come about.

Despite the superior empirical performance of the Black CAPM discussed above, the AER relegates this model to a secondary status on the following basis:[157]

> *the model is not empirically reliable;*

and

> *the model is not widely used to estimate the return on equity by equity investors, academics or regulators.*

The AER elaborates on the first criticism, stating that the return on the zero beta asset is unobservable and the methods for estimating it are unreliable. Both the AER and McKenzie & Partington appear to reach that conclusion by observing differences between the reports lodged by the businesses on this question. However, the AER at least concedes that:[158]

> *While we consider SFG's latest estimate of the zero beta premium appears more plausible, we believe that the large range of zero beta estimates by consultants for the NSPs indicates the model is unsuitable to use to estimate the RoE of our benchmark efficient entity.*

This is no different from the estimation of beta and the MRP for use in the SL-CAPM's primary model which can be specified in a broad range of plausible and implausible ways. For example, the AER's own consultants produce beta results that range from 0.3 to 0.8 and for the MRP that are a full percentage point apart. With the NSP's studies included, the ranges are considerably wider again yet the yard-stick used to exclude the Black-CAPM is not a basis upon which the SL-CAPM is excluded.

Similarly, with respect to the (arguably irrelevant) consideration of whether the model is widely used, SFG notes that:[159]

> *[I]t is common for U.S. regulatory cases to use what is known as "the empirical CAPM." This is an implementation of the CAPM formula with an intercept above the contemporaneous risk free rate – to be*

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[157] SFG Consulting, Beta and the Black Capital Asset Pricing Model, Feb 2015, p18.
[158] AER, Ausgrid draft determination, November 2014 [3-182].
[159] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 21.

> *consistent with the Black CAPM and the empirical evidence that supports it. The AER's contention that the Black CAPM is not widely used in practice relies only on the label of the model, and not on its substance.*

In its letter, Grant Samuel shares its views more broadly concerning the AER's model selection choices:[160]

> *In this case, it seems that the AER's approach has been to avoid changing its existing (single) formula "foundation model" and proceed on the basis that as long as it can show that the model is widely used and the individual inputs can be justified, there is no need to concern itself with whether or not the final output is commercially realistic.*

Despite conceding that the model is useful indirectly, the AER decided not to use the Dividend Discount Model directly in estimating the allowed return on equity because it considers that its results are too sensitive to its input assumptions, but the AER does not give equal handed acknowledgement to the same criticisms concerning the CAPM. In Grant Samuel's words:[161]

> *The DGM, in its simplest form, has only two components to estimate – current dividend yield and the long term growth rate for dividends. The current yield is a parameter that can be estimated with a reasonably high level of accuracy, particularly in industries such as infrastructure and utilities. We accept that the question of the long term dividend growth rate becomes the central issue and is subject to a much higher level of uncertainty (including potential bias from sources such as analysts) and we do not dispute the comments by Handley on page 3-61.*
>
> *However, there is no way in which the issues, uncertainties and sensitivity of outcome are any greater for the DGM than they are with the CAPM which involves two variables subject to significant measurement issues (beta and MRP). The uncertainties attached to MRP estimates in particular are widely known yet are glossed over in the AER's analysis of the relative merits. Section D of Attachment 3 of the Draft Decision contains almost 40 pages discussing the most esoteric aspects of methodologies for calculating beta but in the end the AER's choice of 0.7 is, in reality, an arbitrary selection rather than a direct outcome of the evidence. Moreover:*
>
> - *the plausible beta range nominated by the AER (0.4-0.7) creates a 2 percentage point swing factor for the CAPM-based cost of equity. Its own expert nominated an even wider range (0.3-0.8);*
> - *the 40 pages contain little meaningful discussion of issues such as standard errors or stability over time (as opposed to different time periods). Data on these aspects would be important to properly evaluate the overall reliability of the statistics; and*
> - *the publication of only averages for individual companies and not the range hides the underlying level of variability in these measures.*
>
> *In short, the claim of superiority for the CAPM is unfounded.*

The Grant Samuel letter adds:

> *It is also difficult to fathom why the AER states that the DGM is highly sensitive to interest rates but makes no mention of the sensitivity of CAPM to interest rates.*

The AER's treatment of the Fama French model is the most concrete illustration of the double-standards applied in excluding its results from consideration altogether. SFG Consulting's rejection of the AER's criticisms also illustrate that criticisms (a) and (b) apply equally to the SL-CAPM while criticisms (c) and (d) are incorrect—yet the Fama French model not the SL-CAPM model is excluded on this basis:

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160 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, p. 2.

161 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, p. 3.

In our view, the reasons that the AER provides for dismissing the Fama-French model are without basis:[162]

a. *Sensitivity to different estimation periods and methodologies.*
The AER states that the estimates from the Fama-French model can vary across different estimation periods and techniques. In response, we note that this applies to all models that require the estimation of parameters. For instance the AER's own estimates for beta vary materially over time and across estimation methods. Moreover, the fact that some estimates of the Fama-French model might produce inconsistent results is not a basis for dismissing all estimates. A better approach would be to consider the relative quality and reliability of estimates.

b. *Estimation of ex ante required returns.*
The purpose of the Fama-French model is the same as the purpose of the Sharpe-Lintner CAPM – to explain the cross-section of stock returns. That is, the purpose of these models is to identify the features of stocks that can be used to predict what average returns they are likely to generate in the future. The key difference is that the predictions from the Fama-French model have been shown to be more closely associated with stock returns. It is theoretically possible that the superior empirical performance of recent decades might not continue into the future, but that should not be the basis for dismissing the Fama-French model.

c. *Lack of a theoretical foundation.*
We note that the Fama-French model was originally motivated by the poor empirical performance of the Sharpe-Lintner CAPM. Fama and French identified that the Sharpe-Lintner CAPM did not work and set about developing a model that did. Since that time, theoretical justifications for the Fama-French factors have been developed, in a way that is quite standard for scientific progression. In our view it would be illogical to reject the Fama-French model in favour of the Sharpe-Lintner CAPM on the basis that its original motivation was the poor performance of the very model that is to be adopted in its stead.

d. *Complex to implement.*
The Fama-French model is not complex to implement. It requires the estimation of factor returns and factor sensitivities (betas). There are simply three factors instead of one. In any event, a superior model should not be rejected in favour of an inferior one on the grounds of simplicity.

The inconsistent treatment that the AER applies to the different models betrays its affection for the SL-CAPM and this explains how the other flaws below may have arisen.

Extra-legislative criteria distort the evaluation of the merits of the available inputs

Instead of directly applying the rate of return objective, the National Electricity Objective (**NEO**) and the Revenue and Pricing Principles (**RPP**), the Guideline applies a set of extra-legislative criteria that do not appear in the NER or the NEL.[163] These criteria are expressed in such abstract terms that they invite irrelevant matters to be considered causing the decision-making process to be directed away from the matters referred to in the NER and the NEL.

The AER's application of these criteria has incorporated irrelevant considerations, contrary to the requirements of the Rules. For example estimation methods and financial models are required to be consistent with 'well accepted economic and finance principles' and promote 'simple over complex approaches'.[164]

[162] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, p. 2.
[163] AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 24.
[164] AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 24-28.

As a consequence there is a strong preference for conservatism that has resulted in the decision being based on the SL-CAPM as the foundation model, with secondary weight being given to the DDM, the Black-CAPM only in the limited role of informing certain parameter estimates used within the SL-CAPM, and no weight at all being given to the Fama-French Model which is of a substantially younger vintage than the SL-CAPM. This conservatism runs directly counter to the intention of the AEMC that the new Rules do away with the incumbency of the SL-CAPM and open the decision making to the inclusion of all the relevant models and other inputs.[165] Models chosen on the basis of being simple can easily fall into error by excluding a proper consideration of the full range of factors affecting the prevailing cost of equity.

In fact there is overwhelming evidence that the SL-CAPM's dominant role should cease. The model has a poor empirical performance and it is demonstrably producing downwardly biased results. The Black CAPM avoids the bias but further empirical improvements are possible by using the Fama French three factor model. The DGM has been used for many years in the US and it provides an independent, wholly alternative basis to setting a rate of return that is also free of the flaws in the SL-CAPM but the AER rejects all these other models from playing a material role in the AER's estimation process.

The criterion that the choice of inputs should 'promote the simple over the complex where appropriate' has been instrumental in the selection of the SL-CAPM as the 'foundation model'; even though there is a requirement to consider all the relevant estimation methods regardless of the degree of complexity that could emerge. The models show that some of the additional detail (which the AER refers to as complexity) is required to avoid downward biases for stocks with betas of less than one (i.e. Black CAPM) or which are 'value stocks' (i.e. Fama French).

The 'fit for purpose' criterion imports the notion that each relevant model should be employed in a manner that is 'consistent with the original purpose for which it was compiled'. There is no logical basis to apply this constraint upon the use of the models.

The AER has also adopted the criterion for consideration: 'where applicable, reflective of economic and finance principles and market information'. In discussing what the AER has in mind, it appears that the theoretical pedigree of the model is one of the key considerations as to whether the criterion is met or not:[166]

> *We consider economic and finance theory provides important insights into the conditions for achieving economic efficiency, including for the setting of revenue and prices for natural monopoly service providers. Economic theory also suggests economically efficient outcomes are in the long-term interests of consumers. This criterion is intended to draw on these theoretical insights to maximise the likelihood that regulatory outcomes would promote economic efficiency, and thus would achieve the allowed rate of return objective and the (national electricity and gas) objectives.*

Expressed in that way, the criterion appears unobjectionable but the AER has in fact used it as a criterion of inclusion and exclusion—as well as 'ruling in' a model the AER considers has a strong theoretical foundation despite its dubious empirical credentials (i.e. the SL-CAPM), the AER also 'rules out' the Fama French model in large part because it is perceived as lacking a theoretical pedigree even though its empirical credentials are strong.

Excluding models on this basis is likely to frustrate the achievement of the rate of return objective. We reject the notion that the lack of a theoretical foundation is criteria that can further the attainment of the rate of return objective.

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165 AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 49.

166 AER, Rate of Return, Guideline Explanatory Statement, page 27.

A final concern with the criteria is that they are inconsistently applied. For instance, the AER's own foundation model concept is a good deal more complex than any of the SL-CAPM, Black CAPM and DGM taken individually and the aggregate result is clearly more complex than simply estimating the Fama French model. It is also a good deal more complicated than simply estimating all the models and taking a (weighted) average of the results.

The Guideline does not give real weight to all the relevant inputs as required

The approach to establishing the return on equity set out in the Guideline is not consistent with the NER and is not the best possible estimate of the required rate of return for equity that progresses the NEO. In particular, the Guideline does not meet the requirements of the new Rules that regard must be had to 'relevant estimation methods, financial models, market data and other evidence'. It is recognised that 'an expression such as 'have regard to' is capable of conveying different meanings depending on its statutory context'.[167] And in the absence of a definition of relevant, it is to be given its ordinary meaning in the context.[168] In this regard, it was noted by the AEMC in its draft rule determination and final rule determination:[169]

> *The final rule provides the regulator with sufficient discretion on the methodology for estimating the required return on equity and debt components but also **requires the consideration of a range of estimation methods, financial models, market data and other information so that the best estimate of the rate of return can be obtained overall that achieves the allowed rate of return objective**.*

Nor can it be adequate to elevate a single model as the foundation model and limit the role of all other models to the secondary status of estimating parameters within that foundation model unless there is a proper basis for concluding that they are unsuitable for contributing directly to the return on equity or that the return on equity cannot lie outside those constraints and that the 'right answer' must fall within the range of outputs that the foundation model could deliver.

Further, it is relevant to consider the context of the overall regulatory structure into which this new Rule has been inserted. The same language requiring 'regard' to be had to the full range of relevant inputs now appears in both the new Rules and National Gas Rules and should be similarly applied. In understanding the meaning of these words, they need to be understood as both a reform to previous regulatory practice in electricity and to previous regulatory practice in gas. In this regard, two points from the gas industry are important:

- the AER was permitted under the previous National Gas Rules to depart from solely using the SL-CAPM and it could have chosen to use alternatives for setting the return on equity. Network providers had previously proposed other methodologies that the AER had given consideration to but either rejected outright or consigned to a secondary role as a 'cross check'. The AEMC recognised that this approach needed reform to remove consequent constraints that concepts such as 'well accepted' had placed on the AER of accommodating broader range of inputs and the AEMC considered that the new rules would achieve their stated aim; and
- the National Gas Rules are the successor to the Gas Code and much of the language is inherited from that document. The use of the term 'have regard' in the Gas Code has been the subject of extensive litigation and the courts construed the term within the context of that document as imposing a requirement on the regulator to give 'real weight' to the material and that it was inadequate to consider and give no weight to

[167] Re Dr Ken Michael Am; Ex Parte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231, para 55; Project Blue Sky v Australian Broadcasting Authority (1998) 194 CLR 355.
[168] Project Blue Sky v Australian Broadcasting Authority (1998) 194 CLR 355.
[169] AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 9-10; AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, page 8.

relevant information.[170] Given the prominence of that litigation in the history of the development of the current National Gas Rules, it is difficult to accept that the AEMC envisaged that it would be sufficient for the AER to consider all the relevant inputs and then give certain of those inputs no probative weight or only a constrained or secondary form of weighting.

The Guideline does not adhere to the requirement to give real weight:

- to the Fama French Model because it is not used at all (specifically given no role) in the establishment of the return on equity; and
- although some limited role may be given to the other two relevant models (the Black CAPM and DGM), these other models are each only used to inform one single parameter of the SL-CAPM. Even when used to inform a parameter of the SL-CAPM, they are used as secondary evidence that is disregarded to the extent that it is inconsistent with the primary range that is established using a different subset of the available evidence. Limiting their use this way severely constrains their ability to improve the quality of the return on equity estimate.

The Guideline Explanatory Statement describes the foundation model as follows:

> *Use one primary model with reasonableness checks. Generally, it would be expected that the output from the primary model would be adopted as our estimate of the expected return on equity (as per option one). However, where the reasonableness checks suggested the output from the primary model was not reasonable, the expected return on equity would be* ***determined based on regulatory judgement*** *(informative use of primary model).*

The more detailed specification of the foundation model, and the NSW draft decisions, give examples of the 'cross check' and 'regulatory judgement' – each of which have been problematic concepts in energy regulation. With respect to 'cross-checking' it is easy to decide what to do when all the evidence is mutually corroborative. However, there is a problem when the secondary 'cross check' material contradicts the primary material (and usually there is no concrete explanation by the regulator of what would happen). Where there is a conflict, either the initial estimate is to be preferred regardless of what the 'cross check' suggests or the secondary material is used to displace the initial estimate. In either case, one piece of information is in effect being given determinative weight and the other information is being given no weight.

The only 'circuit breaker' is to suggest that in the event of a conflict 'regulatory judgement' will prevail. The problem with this concept is that it is generally the term used when a regulator selects a value within a list of conflicting factors without providing the reasoning as to how the particular value was chosen. In other words, this term is usually used when there is no reasoning provided, and in that sense the decision is unreasonable. In this circumstance, it is impossible to know whether real weight was given to all the relevant material. This is not consistent with the Rules which require reasons to be given at both the draft determination stage and the final determination stage.[171]

For example, the AER uses 'regulatory judgement' in selecting a beta at the high end of its depressed range of 0.4 to 0.7 but there is no positive rationale expressed about why the 0.7 figure and this means that if (as we contend) the range is incorrect, it is not possible to discern whether the 0.7 number is then also incorrect if, say, the AER considers that unencumbered by the depressed range the number would be higher or whether there is a rationale for choosing that number.

The NSW draft determinations identify a number of matters that have not been the basis of selecting the 0.7 number but the closest the NSW draft decision come to an articulation of why the 0.7 number has been chosen

[170] RE Dr Ken Michael AM; ExParte Epic Energy (WA) Nominees Pty Ltd & Anor [2002] WASCA 231 at [54–6].
[171] NER, r. 6.10.2(3) and 6.11.2(3).

is to repeat that the AER has read all the materials submitted to it and reached a 'balanced outcome' by using 'regulatory judgement' that the result in it being 'satisfied' as to the furtherance of the rate of return objective:[172]

> *After taking these considerations into account, we adopt an equity beta point estimate of 0.7 for this draft decision, consistent with the Guideline. We consider this approach is reflective of the available evidence, and has the advantage of providing a certain and predictable outcome for investors and other stakeholders. We recognise the other information we consider does not specifically indicate an equity beta at the very top of our range. However, a point estimate of 0.7 is consistent with these sources of information and is a modest step down from our previous regulatory determinations. It also recognises the uncertainty inherent in estimating unobservable parameters, such as the equity beta for a benchmark efficient entity.*
>
> *We consider an equity beta of 0.7 for the benchmark efficient entity is **reflective of the systematic risk** a benchmark efficient entity is exposed to in providing regulated services. In determining this point estimate, we applied our regulatory judgement while having regard to all sources of relevant material. **We do not rely** solely on empirical evidence and we do not make a specific adjustment to equity beta to correct for any perceived biases in the SLCAPM. **We also do not rely** on empirical evidence from the Black CAPM, FFM or SFG's construction of the DGM (see appendix A and C). **We do not consider** our use of the SLCAPM as the foundation model will result in a downward biased estimate of the return on equity for a benchmark efficient entity (see appendix A.2.1).*
>
> *Our equity beta point estimate provides a balanced outcome, given the submissions by stakeholders and services providers. Figure 3-6 shows our equity beta point estimate and range in comparison with other reports and submissions. **We are satisfied** this outcome is likely to contribute to a rate of return estimate that achieves the allowed rate of return objective, and is consistent with the NEO and RPP.*

And finally,

> *We note McKenzie and Partington have now indicated the Black CAPM (of itself) does not justify any uplift to the estimated equity beta to be used in the SLCAPM. Nevertheless, we consider the model does theoretically demonstrate that market imperfections **could lead to the SLCAPM generating RoE estimates that are too high or too low. We have taken this into account in exercising our regulatory judgment** in choosing to use an equity beta of 0.7 in the SLCAPM. This is the equity beta we indicated we would use at the time we published the Guideline.*
>
> *We also acknowledge an equity beta of 0.7 is well above the fixed weight portfolio and average of individual firm equity beta estimates in Henry's 2014 report. However, in using an equity beta of 0.7 in applying the SLCAPM, we have exercised our regulatory judgment taking into account a range of information beyond the empirical beta estimates. We have selected an equity beta point estimate of 0.7 because we consider will this lead to a RoR that meets the RoR objective and best advances the RoR objective. We consider this is appropriate in all the circumstances. (Emphasis added).*

While the NSW draft decision discloses a series of matters that were <u>not</u> the reason for the 0.7 figure, from what has been written, it is not possible to understand how the figure of 0.7 was reached, and in the absence of disclosed rationale, it is not possible to hold the NSW draft decision to account.

Related to the lack of rationalisation for the adoption of a value of 0.7 is the lack of any reasoning that explains why this figure has been significantly reduced since the AER's 2009 NSW final determination when essentially the same information was considered (other than information which now points to a higher beta). SFG Consulting

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[172] AER, Ausgrid Draft Determination, November 2014 [3-83, 3-171].

explains this in more detail in paragraphs 89 to 92 of its 13 February 2015 report titled 'The required return on equity for the benchmark efficient entity'.

Both of these problems are illustrated in the AER's NSW draft determinations. For example, when selecting a beta range of 0.4 to 0.7 the AER relies on a small set of partly dated data for domestic firms which is rapidly dwindling. It purports to apply a 'cross-check' comparison with international data from the United Kingdom and US but the US material, and the average of the combined material deliver results above the 0.7 level. To resolve the inconsistency, the AER adheres to the initial range, effectively rendering the international 'cross check' material of no value.

The same problem arises in relation to the 'cross checking' that is said to occur of the Ibbotson inspired AER approach to specifying the SL-CAPM using the Wright approach. SFG Consulting states:

> *This highlights the problem of using one subset of relevant evidence when estimating the original MRP parameter while relegating another subset of the relevant evidence to the role of "cross checks." Having determined that the Wright approach for estimating the MRP is relevant evidence, and having obtained a Wright estimate of the return on equity that is materially inconsistent with the AER's proposed estimate, there are two possible courses of action. Either:*
>
> *(1) The AER would retain its original estimate – in which case the cross check has no effect and there seems to be no point performing it; or*
>
> *e. The AER would revise its original estimate to make it consistent with the cross-check estimate – in which case the original evidence has effectively been discarded in favour of the cross check evidence.*

The improper search for a pre-eminent model and improper constraints inherent in using a 'foundation' model

The concept of a foundation model does not appear in the Rules or the NEL. Indeed, when amending the Rules, the AEMC notes:[173]

> *Ultimately it is important to keep in mind that all these financial models are based on certain theoretical assumptions and* ***no one model can be said to provide the <u>right</u> answer****.*

The Guideline proceeds on the basis that it is possible to select a foundation model, which will effectively provide outer limits to the range of possible values for the return on equity. As discussed in the next section, there are strong reasons why the SL-CAPM is not the best of the available models. However, even if it were the best of the available models, using it in the way that the AER has done constrains, and in some cases prevents, insights from the other models from being employed.

Elevating any one model to the 'foundation' status necessarily gives that model primary weight and all the other models less weight. Given the significant downward bias of this model for low beta stocks and the over-all empirical shortcomings of the SL-CAPM, the AER's approach gives undue primary weight to the foundation model and, contrary to the requirement to take into account all the available information, the AER's framework improperly constrains the regard the AER can effectively give to those other models.

There is substantial evidence that the SL-CAPM produces a downwardly biased estimate of the return on equity for low beta firms and value stocks – both characteristics apply to the benchmark efficient entity.[174] Further,

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173 AEMC, Draft Rule Determinations: National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, August 2012, page 48.

174 SFG Consulting, referring to the extensive empirical research in this respect, such as the work of Black, Jensen and Scholes (1972), Friend and Blume (1970) and Fama and Macbeth (1973) in SFG Consulting, Cost of Equity in the Black Capital Asset Pricing Model, May 2014, page 6-10.

using current data, SFG calculates returns using the various models, which illustrates that the SL-CAPM delivers a lower result than any other model.

In fact, recently NERA, with respect to its in-sample tests of the SL-CAPM, concluded:

> *the data indicate that there is a negative rather than a positive relation between returns and estimates of beta. As a result, the evidence indicates that the SL CAPM significantly underestimates the returns generated by low-beta portfolios and overestimates the returns generated by high-beta portfolios. In other words, the model has a low-beta bias. The extent to which the SL CAPM underestimates the returns to low-beta portfolios is both statistically and economically significant.*

An important basis for the AER's exclusion of the Fama-French Model was that the AER considered there to be no clear theoretical foundation to identify risk factors. This is an improper basis upon which to exclude a model that in fact performs well empirically in explaining stock market returns. Indeed, there is a lot to be said for giving primacy to empirical performance over theories as, until they are tested robustly, theories are simply one idea as to reality.

There is no reason to suppose that selecting from the upper range of possible outcomes for SL-CAPM parameters will correct for these biases. Indeed by selecting from ranges set using a downwardly biased model there is logically a significant risk that the true or unbiased return on equity will lay outside that range.

The AER has acknowledged that the DDM, Black-CAPM and survey evidence can also be informative in addressing some of these limitations but those inputs are only taken into account within an upper limit selected from an application of the SL-CAPM that has not corrected for those biases and there is, therefore, every reason to suppose that the results do not accord with prevailing (unbiased) equity returns.

Moreover this is contrary to the AER's own 'fit for purpose' criterion that regard should be had to the limitations of the model's original purpose.[175] The SL-CAPM was not originally implemented by drawing parameter estimates from competing models nor was the competing models developed for the purpose of estimating parameters of the SL-CAPM.

Flawed selection of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model

Even if the Rules did allow a foundation model to constrain the ways in which other relevant data can contribute to the allowed rate of return, there is no basis to conclude that the SL-CAPM is the 'superior model in terms of estimating expected equity returns'.

SFG Consulting states that:[176]

> *The AER adopts a model that does not fully account for factors that are associated with stock returns. The AER's use of the Sharpe-Lintner CAPM, without giving consideration to the Fama-French model, means that is places sole reliance on a model that has been shown to have less ability to explain stock returns.*

Maine Public Utilities Commission states that:[177]

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175 As noted above, we consider this criterion to be a distraction that is likely to lead the AER away from the attainment of the rate of return objective. However, even it were a relevant criterion, there is a failure to apply the criterion properly.

176 SFG Consulting, The required return on equity for the benchmark efficient entity, Feb 2015, page 10.

177 PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1998 Me. PUC LEXIS 603 at [42]. (see also PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1999 Me. PUC LEXIS 259 at [41]). Note: these cases predate decisions in which an equal weighting between the Black CAPM and the SL CAPM models have been adopted.

The theoretical weaknesses of the CAPM spelled out in the Bench Analysis causes us to rely more heavily on the DCF analysis in our decision making. In this particular case, the lack of a true forward looking beta is a large obstacle given that a pure T&D-utility industry does not exist at this point in time.

With models that do not suffer from the flaws of the SL-CAPM, any of them would be preferable to select as a foundation model (if the Rules required or permitted such a foundation model).

It is not surprising, therefore that all the other models provide mutually corroborating cluster of benchmark returns on equity for benchmark energy network businesses in the vicinity of 9.93 to 10.32 per cent while the SL-CAPM falls well below that cluster at 9.3 per cent when estimated by SFG Consulting, and orders of magnitude lower when estimated using the AER's Ibbotson inspired implementation at approximately 8.1 per cent.[178]

These figures also highlight the significance of choosing between different approaches to implementing the SL-CAPM when using it as a foundation model.

Having chosen to adopt the SL-CAPM as the foundation model, the AER is confronted with two approaches to implementing the model at opposite ends of a spectrum: the Ibbotson and Wright approaches. The AER elects to adopt the 'status quo' and by primarily relying on the 'Ibbotson Approach', to measuring the historical MRP. The AER combines its estimate of historical MRP with an 'on the day' risk free rate. The AER, has quite elaborately chosen to constrict itself to the Ibbotson approach, paying no regard to the notion of the Wright approach by adopting 'cross checking' of the sort described above that gives the secondary material no weight.

In the current economic conditions, the AER's approach of combining a contemporaneous measure of the risk free rate with an essentially constant MRP delivers values that are necessarily materially lower than prevailing market conditions.

Experts explain that there is no one-to-one relationship between movements in the risk free rate and the risk adjusted returns that investors require. In fact the MRP tends to fluctuate in the reverse direction from risk free rates.[179]

Although the expert work is informative at an aggregate level, there are also occasions when this concept is readily apparent to any intelligent observer. For example, shortly after the collapse of Lehman Brothers, two key propositions were inescapably prominent to finance market practitioners and the general business community alike – at the same time that investors became nervous and were demanding significantly increased returns, central banks were significantly reducing wholesale interest rates to try and stimulate the economy. This is a stark example of what the expert evidence shows is generally the case: the MRP and risk free rates tend to move in opposite directions.

This means that adding a long run average MRP to an immediately observed risk free rate will deliver downwardly biased results when risk free rates are low and upwardly biased results when risk free rates are high. In the current environment of record low risk free rates, a simple addition of a very long term MRP with a current risk free rate is almost bound to significantly under compensate equity investors.

Indeed, the approach in the NSW draft determinations delivers a nominal post tax return on equity of just 8.1 per cent which is substantially lower than five years previously which provided for a return on equity of, in Ausgrid's case 11.82 per cent. More than two percentage points of that drop can be attributed to the fall in the underlying risk free rate. While the risk free rate has dropped in this way, there is simply no evidence available from which to conclude that equity investors' required rates have fallen in proportion to the fall in the risk free rate.

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178 SFG Consulting, The required return on equity for the benchmark efficient entity, Feb 2015 page 35; AER, Ausgrid draft determination, November 2014, [3-45].

179 Incenta, Further update on the required return on equity from Independent Expert Reports, Feb 2015.

Exactly the same question confronted the AER's US counterpart in its 28 January 2014 decision concerning the New York Independent system Operator. In that case FERC decided as follows:[180]

> *We find NYISO's proposed ROE value of 12.5 per cent is adequately supported by substantial evidence. NYISO argues that current conditions in financial markets created a downward bias in the CAPM results, necessitating a calibration adjustment of 1.21 per cent to calculated return on equity of 11.29 per cent. Specifically, NYISO argues that the result yielded by the CAPM analysis "appeared potentially too low relative to regulated rates of return and as the CAPM is subject to bias at times during the interest rate cycle" because of the potential impact on the historic relationship between the market returns for government debt and common equities. Given the recent trends of historic low yields for long-term U.S. Treasury bond rates, the CAPM's input for the "risk free" rate, we find that it is a reasonable assumption that the current equity risk premium (which is added to the risk-free rate to calculate the cost of equity data point that determines the slope of the CAPM curve) exceeds the 86-year historical average used as the consultants' CAPM input. The current low treasury bond rate environment creates a need to adjust the CAPM results, consistent with the financial theory that the equity premium exceeds the long-term average when long-term U.S. Treasury bond rates are lower than average, and vice-versa.*

It might be tempting to jump to the conclusion that under-compensating investors at this time is of little concern if, once the economic cycle turns, the current under-compensation could be offset by future over-compensation but this is not the case. If there is a mismatch in either direction between prevailing rates and regulatory allowances, inefficiencies will arise. Firstly, there are costs for a business of absorbing inter-temporal fluctuations in returns through explicitly or implicitly carrying a balance sheet provision for such a mismatch. Secondly, at times of under-compensation timely investments are discouraged or delayed and at times of over-compensation the opposite effect applies and there is an incentive to invest earlier than required. Neither is efficient. Note also that these effects are pro-cyclical which means that the direction of the mismatch encourages a business to reduce capital expenditures at times when input costs are likely to be low and to increase capital expenditures at times when input costs are likely to be high.

It is appropriate, therefore, that the Rules require (as they do) that each determination provides for a regulatory allowance that is commensurate with the prevailing efficient costs for a benchmark firm at the time. In the AEMC's words:

> *If the allowed rate of return is not determined with regard to the prevailing market conditions, it will either be above or below the return that is required by capital market investors at the time of the determination. The Commission was of the view that neither of these outcomes is efficient nor in the long term interest of energy consumers.*

In other words, unless the AER has a proper basis to conclude that the investors' expectations move in parallel with the risk free rate, placing effectively sole reliance on the Ibbotson inspired implementation of the SL-CAPM as it does, prevents its MRP estimate from adjusting to produce an allowed rate of return that can accommodate the prevailing expectations of equity investors.

The flaws in AER's selection of beta

Equity beta is the key input into the SL-CAPM representing the AER's view as to the risks associated with the operation of an energy network business relative to benchmark efficient businesses. The AER has indicated that it intends to adopt an 'equity beta' to its lowest level ever in its regulatory decision making. The equity beta has

180 Federal Energy Regulatory Commission (28 January 2014): "Order accepting tariff filing subject to condition and denying waiver". Docket No. ER14-500-000, page 35-36.

progressively been down-graded from 1.0 for most of the period since the NEM began to 0.8 and now proposed to be 0.7 (including in NSW).[181]

The AER's decision to significantly downgrade the beta value is based on two principal inputs. Work by Frontier Economics sets the scene in a broad qualitative sense, suggesting that electricity businesses are comparatively safe – even with high levels of leverage. In our view, that report fails to properly assess the risks facing the business as noted by SFG.[182] Specifically, the Frontier Economics report only deals with operational risks and does not make any recommendation about whether the equity beta is likely to be above or below 1.

Further, it proceeds in the face of firm evidence that electricity network businesses are becoming more risky over time compared with a balanced market portfolio. By contrast, as discussed in detail in section 12.2, there is significant evidence to conclude that electricity network businesses are experiencing significant increases in risk. Debates can be had as to whether these risks are best included in the beta or elsewhere but presently these increases are accommodated neither in the equity beta nor in any other part of the regulatory framework.

