Jemena Electricity Networks (Vic) Ltd

Regulatory Proposal

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ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AMI	Advanced Metering Infrastructure
AMP	Asset Management Plan
ARR	Annual Revenue Requirement
CAM	Cost Allocation Methodology
CCP	Consumer Challenge Panel
CESS	Capital Expenditure Sharing Scheme
CGS	Commonwealth Government Securities
COAG	Council of Australian Governments
CROIC	Cost Recovery Order-in-council
DM	Demand Management
DMEGCIS	Demand Management and Embedded Generation Connection Incentive Scheme
DMIS	Demand Management Incentive Scheme
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EMS	Emergency Management System
ESV	Energy Safe Victoria
F-factor	fire-factor
GSL	Guaranteed Service Level
HV	High Voltage
IT AMP	IT Asset Management Plan
JEN	Jemena Electricity Networks (Vic) Ltd
kVA	Kilovolt-amps
kW	Kilowatt
LRMC	Long Run Marginal Cost
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MAR	Maximum Allowed Revenues
MRP	Market Risk Premium
NER	National Electricity Rules
NMI	National Meter Identifiers
OMR	operation, maintenance, repair and replacement

PMM	Project Management Methodology
PTRM	Post-Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RIN	Regulatory Information Notice
SAIDI	System Average Interruption Duration Index
SAMP	Strategic Asset Management Plan
s-factor	a service standards factor
SL-CAPM	Sharpe–Lintner Capital Asset Pricing Model
STPIS	Service Target Performance Incentive Scheme
TSS	Tariff Structures Statement
VCR	Value of Customer Reliability
WACC	Weighted Average Cost of Capital

OVERVIEW

1. Jemena Electricity Networks (Vic) Ltd (**JEN**) owns and operates the electricity network that safely, reliably and affordably services over 319,000 homes and businesses across North West Melbourne—from Mickleham to Footscray, and Gisborne South to Ivanhoe. We also own, maintain and read the meters that allow retailers to bill our customers for their electricity usage, and provide them with information to help them better manage this usage. Our customers, stakeholders and community depend on our service performance every day to enhance their lifestyle and support their businesses.

2. We have developed a detailed proposal, based on extensive engagement with our customers, stakeholders and community that sets out how JEN plans to operate and maintain our network over the period 1 January 2016 to 31 December 2020 (the 2016 regulatory period).

3. In developing this proposal, we analysed the changes occurring in our energy market—in particular our customers' increasing willingness to engage with new technologies to help them manage their energy needs—and considered the implications of these changes for our network and customers over the 2016 regulatory period and beyond.

4. We also engaged extensively with customers, stakeholders and the broader community through a series of targeted workshops, meetings and interviews to understand their priorities and preferences in how we operate and maintain our network. This engagement has helped us develop a proposal that responds to the changing energy market in a way that promotes our customers' long-term interests in terms of our service levels, costs, prices and tariff structures.

LOWER AVERAGE PRICES AND NETWORK BILLS

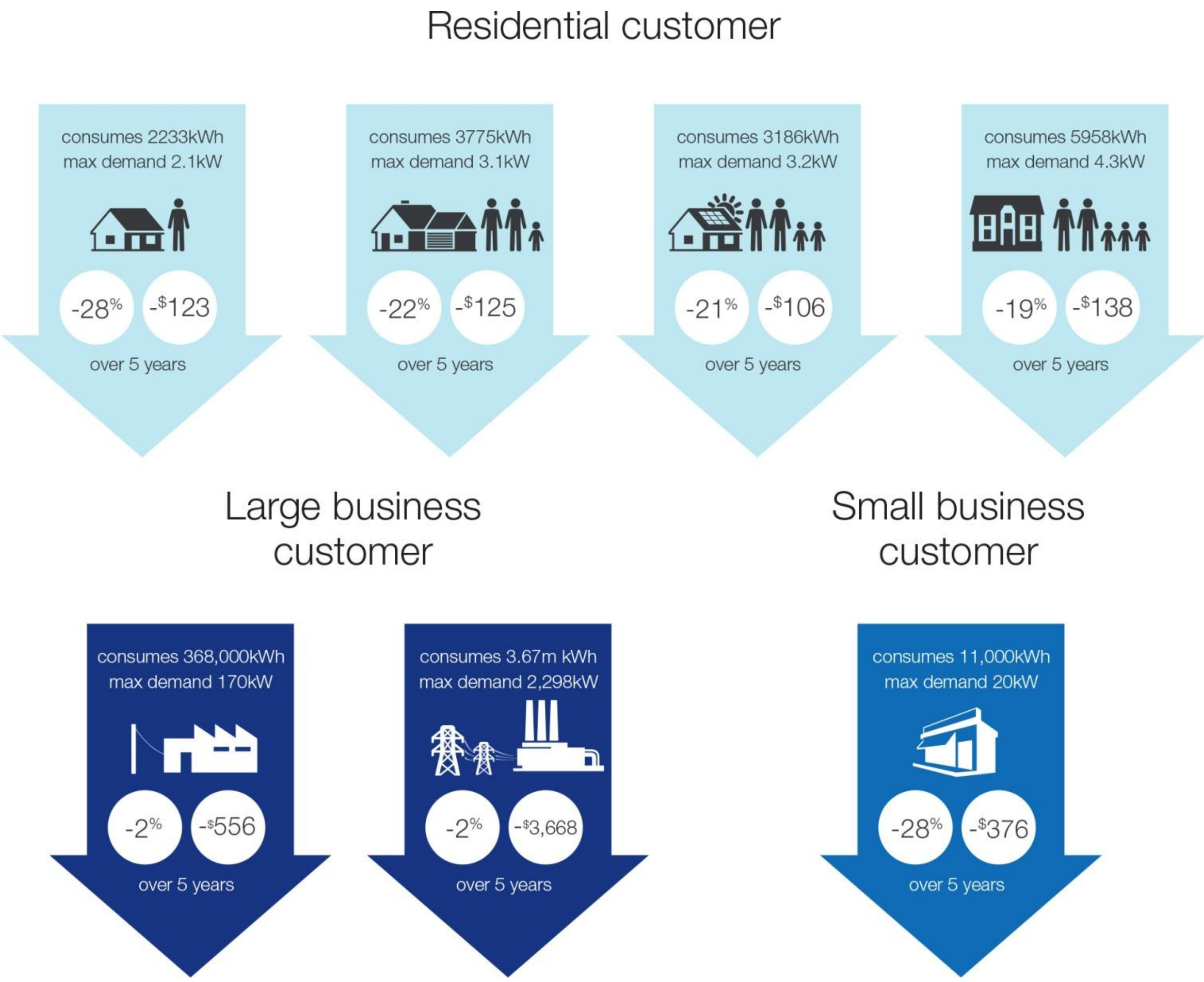
5. Our proposal includes an 8.2% decrease in our average network charges over the 2016 regulatory period (excluding the impact of inflation). This will deliver savings of up to:

   - 28% or $138 for our residential customers and $376 for our small business customers (excluding the impact of inflation)
   - 2% or $3,668 for our large business customers (excluding the impact of inflation).

6. In setting our proposed prices, we have taken account of our customers concerns about the affordability of energy, and tried to minimise any adverse impacts of our proposed tariff structure changes on specific customers. In particular, we have proposed to reduce the levels of our existing charges for residential and small business customers (such as the fixed standing and usage charges) to more than offset the introduction of a new charge in 2018. This new charge will empower residential and small business customers with new ways to save on their electricity bills during peak times when the costs to build and maintain a network are highest.

7. We estimate that over 98% of our customers will receive a reduction in the network component of their bill over the 2016 regulatory period (excluding the impact of inflation). The extent of these savings will depend on a range of factors—including how and when they currently use our network, and how they respond to the new price signals. Figure OV–1 outlines indicative impacts for a range of typical customers.

Figure OV–1: Indicative customer impacts of our 2016 Regulatory Proposal (excluding inflation)



CHANGES IN OUR TARIFF STRUCTURES

8. Our customers agreed that our network tariff structures need to accommodate future changes in how they may use our network. They told us they would prefer us to transition to the updated tariffs as soon as practicable. In line with this feedback, we propose changes to our tariff structures to send clearer price signals, share our costs between customers in the most fair and equitable way, and put downward pressure on our costs and average prices over the long term.

9. From 1 January 2018, we plan to introduce a new charge for all residential and small business customers that will be based on customers' highest electricity use at peak times (10am to 8pm on weekdays) when the costs to build and maintain a network are highest. We call this a 'maximum demand charge'.

10. The new charge will empower our customers with new ways to save on their electricity bill and encourage them to make informed decisions about how they use the network, which in turn will drive technological and market innovation and reduce network costs and average prices in the long-term. It will not mean we recover more from

customers—rather, it will change the way we recover revenue from our customers. We will continue to have a fixed standing charge and variable usage charges, and on average these charges will be lowered.

11. We will publish targeted information and engage with customers to help them understand how they can save money by responding to the new charge. We encourage our customers to make use of the Jemena Electricity Outlook Portal, which provides customers with easy-to-access information on their electricity usage. This tool, together with our smart meters, will enable our customers to see how much electricity they are using and when they are using it, to set savings targets and track their progress, and to use their usage information to compare retail market offers.

MAINTAIN SERVICE LEVELS THAT CUSTOMERS VALUE

12. Our proposal ensures we can continue to provide safe, reliable and responsive distribution network and metering services that our customers value. It includes targeted investments to maintain our current service levels across the network—including in new growth areas, in established areas where assets are aging, and in IT systems to support the services our customers told us they value. We have followed our internationally-recognised governance process for asset management to ensure that our program is planned, managed and delivered prudently and efficiently for the long-term benefit of our customers.

13. At the same time, the proposal enables us to adapt our services to our changing energy market. For example, we will make it fast and easy for customers to connect solar photovoltaic units and other technologies to our network by remotely turning on the features within the smart meters that we manage.

14. Maintaining our asset condition is critically important to our customers' long-term interests. Failure of network operators to stay within the efficient asset investment and maintenance frontier can have material consequences for our customers and economy. This is due not only to the costly catch-up investment that would hit our energy prices, but more importantly it is due the consequences that network service levels slipping into frequent and prolonged blackouts would have on our Victorian economy's ability to compete nationally and globally.

STABLE COSTS PER CUSTOMER

15. Our proposal to maintain service levels that customers value will result in a modest increase in our distribution and metering network revenue of 0.7% per customer per year when compared to the 2011 regulatory period (excluding the impact of inflation). There are several reasons for stable costs per customer:

- Our funding costs for the 2016 regulatory period are lower than the 2011 regulatory period
- Our capital expenditure for metering services are lower than the 2011 regulatory period, however these are offset by our capital and operating expenditure for our distribution network services being higher than the 2011 regulatory period
- We have forecast a 4.5% productivity saving in our operating expenditure forecasts
- The total volume of electricity consumed by our new and existing customers is forecast to increase modestly.

PROMOTING THE LONG-TERM INTERESTS OF OUR CUSTOMERS

16. We think our proposal strikes the right balance between our business and customer outcomes necessary to promote the long-term interests of our customers.

17. Our proposal ensures we recover our efficient costs necessary to maintain the safety, reliability and responsiveness of our services over the 2016 regulatory period. This includes the cost of funding our investments from debt and equity markets over this period, which is the biggest single driver of our total costs. We must pay the market rate for debt and equity capital, and need to be able to fund our proposed investments if we are to maintain our current service levels across our network.

18. We have engaged with our customers, stakeholders and community in getting this balance right. Our proposal includes targeted investments to ensure we can maintain our current service levels across the network over the 2016 regulatory period and beyond. While deferral of this targeted investment may reduce prices temporarily, it could impact the long-term safety and reliability of the network and require higher prices in future regulatory periods. This is not in the long-term interests of our customers.

19. Our private ownership alongside our customers' expectations and the regulatory framework provide us with strong incentives to invest in and operate our network business efficiently and respond to changing energy market conditions. We are committed to lowering our costs by pursuing efficiencies including improving our operating cost efficiency by 4.5% over the 2016 regulatory period.

20. In our experience, the regulatory regime is working well and as intended. For example, we have responded to the incentives created by the regulatory framework—as well as those created by our customers' and shareholders' expectations—and we are among the most efficient network businesses in Australia.

Paul Adams

Managing Director

1. ABOUT THIS PROPOSAL

21. This document is Jemena Electricity Network's (**JEN**) regulatory proposal to the Australian Energy Regulator (**AER**) for 2016 regulatory period. The proposal has been submitted in compliance with the National Electricity Rules (**NER**).[1] It provides all the information we are required to submit to comply with the NER, as well as supporting information. We have also prepared and submitted a response to the Regulatory Information Notice (**RIN**) served on JEN on 2 Feb 2015.[2]

1.1 APPROACH USED TO DEVELOP THE PROPOSAL

22. To develop this proposal, we first:

- Analysed the changes occurring in the energy market and their implications for our network and our customers over the 2016 regulatory period
- Engaged with our customers, stakeholders and the broader community to understand their priorities and preferences in relation to our service and safety standards, and our prices and tariff structures for the 2016 regulatory period.

23. We used this information to inform our analysis and decisions for each of the key components of the proposal, and help ensure that the proposal responds to market changes in a way that promotes the long-term interests of customers. These components include:

- The proposed application of the form of regulation ('the classification of distribution services'), and the proposed incentive and risk management frameworks to apply for the 2016 regulatory period
- The proposed Annual Revenue Requirement (**ARR**) to be recovered from our customers through network prices (or charges), and the annual changes in these prices required to generate this amount of revenue (X-factors)
- The forecast capital and operating expenditures and proposed rate of return, which are key inputs to the proposed ARR
- The proposed network tariff classes, tariff structures and indicative price levels
- The proposed fees and charges for user-requested activities.

1.2 HOW TO NAVIGATE THE PROPOSAL

24. The remainder of this proposal is structured broadly in line with the approach outlined in section 1.1:

- Chapter 2 provides background information on JEN, our role in the energy market, and the regulatory framework we operate in
- Chapters 3 and 4 focus on the changes occurring in the energy market and the engagement we undertake with customers and stakeholders

[1] NER cl 6.8.2(a) requires us to submit a regulatory proposal to the AER.

[2] NER cl 6.3.1 require us our proposal to be accompanied by the information required by, any relevant regulatory information instrument.

- Chapters 5 to 11 detail each of the main components of the proposal—including the proposed regulatory and incentive frameworks, proposed change in ARR and X-factors, forecast capital expenditure, forecast operating expenditure, proposed rate of return and proposed tariffs and other fees
- We have also provided additional detail via a range of customer-focused summaries and explanations including:
  - An accessible 2-page summary that highlights the key elements of our proposal and what it will mean for our customers
  - An easy-to-read customer overview,[3] which explains our proposal, what it will mean for our customers in terms of price and other changes, and how we engaged with customers and stakeholders in developing the proposal
  - A range of short targeted 'fact sheets' focusing on specific aspects of the proposal to further assist customers in understanding the proposal and how it will impact them[4]
  - A Tariff Structures Statement (**TSS**) that provides clear, accessible information on how we set our network tariffs, and how these may change in the future.[5]

25. Table 1–1 provides a more detailed overview of the structure and content of the proposal, and lists the key attachments and supporting information for each chapter.

26. All amounts in this document are in real $2015 unless otherwise specified.

1.3 CLAIMS FOR CONFIDENTIALITY

27. From time to time the benefit of publishing some confidential information may be outweighed by the potential harm. For example, we may provide an estimate of the cost of providing a service we plan to competitively tender for. If the AER were to publish this information it could impact our ability to be competitive in the tender, and ultimately increase the costs to consumers. To overcome this we have marked some of the information in this proposal as confidential.

28. The AER has sought to balance transparency and confidentiality by outlining, in a guideline[6], what information should be marked as confidential and how this should be done. We have applied the guideline requirements in to this regulatory proposal as outlined in Attachment 1-1.

1.4 FEEDBACK ON THIS PROPOSAL

29. We recognise that Australia's energy markets are undergoing significant change that has major implications for JEN and our customers. We are committed to engaging with our customers, stakeholders and the broader community to help ensure the business decisions we make respond to these changes in a way that reflects our customers' preferences and promotes their long-term interests.

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3 NER cl 6.8.2(c1) requires distribution network businesses to submit an overview paper which explains the proposal in plain language to consumers.