When it comes to making a quantitative estimate, it would be surprising if all parties did not agree with the following proposition:[183]

> *In an ideal world there would be a very large number of domestic comparators and there may be no need to consider international comparators at all.*

Unfortunately the current situation could not be further from the ideal world because the number of domestic firms has dwindled to an unworkably small number with current data available of just four. When the US Federal Energy Regulatory Commission was confronted with the same problem (i.e. a comparator set that shrank below ten or so) in relation to interstate gas pipeline businesses, it broadened the sample:[184]

> *[S]tructural changes have strained the Commission's prior approach towards proxy group composition to breaking point. As a result of mergers, acquisitions, and other changes in the natural gas industry, fewer and fewer interstate natural gas companies have satisfied our prior requirements for proxy group composition.*
>
> *Our policy change was born out of a practical recognition that the size of the proxy group used under our prior approach had shrunk dramatically.*

However, the AER clings to an ever narrowing set of current data supplemented by ever more out of date observations. As SFG Consulting explains:[185]

> *The AER adopts a set of nine domestic comparator firms, only four of which remain listed. Two of the firms have not been listed since 2006 and one has not been listed since 2007. The AER's approach is to maintain the beta estimates for these firms in its sample, even though those estimates become progressively more dated with the passage of time. That is, the beta estimate at the time a firm delists becomes a permanently determinative observation in the AER's sample. By the time the current Guideline expires, three of the nine beta estimates will be more than 10 years out of date. These estimates will, by definition, not reflect anything that has transpired in financial markets for over a decade.*

In the Guideline process, the AER picked over this scarce dataset generating several results that appear to be mutually corroborative but which are in fact averages drawn from substantially over-lapping datasets or the same data-sets reworked using two different statistical techniques. This delivered a range of 0.4 to 0.7. The

181 Note that in South Australia the figure was 0.9.

182 SFG Consulting, Equity beta, May 2014, page 20-22.

183 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 12 [38].

184 Federal Energy Regulatory Commission, Statement of Chairman Joseph T. Kelliher, April 2008.

185 SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 10 [28]-[29].

principal analysis that was intended to inform the estimate was a report by Professor Henry which was not delivered until five months after the Guideline was issued.[186]

In this report, the AER's brief tightly specified the data he was to use ('nine specified Australia gas/electricity firm', 'short term Australian Government debt' and the 'ASX 300 Accum') and precisely what work was to be done. There were specific instructions on use of Australian data, weekly returns, no Blume or Vasicek adjustment etc. In other words, Professor Henry's work does not set out his expert opinion as to the level of beta at large and instead he has undertaken a highly constrained process of employing inputs provided by the AER in a manner specified by the AER and the results are product of the AER's views concerning each of the relevant inputs.

Even using the AER's tightly constrained set of instructions, Professor Henry states that the range for equity beta is 0.3 to 0.8, not 0.4 to 0.7 as published in the AER's Guideline.

The AER sought to bolster the domestic data with one set of international comparators for the Guideline and another in the NSW draft determinations. SFG Consulting has examined all that material and concluded that in relation to the first set of data relied upon, all the contemporaneous estimates are above 0.7.

In relation to the latter data, the analysis is of very poor quality. For example, the AER has relied upon the following:[187]

> *Alberta Utilities Commission (2013). This report documents submissions to the regulator in relation to equity beta – it does not present any estimates of beta. Unsurprisingly, user groups such as the Canadian Association of Petroleum Producers (CAPP) submitted that a low equity beta should be used. The report provides no information at all about the basis for the equity beta submissions. There is no information about how many, or which comparator firms were used. There is no information about what statistical techniques were employed or how the range of resulting estimates was distilled into a point estimate or range.*

It is also important to note that the beta used in Alberta is the starting point for the analysis and after which an assessment is made of whether 'adders' are required to increase the returns to meet the required returns.

SFG Consulting has identified significant flaws in the use of the following report:[188]

> *PWC (2013) In its recent draft decisions the AER summarises the evidence from the PWC report for the NZCC as follows:*
>
> *'PwC's June 2014 report presents the following raw equity beta estimates for New Zealand energy network firms as at 31 December 2013: 0.6 for the average of the individual firm estimates.'*
>
> *The AER implies that this estimate of 0.6 can be compared with its allowed equity beta of 0.7. However, such a comparison would be an error for the reasons set out below. First, the 0.6 estimate does not appear anywhere in the PWC report. The beta estimates set out in the "Utilities" section of the report are set out in the table below.*

[186] Henry, University of Liverpool Management School; *Estimating Beta: An update*, April 2014.
[187] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 15 [56(c)].
[188] SFG Consulting, Beta and the Black Capital Asset Pricing Model, 2015, 16 [50(d)].

Table 12.2 PwC beta estimates for the NZCC

Company	Raw beta	Leverage	Regeared beta (to 60% debt)
Contact	0.9	0.27	1.64
Horizon	0.5	0.31	0.86
NZ Windfarms	0.5	0.33	0.84
NZ Refining	0.8	0.17	1.66
TrustPower	0.5	0.36	0.80
Vector	0.7	0.50	0.88

> *The AER's estimate of 0.6 is the average of the raw beta estimates for Horizon and Vector, which are considered to be the firms most comparable to the benchmark efficient entity. The average of the regeared estimates for these two firms is 0.87.*

In summary, the AER's range for beta of 0.4 to 0.7 is erroneous and inconsistent with the evidence before it. Although Appendix C of the Rate of Return Guideline Explanatory Statement is replete with criticisms and rejections of the point estimates proposed by user groups and businesses alike, exactly how the AER choses to adopt the upper 0.7 value from its (excessively) constrained range of 0.4 to 0.7 is unclear. The closest that Appendix C comes to an explicit statement is as follows:

> *[Our] proposed point estimate of 0.7 is not inconsistent with our consultants' advice.*[189]
>
> *Adopting a point estimate around the mid-point would be more reasonable if our intention was to base the allowed return on equity on the Sharpe-Linter CAPM and empirical estimates alone. However, the rules require us to have regard to relevant estimation method, financial models, market data and other evidence when determining the allowed rate of return. When this information is taken into account, we consider it reasonable to select a point estimate form the upper end of the range of empirical equity beta estimates.*[190]

The best inference from the totality of the AER's document appears to be that the selection is primarily chosen as an apology for the downward biases of the SL-CAPM. However, there is no basis to support the conclusions that selecting the upper bound of the AER's assessment of the range supported by the sample of four current and five former domestic comparators will be exactly sufficient to redress all the known biases in the SL-CAPM. A better and more transparent approach would be to allow for a wider sample and to simply estimate the models that have been developed to redress the well-documented problems with the SL-CAPM and then use the available evidence at hand.

The flaws in the AER's implementation of the Ibbotson approach to measuring the historical MRP for use in the SL-CAPM

The AER sets a MRP of 6.5 per cent on the basis of its long run estimates but again it has not explicitly explained how its 6.5 point estimate is drawn from a range of 5.1 per cent (which is 20 basis points above the geometric means of various cuts of the data going back to 1883) to 7.8 per cent (which is drawn from the high-point of the AER's DGM):

189 AER, Rate of Return guideline, Appendix B, December 2013, page 76.
190 AER, Rate of Return guideline, Appendix B, December 2013, page 76-77.

We propose to estimate the MRP point estimate based on our regulatory judgement taking into account estimates from each of those sources of evidence and considering their strengths and limitations.

NERA has undertaken analysis of the historical MRP estimates relied upon by the AER and identified a number of issues[191].

NERA's first concern is that the AER insists on using geometric means on the basis of advice from McKenzie & Partington in 2011 and 2012 to the effect that an arithmetic mean would be upwardly biased where WACC estimates are compounded. However, both the AER's own consultant, Lally, and NERA have more than once pointed out that the regulatory arrangements do not provide for compounding. Since the regulatory arrangements do not involve compounding, the reverse is true and the use of a geometric mean is downwardly biased as has been noted by the Maine Public Utilities Commission: *'….[W]we agree with the Company that it is improper to use a geometric mean in the CAPM model…'*.[192]

NERA's second concern is that the AER continues to adopt a paper authored by Brailsford, Handley and Maheswaran, first published in 2008 and updated in 2011 and again in 2012 reaching a value for the MRP (for identifying a value for the MRP used in the SL-CAPM).[193] The AER continues to take this approach despite that the reliability of the data underlying the article has been brought into question repeatedly.

The original source of the adjusted data is identified in the footnote 13 and 16 in Brailsford et al 2013 as emails received from the ASX on 11 April 2003 and 26 May 2004.[194] Within one full page of those footnotes, the authors had already described these emails, asserting that '*staff carefully considered the issue and ultimately decided on an adjustment factor of 0.75'.*[195]

The AER has effectively (falsely) invested the adjustment with the ASX corporate endorsement and created the impression that the adjustment carries the ASX's corporate approval. In this way, the AER is creating an apparently indisputable ground for its position.

Further, the AER has given weight to the notion that the Brailsford et al article has been published in a 'peer reviewed academic review' without making inquiries to understand what that peer review entailed.[196] Certainly, the review did not require the source and context of the email correspondence to be set out in the published paper. By contrast, the NERA work was prepared according to the *Federal Court's Guidelines for Expert Witnesses in Proceedings in the Federal Court of Australia – Practice Note CM7* including disclosing all sources upon which they rely. Accordingly, NERA's adjustment factor must be preferred.

The AER's flawed use of expert reports

The AER performs a 'cross check' for its beta estimates against expert reports (reports prepared for the purpose of stock market valuations in the context of takeovers). It is relevant to note that the question posed to these experts is whether a specific takeover offer is 'fair' – i.e. sufficient to be fair. This is not the same question that the AER is required to answer.

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191 NERA, Historical Estimates of the Market Risk Premium, February 2015

192 PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1998 Me. PUC LEXIS 603 at [41] and PUBLIC UTILITIES COMMISSION; Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design 1999 Me. PUC LEXIS 259 at [42].

193 Draft determination for Ausgrid's 2015-2019 regulatory period and the 2013 WACC Guideline determination.

194 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008.

195 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008 page 80.

196 Brailsford, T., J Handley and K. Maheswaren, Re-examination of the historical equity risk premium in Australia, Accounting and Finance, 2008.

Incenta has examined the AER's reasoning and found it to be wanting.

The first issue concerns whether the Ibbotson inspired approach reflects current equity market expectations. In this regard Incenta reports the following:[197]

> *The AER has compared the risk premium over the 'spot' risk free rate that independent experts have applied to the risk premium over the spot risk free rate that it applies, and so implicitly assumed the risk premium that experts apply has remained (and will remain) constant in the face of large changes in the risk free rate. However, this masks the actual behaviour of independent experts, with almost 90 per cent having adjusted the risk free rate and / or the market risk premium in response to changes in the risk free rate.*

The AER gives particular attention to the Grant Samuel report concerning APA's unsuccessful takeover of Envestra. Grant Samuel itself has expressed serious reservations about how its report has been interpreted and used by the AER, both in relation to the MRP and other issues such as the beta adopted, and whether in fact experts use the SL-CAPM.

In essence, the AER sought to gain support from the report for the use of the CAPM to the exclusion of other approaches. Grant Samuel states:[198]

> *[O]ur approach … is to form an overall judgement as to a reasonable discount rate rather than mechanistically applying a formula. The fact is that, particularly in some market circumstances, the CAPM produces a result that is not commercially realistic. When this occurs it is necessary and appropriate to step away from the methodology and use alternative sources of information to provide insight as to what is, after all, an unobservable number that can only be inferred. In our view, Envestra was clearly a case in point.*
>
> *In using the Envestra report, the AER seems to be to trying to co-opt the parameters that we used for calculating the initial CAPM based rate to bolster its own case while trying to find ways to justify not having to recognise the fact that for the valuation of Envestra Limited's assets, we actually selected a different rate (i.e. 6.5-7.0% or, more correctly 6.5-8.0%, rather than 5.9-6.5%).*

The AER expresses concerns about the transparency of Grant Samuel's methodology but Grant Samuel responds as follows:[199]

> *In view of the apparent importance of the Envestra Report in supporting the AER's findings we are surprised that, if there were such transparency issues, the AER did not approach us for clarification. To our knowledge, we have never been approached to discuss any aspects of our discount rate or other valuation approaches.*

The AER asserts that:[200]

> *[T]he return on equity and equity risk premium estimates contained in Table 3- 20 are the final values used in the independent valuation report and reflect any uplifts applied.*

As Grant Samuel disavows that assertion:[201]

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197 Incenta Economic Consulting, Further update on the required return on equity from Independent expert reports, Feb 2015.

198 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 4-5.

199 Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, page 6.

200 AER, *Ausgrid Draft Determination*, November 2014 [3-140].

This statement is simply not true as the table, at least in the case of Grant Samuel's reports for Envestra Limited, DUET Group and Hastings Diversified Utilities Fund, only reflects the calculated post tax WACCs ignoring the uplifts and adopts midpoints for post tax WACC and return on equity, an approach which Grant Samuel considers inappropriate.

And in a similar vein:[202]

the AER claims that the implied adjusted equity risk premium range in three of the four uplift scenarios referred to by Grant Samuel in Appendix 3 of the Envestra Report justifying its uplift is consistent with its foundation model premium of 4.55%. We do not know how the AER determined this but our calculations indicate that in fact the 4.55% is well in the range in only one of the scenarios, is right at the bottom of the range in one other scenario and is outside the range in the other two.

In summary it is not surprising that Incenta reaches the following conclusions with respect to the AER's whole approach to expert reports:

Taken together, our findings indicate strongly that were the AER to continue to apply the same mechanistic SL-CAPM approach that was applied in its draft decision, with JGN's current averaging period risk free rate at 2.64 per cent, the resulting estimated rate of return on equity will fall materially short of the required rate of return in the market that is implied by a consideration of independent expert reports, and not be commensurate with the efficient financing costs a benchmark entity will face over the access arrangement period.

Inconsistent treatment of the imputation adjustment

In the section on Gamma, we discuss our approach to the valuation of imputation credits. However, it is important to recognise that there is an inter-relationship between the regulatory estimates of the required return on equity and gamma. This relationship is most apparent in the AER's post-tax revenue model (**PTRM**).

The PTRM requires the regulator's assumed value of the with-imputation required return on equity. It then removes the regulator's assumed value of imputation credits, leaving an estimate of the ex-imputation required return on equity. Allowed revenues are then based on this ex-imputation required return. The idea is that the firm requires sufficient revenue to provide investors with their ex-imputation required return, which is supplemented by imputation credits to provide them with their total required return.

The first step in this process requires an estimate of the with-imputation required return on equity. The AER's approach to this task is to 'gross up' its estimates of MRP to include the AER's assumed value of imputation credits. For example, when implementing its DGM approach for estimating MRP, the AER grossed-up forecast future dividends to include its estimate of the value of the imputation credits that will be attached to those dividends.

The adjustments for imputation credits are made in two places in the AER's estimation process:

1. The assumed value of imputation credits is **added** to produce an estimate of the with-imputation required return on equity; and then
2. The assumed value of imputation credits is **subtracted** to produce an estimate of the ex-imputation required on equity.

[201] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, January 2015, page 6-7.

[202] Grant Samuel & Associates Pty Limited, Letter to The Directors TransGrid, Australian Energy Regulator – Draft Decision, January 2015, January 2015, page 7.

Internal consistency problems arise when the assumed value that is added in step 1 above is different from the assumed value that subtracted in step 2 above. In the AER's recent NSW draft determinations, the value that is added in step 1 is materially lower than the value that is subtracted in step 2, creating a downward bias to the allowed return on equity. On this point we consider that AER should ensure the same adjustment for imputation credits should be applied in both the steps of the AER's estimation approach.

Summary

As demonstrated above, the AER's approach to establishing an allowed return on equity is ill conceived. AER does not take into account important pieces of empirical evidences.[203] Consequently we have chosen to depart from the Guideline in all respects other than the identification of the relevant models. Our approach is described in the next section.

12.3.3 Rate of return allowance proposed in place of the AER Guideline

For all the above reasons, we consider that the approach in the Guideline cannot appropriately be remedied through adjustments correcting isolated errors and instead a new ground-up assessment of each of the inputs and how they are combined needs to be undertaken. SFG has conducted such an evaluation including with the assistance of work undertaken by other experts. Our proposal, described in the next section, is based on that work.

Instead of the approach adopted in the Guideline, we propose to establish a rate of return giving real weight to all the relevant models and inputs by:

- identifying the relevant rate of return models (which are, in fact, the same as those identified by the AER);
- identifying the relevant evidence which may be used to estimate the parameters within each of the relevant return on equity models;
- estimate model parameters for each relevant return on equity model, based on relevant market data and other evidence;
- separately estimate the required return on equity using each of the relevant models; and
- synthesise modelling results as a weighted average of the individual estimates with the weights that avoid double-weighting any of the key conceptual elements of the models.

12.3.4 Estimate the parameters for use within each of the four models

Between them, the four models require estimates of the following parameters:

- a risk free rate of return;
- a required rate of return on the market portfolio (or an MRP to combine with the risk free rate);
- an equity beta (for the two CAPM models);
- a zero-beta return (for the Black-CAPM), or zero-beta risk premium;
- market exposure, size and book to market factors (Fama-French Model only); and
- a risk premium for comparable firms (for use with the DDM only).

The proposed source of each of these parameters is discussed below.

[203] SFG, The foundation model approach of the Australian Energy Regulator to estimating the cost of equity, March 2015; NERA, Review of the Literature in Support of the Sharpe-Lintner CAPM, the Black CAPM and the Fama French Three Factor Model, March 2015.

Risk free rate averaging period

We accept the approach to setting the risk free rate proposed in the Guideline which is to adopt a 20 consecutive business days that is as close a practicably possible to the commencement of the regulatory control period. For illustrative purposes, the figures presented in this Regulatory Proposal are calculated using a 20 business day period ending on 30 January 2015. We propose the averaging period for return on equity in the letter attached to our regulatory proposal.[204]

Required return on the market portfolio (or its corollary, the market risk premium)

A number of the four models include a MRP which is simply the required return on the market portfolio less the risk free rate. In the past the AER has adopted the approach of using long run average excess returns (i.e. the returns of a representative portfolio above the risk free rate) as Ibbotson calculates an MRP. It is noted that there are other ways to estimate an MRP including historical data using an approach championed by Wright, the estimates derived from a dividend growth model, and estimates from independent experts and surveys. Wright did not develop an alternative implementation of the SL-CAPM. Wright simply proposed an alternative method of estimating the MRP for use in the SL-CAPM—as the difference between the historic average market return and the current risk free rate—on the basis that market returns may be more stable over time than excess returns.

SFG note that the Ibbotson approach involves adding an effectively constant MRP to the contemporaneous risk-free rate to produce an estimate of the required return on equity that varies one-for-one with changes in the risk-free rate:[205]

> *[T]he Ibbotson approach implies that equity is more expensive than average during economic expansions and bull markets (the late 1990s and mid 2000s) and cheaper than average during financial crises (the pronounced reduction in 2008).*

It is counter-intuitive that the required return on equity should be lower during financial crises than during periods of economic expansion. This should be taken into account when the AER considers how to best employ historical data to inform estimates of MRP. In the Guideline, the AER uses historical data only via the Ibbotson approach (which leads to these counter-intuitive results) and places no weight on the Wright method for processing the historical data. By contrast, SFG recommend that both methods provide relevant evidence in which case both should be given regard.

The Guideline proposes that the AER would consider all this material and determine an MRP using 'regulatory judgment'. The Guideline provides a worked example as at December 2013 but the AER would not necessarily exercise judgement in the same way in our Regulatory Proposal. We consider that there are a number of flaws in the worked example as detailed by SFG Consulting. The detailed analysis is summarised as follows:[206]

> *[I]n some places the Guideline relies on dated evidence that has now been updated, in other places it relies on inaccurate data that has since been corrected, and in other places it makes improper comparisons (e.g., where estimates that include the benefit of imputation credits and estimates that exclude the benefit are compared as equals).*

Our proposal adopts SFG Consulting's view as to the appropriate manner in which the AER should exercise judgement establishing MRP. To a significant extent it relies on similar information, although certain information (such as inherently unreliable surveys) were not used. There are, however, other important differences in the

[204] Powercor, Letter proposing return on debt averaging periods (confidential version), 29 April 2016.
[205] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 56.
[206] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 44.

details of how the other sources would be used to address flaws that SFG Consulting have identified above. SFG Consulting notes:[207]

[SFG Consulting would] have regard to the following evidence:

First, we note that historical returns can be processed in two ways – by assuming that MRP is constant in all market conditions (Ibbotson approach) or by assuming that real required returns are constant in all market conditions (Wright approach). We apply equal weight to each of these approaches, producing an estimate of MRP from historical returns of 7.11%;

a. The estimate of MRP from dividend discount models of 7.31%; and

b. The estimate of MRP from independent expert reports of 7.08%.

The same report illustrates why the outcome is not sensitive to the weightings given to the three sources. The relevant evidence is discussed in detail in the report. A summary is provided in table 12.3 (each grossed up for a theta estimate of 0.35) of updated SFG analysis.[208]

Table 12.3 Summary of SFG findings

Approach	Value (%)
A historical average market return using the Ibbotson approach (%)	9.20
A historical average market return using the Wright approach (%)	11.64
A DDM estimate	11.37
Independent expert evaluation reports	9.57

Source: SFG Consulting

SFG Consulting synthesises this information to provide a single point estimate of 10.81 per cent.

Equity beta

We consider the reduction of the equity beta from 0.8 to 0.7 proposed by the Guideline to be incorrect on the basis of the following considerations emerging from work undertaken by SFG Consulting:[209]

a. The estimate of 0.7 is the outcome of a convoluted multi-stage approach whereby:

i) a sub-set of the relevant evidence … is used to constrain the range of possible estimates to 0.4 to 0.7;

ii) the other relevant evidence that is considered in the Guideline … all supports an estimate above 0.7, but the first stage of the process constrains the maximum estimate to be 0.7; and

iii) there is relevant evidence that is not considered in the Guideline …;

b. The subset of evidence that is used to produce the constraining range of 0.4 to 0.7 is not sufficiently reliable to be used for that purpose because: the beta estimates vary wildly … across firms;… over time; …

[207] SFG Consulting, The Required Rate of Return on Equity for Regulated Gas and Electricity Network Businesses, June 2014, page 6.
[208] SFG Consulting, The Required Return on Equity for Benchmark Efficient Entity, Feb 2015
[209] SFG Consulting, Equity Beta, May 2014, page 3-4.

depending on which sampling frequency is used;… depending on which regression specification is used; and …depending on the day of the week and month on which they are computed;

c. The evidence from international comparable firms suggests an equity beta materially above 0.7;

d. To the extent that the 0.7 estimate has been influenced by the AER's conceptual analysis, it is wrong. The AER concludes that the conceptual analysis supports an equity beta materially below 1, but it does not. In this regard:

i) The Frontier Economics (2013) report does not support an equity beta below 1 … ; and

ii) The McKenzie and Partington (2012) report sets out two pieces of empirical evidence. One suggests that energy networks have equity betas materially above one, and the other suggests that finance risk is the primary component of beta for utilities;

e. To the extent that the 0.7 estimate has been set to match the equity beta that the ACCC uses for water utilities, it is wrong. Regulatory estimates of beta for water utilities are based on regulatory estimates of beta for energy networks (which introduces circularity) and on international water utilities … .

Additionally, the modelling of the equity beta is flawed in that the sample is too small and the estimate too variable in response to the choice of statistical method. Further, irrelevant water utility data is included instead of relevant international data on the energy network sector.

We submit, based on SFG Consulting's expert opinion, that the most appropriate estimate for the equity beta is 0.82 on the following basis:[210]

One way of having regard to the range of relevant models and evidenced is to estimate the required return on equity under each of the relevant approaches and then to determine an allowed return on equity after having regard to the relative strengths and weaknesses of each approach. Under such a multi-model approach, we would adopt a Sharpe-Lintner CAPM beta of 0.82 – the raw estimate of beta that does not reflect any evidence other than the historical statistical relationship between stock returns and market returns for the relevant set of comparable firms.

The AER's consultant concludes:[211]

In the opinion of the consultant, the majority of the evidence presented in this report, across all estimators, firms and portfolios, and all sample periods considered, suggests that the point estimate for β lies in the range 0.3 to 0.8.

Adopting 0.7 is not supported by any empirical evidence.

Black CAPM return on a zero beta asset

SFG Consulting have estimated the return on a zero beta asset by adding a zero beta premium 3.34 per cent to the risk free rate of 2.64 per cent to give an estimated return of 5.98 per cent return on a zero beta asset.

This is within the reasonable range in the Guideline and for that reason this issue does not warrant a detailed treatment in this identified document.

Fama-French model market exposure, SMB and HML factors

Because the Guideline does not use the Fama-French model, there is no relevant departure from the Guideline in relation to these factors.

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210 SFG Consulting, Equity beta, , May 2014, page 42.

211 Henry O., University of Liverpool Management School; Estimating Beta: An update, April 2014, page 63.

Recent regressions conducted by SFG Consulting have concluded that the best estimates for the three relevant Fama-French model factors are as follows:

Table 12.4 SFG estimates for Fama French model factors

Fama French factor	Value
Market exposure (%)	6.33
Size exposure (%)	-0.19
Book to market exposure (%)	1.15

Source: SFG Consulting

The attached report fully substantiates these figures.[212]

Risk premium for use in the DDM

SFG Consulting has estimated the risk premium for relevant comparable firms at 94 per cent of the over-all market returns.

12.3.5 Our proposal to separately estimate the required return on equity using each of the relevant models

Using the above parameter estimates, SFG Consulting estimates for the four models using an indicative averaging period spanning the 20 days to 30 January 2015 are detailed in table 12.5.[213]

Table 12.5 SFG Consulting return on equity model estimates

Model	Return on equity (%)	Weight (%)
SL-CAPM	9.32	12.5
Black-CAPM	9.93	25.0
Fama French model	9.93	37.5
DDM	10.32	25.0
Proposed cost of equity	**9.95**	**100.0**

Source: SFG Consulting

On the basis of the above, our proposed return on equity is 9.95 per cent. In the PTRM this is rounded to 9.90 per cent.

12.3.6 If our weighted average of all four models is rejected

It is our position that the approach to establishing the return on equity set out in the Guideline is not consistent with the Rules and is not the best possible estimate of the required rate of return for equity. In particular, we are concerned that the approach set out in the Guideline does not meet the requirements of the new Rules that regard must be had to 'relevant estimation methods, financial models, market data and other evidence'.

212 SFG Consulting, Using the Fama-French model to estimate the required return on equity, February 2015, page 29.
213 SFG Consulting, The Required Return on Equity for Benchmark Efficient Entity, Feb 2015, page 35.

Accordingly, we do not agree with the approach in the Guideline that an estimate for the return on equity in compliance with the Rules can be generated using the SL-CAPM as a 'foundation model'. Nonetheless, SFG Consulting has considered what approach could be made to improve the performance of the SL-CAPM. The attached report sets out those amendments and the key ones are summarised here.

SFG Consulting identified, two significant flaws in the SL-CAPM being that it is downwardly biased for both low beta assets and value assets. SFG Consulting has separately estimated three CAPM equity betas using each of the other models to correct for these biases. The Black-CAPM in particular addresses the issue of the bias for low beta assets, the Fama French Model addresses the issue of the bias for value assets and the DGM uses contemporaneous evidence.

We believe that if the employment of the SL-CAPM as a foundation model is pursued, the correct parameters as identified by SFG are as follows.

Table12.6 SFG Consulting return on equity estimate for SL-CAPM

Parameter	Return on equity
Beta	0.82
Risk free rate (%)	2.64
Market risk premium (%)	8.17
Return on equity (%)	**9.32**

Source: SFG Consulting

12.3.7 Departure from Guidelines: Equity

The Rules require that our proposal identify where we propose departures from Guideline. The following table summarises these:

Table 12.7 Identified departures from Guideline (Equity)

Description	Guideline	Regulatory Proposal	Rationale
Relevant models to consider	SL-CAPM, Black CAPM, Fama French Three Factor model and the Dividend Growth Model.	Adopts the use of these models.	These are relevant models for estimating the required return on equity. (For detailed explanation see section 12.3.1)
Models to be used in setting allowance	SL-CAPM, Black CAPM and the Dividend Growth Model. Fama French model not to be used.	Diverges such that all four models are used.	The Fama French Three Factor Model provides valuable insights and corrects for well-documents biases that the other models do not. (For detailed explanation see section 12.3.1 and 12.3.2)
Regard to financial models	SL CAPM is used as central foundation model and any other model, information and evidence is restricted to a secondary role, at most being used to inform the estimates of SL-CAPM.	All four models should contribute directly to the allowed rate of return for equity as they provide valuable mechanism to correct for the short fallings of using a mechanistic approach that relies only on a particular implementation of SL-CAPM estimates.	There is no correct basis for relying only the AER's Ibbotson inspired implementation of SL-CAPM and for it to constrain the extent to which other evidence and information can be used to affect the computation of the allowed rate of return for equity. (For detailed explanation see under section 12.3.2 – *'The Guideline does not give real weight to all the relevant inputs as required'* and *'The improper search for a pre-eminent model and improper constraints inherent in using foundation model'*)
Implementing the SL-CAPM : beta	The SL-CAPM should be implemented using a beta of 0.7.	The beta should be at least 0.82 using a broader sample of domestic and international firms.	Network businesses face greater systematic risk than the AER assumes. (For detailed explanation see section 12.2) SL-CAPM is downwardly biased for low beta stocks and for sticks with a high book-to-market ratio. The sample of firms used by AER is too small to provide a reliable estimate and the upper end of the range (0.7) is below the upper end of the range (0.8) produced by its own consultant. (For detailed explanation see under section 12.3.2 – *'The flaws in AER's selection of beta'*)

Description	Guideline	Regulatory Proposal	Rationale
Implementing the SL-CAPM : MRP	Estimate a range for the MRP, and then select a point estimate within that range. Range estimated with regard to theoretical and empirical evidence – including historical excess returns, dividend growth model estimates, survey evidence and conditioning variables. Point estimate to be based on regulatory judgement, taking into account the strengths and weakness of the evidence.	The MRP should be estimated using both Ibbotson and Wright approaches. When implementing the Ibbotson approach, the MRP should be the arithmetic average for the longest available series. The appropriate role for the DGM is as a model to be employed directly in delivering an estimate for the return on equity rather than as an input to estimating the MRP for the SL-CAPM.	The Ibbotson and Wright approaches for estimating MRP are based on the same historical data but different methodologies return different results and as such regard should be given to both. When seeking to employ the Ibbotson approach, the AER identifies a historic MRP range of 5.1% to 6.5%. The low end of this range is flawed as it relies on an incorrectly adjusted yield series and irrelevant geometric averages. (For detailed explanation see under section 12.3.2 – *'Flawed selection of the Ibbotson inspired AER approach to implementing the SL-CAPM as the foundation model'* and *'The flaws in AER's implementation of Ibbotson approach to measuring the historical MRP for use in the SL-CAPM'*)

Source: Powercor

12.4 Return on debt

The relevant aspects of establishing an allowed rate of return for debt are as follows:

- establish the tenor of the benchmark debt;
- establish a credit rating for the benchmark business;
- establish whether it is ultimately preferable to set the benchmark on the basis of the 'on the day' method, the trailing average method or a combination;
- decide whether to undertake annual updating or set a single benchmark each regulatory determination with a 'look back' if a trailing average is to be used;
- determine whether and what transition should apply;
- identify a data source;
- select averaging periods; and
- assess debt transaction costs and the cost of the new issue premium.

Each of these aspects is discussed below.

12.4.1 Tenor of the benchmark debt instrument

The Guideline adopts a term to maturity of ten years for the debt portfolio of the benchmark efficient firm based on a review by the AER of actual debt portfolios of comparable businesses. The AER has concluded that the benchmark entity's debt portfolio minimises refinancing risk by comprising long dated bonds to match the long run nature of network capital investments.

We support the position in the Guideline.

12.4.2 Benchmark credit rating

The Guideline considers that the benchmark credit rating should be BBB+. Further, the AER has rejected CEG's position with respect to the appropriate credit rating for a benchmark efficient firm it its NSW gas and electricity distribution decisions.[214] CEG found that each year from 2009 to 2013, the median credit rating of energy network service providers was BBB, amid a clear trend of downgrades in the industry.

However, the AER contends that in 2013, the median was actually BBB+ and based on only a partial 2014 data set, predicted the median in the projected full year to be BBB+. The information before the AER clearly provides sufficient weight to warrant a departure from the Guideline and a reduction in the median credit rating relied on.

In relation to the comparator group used to determine the median credit rating, while the AER has deleted Ergon Energy Corp Ltd from its comparator group on the basis that its credit rating is obviously influenced by government ownership, the AER has taken the view that its comparator set should include both AusNet Services and SGSP Australia Assets Pty Ltd, even though clear evidence exists that Singaporean Government ownership in these businesses has significant effect on the consideration of their credit ratings by credit rating agencies. For example both companies were placed on negative watch when the Singapore Government diluted its ownership in 2013.

The AER has also taken the view that even if it were to consider Singapore Government ownership in AusNet Service and SGSP, some time has passed since the dilution of Singapore Government ownership (which is evidence of the effect of the ownership on the rating), and it therefore considers that credit rating agencies have had time to revise their credit ratings.[215] This statement seems to misunderstand the issue that the continuing effect of Singapore Government ownership is to provide greater comfort to credit rating agencies as to key issues relevant to their consideration of the appropriate credit rating, such that the credit rating applied to these companies is not one that would be applied to a pure play, regulated energy network business operating within Australia (which is defined as the benchmark efficient entity in the Guideline). Evidence of dilution of government ownership having a negative effect on a credit rating agency's views of the risk of a downgrade in a credit rating supports this proposition.

Further the AER appears to take comfort in the fact that the credit rating of SGSP has changed since the dilution to assert that government ownership has not been sufficient to maintain an A- credit rating.[216] The issue however is that government ownership has maintained the credit rating at a higher level that it would otherwise been over this period, and therefore the credit rating of this business is not reflective of the credit rating of an efficient private service provider which is the standard that informs the definition of a benchmark efficient firm.

We consider that the AER should review the appropriate criteria for businesses to be included in its comparator set and remove those businesses who do not reflect the risk profile of a benchmark efficient firm due to

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214 AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296]; and AER, Attachment 3 Rate of Return – Essential Energy 2014-19, [3-315].

215 AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296].

216 AER, Attachment 3 Rate of Return - Jemena Gas Networks 2015-20, [3-296].

government ownership (full or partial) or other relevant factors such as implicit support from parent companies which improves subsidiary individual credit ratings.

12.4.3 Trailing average portfolio approach

The trailing average portfolio approach recognises that in practice a firm's actual cost of debt will be determined by historical rates. In addition, it recognises that energy networks do not raise all their capital at one time and instead have staggered debt maturities. In practice, network businesses need to balance a number of considerations when determining how much debt to refinance at what times, including:

- diversification of debt instruments and maturities;
- liquidity management;
- changes in the aggregate capital required as new investments are made contributing to a growth in the Regulatory Asset Base and as aging assets are depreciated;
- credit metrics; and
- market conditions, including access to foreign and domestic markets and the ability to hedge interest rate movements.

For this reason, firms will have different amounts of debt maturing at different points in time. It is not the case as the AER, has asserted in NSW draft decision, that a benchmark efficient entity would hold an evenly staggered portfolio of long-term (10 year) debt where exactly 10 per cent of the debt is refinanced each year.[217] Due to the considerations set out above, a benchmark efficient entity would make decisions as to the amount of debt to be refinanced in any given year to minimise its debt financing costs and these amounts may vary each year.

Nevertheless, the trailing average portfolio approach is likely to more closely align with the staggered approach to refinancing a debt portfolio than the 'on the day' method, noting that the trailing average method is a substantial simplification of what actually occurs. The trailing average portfolio approach significantly reduces the risk that prices for customers on a given network might be higher or lower than the average interest rate over time simply because the 'on the day' rate for their particular service provider occurred at a high or low point in interest rate movements.

We therefore accept the ten year trailing average portfolio approach set out in the Guideline.

12.4.4 Annual updating

At one stage during the Guideline consultation process, the possibility of a 'true up' at the conclusion of the regulatory control period was canvassed as a possibility rather than annual updating. We consider that annual updating is an important feature of moving to a trailing average approach because otherwise the two principle advantages of the trailing average would not be fully obtained (i.e. more closely matching the regulatory allowance to a portfolio of progressively refinanced debt and delivering customer prices that more closely track the evolution of market interest rates).

12.4.5 Transitional arrangements

The Guideline proposes to apply transitional arrangements in respect of the return on debt based on the QTC method. We do not consider the transition in the Guidelines complies with the Rules. The rationale for a transition articulated in the AER's Guideline was that it would reflect the 'transition' in the regulated benchmark efficient entity's efficient debt management strategies from those adopted under the 'on the day' approach to

[217] AER, Draft Decision, Essential Energy 2015-19 - Overview, page 43.

those adopted under the trailing average approach and, thus, eliminate the mismatch between the actual and allowed return on debt. As the AER now concedes, this rationale does not apply to the debt risk premium component of the return on debt because the benchmark efficient entity could not have entered into hedging arrangements for the debt risk premium under the previous 'on the day' approach to estimating the return on debt.

To the contrary, in circumstances where the AER has determined that the benchmark efficient entity would hold a debt portfolio with staggered maturity dates (a trailing average debt risk premium), there is no legal basis for applying a transition to the debt risk premium component of the return on debt. On the AER's own statutory construction of the allowed rate of return objective, the requirement in Rule 6.5.2(h) to determine a return on debt commensurate with the efficient debt financing costs of the benchmark efficient entity renders it legally impermissible to the transition the debt risk premium component of the return on debt.

Further, the reasons now advanced by the AER in support of its transition on the debt risk premium component of the return on debt do not justify its approach and similarly involve errors of law.

Rather than adopting the transition proposed in the Guideline, we consider that there should be:

- a ten year transition to the trailing average estimation of the risk free rate component of the return on debt; but
- no transition for the debt margin (or debt risk premium) component of the return on debt. That is, the AER should immediately move to a trailing average estimation of the debt risk premium component.

Rule Requirement

We consider that under the new Rules, estimating a return on debt that contributes to the allowed rate of return objective is paramount and the primacy of the allowed rate of return objective extends to the AER's decision as to whether to apply a transitional arrangement in estimating the return on debt. This was expressly acknowledged by the AER in the course of developing its Guideline. The AER stated: [218]

> *We consider that the key objective of the transitional arrangements is to estimate the return on debt so that it contributes to the achievement of the allowed rate of return objective.*

While the factors in Rule 6.5.2(k) provides guidance to the AER in estimating the return on debt, it does not override or alter the requirement under the Rules to the estimate a return on debt such that it contributes to the allowed rate of return objective. As noted by the AEMC in discussing the relationship between objectives and factors in introducing the current Rules:[219]

> *The objective, where one exists, should indicate to the regulator how the factors should influence its decision. The regulator should not assume that it may consider the factors (or other relevant provisions) and that this will of itself mean that the objective has been achieved. The overriding consideration for the regulator is the objective.*

AER's rationale for its proposed transition

In the context of the return on debt, the AER construes (expressly or implicitly) the allowed rate of return objective as follows:

- first, it ascribes to the 'benchmark efficient entity' referred to in the allowed rate of return objective the characteristic of being regulated; and

218 AER, Rate of Return Guideline, Explanatory Statement, December 2013, page 124.

219 AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, page 19.

- secondly, as the benchmark efficient entity is a regulated energy business, it concludes that it follows that the debt financing practices of relevance to the allowed rate of return objective are those of a regulated energy business and thus, fall to be considered against the background of the regulatory regime and, in particular, the AER's adopted approach to the estimation of the return on debt.[220]

On the basis of this approach to the statutory construction of the allowed rate of return objective the AER concludes that 'the efficient financing costs of a benchmark efficient entity' are the financing costs resulting from the benchmark efficient entity minimising the expected present value of its financing costs over the life of its assets, taking into account the regulatory framework and the associated financial risks it faces and expects to face in the future.[221] These risks are identified by the AER to be:[222]

- refinancing risk (i.e. the risk that a firm would not be able to efficiently finance its debt at a given point in time); and
- the interest rate risk of a regulated entity, that is the risk of a mismatch between the regulatory return on debt allowance and its actual return on debt.

Put another way, the AER construes the term 'efficient financing costs' in the allowed rate of return objective to mean the financing costs incurred by the benchmark efficient entity, which it has defined to be a regulated entity, as a result of debt financing practices adopted in response to the regulatory method of estimating the regulated return on debt, so as to minimise the expected present value of its financing costs over the life of its assets while managing refinancing risk and interest rate risk.

It is on this basis the AER's statutory construction of the allowed rate of return objective outlined above that the AER determines that the establishment of a transitional arrangement in respect of the move from the 'on the day' approach to the trailing average portfolio approach is required if the return on debt is to contribute to the achievement of the allowed rate of return objective.[223]

The AER considers that:[224]

- under the 'on the day' approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates and use swaps to hedge interest rate exposure for the duration of a regulatory control period;
- under the trailing average approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt; and
- in moving from the 'on the day' to the trailing average approach to estimating the return on debt, a transition is necessary as the benchmark efficient entity would need to unwind its hedging contracts entered into under the 'on the day' approach.

In this manner, the AER statutory construction of the allowed rate of return objective as requiring a consideration of the debt financing practices adopted, and resultant costs incurred, by a regulated entity in response to the regulatory method of estimating the return on debt, provides the legal foundation for the establishment of transitional arrangements for the return on debt.

In support of its decision to include transitional arrangements for the return on debt allowance in the Guideline, the AER cited the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt set according to the trailing average portfolio approach that would otherwise arise in

[220] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 102-103.
[221] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 103; AER, Ausgrid Draft Determination [3-105].
[222] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 104; AER, Ausgrid Draft Determination [3-105].
[223] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121-122; AER, Ausgrid Draft Determination [3-112] and [3-113].
[224] AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121

the absence of transition.[225] The AER also cited the disruptive effect of unexpected and immediate changes in approach to setting regulatory allowances for businesses and consumers, issues with availability of historical data and the potential for opportunistic switching between approaches to the return on debt calculation.[226]

Subsequent to finalising its Guideline, however, the AER changed its reasoning for a transition on the debt risk premium component of the return on debt. The AER indicates in recent NSW draft determinations that the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt is relevant only in respect of a transition on the risk free rate component of the return on debt (and not the debt risk premium component as this could not have been hedged).[227]

The AER maintained that a transition arrangement was nonetheless desirable for debt risk premium component of the return on debt because a transition:[228]

- avoids potential windfall gains and losses to service providers or consumers from changing the regulatory regime;
- avoids practical problems with the use of historical data;
- maintains the same average price level while decreasing price volatility over time; and
- reduces the potential for opportunistic behaviour from stakeholders.

The reasons why the AER's proposed transition does not meet the requirements of the Rules, and why the reasoning of the AER in applying its proposed transition is otherwise flawed, are discussed below.

AER's proposed transition does not comply with the Rules requirements

As a consequence of its construction of the allowed rate of return objective, as discussed above, the AER considers the transition required for the return on debt by comparing the efficient debt management practices of the benchmark entity subject to regulation by the AER under the previous Rules and the efficient debt management practices of the benchmark entity subject to regulation under the new Rules.[229] As noted, the AER considers that:

- under the 'on the day' approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to hedge interest rate exposure for the duration of a regulatory control period; and
- under the trailing average approach, a benchmark efficient entity would hold a debt portfolio with staggered maturity dates to align its return on debt with the regulatory return on debt.

This construction may not be necessarily correct.[230] However, if it is accepted that the AER's construction of the allowed rate of return objective is correct, in applying a transition, the AER is required by Rule 6.5.2(h) to estimate the costs (efficiently incurred) of an entity moving from the first financing strategy identified above to the second in the 2016-2020 regulatory control period.

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225 AER, Explanatory Statement Rate of Return Guideline, December 2013, page 121-122

226 AER, Explanatory Statement Rate of Return Guideline, December 2013, page 122-123

227 AER, Ausgrid Draft Determination [3-112], [3-113]. The issue was highlighted by AER's own consultant Associate Professor Lally, Capital Financial Consultants Ltd., Transitional Arrangements for the Cost of Debt, November 2014 (Lally Transition Report), Page 7.

228 AER, Ausgrid Draft Determination [3-115], [3-118]

229 The AER highlights, for example, that its 'benchmark approach to transitional arrangements' is consistent with the definition of a single benchmark entity for the purposes of estimating the cost of debt: AER, Ausgrid Draft Determination [3-124].

230 AEMC, Final Position Paper, National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012; National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012, November 2012, Page 57 states that "In its draft rule determination, the Commission considered that the long-term interests of consumers would be best served by ensuring that the methodology used to estimate the return on debt reflects, to the extent possible, the efficient financing and risk management practices that might be expected **in the absence of regulation**".

The AER's objective at the time the Guideline was published was to address the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt allowance. The AER has correctly identified that its reasoning by reference to the allowed rate of return objective offers a potential justification only in respect of the risk free rate component of the return on debt and not debt risk premium. As the debt risk premium could not have been hedged, the efficient debt management strategy of the benchmark efficient entity under the 'on the day' approach involved only hedging of the interest rate exposure for the duration of the regulatory control period.

Rather than addressing a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance, applying a transition to the debt risk premium (as the AER's proposed transition does) creates a mismatch. This is contrary to AER's own objective at the time of Guideline, the AEMC's intention in amending the cost of debt provisions and the allowed rate of return objective.

In circumstances where the AER has determined that the benchmark efficient entity would hold a debt portfolio with staggered maturity dates (a trailing average debt risk premium), there is no legal basis for applying a transition to the debt risk premium component of the cost of debt. To the contrary, on the AER's own statutory construction of the allowed rate of return objective, the requirement in Rule 6.5.2(h) to determine a return on debt commensurate with the efficient debt financing costs of the benchmark efficient entity renders it legally impermissible to transition the debt risk premium component of the return on debt.

The AER also considers that a transition regime to bring to account differences between the return on debt allowance and the actual return on debt mitigates the potential windfall gains or losses to service providers or consumers with respect to the debt risk premium. The AER relies on a report by Associate Professor Lally wherein he raises the mitigation of windfall gains as an argument in support of transitional arrangements. We believe that AER's reasoning (and that of Associate Professor Lally) involves a fundamental misunderstanding of the allowed rate of return objective.

The rate of return objective necessarily requires a forward looking approach.[231] It is concerned with the required rate of return for the 2016-2020 regulatory control period. The proposed transition is intended to, and in fact would, result in a rate of return that is less than the efficient financing costs of a benchmark efficient entity for the 2016-2020 regulatory control period. This is patently contrary to the rate of return objective and the NEO (being to promote the efficient investment in, and efficient operation and use of electricity services for the long term interests of consumers of electricity).

Both CEG and SFG Consulting similarly understand the rate of return objective as being prospective in nature.[232] CEG observes that, on the AER's own terms, its transition creates a prospective mismatch between the allowed and actual debt risk premium of a benchmark efficient entity. SFG Consulting also describes the problems with the AER's approach of setting inefficient prices for individual regulatory periods on the basis they might average out over the life of the asset.

It follows that the AER's approach is contrary to the revenue and pricing principles in Section 7A of NEL. Those principles include (among other things) that their service provider must be provided with a reasonable opportunity to recover at least its efficient costs, that a price or charge for the provision of services should allow for a return commensurate with the regulatory and commercial risks involved in providing the services and that regard should be had to the economic costs and risks of providing the services and that regard should be had to

[231] Under the building block approach, the only circumstances in which matters arising in prior regulatory control periods are relevant is if those matters affect three specified inputs to the building blocks: the value of the regulatory asset base (clause 6.5.1(e)); revenue increments and decrements arising from the application of relevant incentive schemes (clause 6.4.3(a)); and revenue increments or decrements arising from the application of a control mechanism in the previous period (clause 6.4.3(a)(6)).

[232] CEG, Critique of the AER's JGN draft decision on cost of debt, April 2015; SFG Consulting, Return on debt transition arrangements under the NGR and NER, February 2015.

the economic costs and risks of the potential for under and over investment by a service provider. Further, clawing back past gains creates regulatory risk and uncertainty, resulting in investors requiring higher returns as compensation in future.[233]

It is also important to note that if it was intended that any new approach to estimating the return on debt implemented by the AER under the new Rules be delayed or staggered, the AEMC would have expressly provided for this in savings and transitional provisions in Chapter 11 of the Rules. The AEMC did not do so. Rather, the AEMC responded to concerns in relation to transition by requiring that any significant costs and practical difficulties in moving from one approach to another to be a matter to which AER has regard to in estimating the return on debt.

On the issue of practical problems with the use of historical data, CEG observes the following:

- regulators (including the ACCC/AER) have been estimating the return on debt over the entire period and all of the relevant data that was available then is available now;
- while there may be differences in the available historical data series, the same will almost certainly be true prospectively. The AER has proposed to deal with this by giving equal weight to the currently available third party estimate and the same method could be easily be applied historically; and
- any variation in data sources is likely to be exacerbated by the AER's proposed transition. Whereas the AER's transition gives 100% weight to yields estimated during the initial short, averaging period and this estimate dominates the AER return on debt estimate over the transition (it still has 60 per cent weight in the last year of the next regulatory period), estimating a trailing average return on debt over the last ten years results in less than 1 per cent weight being given to each available month.

SFG Consulting similarly maintains that the AER's concerns about the availability of historical data are overstated and observes that the availability of data should not drive regulatory practice. In circumstances where the AER has determined that the regulatory allowances under the trailing average approach to estimating the return on debt is commensurate with the efficient financing costs of the benchmark efficient entity, and there is a robust means of calculating it, complexity in the estimation of that return using historical data is not a basis for determining to apply a transition.

Finally, as CEG outlines, the AER's proposed transition does not, in any event, address any incentives for opportunistic behaviour. Rather in proposing a transition that is divorced from the benchmark efficient entity's debt management practices, the AER is creating a framework where the opportunistic behaviour it is concerned about can exist.

12.4.6 Estimation procedure

Our approach

As mentioned above, the AER has indicated in its recent NSW draft determinations that the mismatch between the expected return on debt of the benchmark efficient entity and the regulatory return on debt is relevant only in respect of a transition on the risk free rate component of the return on debt (and not the debt risk premium component as this could not have been hedged). Given this, it would not be correct for the AER to adopt the transition approach described in the Guideline.

Applying a transition to the debt risk premium (as the AER's Guideline transition does) would create a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance. Therefore, for our Regulatory Proposal, we propose to adopt the transition from the hybrid approach to the

233 SFG Consulting, Return on debt transition arrangements under the NGR and NER, February 2015.

trailing average approach which is consistent with CEG's advice.[234] Under this approach the return on debt is set equal to the sum of:

- trailing average debt risk premium (measured relative to swap rate);
- average of swaps rates utilised in the unwinding of the business's swap portfolio; and
- the cost of swap transactions required to effect the transition and any new issue premium;

Consistent with this, the return on debt for the regulatory year 2016 for our Regulatory Proposal is estimated as the sum of:

- the ten year trailing average of ten year debt risk premium measured relative to swap rate over the period 2006-2015;
- the average of 1-10 year swap rates over the nominated averaging period; and
- the costs of swap transactions required to effect the transition.

This reflects the fact that if the hybrid debt management strategy is the assumed starting point then it is possible to define a transition from this starting point to the trailing average debt management strategy. It also highlights that maintaining a swap portfolio will lead to transaction costs.

Source of data

The Guideline did not express a definitive proposal as to the source of the data for the benchmark return on debt and as such it is not a matter of accepting the guideline or proposing a departure. The AER has noted that the use of independent third party estimates may be less controversial where the published source is already available and not explicitly constructed for the regulatory process.

There are currently two principal options for independently published BBB yield estimates under consideration. Namely, the Bloomberg BBB BVAL curve and the RBA published aggregate measure of ten year Australian BBB corporate debt.[235]

The RBA measure of the return on debt is a month end measure. The AER's approach (as most recently seen in the NSW draft determinations) has been to interpolate the end of month results for the RBA measure of the return on debt. For our Regulatory Proposal we accept this approach.

Although neither curve publishes an estimate for ten year debt, the Bloomberg service produces a 7 year fair value estimate, and the RBA's publication provides a fair value estimate for a 'target tenor' of ten years but, because most bonds in its sample are less than ten years, this is generally associated with a published 'effective tenor' of less than ten years. Extrapolation can be used to arrive at a ten year figure for both published yield estimates.

In the recent NSW draft determinations, the AER proposed a new method for extrapolating the RBA and BVAL curve to ten years target tenor. CEG reviewed AER's methodology and the extrapolation methodology proposed by SAPN in the context of its Regulatory Proposal to the AER. Based on its analysis, CEG concluded that over the period from 2 January 2015 to 30 January 2015, the SAPN method provides a better fit to the available data. However, CEG considered that the AER draft decision extrapolation methodology provides a better fit to data over the 9 years from 2006 to 2014.

In light of CEG's analysis, we consider that it may not be appropriate to lock in the AER's extrapolation method for all averaging periods. Instead it may be more appropriate to perform the test for the goodness of fit for both

[234] CEG, Critique of the AER's JGN draft decision on the cost of debt, April 2015.
[235] RBA, Aggregate Measures of Australian Corporate Bond Spreads and Yields - F3.

the methodologies for each averaging period especially when the results from the two methodologies are materially different.

The SAPN extrapolation formula is as follows:

For each service provider the average slope of the DRP with respect to changes in maturity at each point on the published yield curve at or above 1 year maturity is estimated as the slope coefficient using ordinary least squares (OLS) regression on observations of fair value DRP against maturity with an intercept term. That is, the formula below:

Average slope = $\frac{\sum_{i=1}^{n}(\mathrm{DRP}_i-\overline{\mathrm{DRP}})(\mathrm{M}_i-\overline{\mathrm{M}})}{\sum_{i=1}^{n}(\mathrm{M}_i-\overline{\mathrm{M}})^2}$; where

$\mathrm{DRP_i}$ = published yield at maturity of 'i' years less the swap rate at maturity 'i' based on data published by the relevant service provider;

$\overline{\mathrm{DRP}}$ = the mean of all $\mathrm{DRP_i}$ for 'i' greater than or equal to 1;

$\mathrm{M_i}$ = is the maturity of 'i' years associated with $\mathrm{DRP_i}$ (in the context of the RBA publication this is effective maturity);

$\overline{\mathrm{M}}$ = the mean of all $\mathrm{M_i}$ for 'i' greater than or equal to 1;

n = the number of observations of fair value DRPs with maturity greater than or equal to 1.

The extrapolated DRP at ten years is given by:

$\mathrm{DRP_{10}} = \mathrm{DRP_{i_{max}}}$ + (Average slope)×(10 - $\mathrm{i_{max}}$)

Where $\mathrm{i_{max}}$ is the longest maturity associated with a published yield.

The extrapolated yield at ten years is given by:

Extrapolated yield = ten year swap rate + $\mathrm{DRP_{10}}$

The RBA publishes the DRP to swap at each maturity and the yield at each maturity, so the implied swap rate at each maturity to be used for RBA data can be calculated as:

$\mathrm{Swap_i} = \mathrm{Yield_i} - \mathrm{DRP_i}$

Our Regulatory Proposal gives a 50 per cent weighting to each of the Bloomberg BBB BVAL and RBA published series each extrapolated out to a ten year tenor which is consistent with the AER's approach in the recent NSW draft determinations.

12.4.7 Averaging period

Accompanying this Regulatory Proposal and forming part of it is a confidential letter to the AER that details our proposal with respect to the averaging periods for each regulatory year of the regulatory control period. In this confidential letter we propose the averaging period nominated for the regulatory year 2016.[236]

The Guideline proposes, that for each regulatory year in the regulatory control period, the averaging period should be specified prior to the commencement of each regulatory year in a regulatory control period. The Guideline, is however, not binding on the AER or us and, accordingly, the AER is required to assess that proposal by direct reference to the requirements of the Rules, including in particular the requirement established by

[236] Powercor, Letter proposing return on debt averaging periods (confidential version), 29 April 2016.

clause 6.5.2(h) to estimate the return on debt for a regulatory year such that it contributes to the achievement of the allowed rate of return objective specified in clause 6.5.2(c), rather than by reference to the conditions for debt averaging periods set out in the Guideline.[237]

We do not agree with the AER that the specification of debt averaging periods prior to the commencement of the regulatory control period contributes to the achievement of the rate of return objective or that this is required by the Rules. For each of the second and subsequent regulatory years of the regulatory control period we propose an approach whereby we could nominate and the AER could approve the averaging period for use in calculating the annual rate of return on debt for that regulatory year in accordance with the process set out below:

1. We would notify the AER in writing of our nominated averaging period for use in determining the annual return on debt for regulatory year 't' (where regulatory year t is 2017, 2018, 2019 or 2020) by no later than 31 July in regulatory year t-2.
2. The nominated averaging period notified by us in accordance with [1] must:
   - be a period of at least ten consecutive business days;
   - fall entirely within the period 1 September in regulatory year t-2 to 31 August in regulatory year t-1; and
   - not overlap with the nominated and agreed averaging period for use in any other regulatory year.
3. If we fail to notify the AER of our nominated averaging period for use in determining the annual return on debt for regulatory year t within the time specified in [1] above, the agreed averaging period is taken to be that mentioned in the confidential letter.
4. The AER must notify us in writing within 20 business days after receiving notice from us of a nominated averaging period under [1] of its decision as to whether it agrees to the nominated averaging period.
5. The AER must not withhold agreement to the nominated averaging period unless the nominated averaging period does not comply with [2] above.
6. If the AER withholds agreement to the nominated averaging period in accordance with [4] and [5] above, the agreed averaging period is taken to be as that mentioned in the confidential letter.
7. If the AER fails to notify us of its decision within the time period specified in [4] above, the AER is taken to have agreed to the nominated averaging period.

This process implies that the averaging period used to calculate the annual return on debt for the 2017 regulatory year must be nominated by 31 July 2015 and fall entirely within the period 1 September 2015 to 31 August 2016 inclusive. That is we will nominate an averaging period for use in determining the annual return on debt for 2017 regulatory year that complies with this process by 31 July 2015. We will ensure that the averaging period for 2017 does not occur before or overlap with the averaging period for 2016.

The reason for proposing a departure from the Guideline is that the averaging period proposal in respect of the second and subsequent regulatory years will better promote efficient debt management practices without harming consumers. Specifically, the nomination of debt averaging period closer in time to debt raising better

[237] We observe that, insofar as the AER proceeds as suggested in its letter to Jones Day dated 16 March 2015 concerning averaging periods for the regulatory control period commencing 1 January 2016, in stating at Page 2, that 'we will assess the averaging periods the businesses propose against the conditions for debt averaging periods the AER proposed in the rate of return guideline(Guideline)' the AER will fall into legal error, in that this would involve a substitution of conditions of the AER's own devising for the statutory criteria and consideration of relevance. The AER is instead required to assess our debt averaging period proposal directly against those statutory criteria and considerations.

aligns the debt averaging period with the period over which we, or the benchmark efficient entity in our circumstances, would raise debt based on expected debt management practices in response to:

- market conditions, including changes in market sentiment and the products available for efficient debt management; and
- the debt refinancing and new issue requirements of that entity, including as a consequence of changes in capital expenditure needs or early refinancing requirements set by rating agencies such as Standard and Poor's (**S&P**).[238]

The purpose of providing service providers with an opportunity to nominate future averaging periods is to enable them to align their actual debt costs with the return on debt allowance. Whereas under the AER's previous regulatory approach to estimating the return on debt the time that elapsed between the nomination and occurrence of the debt averaging period was at most one year, a requirement to specify debt averaging periods prior to the regulatory control period where annual updating of the return on debt is to occur means this interval may now be up to five years.

There is considerable uncertainty around when refinancing will need to occur. Although the maturity of existing debt is known now, the exact timing of refinancing is subject to market conditions around the time of maturity and requirements of rating agencies. While S&P and other credit rating agencies typically require debt to be refinanced at least three months before it matures (for maintenance of an investment grade credit rating), the timing of refinancing typically occurs between three and six months prior to maturity depending on market conditions, specifically market interest in the purchase of longer term debt, that are difficult to predict.

By providing for the fixing of debt averaging periods for later years closer to the time of debt raising when these market conditions are better known, our averaging period proposal renders it more likely that those averaging periods will align with the period over which we or the benchmark efficient entity in our circumstances would raise debt. This, in turn, contributes to the estimation of a return on debt that achieves the allowed rate of return objective as required by clause 6.5.2(h) of the Rules, in that it delivers a return on debt that better reflects the efficient debt financing costs of the benchmark efficient entity.

Our averaging period proposal in respect of the second and subsequent regulatory years delivers the above benefits without giving rise to any harm for consumers of electricity. It is also important to note that by reducing the time that will elapse between the nomination and occurrence of the averaging period for use in calculating the annual return on debt for the second and subsequent regulatory years, our averaging period proposal in respect of those years reduces the risk of those averaging periods becoming known to third parties to our commercial detriment, in issuing debt and entering hedge transactions.

Our averaging period proposal therefore contributes to the achievement of the allowed rate of return objective and NEO, to a greater degree than nomination and agreement of all debt averaging periods prior to commencement of the regulatory control period. It follows that the AER is required by clause 6.5.2(h) of the Rules and section 16(1)(a) and (d) of the NEL, to accept our proposal.

12.4.8 Automatic application

Once the averaging period is nominated and approved as per the process set out above, the calculation of the annual return on debt is mechanistic and occurs in accordance with the annual debt updating process proposed in Appendix I of our Regulatory Proposal on annual updating process and formula and the resultant change to the annual revenue requirement is effected through the automatic application of the formula specified in Appendix I.

[238] Incenta, Debt raising costs, April 2015

Whereas the AER's recent draft determinations for the ACT electricity distributor ActewAGL Distribution and the NSW gas distributor JGN, contemplate the establishment of an additional annual process for the AER calculation of the updated annual rate of return, annual revenue requirement and X factor for the later years of the period, we explain in Appendix I that these calculations can be included in the annual pricing proposal for the second and subsequent regulatory years. The AER will be able to assess these for compliance with any applicable requirements embodied in the distribution determination and remedy a non-compliance in approving that pricing proposal under clause 6.18.8 of the Rules. This proposed approach renders a discrete, additional annual return on debt update process unnecessary.

12.4.9 New issue premium

The proposed sources of debt data (i.e. the RBA and Bloomberg series) are observations of the secondary debt market – that is the market in which debt issued in the past, but which has not yet reached maturity, is sold from one bond holder to another. Alternatives to the RBA and Bloomberg series were identified in the AEMC Rule change and AER Guideline processes but these sources are also derived from the secondary market.

By contrast, when network businesses raise debt, it is by issuing new bonds to bond holders. This is known as the primary market. There are a number of differences between the primary and secondary bond markets. For example, the quantum of debt that is the subject of an issue is much greater than the later secondary trade in bonds with only a small proportion (if any) re-traded each business day.

The difference between the costs facing a business issuing bonds into the primary debt market and trading in the secondary debt market is commonly referred to as the 'new issue premium'. It is accepted that this premium is, on average, positive - due to reasons identified in the literature such as market imperfections or underwriters pricing policies.

CEG has prepared a report detailing its views on the extent of the new issue premium.[239] The new issue premium is measured as the change in yields from issue relative to changes in yields of a bond market index. Both the Bloomberg BBB BVAL fair value curve and the RBA BBB fair value curve are calculated based on Bloomberg indicative yields.

CEG's report notes that economic logic suggests that compensation for the cost of debt should be based on the cost of issuing debt into primary (issuance) markets. This is because this is the market which determines the actual yield paid by an issuer on debt raised. Further, these costs are consistent with the allowed rate of return objective.

CEG finds that the best estimate of the new issue premium that is relevant to a benchmark debt management strategy of issuing ten year BBB rated debt is 27 basis points.[240] We will continue to assess whether CEG's recent quantification of the new issue premium is appropriate, but for the purposes of our Regulatory Proposal have set the value to zero. Our return on debt estimate is therefore conservative.

12.4.10 Transaction costs

In order to account for the efficient financing costs a benchmark efficient entity in our circumstances would incur in maintaining a swap portfolio, it is necessary to take into account the transaction costs of entering swap contracts in the return on debt estimate. CEG considered two recent expert reports (UBS and Evans and Peck) on the expected cost of entering swap contracts.[241] Based on CEG's report we adopt an estimate of swap transaction costs of 23 basis points to be included in our return on debt estimate.

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[239] CEG, New Issue Premium, 2014.
[240] CEG, New Issue Premium, 2014, page 54.
[241] CEG, Critique of the AER's JGN draft decision on the cost of debt, April 2015.