4 Available from http://jemena.com.au/home-and-business/price-reviews

5 NER cl 6.8.2(a) requires distribution network businesses to submit a tariff structures statement to the AER.

6 AER, *Better Regulation: Confidentiality guideline*, 19 November, 2013

30. We invite our customers, stakeholders and the broader community to get involved in the AER's review of our proposal.

31. Customers can make a submission to the AER at VICelectricity2016@aer.gov.au. Customers can also provide feedback or seek further information from us directly—either by sending an email to haveyoursay@jemena.com.au, or via the 'get involved' section on our website.[7]

32. We encourage our customers and stakeholders to subscribe to receive email updates about our pricing and other customer engagement activities via our website.[8]

Table 1–1: Structure of the proposal

Chapter	Content	Supporting attachments
1. About this proposal	• A description about this proposal	• 1-1: Claims for Confidentiality • 1-2: Statement of interdependencies for regulatory proposal
2. About Jemena	• Our network, and our role and vision in providing energy services • The regulatory framework	• 2-1: JEN service performance
3. Changes in our energy market	• The changes occurring in our energy market, and what they mean for our network and our customers, including changes in: – the roles and responsibilities of energy market participants – the way customers are using our network (including forecast electricity demand) – the way customers will pay to use our network – the impact of these changes on risk	• 3-1: Electricity demand forecasts report - ACIL Allen • 3-2: Electricity demand forecast models - ACIL Allen • 3-3 Electricity consumption forecasts - ACIL Allen • 3-4: Electricity consumption forecast model - ACIL Allen • 3-5: JEN demand summary report
4. Engagement with our customers, stakeholders and the broader community	• Our commitments to engaging with the community • Who we engaged with and how • What issues on which we engaged • What we learnt and how we are responding	• 4-1: Our customer, stakeholder and community engagement • 4-2: Jemena Electricity Network community and small business consultation report
5. Form of regulation and incentive and risk management frameworks	• Proposed classification of services • Proposed form of regulation to apply to our network services • Proposed incentive schemes to encourage service and cost improvements • Proposed mechanisms to manage risks and uncertainties	• 5-1: Classification of services • 5-2: Demonstration of compliance with price control mechanisms • 5-3: Application of incentive schemes • 5-4: Risk management framework • 5-5: Innovation and technology investment

7 http://jemena.com.au/home-and-business/price-reviews/get-involved

8 http://jemena.com.au/home-and-business/price-reviews/get-involved

Chapter	Content	Supporting attachments
6. Annual revenue requirement, maximum allowed revenue, and X-factors	• Overview of proposed annual revenue requirement (ARR or building block costs): – proposed return on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation) – operating and tax costs, and – other proposed revenue adjustments • Proposed maximum allowed revenue and X-factors	• 6-1: JEN revenue model (distribution services) • 6-2: JEN revenue model (metering services) • 6-3: JEN roll forward model (distribution services) • 6-4: Gamma proposal • 6-5: Close-out 2010 s-factor balance • 6-6: Shared asset cost reduction • 6-7: SFG report on estimating gamma for regulatory purposes • 6-8: NERA report on estimating distribution and redemption rates from taxation statistics • 6-9: Guy Debelle on global and domestic influences on the Australia bond market • 6-10: Economic considerations for the interpretation of the National Electricity Objective (G Swier expert report)
7. Forecast capital expenditure	• Our forecast of capital expenditure • Our governance and network strategy • The outcomes and our performance in the 2011 regulatory period • How our forecast expenditure meets the NER and promotes the long-term interests of customers	• 7-1: Historical capital expenditure report for 2011 regulatory period • 7-2: Asset management framework and governance • 7-3: Forecast capital expenditure report for 2016 regulatory period • 7-4: JEN capex forecast model • 7-5: 7-year Asset Management Plan • 7-6: 20-year asset strategy • 7-7: IT 7-year Asset Management Plan • 7-8: JEN EDPR16 delivery plan • 7-9: JEN cost allocation methodology • 7-10: JEN cost estimation methodology • 7-11: Nuttall Consulting - Independent analysis of replacement expenditure • 7-12: Nuttall Consulting - Independent analysis of augmentation expenditure • 7-13: Jacobs - Real cost escalation indices forecast • 7-14: Director's certification of reasonableness of assumptions

Chapter	Content	Supporting attachments
8. Forecast operating expenditure	• Our forecast of operating expenditure • The outcomes and our performance in the 2011 regulatory period • How our forecast operating expenditure meets the NER and promotes the long-term interests of customers	• 8-1: Historical operating expenditure report for 2011 regulatory period • 8-2: Forecasting method and base year efficiency • 8-3: JEN opex forecast model • 8-4: Role of benchmarking • 8-5: Supporting expert report on benchmarking, rate of change and productivity • 8-6: Step changes • 8-7: Incenta report on debt raising transaction costs • 8-8: Real labour and material cost escalation forecasts to 2020 (BIS Shrapnel)
9. Rate of return	• Our proposed rate of return including return on debt and return on equity and how this promotes the long-term interest of our customers • Key areas of agreement and departure from the AER rate of return guidelines • Our proposed implementation of annual updates to the return of debt • How changes to the energy market affects risk and estimates of the rate of return	• 9-1: JEN rate of return model • 9-2: Rate of return proposal • 9-3: Averaging period proposal • 9-4: SFG report on the CAPM (equity beta and Black CAPM) • 9-5: SFG report on using the Fama-French model to estimate the required return on equity • 9-6: SFG report on share prices, the dividend discount model and the cost of equity for the market and a benchmark energy network • 9-7: SFG report on the required return on equity for the benchmark efficient entity • 9-8: NERA report on empirical performance of the Sharpe-Lintner and Black CAPMs • 9-9: NERA report on historical estimates of the market risk premium • 9-10: NERA literature review on the Sharpe-Lintner CAPM, Black CAPM, and Fama-French three factor model • 9-11: SFG review of the AER return on equity foundation model • 9-12: Incenta report on independent expert reports • 9-13: Grant Samuel letter response to the AER draft decision (for JGN) • 9-14: SFG report on return on debt transition • 9-15: CEG report on critique of the AER's JGN draft decision on the cost of

Chapter	Content	Supporting attachments
		debt • 9-16: CEG report on the new issue premium • 9-17: UBS report on transaction costs in the hybrid transition
10. Our network tariffs	• How we set our proposed network tariffs • How the proposed tariffs meet the NER and promote the long-term interests of customers • Key customer outcomes of our proposed network tariffs • How we will update and consult on changes to our network tariffs	• 10-1: Draft Tariff Structures Statement • 10-2: Proposed tariffs and calculation of customer impacts
11. Our fees and charges for user-requested activities	• How we propose to change fees and charges for user-requested activities	• 11-1: Negotiating framework • 11-2A: Public lighting charges model • 11-2B: Public lighting – capex and RAB apportionment to alternative control services model • 11-3: Public lighting charges explanatory statement • 11-4: Fee-based alternative control services pricing model • 11-5: User-requested services explanatory statement • 11-6: Metering exit fee application • 11-7: Metering exit fee model

2. ABOUT JEMENA AND OUR NETWORK

Key messages

- Our role is to ensure the community has access to a safe, reliable source of power by operating and maintaining the low-voltage network that transports electricity to over 320,000 homes and businesses across north west Melbourne.
- Our service levels reflect what our customers expect and value, and our cost efficiency is in line with, or better than, that of other comparable Australian electricity networks.
- Our charges make up around 37% of a typical residential customer's retail electricity bill, which is significantly less than in other states.
- Our services, costs and prices are independently regulated, and this regulation together with our private ownership provides us with strong financial incentives to continually improve our cost efficiency and share these improvements with our customers over time.

2.1 OUR NETWORK

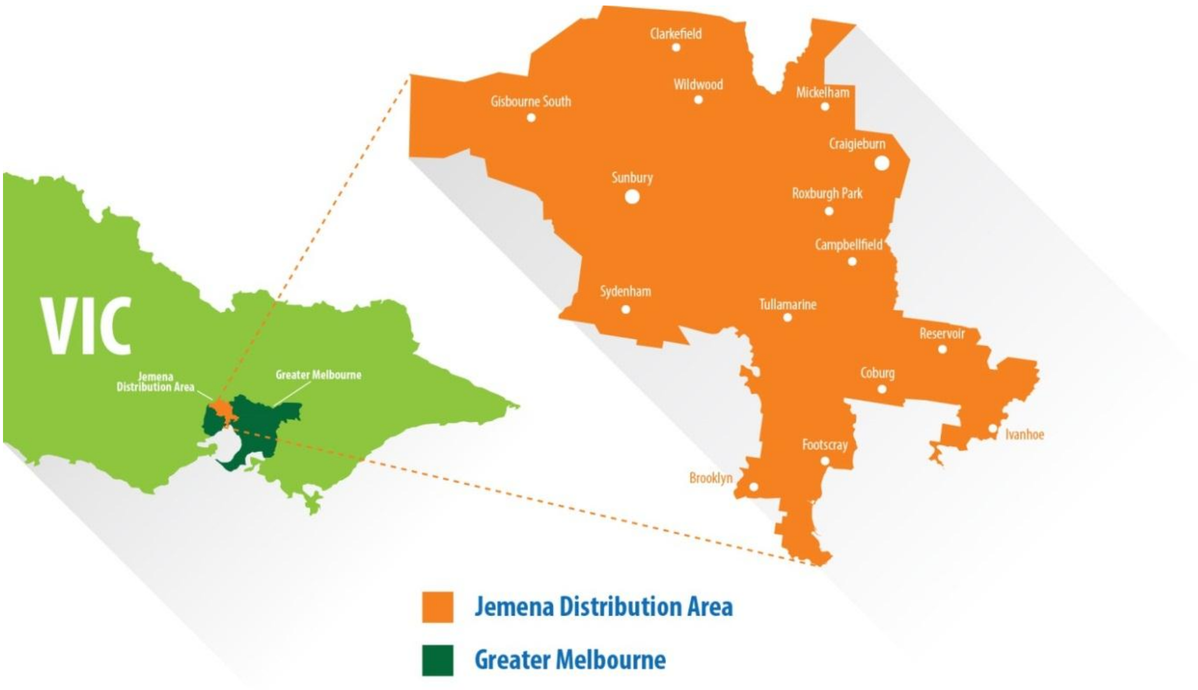
33. Our network covers approximately 950 square kilometres of the North Western area of greater Melbourne (Figure 2–1). This area includes a mixture of residential and industrial suburbs extending from Mickleham in the north to Footscray in the south, and from Sydenham in the west to Ivanhoe in the east. It includes the city's international airport and some major transport routes.

34. Many of the suburbs within our network are well established. The assets within these parts of our network are nearing the end of their life[9] and many of these aging assets need replacement or greater inspection and maintenance. We expect that targeted capital and operating expenditure will be needed to meet safety requirements and provide the service levels our customers expect.

35. In addition, our network is undergoing significant change and development. On the one hand, there are pockets of high residential and industrial growth, particularly in newly established suburbs, which is leading to increases in electricity demand in these areas. On the other, our network supplies a relatively large proportion of industrial customers and is experiencing pockets of low or declining electricity demand as several large industrial customers close operations. Only some of these industrial customers are being replaced by new residential customers. While we are forecasting modest growth in electricity consumption, overall we are expecting the need for increased capital expenditure to meet our customers' existing and future needs.

9 Many of our network assets were built 50 years ago or more.

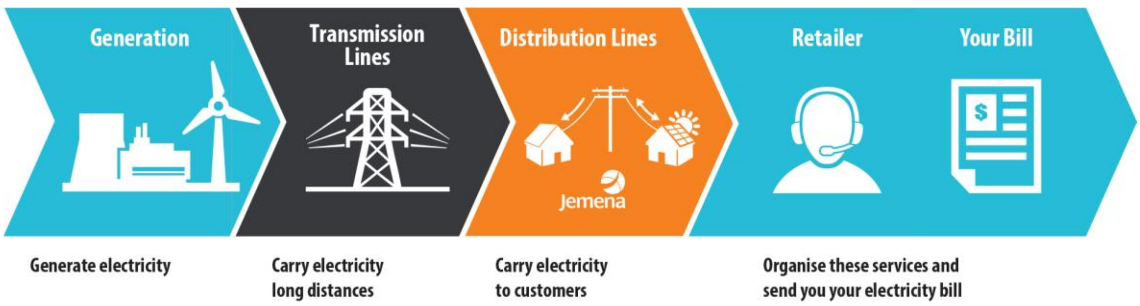
Figure 2–1: JEN's electricity distribution network area



2.2 OUR ROLE IN POWERING HOMES AND BUSINESSES

36. Typically, electricity is generated in locations that are far from where most people live and work. It is then transported long distances to the outskirts of cities and towns via a transmission network. From there, it is transported to end-users' premises via a distribution network like JEN (see Figure 2–2). However, increasingly electricity is also generated near or within cities and towns—such as by solar photovoltaic (**PV**) units in residential homes and cogeneration plants—and transported by our network *between* our customers' generation units and their homes and businesses. This change has contributed to peak demand on our network growing at a faster rate than energy consumption (see section 3).

Figure 2–2: JEN builds, operates and maintains a distribution network



37. Our primary role is to design, operate and maintain our distribution network so we can safely, reliably and efficiently transport electricity through the suburbs and streets of North West Melbourne and into our customers' homes and business when it's needed. We also measure the flow of electricity to our customers' premises through smart meters.

38. Among other things, this role involves ensuring that over 6,000 km of power lines on over 95,000 high and low voltage poles can manage extreme fluctuations in both electricity usage and temperature. We must also keep

trees away from power lines to minimise the chance of power outages during storms, and promptly restore power when outages do occur.

39. We also connect over 5,000 new homes and businesses to our network each year and provide a range of other user-requested services to the community, including public lighting and electricity connection and reconnection.

40. However, our role is evolving in response to changes to technology, policy and market factors, as well as our customers' attitudes to energy (see section 3).

2.3 OUR PERFORMANCE IN POWERING HOMES AND BUSINESSES

41. We provide a highly reliable and efficient supply of electricity that meets our customers' expectations and is consistent with what they value (see Box 2–1).

Box 2–1- Providing a highly reliable and cost efficient supply of electricity

Our customers consistently tell us they value a safe and reliable supply of electricity. They also tell us that rising energy prices have become a household and business concern. They want us to put downward pressure on our costs and network prices.

Our customers' expectations, together with our private ownership and the regulatory framework, provide us with strong incentives to invest in, and operate our network business efficiently and respond to changing energy market conditions. As a result, we have delivered continued cost efficiency and service performance improvements across our network.

One of the ways we measure the reliability of our network is to use the System Average Interruption Duration Index (**SAIDI**). This index measures the average number of unplanned minutes that customers are without electricity each year, excluding the impact of significant storms.

Between 2006 and 2013, unplanned SAIDI on our network decreased from 91.0 to 59.8 minutes,[10] which indicates that the reliability of our network has improved.

One of the ways to evaluate our cost efficiency is to benchmark our performance against other electricity network businesses in Australia. The AER benchmarks our performance on an annual basis using a variety of techniques, and its analysis highlights that our performance—based on the total expenditure required to provide our services—means we are within the top quartile of efficient businesses in Australia.[11]

Attachment 2-1 provides detail on our cost and service performance over the 2006 and 2011 regulatory periods.

42. Providing a highly reliable and efficient supply of electricity involves significant investment in a range of assets, including poles, wires, meters, substations, property and IT systems. It also involves dedicated field and office staff to operate, inspect, maintain and replace these assets, and provide responsive connection, reconnection, market (including providing billing information to retailers) and management services. We are also supported by our shareholders (see Box 2–2).

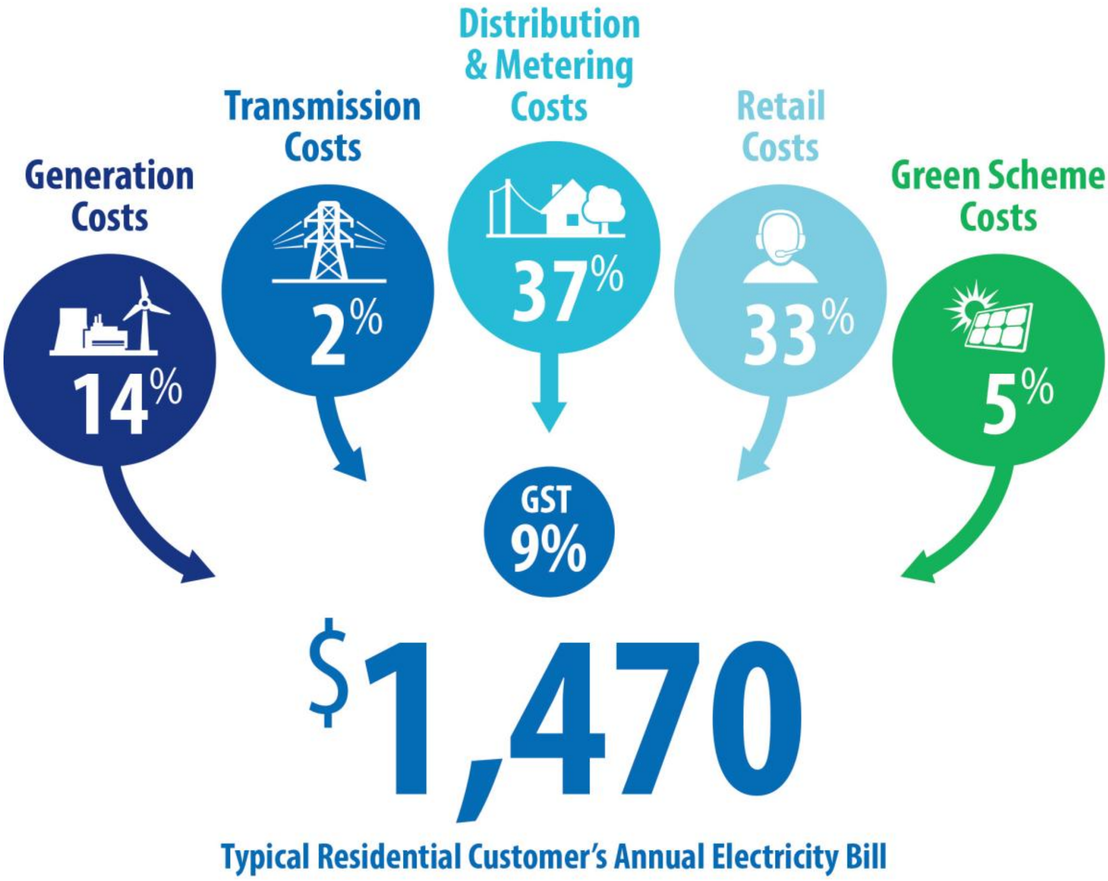
43. The costs of us providing a reliable and efficient supply of electricity are recovered through our network charges (including our distribution and metering charges), which make up around 37% of a typical residential retail

10 This excludes all excluded events and Major Event Days (**MED**)

11 AER, *Annual distribution benchmarking report*, November 2014

customer bill (see Figure 2–3). Our network charges are a significantly smaller proportion of residential retail customer bills than in other states.[12]

Figure 2–3: The contribution of the energy supply costs to our typical residential customers' electricity bill



Source: Oakley Greenwood, *Causes of residential electricity bill changes in the Jemena service area, 1995 to 2014,* December, 2014.

44. Although the smallest of the five distribution networks in Victoria, with a uniquely challenging operating environment, we provide our services efficiently. Our cost efficiency is in line with, or better than, other comparable electricity networks in Australia—as evidenced in the AER's economic benchmarking analysis[13] and by our network charges being a lower proportion of residential retail customer bills compared with distributors in other states (see Attachment 2-1 for detail on our cost efficiency).

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12 For example, network charges make up around 40-45% of a typical residential retail customer bill in NSW. See Essential Energy, *Regulatory Proposal: 1 July 2014 to 30 June 2019*, May 2014, p 4.

13 AER, *2014 Annual distribution benchmarking report*, November 2014.

45. Our cost efficiency reflects our strong governance and management arrangements, as well as the long history of private ownership and independent economic regulation in Victoria (see section 2.4). It also reflects our focus on thinking and planning for the long term, being responsive to changes in our market, seeking out new and non-traditional network solutions, and making decisions that reflect our customers' long-term interests and preferences (see chapter 4).

Box 2–2 JEN's ownership structure

JEN is 100% owned by Jemena, an Australian infrastructure group that builds, owns and maintains a combination of major electricity, gas and water assets. In addition to JEN, Jemena's assets include:

- Jemena gas distribution network (JGN), which transports gas to over 1.3m homes and businesses in NSW
- Eastern Gas Pipeline (EGP), which transports gas from the Gippsland Basin in Victoria to markets in Sydney and regional NSW centres (including JGN)
- Queensland Gas Pipeline (QGP), which transport gas from the Surat Basin in Queensland to large industrial customers and retail distribution networks in Gladstone and Rockhampton.
- Aquanet, which supplies recycled water to industrial and commercial customers in Western Sydney

Jemena is 100% owned by SGSP (Australia) Assets Pty Ltd (SGSPAA), which is jointly owned by State Grid Corporation of China (60%) and Singapore Power (40%).

2.4 THE FRAMEWORK FOR INDEPENDENT ECONOMIC REGULATION HAS EVOLVED

46. Like other electricity distribution network businesses in Australia, JEN is now regulated by the AER (see Figure 2–4). This means every five years we must submit a regulatory proposal to the AER setting out the services we will offer, the costs we expect to incur, and the prices we need to charge to recover our costs. Among other things, our proposal must promote the long-term interests of customers in terms of price, quality, safety, reliability and security of supply (see Box 2–3).

Box 2–3 What do we mean by the long-term interest of customers?

The National Electricity Law requires our proposal to promote “the long-term interests of customers”. In turn, the NER provide guidance on how the AER should make decisions that promote this objective.

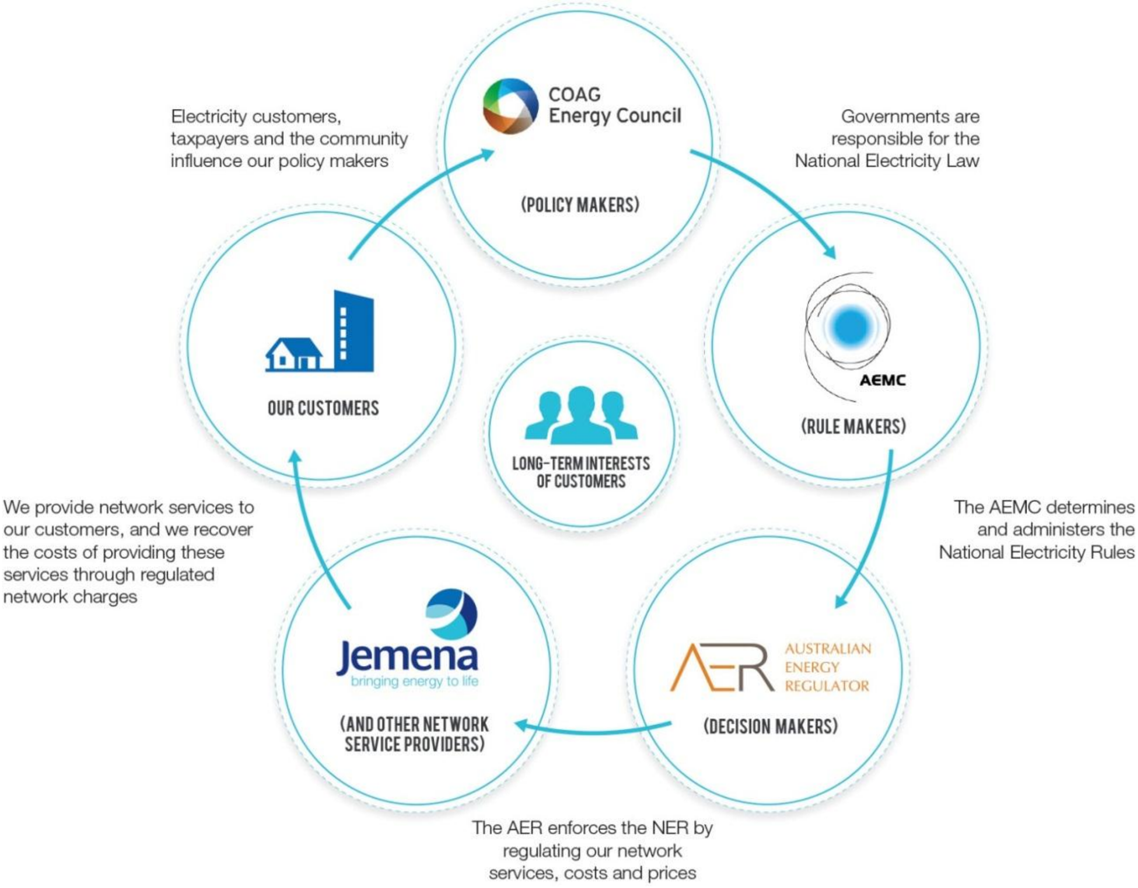
Ultimately, we think promoting the long-term interests of customers means that our proposal needs to ensure we continue to provide a safe, reliable supply service consistent with our customers’ expectations and to price these services in a way that encourages our customers to use our network efficiently. To do this, we must be customer-focused, strive to run our business as smartly and efficiently as possible, and think and plan for the long-term so that:

- Our prices reflect the lowest sustainable cost of providing our services and meeting the required safety and service levels (and are not higher than they need to be because of inefficient operations or poor investments). This promotes productive and allocative efficiency.
- Our service levels reflect what our customers want and are willing to pay for. This promotes allocative efficiency.
- Our services are priced to encourage customers to make informed energy decisions about the way they use our network, which lowers network costs and helps drive innovation in new technologies. This promotes allocative and dynamic efficiency.
- Our combination of prices and service levels represents good value for money and encourages customers to continue to use our network efficiently over the longer term, reducing our costs per customer. This promotes dynamic efficiency.

47. The AER applies the regulatory framework specified in the NER, and these rules are determined and administered by the Australian Energy Market Commission (**AEMC**). Commonwealth and State energy ministers—through the Council of Australian Governments (**COAG**) Energy Council—administer and review the National Electricity Law, and the broader governance framework of independent economic regulation.

48. This framework of independent economic regulation provides clear, separate and accountable decision making responsibilities—including relating to policy, the ‘rules of the game’ and economic regulation—and an overarching focus on promoting customers’ long-term interests.

Figure 2–4: The framework of independent economic regulation



49. In 2012 changes were made to the NER in relation to how network revenues are determined and adjusted over time, they also enhanced the ability of customers to meaningfully participate in this decision making process.[14]

50. Following recommendations from the COAG Energy Council, further changes were made to the regulatory framework in 2014. This included changes to how network revenues are recovered from customers through network prices, covering the guidance provided to network businesses in balancing cost, efficiency and customer considerations and the timeframe for annual changes in network prices.[15]

[14] AEMC, *Rule determination, National electricity amendment (Economic regulation of network service providers) rule 2012, National gas amendment (Price and revenue regulation of gas services) rule 2012*, 29 November 2012.

[15] AEMC, *Rule determination, National electricity amendment (Distribution Network Pricing Arrangements) Rule 2014*. 9 November 2014.

2.5 THE FRAMEWORK FOR INDEPENDENT ECONOMIC REGULATION HAS BENEFITED OUR CUSTOMERS

51. We have had private ownership and independent economic regulation of our services, costs and prices for more than two decades.[16] This ownership and regulatory framework has provided us with financial incentives to continually improve our cost efficiency and share these improvements with our customers over time.[17]

52. As highlighted in section 2.4, this regulatory framework alongside our strong governance and management arrangements has delivered network price reductions over a long period,[18] and ensured that our network charges are a significantly smaller proportion of residential retail customer bills than in other states. Economic regulation has also encouraged us to continually provide high levels of service (see Attachment 5-3).[19]

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16 The AER took responsibility for economic regulation of Victorian distribution network businesses from 1 January 2009. Prior to this the Essential Services Commission of Victoria was responsible for economic regulation of Victorian distribution network businesses.

17 Economic regulation provides us with financial incentives to continually improve our cost efficiency by setting network prices based on forecast efficient costs, rather than our actual costs, over the regulatory period. This provides us with incentives to 'beat the benchmark' costs set by the regulator, with improvements in our cost efficiency shared with our customers over time.

18 The Victorian Government notes that the regulatory framework has generally served Victorian interests well, including an 18% reduction in average annual electricity network prices for Victoria, in real terms, from 1996 to 2013 while New South Wales and Queensland experienced substantial increases at 122 and 140% respectively over approximately the same time. Network service levels have also generally improved. *Victorian Government, Department of State Development, Business and Innovation, Victoria's Electricity Statement*, 2014, p 39.

19 The Victorian Government notes service levels have also generally improved. *Victorian Government, Department of State Development, Business and Innovation, Victoria's Electricity Statement*, 2014 p 39.

3. CHANGES IN OUR ENERGY MARKET

Key messages

- Our electricity market is changing—driven by interrelated changes in customers' attitudes and use of our network, technological and market innovations, and policy and regulatory developments.
- These changes have implications for us, and for our customers in the 2016 regulatory period:
  - Our role, services and engagement with customers and the community are evolving in response to the changes
  - Our customers' electricity demand is becoming more difficult to forecast, partly due to changes in their use of the network; however, we expect that aggregate and peak demand will increase modestly over the period, but that the rates of growth will vary significantly across our network
  - Our network prices need to be updated to reflect the diversity in how customers use the network and encourage more informed customer decision making.
- These changes also have longer-term implications. They are likely to drive further innovation in the energy market, leading to new market players and further changes to the roles of existing energy market players and the ways our customers use our network. In turn, this is likely to necessitate refinements to the regulatory framework to ensure existing players can adapt to these changing circumstances.
- We are striving to meet our customers' changing expectations—utilising the benefits of our investment in Advanced Metering Infrastructure (**AMI**) and trialling new technologies and ways of operating—to ensure we continue to provide a safe, reliable and responsive energy delivery options to our customers.

53. To guide us in developing this proposal we analysed the changes occurring in our energy market and their implications for our network and our customers over the 2016 regulatory period and beyond. We identified four interrelated trends:

- In contrast to previous generations (for whom energy was a 'low involvement' product), today's customers increasingly want to have more control over their electricity supply and consumption so they can better manage their energy bills
- The installation of small distributed generation units (such as solar PV units) at our customers' homes and businesses has continued to grow—and collectively have become a significant source of generation (over 56MW) and we expect this trend to continue
- There is greater interaction and engagement between network businesses and their customers on day-to-day electricity matters
- There is a growing focus on encouraging informed decision making by customers about energy, supported by a range of technological, policy, regulatory and industry developments—including network businesses' investments in AMI (or 'smart meters') which make it possible for customers to access information on their energy usage in real time. This is likely to facilitate the entry of new energy market players with innovative applications of new and existing technologies to enable customers to reduce peak demand and make better use of existing network infrastructure, and thereby lower network costs.

54. Together, these trends are driving changes in the roles and responsibilities of energy market players, as well as changes in the way our customers use our network. This necessitates changes to the way customers pay for our services.

3.1 CUSTOMERS WANT MORE CONTROL OVER THEIR ELECTRICITY SUPPLY AND CONSUMPTION

55. As chapter 2 outlines, historically electricity has been generated in locations far from Australia's population centres, and the design of electricity networks was largely the domain of engineers and regulators. The networks were used to provide a one-way flow of electricity to customers. Customers did not have access to information on their energy usage patterns, and had little opportunity to manage their energy needs. They were largely passive consumers of a 'low involvement' product.

56. However, this is changing. Recent research[20] shows that customers are more concerned about their electricity bills than any other cost of living expense.[21] This has heightened customers' awareness of the market choices and options available to them to reduce their bills. As a result, many customers no longer want to be passive consumers of energy with little knowledge and control over their usage. They increasingly see managing or reducing their electricity consumption as the best way to control their costs.

57. Customers are increasingly engaged in decisions on energy. They are monitoring their energy usage, responding to price signals and shopping around for better retail offers to manage their consumption and lower their bills.[22] They are also looking to new (and increasingly affordable) technologies including solar PV, solar hot water, and battery storage—to help them control their energy bills, both by producing their own energy and managing their consumption.[23]

58. Policy makers, rule makers and regulators have highlighted the importance of customers taking advantage of technological changes that can contribute to the reliable and affordable supply of energy.[24] To ensure we can accommodate the diversity in how customers use our network we have proposed changes to our network tariff structures to encourage more informed customer decision making. We will also need to empower our customers with information about their energy usage (for example, through Jemena's Electricity Outlook Portal) utilising the benefits of our investment in smart meters.

3.2 SMALL DISTRIBUTED GENERATION UNITS HAVE BECOME A SIGNIFICANT SOURCE OF GENERATION

59. Traditional forms of power generation are increasingly being displaced by new and lower emissions forms of energy. While much of this new generation comes from large-scale wind and solar generation units connected to the National Electricity Market, a significant portion is from customers who have installed small-scale solar PV, solar hot water and cogeneration units at their premises. For example, over 21,000 (or around 10%) of our

[20] CHOICE, the Brotherhood of St Laurence and the Energy Efficiency Council, *Survey of Community Views*, 2013.

[21] One likely reason is that the retail price increases have heighted customers' awareness of this cost. In addition, most customers don't know how much electricity they are using at a particular point in time, and are generally billed after use.