12.4.11 Departure from Guidelines: Debt

The Rules require that our proposal identify where we propose departures from Guideline. The following table summarises these:

Table 12.8 Identified departures from Guideline (Debt)

Description	Guideline	Regulatory Proposal	Rationale
Credit Rating	BBB+	BBB	The AER should remove those businesses who do not reflect the risk profile of a benchmark efficient firm due to government ownership (full or partial). (For further detail, see section 12.4.2).
Transition	Transition provided in the guideline includes transition on both risk free rate and debt risk premium components of return on debt.	Transition only on risk free rate component of the return on debt and no transition on debt risk premium component.	Applying a transition to the debt risk premium would create a mismatch between the expected debt risk premium component of the return on debt and the regulatory allowance. This is contrary to AER's own objective at the time of Guideline, the AEMC's intention in amending the cost of debt provisions and the allowed rate of return objective. (For detailed explanation see section 12.4.5).
Averaging period nomination	The averaging periods for all regulatory years with the regulatory control period must be specified prior to commencement of the regulatory control period.	We propose an approach whereby we could nominate and the AER could approve the averaging period for use in calculating the annual rate of return on debt for that regulatory year in accordance with the process set out in this Regulatory Proposal.	The nomination of debt averaging period closer in time to debt raising better aligns the debt averaging period with the period over which we, or the benchmark efficient entity in our circumstances, would raise debt based on expected debt management practices in response to market conditions and debt refinancing requirements. (For further detail, see section 12.4.7).

Description	Guideline	Regulatory Proposal	Rationale
New Issue Premium and Transaction costs associated with entering swap contracts	No provision made for these costs.	23 basis points for hedging related transaction costs and acknowledgement of existence of new issue premium (without including the cost of new issue premium in our return on debt estimate).	These reflect the efficient costs incurred by a benchmark efficient firm raising debt in primary markets. (For detailed explanation see section 12.4.9).

Source: Powercor

12.5 Expected inflation

At this stage, we do not oppose the AER's current approach to determining the expected rate of inflation. However, we note that very recently in Australia and globally, expectations concerning inflation appear to be volatile and it may be that the best method for estimating inflation may evolve during the period that our revenue proposal is being considered.

Using the AER's method, the relevant inflation rate, in our view, would be 2.60 per cent.

12.6 Conclusion

Using the indicative averaging period spanning the 20 days to 30 January 2015, our proposed allowed rate of return, based on the SFG Consulting approach to apply in each regulatory year of the regulatory period outlined above would be calculated as follows:

Table 12.9 Overall rate of return

Input	Rate
Overall return on equity[242] (%)	9.90
Overall return on debt (%)	5.39
Rate of return (%)	7.20

Source: Powercor

12.7 Gamma

The Rules require an estimate of 'the value of imputation credits' (also referred to as 'gamma') as an input to the calculation of the corporate income tax building block.[243] In order to promote the NEO, the estimate of gamma must reflect the value that equity-holders place on imputation credits (as opposed to simply their face value or utilisation rate).[244] This is because, although gamma is an input into the corporate income tax calculation, the value adopted for gamma ultimately has a role in determining returns for equity-holders. If the value ascribed to imputation credits is higher than the value that equity-holders place on them, the overall return to equity-holders will be less than what is required to promote efficient investment in, and efficient operation and use of, electricity distribution services for the long term interests of consumers.

[242] Rounded in PTRM.
[243] NER, cl. 6.5.3.
[244] NEL, section 8.

The estimation method that we propose to adopt will result in an estimate of gamma that reflects the value equity-holders place on imputation credits. In particular, we propose to calculate gamma in the orthodox manner with the Monkhouse formula, as the product of:

- the distribution rate (i.e. the extent to which imputation credits that are created when companies pay tax, are distributed to investors) using Australian Tax Office data; and
- the value of distributed imputation credits to investors who receive them (theta) based on the value of imputation credits reflected in share price movements (i.e. using dividend drop-off analysis).

We propose the observed distribution rate (0.7), which is consistent with the Guideline and findings of the Australian Competition Tribunal. We propose that the distribution rate be combined with the best estimate of theta from market value studies (0.35) which is a departure from the Guideline. This leads to an estimate for gamma of 0.25. This proposal is consistent with the expert advice from SFG and NERA.[245] We consider that the AER's recent approaches fail to estimate gamma reflecting the value equity-holders place on imputation credit as the AER:[246]

- proposes to revise the definition of theta to exclude the effect of certain factors on the value of imputation credits. We consider that this is conceptually incorrect and inconsistent with the requirements of the Rules;
- the AER incorrectly proposes to use equity ownership rates as direct evidence of the value of distributed credits (theta). In fact, equity ownership rates will only indicate the maximum set of investors who may be eligible to redeem imputation credits and who may therefore place some value on imputation credits. Theta can be no higher than the equity ownership rate and will in fact be lower due to factors which reduce the value of credits distributed to Australian investors;
- has erred in its interpretation of the equity ownership data – the ranges used by the AER for the equity ownership rate are inconsistent with evidence;
- has erred in not recognising that the share prices the AER uses to estimate other rate of return parameters reflect the extent to which investors value (dividends, capital gains and) imputation credits and not the extent to which investors might be able to redeem imputation credits;
- uses redemption rates as direct evidence of the value of distributed credits (theta), when in fact redemption rates are no more than an upper bound (or maximum) for this value;
- has erred in concluding that market value studies can reflect factors, such as differential personal taxes and risk, which are not relevant to the task of measuring theta. Market value studies are direct evidence of the value of imputation credits to investors;
- the AER has erred in its interpretation of market value studies. The AER considered market value studies in a very general manner, rather than considering the merits of the particular market value estimates. This is an irrational and unreasonable approach to considering the evidence put forward in relation to the market value of imputation credits;
- has relied on a higher estimate of the distribution rate for listed equity only. Given that data on the distribution rate is available for all equity, it is neither necessary nor appropriate to separately identify a distribution rate for listed equity only based on a limited sample; and

[245] SFG, Estimating gamma for regulatory purposes, February 2015; NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, March 2015.

[246] AER Draft Determinations of Ausgrid, Directlink, Endeavour Energy, Essential Energy, and Transgrid November 2014.

- reaches an ultimate conclusion as to the value for gamma is inconsistent with evidence, including the AER's own analysis of the equity ownership rate and redemption rate – these measures show that the AER overestimated the value of imputation credits.

The issues raised in relation to gamma are discussed further in appendix J.

Revenue and pricing 13

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13. Revenue and pricing

13.1 Introduction

As shown in this Regulatory Proposal, our investment plan ensures the long term interests of customers and demonstrates a commitment to providing value for money.

This chapter provides a summary of our proposed 2016–2020 annual revenue requirements for standard control services which reflect the efficient costs that we reasonably expect to incur. The building block approach required by the Rules for the calculation of revenue requirements for standard control services has been applied. The AER's post tax revenue model (**PTRM**) has been used to calculate the revenue requirements. We have not departed from the AER's published PTRM. Attached is the model *PAL 2016-20 PTRM*.

The following building block components have been used to calculate the annual revenue requirement for each year of the regulatory control period:

- return on capital for that year, calculated by applying the rate of return with the regulatory asset base (**RAB**) value for that year;
- depreciation for that year;
- forecast operating expenditure for that year;
- the revenue increments or decrements for that year arising from the application of:
  - the Efficiency Benefit Sharing Scheme (**EBSS**) revenue;
  - the S factor true up; and
  - the shared asset revenue reduction.
- the estimated cost of corporate income tax for that year.

13.2 Regulatory asset base

13.2.1 Roll forward of the RAB to 1 January 2016

The estimated value of our RAB for standard control services as at 1 January 2016 is shown in table 13.1. The AER's Roll Forward Model has been used to calculate the 1 January 2016 opening RAB. Refer to the attached model, *PAL 2011-15 RFM*. The attached, *Six-month inflation correction,* sets out why and how the six-month inflation correction has been calculated. Depreciation based on actual capital expenditure has been deducted in accordance with the AER's 2011–2015 Final Determination (**Final Determination**). The RAB has been adjusted for actual inflation, consistently with the method used for the indexation of the control mechanism.

Table 13.1 Roll forward of the RAB to 1 January 2016 ($m, nominal)

RAB roll forward	Total
1 January 2010 opening RAB from previous determination	2,105.0
Add: Correction for six months of inflation	30.4
Add: Difference between actual and estimated capital expenditure in 2010	1,750.1
Add: Actual/estimated net capex for 2011-2015	-21.6
Add: Return on difference between 2010 actual and estimated capital expenditure	-12.4
Less: Actual straight line depreciation for 2011-2015	-850.9
Add: Adjustment for actual inflation	362.4
1 January 2016 opening RAB	**3,362.9**

Source: Powercor

13.2.2 Roll forward of the RAB from 2016 to 2020

The RAB has been rolled forward from 2016 to 2020 in accordance with the Rules using the AER's PTRM, refer to attached model, *PAL 2016–20 PTRM*.

We have separated out two new asset classes from the asset classes used in the Final Determination. These two new asset classes have been separated because they cover assets that will become redundant before 2020, and therefore they need to be separated to ensure they receive the appropriate economic lives. These two asset classes are:

- single wire earth return (**SWER**) and automatic circuit reclosers (**ACRs**) which will be replaced by 2020. We received a Direction from Energy Safe Victoria to replace existing electro-mechanical circuit reclosers with new generation electronic ACRs to SWER lines. The Direction issued on 5 April 2012 required us to ensure that our 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; and
  - the development of a program by 31 August 2012 to ensure that the protection settings and reclose functions can be remotely controlled by our Supervisory Control and Data Acquisition (**SCADA**) system for all SWER ACRs that are unable to be remotely controlled by our SCADA system and SWER fuses downstream from the SWER isolating transformer (excluding distribution substation fuses).

  We submitted our revised BMP, which is attached, to Energy Safe Victoria (**ESV**) in June 2012.

  Refer to the attached model, *PAL SWER ACRs opening asset values*, which sets out the calculation of the depreciated value of SWER ACRs which will be replaced by 2020.

- supervisory cables which will be redundant by January 2016. Urban supervisory networks were designed to carry protection signalling between zone substations. Over the last 20 years with the advent of computerised relays, the communications interfaces on relays have moved to high speed fibre optic interfaces. Along with this, the standard protocols for SCADA communications have moved from low speed analogue to high speed digital communications demanding ethernet based networks. Noise and performance problems means that existing copper supervisory network is at best usable only up to a maximum of approximately 2km.

> Therefore, the old urban supervisory network is totally inadequate for SCADA communications where we now run gigabit ethernet ring topologies and for protection relays that also demand fibre optic interfaces. Given the nature of the shift in technology, the urban supervisory system has no longer any viable use for us.
>
> Refer to the attached model, *Supervisory Cables opening asset value*, which sets out the calculation of depreciated value of supervisory cables which will become redundant.

Depreciation is set out in section 13.3. Table 13.2 shows the roll forward of our RAB over 2016–2020.

There are no actual or forecast disposals for the purposes of clause S6.2.1(e)(6) and there are no forecast disposals for the purposes of clause S6.2.3(c)(3), respectively, of the Rules.

We have estimated inflation in accordance with section 12.5 of this Regulatory Proposal and have estimated the annual inflation figures over the relevant period on the basis that inflation is constant.

The figures of forecast net capital expenditure for the roll forward of the RAB over the 2016-2020 regulatory control period replicate the forecasts of net capital expenditure in table 9.1 of this Regulatory Proposal save for the fact that the figures in table 13.2 are in nominal terms and include a half year's weighted average cost of capital, whilst the figures in table 9.1 are in real terms and do not include a half year's weighted average cost of capital.

Table 13.2 Roll forward of the RAB over 2016-2020 ($m, nominal)

RAB roll forward	2016	2017	2018	2019	2020
Opening RAB	3,362.9	3,696.2	4,041.8	4,393.4	4,733.4
Forecast net capex	421.1	429.6	448.6	450.5	477.1
Depreciation	175.1	180.1	202.2	224.7	247.3
Inflation on opening RAB	87.4	96.1	105.1	114.2	123.1
Closing RAB	**3,696.2**	**4,041.8**	**4,393.4**	**4,733.4**	**5,086.3**

Source: Powercor

13.3 Depreciation

The depreciation of the RAB has been calculated using the straight line depreciation method which divides the opening asset values as at 1 January 2016 by the remaining lives and new assets (i.e. forecast net capex for the 2016–2020 regulatory control period) by the standard lives.

Standard asset lives are equal to standard lives in the current regulatory control period as determined by the AER. The remaining asset lives have been calculated in the attached model, *PAL 2011–15 RFM*. The 1 January 2016 asset remaining lives have been calculated so that the resulting depreciation over the 2016–2020 regulatory control period is equivalent to the depreciation that would have been calculated if it had been calculated from the sum of:

- depreciation of the 1 January 2011 opening RAB value using the remaining asset lives from the last determination; and
- depreciation of each year of capital expenditure over 2011–2015 using the standard asset lives from the last determination.

This approach is materially preferable to the default approach set out in the electricity transmission network service provider roll forward model; refer to appendix K.

The written down value of SWER ACRs which will be replaced over 2016–2020 regulatory control period are fully depreciated in their expected year of replacement. The attached model, *PAL SWER ACRs opening asset value*, sets out the calculation of depreciated value of supervisory cables.

The written down value of supervisory cables which will become redundant by 2016 is fully depreciated in 2016. The attached model, *Supervisory Cables opening asset value*, sets out the calculation of depreciated value of supervisory cables.

Table 13.3 shows our proposed standard and remaining lives.

Table 13.3 Standard and remaining asset lives (years)

Asset	Standard life	Remaining life
Sub-transmission	50.0	32.0
Distribution system assets	51.0	26.5
Standard metering	n/a	0.8
Public lighting	n/a	8.1
SCADA/Network control	13.0	9.5
Non-network general assets – IT	6.0	5.4
Non-network general assets – Other	15.0	7.2
Victorian Bushfires Royal Commission	26.5	24.4
Equity raising	42.7	41.2
Supervisory cables	n/a	1.0
Old SWER ACRs	n/a	5.0

Source: AER, *Final decision, Victorian Electricity Distribution Network Service Providers, Distribution Determination 2011–2015*, October 2010

Regulatory depreciation is the calculated straight-line depreciation less the inflation adjustment to the RAB. Regulatory depreciation for each year of the 2016–2020 regulatory control period is shown in table 13.4.

Table 13.4 Regulatory depreciation ($m, nominal)

	2016	2017	2018	2019	2020
Straight-line depreciation	175.1	180.1	202.2	224.7	247.3
Inflation adjustment	87.4	96.1	105.1	114.2	123.1
Regulatory depreciation	**87.7**	**84.0**	**97.1**	**110.5**	**124.2**

Source: Powercor

We have estimated inflation in accordance with section 12.5 of this Regulatory Proposal and have estimated the annual inflation figures over the relevant period on the basis inflation are constant.

13.4 Efficiency benefit sharing scheme

The EBSS provides a continuous incentive for us to achieve efficiency gains in our operating expenditure. The EBSS scheme outlined by the AER in its final determination has been applied to operating expenditure over the 2011–2015 regulatory control period to calculate the EBSS revenue increments and decrements which must be included in the 2016–2020 building blocks.

The EBSS scheme outlined in the final determination specified that the following operating expenditure categories must be excluded from the operation of the EBSS:

- debt raising costs;
- self insurance costs;
- superannuation costs for defined benefits and retirement schemes;
- the demand management incentive allowance; and
- guaranteed service level payments.

The final determination states, that for the purpose of calculating carryover amounts, the AER will substitute actual values for customer numbers, the number of distribution transformers and zone substation capacity MVA and line length for the years 2011–2014 and a revised forecast for 2015, for the forecasts of these metrics used in the final determination using the scale escalation method described in appendix J of the final determination. Benchmark EBSS operating expenditure has been calculated in accordance with this requirement and the calculation is provided in the attached model, *PAL EBSS*.

The final determination states that cost adjustments for the EBSS calculation include the adjustments set out in section 2.3.2 of the EBSS. One of the EBSS adjustments is adjustments to forecast operating expenditure for any changes in responsibilities that result from compliance with a new or amended law or licence, or other statutory or regulatory requirement. In 2014 we were required for the first time to provide an audited Economic Benchmarking Regulatory Information Notice (**RIN**) and an audited Category Analysis RIN. The incremental costs incurred for preparation of these RINs and their audit were not forecast in the final determination and have, therefore, been added to benchmark operating expenditure used to calculate EBSS carryover amounts to be applied in 2016–2020 regulatory control period.

Table 13.5 EBSS calculation ($m, real)

Excluded costs	2011	2012	2013	2014	2015
Adjusted benchmark EBSS operating expenditure	163.5	181.1	192.0	182.1	184.4
Actual EBSS operating expenditure	151.3	174.2	189.2	171.1	173.4
Incremental efficiency	12.1	-5.2	-4.1	8.2	-
Carryover year	**2016**	**2017**	**2018**	**2019**	**2020**
EBSS efficiency carryover	**11.0**	**-1.1**	**4.1**	**8.2**	**-**

Source: Powercor

13.5 S factor true-up

The AER closed out the Essential Services Commission (**ESC**) service performance scheme in 2010 and replaced it with the Service Target Performance Incentive Scheme (**STPIS**). All revenue increments and decrements that were due to arise from the ESCV scheme after 2010 were accounted for the 2011-15 revenue requirements. However, service performance in 2010 was only estimated at the time of the Final Determination. The Final Determination flagged that the final reconciliation (i.e. true up) of actual 2010 performance would be addressed in the 2016-20 distribution determination and provision for the true up was made in the Final Determination S Factor model. The calculation of the true up is provided in attached model *PAL - S-factor true up - final decision*, and the S factor true amount shown in the table below.

Table 13.6 S factor true up ($m, real)

	2016	2017	2018	2019	2020
S factor	-9.3	-	-	-	-

Source: Powercor

13.6 Shared asset revenue reduction

Shared assets are those that are used to provide both regulated and unregulated services. The AER may reduce our annual revenue requirement for a regulatory year to reflect the costs of using shared assets that are being recovered from unregulated revenue. In making this decision, the AER must have regard to the shared asset principles and the Shared Asset Guideline.[247]

One of the shared asset principles is that a shared asset cost reduction should be applied where the use of the assets other than for standard control services is material. The AER's shared asset guideline sets out how materiality would be tested. It defines that the use of shared asset is material when a distributor's annual unregulated revenue from shared assets is expected to be greater than 1 per cent of its total smoothed revenue requirement for a particular regulatory year. If this materiality threshold is not exceeded, no shared asset cost reduction applies.

The AER's shared asset guideline has been applied to calculate the materiality of our use of shared assets to earn unregulated revenue. Our shared asset revenue is primarily earned from renting poles and ducts to telecommunications companies. We understand that National Broadband Network (**NBN**) is negotiating with Telstra and Optus regarding their new network design which is fibre to the node. It is anticipated that there will be a transfer of rental revenue from Telstra and Optus to NBN, but that pole and duct rental revenue will remain, in real terms, consistent with the recent trend. We have therefore assumed that shared asset revenue will remain constant in real terms at 2014 levels.

The calculation of materiality for each year of the 2016–2020 control period is shown in table 13.6. Since the materiality percentage does not exceed 1 per cent in any year, no shared asset cost reduction applies.

Table 13.7 Materiality of shared asset use ($m, nominal)

	2016	2017	2018	2019	2020
Forecast unregulated revenue from shared assets	3.4	3.4	3.4	3.4	3.4
Smoothed revenue (prior to shared asset reduction)	652.2	689.2	728.4	769.7	813.4
Materiality percentage (%)	0.52	0.50	0.47	0.44	0.42

Source: Powercor.

[247] AER, Shared Asset Guideline, November 2013

13.7 Estimated cost of corporate income tax

The Rules require that the estimated cost of corporate income tax must be for a benchmark efficient entity. The estimated cost of corporate income tax for each year of the 2016-20 regulatory control period are shown in table 13.7 and have been calculated using the AER's PTRM which complies with clause 6.5.3 of the National Electricity Rules (**Rules**). The tax opening asset values, remaining lives and standard lives inputs for the PTRM have been calculated in the roll forward model. The standard tax asset lives are consistent with the Australian Tax Office ruling *Income tax: effective life of depreciating assets (applicable from 1 July 2014)*. The remaining tax asset lives have been calculated assuming that the proportion of assets depreciated for tax purposes is the same as that for the RAB.

We have set the PTRM to treat incentive scheme revenues as taxable income, and not as taxable expense. Incentive scheme revenue affects a distributor's actual taxable income and should therefore not be taxable expense in the PTRM.

Table 13.8 Estimated cost of corporate income tax ($m, nominal)

	2016	2017	2018	2019	2020
Estimated cost of corporate income tax	50.1	47.8	45.9	49.6	51.5

Source: Powercor

We have departed from the underlying methods in the AER's Roll Forward Model (2011-15) by using declining balance depreciation to roll forward the Tax Asset Base during the current regulatory control period. This approach was adopted in accordance with clause 11.17.2 of the Rules, which required tax allowance for the current regulatory control period to be estimated using an approach established by the ESC.

13.8 Revenue requirement

For the purposes of clause 6.4.3(a)(6) and clause 6.4.3(b)(6) of the Rules there are no other revenue increments or decrements to be carried forward from the previous regulatory control period.

The previous sections set out our proposed building blocks. The building blocks are used to derive our proposed unsmoothed annual revenue requirement for standard control services which are shown in table 13.8.

We propose to adopt the revenue cap form of price control and formulae that give effect to the control mechanism as set out in the Framework and Approach Paper. Our proposed smoothed revenue is based on revenue X factors which have been calculated so that smoothed revenue relatively closely follows the underlying building block costs (net of efficiency scheme revenue increments or decrements). Further, revenue X factors to be included in table 13.10, which relate to standard control services, are designed to equalise (in terms of Net Present Value (**NPV**)) the revenue to be earned by us from the provision of standard control services over the 2016-2020 regulatory control period with our proposed total revenue requirement for that period. We have estimated inflation in accordance with section 12.5 of this Regulatory Proposal.

Table 13.9 Revenue requirement ($m, nominal)

	2016	2017	2018	2019	2020
Return on assets	242.0	266.0	290.8	316.1	340.6
Regulatory depreciation	87.7	84.0	97.1	110.5	124.2
Operating expenditure	254.0	269.2	289.2	306.7	325.0
EBSS efficiency carryover	11.3	-1.2	4.4	9.1	-
S factor true up	-9.3	-	-	-	-
Shared asset revenue reduction	-	-	-	-	-
Corporate income tax	50.1	47.8	45.9	49.6	51.5
Unsmoothed revenue requirement	635.7	665.8	727.4	792.0	841.3
Smoothed revenue requirement	652.2	689.2	728.4	769.7	813.4
Forecast CPI %	2.6	2.6	2.6	2.6	2.6
Revenue X factor[248]%	**3.55**	**-3.00**	**-3.00**	**-3.00**	**-3.00**

Source: Powercor

13.9 Indicative charges and bill impact

For indicative impact on distribution use of system charges, refer to the table below and the attached *PAL 2016-20 PTRM.*[249]

Table 13.10 Distribution bill impact for typical customer (excluding smart metering charges) (per cent)

Typical annual bill	2016	2017	2018	2019	2020
Residential	-6.0	0.1	0.4	0.1	0.5
Small commercial	-4.3	1.8	2.3	2.0	2.3
Large	-4.5	1.9	1.9	1.6	2.1

Source: Powercor

Whilst these movements provide an early indication of our commitment to customers for the next regulatory control period, they are indicative only at this stage. The actual prices that will be charged to customers for the 2016–2020 regulatory control period are dependent on:

- the X factors that the AER will determine for us for the 2016–2020 regulatory control period;
- actual energy consumption:

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248 A positive revenue X factor means a real revenue decrease and a negative revenue X factor means a real revenue increase.

249 Clause 6.8.2(c)(4) of the Rules requires us to provide indicative prices. Further, please note these prices differ from those set out in the executive summary which includes both network and metering charges.

  - if energy consumption falls below our forecast, average charges would need to increase more than indicated; or
  - if energy consumption rises above our forecast, average charges would decline below the estimates indicated.
- the impacts of incentive schemes such as service target performance incentive scheme and F-Factor;
- the impacts of ‘unders and overs’ amounts adjusted for the time value of money due to variances between actual and forecast volumes;
- implementation of the new pricing objective and pricing principles. We are required to submit a proposed tariff structure statement to the AER for approval by 25 September 2015 in accordance with the pricing objective and pricing principles. Implementation of the statement must commence on 1 January 2017. As a consequence, individual customers may experience tariff changes which are more or less than the forecast average change in distribution charges; and
- we note that the percentage changes outlined in table 13.10 represent only a portion of the total network use of system charge to customers. Network use of system charges also include the cost of the services provided by the transmission network service provider and the recovery of an amount to satisfy obligations under the jurisdictional scheme requirements. These components are outside our control.

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Managing uncertainty 14

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14. Managing uncertainty

While our expenditure forecasts have been prepared based on the best information currently available for what we will need to do during the 2016–2020 regulatory control period, we are unable to predict each and every event that will occur.

Rather than building up our expenditure forecasts to cover all possible eventualities, the uncertainty regime allows us to request extra funding from the Australian Energy Regulator (**AER**) during the regulatory control period if a large unexpected event occurs, or if a large event occurs that we had anticipated but we had previously been unable to cost given the lack of clarity about what we would be required to do.

The exclusion of the costs of uncertain events from our Regulatory Proposal ensures that our customers face the lowest possible prices.

We operate in an uncertain environment. Uncontrollable external events can alter the quantity and nature of services that we are required to provide. The 'uncertainty regime' under the National Electricity Rules (**Rules**) comprises:

- pass through events;
- capital expenditure (capex) reopeners; and
- contingent projects.

These mechanisms deal with expenditure that may be required to be undertaken during a regulatory control period but which are not able to be predicted with reasonable certainty at the time of preparing or submitting a Regulatory Proposal to the AER.

Greater description of the uncertainty regime and our proposal is contained in the appendix L.

14.1 Pass through events

The pass through mechanism in the Rules recognises that a distribution network service provider can be exposed to risk of loss beyond its control, which may have a material impact on its costs. A cost pass through enables a business to seek the AER's approval to recover (or pass through) the cost of a defined unpredictable, high cost event for which the distribution determination does not provide a regulatory allowance.

A building block proposal may include a proposal as to the events that should be defined as pass through events, in addition to the events defined in the Rules, which are:

- a regulatory change event;
- a service standard event;
- a tax change event; and
- a retailer insolvency event.

We have undertaken a thorough risk assessment of our operations to ensure we have appropriate risk mitigation mechanisms in place to address those risks, in addition to reviewing the appropriate level of insurance cover. However, we have identified a number of risks which we consider would be prudently managed via a nominated pass through event rather than as an allowance in our Regulatory Proposal. The nominated pass through events are those which are beyond our control to prevent, are expected to have significant or catastrophic cost impacts and have a low likelihood of occurring.

We propose the following events to be approved as part of our distribution determination, which are to apply as nominated pass through events for the 2016–2020 regulatory control period.

Table 14.1 Nominated pass through events

Pass through event	Description
Insurer credit risk event	The insolvency of an insurer of the distributor.
Insurance event	Exposure to the risk of incurring liabilities above the insurance caps.
Natural disaster event	Occurrence of natural disasters such as floods, earthquakes, major storms and bushfires.
Terrorism event	Occurrence of act of terrorism.
End of metering derogation event	The existing metering derogation that provides exclusivity for Victorian distributors providing metering services to residential and small customers ends, leading to metering contestability.
Multiple trading relationships event	An event to capture the costs incurred should we be required to change the manner in which we interact with meters and customers.
Retailer failure event	To enable us to pass through costs (including unpaid charges for the provision of direct control services) we incur as a result of the insolvency of a retailer

These events are discussed in turn below.

In proposing these events, we have had regard to the nominated pass through event considerations outlined in chapter 10 of the Rules and we consider that each event meets the necessary requirements to be approved as a pass through event. Our proposed definition for these events and detailed assessment of how these events meet the nominated pass through event considerations is provided in appendix L.

Further, we consider that the AER's distribution determination should provide for the pass through provisions of the Rules to apply to alternative control services. The risks faced by distributors in relation to these services are the same as those faced in providing standard control services and the availability of cost pass through provisions is consistent with the basis of the control mechanism which have been developed in relation to those services.

We also propose a slight modification to the definition of 'materiality' that applies for pass through events relating to alternative control services. The current definition in the Rules relates solely to standard control services, and therefore the word 'materiality' should be taken to refer to its ordinary and nature meaning when applied to alternative control services.

Insurer credit risk event

We propose a pass through event for an 'insurer credit risk event'. This event would be triggered where an insurer becomes insolvent and we are subject to higher or lower premiums than those allowed in the distribution determination or a higher or lower claims limit or deductible than those allowed under the insurance policy will that insurer. This event is included in our regulatory determination for the 2011–2015 regulatory control period.

The proposed definition of the insurer credit risk event is:

An insurance credit risk event occurs if, as a result of the insolvency of an insurer, the distributor:

(1) incurs higher or lower costs for insurance premiums;

(2) in respect of a claim for a risk that would have been insured by the distributor's insurers, is subject to a higher or lower claim limit or a higher or lower deductible than would have otherwise applied under the relevant policy; and/or

(3) incurs additional costs associated with self funding an insurance claim, which would have otherwise been covered by the insolvent insurer.

The AER has previously recognised that the occurrence of increased insurance premiums or deductibles from external insurers is largely beyond the control of the distributors, and that the costs associated with higher insurance premiums are also beyond the control of the distributor.[250]

While we have in place a number of mitigation strategies to avoid being in a situation where one of our insurers becomes insolvent, the risk of such an event occurring is very low but not improbable. For example, HIH Insurance was placed into liquidation in 2001; similarly AIG faced a liquidity crisis during the global financial crisis but was bailed out by the US Government. It is clear that such events are infrequent. Consequently, to manage our exposure to any of our insurer's becoming insolvent, we propose to continue to include an 'insurance credit risk event' in our regulatory determination.

Insurance event

We propose a pass through event for when we incur a liability above the insurance cap. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is :

An "insurance event" occurs if:

a) the distributor makes a claim on a relevant insurance policy; and

b) the distributor incurs costs beyond the relevant policy limit.

For the purposes of this insurance event:

a) the relevant policy limit is the distributor's actual policy limit at the time of the event that gives rise to the claim; and

b) a relevant insurance policy is an insurance policy held during the 2016-2020 regulatory control period or a previous regulatory control period in which Powercor was regulated.

We have an incentive to choose the most efficient mix of risk mitigation mechanisms, and consider that our level of insurance cover is appropriate, taking into account the probability of an insurance event occurring, the financial consequence of any such event occurring, and the cost and availability of insurance in the market.

The probability of an insurance event occurring that results in liability above our insurance cap is very low, however to continue to manage the risk, we propose to continue to include an 'insurance event' in our regulatory determination.

Natural disaster event

We propose a pass through event for a natural disaster. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is:

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250 AER, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, Draft decision, June 2010, page 725.

A natural disaster event occurs if:

Any major fire, storm, flood, earthquake or other natural disaster beyond the reasonable control of the DNSP that occurs during the 2016-20 regulatory control period.

The term 'major' in the above paragraph means an event that is serious and significant. It does not mean 'materially' as that term is defined in the Rules (that is 1 per cent of the distributor's annual revenue requirement for that regulatory year).

The AER has previously stated that the occurrence of natural disasters such as floods, earthquakes, and major storms is entirely beyond the control of distributors.[251] The timing of such an event cannot be determined in advance, and the costs are variable depending on the type and magnitude of the event.

We cannot reasonably prevent a natural disaster event from occurring. That said, we have in place a number of preventive measures to manage the risks, including a Crisis and Emergency Management System which provides an effective state of readiness to prepare for, respond to and recover from, a range of credible and potential events with the aim of mitigating the effects of the event as far as practicable. In addition, we have a number of activities in relation to bushfire mitigation.

While we have obtained efficient levels of commercial insurance cover which are commensurate with our assessment of our business risk arising from natural disasters, we consider a pass through event represents a more appropriate means for managing our risk exposure to such an event given the complexity associated with developing credible self-insured risk quantifications for very low probability events.

Terrorism event

We propose a pass through event for an act of terrorism. This event is included in our regulatory determination for the 2011–2015 regulatory control period. Our proposed definition is:

An act (including, but not limited to, the use of force or violence, the threat of force or violence, attacks or other disruptive activities against, or the deliberate introduction of harmful code or viruses to, computer systems, computer networks, data and/or communication systems, or the threat of such attacks or disruptive activities, or of the deliberate introduction of such harmful code or viruses) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons (including the intention to influence or intimidate any government and/or put the public, or any section of the public, in fear).

Our ability to reasonably prevent an event of that nature or type from occurring or substantially mitigate the cost impact of such an event is limited. Whilst the occurrence of a terrorism event is largely beyond our control to prevent, we continue to review and assess the level of security at our sites in addition to undertaking security surveys.