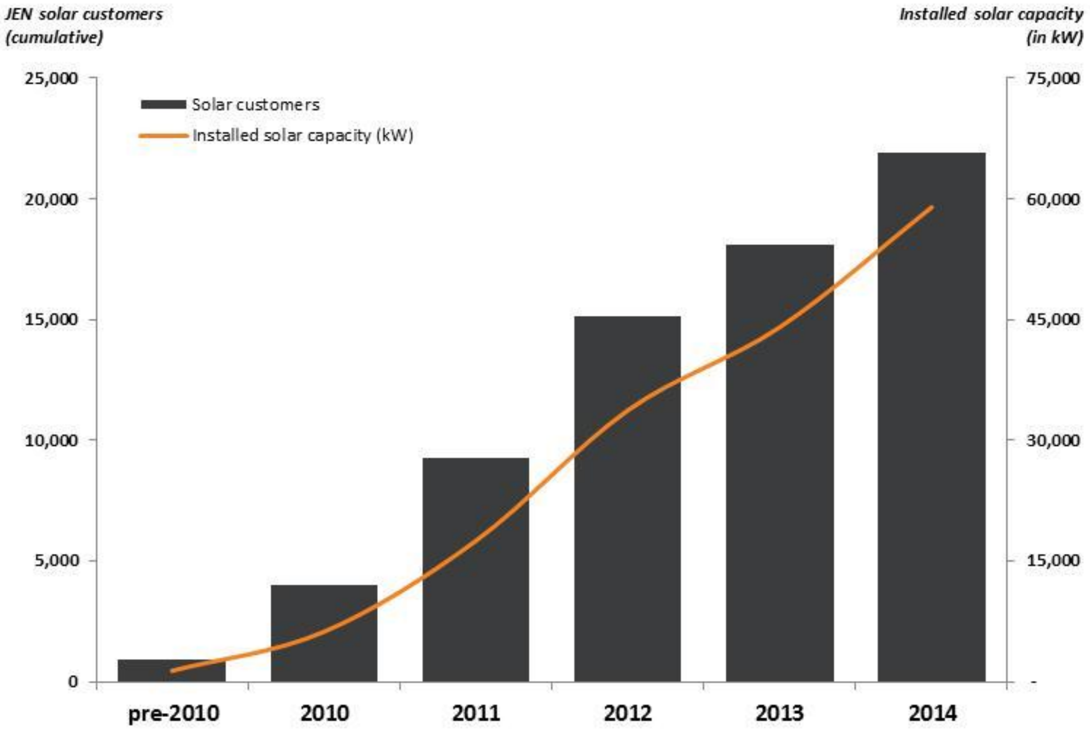
[22] Recent research of our customers highlighted that 70% of respondents actively monitor their energy usage and around half had made a behavioural change in the past year - most commonly in response to price. Refer Attachment 4-1 for further information and results of our survey.

[23] Surveyed respondents indicated that pricing or competitiveness plays a key role in considering alternative energy sources, as does the need for control. These engaged consumers are often called 'prosumers', who become involved with designing and customising products for their own needs, including the way they source and use energy. Victorian Government – Department of State Development, Business and Innovation, Victoria's Electricity Statement, p39.

[24] Australian Government, *Energy White Paper,* 2015.; AER, *Perspectives on the changing role of energy users, Speech by AER CEO—* Michelle Groves, 14 October 2014;

customers have installed solar PV units for a combined generation capacity of 56MW, equivalent to a wind farm in Victoria (see Figure 3–1).[25]

Figure 3–1: The growth in solar small-scale PV capacity in our network (2009 to 2014)



While solar PV units currently provide a modest part of any individual customer's energy needs, our customers are increasingly looking to other technologies to help them control their energy bills, both by producing their own energy and managing their consumption. We also expect continued growth in the number of our customers installing solar PV units in the 2016 regulatory period.

60. This trend is being driven by a combination of factors, including Government financial incentives,[26] the falling cost of new technologies, and changing community attitudes to energy. It is also changing the way our network is being used and will influence our role and the services we provide in future (see section 3.4).

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25 AGL's Oaklands Hill Wind Farm in Southern Grampians in Western Victoria has 32 wind-turbines with a generation capacity of 63 MW http://www.agl.com.au/about-agl/how-we-source-energy/renewable-energy/oaklands-hill-wind-farm

26 Over the current regulatory period, households and businesses have received significant financial support to install small-scale renewable technology from a range of Commonwealth and State Government programs including the Commonwealth Government's Renewable Energy Target (**RET**), including the Small-scale Renewable Energy Scheme (**SRES**), as well as State Government feed-in tariffs. The SRES provides upfront financial support to households and businesses that install eligible small scale renewable units, such as solar PV units and solar hot water systems. The Victorian Government's feed-in tariffs provided ongoing financial support to eligible households and businesses (those that installed PV units prior to 31 December 2012) with subsidised feed-in tariffs for electricity that was generated and exported to other customers. However, given the successful take up of such schemes, Government support is winding back on incentives. For example, the Essential Services Commission of Victoria (**ESC**) has released a draft decision to adopt a minimum feed-in tariff rate of 6.2 c/kWh from 1 January 2015, ESC, *Minimum feed-in tariff to apply from 1 January 2015, final decision*, August 2014.

3.3 GREATER INTERACTION AND ENGAGEMENT BETWEEN NETWORK BUSINESSES AND THEIR CUSTOMERS

61. Policy makers, regulators and network businesses are increasingly focused on ways to encourage more meaningful, transparent and effective engagement between network businesses and their customers.

62. This is important, not only because of the changes in our energy market, but also because:

- Electricity is as an essential service in powering homes and businesses, and customers need to be informed and confident in their rights and obligations
- Our investments in electricity infrastructure and other assets can be significant, and these assets last for a long time, meaning the decisions we make today affect our services, costs and prices over many years.

63. For these reasons, it is critical that our decisions reflect our customers' priorities and preferences. To ensure we understand these priorities and preferences, we need to establish clear, accessible two-way communication with our customers, stakeholders and the community.

64. We welcome and support the AER in encouraging the effective integration of customer engagement into network business and AER decision making, including releasing of its consumer engagement guideline[27] and establishing the Consumer Challenge Panel (**CCP**) to provide input on consumer perspectives to the AER.

3.3.1 THE CREATION OF ENERGY CONSUMERS AUSTRALIA

65. On 31 May 2013, policy makers agreed to establish a national energy consumer advocacy body—Energy Consumers Australia (**ECA**)—to provide coordinated and evidence based consumer advocacy on national energy market matters on behalf of energy consumers—particularly residential and small business consumers.[28] On 1 January 2015, ECA was founded.

66. We welcome the ECA playing a strong and strategic role in the evolution and application of the regulatory framework, particularly in relation to services, costs and prices, and we will engage with the ECA to help ensure we manage the changes occurring in our energy market in a way that promotes customers' long-term interests.

3.4 ENCOURAGING INFORMED CUSTOMER DECISION MAKING ABOUT ENERGY

67. Electricity networks are built to provide customers with electricity whenever and however they choose to power their homes and businesses. However, as the majority of our customers use most of their electricity at the same time demand on the network peaks during this period—typically weekday afternoons and evenings. Therefore, our network needs to be designed, built and maintained to meet our customers' needs during these peak periods in a safe and reliable way.

68. Building and augmenting the network to meet peak demand is relatively costly, and so has a significant influence on our capital expenditure program and ultimately on our network prices. It also means that for much of the time, the network is relatively underutilised (like a suburban road late at night).

69. Reducing peak demand by encouraging customers to reduce or shift some of their consumption into other periods, can result in significant savings to our customers by reducing the need to design, build and maintain the network to manage the peaks in electricity consumption.

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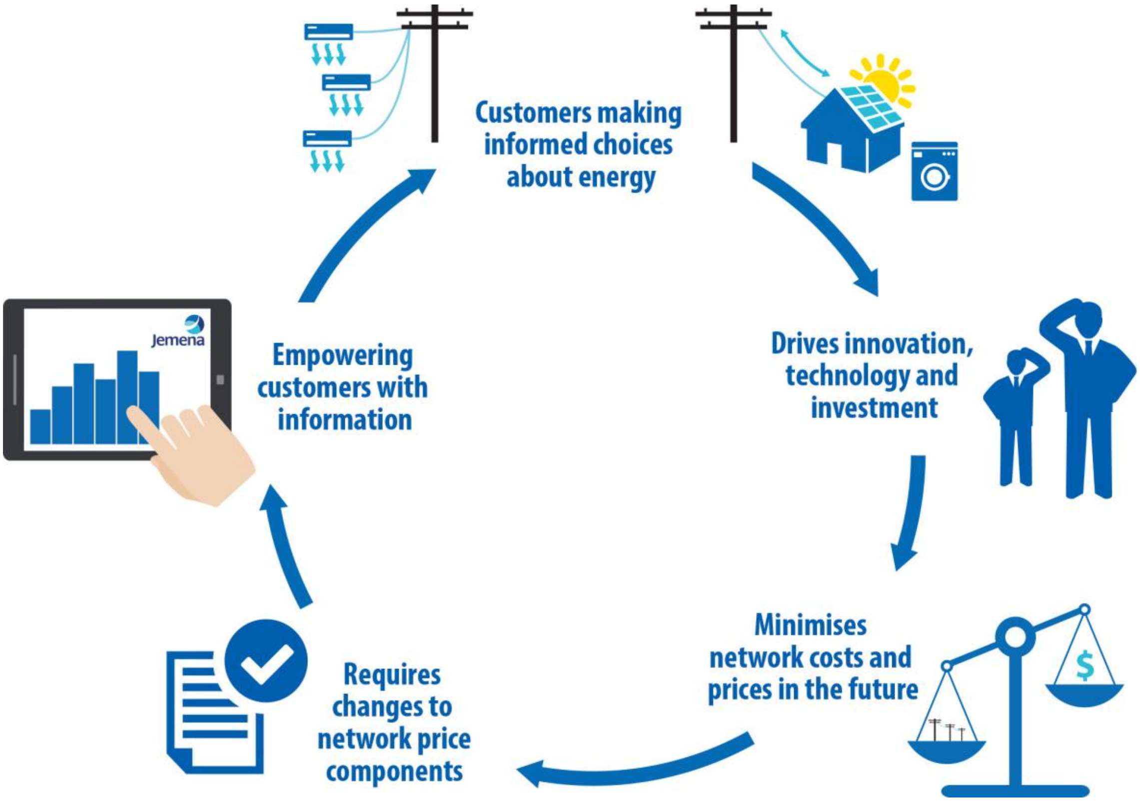
27 AER, *Consumer Engagement Guideline for Network Service Providers*, November 2013.

28 http://www.scer.gov.au/workstreams/energy-market-reform/energy-consumers-australia/

70. Policy makers, regulators and network businesses are increasingly focused on ways to encourage more informed customer decision making about their energy use. These efforts will likely lead to new energy market players in previously non-competitive markets, offering innovative solutions using new or existing technologies. Over time this should reduce peak demand and make better use of existing network infrastructure, thereby lowering network costs and customer bills (Figure 3–2).

71. For this approach to succeed, we will need to change the way we structure prices for using our network. We will also need to empower our customers with information about their energy usage (for example, through Jemena's Electricity Outlook Portal), the impacts of their investments in and use of appliances (such as air-conditioning) on our network, and likely changes in the prices they pay for using our network in the future.

Figure 3–2: Encouraging informed customer decision making about energy



72. Several recent developments are likely to assist in encouraging customers to make more informed energy decisions. These include improved metering technology and its deployment in Victoria, changes to the NER and the ongoing development of Jemena's Electricity Outlook Portal.

3.4.1 IMPROVED METERING TECHNOLOGY

73. In the past, the ability of network businesses to set prices that send effective price signals about the different costs to supply electricity at different times—and the ability of customers to make informed decisions about how and when they use electricity—have been constrained by limitations in the metering technology used in homes

and small businesses.[29] Most electricity meters only recorded total customer electricity usage—in the same way as a car odometer measures the total distance travelled—not how or when the electricity was used.

74. As a result customers have paid for electricity based on how much energy they consume over the billing period (typically 3 months). This has not provided effective signals to customers about the way that they use and/or produce electricity.[30] It has also meant that customers who consume a significant proportion of their electricity during peak periods (or those that generate a significant proportion of electricity from solar PV but draw significantly on the network during peak periods) are being subsidised by those who do not.

75. In recent years, technological improvements in metering have enabled customer usage at different times of the day to be recorded. Smart meters also make it possible for customers to access information on their energy usage in real time, and make more informed energy decisions.

76. Currently, more than 98% of JEN's customers have a smart meter in their home or business (see Box 3–1). This creates significant potential for us to change the way we charge customers for using electricity to encourage more efficient use of the network and thus lower network costs. Our customers are currently paying for the costs of these new meters, and we are committed to ensuring they can realise the benefits of the meters. Our proposal includes a range of initiatives that seek to leverage the benefits of smart meters including encouraging more informed energy decision making and ultimately lower network costs.

Box 3–1: Roll-out of AMI across our network and the benefits to our customers

In 2009, the Victorian Government, through the AMI Cost Recovery Order-in-Council (**CROIC**),[31] placed obligations on Victorian network businesses to roll-out AMI meters.

In our network area, installation of these meters began in September 2009, and the program was completed by June 2014. More than 98% of our customers now have smart meters, and these meters are being read remotely.

We are committed to ensuring customers can benefit from our investment in smart meters through more informed energy decision making—for example our meters can facilitate the provision of real time usage information to customers and will facilitate changes to the way we charge customers for using our network—and lower network costs.

3.4.2 CHANGES TO THE NATIONAL ELECTRICITY RULES

77. The AEMC has made several changes to the NER that facilitate more informed customer decision making about electricity. Changes to network pricing, improve the ability of customers to access information about their electricity consumption, and enable a competitive market for the provision of smart metering and related energy services. The changes include a suite of reforms in response to the AEMC's 2012 Power of Choice Review, including changes to the NER to:

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29 While increased customer interest and other initiatives (such as the Victorian Energy Efficiency Target) have encouraged customers and other market participants to reduce their overall energy consumption, until recently, we have not been able to provide small customers with signals that reflect the costs of transporting electricity supply electricity at different times.

30 For example, a flat rate for energy supply does not signal to customers the higher cost of supplying electricity during peak periods. Therefore, customers do not consider this cost when deciding to turn on (or off) their appliances. As result, peak demand is likely to be higher than it could be which imposes higher costs on all customers.

31 Victorian Government Gazette No S314, 25 November 2008.

- Ensure network prices better reflect the costs of providing network services to individual customers[32] - The NER now requires network prices to reflect the efficient costs of providing network services to each customer at different times of the day, and sets out new pricing principles that we must comply with in setting the structure and level of our network prices.[33] It also requires network businesses to engage in meaningful consultation with customers and other stakeholders when developing network prices. As our network prices form part of the retail prices, the Victorian Government's decision to require retailers to introduce more cost-reflective pricing complements these changes in the NER.[34]

- Allow customers to request access to their electricity consumption data from their network business and retailer[35] - The NER also allows parties authorised by customers to request access to customers' electricity consumption data and specifies minimum requirements relating to the format, timeframes and costs of the information provided.

- Implement arrangements to support a competitive market for the provision of metering and related energy services[36] - These arrangements[37] will clarify the roles and relationships between consumers, retailers, distribution network businesses and other parties involved, and will allow competition in the provision of metering services to smaller consumers (including the owner and operator of the meter and associated data services) from 1 July 2017.

3.4.3 ONGOING DEVELOPMENT OF JEMENA'S ELECTRICITY OUTLOOK PORTAL

78. We recognise that providing our customers with information[38] can empower them to make informed energy decisions about how and when they use energy—including how they use our network—and provide them with more control over their energy bills. Ultimately, this will encourage more efficient use of our network, improving allocative efficiency.

79. We are committed to empowering our customers with information about their energy usage, and in recent years, we have consulted on and developed Jemena's Electricity Outlook Portal to give customers access to their usage information (see Figure 3–3). We are encouraging our customers to make use of this information to allow them to make informed energy decisions and better target energy efficiency measures.[39]

80. We have also consulted on how best to encourage the community to make use of this information and the benefits of their smart meters, including the community benefits of trialling the installation of in-home energy displays to assist vulnerable customers take better control of their electricity bills (see chapter 4).

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[32] AEMC, *Rule determination, National electricity amendment (Distribution Network Pricing Arrangements) Rule 2014 No. 9*, November 2014.

[33] This is intended to encourage households and businesses to make more informed decisions on how they use electricity – including how customers or new energy market participants use our network and emerging technologies – to manage their energy needs.

[34] In September 2013, the Victorian government enabled retailers to introduce flexible pricing where different rates are charged for electricity use at different times of the day. Victorian Government – Department of State Development, Business and Innovation, Victoria's Electricity Statement, 2014 p20.

[35] AEMC, *Rule Determination – National Electricity Amendment (Customer access to information about their energy consumption) Rule 2014*, November 2014.

[36] AEMC, *Rule Determination – National Electricity Amendment (Expanding competition in metering and related services) Rule 2015*, March 2015.

[37] Including changes to National Electricity Retail Rules (**NERR**)

[38] We recognise that many of our customers were born overseas and may speak a language other than English at home and could benefit from the provision of targeted information about the energy usage and the impacts of their investments in energy appliances.

[39] We also recognise the benefits of providing our customers and stakeholders with information about how the network prices they pay for using our network are developed – including the matters we must consider and the process we undertake to design, consult and receive AER approval of the prices –and how these are likely to change over time. This information is provided in our Tariff Structures Statement (see Attachment 10-2).

Figure 3–3: Jemena's Electricity Outlook Portal and smart meters allow customers to take control of their energy bills.

Source: Jemena Electricity Networks

3.5 THESE CHANGES HAVE IMPLICATIONS FOR US AND OUR CUSTOMERS

81. The trends outlined in section 3.1 are likely to drive further innovation in the energy market, which in turn will lead to new energy market players and changes in the roles of existing energy market players. Among other things, we expect we will need to make changes in the way we set our prices for using the network, and continue to evolve the way we engage with our customers, stakeholders and the community to understand their priorities and preferences.

3.5.1 OUR ROLE AND THE SERVICES WE PROVIDE ARE LIKELY TO EVOLVE

82. As customers increasingly look to manage their energy needs, their expectations of their energy providers will change. This will drive further innovation in the energy market, which means the role of existing energy market providers, including us, is likely to change.

83. We support policy makers' intention to allow markets to work in a way that gives consumers choice in how they access electricity, and also gives suppliers the ability to respond to those choices.[40] This will ensure that competition and innovation encourage efficient and competitively priced energy (see Figure 3–4).

84. Electricity distribution networks like ours will still play a critical role in transporting electricity to and between homes and businesses. For example, we will continue to:

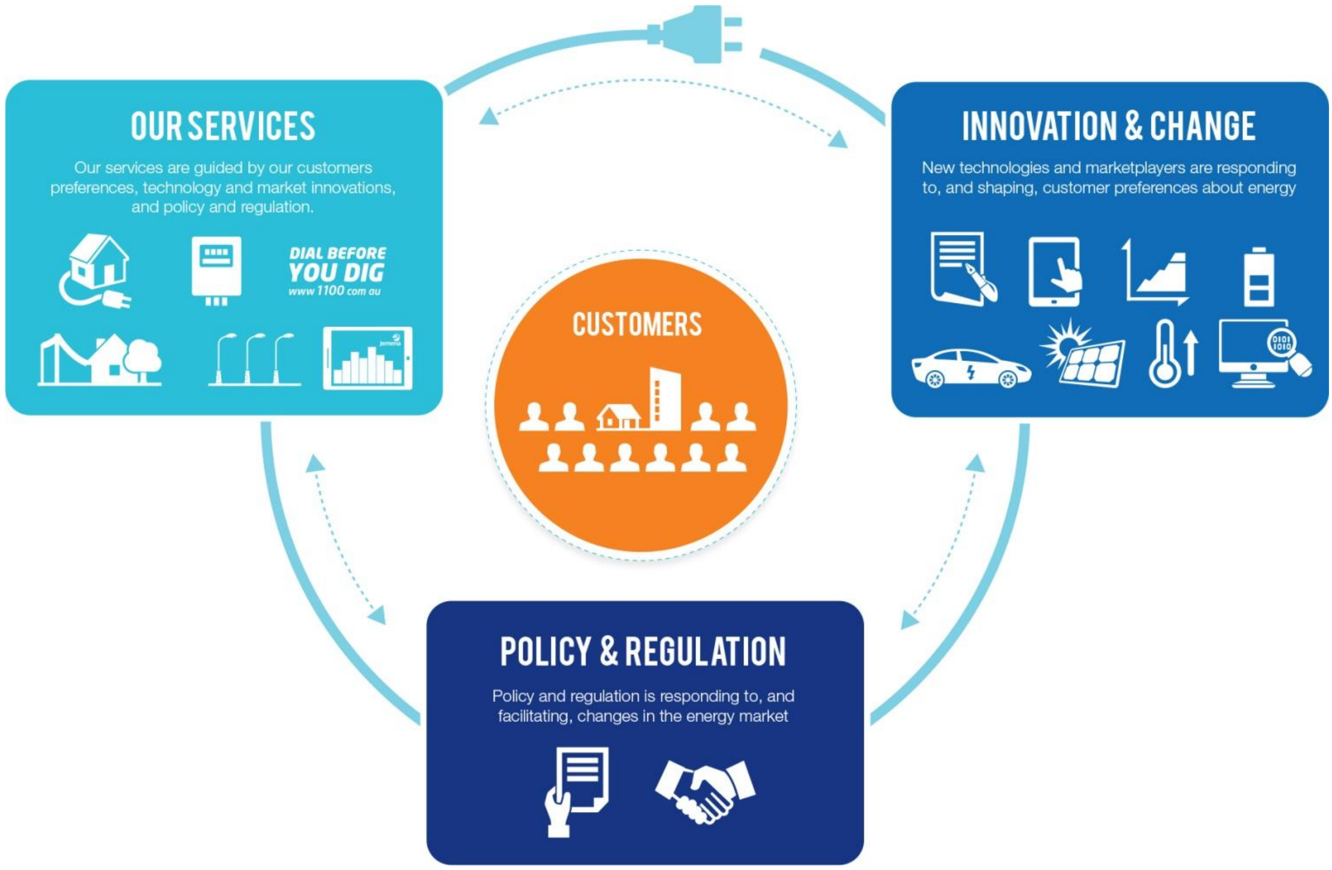
- Provide a safe, reliable and responsive energy delivery option to our customers

[40] Australian Government, *Energy White Paper—Green Paper* 2014, p viii.

- Facilitate innovation in new technologies and customer choice in their energy supply by enabling the installation of solar PV units and other technologies in our customers' homes and businesses, and ensuring our network can safely and reliably manage energy that is exported into our network.

85. However, new industry players may also emerge to help customers manage their energy—including their energy use, production and potentially storage—or to act as intermediaries between the network and the retailer/customer. For example, these players could include virtual power plants,[41] energy storage operators, and providers of energy usage data and energy management 'gadgets'.

Figure 3–4: Our role in serving the community is evolving in response to customer, market and policy changes



86. This is likely to lead to changes in the services we provide. For example, our role in the provision of metering equipment and data provision—historically, one of the core services provided by energy and other network businesses—is likely to evolve as a result of the changes in the NER (see section 3.4.2).

87. As we increasingly compete against a range of other technologies and energy market players, the regulatory framework and energy market design will need to be capable of adapting to these changing circumstances. Policy makers have highlighted the importance of the regulatory and policy settings encouraging innovation, new business models (including network business models) and competition if we are to manage these changes in a way that continues to promote customers' long-term interests.[42,] For example, it is critical that the regulatory

[41] A virtual power plant is a group of distributed generation installations which are run collectively by a central control entity.

[42] Australian Government, *Energy White Paper—Green Paper* 2014, p viii; CoAG Energy Council, *Meeting Communique*, May 2014.

framework encourages us to compete in these emerging markets, to drive innovation and make use of our knowledge and capabilities in way that promotes the interests of our customers.[43]

3.5.2 THE WAY CUSTOMERS USE OUR NETWORK WILL CONTINUE TO CHANGE WHILE ELECTRICITY DEMAND CONTINUES TO GROW

88. The widespread installation of solar PV and other small distributed generation units has changed the way customers use our network. We expect further changes in the way our network is used as new technologies (for example, battery storage, electric vehicles and smart grids) and new market players emerge to assist customers manage their energy needs.[44]

89. It is difficult to predict the pace of technological development, and to forecast how, where and when our customers will chose to use these new technologies. These uncertainties will make it even more challenging to forecast electricity demand, which is driven by a range of complex economic and demographic factors.[45]

90. To understand the impact of these changes and a range of other factors, we engaged independent experts ACIL Allen to assist us in forecasting how customers are likely to use our network over the next 5 years. This includes forecasts of the number of new customers that are likely to require electricity supply, the total volume of electricity consumed by the new and existing customers, and the level of peak demand. These independent forecasts of energy demand are key inputs for forecasting the capital expenditure required to deliver the services our customers expect (see Chapter 7), and the prices and charges required to recover the costs of these services from our customers (see Chapter 10).

91. ACIL Allen's expert analysis suggests that, in aggregate, the total volume of electricity consumed by the new and existing customers will increase modestly at a rate of 1.3% per annum,[46] and the level of peak demand will grow at 1.4% per annum over the 2016 regulatory period. ACIL Allen's forecasts of electricity demand are comparable to those prepared by the Australian Energy Market Operator (**AEMO**) for its forecasting of national electricity consumption and peak demand.

92. However, the total volume of electricity consumed by our customers and the level of peak demand is forecast to grow at different rates across our network (see Figure 3–5). As our network is undergoing significant change and development (see Attachment 3-2), there are pockets where peak demand is expected to grow by greater than 5% per year, particularly in newly established suburbs. There are also pockets where peak demand is forecast to decline by more than 2% per year. Box 3–2 outlines the drivers of the uneven growth in peak demand across our network.

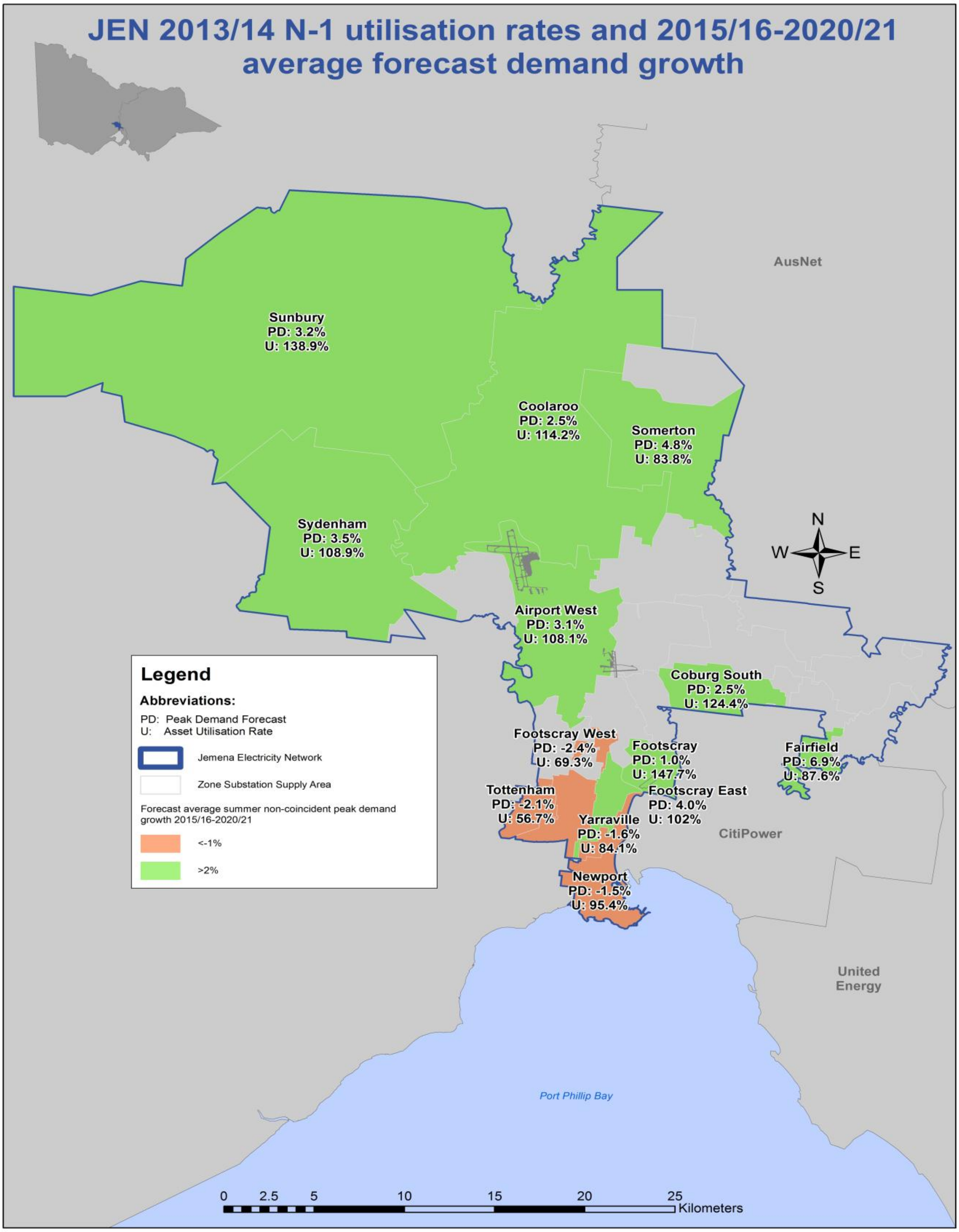
43 For example in the context of expanding competition in metering and related services, the policy, regulatory and technical settings being considered by the AEMC, the Australian Energy Market Operator (**AEMO**) and the AER will play a critical role in ensuring we can effectively participate and innovate in these newly contestable markets for the long-term benefit of customers. Onerous ring fencing requirements that seek to remove the economies of scale and scope that could benefit customers would diminish the incentives for network businesses to participate in the newly contestable markets and would likely place upward pressure on prices in the newly contestable markets.

44 Now, customers with solar PV use the network to export excess electricity primarily during daylight hours to the grid. New technologies and market players may mean electricity is exported at other times of the day, say during peak periods.

45 AEMO note the challenges in forecasting demand as a result of uncertainty around the take-up and use of air-conditioning and new technologies such as solar PV. AEMO note these factors contributed to forecast demand made as part of the National Electricity Forecasting Report (**NEFR**) Update, being significantly lower than actual demand over the July-December 2014 period in Queensland. http://www.aemo.com.au/Electricity/Planning/Forecasting/National-Electricity-Forecasting-Report

46 ACIL Allen is forecasting growth of 1.8% per annum in residential electricity consumption, primarily driven by the need to supply over 19,000 new residential customers over the 2016 regulatory period. ACIL Allen is forecasting growth of 0.94% per annum in business consumption, primarily driven by the need to supply over 2,000 new business customers over the 2016 regulatory period.

Figure 3–5: Heat-map of forecast peak demand growth in our network



Source: Jemena Electricity Networks, 20 Nov, 2014

93. Further details of ACIL Allen's methodology, assumptions and forecasts are provided in Attachment 3-1.

Box 3–2 Peak demand is forecast to grow at a modest and uneven rate across our network

We are forecasting peak demand on our network (or system maximum demand forecasts) to increase from 936MW in 2014/15 to 1016 MW in 2020/21, growth of around 1.35% per year over the 2016 regulatory period.

However, our peak demand is forecast to grow unevenly across our network:

- Our network encompasses part of three of the four Victorian Government's identified growth areas—the Northern Growth Corridor (including Craigieburn and Mickleham), the Sunbury/Diggers Rest Growth Corridor and the Western Growth corridor (including Plumpton)—despite our network being the smallest in Victoria. This significant change and development will result in pockets of residential and commercial growth, particularly in newly established suburbs—and thus require capital investment in our network to ensure we can provide the service levels our customers value (see chapter 7).
- In general, Jemena expects strong growth in maximum demand in the northern half of the network, largely due to new developments associated with Melbourne's continuing urban sprawl towards the edge of the Urban Growth Boundary. As a result, we are forecasting high growth in annual maximum demand over the next six years for areas currently supplied by Somerton (+4.8%), Sydenham (+3.1%), Sunbury (+2.8%) and Coolaroo (+2.1%) zone substations.
- Some pockets within established inner suburbs are also experiencing strong demand growth resulting from amendments to council planning schemes to high density living. The high growth is mostly driven by high rise residential developments and commercial office buildings. Accordingly, we are forecasting high growth in annual maximum demand for the next six years for areas also supplied by Footscray East (+5.1%), Fairfield (+3.4%) and Coburg South (+2.4%) zone substations.
- Jemena expects other parts of the network, generally in the south, to experience low growth or even a decline in maximum demand, particularly those areas with a large number of industrial businesses.

3.5.3 WE NEED TO CHANGE THE WAY CUSTOMERS PAY FOR USING OUR NETWORK

94. Our current network prices for residential and business customers have not evolved to provide signals for informed energy decision making. To some extent, the structure of our network pricing has not kept up with the diversity in how people use the network.

95. We want to improve the way our customers pay for using our network. The effect of these changes means that customers will increasingly pay for energy based on how (maximum demand) and when (what time of day) they draw energy from our network.

96. This may result in some customers paying less to use our network and others paying more. The key factor will depend on how and when customers use our network, and how they respond to these new price signals. It will also depend on how retailers incorporate these network price signals in their retail price structures.

97. Chapter 10 outlines the proposed tariff structures for the 2016 regulatory period. Our Tariff Structures Statement (**TSS**) details how the proposed tariff structures comply with the NER and provides indicative tariff levels and customer outcomes for the regulatory period (see Attachment 10-1 and Attachment 10-2).

3.5.4 ONGOING ENGAGEMENT WITH OUR CUSTOMERS, STAKEHOLDERS AND COMMUNITY WILL BE IMPORTANT

98. As chapter 1 outlined, to develop this proposal we engaged with our customers, stakeholders and the community on issues to understand their priorities and preferences in relation to our service and safety standards, as well as our prices and tariff structures for the 2016 regulatory period.

99. One of the issues we engaged on was the potential benefits and impacts of changing our network prices for customers, and customer preferences on the design and transition to the new tariffs. The engagement process also highlighted the importance of ongoing engagement with our customers, to guide the evolution of the appropriate role for us (and other energy market players) in assisting customer to make informed energy decisions and providing other customer and financial assistance if necessary.

100. Chapter 4 outlines our engagement process in developing this proposal, including how we designed the process, what we heard from our customers, stakeholders and the community, and how this shaped our proposal.

4. OUR ENGAGEMENT WITH CUSTOMERS, STAKEHOLDERS AND THE COMMUNITY

Key messages

- We recognise the importance of engaging with our customers and stakeholders, and are committed to effective engagement both in developing our regulatory proposals and conducting our business as usual.
- We redesigned our engagement approach for this proposal, and conducted an extensive engagement process that was consistent with the best-practice principles in the AER's guidelines.
- We received valuable feedback from this process, which we have taken into account in our decision making for the proposal.