While we hold an insurance policy that covers property damage and business interruption as a result of terrorism, it may not cover all of the impacts of a terrorism event on our network and business.

We therefore consider that a pass-through event represents the most prudent and efficient means for managing a risk of this nature during the 2016–2020 regulatory control period.

[251] AER, *Victorian electricity distribution network service providers*, Distribution determination 2011-2015, Draft decision, June 2010, pp. 725-726.

End of metering exclusivity event

We propose an ending of the metering derogation event. While the Australian Energy Market Commission (**AEMC**) has published a draft rule determination, this event would occur when the detail of the framework for metering contestability is determined prior to the expiration of the derogation which provides Victorian distributors with exclusive responsibility for metering services for smart meters.

Our proposed definition is:

> *An ending of the metering derogation event occurs if the impending or actual expiry of the Victorian Metering Derogation:*
>
> *(1) results in the distributor incurring costs to facilitate the introduction of metering contestability (whether prior to, or subsequent to the expiry of that Derogation) including, but not limited to:*
>
> > *(a) system costs for establishing metering contestability;*
> >
> > *(b) meter provider of last resort costs; and*
> >
> > *(c) costs incurred to obtain non-metrology data from meters to enable the distributor to operate its network; and*
>
> *(2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules.*
>
> *For the purposes of this metering derogation event, the Victorian Metering Derogation is the derogation currently provided for in clause 9.9C of the Rules pursuant to the AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering infrastructure) Rule 2013, 28 November 2013 and any subsequent derogation which may be made with similar effect to that in clause 9.9C of the Rules, albeit with a different expiry date.*

At this stage, there is uncertainty regarding aspects of the framework for competition in metering and related services which may not be resolved with the final rule determination. We will be required to implement new systems and processes to facilitate the contestable metering framework, however there is uncertainty as to the detail of the framework, including:

- our roles and responsibilities;
- the IT investment required to facilitate ad operate in a contestable metering market;
- business to business (**B2B**) protocols; and
- the shared market protocol.

These will be determined through a range of procedures, processes and guidelines to be published by industry, government and other parties before the new rule takes effect.

We are unable to include these costs in our Regulatory Proposal given the uncertainty associated with the detail of the framework for metering contestability. We consider that the event may not be classified as either a regulatory change event or a service standard event as it is possible that it will be necessary for us to incur at least some of the costs prior to the expiration of the derogation. We therefore consider that a prudent approach is to nominate this as a pass through event for the 2016–2020 regulatory control period.

Multiple trading relationships event

We are proposing an event relating to the proposed introduction of multiple trading relationships at a single connection point. This follows the recommendation of the AEMC in its Power of Choice review that a customer has the ability to select more than one retailer for services connected to a National Meter Identifier (**NMI**) – for example, to purchase electricity off one retailer but sell the distributed generation electricity back into the grid via another retailer.

Our proposed definition is:

> *A multiple trading relationships event occurs if a change (including without limitation any NEM procedure or system change) occurs that:*
>
> *(1) facilitates two or more entities being able to provide services at a single connection point; and*
>
> *(2) does not constitute any category of pass through event specified in clause 6.6.1(a1)(1) to (4) of the Rules.*

This event would occur after the Rule change determination and/or retail market procedures have concluded.

While the rule change proposal lodged by Australian Energy Market Operator (**AEMO**) provides a high level framework in which multiple trading relationships can operate and evolve, it does not contain detailed prescriptive requirements. However, following the AEMC rule change determination, AEMO will develop retail market procedures which will contain detail of the multiple trading relationships day-to-day operation.

We are unable to include these costs in our Regulatory Proposal given the uncertainty as to the model of multiple trading relationships and the manner of its implementation. We are also uncertain as to whether the event falls within the definition of a service standard event. Accordingly, we propose that the event should be a nominated pass through event in order to provide certainty that the costs incurred following this event will be treated as a pass through event in the 2016–2020 regulatory control period.

Retailer failure event

We are proposing an event relating to the failure of a retailer. There is uncertainty regarding whether the retailer insolvency event specified in the Rules applies to Victorian distributors given that the pass through event was associated with the introduction of the National Energy Customer Framework (**NECF**), which has not been adopted in Victoria.

Our proposed definition is:

> *A retailer failure event occurs if a distributor incurs costs as a result of the failure of a retailer during a regulatory control period to pay a distributor an amount to which the distributor is entitled for the provision of direct control services, if:*
>
> *(a) an insolvency official has been appointed in respect of that retailer; and*
>
> *(b) the distributor is not entitled to payment of that amount in full under the terms of any credit support provided in respect of that retailer.*
>
> *For the purposes of this definition:*
>
> *(a) The term 'costs' includes amounts which the distributor was entitled to be paid (but which are or will be unpaid as a result of a retailer failure event) for the provision of direct control services, including, but not limited to:*
>
> *(i) charges for direct control services provided by the distributor;*
>
> *(ii) charges to recover the designated pricing proposal charges incurred by that distributor, and*
>
> *these amounts must be taken to be a cost that can be passed through and not a revenue impact of the event.*
>
> *(b) The term 'insolvency official' means a receiver, receiver and manager, administrator, provisional liquidator, liquidator, trustee in bankruptcy or person having a similar or analogous function.*

(c) *The term 'credit support' takes its ordinary and natural meaning.*

(d) *Other terms used in this definition that are defined in the Rules take their definition in the Rules.*

The proposed definition takes into account the recent rule change request proposed by the COAG Energy Council that seeks to ensure that distributors are able to pass through foregone revenue for the provision of direct control services following the insolvency of a retailer.[252]

Similar to distributors in jurisdictions which have implemented NECF, we are unable to manage the risk of retailers defaulting on payment of their network charges. Given the uncertainty of the application of the retailer insolvency event in Victoria, we seek the AER to include this event as a nominated pass through event in our distribution determination.

14.2 Contingent projects

The contingent project mechanism is intended to address 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 either $30 million or five per cent of the annual revenue requirement of the distributor for the first year of the regulatory period, whichever is the greater amount. The relevant threshold for us is $31.8 million ($2016, nominal).

The project must have a clearly defined trigger, which if it occurs during the regulatory control period, allows the distributor to apply to the AER for the AER to determine an additional portion of revenue to be recovered during the period based on the additional required capital and operating expenditure.

We propose the following contingent projects to be approved as part of our Distribution Determination for the 2016–2020 regulatory control period.

Table 14.2 Contingent projects capital expenditure proposed for 2016–2020 regulatory control period

Event	Value ($2015, real)	Trigger
Installation of Rapid Earth Fault Current Limiter (**REFCL**)	Approximately $63 million	Imposition on Powercor of new or changed regulatory obligation in respect of earth faults.
Codified areas	Approximately $235 million	Imposition on Powercor of new or changed regulatory obligation in respect of high consequence bushfire ignition areas within Victoria specified as ‘codified areas’
Change in responsibility for Private Overhead Electric Lines (**POELs**)	Approximately $47 million	Changes to the Electricity Safety Act 1998 and/or revised Electricity Safety (Installations) Regulations that result in a change of responsibility for POELs.

Source: Powercor

In proposing these projects and triggers, we have had regard to the contingent project criteria outlined in clause 6.6A.1 of the Rules and we consider that each project and trigger meets the necessary requirements to be approved as a contingent project. Our proposed projects and detailed assessment of how they meet the required criteria is provided in appendix L.

[252] AEMC, National Electricity Amendment (Retailer insolvency events – costs pass through provisions) Rule 2015, Consultation, 30 October 2014.

Standard for earth fault current

The Powerline Bushfire Safety Taskforce (**PBST**) has recommended the installation of REFCLs in extreme, very high and high fire loss consequential areas. The PBST claims that REFCLs are able to reduce the fault current almost instantaneously when wire-to-earth faults occur.[253]

The PBST concluded that the most cost-effective solution is the widespread deployment of new protection network technologies (REFCL's and new generation Single Wire Earth Return (**SWER**) Automatic Circuit Reclosers (**ACRs**) in its 2011 report.[254] The PBST recommended a range of packages, with the minimum $500 million package requiring the installation of 108 REFCLs in extreme, very high and high fire loss consequence areas.

Trials in Australia are being used to determine whether the installation of a REFCL may reduce the possibility of a bushfire starting. The first REFCL in Australia, Swedish Neutral's 'Ground Fault Neutraliser' (**GFN**) was installed in United Energy's Frankston South zone substation in 2013 and 2014. Additionally, AusNet Services have installed a REFCL in its Woori Yallock zone substation, and plans to install a REFCL in its Kilmore South zone substation in 2015.

We have proposed to install REFCLs in our network at the Woodend and Gisborne zone substations. The costs for this trial site have been proposed for inclusion in the capital expenditure for the Regulatory Proposal. The trials should determine whether the installation of a REFCL will reduce the risk of a bushfire being started by the fault energy released by a broken overhead powerline.

However following the outcome of the trials, we may be required by Energy Safe Victoria (**ESV**) for our network to achieve a new or changed standard in response to earth faults. This obligation would arise through ESV issuing a regulatory obligation which obliges us to comply with the new or changed standard.

Codified areas

ESV, together with the PBST, is committed to introducing codification of the high consequence bushfire ignition areas within Victoria, which requires the determination of the minimum technically acceptable standard for electric lines that are new, upgraded, or subject to significant maintenance in the area of the highest bushfire ignition consequence.

ESV has noted that:[255]

> *In higher bushfire risk areas, new and higher standards of construction will be required increasing further the risk of asset stranding in the face of reducing demand. The future of the network itself as the only option for energy delivery will need to be re-assessed by industry, governments and regulators as they consider the form of regulation and the traditional notion of the natural monopoly.*

The Victorian Government's response to the PBST's report noted that there will still be 'black spots' in the electricity distribution network where dangerous poles and wires create an unacceptable bushfire hazard. As a result, the Government committed to contributing up to $200 million over ten years for a program of power line conductor replacement in locations of the highest fire loss consequences.[256] Through the Powerline Replacement Fund, taxpayers are funding the undergrounding of bare open wire powerlines in High Bushfire Risk Area (**HBRA**), such as in the Otway region.

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[253] Powerline Bushfire Safety Taskforce, Final Report, 30 September 2011, p 47.
[254] Powerline Bushfire Safety Taskforce, Final Report, 30 September 2011.
[255] ESV, Safety Performance Report on Victorian Electricity Networks 2013, June 2014, p. 15.
[256] 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

It is counterproductive for taxpayers to fund the undergrounding of existing bare open wire powerlines while we are able to construct new bare open powerlines in the same locations, such as:

- new overhead powerline construction resulting from new customer connections;
- existing bare open wire powerlines being upgraded as the load increases resulting in further investment in bare open wire construction; or
- the condition of the bare open wire powerlines may require like-for-like replacement.

The PBST is proposing that a 'codified area' is designated where distributors are required to place underground new conductors or conductors to be upgraded or replaced in the same areas where the Victorian Government is to fund the undergrounding of powerlines, to provide a consistent bushfire mitigation approach in the highest fire loss consequence areas.

This would be enforced through ESV issuing a regulatory obligation which obliges us to comply with the new or changed service standard in the designated areas.

Change in responsibility of Private Overhead Electric Lines

ESV is currently revising the Electricity Safety (Installations) Regulations 2009, where it has indicated that the definition of Point of Supply will be amended.

The 'point of supply' represents the demarcation between our distribution network and the customer's network. Assets downstream of the point of supply are owned by the customer, and may be referred to as POELs. These lines can be a combination of privately owned poles and lines or just a span of line that is privately owned. These are generally for rural properties and their various buildings, including sheds.

A discussion paper titled *Private Electric Lines and the point of supply – Initial Distribution Business Discussion Paper* was issued by ESV on 5 November 2014 and feedback was sought from distributors. Based on indications from this discussion paper, we will acquire responsibility for maintaining a greater number of assets, including overhead service lines on private property to the newly defined Point of Supply.

We forecast that there will be around 30,000 POELs in our distribution area during the 2016-2020 regulatory control period. Around 67 per cent of those are likely to become our responsibility if ESV changes the definition of Point of Supply in the manner indicated in the discussion paper.

We anticipate that many of the POELs which we inspect will be in poor condition. As we will be obligated to ensure the POELs are safe, we would need to inspect the poles in accordance with the required asset management practices, as well as maintain the clearance space between vegetation and the conductor. We will also need to undertake maintenance and rectification of defects. As a result, many of the POELS will require replacement. In addition, asset management records would need to be created and maintained for these assets.

The change in the ownership of POELs is likely to be through the revised Electricity Safety (Installations) Regulations issued by ESV, or through a change in the Electricity Safety Act 1998.

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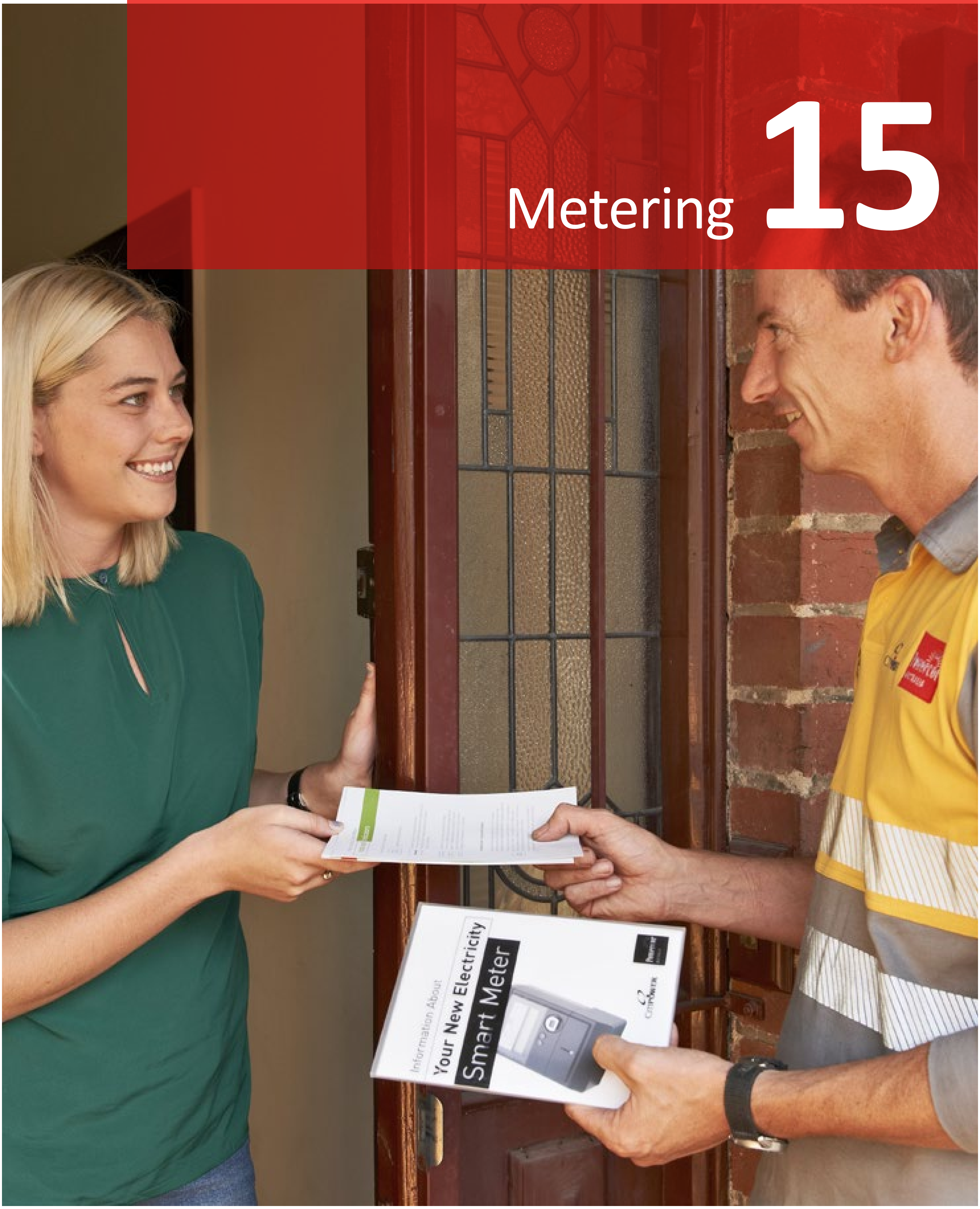
Metering 15



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15. Metering

We had a successful metering program. Our Advanced Metering Infrastructure (**AMI**) roll out has been delivered on time and on budget and we have the lowest metering charges in Victoria.

We are already realising network benefits from the AMI metering program and will continue to do so. These network benefits provide long term benefits to our customers.

The introduction of contestability in the metering market creates considerable uncertainty regarding our expenditure requirements for the 2016–2020 regulatory control period and may also affect our ability to realise network benefits.

Our Regulatory Proposal is based on a set of assumptions regarding the introduction of contestability from 1 January 2017. Should these assumptions prove incorrect we could incur significant additional costs that are not captured in our proposed annual revenue requirement for the 2016–2020 regulatory control period. We have therefore proposed a pass through event to manage this risk, refer to chapter 14.

We are currently responsible for metering services associated with types 5, 6 and smart meters. These meters are installed in residential and small business premises consuming up to 160 megawatt hours (**MWh**) per annum. The services we provide in relation to these meters include:

- meter provision – includes purchasing meters and installing these meters at the customer's premises;
- meter maintenance – includes inspecting, testing, maintaining and repairing meters;
- meter replacement – replacement of a meter and associated equipment, at a site with existing metering infrastructure, with a modern equivalent where the meter has reached the end of its economic life;
- meter reading and data services – includes collection, processing, storage and delivery of metering data to other market participants for billing and market settlement purposes and the management of the relevant National Meter Identifier (**NMI**); and
- meter communications – includes maintaining and installing communication devices required to operate the mesh radio network and management of the day to day operation of the meter communications systems including meter data delivery, testing, fault detection, investigation and resolution.

For the 2016–2020 regulatory control period, types 5, 6 and smart meters installed up to 31 December 2016 will be regulated as alternative control services subject to a revenue cap. This chapter sets out our proposed annual revenue requirement for these meters.

It should be noted that, based on current legislative provisions, types 5, 6 and smart meters installed on or after 1 January 2017 will be subject to a contestable market and will be an unregulated service. Our proposed annual revenue requirement therefore excludes any costs for metering services associated with types 5, 6 and smart meters installed from 1 January 2017.

We are also responsible for providing customer requested auxiliary metering services and type 7 metering services relating to unmetered supply both of which are regulated services. Consistent with the Framework and Approach Paper, these services are classified as alternative control services. Our approach to auxiliary metering services is therefore discussed in chapter 16. We do not propose a fee for providing type 7 metering services as the supply is unmetered and the cost of providing the service is immaterial.

Services relating to metering types 1-4 meters, excluding smart meters, are generally used by large customers who consume greater than 160 MWh of electricity per annum. These meters are competitively available and therefore unclassified (unregulated) services in accordance with the Framework and Approach Paper.

15.1 Smart meter rollout

The Victorian Government decided to implement a distributor-led mandated smart meter rollout for all residential and small business customers using up to 160 MWh of electricity per annum. The Victorian distributors were required to replace the existing types 5 and 6 meter installations at these premises with smart meters.

The distributor-led mandated roll out of smart meters was facilitated by:

- a Victorian Government derogation in the National Electricity Rules (**Rules**) which had the effect of assigning Victorian distributors with sole responsibility for the installation of smart meters in their network area, referred to as 'the derogation';[257] and
- the Victorian Advanced Metering Infrastructure Order in Council (**AMI OIC**) which specifies how the Victorian distributors are to recover their costs of the smart meter roll out.[258]

Key differences between smart meters and the pre-existing types 5 and 6 meters are that smart meters have the capability to record the time of energy use and are read remotely rather than manually.[259]

The co-ordinated replacement of types 5 and 6 meters with smart meters throughout the network has facilitated the potential for significant savings in network related costs for customers, including, but not limited to:

- reduced supply restoration times;
- remote energisation and de-energisation of connections;
- efficient load management to promote security of supply; and
- remote meter reading.

As at December 2014, the smart meter roll out phase is effectively completed and we have now moved into a 'business as usual' phase of meter management. The quantity of each type of meter currently installed by us and connected to our network as at 31 December 2014 is set out in table 15.1.

[257] The derogation is contained in clause 9.9C of the Rules.
[258] Electricity Industry Act 2000, Order under section 15A and section 46D, Order in Council (Gazetted S200, 28 August 2007) and as amended.
[259] Type 5 meters record time of use and are manually read. Type 6 meters are accumulation meters which report total energy consumption only and are read manually.

Table 15.1 Quantity of meters installed as at 31 December 2014

Meter type	Volume
AMI 1Ph 1e	427,222
AMI 1Ph 1e + contactor	54,376
AMI 1Ph 2e + contactor	195,809
AMI 3 Ph	110,279
AMI 3 Ph + contactor	19,482
AMI 3 Ph CT	4,872
Total	**812,040**

Source: Powercor

15.2 Meter contestability

The derogation is due to expire on the earlier of 31 December 2016 or the introduction of a national contestable market. From this time, the Victorian distributors will no longer have sole responsibility for types 5, 6 and smart metering services.

However, at the end of the derogation, we will have significant unrecovered capital costs associated with the smart meter roll out during the 2009 to 2016 period. We will also have ongoing costs associated with maintenance of meters installed during the derogation and with maintaining the communications and Information Technology (**IT**) systems which support the transmission and management of data received from smart meters installed during the derogation.

There is currently considerable uncertainty however regarding the framework for metering contestability that will apply nationally and in Victoria over the 2016–2020 regulatory control period. We have, therefore, developed our proposed annual revenue requirement based on the current regulatory arrangements. In particular, we have assumed that:

- the smart meter derogation will expire on 31 December 2016, at which point the market will be contestable;
- we will not be required to obtain type 4 accreditation to continue to operate, maintain and replace smart meters installed during the derogation;
- we will not incur licence fees for operating the communications network within 900Mhz range;
- we will not have to upgrade our IT and back-office systems to manage the receipt of data from multiple third parties; and
- we will not be required to provide 'metering provider of last resort' services following the expiry of the derogation.

We will update our assumptions for any known changes in the metering contestability framework in our revised Regulatory Proposal.

However, should our Revised Regulatory Proposal assumptions prove incorrect, we could incur significant additional costs that are not captured in the proposed annual revenue requirement for the 2016–2020 regulatory control period. To manage this risk we have proposed a pass through event to apply as discussed in chapter 14.

15.3 Revenue forecast

For the 2016–2020 regulatory control period, the AER must regulate cost recovery of smart meter services in accordance with the AMI OIC.

The *Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016* (**F&A Paper**) states that types 5, 6 and smart metering services for meters installed prior to the expiry of the derogation will be subject to a revenue cap coupled with:

- an exit fee for customers choosing to remove or replace our installed meter with a competitive sourced meter; and
- a restoration fee for when a distributor reinstates a metering installation (as a metering provider of last resort) or replaces a defective installation.

We have developed the annual revenue requirement for the 2016–2020 regulatory control period using the building blocks approach as set out below.

Our proposed exit fee is set out in section 15.4.

We do not propose a restoration fee as we have assumed that we will not be required to be a meter provider of last resort.

Importantly, our proposed annual revenue requirement is based on a number of assumptions. Our annual revenue requirement could change significantly depending on the final framework for metering contestability.

15.3.1 Regulatory Asset Base (RAB)

Opening RAB

We used the AER's approved 2015 charges application model, updated with actual 2014 revenue and expenditure, to calculate our opening metering RAB as at 1 January 2016 which is $338.3 million ($2015), refer to the attached model, *Powercor - AMI Charges Model (2015 Charges Application) FD 2014 act*. This is based on:

- the depreciated value of actual capital expenditure incurred up to 31 December 2014. Actual expenditure relates to the purchase and installation of smart meters, investment in the communications network and IT and other back-office systems used to support the smart metering services. Type 5 and 6 meters are fully depreciated and therefore have a value of zero in the RAB;
- forecast capital expenditure in 2015 of $22.4 million ($2015) based on our attached, *AMI Revised Charges Application dated August 2014*, and
- depreciation of the 2015 opening RAB and forecast capital expenditure in 2015.

The 2016 opening RAB value by asset category is set out in table 15.2.

Table 15.2 Opening RAB value by asset category ($m, real)

Asset category	Closing RAB 2014	Forecast capex 2015	Forecast depreciation 2015	Opening RAB 2016
Meters	307.4	7.6	25.7	289.4
Communications	22.7	5.6	5.9	22.4
IT	38.6	1.1	13.9	25.9
Other	0.8	0.1	0.3	0.6

Source: Powercor

RAB roll forward from 1 January 2016

We have rolled forward the metering RAB for the 2016–2020 regulatory control period using the Post Tax Revenue Model (**PTRM**). This has involved:

- adding forecast capex;
- deducting forecast customer contributions. We forecast zero customer contributions;
- deducting forecast depreciation;
- deducting forecast asset disposals. We forecast zero asset disposals; and
- indexing the annual closing RAB using the forecast inflation rate for each year of the regulatory control period. The forecast inflation rate is consistent with the approach for standard control services (refer to chapter 12).

The RAB roll forward calculation is provided in the attached model, *PAL Metering PTRM.*

15.3.2 Depreciation

We have calculated forecast depreciation based on the following asset lives:

- smart meters have a standard asset life of 15 years. As most smart meters were installed between 2009 and 2014, on 1 January 2016 the average remaining asset life of our smart meters is 11.2 years; and
- communications and IT assets have a standard asset life of seven years. The average remaining life as at 1 January 2016 is 3.0 years.

Forecast depreciation is calculated for each year of the 2016-2020 regulatory control period for each asset category in the PTRM.

Forecast depreciation is set out in table 15.17.

15.3.3 Rate of return

To calculate the return on capital we have applied the same rate of return as that used for standard control services, provided in table 12.10. We also propose the same approach to annually proposing and updating the return on debt as for standard control services, discussed in chapter 12. Our reasons for deviating from the AER's rate of return Guideline are also set out in chapter 12.

We have applied this same rate of return as standard control services on the basis that the exit fee applied to customers removing or replacing our installed smart meters with competitively provided meters will ensure that we receive full recovery of our sunk investment costs, including the meter provision and installation costs and the back-office costs. However, if the operation of the exit fee did not provide assurance that all sunk costs would be recovered, then a premium should be added to the standard control services rate of return to reflect this added risk.

The rate of return has been applied to the RAB to calculate the return on capital set out in table 15.17.

15.3.4 Forecast capital expenditure

During the 2016-2020 regulatory control period we forecast to incur capital expenditure associated with:

- new metering connections – this relates to the purchase of new meters in 2016. We assume no new connections for the 2017 to 2020 period following the introduction of metering contestability;
- replacement of faulty meters – this relates to purchase and replacement of faulty meters that were originally installed during the derogation;
- customer initiated upgrades – this relates to upgrades to the meter installation to accommodate customer requested supply upgrades in 2016. We assume no customer initiated upgrades for the 2017 to 2020 period following the introduction of metering contestability;
- communications network – relates to the cost of augmenting the mesh metering communications network and replacing faulty communications devices. The communications network provides the delivery of metering data to the central database collection point; and
- IT system – relates to costs of the UtilityIQ system which supports the mesh communications networks.

Our capital expenditure forecasts for each of the above categories are discussed in the following section. The calculations are set out in the attached model, *PAL Metering Capex & Opex*.

New metering connections

The forecast volume of total new metering connections in 2016 is based on our forecast new residential connections for standard control services which are developed by the Centre for International Economics (**CIE**), refer to attached model, *CIE Tariff volume forecasts 18 February 2015*. To estimate the volume of new meters in 2016 by meter type, we applied the proportion of new meters installed by meter type in 2014.

We have forecast no new metering installations from 1 January 2017. This is because, following the expiry of the derogation, any new meter installations are assumed to be subject to a contestable metering market and treated as an unregulated service. As noted above, we have also assumed that we will not be required to be a metering provider of last resort.

For 2016, the costs of new metering connections are recovered as follows:

- the capital cost for purchasing the new meter is part of the type 5, 6 and smart meter regulated service;
- the labour cost for installing the new meter is charged directly to customers as an alternative control service, refer to chapter 16.

To develop our forecast capital expenditure for purchasing new meters, we sought quotes from our two main meter providers, Landis + Gry Pty Ltd and Secure Australasia Pty Ltd, on the per unit meter purchase cost for each meter type. The service provider quotes are stated in US$2015, therefore we have:

- converted these to Australian dollars based on a forecast exchange rate between Australia and US dollars derived from Bloomberg; and
- applied a real price escalator based on our contracts escalator applied to standard control services, refer to chapter 7.

To develop a unit price for each meter type we have taken a weighted average of the two service providers quotes, based on 80 per cent Landis + Gry Pty Ltd and 20 per cent Secure Australasia Pty Ltd. The weights reflect our historical purchase proportions from the two service providers.

Table 15.3 sets out our forecast new connections volumes and unit price for each meter type.

Table 15.3 Forecast capital expenditure for new metering connections in 2016 ($, real)

Meter type	Volume	Weighted average unit price
AMI 1Ph 1e	10,353	213.3
AMI 1Ph 1e + contactor	267	238.2
AMI 1Ph 2e + contactor	2,319	262.1
AMI 3 Ph	2,214	388.5
AMI 3 Ph + contactor	149	416.3
AMI 3 Ph CT	203	496.6

Source: Powercor

Replacement of faulty meters

Reactive replacement

For meters installed during the derogation up to 31 December 2016, we forecast capital expenditure associated with reactive replacement of defective metering equipment. Reactive replacement occurs where the meter, or communications device within the meter, fails before end of life.

Replacement of faulty metering equipment originally installed on or after 1 January 2017 is assumed to be subject to contestability and classified as an unregulated service. We therefore forecast no capital expenditure associated with reactive replacement of meters installed from 1 January 2017.

For meters installed before 1 January 2017, our forecast fault rates are based on our fault rate in 2014. The 2014 meter fault rate reflects the current fault rate given the current age and meter mix of the existing metering fleet. The 2014 fault rate provides an appropriate base for forecasting the meter fault rate over the 2016–2020 regulatory control period because it reflects the fault rate of meters during the middle period of their 15 year economic life, and not at either the beginning or end of life. Our forecast fault rates for meters are provided in table 15.4.

Table 15.4 Meter forecast fault rates (per cent)

	2014	2015	2016	2017	2018	2019	2020
Fault rate	0.17	0.17	0.17	0.17	0.17	0.17	0.17

Source: Powercor

The cost of reactive meter replacement includes the:

- cost of a new meter. The unit price of a new meter is sourced from quotes from our two meter providers and is dependent on the meter type, refer to table 15.3 above; and
- labour costs associated with installing the new meter. Our forecast labour costs associated with installations are forecast for each type of metering installation. Forecast labour hours are based on the average number of

labour hours incurred for installing each meter type. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Table 15.5 sets out our forecast volumes and capital expenditure for reactive replacements.

Table 15.5 Reactive replacement capital expenditure ($m, real)

Reactive replacement capex	2016	2017	2018	2019	2020
Volume of meters replaced	3,930	3,982	3,973	3,963	3,954
Meter costs	1.10	1.18	1.26	1.31	1.36
Labour costs	2.33	2.46	2.60	2.67	2.75
Total reactive replacement capex	3.43	3.65	3.87	3.97	4.11

Source: Powercor
Note: Unit cost of a replacement meter and the labour costs of installation are aggregated across all meter types. The costs vary by meter type.

Proactive replacement

We propose capital expenditure associated with proactive replacement in 2016 only. Proactive replacement relates to:

- the replacement of meters that, through company initiated testing, are identified as faulty; and
- the replacement of any remaining type 5 and 6 meters with smart meters.

The cost of proactive meter replacement includes the:

- cost of a new meter – The unit price of a new meter is sourced from quotes from our two meter providers and is dependent on the meter type, refer to table 15.3.
- labour costs associated with installing the new meter. Our forecast labour costs associated with installations are forecast for each type of metering installation. Forecast labour hours are based on the average number of labour hours incurred for installing each meter type. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

We have assumed that from 1 January 2017, proactive replacement is subject to a contestable market and is classified as an unregulated service. We therefore forecast no proactive replacement for the 2017-2020 period.

Table 15.6 sets our volumes and capital expenditure for proactive replacements.

Table 15.6 Proactive replacement capital expenditure ($m, real)

	2016	2017	2018	2019	2020
Volume of meters replaced	3,661	-	-	-	-
Meter costs	1.14	-	-	-	-
Labour costs	1.87	-	-	-	-
Total reactive replacement capex	3.01	-	-	-	-

Source: Powercor
Note: Unit cost of a replacement meter and the labour costs of installation are aggregated across all meter types. The costs vary by meter type.