101. In developing this proposal, we engaged extensively with our customers, stakeholders and the broader community to better understand their priorities and preferences in relation to our services, costs and prices over the 2016 regulatory period and beyond. We used the information and insights from this engagement to inform our analysis and decisions on the key components of our proposal, to help ensure the proposal responds to the market changes outlined in chapter 3 in a way that promotes the long-term interests of our customers.

102. We provide an overview of our engagement process and outcomes, including:

- The importance of engaging with customers, stakeholders and the community
- Our commitment to this engagement
- Our engagement approach for this proposal
- What we heard from our customers and stakeholders, and how we have responded.

103. For more detailed information on the design, implementation and results of our customer engagement on this proposal, see Attachment 4-1.

4.1 THE IMPORTANCE OF ENGAGING WITH CUSTOMERS

104. Policy makers, regulators and network businesses increasingly recognise the importance of effective engagement with customers in the energy market, to help ensure that their decisions promote the long-term interests of customers. Rising energy prices in recent years have highlighted the need for customers to be more effective participants in:

- The network businesses' regulatory proposal development process
- The AER's review of these regulatory proposals, and
- Decision making related to the design of the energy market, including the AEMC's review processes.

105. Engaging with our customers and stakeholders to better understand their preferences and values is important because we need to make decisions and trade-offs on behalf of our customers, and because these decisions influence our customers' energy decision making.

4.1.1 WE NEED TO MAKE DECISIONS ON BEHALF OF OUR CUSTOMERS

106. Like many businesses, we need to make decisions on behalf of our customers. For example, we need to decide on what service levels we provide to meet our obligations, what costs we incur in providing our services, and how we price our services to recover these costs (see Figure 4–1).

107. Making these decisions inevitably involves trade-offs. For example, our customers consistently tell us they value a safe and reliable supply of electricity. However, they also tell us that rising energy prices have become a household or commercial concern, and they want us to put downward pressure on our costs and network prices. These priorities are potentially conflicting, as higher services levels often involve higher costs.

108. In a competitive market, customers would be able to choose the product or service that best aligns with their preferred trade-off between these priorities. But in a network business like ours, we need to make these decisions on behalf of our customers, within the context of the regulatory framework. We must balance a range of competing, and potentially conflicting objectives, in relation to the services we charge, the costs we incur and the prices we charge to promote our customers' long-term interests.

Figure 4–1: We need to make trade-offs to promote our customers' long-term interests

109. In addition, our investments in electricity infrastructure and other assets tend to be costly, and these assets last for a long time (in some cases, up to 50 years). This means the decisions we make today affect our services, costs and prices over many years. With our energy markets expected to undergo big changes in the future, it's important we understand our customers' priorities and preferences, including what they want from our network and how they are likely to use our network over the short and longer term.

4.1.2 OUR DECISIONS INFLUENCE OUR CUSTOMERS' ENERGY DECISION MAKING

110. Our decisions—particularly our pricing decisions—influence our customers' energy decisions—including how they use energy to power their home or business, and the investments they make in energy-using appliances and energy-generation units. These decisions shape their ongoing energy costs.

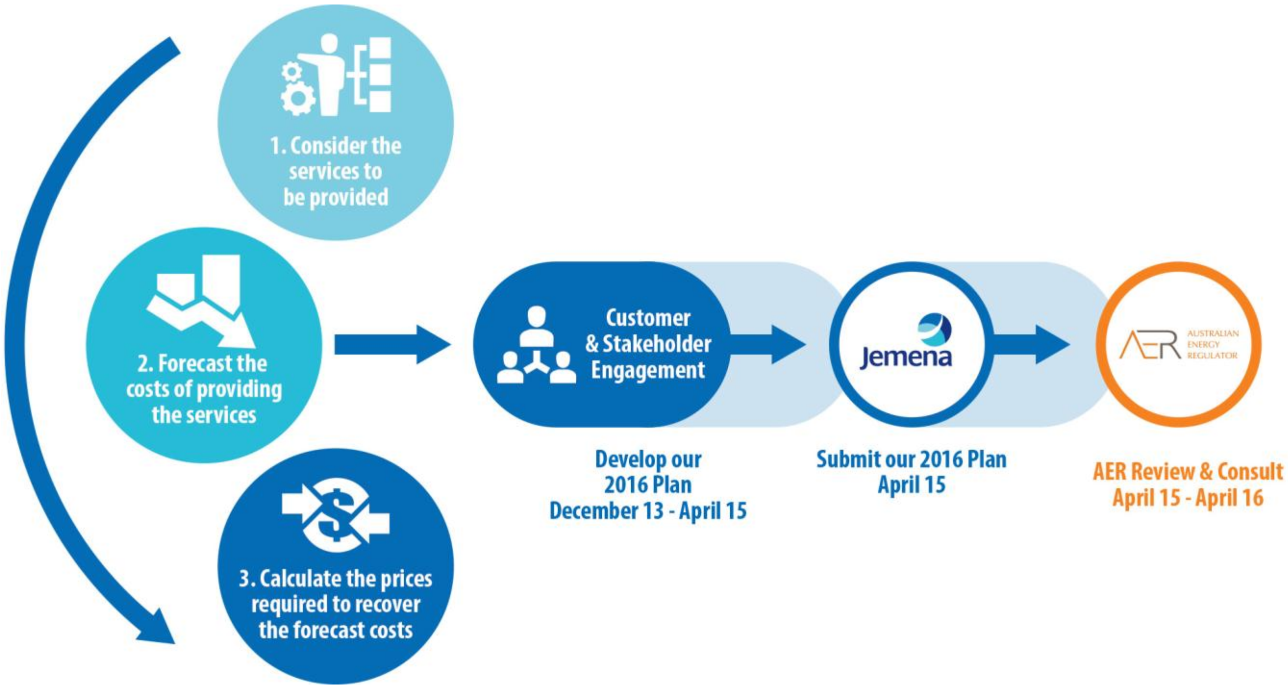
111. As chapter 3 outlines, there is a growing focus on facilitating more informed energy decision making by customers. One way to do this is by improving the price signals created by network tariff structure and levels, given that most retailers pass on our costs. In our view, our tariffs for residential and small business customers have not evolved to provide signals for informed energy decision making. To some extent, our tariff structures have not kept up with the diversity in how people now use our network.

112. To improve our price signals, we need to understand how and why our customers use energy, and their ability to change the way they use energy, including their ability to shift consumption into different times of the day and hence potentially reduce our costs. In addition, to make informed investment and usage decisions, our customers need to be able to understand and respond our network prices. Thus it is important to empower them with information on the structure and level of our network prices over the 2016 regulatory period and beyond.

4.2 OUR ENGAGEMENT APPROACH FOR THIS PROPOSAL

113. We are committed to engaging with our customers, stakeholders and the broader community as part of our process for developing regulatory proposals (see Figure 4–2), and as part of our role in providing an essential service to the community.

Figure 4–2: Our engagement on this proposal covered the key areas of services, costs and pricing

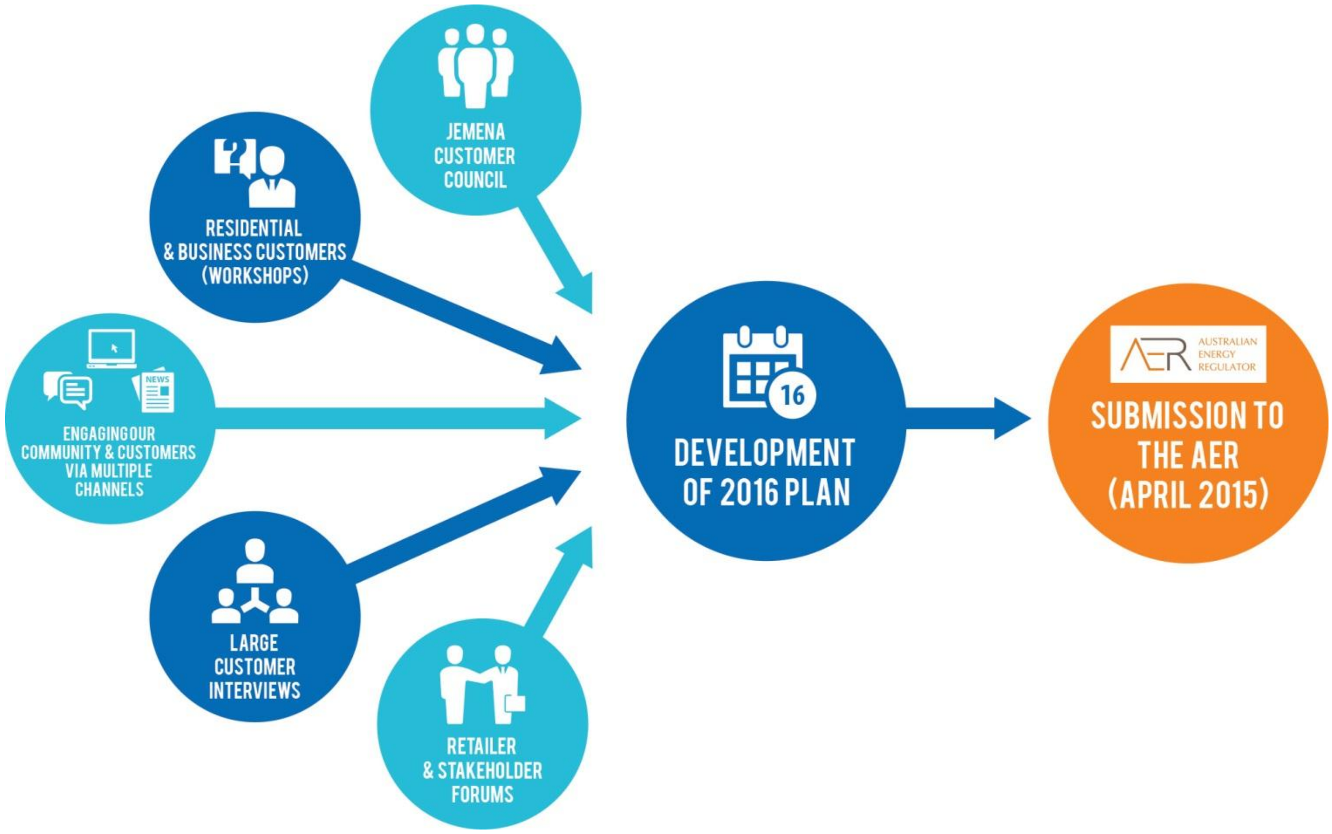


114. While we have a long history of engaging with the community on business-as-usual issues, and we will continue to do this, we redesigned our approach to customer, stakeholder and community engagement for this proposal. In doing so, we were guided by the AER's Consumer Engagement Guidelines and the input from Jemena's customer council.

115. The first stage in our approach was to establish our priorities for the engagement, including:

- What we should achieve from the engagement, including clarifying our main objectives
- Who we should engage with, including identifying the relevant 'cohorts' or groups within our diverse customer and stakeholder base (Figure 4–3)
- How we should engage with them, including selecting the best way to engage with each group, given our objectives and their capacity to engage effectively on the key issues of concern to them
- What we should engage them on and why, including identifying, prioritising and validating the important issues for consultation with each group, and our objectives for this consultation.

Figure 4–3: We divided our customers, stakeholders and community into five groups



116. We then designed an effective engagement approach to achieve these objectives and engage with each group on these issues. We ensured that we provided enough background information so customers could understand the context for our proposal—including information on:

- Our role within the different parts of the energy supply chain
- The costs associated with each part, and
- The roles of the AER in regulating our network service prices.

117. We also provided information on the changes that are occurring in our energy market and the decisions we need to make for the coming five years—including on our services, costs and prices—and in future years to respond to these changes.

118. Next, we explored the views of each group (and the general community via our website), by outlining how alternative decisions would affect our services, costs and prices over the 2016 and future periods.

119. Finally, we confirmed what we had heard with each group, and directly incorporated their feedback into our decisions for our proposal.

120. We are confident our process and implementation are consistent with the best-practice principles in the AER guidelines, and benefit from the findings and experiences detailed by consumer advocates' and businesses in other jurisdictions[47], including our engagement on the Jemena Gas Network's Access Arrangement. We are also confident that the process provides a platform for continued engagement as our energy market and our customers' priorities and preferences evolve.

4.3 WHAT OUR CUSTOMERS TOLD US THROUGH OUR ENGAGEMENT

121. In general, our customers and stakeholders told us that they are increasingly interested in energy market issues—and want to be better informed and empowered to make energy decisions.

122. They want us to provide a safe and reliable energy service that facilitates innovation in new technologies and customer choice in their energy supply—for example, by enabling the installation of solar PV units and other technologies in their homes and businesses, and ensuring our network can safely and reliably manage energy that is exported to other homes and businesses.

123. They want us to do what we can to minimise our network prices and put downward pressure on energy bills, by pursuing strategies to reduce our overall costs per customer.

124. In addition, our customers told us:

- They see the energy market as complex and would value us doing what we can to make it easier for them to participate in the market, including being transparent in the way we make pricing decisions today and in the future, and
- They want us to do more to help vulnerable customers manage their energy bills and make energy markets work better for these customers—particularly by assisting them with the upfront costs of upgrading their electric appliances, and improving the information available on managing energy bills.

125. To get a deeper understanding of what our customers and stakeholders want, we tested their views on some of the key trade-offs we could make to help minimise the impact of the expected market changes and understand their preferences. The key trade-offs we tested were:

- Our services levels versus our costs and prices—for example, providing higher (or lower) levels of service may lead to higher (or lower) costs, which in turn may lead to higher (or lower) distribution network prices. We tested the key attributes of the service we provide to customers—reliability, responsiveness and visual amenity.
- The structure of our proposed tariffs, including maximum demand based charges, and the transition to these new tariffs. We tested how these charges should apply to our residential and small business customers, and how quickly we should move to these new charges.
- The scope and level of assistance we provide to customers who are vulnerable and the cost to all customers of doing so.

47 For example, Yarra Valley Water's customer engagement in developing its 2013/14 to 2017/18 Water Plan.

4.4 HOW WE RESPONDED TO OUR CUSTOMERS' FEEDBACK

126. The feedback we received from customers, stakeholders and the community was valuable in helping us understand and take account of our customers' interests in our decision making for our proposal.

127. We are confident our proposal supports our customers' long-term interests by responding to changes occurring in the energy market, to encourage innovation, facilitate customers being active and informed energy decision-makers, and assist customers who are vulnerable to rising electricity prices (see Figure 4–4).

Figure 4–4: What our customers told us and how we responded

	What you told us	Our response and the benefits for you
Our safety and service levels	*Safety should remain our top priority* *You want us to maintain our current service levels, and support our planned investments to enable this*	*We will maintain our current safety and service levels, continuing to provide the safe, reliable and responsive services our customers expect.* *We will make efficient investments to ensure demand from new growth areas and aging assets in well-established areas don't compromise our service levels and our investments in new growth areas will enable local economic development.*
Our costs	*You want us to be transparent about our costs* *You want us to continually improve our efficiency and put downward pressure on customer bills* *You support us exploring innovative technologies which can help lower our costs over the long term*	*We will keep our average prices as low as possible by:* • *continuing to improve our cost efficiency* • *passing through the benefits of the reduction in our funding costs* • *ensuring our customers only pay for expenditure that is necessary, and exploring new alternatives to future network investment.*
Our prices	*You want prices that better reflect and more equitably share the costs of using our network*	*We propose to update the individual components of our network tariffs to provide better price signals and reduce cross-subsidies between customers. This will empower you with new ways to save on your bills, and encourage you to make informed choices in using our network.* *We have proposed measures to minimise the adverse impacts of the proposed changes in our price components.*
Empowering customers	*You want to be more active decision-makers and take control of your energy decisions*	*We will continue to facilitate your use of new technologies to manage your energy needs and provide information you need to take control of your energy decisions.*
Helping vulnerable customers	*Some customers are struggling to pay electricity bills* *You think we have a role to play in assisting vulnerable customers*	*We will assist vulnerable customers struggling to pay electricity bills by helping them to replace inefficient appliances and providing them with targeted information about their energy usage and bills.*
Engaging and responding to our customers	*You value us engaging with you on a range of issues*	*We will continue to engage with our customers, stakeholders and the community on our services, costs and prices.* *We will continue to learn from and improve our engagement processes.*

5. FORM OF REGULATION AND INCENTIVE AND RISK MANAGEMENT FRAMEWORKS

Key messages

- We propose that:
  - Our distribution services be classified consistently with that outlined in the AER's framework and approach paper
  - The incentive schemes in the NER be applied broadly in line with the AER's intended application, with two modifications:
    - the efficiency benefit sharing scheme incorporate a number of excluded costs from the calculations of efficiency gains or losses
    - the capital expenditure sharing scheme exclude capital expenditure related to reliability improvement
  - Risk be managed through the cost pass-through mechanism specified in the NER, with the nomination of seven additional pass-through events.

In proposing a risk management framework, we had regard to the considerations outlined in the NER, and our ability to efficiently manage risks. For example, we consider that each of our proposed pass-through events has a low probability of occurrence, the potential to have a significant cost impact, and is beyond our reasonable ability to control, and therefore meets the necessary requirements to be approved as a nominated event for the 2016 regulatory period.

128. The NER require us to propose the:

- **Form of regulation** to apply over the regulatory period, including how each network service we provide is to be regulated ('the classification of distribution services'[48]), and for services that are to be directly regulated, the form of price control to apply ('the control mechanisms'[49]), taking account of the AER's position in its framework and approach paper[50]
- **Incentive framework** ('incentive schemes'[51]) to apply over the period to encourage continued improvement in the services we provide, including our cost efficiency, service standards and management of network demand, consistent with the incentives specified by the AER in its framework and approach paper
- **Risk management framework** ('pass-through mechanism'[52]) to apply over the period to allow the AER to adjust our network prices up or down in response to unforseen, uncontrollable and material changes in our costs.

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48 NER cl 6.8.2(c)(1)(i) and (ii) require us to include a classification proposal in our regulatory proposal

49 NER cl 6.8.2(c)(3) requires our regulatory proposal to demonstrate the application of the control mechanism, as set out in the framework and approach paper, and the necessary supporting information, for services classified as alternative control services. However the NER do not prevent us from proposing changes to the formula that gives effect to the control mechanism, and the AER is able to amend its formulae if the AER considers that unforeseen circumstances justify departing from the formulae.

50 NER cl 6.8.1(a)(2) requires the AER to publish a framework and approach paper to apply for the 2016 regulatory period if it has signalled its intent to make an amended or replacement framework and approach paper. Among other things the framework and approach paper must set out the AER's proposed approach to the classification of services, the formula to give effect to the control mechanisms and the application of the incentive schemes.

51 NER cl Schedule 6.1.3(3), (3A), (4), (5) and (5A)

52 NER cl 6.6.1(a1)

129. If we are to manage our business in a way that promotes our customers' long-term interests, each of these elements needs to be responsive and adaptable to changing circumstances—including changes in the way our network is used as new technologies and new market players emerge and develop. For example, the form of regulation for our different network services needs to be adaptable to reflect new competitive tensions that may emerge during the regulatory period. Similarly, the risk management framework needs to accommodate the new risks and uncertainties in our energy market.

130. We provide an overview of our proposed form of regulation, incentive framework and risk management framework for the 2016 regulatory period, and then outline each proposed element in more detail.

5.1 OVERVIEW OF PROPOSED FORM OF REGULATION AND INCENTIVE AND RISK MANAGEMENT FRAMEWORKS

131. For the 2016 regulatory period, we propose that:

- Our distribution services be classified in line with AER's classification[53] as outlined in Attachment 5-1.
- The incentive schemes in the NER be applied broadly in line with the AER's intended application, with the following modifications:
  - The EBSS incorporate a number of excluded expenditure categories from the calculations of efficiency gains or losses
  - The CESS exclude capital expenditure related to reliability improvement
- In addition to the pass-through events specified in the NER, seven further events be specified to enable the AER to efficiently and cost-effectively manage the risks for us and our customers associated with the provision of direct control services over the 2016 regulatory period. These include a:
  - Natural disaster event
  - Insurer credit risk event
  - Insurance cap event
  - Terrorism event
  - Carbon cost event
  - End of metering derogation event
  - A retailer insolvency event.

5.2 PROPOSED FORM OF REGULATION

132. We provide a range of essential services to our customers. Some of these services—such as our core distribution network service—are well-known. Other services—such as user-requested activities—may be less familiar to many of our customers.

53 AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p11.

133. In addition, some of these services, such as our core distribution network services, are provided solely by us. However, other services are provided in more competitive markets, meaning we compete alongside other businesses to provide these services to our customers.

134. The NER and the AER[54] recognise that there are varying levels of competition in providing the network services that customers value, and therefore that direct regulation of services, costs and prices may only be required for those services where minimal competition exists.

5.2.1 CLASSIFICATION OF OUR DISTRIBUTION SERVICES

135. The NER require us to propose how our services should be regulated ('the classification of distribution services'),[55] including which services:

- Require direct regulatory control by the AER of the prices we charge or revenues we recover from our customers, including standard control or alternative regulatory controls[56]
- Require indirect regulatory control with the AER approving a negotiating framework and/or being involved in any arbitration[57]
- Are best left unregulated with outcomes determined in the competitive market.

136. To guide our proposal, the AER's framework and approach paper outlines how it intends to classify our services for the 2016 regulatory period (the AER's intended classification is shown in see Box 5–1).

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54 The AER's Framework and Approach paper highlights that "where there is considerable scope to take advantage of market power, our regulation is more prescriptive. Less prescriptive regulation is required where prospect of competition exists. In some situations we may remove regulation altogether." AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p11.

55 NER cl 6.8.2(c)(1)(i) and (ii) require us to include a classification proposal in our regulatory proposal

56 The AER notes that they classify standard control services as those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers, with alternative control services being customer specific or customer requested services. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p15-16.

57 The AER notes that this is appropriate for services where all relevant parties have sufficient countervailing market power to negotiate the provision of those services. AER, *Final Framework and Approach for the Victorian Electricity Distributors,* October 2014, p18.

Box 5–1: AER's intended classification of our services for the 2016 regulatory period

In its final framework and approach paper,[58] the AER indicated its preference for the following classification:

- **Standard control services** – core distribution network services and new connection services requiring augmentation (including customer initiated connections)[59]
- **Alternative control services** – routine connections; metering for 'small customers' (Type 5 and 6 metering);[60] Type 7 metering; ancillary network services;[61] ancillary metering services; and shared public lighting services
- **Negotiated services** – new public lighting services (including greenfield sites); alteration and relocation of public lighting assets; operation, maintenance and repair of dedicated public lighting assets; replacement of dedicated public lighting assets; and construction of reserve feeders
- **Unregulated services**[62] – emergency recoverable works; type 1-4 metering; and type 5-6 smart metering subject to competition.

137. Our proposed services classification (shown in Figure 5–1) is consistent with the AER's intended classification. Our proposed classification is also broadly in line with the classification that applied in the 2011 regulatory period.

138. We consider that consistency with the AER's proposed classification provides customers and stakeholders with confidence that prices and charges for our distribution network services and user-requested services will continue to be directly regulated by the AER, while the prices and charges for other services will be determined through a competitive process. As policymakers have highlighted, the emergence of new technologies and energy market players requires the regulatory framework to evolve[63] so that regulation does not get in the way of business competition and innovation.[64]

58 AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p. 20.

59 Including new connections requiring augmentation of our shared network.

60 With annual consumption under 160MWh per year.

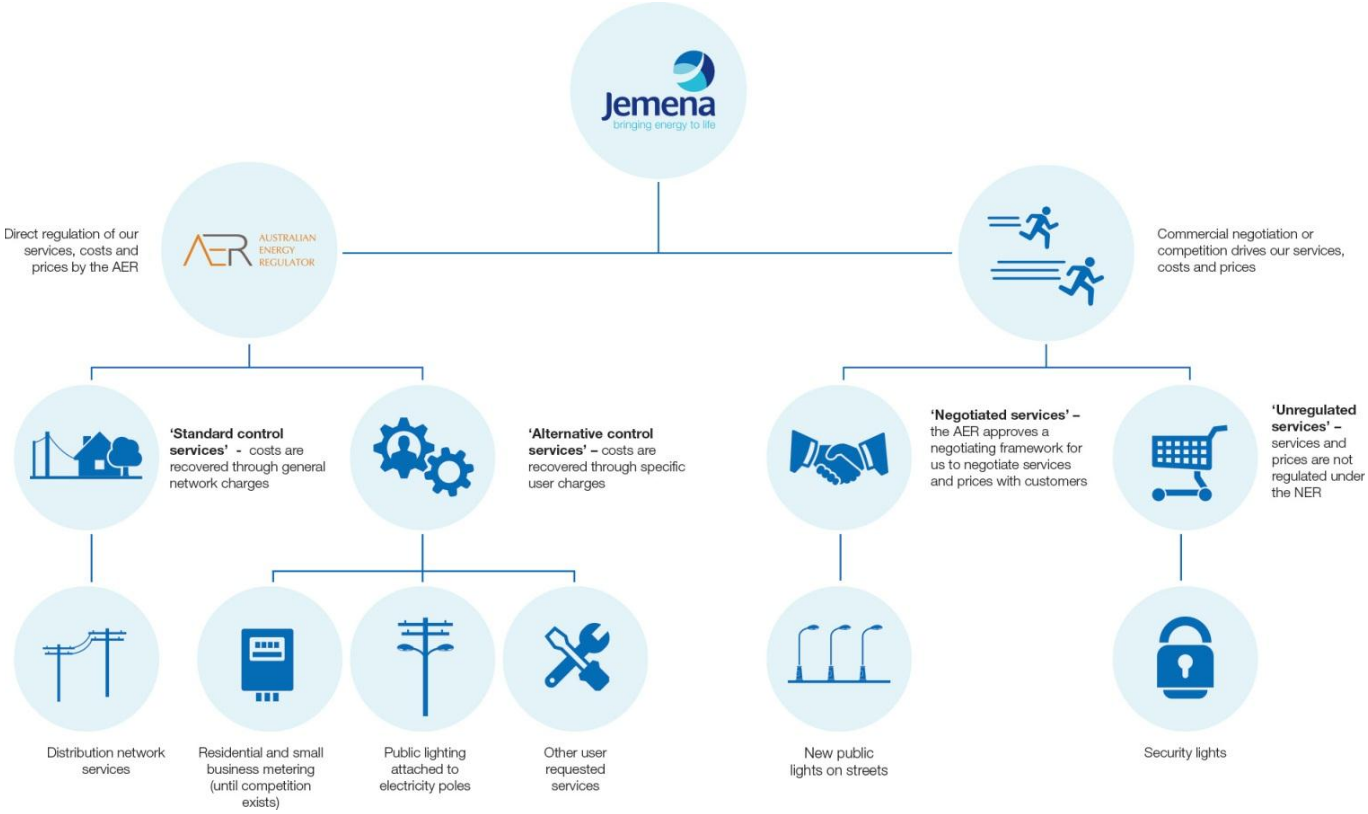
61 Ancillary network services are non-routine or user-requested services provided to individual customers on an 'as needs' basis. They can be classified as 'fee based service' or 'quoted service'.

62 Termed unclassified by the AER.

63 CoAG Energy Council, Meeting Communique, May 2014.

64 Australian Government, *Energy White Paper—Green Paper 2014*, p viii.

Figure 5–1: Proposed classification of our services for the 2016 regulatory period



5.2.2 CONTROL MECHANSIMS TO APPLY TO DIRECTLY REGULATED SERVICES

139. The NER requires a form of price or revenue control (known as the control mechanism) for those services that are to be directly regulated,[65] and the formulae to give effect to the control mechanism. The control mechanism determines how prices or revenues are adjusted over time.

140. The NER also specify that the AER may only approve proposed control mechanisms if they are consistent with the AER's final decision in its framework and approach paper (see Box 5–2).[66] Therefore, consistent with the framework and approach final decision, we propose that:

- Our distribution services be regulated through a revenue cap with the basis of control being CPI-X
- Our metering services[67] (those not subject to competition) be regulated through a revenue cap with the basis of control being CPI-X
- Our user-requested services (other alternative control services) are regulated through a cap on individual prices.[68]

[65] NER cl 6.2.5(b).

[66] NER cl 6.12.3(c).

[67] See chapter 11 for a definition of metering services

[68] These services can be 'fee based service' or 'quoted service'.

141. In relation to the formulae that give effect to the control mechanisms, the NER specify that the AER may amend these formulae if it considers unforeseen circumstances justify departing from them.[69] Under this provision, we seek confirmation that the control mechanism for our distribution and metering services account for the annual update to the return on debt through modification of the X-factor, and therefore no formulae amendments are required. The formulae are detailed in Attachment 5-2.

Box 5–2: AER's final decision on the control mechanisms to apply to our directly regulated services in the 2016 regulatory period

In its final framework and approach paper,[70] the AER made decisions on the control mechanisms to apply to our distribution network services for the 2016 regulatory period. These included that:

- **Standard control services would be regulated through a revenue cap** with the basis of control being CPI-X.[71] In making this decision the AER:
  - Noted that in its view a revenue cap would provide a higher likelihood of revenue recovery at efficient cost, better incentives for demand-side management, less reliance on energy forecasts and further alignment with the development of efficient prices
  - Noted that any within-period pricing instability and weak pricing incentives as a result of the revenue cap were able to be mitigated
  - Set out its proposed approach to the formulae to give effect to the revenue cap
- **Alternative control services for Type 5, 6 and smart metering (regulated service) would be regulated through a revenue cap.** In making this decision the AER:
  - Noted that consistency across regulatory periods is generally desirable
  - Set out the formulae to give effect to a revenue cap
- **Other alternative control services would be regulated through a cap on individual price.** In making this decision the AER:
  - Noted that in its view this approach will provide efficiency benefits from cost reflective pricing
  - Highlighted there is no material impact on administrative costs as the classification is largely following the formulae from the previous regulatory period.

5.3 PROPOSED INCENTIVE FRAMEWORK

142. The incentive framework set out in the NER provides for a number of specific incentive schemes to encourage continued improvements in the services we provide, including improvements in our cost efficiency, service standards and management of network demand. These include the efficiency benefit sharing scheme, the capital expenditure sharing scheme, the service target performance incentive scheme, the demand management and embedded generation connection incentive scheme, and the small-scale incentive scheme (see Figure 5–2).

[69] NER cl 6.12.3(c1)

[70] Final Framework and Approach for the Victorian Electricity Distributors—October 2014.

[71] For standard control services, the rules mandate the basis of the control mechanism must be the prospective CPI–X form, or some incentive-based variant. NER cl 6.2.6(a).

Figure 5–2: Incentive schemes in the NER are designed to improve long-term outcomes for our customers

143. The NER require the AER to publish an efficiency benefit sharing scheme (**EBSS**)[72] and service target performance incentive scheme (**STPIS**).[73] The NER also allow the AER to develop a capital expenditure sharing scheme (**CESS**),[74] demand management and embedded generation connection incentive scheme (**DMEGCIS**),[75] and small-scale incentive scheme.[76] The AER is required to publish its proposed approach to incentive schemes in its framework and approach paper.[77]

144. The NER[78] require us to indicate how these incentive schemes should apply to our services for the 2016 regulatory period, taking account of how the AER intends to apply these schemes as set out in its framework and approach paper (see Attachment 5-3).

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72 NER cl 6.5.8(a)

73 NER cl 6.6.2(a)

74 NER cl 6.5.8A

75 NER cl 6.6.3(a)

76 NER cl 6.6.4(a)

77 NER cl 6.8.1(b)(2)

78 NER cl S6.1.3

5.3.1 EFFICIENCY BENEFIT SHARING SCHEME

145. In most markets, businesses are driven to continually seek to improve their cost efficiency by customer expectations, competitors or shareholders. However, regulated network businesses can have an uneven incentive to seek such improvements because the five year price reset process creates an artificial break in the incentives they face.[79]

146. The EBSS is designed to overcome this shortcoming by providing a continuous incentive for us to achieve efficiency savings over time, and improve the value for money of our services by sharing these savings with our customers.[80] Under this scheme, savings from efficiency gains over a regulatory period (or penalties for efficiency losses over this period) are added to (or subtracted from) our annual revenue requirements for the next regulatory period. The EBSS has applied for the 2011 regulatory period.

147. The AER made amendments to the EBSS as part of its Better Regulation program,[81] and proposed that the revised EBSS apply for the 2016 regulatory period. Among other things, the amendments to the EBSS relate to the types of operating expenditure that may be excluded from the calculations of efficiency gains or losses (excluded costs). For example, the amendments result in any operating expenditure incurred as a result of events that are beyond our control no longer being excluded from the calculations of efficiency gains or losses.

148. We propose that the revised EBSS apply for the 2016 regulatory period, however, also propose that the list of costs shown in Box 5–3 be excluded from the calculations of efficiency gains or losses. In our view, excluding these costs will ensure that our performance against the operating expenditure benchmarks is not distorted, consistent with the original intent of the EBSS. Our Customer Council is supportive of uncontrollable costs being excluded from the EBSS, in order to best encourage us to improve our performance in a way that promotes our customers' long-term interests (see Attachment 4-1).

Box 5–3: Our proposed list of costs to be excluded from the EBSS over the 2016 regulatory period

- The impact of any pass-through events, given these are beyond our control
- Debt raising costs, given the cost of capital is set on the basis of a benchmark utility
- Self-insurance costs, given the events that cause these costs are beyond our control
- The impact of superannuation defined benefits schemes, given these are beyond our control
- Non-network alternative costs, to account for the impact of (for example) demand management alternatives which involve converting forecast capital expenditure into actual operating expenditure
- Demand management incentive scheme costs, given these are part of a separate scheme with a discrete allowance
- Guaranteed service level payments, given these have historically being considered an uncontrolled cost
- Losses on the scrapping of assets

79 If we make savings late in the regulatory period they will be immediately taken out of allowed prices as part of the five year price reset. This dampens our incentives to make efficiency savings, and is unlikely to be in the long-term interest of our customers.