Customer initiated upgrades

We provide meter upgrades for existing metering customers upon request. Customer initiated meter upgrades occur when, for example, the customer requests an upgrade to the electricity supply capacity and their existing metering service can not accommodate this.

For 2016, the cost of customer initiated metering services will be recovered as follows:

- the meter cost is part of the type 5, 6 and smart meter regulated service. The per unit meter cost is sourced from quotes from meter providers and escalated to real $2015 as shown in table 15.7; and
- the labour cost is charged directly to customers as an auxiliary metering service which is an alternative control service, refer to chapter 16.

We forecast the volume of customer initiated upgrades in 2016 by meter type based on our actual 2014 volume of customer initiated upgrades. Our forecast volumes, unit costs and total cost of customer initiated metering upgrades in 2016 is provided in table 15.7.

Note that customer initiated upgrades from 2017 are assumed to be an unregulated service.

Table 15.7 Forecast capital expenditure for customer initiated upgrades in 2016

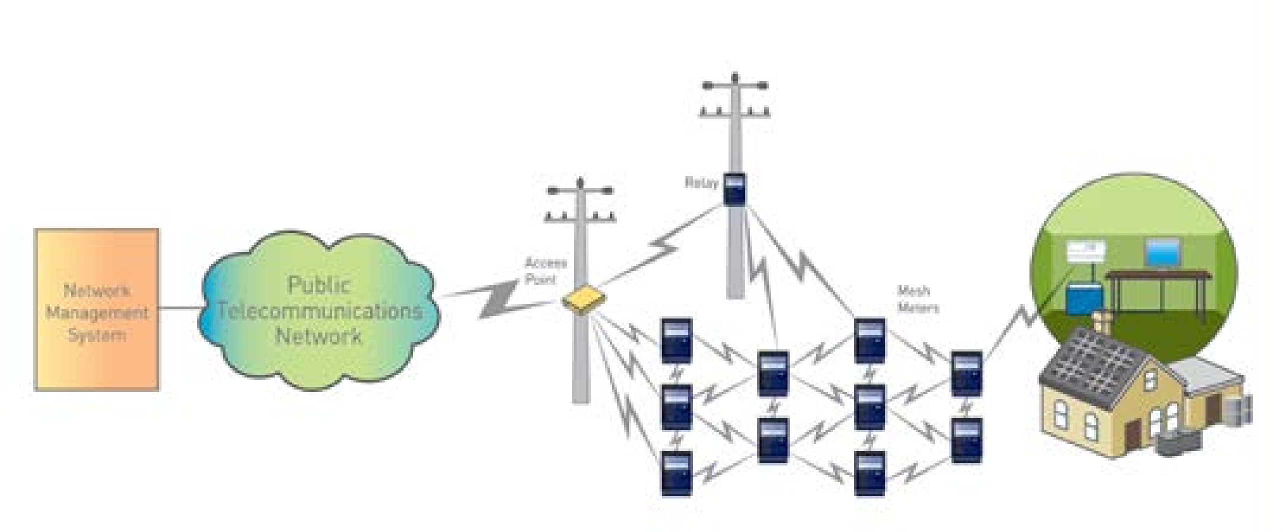
Meter type	Volume of customer initiated upgrades	Meter cost ($, real)
AMI 1Ph 1e	115	213.31
AMI 1Ph 1e + contactor	40	238.16
AMI 1Ph 2e + contactor	64	262.13
AMI 3 Ph	104	388.48
AMI 3 Ph + contactor	40	416.27
AMI 3 Ph CT	46	496.61
Total volume	**409**	
Total new meter connection capex ($m, $ real)		**0.13**

Source: Powercor

Communications network

The mesh metering communications network consists of access points, relays and antennas which enable metering data to be transferred from the meter to the data collection point. Figure 15.1 demonstrates how meter data is transmitted between meters and communication devices and transported back to the central data collection point.

Figure 15.1 Data transmission between meters and communication devices



Source: Powercor

We forecast capital expenditure in the 2016-2020 regulatory control period for:

- augmentation of the communications network;
- replacement of back-up batteries in communications devices; and
- replacement of faulty communications devices.

<u>Augmentation of communications devices</u>

Our forecast capital expenditure for augmentation of the communications network is based on the:

- forecast quantity of communications assets required to:
  - extend the communication network to accommodate new smart meter connections;
  - infill the communications network when smart meters are removed from the fleet due to supply abolishments; and
  - extend the communications network to achieve communication from non-communicating smart meters. As at 31 December 2014 we had 3,025 smart meters which due to the external environment are not communicating through the communications network and therefore are being manually read;
- forecast cost of the communications assets. Based on quotes provided from our communications network service provider Silver Spring Networks Pty Ltd. As quotes were provided in US dollars we have converted the price to Australian dollars using a forecast exchange rate sourced from Bloomberg; and
- forecast labour cost of installing the forecast quantity of communications assets. Forecast labour hours are based on the average number of labour hours incurred for installing communications assets. The hourly labour rate reflects our current labour rate for installations escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Importantly, our capital expenditure forecast for augmenting the communications network is based on the assumption that we do not need to back-fill the communications network as a result of customers choosing to replace existing smart meters with competitively sourced meters. Instead, the costs of back-filling the communications network as a result of customers exiting our metering network have been captured in our proposed exit fee.

Replacement of back-up batteries in communications devices

We forecast capital expenditure associated with the replacement of batteries in communications devices. Batteries contained in access points and relays have an expected life of five years based on manufacturer advice. We have developed our forecasts of battery replacement capital expenditure based on:

- a five year average battery life;
- on the unit price quoted by our communications service provider Silver Spring Networks Pty Ltd. As the quote was provided in $US we have converted the price to Australian dollars using a forecast exchange rate sourced from Bloomberg; and
- forecast labour cost of installing a battery. Forecast labour hours are based on the average number of labour hours historically incurred for installing new batteries. The hourly labour rate reflects our current labour rate for installations escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Replacement of faulty communications devices

We forecast capital expenditure associated with the replacement of faulty communications devices. Our forecast fault rates are based on our average fault rates in 2013 and 2014. It is appropriate to base the fault rates for the 2016–2020 regulatory control period on the average rate of 2013 and 2014 actual fault rate because the volume of communication device faults per year is very small and therefore a longer sample period is necessary to provide a representative forecast. Our forecast fault rates for communications devices are provided in table 15.8.

Table 15.8 Communications devices forecast fault rates (per cent)

	Average 2013-2014	2015	2016	2017	2018	2019	2020
Fault rate	1.63	1.63	1.63	1.63	1.63	1.63	1.63

Source: Powercor

The cost of replacing faulty communications devices includes the:

- cost of a new communications device. The forecast unit price of new communications devices are based on a quote from our communications network service provider, Silver Spring Networks Pty Ltd; and
- labour costs associated with installing a communications device. Our forecast labour hours are based on the average number of labour hours incurred for installing communications devices. The hourly labour rate reflects our current labour rate for installers escalated for the real increase in labour prices using the same labour escalator as for standard control services, refer to chapter 7.

Table 15.9 sets out our forecasts capital expenditure for the communications network.

Table 15.9 Communications network forecasts capital expenditure ($m, real)

	2016	2017	2018	2019	2020
Augmentation capital expenditure	2.84	0.46	0.17	0.19	0.20
Battery replacement capital expenditure	2.78	3.97	0.32	0.31	0.23
Fault replacement capital expenditure	0.49	0.57	0.61	0.64	0.66
Total communications network capital expenditure	6.11	5.00	1.10	1.10	1.10

Source: Powercor
Note: Unit cost of a replacement communications device varies depending on the device.

Information technology

Our smart meter communications network is supported by the UtilityIQ information technology (**IT**) system. UtilityIQ is a web-based network management system that provides services such as device management, device health monitoring, remote firmware upgrades and outage detection.

We forecast IT capital expenditure for:

- software and hardware upgrades associated with UtilityIQ which are required by our communications network service provider, Silver Spring Networks Pty, to ensure continued operation, support and compatibility; and
- security upgrades associated with UtilityIQ and the smart meter communications network required to ensure the security of our smart meter network and associated systems.

Our proposed IT capital expenditure is set out in table 15.10.

Table 15.10 IT capital expenditure forecasts ($m, real)

	2016	2017	2018	2019	2020
Software upgrades	0.30	0.17	0.29	0.18	0.30
Hardware upgrades	-	-	-	-	1.21
Security	0.38	0.55	0.29	0.18	0.38
Total IT capital expenditure	0.68	0.72	0.58	0.36	1.89

Source: Powercor

15.3.5 Operating expenditure

We incur operating expenditure in relation to types 5, 6 and smart metering for the following categories of services:

- meter data services;
- meter maintenance;
- customer service;
- backhaul communications;

- communication operations;
- direct and corporate overheads; and
- information technology (**IT**).

We propose a base-step-trend approach to forecast each of the above categories of operating expenditure for the 2016-2020 regulatory control period. The base-step-trend approach involves:

- identifying the appropriate base level of expenditure;
- remove non-recurrent expenditure;
- adjusting the base year to present the forecast operating expenditure in accordance with our approved cost allocation methodology (**CAM**);
- identifying any new services to be provided in the regulatory period that are not reflected in the base year expenditure;
- escalating base level of expenditure for growth in the size of the metering service; and
- escalating for real price increases in labour, materials and contracts.

Each of these steps is discussed in the following sections. The calculations are set out in the attached model, *PAL Metering Capex & Opex*.

Table 15.11 sets out our forecast operating expenditure for the 2016–2020 regulatory control period.

Table 15.11 Forecast operating expenditure ($m, real)

Operating expenditure	2016	2017	2018	2019	2020
Actual operating expenditure (2014)	18.92	18.92	18.92	18.92	18.92
Non recurrent operating expenditure	-5.00	-6.00	-6.00	-6.00	-6.00
Adjustment for capitalisation policy in accordance with the CAM	0.76	0.76	0.76	0.76	0.76
Step changes	0.37	0.40	0.41	0.41	0.42
Scale escalation	0.27	0.23	0.19	0.15	0.11
Real price growth	0.52	0.73	0.95	1.18	1.41
Total	**15.49**	**15.07**	**15.27**	**15.46**	**15.66**

Source: Powercor

Base expenditure

We propose using actual 2014 operating expenditure as the base level of expenditure for each operating expenditure category. Our 2014 operating expenditure reflects business as usual (**BAU**) operating expenditure, this is because we had completed 96 per cent of the roll out of smart meters within our network area by 31 December 2013 and therefore were effectively operating in a BAU state in 2014.

We propose adjustments to the 2014 operating expenditure to remove non-recurrent operating expenditure in relation to:

- manual meter read costs that are permitted to be recovered directly from customers in accordance with the AMI OIC from 1 April 2015;
- direct overheads as the move to BAU metering activity and the introduction of contestability will require fewer overheads; and
- IT systems other than the UtilityIQ system. As discussed in appendix F, we have identified that, from 1 January 2016, the only IT system required primarily for metering related services, and would not be required if we did not own and operate the metering assets, is UtilityIQ. We have therefore applied the 2014 operating expenditure associated with UtilityIQ as the base expenditure for escalating our IT operating expenditure in the 2016-2020 regulatory control period. The remaining IT operating expenditure in 2014, which relates to other IT systems required to provide network services, has been transferred to standard control services.

We also propose to adjust the 2014 operating expenditure for our change in capitalisation policy to ensure our forecast operating expenditure is allocated in accordance with the approved CAM.

Step changes

We have identified one step change in relation to types 5, 6 and smart meters for the 2016–2020 regulatory control period.

In 2012 and 2013 we rolled out 5004 AMI meters with current transformers (**CT meters**). CT meters were rolled out toward the end of the AMI roll out as they are placed in more complex sites. CT meters are three phase meters which are generally installed for small commercial customers.

In accordance with chapter 7, clause 7.6, schedule 7.3 of the National Electricity Rules (**Rules**), CT meters are required to be tested within five years. Unlike direct current meters which are sample tested, all CT meters are required to be individually tested within five years. As we did not undertake testing of CT meters in 2014 we will incur additional operating expenditure during the 2016–2020 regulatory control period which is not included in our 2014 base year expenditure.

We therefore propose a step change for the labour costs of testing our CT meters to meet our regulatory obligations under the Rules. Our proposed labour costs are based on our current labour rate multiplied by testing time per meter of 2.5 hours.

A step change is the only mechanism for recovering the costs associated with CT meter testing. CT meter testing costs are not captured in either the scale escalation or real price growth components of our operating expenditure forecasts because they do not relate to either future growth in meter numbers or growth in the real price of labour or material inputs. Further, CT meter testing is a regulatory obligation prescribed in the Rules which must be undertaken to the standards specified by AEMO. AEMO also undertakes audits of our meter testing compliance. We therefore have no alternative option to undertaking CT meter testing.

Table 15.12 sets out our proposed step change in operating expenditure for CT meter testing.

Table 15.12 CT meter testing step change ($m, real)

	2016	2017	2018	2019	2020
CT meter testing step change	0.37	0.40	0.41	0.41	0.42

Source: Powercor

Scale escalation

For each category of operating expenditure, we have analysed the costs incurred and identified the proportion of costs that increase with the number of meters in service. This is set out in table 15.14.

We have forecast the growth rate in the volume of meters in service based on our forecast of new connections less our forecast of abolishments. New connections are only forecast for the 2016 year. From 1 January 2017, following the expiry of the derogation, we have forecasted zero growth in new metering connections. Our forecasts of abolishments are based on forecast abolishments for standard control services.

Table 15.13 sets out the growth rate in meter volumes for the 2016-2020 regulatory control period.

Table 15.13 Meter volume growth rates (per cent)

Meter connection volumes	2016	2017	2018	2019	2020
Gross new connections	1.98	-	-	-	-
Customer abolishment rate	-0.35	-0.35	-0.35	-0.35	-0.35
Customer supply upgrade rate	-	-0.12	-0.12	-0.12	-0.12
Net customer growth rate	1.63	-0.47	-0.47	-0.47	-0.47

Source: Powercor

We have calculated the proportion of each category of operating expenditure that varies with meter volumes as shown in table 15.14.

Table 15.14 Proportion of operating expenditure that varies with meter volumes

Operating expenditure category	Explanation	Proportion of variable costs
Meter data services	Back-office activity relating to data management and processing increases as a result of meter volume growth.	50%
Meter maintenance	Meter testing and investigation activity increases as a result of meter volume growth.	50%
Customer service	Back-office activity relating to customer services such as service order processing increases with meter volume growth.	75%
Backhaul communications	Back-haul communications costs are directly proportional to the volume of meter data being collected and transmitted via 3G access points.	100%
Communication operation	Back-office activity relating to monitoring meter communication activity increases as a result of meter volume growth.	75%
Direct Overheads	Relatively fixed costs.	0%

Operating expenditure category	Explanation	Proportion of variable costs
Corporate overheads	Relatively fixed costs.	0%
IT	Ongoing annual licence fees for UtilityIQ increase in direct proportion to meter volume.	80%

Source: Powercor

To calculate scale escalation rates we multiple the net growth in meter volumes from table 15.13 by the proportion of costs that vary with meter volumes from table 15.14. The resulting scale escalation rates are presented in table 15.15.

Table 15.15 Operating expenditure scale escalation rates (per cent)

Operating expenditure category	2015	2016	2017	2018	2019	2020
Meter data services	0.8	1.6	1.4	1.2	0.9	0.7
Meter maintenance	0.8	1.6	1.4	1.2	0.9	0.7
Customer services	1.2	2.5	2.1	1.7	1.4	1.0
Backhaul communications	1.6	3.3	2.8	2.3	1.8	1.4
Communication operations	1.2	2.5	2.1	1.7	1.4	1.0
Direct and corporate overheads	-	-	-	-	-	-
IT	1.3	2.6	2.2	1.9	1.5	1.1

Source: Powercor

Real price escalation

For each operating expenditure category we have identified the costs in the 2014 base level expenditure that are associated with each of labour, materials and contracts costs. The proportion of labour, materials and contracts costs in each operating expenditure category is presented in table 15.16.

Our real price escalators for metering services operating expenditure is the same as the real price escalators developed for standard control services, refer to chapter 7.

We have applied the real price escalators to the respective labour, materials and contracts costs in the 2014 base level of expenditure for each category of metering operating expenditure.

Table 15.16 Proportion of operating expenditure (per cent)

Operating expenditure category	Proportion of operating expenditure
Labour	83
Materials	7
Contracts	10

Source: Powercor

15.3.6 Tax allowance

The tax allowance is calculated in the PTRM. The cumulative tax loss as at 31 December 2015, opening tax assets as at 1 January 2016 and standard tax lives are sourced from the AER's approved 2015 charges application model, updated with actual 2014 revenue and expenditure, refer to the attached model, *PAL Metering PTRM*. The value of imputation credits over the 2016-2020 regulatory control period is the same as that used for standard control services, refer to chapter 12.

15.3.7 Annual revenue requirement

Based on the above building blocks components we have derived the annual revenue requirement for the 2016-2020 regulatory control period as set out in table 15.17.

Table 15.17 Annual revenue requirement ($m, real)

	2016	2017	2018	2019	2020
Depreciation	34.68	37.04	35.56	23.51	24.25
Return on capital	23.72	21.94	19.47	16.89	15.22
Operating expenditure	15.89	15.45	15.60	15.75	15.92
Tax	-	-	-	-	5.22
Unsmoothed revenue requirement	74.29	74.42	70.62	56.15	60.61
X-factor (%)	15	6.3	6.3	6.3	6.3
Smoothed revenue requirement	76.28	71.46	66.95	62.72	58.76

Source: Powercor

15.3.8 Control mechanism

The F&A Paper requires that a revenue cap be applied to metering alternative control services. The F&A Paper sets out our proposed control mechanism for metering services. We agree with these formulae.

15.4 Exit fee

We have implemented the smart meter roll out over the period 2009 to 2014 in accordance with the derogation and AMI OIC. In undertaking the roll out, we have incurred significant costs which we are currently recovered from customers over the life of the assets.

In accordance with the AMI OIC, we propose an exit fee apply to a customer that chooses to replace the meter we installed under the derogation with a competitively sourced meter.

We propose the exit fee include three key components:

- recovery of the sunk investment costs;
- administrative costs to facilitate meter exit; and
- costs to ensure no other customer is made worse off. These costs are effectively the costs of lost economies of scale which should be borne by exiting customers rather than remaining customers.

A key philosophy that we have applied to develop our proposed exit fee is that no customer should be made worse off by another customer's decision to exit. As discussed in section 15.4.3, economic efficiency is best achieved when there are no cross subsidies and customers face the full economic costs of the decision whether to replace an existing metering installation.

15.4.1 Recovery of sunk investment costs

Sunk investment costs associated with the smart meter roll out which we propose should be recovered from an exiting customer include:

- the remaining RAB value associated with meter purchase and capitalised installation costs. We have divided the RAB value into meter categories to reflect the different costs of purchasing different types of metering installations. We then divide the RAB value for each category by the volume of meter installations (NMIs) in each category to calculate the share of the RAB value that is payable by an exiting customer. The relevant exit fee for a particular customer therefore depends on the meter type that the exiting customer currently has installed; and
- the customer's share of the RAB value associated with the IT system, the communications network and other shared costs relating to project deployment and project management. The exiting customer's share is based on the RAB value divided by the number of existing metering customers (based on number of NMIs) as at 31 December 2016. This component of the sunk investment cost does not vary with the type of metering installation.

The sunk investment cost to be included in the exit fee reduces over the 2017 to 2020 period. This is because the RAB value reduces over time as the average remaining life of the assets decline and the exit fee is calculated for each year of the 2017 to 2020 period based on the RAB values at the beginning of the relevant year.

The exit fee does not take into account the specific age of the exiting customer's metering installation as this would be administratively uneconomic. We also make no allowance for meters that may be reusable as the cost of recycling meters is expected to be uneconomic.

15.4.2 Administrative costs

This component of the exit fee captures the cost of facilitating exit of the customer's meter installation including:

- back-office processing costs, including data management costs; and
- costs of processing and disposal of returned meters.

The administrative fee is the same irrespective of the meter installation type or the year in which exit occurs.

We have considered whether it would be economic to recycle or scrap returned meters. We consider the handling and logistics costs of implementing either approach would exceed the potential benefits. In particular, recycling meters would also require re-testing and re-verification of the meters before deployment.

15.4.3 No customer worse off

As a result of meters exiting the network there will be a loss of economies of scale in terms of our fixed component of operating expenditure and the efficiency of the meshed communications network.

As a result of a customer exiting the average operating expenditure per meter will increase. 41 per cent of our operating expenditure costs are fixed. To ensure that remaining customers are not made worse off, we propose that exiting customers should pay the net present value of a share of the fixed operating costs incurred over the remaining years in the regulatory control period from the year of exiting. We calculate the share of fixed operating costs based on the forecast number of customers (NMIs) as at 31 December 2016, the end of the derogation. The net present value of future operating costs is discounted based on the rate of return applied for standard control services.

Additionally, our metering communications network is a meshed network. The mesh nature of the network means that data is transmitted to the data collection point using the most efficient route, this includes transmission of data via other smart meters. To maintain effective communications when meters are removed from the network additional communications devices are required to infill the gaps created by removed meters. We have calculated the communications infill component of the exit fee by:

- calculating the ratio of communications assets per NMI as at 31 December 2016;
- calculating the increase in communications devices required to maintain the ratio of communications assets to NMIs when a meter is removed from the network; and
- calculating the cost of the increase in communications devices required to maintain the current ratio based on the unit cost of purchasing the communications devices and the labour cost of installing these devices.

15.4.4 Exit fee value and recovery

Table 15.18 sets out our proposed exit fee for each meter installation type for each year from 2017 to 2020 based on the above three cost components. The calculations are set out in the attached model, *PAL Metering Exit Fees*.

To promote economic efficiency, we propose that the exiting customer should pay the full value of the exit fee. This is necessary to ensure that each customer makes the decision which reflects the actual economic costs to society of the decision to exit. Otherwise, if a customer faces less than the full economic costs of exit, its individual decisions may be inefficient when considered from broader society perspective. It is inappropriate for non-exiting customers to bear the burden of the costs of exiting customers.

Essentially, we consider economic efficiency is best promoted when the benefits of competition (which will flow exclusively to individual customers as a result of their individual decision to change metering coordinators) do not exceed the costs imposed on other participants and consumers in the electricity industry. This can only be achieved if exit fees are fully cost reflective and payable by the decision making party.

The AEMC also states that the regulatory framework should not encourage the inefficient replacement of existing Victorian AMI meters and it is therefore appropriate for customers to pay an exit fee.[260]

We note that the AER's Draft Decision for the NSW distributors involved metering exit fee costs being recovered through standard control services revenue.[261] We consider that applying the same approach in Victoria would be inconsistent with the AMI OIC. The AMI OIC states that:

- an exit fee must be paid by the retailer to the distributor, where the retailer becomes responsible for the metering installation previously the responsibility of the distributor (clause 7.1); and

[260] AEMC, Draft Rule Determination, National Electricity Amendment (Expanding competition in metering and related services) Rule 2015, National Energy Retail Amendment (Expanding competition in metering and related services) Rule 2015, March 2015, p.75.

[261] AER, Draft Decision Ausgrid distribution determination 2015-26 to 2018-19, Attachment 16 Alternative control services, November 2014, p. 29.

- the exit fee is to be determined in such a way that enables the distributor to recover the costs in a lump sum which is payable upon a change in the person responsible for the metering installation (clause 7.2).

Consequently, the exit fee must be payable in full upon exit and by the person that takes responsibility for the metering installation.

Further, in March 2015, the AER released a consultation paper seeking feedback on a proposal that the exit fee for NSW, ACT, Queensland and South Australian distributors only include the cost of removing the existing meter. The costs of the meter asset base would then be recovered through an annual charge on all customers, including customers that have exited. We also consider that this proposal could not be implemented in Victoria as the AMI OIC specifies that the exit fee must be a lump sum payment and must include both the costs of removing the meter installation and the unavoidable costs that a prudent distributor has incurred or would incur as a result of the metering installation being removed before the expiry of its economic life.

Table 15.18 Exit fees ($, nominal)

	2017	2018	2019	2020
AMI 1P	478.12	432.72	390.05	356.49
AMI 3P	596.56	537.29	489.46	450.45
AMI 3P CT	1,209.92	1,101.08	1,025.62	957.48
Non AMI NMIs	41.92	42.63	43.35	44.08

Source: Powercor

15.5 Restoration fee

The F&A Paper proposes that a restoration fee would apply where, as a metering provider of last resort, a distributor reinstates a metering installation or a distributor replaces a defective installation.[262]

We do not propose a restoration fee as we have assumed that we will not be the metering provider of last resort upon the expiry of the derogation. As noted in section 15.2, we will update our assumptions for the revised Regulatory Proposal for any known changes in the metering contestability framework. We also propose a pass through event for the additional costs associated with changes in the metering contestability framework, including the costs of providing metering of last resort services should this be a legislated requirement, refer to chapter 14.

[262] AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, October 2014, p.54, footnote 117.

16 Non standard control

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16. Non standard control

16.1 Introduction

This chapter provides information in relation to alternative control services and addresses the requirements of the National Electricity Rules (**Rules**) and paragraphs 12, 13 and 15 of the Australian Energy Regulator (**AER's**) Regulatory Information Notice (**RIN**). Alternative control services are ancillary network services, public lighting and some metering services which are not categorised as standard control services. The alternate control services described in this chapter are ancillary network services in section 16.2 and public lighting in section 16.3.

Metering services, whilst also classified as alternative control services, are outlined in chapter 15.

We are proposing the methodology for calculating ancillary network service charges for the next regulatory control period remain largely the same as the methodology used in the current regulatory control period. While we propose a bottom up build for public lighting for the 2016-2020 regulatory control period consistent with the current regulatory period, the service classification for public lighting services has changed with only shared public lighting assets classified as alternative control services as per the Framework and Approach (**F&A**) Paper.

16.2 Ancillary network services

The F&A Paper proposes classifying alternative control services, fee based services and quoted services, as they are termed in the current regulatory period, with a single group called 'ancillary network services'. Ancillary network services are 'non-routine services provided to individual customers on an 'as needs' basis'. The charges, however, are still grouped based on whether they are a fee based service or a quoted service.

16.2.1 Fee based services

Nature of the service

Fee based services are activities that are relatively fixed in nature and are charged on a per activity basis. A description of our fee based services is provided in table 16.3.

Changes to the services

We accept the service classification as specified by the F&A Paper, however, there are a number of services we do not offer, refer to table 16.1

Table 16.1 Differences between AER's, and our proposed, fee based services classification

Service	AER's classification in F&A paper	Proposed amendments
Temporary disconnect/reconnect services	Alternative control (fee-based)	Delete as not used
PV & small generator installation pre-approval (up to 5kW) 263	Alternative control (fee-based)	Delete, no longer provided due to a change in obligations
PV & small generator installation pre-approval (>5kW) 264	Alternative control (fee-based)	Delete, no longer provided due to a change in obligations
Re-test of types 5 and 6 metering installations (including smart meters) for first tier customers with annual consumption greater than 160 MWh	Alternative control (fee-based)	Delete as not used
Fault response – not DNSP fault	Alternative control (fee-based)	Delete as not used
Temporary supply services	Alternative control (fee-based)	Delete as not used
After hours field based re-energisation services	Alternative control (fee-based)	Delete as not used.
Manual meter read charge	No classification	Alternative control (fee based) – for customers that are not able to have their cyclical meter readings read remotely.[265]
Customer access to metering data	No classification	Alternate control (fee based) – for customers requesting non-standard provision of meter data.

Source: Powercor

Methodology

Our proposed methodology for developing charges for fee based services involves applying a bottom up build of labour, materials and or contractor costs. We have quantified the labour costs for each fee based service by:

- identifying the tasks involved in performing each fee based service;
- quantifying the time that each task will take;
- identifying the types of personnel that will be required to undertake each task, based on the skills required;
- quantifying the number of personnel that are required to undertake each task; and
- developing a labour rate, including an escalator, for each type of personnel required.

This methodology has been chosen to provide the most cost reflective assessment of these activities.

263 Changes to the "Service Installation Rules" (2014) (SIR's) has resulted in Powercor Australia desiring to change to an audit based approach to inspecting small scale PV connections rather than charging for every site installation.

264 Changes to the "Service Installation Rules" (2014) (SIR's) has resulted in Powercor Australia desiring to change to an audit based approach to inspecting small scale PV connections rather than charging for every site installation.

265 Advanced Metering Infrastructure Order in Council 2014, Government Gazette S263, 5 August 2014.

Labour, contract and material rates and escalation factors

We use internal and outsourced labour to provide fee based services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

Fee based services have a number of materials associated with routine connections including service cable, fuses, clamps and brackets.

The input price escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

Update delivery times and personnel requirements

The back office and field activity inputs in relation to time allocation and number of personnel have all been reviewed based on actual times and number of personnel that are required to complete each activity as at 2014. This involved looking through work plans and discussions with technical experts. Given that the delivery times and personnel requirements changed very little they have remained the same as the current regulatory control period.

Margins

We propose a profit margin of seven per cent in accordance with a KPMG report which has benchmarked margins earned by similar service contractors.

Charges, revenue and unit costs

Section 2.1 of the F&A Paper indicates the control mechanism to apply to ancillary network services in the 2016-2020 regulatory control period is caps on the prices of individual services.

We have developed our proposed price caps for each fee based service based on a bottom up approach.

In accordance with the price control formula in the F&A Paper, the price caps for each service increase each year from 2016 to 2020 by (1+CPI)(1-X), where X is different for each service and each year. This is demonstrated in the attached *PAL ACS Model.*

The indicative charges and revenues for our fee based services for each year of the 2016-2020 regulatory control period is also detailed in the *PAL ACS Model* attachment. A description of our fee based services is provided in table 16.3.

Information about the unit cost inputs for labour and material categories used to calculate the proposed charges for fee based services in the next regulatory control period can be found in the *PAL ACS Model* attachment.

16.2.2 Quoted services

Nature of the service

Quoted services are charges levied on a time and materials basis. These services are highly variable. A description of our quoted services is provided in table 16.4.

Methodology

Our proposed methodology for developing charges for quoted services involves recovering the costs of both labour and materials. Unlike the charges for fee based services, the charges for quoted services are developed on a case by case basis in order to meet the specific needs of the customer.

We quantify labour costs for each quoted service by:

- identifying the tasks involved in performing the quoted service;

- quantifying the time that each task will take;
- identifying the types of personnel that will be required to undertake each task, based on the skills required;
- quantifying the number of personnel that are required to undertake each task; and
- applying a labour rate for each type of personnel required.

We quantify the material costs, where applicable, for each quoted service by:

- identifying the tasks involved in performing the quoted service;
- identifying the type and number of materials that are required for each task; and
- applying a materials rate for each type of material required.

This methodology is consistent with the current regulatory control period.

Labour, contract and material rates and escalation

We use internal and outsourced labour to provide quoted services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

The labour and contracts price escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

Where quoted services include materials these are passed onto customers at cost.

Charges, revenue and unit costs

Section 2.1 of the F&A Paper indicates the control mechanism to apply to ancillary network services in the 2016-2020 regulatory control period is caps on the prices of individual services.

We have developed our proposed price caps for each quoted service based on a bottom up approach.

In accordance with the price control formula in the F&A Paper, the price caps for each quoted service increase each year from 2016 to 2020 by (1+CPI)(1-X), where X is different for each service and each year. This is demonstrated in the attached *PAL ACS Model.*

The indicative charges and revenues for our quoted based services for each year of the next regulatory control period are also detailed in the *PAL ACS Model* attachment. A description of our quoted services is provided in table 16.4.

Information about the unit cost inputs for labour and material categories used to calculate the proposed charges for quoted services in the 2016-2020 regulatory control period is in the *PAL ACS Model* attachment.

16.3 Public lighting

16.3.1 Nature of the service

We provide public lighting services for thirty nine customers including local councils and Victorian government departments responsible for public lighting. The provision of public lighting, minimum standards and the obligations of distributors and public lighting customers is regulated by the *Victorian Public Lighting Code* (**Public Lighting Code**). A copy of the *Public Lighting Code* is attached.

There are a number of public lighting services, including a new category relating to dedicated public lighting assets, detailed in table 16.2.

Table 16.2 Different public lighting services

Service	Classification of Services
Operation, maintenance, repair and replacement of shared public lighting assets	Alternative control service
Operation, maintenance, repair and replacement of dedicated public lighting assets	Negotiated service
Provision of new public lighting	Negotiated service
Alteration and relocation of DNSP public lighting assets	Negotiated service

Source: F&A Paper

For alternative control services, we propose using the AER's 2011–2015 price reset public lighting model updated for the next regulatory control period and a number of inputs including updating the light types for new and eliminated light types, traffic management costs, updates to the expected fault rates and removing operation, maintenance, repair and replacement of dedicated public lighting assets.

For avoidance of uncertainty we understand dedicated public lighting assets to be those assets which are attributed to a single customer (not cost shared assets) and which are specialised public lighting columns and the associated lighting equipment on those columns. The operation, maintenance and replacement costs associated with these assets have been removed from the attached *PAL ACS Model* and must be recovered through a negotiated service regime which is further discussed in section 16.4.3.

16.3.2 Treatment of services

Given that energy efficient lighting offers lower energy usage and reduced greenhouse emissions, public lighting customers have been negotiating with distributors to replace existing public lighting with more energy efficient public lighting during the current regulatory control period. We expect this movement to continue into the 2016-2020 regulatory control period and have updated the public lighting model accordingly.

The *Public Lighting Code* defines standard lighting as:

'a lamp, luminaire, mounting bracket, public lighting pole, supply cable or control equipment, normally used by or acceptable to a distributor.'

All other fittings are classed as non-standard lighting. We are obligated under clause 9.1 of our *Electricity Distribution Licence* to make an offer where a public lighting customer requests operation, maintenance, repair or replacement (**OMR**) services for public lighting with non-standard fittings. In such circumstances we charge for non-standard lighting. We propose to charge the same rate for both light fitting types.

For the 2016-2020 regulatory control period we propose to eliminate light types that are no longer in use and to include light types which have been treated as negotiated during the current regulatory control period, due to them not being available at the last price reset.

16.3.3 Methodology

We have adopted the AER's 2011–2015 public lighting model for the purposes of determining the public lighting charges for the next regulatory control period.

Labour rates

We use internal and outsourced labour, determined through competitive tenders, to provide public lighting services.

We have adopted the 2014 labour rates which have been escalated for the next regulatory control period.

Material rates

We have a number of material types associated with public lighting services including:

- lamp – a source made in order to produce an optical radiation;
- photoelectric cell – a device that uses changes in light to generate current;
- luminaire – an apparatus which distributes, filters or transforms the light transmitted from one or more lamps and which includes, other than the lamps themselves, all the parts necessary for fixing and protecting the lamps and where necessary circuit auxiliaries together with the means for connecting them to the distribution system; and
- miscellaneous materials – miscellaneous material required to undertake the bulk light change and fault repairs including cable, fuseholders and connectors.

Input price escalation

The input escalation rates for alternative control services are consistent with standard control services, as set out in chapter 7.

Rate of return

We have used a rate of return consistent with that applied to standard control services, refer to chapter 12.

Traffic management

In some instances traffic management is required in order to perform public lighting services. This cost is a requirement to comply with the *Roads Management Act 2004*. This is also required to comply with the *Occupational Health and Safety Act 2004*, which requires us to, amongst other general workplace health and safety obligations, ensure so far as is reasonably practicable the safety of any workplace that we manage or control. This obligation extends to any person at the workplace, including, for example, employees of any contractor engaged by a municipal council to perform public lighting maintenance services. We have reviewed historical costs to determine what this activity costs us. The costs are determined by the public lighting contract which is developed through a competitive tender process.

Proportion of luminaires that fail between bulk changes

Fault rates have been updated based on analysis of the actual fault rates experienced over the last five years with the average used to determine the rate over four years. Fault rates for T5 and P LED light types have remained unchanged due to limited actual historical data.

16.3.4 Charges, revenue and unit costs

We have provided a completed version of the AER's public lighting model refer to the attached *PAL Public Lighting ACS Model.*

Section 2.1 of the F&A Paper indicates the control mechanism to apply to public lighting services in the 2016-2020 regulatory control period is caps on the prices of individual services. We have determined our charges for each public lighting service based on the outputs of the public lighting model.

Information about our charges and revenues from public lighting services for each year of the 2016-2020 regulatory control period is provided in the attached, *PAL Public Lighting ACS Model*.

Given that the OMR of dedicated public lighting assets are no longer classified as alternative control services, this provides a considerable change in relevant alternative control service charges and total revenue from the current to the 2016-2020 regulatory control period.

The attached public lighting model contains the proposed unit cost inputs for labour and material categories used to calculate the proposed charges for public lighting services in the 2016-2020 regulatory control period. We have applied input price escalators for public lighting consistent with standard control services, refer to chapter 7.

16.4 Negotiated distribution services

16.4.1 Nature of the service

Services classed as negotiated distribution services have prices which are negotiated directly between the distributor and customers. The requirements for the negotiation are determined by the negotiated distribution service criteria and the negotiating framework. The AER has classified the following services as negotiated for the 2016–2020 regulatory control period:

- operation, maintenance and repair of dedicated public lighting assets;
- replacement of dedicated public lighting assets;
- alteration and relocation of Network Service Provider (**NSP**) public lighting assets; and
- new public lights (including greenfield sites).

16.4.2 Negotiated distribution service criteria

Clause 6.7.4 of the rules sets out the negotiated distribution service criteria (**criteria**) such as the terms and conditions of access for the negotiated distribution services and dispute resolution.

16.4.3 New negotiated service for OM&R for dedicated public lighting assets.

The AER's F&A Paper retained the classification of alternate control service for shared public lighting assets while determining to classify dedicated public lighting assets as a negotiated service.

We have understood from the F&A Paper that dedicated public lighting assets are those which are attributed to a single customer (not shared assets) and which are specialised public lighting columns and the associated lighting equipment on those columns.

The classification of dedicated public lighting as a negotiated service means that the replacement costs for dedicated public lighting columns has to be recovered through the negotiated service charge and as such the OMR for dedicated assets will be higher than the OMR charges for public lighting under the alternative control services.

While this Regulatory Proposal deals only with the specific prices for public lighting services classified as alternative control services, we strongly encourage the AER to take a detailed approach in setting out the criteria that will be applied by the AER in resolving any dispute about the terms and conditions of access including the price that is to be charged for the provision of a negotiated distribution service by the provider as required under clause 6.7.4 of the rules.

The following are some of the key assumptions or understandings that will inform our criteria for neogtiating terms and conditions for access including prices for the public lighting assets now classified as negotiated:

- we propose using the AER's 2011–2015 price reset public lighting model updated for the next regulatory control period and a number of inputs including updating the light types for new and eliminated light types, traffic management costs, updates to the expected fault rates and removing operation, maintenance, repair and replacement of shared public lighting assets;

- the prices determined through the above model will be the default price applied to dedicated public lights until and unless an alternate price is negotiated;
- replacement costs will be allocated across the pool of dedicated assets as they were when these assets were classified as alternate control;
- consistent with commentary in the AER's F&A Paper;
- public lighting assets which are built to the VESI standards (rather than general wiring standard) will remained owned by us; and
- access to public lighting assets owned by and directly connected to our distribution network must be in line with our processes as covered in our approved Energy Safety Management Scheme.

16.4.4 Negotiating framework

The negotiating framework sets out the procedure to follow during negotiations with any person who wishes to receive a negotiated distribution service, as to the terms and conditions for the provision of the service. The negotiating framework has been prepared to comply with the requirements of part D of chapter 6 of the Rules.

We have retained the negotiating framework approved for the 2011–2015 regulatory control period but have amended it to include additional classifications as per the F&A Paper. We will apply our negotiating framework where it is required to provide a negotiated service.

Refer to attachment, *Negotiating framework*.

Table 16.3 Description of fee based services

Fee based service	Description
Routine connections – customers below 100 amps	This charge applies when a customer with a supply point with fuses less than 100 Amps moves into a new premises and requests supply. Different charges apply depending on whether we are responsible for the meter or not, whether the meter is single or multi-phase and whether the service is provided during or after business hours.
Temporary disconnect/reconnect services	This charge applies when a request is received to temporarily either disconnect or reconnect a supply point.
De-energisation of existing connections	This charge applies when a request is received to disconnect at a supply point for fuses less than 100 amps by a field visit. This charge includes Disconnection for non-payment. This service is only provided during business hours.
Re-energisation	This charge applies when a request is received to re-energise a supply point for fuses less than 100 amps by a field visit. Three options for re-energisation are available: • reconnections (same day) business hours only; • reconnections (incl. Customer Transfer) business hours; and • reconnections (incl. Customer Transfer) after hours.
PV & small generator installation pre-approval (up to 5kW)	The PV Installation charge applies prior to connection of small scale embedded generation up to 5kW to the network. This charge specifically covers the inspection of the customer's site to ensure safe connection to the network and includes anti-islanding testing.
PV & small generator installation pre-approval (>5 kW)	The PV Installation charge applies prior to connection of small scale embedded generation greater than 5kW to the network. This charge specifically covers the inspection of the

Fee based service	Description
	customer's site to ensure safe connection to the network and includes anti-islanding testing.
Meter investigation	This charge applies when a request is received to investigate the metering at a given supply point. This request may be initiated by either the retailer or a customer. Different charges apply depending on whether the service is provided during or after business hours.
Meter testing	This charge applies when a request is made to test the accuracy of a meter at a given supply point. Different charges apply depending on the type of meter being tested, if it is the first or subsequent meter and whether the meter is single or multi-phase and whether the service is provided during or after business hours.
Special meter reading	This charge applies when a request for a Special Meter Read is to be performed by a field visit outside the scheduled meter reading cycle. Where customers have multiple metering installations, such as farms and units, a separate charge applies to each meter on the property. This service is only available during business hours.
Re-test of types 5 and 6 metering installations for first tier customers with annual consumption greater than 160 MWh	This charge applies to customers with an annual consumption greater than 160MWh who do not have a metering installation that has the capability of a type 1, 2, 3 or 4 installations which requires re-testing.
Fault response – not DNSP fault	This charge applies when we make a service truck visit at the request of a customer or contractor where the fault is found to be caused by the customer, rather than us. For example, the customer would be at fault: • where they are not receiving supply and they have not checked that the cause is that the main switch or safety switch is not in the 'on' position; and • where there are quality of supply issues that have been caused downstream of our distribution system. Different charges apply depending on whether the service is provided during or after business hours.
Wasted attendance – not DNSP fault	This charge applies to service truck visits requested where: • the crew arrives to find the site is not ready for the scheduled work within 15 minutes of arriving; • the truck attendance is no longer required once on site; • 24 hours' notice is not provided for a cancellation; • the site is locked with a non industry lock; • asbestos removal or warning on site; • scaffolding obstructing meter position; • non adherence to VESI Service and Installation Rules; or • other issues associated with safety assessment of the site. Once the site is ready for the service truck visit another appointment needs to be booked and the normal service truck visit charge applies. Business hours and after hours charges apply where appropriate.
Service truck visits	This charge applies when a service crew is requested for up to an hour in a number of circumstances including:

Fee based service	Description
	• disconnection of complex site; • reconnection of complex site; • metering additions or alternations; and • shutdowns. While larger scale works will be charged through a Quoted Service 'After hours truck by appointment' charge, where the job unexpectedly goes above the hourly mark additional half hourly intervals will be charged up to two hours. Different charges apply depending on whether the service is provided during or after business hours.
Temporary supply services	This charge applies when a customer requests a temporary supply. This also applies where a builder wishes to provide a temporary supply to new properties under construction.
Remote de-energisation	This charge applies when a request is received to de-energise a customer that has smart metering and related infrastructure in place which is then used to disconnect the customer from our network.
Remote re-energisation	This charge applies when a request is received to re-energise a customer that has smart metering and related infrastructure in place which is then used to connect the customer to our network.
Manual meter reading	This charge applies to customers who have elected not to have their manually read meter replaced with a remotely read smart meter.
Customer access to meter data	This charge applies when a request is received from a customer more than four times in any given 12 month period; or in a different manner or form than specified in the AEMO metering data provision procedures; or by a customer authorised representative as part of a request for information about more than one customer.

Table 16.4 Description of quoted services

Quoted service	Description
Routine connections - customers above 100 amps	This charge applies when customers above 100 amps request a routine connection.
Supply abolishment (>100 amps)	This charge applies when customers above 100 amps request a permanent removal of our supply assets. A separate charge applies per site.
Rearrangement of network assets at customer request, excluding alteration and relocation of existing public lighting assets	This charge applies when a customer requests capital work for which the prime purpose is to satisfy a customer requirement other than new or increased supply, other than where Guideline 14 is applied. Examples include: • Vic Roads and Council requested asset relocations to allow for new road works; and • customer removal or relocation of service wire to allow work on private installation.
Auditing, design and construction	This charge applies when either a third party requests or we deem it necessary to review, approve or accept work undertaken by a third party.

Quoted service	Description
	Examples include: • customer provided buildings, conduits or ducts used to house our electrical assets; • customer provided connection facilities including switchboards used in the connection of an electricity supply to their installation; • any electrical distribution work completed by our approved contractor that has been engaged by a customer under Option 2 provisions; • provision of system plans and system planning scopes, for Option 2 designers; and • reviewing and/or approving plans submitted by Option 2 designers.
Specification and design enquiry fees	This charge applies when an element of detailed design is required to fairly assess the costs so that an Offer for Connection Services can be issued to a customer. Examples include: • the route of the network extension required to reach the customer's property; • the location of other utility assets; • environmental considerations including tree clearing; and • obtaining necessary permits from State and Local Government bodies.
Elective undergrounding where above ground service currently exists	This charge applies when a customer with an existing overhead service requests an underground service, other than where Guideline 14 is applied.
Damage to overhead service cables caused by high load vehicles	This charge applies to an identifiable third party when overhead service cables require repairing because they have been damaged by high load vehicles pulling down cables.
High load escorts —lifting overhead lines	This charge applies when a third party requires safe clearance of overhead lines to allow high load vehicles to pass along roads.
Covering of low voltage mains for safety reasons	This charge applies when customers request coverage of powerlines for safety reasons. The charge applied will depend on the time taken to perform the service. Differing charges can arise as a result of the type of line being covered; street mains (two wires or all wire) or service cables.
After hours truck by appointment	This charge applies when a request is received to undertake larger scale works by a Service Truck. Examples of types of works include: Disconnection of complex site; Reconnection of complex site; Metering Additions or Alternations; and Shutdowns (includes preparation works).
Reserve feeder maintenance	This charge applies when a customer requests continuity of electricity supply should the feeder providing normal supply to their connection experience interruption. The fee covers the maintenance of the service, it does not include the capital required to implement or replace the service as this is covered in the connection agreement. This service is not available to new customers.

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Glossary 17

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17. Glossary

Term	Definition
ACR	Auto Circuit Recloser
ACS	Alternate control services
ACT	Australian Capital Territory
AEMC	Australian Energy Markets Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMI OIC	Advanced Metering Infrastructure Order in Council
APESMA	Association of Professional Engineers, Scientists and Managers Australia
ASU	Australian Services Union
Augex	Augmentation expenditure model
BAU	Business-as-usual
BMP	Bushfire Mitigation Plan
CAM	Cost allocation methodology
Capex	Capital expenditure
CatA RIN	Category Analysis Regulatory Information Notice
CBRM	Condition based risk management
CEPU	Communications Electrical Plumbing Union
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Bond Securities
CHED Services	CHED Services Pty Ltd (ACN 112 304 622)
CIC	Capital Investment Committee
CIE	Centre for International Economics
CIS OV	Customer Information System - Open Vision
CitiPower	CitiPower Pty (ACN 064 651 056)
CoAG	Council of Australian Government
Code	Victorian Electricity Distribution Code
CoF	Consequence of failure
consumer engagement guideline	Consumer Engagement Guideline for Network Service Providers

Term	Definition
CPI	Consumer Price Index
CRM	Customer Relationship Management
CT meters	Meters with current transformers
DAE	Deloitte Access Economics
DAPR	Distribution Annual Planning Report
Deloitte	Deloitte Touche Tohmatsu
DMIA	Demand Management Innovation Allowance
DMIS	Demand Management Incentive Scheme
DMS	Distribution Management System
DNSP	Distribution Network Service Provider
DRP	Debt Risk Premium
DUoS	Distribution Use of System
EBAs	Enterprise Bargaining Agreements
EBSS	Efficiency Benefit Sharing Scheme
EDPR	Electricity Distribution Price Reset
EGWW	Electricity Gas Water and Waste
ELCMPs	Electric Line Clearance Management Plans
EPA	Environmental Protection Authority
ESCV	Essential Services Commission of Victoria
ESMS	Electricity Safety Management Scheme
ESV	Energy Safe Victoria
EUDs	End user devices
EWOV	Energy and Water Ombudsman (Victoria)
EWP	Elevated work platform
F&A	Framework and Approach Paper Final Framework and approach for the Victorian Electricity Distributors Regulatory control period commencing 1 January 2016
Final Determination	AER's 2011-15 Final Determination
FRMPS	Financially Responsible Market Participants
FW Act	Fair Work Act 2009
GFC	Global Financial Crisis

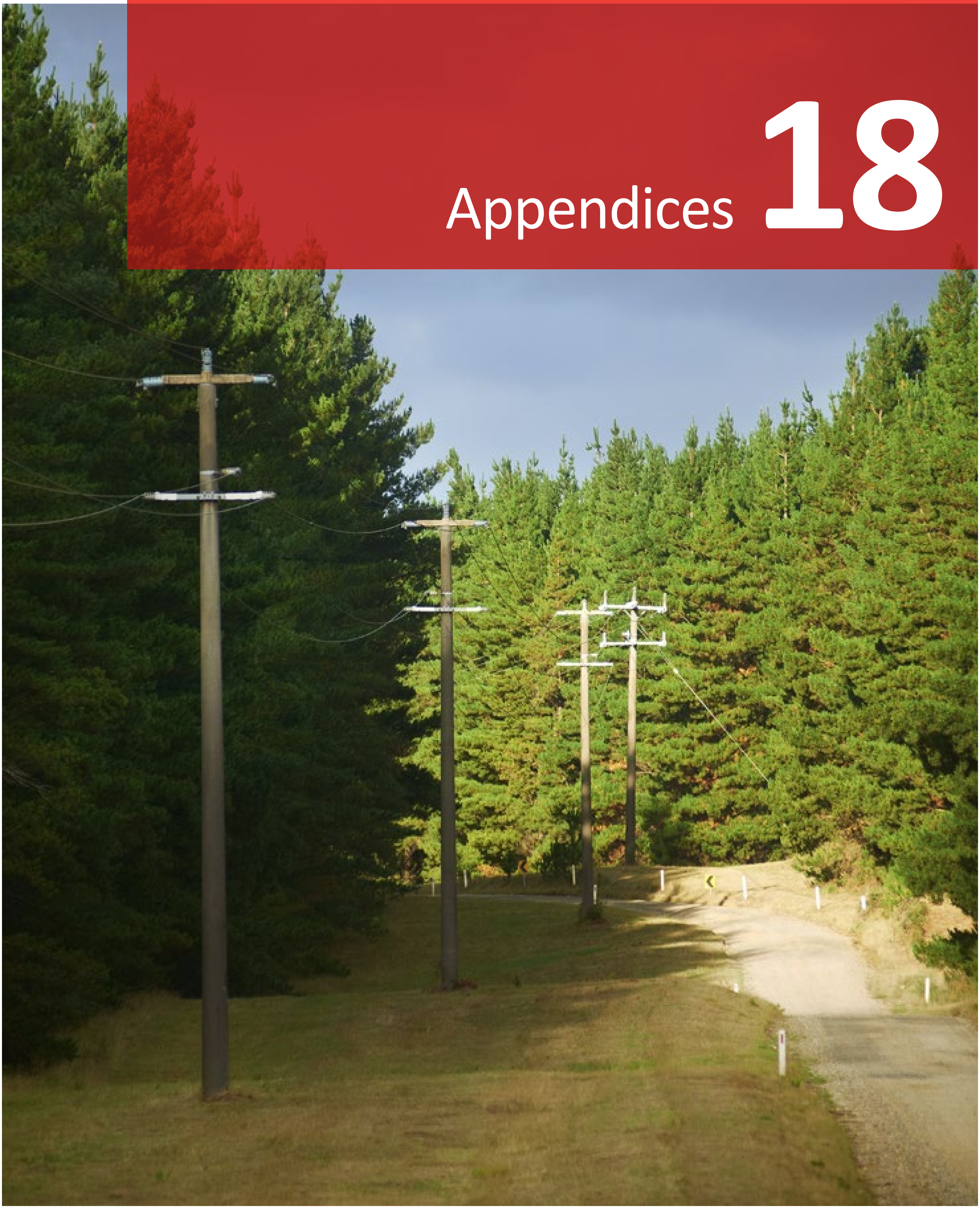
Term	Definition
GFN	Ground fault neutraliser
GSL	Guaranteed service level
GSP	Gross State Product
Guideline 14	Electricity Industry Guideline No 14 – Provision of Services by Electricity Distributors
Guideline 15	Electricity Industry Guideline No 15- Connection of Embedded Generation
GWh	Gigawatt Hour
HAN	Home area network
HBRA	Hazardous bushfire risk areas
HI	Health index
HMIs	Human machine interfaces
HV	High voltage
IAP2	International Association of Public Participation
IC	Incremental cost
IR	Incremental revenue
IT	Information technology
KTS	Keilor terminal station
kV	Kilovolt
kVA	Kilovolt ampere
kW	Kilowatt
kWh	Kilowatt hour
LAN	Local area network
LBRA	Low bushfire risk areas
LGA	Local government area
LI	Load index
LSA	Local service agents
LTIFR	Lost time injury frequency rate
LV	Low-voltage
MAIFI	Momentary average interruption frequency index
MDC	Mildura Development Corporation

Term	Definition
MED	Major event day
MON	Meter outage notification
MRP	Market risk premium
MTIFR	Medical treatment injuries frequency rate
MVA	Megavolt ampere
MW	Megawatts
MWh	Megawatt hour
NBN	National Broadband Network
NECF	National Energy Customer Framework
NEFR	National Electricity Forecast Report
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NEVA	National Electricity (Victoria) Act 2005
NMI	National meter identifier
NPC	Network Planning Committee
NPV	Net present value
NSW	New South Wales
NUOS	Network use of system
NUW	National Union of Workers
OLS	Ordinary least squares
OMR	Operation, maintenance, repair or replacement
OMS	Outage management systems
Opex	Operating expenditure
Order	F-Factor Scheme Order 2011
PB	Parsons Brinckerhoff
PBST	Powerline Bushfire Safety Taskforce
PNS	Powercor Network Services
PoE	Probability of exceedance

Term	Definition
POEL	Private overhead electric line
PoF	Probability of failure
Powercor	Powercor Australia Ltd (ACN 064 651 109)
PTRM	Post tax revenue model
Public Lighting Code	Victorian Public Lighting Code
PV	Photovoltaic
QoS	Quality of supply
RAB	Regulatory asset base
RBA	Reserve Bank of Australia
RCM	Reliability centred maintenance
RECs	Registered Electrical contractors
RECs	Renewable Energy Certificates
REFCLs	Rapid earth fault current limiters
Repex	Replacement expenditure model
Reset RIN	Price Reset Regulatory Information Notice
RET	Renewable energy target
RIN	Regulatory information notice
RIT-D	Regulatory investment test – distribution
RoR	Rate of return
Rules	National Electricity Rules
SA	South Australia
SAIDI	System average interruption duration index
SAIFI	System average interruption frequency index
SCADA	Supervisory control and data acquisition
SCS	Standard control services
SCER	Standing Committee on Energy and Resources
SIRs	Service and Installation Rules
SF	Security fee
SL-CAPM	Sharpe-Lintner Capital Asset Pricing Model

Term	Definition
STPIS	Service Target Performance Incentive Scheme
STPIS Guideline	Electricity distribution network service providers, Service target performance incentive scheme
SWER	Single wire earth return
UK	United Kingdom of Great Britain
US	United States of America
VBRC	Victorian Bushfires Royal Commission
VCR	Value of customer reliability
VESI	Victorian Electricity Supply Industry
VPN	Victoria Power Networks
WACC	Weighted average cost of capital
WPI	Wage price index

Appendices 18



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18. Appendices

Reference	Appendix	Chapter reference	Confidential
PAL PUBLIC APP A	Our customer engagement	6	No
PAL PUBLIC APP B	Labour cost efficiency	7	No
PAL PUBLIC APP C	Demand, energy and customer forecasts	8	No
PAL PUBLIC APP D	Expenditure factors and criteria	9, 10	No
PAL PUBLIC APP E	Capital expenditure	9	No
PAL PUBLIC APP F	Base year adjustment	10	No
PAL PUBLIC APP G	Step change	10	No
PAL PUBLIC APP H	Service target performance incentive scheme	11	No
PAL PUBLIC APP I	Annual updating process for cost of debt	12	No
PAL PUBLIC APP J	Gamma	12	No
PAL PUBLIC APP K	Depreciation method	13	No
PAL PUBLIC APP L	Managing uncertainty	14	No

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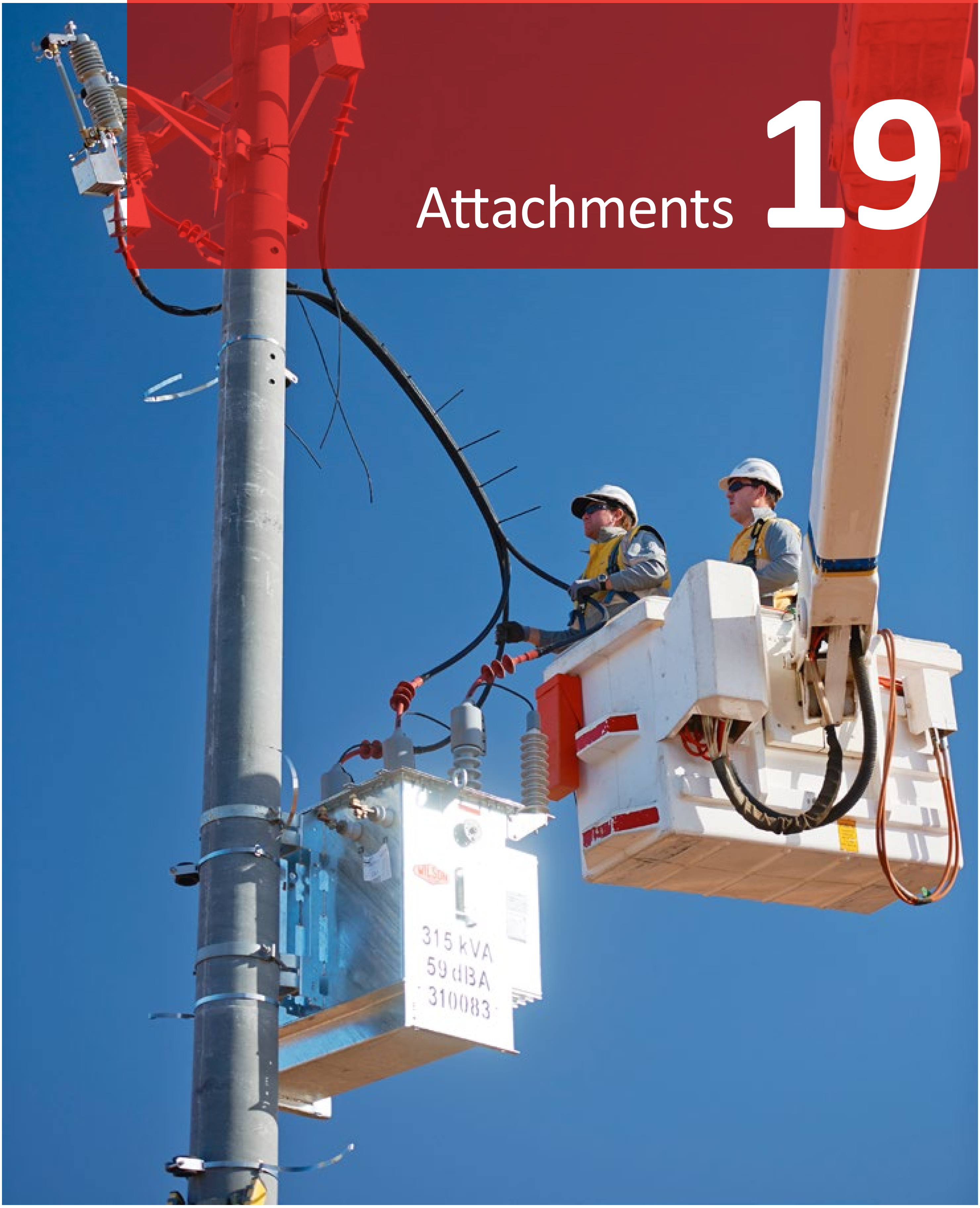
Attachments 19



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19. Attachments

Reference	Attachment	Chapter reference	Confidential
PAL PUBLIC ATT 0.1	Powercor, Certification of reasonableness of key assumptions, 30 April 2015	All	No
PAL PUBLIC ATT 1.1	Oakley Greenwood, Powercor pricing comparisons, 1995 to 2014, 29 December 2014	1,3	No
PAL PUBLIC ATT 1.2	Powercor, NER Cross Reference Matrix, April 2015	1	No
PAL PUBLIC ATT 2.1	Powercor, Bushfire Mitigation Strategy Plan 2014-2019, 2014	2,9	No
PAL PUBLIC ATT 2.2	AER, Final Framework and approach for the Victorian Electricity Distributors, Regulatory control period commencing 1 January 2016, 24 October 2014	2,9,10,11,13, 14,15,16	No
PAL PUBLIC ATT 2.3	Essential Services Commission of Victoria, Electricity Distribution Code, Version 8, 13 October 2014	2,9,10,11	No
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PAL PUBLIC APP E.35	Ofgem, Strategy consultation for the RIIO-ED1 electricity distribution price control – reliability and safety, Supplementary annex to RIIO ED1 overview paper, 28 September 2012	Appendix E	No
PAL PUBLIC APP E.36	AEMO, Jemena and Powercor, Joint Regulatory Test Report: Western Metropolitan Melbourne Transmission Connection and Subtransmission Capacity, 1 May 2012	Appendix E	No
PAL PUBLIC APP E.37	Powercor, Truganina (TNA) Zone substation regulatory test report, 17 March 2014	Appendix E	No
PAL PUBLIC APP E.38	Powercor, Merbein (MBN) and Mildura (MDA) regulatory test report, 11 April 2014	Appendix E	No
PAL PUBLIC APP E.39	Powercor, Geelong East (GLE) zone substation transformer upgrades regulatory test report, 12 June 2014	Appendix E	No
PAL PUBLIC APP E.40	Powercor, Torquay (TQY) zone substation 2018-2019 regulatory test report, 2 May 2014	Appendix E	No
PAL PUBLIC APP E.41	Powercor, Non-network Options report Melton (MLN) and Bacchus Marsh (BMH), 6 August 2014	Appendix E	No
PAL PUBLIC APP E.42	AER, AER augmentation model handbook, guidance document, November 2013	Appendix E	No
PAL PUBLIC APP E.43	AER, Connection charge guidelines for electricity retail customers, Under chapter 5A of the National Electricity Rules, June 2012	Appendix E	No
PAL PUBLIC APP E.44	Devondale Murray Goulburn, Annual Report 2014, October 2014	Appendix E	No
PAL PUBLIC APP E.45	Acciona Energy, Planning assessment report, Berrimal Wind Farm, 16 December 2013	Appendix E	No

Reference	Attachment	Chapter reference	Confidential
PAL PUBLIC APP E.46	Canberra Times, Simon Corbell reveals wind farm auction winners to supply third of Canberra's electricity needs, 5 February 2015	Appendix E	No
PAL PUBLIC APP E.47	Acciona Australia, Mt Gellibrand Wind Farm, website, undated	Appendix E	No
PAL PUBLIC APP E.48	Energy Business News, $3m grant for Mildura biomass, 24 October 2013	Appendix E	No
PAL PUBLIC APP E.49	Mildura Weekly, Bioenergy plant one step closer, 18 July 2014	Appendix E	No
PAL PUBLIC APP E.50	ABC News, Powerline approved for almond plant biomass plans, 21 July 2014	Appendix E	No
PAL PUBLIC APP E.51	WestWind Energy, Application for a generation licence, 2 December 2009	Appendix E	No
PAL PUBLIC APP E.52	2009 Victorian Bushfires Royal Commission, Final Report, Volume 2, Electricity-Caused Fires, 31 July 2010	Appendix E	No
PAL PUBLIC APP E.53	Glenelg Shire Council, Feedback questions, 27 October 2014	Appendix E	No
PAL PUBLIC APP E.54	Wimmera Development Association, Feedback Request—Directions and Priorities Consultation Paper, 22 October 2014	Appendix E	No
PAL PUBLIC APP E.55	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	Appendix E	No
PAL PUBLIC APP E.56	CitiPower and Powercor, Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines, 1 February 2011	Appendix E	No
PAL PUBLIC APP E.57	Adrian Power, Email submission to Directions and Priorities, 21 October 2014	Appendix E	No
PAL PUBLIC APP E.58	Les Kretzschmar, Email submission to Directions and Priorities, 31 October 2014	Appendix E	No
PAL PUBLIC APP E.59	ESC, Compliance with AMI Regulatory Obligations as at 31 December 2013, October 2014	Appendix E	No
PAL PUBLIC APP E.60	KPMG, Business Case for expenditure to meet RIN requirements, April 2015	Appendix E	No
PAL PUBLIC APP E.61	CSC, Infrastructure requirements, October 2014	Appendix E	No
PAL CONFIDENTIAL APP E.62	CHEDHA Holding Companies, SCADA IT Operations, Internal Audit report, September 2012	Appendix E	Yes
PAL PUBLIC APP E.63	Powercor, Material Project, REPL 22 Bulk replacement of CVTs - porcelain bushing risk	Appendix E	No
PAL PUBLIC APP E.64	Powercor, Material Project, REPL 24 Replacement of defective air break switches	Appendix E	No

Reference	Attachment	Chapter reference	Confidential
PAL PUBLIC APP E.65	Powercor, Material Project, AUG 26 MLN new 3rd transformer & feeders	Appendix E	No
PAL PUBLIC APP E.66	Powercor, Material Project, AUG 27 TNA 3rd Transformer and 3rd bus	Appendix E	No
PAL PUBLIC APP E.67	Powercor, Material Project, AUG 37 Volt VAR Control increase	Appendix E	No
PAL PUBLIC APP E.68	Powercor, Material Project, REPL 21 SU: Redevelopment completion	Appendix E	No
PAL PUBLIC APP E.69	Powercor, Material Project, REPL 23 RVL Transformer replacements	Appendix E	No
PAL PUBLIC APP E.70	Powercor, Material Project, REPL 20 Proactive conductor replacement program	Appendix E	No
PAL PUBLIC APP E.71	Powercor, Material Project, REPL 25 Environmental bunding program	Appendix E	No
PAL PUBLIC APP E.72	Powercor, Material Project, VBRC 36 Install REFCL's in HBRA	Appendix E	No
PAL PUBLIC APP E.73	Powercor, Material Project, CUST 29 Murray Goulburn (Cobram) - Stage 1	Appendix E	No
PAL CONFIDENTIAL APP E.73	Powercor, Material Project, CUST 29 Murray Goulburn (Cobram) - Stage 1	Appendix E	Yes
PAL PUBLIC APP E.74	Powercor, Material Project, CUST 30 Murray Goulburn (Koroit) - Stage 1	Appendix E	No
PAL CONFIDENTIAL APP E.74	Powercor, Material Project, CUST 30 Murray Goulburn (Koroit) - Stage 1	Appendix E	Yes
PAL PUBLIC APP E.75	Powercor, Material Project, CUST 31 Coonooer Windfarm	Appendix E	No
PAL CONFIDENTIAL APP E.75	Powercor, Material Project, CUST 31 Coonooer Windfarm	Appendix E	Yes
PAL PUBLIC APP E.76	Powercor, Material Project, CUST 32 Berrimal Windfarm - St Arnaud	Appendix E	No
PAL CONFIDENTIAL APP E.76	Powercor, Material Project, CUST 32 Berrimal Windfarm - St Arnaud	Appendix E	Yes
PAL PUBLIC APP E.77	Powercor, Material Project, CUST 33 Mt Gellibrand Windfarm	Appendix E	No
PAL CONFIDENTIAL APP E.77	Powercor, Material Project, CUST 33 Mt Gellibrand Windfarm	Appendix E	Yes
PAL PUBLIC APP E.78	Powercor, Material Project, CUST 34 Project Harvest Generation-Carwarp	Appendix E	No
PAL CONFIDENTIAL APP E.78	Powercor, Material Project, CUST 34 Project Harvest Generation-Carwarp	Appendix E	Yes
PAL PUBLIC APP E.79	Powercor, Material Project, CUST 35 Yendon Windfarm	Appendix E	No

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PAL CONFIDENTIAL APP E.79	Powercor, Material Project, CUST 35 Yendon Windfarm	Appendix E	Yes
PAL PUBLIC APP E.80	Powercor, Material Project, CUST 28 Vic Gov Powerline Relocation Fund	Appendix E	No
PAL CONFIDENTIAL APP E.80	Powercor, Material Project, CUST 28 Vic Gov Powerline Relocation Fund	Appendix E	Yes
PAL PUBLIC APP E.81	CitiPower and Powercor Australia, IT Service Delivery, Investment Stream Strategies 2016-2020, April 2015	Appendix E	No
PAL PUBLIC APP E.82	Powercor, Non network alternatives, April 2015	Appendix E	No
PAL PUBLIC APP E.83	Wannon Region Dairy Branch, Response to Powercor/ CitiPower Directions and Priorities consultation paper, 30 October 2014	Appendix E	No
PAL PUBLIC APP E.84	AER, TransGrid network exemption, 30 January 2015	Appendix E	No
PAL PUBLIC APP E.85	ESV, Direction under Section 141(2)(d) of the Electricity Safety Act 1998 Fitting of spacers in aerial lines, 4 January 2011	Appendix E	No
PAL PUBLIC APP F.1	AER, Electricity distribution network service providers, Cost allocation guidelines, June 2008	Appendix F	No
PAL PUBLIC APP F.2	Incenta, Debt raising transaction costs, Powercor, April 2015	Appendix F	No
PAL PUBLIC APP F.3	Ernst and Young, CitiPower and Powercor Australia, Allocation of IT System Operating Expenditure, April 2015	Appendix F	No
PAL PUBLIC APP G.1	Industrial Control Systems Cyber Emergency Response Team, ICS-CERT Monitor (Oct-Dec 2012), 2012	Appendix G	No
PAL PUBLIC APP G.2	Industrial Control Systems Cyber Emergency Response Team, ICS-CERT Monitor (Jan-Apr 2014), 2014	Appendix G	No
PAL PUBLIC APP H.1	AER, Electricity distribution network service providers, Service target performance incentive scheme, Final decision, November 2009	Appendix H	No
PAL PUBLIC APP H.2	AEMC, Final Report, Review of Distribution Reliability Measures, September 2014	Appendix H	No
PAL PUBLIC APP I.1	AER, Final decision, Amendment Electricity Distribution Network Service Providers Post-tax Revenue Model Handbook, January 2015	Appendix I	No
PAL PUBLIC APP J.1	John C Handley and Krishnan Maheswaran, A measure of the Efficacy of the Australian Imputation Tax System, The Economic Record, Vol 84, No. 264, March 2008	Appendix J	No
PAL PUBLIC APP J.2	NERA, Estimating Distribution and Redemption Rates from Taxation Statistics, March 2015	Appendix J	No
PAL PUBLIC APP J.3	NERA, The payout ratio, June 2013	Appendix J	No

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PAL PUBLIC APP J.4	AER, Final decision Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameter, May 2009	Appendix J	No
PAL PUBLIC APP J.5	Lally M, Review of submissions to the QCA on the MRP, risk-free rate and gamma, March 2014	Appendix J	No
PAL PUBLIC APP J.6	Handley John C, Advice on the Value of Imputation Credits, September 2014	Appendix J	No
PAL PUBLIC APP J.7	Australian Trade Practices Reports, Application by Energex Limited (Gamma) (No 5) 43,857 (2011) ATPR 42-356, May 2011	Appendix J	No
PAL PUBLIC APP J.8	SFG, An appropriate regulatory estimate of gamma, May 2014	Appendix J	No
PAL PUBLIC APP K.1	AER, Draft decision Ausgrid distribution determination - Ausgrid 2014 - Roll forward model (distribution), November 2014	Appendix K	No
PAL PUBLIC APP L.1	AEMC, Rule Determination National Electricity Amendment (Cost pass through arrangements for Network Service Providers) Rule 2012, 2 August 2012	Appendix L	No
PAL PUBLIC APP L.2	Victoria Power Networks, Insurance Management Policy Appendix C: Insurance Credit Management Policy	Appendix L	No
PAL PUBLIC APP L.3	AER, Draft decision Victorian electricity distribution network service providers Distribution determination 2011-2015, June 2010	Appendix L	No
PAL PUBLIC APP L.4	AER, Draft Distribution Determination – Aurora Energy Pty Ltd 2012-13 to 2016-17, November 2011	Appendix L	No
PAL PUBLIC APP L.5	AER, Final Distribution Determination – Aurora Energy Pty Ltd 2012-13 to 2016-17, April 2012.	Appendix L	No
PAL PUBLIC APP L.6	Cagle J. and Harrington S, Insurance supply with capacity constraints and endogenous insolvency risk, Journal of Risk and Uncertainty, Vol. 11 Issue 3, December 1995	Appendix L	No
PAL PUBLIC APP L.7	AER, SPI Electricity Pty Ltd, Distribution Determination 2011-1, August 2013	Appendix L	No
PAL PUBLIC APP L.8	SPI Electricity Pty Ltd, 2011–15 Distribution Determination, Insurance Pass Through Event Pursuant to Orders of the Australian Competition Tribunal in Application by United Energy Distribution Pty Limited [2012] ACompT 8, April 2013	Appendix L	No
PAL PUBLIC APP L.9	Powercor, Bushfire Mitigation Strategy Plan 2014-2019, 2014	Appendix L	No
PAL PUBLIC APP L.10	CitiPower and Powercor, Crisis and Emergency Management System Manual, 21 January 2014	Appendix L	No
PAL PUBLIC APP L.11	Australian Government, Terrorism Insurance Act Review, 2012	Appendix L	No

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PAL PUBLIC APP L.12	AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering Infrastructure) Rule 2009, 29 January 2009	Appendix L	No
PAL PUBLIC APP L.13	AEMC, National Electricity Amendment (Victorian Jurisdictional Derogation – Advanced Metering Infrastructure) Rule 2013, 28 November 2013	Appendix L	No
PAL PUBLIC APP L.14	SCER, Rule Change Request, Introducing a new framework in the National Electricity Rules that provides for increased competition in metering and related services, October 2013	Appendix L	No
PAL PUBLIC APP L.15	AEMC, Expanding competition in metering and related services in the National Electricity Market, Consultation Paper, 17 April 2014	Appendix L	No
PAL PUBLIC APP L.16	AEMC, Final Report Power of choice review – giving consumers options in the way they use electricity, 30 November 2012	Appendix L	No
PAL PUBLIC APP L.17	AEMC, Energy market arrangements for electric and natural gas vehicles, 11 December 2012	Appendix L	No
PAL PUBLIC APP L.18	AEMO, National Electricity Rule Change Request – Embedded Networks, September 2014	Appendix L	No
PAL PUBLIC APP L.19	Letter from SCER to AEMO dated 24 July 2013 regarding metering arrangements to provide for multiple trading relationships at a single site and attached terms of reference	Appendix L	No
PAL PUBLIC APP L.20	AEMO, Rule Change Request – Multiple Trading Relationships, 17 December 2014	Appendix L	No
PAL PUBLIC APP L.21	AEMO, Multiple Trading Relationships – Market Design for High Level Impact Assessment, 28 August 2014	Appendix L	No
PAL PUBLIC APP L.22	CitiPower and Powercor Australia, Response to Consultation (template) on AEMO's Multiple Trading Relationships – Market Design for High Level Impact Assessment, 16 September 2014	Appendix L	No
PAL PUBLIC APP L.23	SA Minister, Making of National Electricity (National Energy Retail Law) Amendment Rule 2012, 27 June 2012	Appendix L	No
PAL PUBLIC APP L.24	SCER, Definition of Retailer Insolvency Costs Rule Change Request, March 2014	Appendix L	No
PAL PUBLIC APP L.25	Joint Implementation Group (Retail Policy Working Group), National Energy Customer Framework Implementation issue No. 0001 Retailer insolvency event and pass through, 8 February 2012	Appendix L	No
PAL PUBLIC APP L.26	ESCV, Powercor distribution licence, varied 31 August 2005	Appendix L	No
PAL PUBLIC APP L.27	Powercor, Default Use of System Agreement Victorian Electricity Industry, June 2011	Appendix L	No

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PAL PUBLIC APP L.28	ESCV, Credit Support Arrangements, Final Decision, October 2006	Appendix L	No
PAL PUBLIC APP L.29	The Allen Consulting Group, Retailer DuOS Credit Support Arrangements Implementation Issues in Victoria, Report to Essential Services Commission, June 2006.	Appendix L	No
PAL PUBLIC APP L.30	AER, Draft Decision South Australian distribution determination 2010-11 to 2014-15, 25 November 2009	Appendix L	No
PAL PUBLIC APP L.31	AER, Draft Decision Queensland distribution determination 2010-11 to 2014-15, 25 November 2009	Appendix L	No
PAL PUBLIC APP L.32	AER, Draft Decision New South Wales distribution determination 2009-10 to 2013-14, 21 November 2008	Appendix L	No
PAL PUBLIC APP L.33	AER, Draft Decision Australian Capital Territory distribution determination 2009-10 to 2013-14, 21 November 2008	Appendix L	No
PAL PUBLIC APP L.34	Marxsen Consulting Pty Ltd, *Notes from workshop between Victorian distributors and ESV regarding codification of powerline fire risk management*, 30 June 2014	Appendix L	No
PAL PUBLIC APP L.35	Powercor, *Codification of High Bushfire Ignition Consequence Area — Powercor Bare Open Wire Construction Metrics*, 2015	Appendix L	No
PAL PUBLIC APP L.36	Powercor, *Private Overhead Electricity Lines – Understanding your responsibility*, 1 October 2011	Appendix L	No
PAL PUBLIC APP L.37	ESV, Private electric lines and the point of supply – initial Distribution Business (DB) discussion paper, 2014.	Appendix L	No
PAL PUBLIC APP L.38	DEDJTR, Confirmation of Regulatory Impact Statement for REFCLs, 16 April 2015	Appendix L	No
PAL PUBLIC ATT 0.10	Powercor, Vegetation Management Expenditure, April 2015	VEG	No
PAL PUBLIC ATT 0.11	GHD, Powercor Forecast Expenditure for Vegetation Management, March 2015	VEG	No
PAL PUBLIC ATT 0.12	Powercor, 2014-2015 Electric Line Clearance (Vegetation) Management Plan	VEG	No
PAL PUBLIC ATT 0.13	Deed of Variation Supply of Vegetation Management Services, 16 December 2009	VEG	No
PAL CONFIDENTIAL ATT 0.13	Deed of Variation Supply of Vegetation Management Services, 16 December 2009	VEG	Yes
PAL PUBLIC ATT 0.14	ESV, Approval of Electric Line Clearance Management Plan 2014-15	VEG	No
PAL PUBLIC ATT 0.15	Supply of Vegetation Management Services Modification No. 1	VEG	No
PAL CONFIDENTIAL ATT 0.15	Supply of Vegetation Management Services Modification No. 1	VEG	Yes

Reference	Attachment	Chapter reference	Confidential
PAL PUBLIC ATT 0.16	Supply of Vegetation Management Services Modification No. 2	VEG	No
PAL CONFIDENTIAL ATT 0.16	Supply of Vegetation Management Services Modification No. 2	VEG	Yes
PAL PUBLIC ATT 0.17	Supply of Vegetation Management Services Modification No. 3	VEG	No
PAL CONFIDENTIAL ATT 0.17	Supply of Vegetation Management Services Modification No. 3	VEG	Yes
PAL PUBLIC ATT 0.18	Deed of Variation Supply of Vegetation Management Services, 1 March 2011	VEG	No
PAL CONFIDENTIAL ATT 0.18	Deed of Variation Supply of Vegetation Management Services, 1 March 2011	VEG	Yes
PAL PUBLIC ATT 0.19	Supply of Vegetation Management Services Modification No. 4	VEG	No
PAL CONFIDENTIAL ATT 0.19	Supply of Vegetation Management Services Modification No. 4	VEG	Yes
PAL PUBLIC ATT 0.20	2012 Deed of Variation Supply of Vegetation Management Services, 1 January 2012	VEG	No
PAL CONFIDENTIAL ATT 0.20	2012 Deed of Variation Supply of Vegetation Management Services, 1 January 2012	VEG	Yes
PAL PUBLIC ATT 0.21	Supply of Vegetation Management Services Modification No. 5	VEG	No
PAL CONFIDENTIAL ATT 0.21	Supply of Vegetation Management Services Modification No. 5	VEG	Yes
PAL PUBLIC ATT 0.22	2013, 2014, 2015 Deed of Variation Supply of Vegetation Management Services	VEG	No
PAL CONFIDENTIAL ATT 0.22	2013, 2014, 2015 Deed of Variation Supply of Vegetation Management Services	VEG	Yes
PAL PUBLIC ATT 0.23	2014 and 2015 Deed of Variation, Supply of Vegetation Management Services between Powercor and Vemco	VEG	No
PAL CONFIDENTIAL ATT 0.23	2014 and 2015 Deed of Variation, Supply of Vegetation Management Services between Powercor and Vemco	VEG	Yes
PAL PUBLIC ATT 0.24	CitiPower and Powercor, Letter to ESV re Proposed Electricity Safety (Electric line clearance) regulations 2015, Response to RIS, 13 Jan 2015	VEG	No
PAL PUBLIC ATT 0.25	Vemco supply of services - conditions of contract (2008)	VEG	No
PAL CONFIDENTIAL ATT 0.25	Vemco supply of services - conditions of contract (2008)	VEG	Yes

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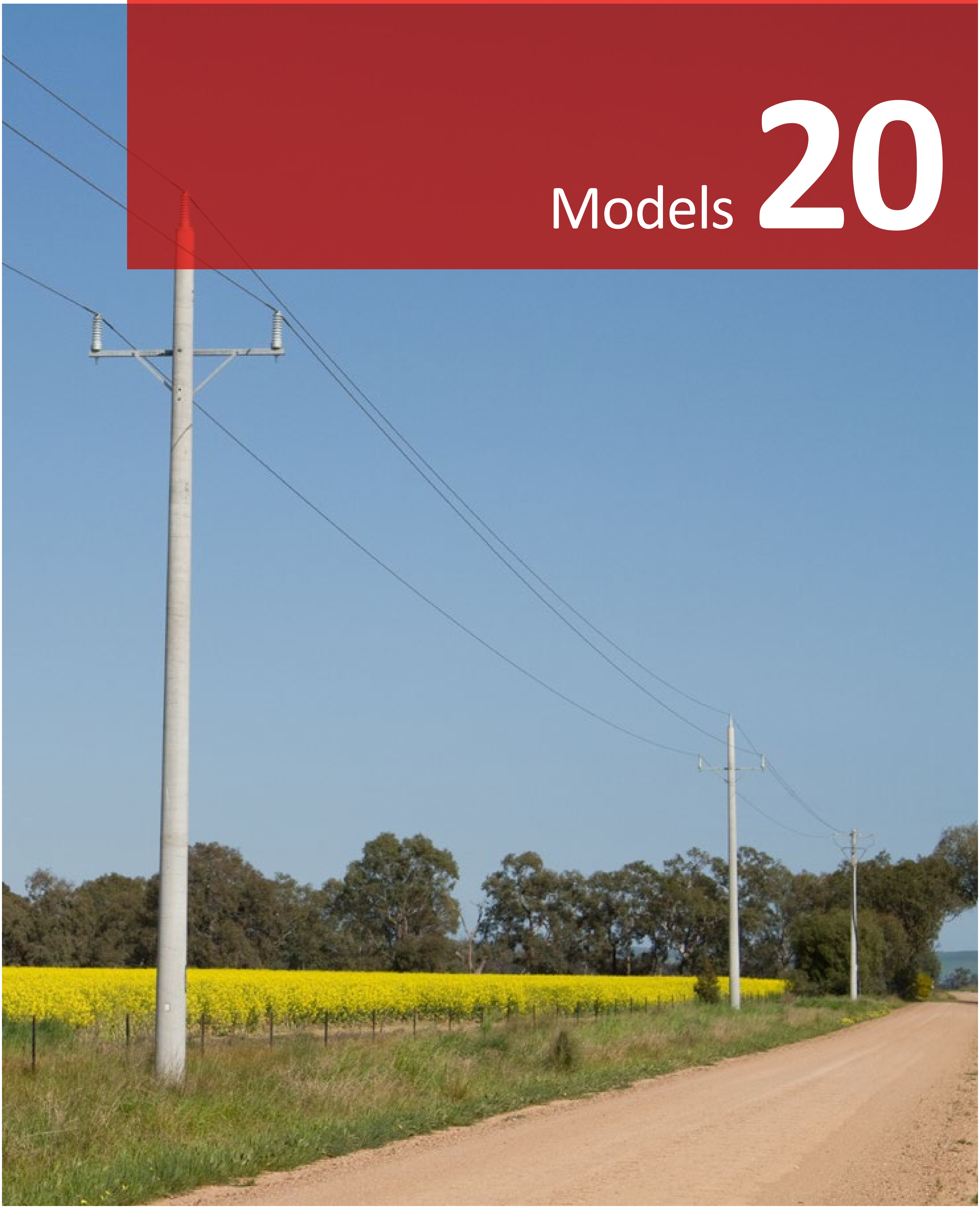

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20. Models

Reference	Topic	Model	Confidential
PAL PUBLIC MOD 1.1	Other alternate control	PAL ACS Model.xlsx	No
PAL PUBLIC MOD 1.2	Metering	PAL Metering Capex & Opex.xlsx	No
PAL CONFIDENTIAL MOD 1.2	Metering	PAL Metering Capex & Opex.xlsx	Yes
PAL PUBLIC MOD 1.3	Metering	PAL Metering Exit Fees.xlsx	No
PAL PUBLIC MOD 1.4	Metering	PAL Metering PTRM.xlsm	No
PAL PUBLIC MOD 1.5	Metering	PAL Metering Volumes.xlsx	No
PAL PUBLIC MOD 1.6	Metering	Powercor – AMI Charges Model (2015 Charges Application) FD 2014 act.xlsx	No
PAL PUBLIC MOD 1.7	Public lighting	PAL Public Lighting ACS Model.xlsx	No
PAL PUBLIC MOD 1.8	Public lighting	PAL Public Lighting Inputs.xlsx	No
PAL PUBLIC MOD 1.9	Standard control	PAL 2011-15 RFM.xlsx	No
PAL PUBLIC MOD 1.10	Standard control	PAL 2016-20 PTRM.xlsm	No
PAL PUBLIC MOD 1.11	2011-2015 determination	PAL 2006-10 RFM.xls	No
PAL PUBLIC MOD 1.12	2011-2015 determination	PAL 2011-15 PTRM.xlsm	No
PAL PUBLIC MOD 1.13	2011-2015 determination	Vegetation clearing appeal.xlsx	No
PAL PUBLIC MOD 1.14	Capital expenditure	PAL AER augex model forecast.xlsx	No
PAL PUBLIC MOD 1.15	Capital expenditure	PAL AER calibrated repex model.xlsx	No
PAL PUBLIC MOD 1.16	Capital expenditure	Contribution rates.xlsb	No
PAL CONFIDENTIAL MOD 1.17	Capital expenditure	PAL augmentation capex.xlsm	Yes
PAL PUBLIC MOD 1.18	Capital expenditure	PAL capex consolidation.xlsx	No
PAL CONFIDENTIAL MOD 1.19	Capital expenditure	PAL connections capex.xlsm	Yes
PAL CONFIDENTIAL MOD 1.20	Capital expenditure	PAL environmental capex.xlsx	Yes
PAL PUBLIC MOD 1.21	Capital expenditure	PAL IT capex.xlsm	No
PAL CONFIDENTIAL MOD 1.22	Capital expenditure	PAL lines replacement capex.xlsx	Yes
PAL CONFIDENTIAL MOD 1.23	Capital expenditure	PAL protection replacement capex.xlsm	Yes
PAL CONFIDENTIAL MOD 1.24	Capital expenditure	PAL network faults capex.xlsx	Yes
PAL CONFIDENTIAL MOD 1.25	Capital expenditure	PAL network SCADA capex.xlsx	Yes
PAL CONFIDENTIAL MOD 1.26	Capital expenditure	PAL plant & stations replacement capex.xlsx	Yes
PAL PUBLIC MOD 1.27	Capital expenditure	PAL POEL contingent project.xlsx	No
PAL CONFIDENTIAL MOD 1.28	Capital expenditure	PAL VBRC capex and contingent project.xlsm	Yes

Reference	Topic	Model	Confidential
PAL PUBLIC MOD 1.29	EBSS	Final Decision Opex.xlsx	No
PAL PUBLIC MOD 1.30	EBSS	PAL EBSS.xlsx	No
PAL PUBLIC MOD 1.31	Operating expenditure	PAL CRM Step Change.xlsx	No
PAL PUBLIC MOD 1.32	Operating expenditure	PAL Customer Charter Step Change.xlsx	No
PAL PUBLIC MOD 1.33	Operating expenditure	PAL GHD Vegetation Management 24032015.xlsx	No
PAL CONFIDENTIAL MOD 1.33	Operating expenditure	PAL GHD Vegetation Management 24032015.xlsx	Yes
PAL PUBLIC MOD 1.34	Operating expenditure	PAL GSL Step Change.xlsx	No
PAL PUBLIC MOD 1.35	Operating expenditure	PAL Mobile Replacement Step Change.xlsx	No
PAL PUBLIC MOD 1.36	Operating expenditure	PAL Opex Consolidation.xlsx	No
PAL PUBLIC MOD 1.37	Operating expenditure	PAL Superannuation Step Change.xlsx	No
PAL PUBLIC MOD 1.38	Rate of change	PAL Contract Escalation.xlsx	No
PAL PUBLIC MOD 1.39	Rate of change	PAL Labour Escalation.xlsx	No
PAL PUBLIC MOD 1.40	Rate of change	PAL Output Growth.xlsx	No
PAL PUBLIC MOD 1.41	Redundant assets	Supervisory Cables opening asset value.xlsx	No
PAL PUBLIC MOD 1.42	Redundant assets	PAL SWER ACRs opening asset value.xlsx	No
PAL PUBLIC MOD 1.43	Rate of return	Rate of return.xlsx	No
PAL PUBLIC MOD 1.44	S factor	2010 Annual PAL.xlsx	No
PAL PUBLIC MOD 1.45	S factor	CP PC – S factor history and 2010 estimate calculations.xlsx	No
PAL PUBLIC MOD 1.46	S factor	PAL – S-factor true up – final decision.xlsx	No
PAL PUBLIC MOD 1.47	S factor	Powercor S Factor.xlsx	No
PAL PUBLIC MOD 1.48	STPIS	PAL STPIS targets.xlsx	No
PAL PUBLIC MOD 1.49	STPIS	PAL STPIS incentive rates.xlsx	No
PAL PUBLIC MOD 1.50	Volumes	CIE tariff volume forecasts 18 February 2015.xlsm	No
PAL PUBLIC MOD 1.51	Volumes	CIE customer number forecasts February 2015.xlsm	No
PAL PUBLIC MOD 1.52	Demand Forecasts	CIE Forecast results FINAL -sent to AEMO.xlsm	No

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Reference	Document	Confidential
PAL PUBLIC RIN 1.1	Powercor, Vic Reset RIN 2016-20 - Consolidated Information	No
PAL CONFIDENTIAL RIN 1.1	Powercor, Vic Reset RIN 2016-20 - Consolidated Information	Yes
PAL PUBLIC RIN 1.2	Powercor, Vic Reset RIN 2016-20 - Back casting	No
PAL CONFIDENTIAL RIN 1.2	Powercor, Vic Reset RIN 2016-20 - Back casting	Yes
PAL PUBLIC RIN 1.3	Powercor, Reset RIN CEO Statutory Declaration	No
PAL PUBLIC RIN 1.4	Powercor, Reset RIN Directors resolution	No
PAL PUBLIC RIN 1.5	Powercor, Reset RIN Cross Reference Matrix	No
PAL PUBLIC RIN 1.6	Powercor, Reset RIN Basis of Preparation	No
PAL PUBLIC RIN 1.7	Deloitte Audit Report, 24 April 2015	No
PAL PUBLIC RIN 1.8	Deloitte Review Report, 24 April 2015	No
PAL PUBLIC RIN 1.9	Deloitte Assurance Report, 24 April 2015	No
PAL PUBLIC RIN 1.10	Deloitte Board Audit Committee Regulatory Audit Report for the year ending 31 December 2014	No
PAL PUBLIC RIN 1.11	Powercor, Confidentiality Claim	No
PAL PUBLIC RIN 1.12	Powercor, Risk management framework attachment, April 2015	No
PAL PUBLIC RIN 1.13	Powercor, Reset RIN schedule 1, Section 6 - Replacement capital expenditure modelling, clause 6.1a and 6.1b	No
PAL PUBLIC RIN 1.14	Powercor, Reset RIN schedule 1, Section 7 - Augmentation Modelling, Clause 7.2b response	No
PAL PUBLIC RIN 1.15	Powercor, Reset RIN schedule 1, Section 8 - Demand and Connections Forecasts, clause 8.3r	No
PAL PUBLIC RIN 1.16	Powercor, Reset RIN schedule 1, Section 8 - Demand and Connections Forecasts, clause 8.3s	No
PAL PUBLIC RIN 1.17	ESV, 2011 Safety Performance Report on Victorian Electricity Distribution and Transmission Businesses, report released 31 August 2012	No
PAL PUBLIC RIN 1.18	ESV, Safety Performance Report on Victorian Electricity Distribution and Transmission Businesses 2012, June 2013	No
PAL PUBLIC RIN 1.19	Powercor, 2009-2013 Category Analysis RIN	No
PAL CONFIDENTIAL RIN 1.19	Powercor, 2009-2013 Category Analysis RIN	Yes
PAL PUBLIC RIN 1.20	Powercor, 2014 Category Analysis RIN	No
PAL CONFIDENTIAL RIN 1.20	Powercor, 2014 Category Analysis RIN	Yes
PAL PUBLIC RIN 1.21	Powercor, Other Entities, 30 April 2015	No

Reference	Document	Confidential
PAL PUBLIC RIN 1.22	Corporate services agreement 2012-2014	No
PAL CONFIDENTIAL RIN 1.22	Corporate services agreement 2012-2014	Yes
PAL PUBLIC RIN 1.23	Corporate services agreement, deed of variation 2014	No
PAL CONFIDENTIAL RIN 1.23	Corporate services agreement, deed of variation 2014	Yes
PAL PUBLIC RIN 1.24	Metering services agreement 2008-2013	No
PAL CONFIDENTIAL RIN 1.24	Metering services agreement 2008-2013	Yes
PAL PUBLIC RIN 1.25	Metering services agreement, deed of variation 2014	No
PAL CONFIDENTIAL RIN 1.25	Metering services agreement, deed of variation 2014	Yes
PAL PUBLIC RIN 1.26	Metering services agreement, deed of variation 2015	No
PAL CONFIDENTIAL RIN 1.26	Metering services agreement, deed of variation 2015	Yes
PAL PUBLIC RIN 1.27	Network services agreement 2012-2014	No
PAL CONFIDENTIAL RIN 1.27	Network services agreement 2012-2014	Yes
PAL PUBLIC RIN 1.28	Network services agreement 2015	No
PAL CONFIDENTIAL RIN 1.28	Network services agreement 2015	Yes
PAL PUBLIC RIN 1.29	Resources agreement 2012-2014	No
PAL PUBLIC RIN 1.30	DRMS: constitution	No
PAL CONFIDENTIAL RIN 1.30	DRMS: constitution	Yes
PAL PUBLIC RIN 1.31	CHED Services, IT Asset Management, 12 February 2015	No
PAL PUBLIC RIN 1.32	CHED Services, IT Data Management Policy, 15 January 2015	No
PAL PUBLIC RIN 1.33	CHED Services, IT Software Management Policy, 12 February 2015	No
PAL PUBLIC RIN 1.34	CHED Services, Telecommunications and Unified Communications Management, 12 February 2015	No

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