80 The AER notes that operating efficiency gains or losses are shared approximately 30:70 between distributors and consumers. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p105.

81 AER, *Efficiency Benefit Sharing Scheme*, 29 November 2013.

5.3.2 CAPITAL EXPENDITURE SHARING SCHEME

149. The CESS is designed to reward network businesses when they improve the efficiency of their capital expenditure, and penalise them when the efficiency of this expenditure diminishes. Under the scheme, financial rewards from capital efficiency gains (or financial penalties for capital efficiency losses) over a regulatory period are added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[82] The CESS is a new incentive scheme, developed in response to AEMC changes to the NER,[83] to enhance the financial incentives for network businesses to improve their capital expenditure efficiency.

150. The AER proposed that the CESS apply for the 2016 regulatory period in its framework and approach paper,[84] and outlined how the scheme would be implemented as part of its Better Regulation program.[85] We propose that the CESS apply to our network business broadly in line with the AER's approach, with only minor modifications.

151. We note that to calculate the rewards or penalties, the AER may make adjustments to account for any excluded costs. To ensure our performance against the capital expenditure benchmarks and other incentive schemes is not distorted, we propose that reliability improvement capital expenditure be excluded from the CESS, for the reasons in our submission to the AER's Better Regulation consultation.[86] We also propose that CESS rewards and penalties be amortised over the regulatory control period.

5.3.3 SERVICE TARGET PERFORMANCE INCENTIVE SCHEME

152. The STPIS[87] is designed to create a financial incentive for network businesses to maintain and improve their service performance. It is intended to work alongside the EBSS and CESS to ensure that cost efficiencies rewarded under these schemes do not arise as a result of network businesses lowering service quality for customers. Like these other schemes, financial rewards (or penalties) over a regulatory period are added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[88]

153. The STPIS contains two measures that create incentives for improved service performance:

- A service standards factor (**s-factor**) reward (or penalty) for improved (or diminished) service compared to service targets for reliability, quality of supply, and customer service
- A Guaranteed Service Level (**GSL**) that requires businesses to make direct payments to customers who experience service under a pre-determined level.

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82 These rewards or penalties are added or subtracted as a separate building block in calculating the annual revenue requirements, as outlined in chapter 6.

83 The AEMC made changes to the NER to improve the 'ex-ante' and 'ex-post' incentives for network businesses to improve their capital expenditure efficiency. The ex-ante measures included the CESS and the ability of the AER to use depreciation based on actual or forecast capital expenditure to update the regulatory asset base at the end of a regulatory period. The ex-post measures included the ability of the AER to exclude inefficient capital expenditure over-spends from the RAB.

84 AER, *Framework and Approach for Victorian businesses*, November 2014.

85 AER, *Better Regulation, Capital expenditure incentive guideline for electricity network service providers*, November 2013.

86 The service target performance incentive scheme provides financial incentives for us to incur prudent capital expenditure that improves levels of service performance. This capital expenditure is not forecast on an ex ante basis and so could contribute to our actual capital expenditure exceeding the benchmark allowance, if not excluded. In turn, this could overstate penalties for capital expenditure overspends, and understate rewards for capital expenditure underspends. Jemena, Submission to AER issues Paper: Expenditure incentives guidelines for electricity network service providers, May 2013.

87 AER, *Electricity distribution network service providers—Service target performance incentive scheme*, November 2009

88 These rewards or penalties are added or subtracted as a separate building block in calculating the annual revenue requirements, as outlined in section 6.2.

154. The s-factor component has applied to our network business for the 2011 regulatory period, while the GSL component has not applied because there is a Victoria-specific GSL scheme in place.[89]

155. The AER has proposed that the s-factor component continue for the 2016 regulatory period, and the GSL component continue not to apply as the Victorian GLS scheme continues to operate.[90] It has also outlined its proposed application of the STPIS scheme over this period (see Box 5–4).

156. We also propose that the s-factor component of the STPIS continue to apply, and that its application be consistent with that set out in the AER's framework and approach paper.

157. In addition, in the interests of customer understanding, national consistency and administrative simplicity, we support the AER engaging with the Victorian Government and the Essential Services Commission of Victoria to assist a timely transition from the Victorian GSL scheme to the national scheme.

Box 5–4: AER's proposed application of the STPIS for the 2016 regulatory period

In its final framework and approach paper,[91] the AER made decisions on the application of the STPIS for the 2016 regulatory period. This included:

- Setting the revenue at risk from the STPIS within the range of ±5%
- Segmenting our network according to feeder categories (including CBD, urban, short rural and long rural feeders)
- Setting the performance measures to include the system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) and customer service (telephone answering) parameters
- Setting the targets for the performance measures based on our average performance over the past five regulatory years
- Excluding specific events from the calculation of annual performance and performance targets, consistent with the methodology outlined in the national STPIS
- Using incentive rates to determine the relative importance of measured performance consistent with the methodology outlined in the national STPIS.

While not included in the framework and approach paper, we propose to include the Momentary Average Interruption Frequency Index (**MAIFI**) performance indicator as an additional parameter within the s-factor as required in the STPIS scheme.[92]

5.3.4 DEMAND MANAGEMENT AND EMBEDDED GENERATION CONNECTION INCENTIVE SCHEME

158. During the 2011 regulatory period, the NER have been amended to explicitly incorporate incentives for connection of embedded generation. In its framework and approach paper for the 2016 regulatory period, the

89 In Victoria, the Electricity Distribution Code and Public Lighting Code set out GSLs that apply to the Victorian distributors. Essential Services Commission of Victoria, Electricity Distribution Code, version 7, May 2012, p. 19; Essential Services Commission of Victoria, Public Lighting Code, April 2005, p. 3.

90 AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014. , p97

91 AER, *Framework and Approach for Victorian businesses,* November 2014.

92 Section 3.1(f) of AER, *Electricity distribution network service providers—Service target performance incentive scheme*, November 2009, requires the MAIFI parameter to be included in the calculation of s-factor if the parameter can be measured. In Victoria this parameter has been recorded for the 2011 Regulatory Period and therefore must be included in the scheme design for the 2016 Regulatory Period.

AER considers that the existing Demand Management Incentive Scheme (**DMIS**) sufficiently covers incentives to connect embedded generation[93] and will continue to operate that scheme.

159. The DMIS is designed to provide electricity distribution businesses with financial incentives to improve the network utilisation,[94] specifically by considering alternatives to building peak network capacity ('demand management').[95] The DMIS comprises two parts, both of which have applied to our business over the 2011 regulatory period:

- Part A, which provides for an innovation allowance to be incorporated into a distribution network business' annual revenue requirements, and
- Part B, which compensates a network business for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A.

160. The AER has proposed that only Part A of the DMIS continue to apply in the 2016 regulatory period. It considers that Part B is no longer appropriate, given its intention to regulate our standard control services through a revenue cap.[96] It has also outlined its proposed application of Part A over this period in its framework and approach paper.

161. We also propose that only Part A of the DMIS continues to apply in the 2016 regulatory period, and that its application be consistent with that set out in the AER's framework and approach paper.

5.3.5 SMALL-SCALE INCENTIVE SCHEME

162. Recent changes to the NER mean that the AER may develop additional incentive schemes including small-scale pilot or test incentive schemes that allow for regulatory innovation (a small‑scale incentive scheme).

163. Given that the AER has not developed such a scheme and or stated a proposed approach to its application for the 2016 regulatory period, we propose that a small-scale incentive scheme not apply to our network business for this period.

5.3.6 F-FACTOR SCHEME

164. The Victorian Government's 'f-factor scheme' provides financial incentives for network businesses to reduce the risk of fire starts and the associated loss or damage.

165. Under an Order-in-Council made by the Victorian Government, the AER must make various determinations under the f-factor scheme, including setting:

- A fire start target for each network business based on the average historical fire starts over the five previous calendar years, and

[93] AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p 113.

[94] Our network is built to provide customers with electricity whenever and however they choose to power their homes and businesses. As the majority of our customers use most of their electricity during "peak times" – such as weekday afternoons and evenings – our network is designed, built and maintained to meet our customers' needs during these peak times. Building and augmenting our network to meet peak demand is relatively costly, and so has a significant influence on our capital expenditure program and ultimately on our network prices. It also means that for much of the time, our network is relatively underutilised.

[95] The AER notes that demand management refers to any effort by a distributor to lower or shift the demand for standard control services, including, agreements between distributors and consumers to switch off loads at certain times and the connection of small-scale 'embedded' generation reducing the demand for power drawn from the distribution network. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014, p113.

[96] Part B compensates network business for any foregone revenue demonstrated to have resulted from demand management initiatives approved under Part A for distributors under a weighted average price cap. Part B is not applied where distributors are subject to a revenue cap rather than a price cap.

- The incentive rate to reward (or penalise) each business for performing better (or worse) that its target.

166. Under the scheme, the total reward (or penalty) over a regulatory period is added to (or subtracted from) the business' annual revenue requirements for the next regulatory period.[97] For the 2011 regulatory period, the AER set our incentive rate at $25,000 (nominal value) per fire start better or worse than our fire start target. While the AER may vary the incentive rates for the 2016 regulatory period, it has made a decision to maintain the incentive rate of $25,000 per fire pending a review by the Victorian Government.

167. We do not propose to vary the scheme as outlined in the AER's framework and approach paper.

5.4 PROPOSED RISK MANAGEMENT FRAMEWORK

168. To manage the risk that a network business incurs uncontrollable and material changes in its costs that were unforeseen at the time of the AER's determination, the NER specify that the AER may use a 'pass-through mechanism' to adjust network prices up or down in response these changes. Provision for this mechanism ensures that in forecasting their operating and capital expenditures (for the purpose of determining prices), network businesses do not include any speculative and significant allowances for events that may not occur.

169. The NER specify five events that may trigger the use of the pass-through mechanism (see Box 5–5). The NER also recognise that the risks facing network businesses and their customers depend on their unique operating environment and the changes occurring in their energy market. It therefore allows businesses to propose additional pass-through events.[98]

Box 5–5: The cost pass-through events specified in the NER

The NER[99] sets out a number of pass-through events that allow the AER to adjust our network prices up or down in response to the costs associated with these events, including:

- A regulatory change event
- A service standard event
- A tax change event
- A retailer insolvency event
- Any other event specified in a distribution determination as a pass-through event for the determination period.

170. We have carefully considered our unique operating environment and our ability to manage the risk of unforeseen, uncontrollable and material costs in a cost-effective way in the 2016 regulatory period. We have also engaged with our customers and stakeholders on the most efficient and cost-effective way to manage this risk. We propose that a further seven pass-through events, in addition to those specified in the NER, apply for the 2016 regulatory period. These events include:

- Natural disaster event
- Insurer credit risk event

[97] These rewards or penalties are added or subtracted as a pass-through amount in calculating the annual revenue

[98] NER cl 6.5.10

[99] NER cl 6.5.10

- Insurance cap event
- Terrorism event
- Carbon cost event
- End of metering derogation event
- Retailer insolvency event.

171. In addition, we propose that the AER's determination provide for the pass-through provisions of the rules to apply to alternative control services. The risks we face in relation to these services are the same as those faced in providing standard control services.

172. In making this proposal, we have had regard to the considerations outlined in the NER, and our ability to prudently manage the risk of these events. We consider that these events have a low probability of occurrence, have the potential to have a significant cost impact, and are beyond our reasonable ability to control. We therefore consider that each event meets the necessary requirements to be approved as a nominated event for the 2016 regulatory period.

173. Attachment 5-4 provides more detail about these proposals, including detail on the proposed definitions for the additional events, and a detailed assessment of how including these events in the cost pass-through mechanism meets the considerations outlined in the NER and promotes the long-term interests of our customers.

6. ANNUAL REVENUE REQUIREMENT, MAXIMUM ALLOWED REVENUE AND X-FACTORS

Key messages

- In developing our proposed revenues and X-factors, we complied with all relevant NER requirements, including using a 'building block' approach and the AER's post-tax revenue model. We also take account of the changes occurring in our energy market and our customers' priorities and preferences.
- Our proposed total revenue requirement for the 2016 regulatory period is $1,466m. This amount reflects the efficient costs of providing our distribution and metering services and meeting the safety and service levels our customers expect and value, while prudently balancing cost and price pressures in future regulatory periods.
- Although our proposal provides for higher capital and operating expenditure on distribution services than we expect to incur in the 2011 regulatory period, our required revenue per customer and average prices are decreasing:
  - our funding costs for both distribution and metering services are lower and we propose to pass these savings on to our customers
  - our capital costs and depreciation costs for metering services are significantly lower
  - the total volume of electricity consumed by our new and existing customers is forecast to increase modestly.
- Our proposed 'smoothed' revenue requirement (or maximum allowed revenues) and X-factors—which include a reduction in our revenues and average prices in 2018 to minimise any adverse impacts of the proposed changes in price components—reflects our customers' feedback.

174. The NER require that we propose the 'X-factors' that determine the average change in our network revenue for distribution and metering services in each year of the regulatory period.[100] The X-factors should reflect the average annual changes in our revenue (on top of changes in the CPI) necessary for us to invest in, operate and maintain our network efficiently, and earn a reasonable return on our investment in this network over the period.

175. The NER require us to determine the X-factors by:

- Calculating our annual revenue requirement (**ARR**) for each year of the regulatory period using a building block approach,[101] including our proposed:
  - returns on and of capital (including opening capital base, forecast capital expenditure, rate of return and regulatory depreciation)
  - operating and tax costs, and
  - other revenue adjustments, including any rewards or penalties from the incentive schemes outlined in chapter 5

[100] As outlined in chapter 5, our distribution network services are classified as standard control services and our metering services (excluding contestable metering) are classified as alternative control services. The ARR in this chapter does not include revenue relating to other alternative control services (such as public lighting services) or unclassified services (see chapter 11 for our proposed fees and charges for these services).

[101] NER cl 6.4.3 requires the ARR for each regulatory year to be determined using a building block approach.

- Calculating our maximum allowed revenues (**MAR**) or 'smoothed revenues' for each year of the regulatory period so that the ARR and MAR for the total period are equal in net present value terms[102]
- Calculating the X-factors for each year of the 2016 regulatory period to recover the MAR.

176. In developing our proposed X-factors we complied with all relevant NER requirements, including using the AER's post-tax revenue model (**PTRM**).[103] We also take account of the changes occurring in our energy market and their implications for our network and our customers over the 2016 regulatory period and beyond, as well as our customers' priorities and preferences.

177. We first provide an overview of our proposed ARR, MAR and X-factors, and the implied average annual price changes over the 2016 regulatory period.[104] The subsequent sections outline the ARR, MAR and X-factors in more detail.

6.1 OVERVIEW OF PROPOSED ARR, MAR AND X-FACTORS

Table 6–1: Proposed ARR, MAR and X-factors for distribution and metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
ARR ('unsmoothed' building block costs) ($m)	291.37	281.90	302.64	291.70	297.91	**1,465.52**
MAR ('smoothed' revenue) ($m)	288.10	291.21	290.76	295.46	300.22	**1,465.76**
X-factors (%)[105]	13.19	-1.08	0.15	-1.61	-1.61	**n/a**
Implied average price changes (%)[106]	-6.42	-	-1.69	-	-	**n/a**

178. Our total proposed ARR for the 2016 regulatory period is $116.9m higher than the ARR allowed for by the AER for the 2011 regulatory period. This is driven by:

- A $227.0m increase in the total proposed ARR for distribution services (Table 6–2), which:
  - Reflects increases in the capital expenditure (see chapter 7), operating expenditure (see chapter 8) and a reward under the EBSS (see section 6.2.5)
  - Is partially offset by and reductions in our funding costs (see chapter 9)
- A $109.9m decrease in the total proposed ARR for metering services (see Table 6–3), which reflects:
  - Reductions in our funding costs (see chapter 9)

102 Subject to minimising the variance between the expected revenue and the annual revenue requirement in 2020.

103 NER cl 6.3.1(c) requires the building block proposal to be prepared accordance with the AER's PTRM, and must comply with the requirements any relevant regulatory information instrument.

104 Chapter 10 provides detail on the annual changes in our tariffs and the outcomes for typical customers over the 2016 regulatory period.

105 As outlined in section 5.2.2 we propose our distribution and metering services will be regulated through a revenue cap with the basis of control being CPI-X. In relation to the formulae that give effect to this control mechanism, a negative X-factor represents a positive change in our revenue (excluding the impact of inflation).

106 The average annual price changes are calculated using independent expert forecasts of demand for these services (Refer Attachment 3-2 for detail on these forecasts). A negative numbers corresponds to a real price increase.

− Significant reductions in our capital expenditure (see chapter 7) and our depreciation costs (see Table 6–6).

179. The total implied average price change for distribution services and for metering services over the 2016 regulatory period is -8.1%. The main reasons for this average price reduction are that:

- The changes in our building block costs for distribution services and for metering services partly offset each other, and
- The total volume of electricity consumed by our new and existing customers is forecast to increase modestly.

180. Our proposed ARR, MAR and X-factors for distribution services and for metering services separately are shown in Table 6–2 and Table 6–3.

Table 6–2: Proposed ARR, MAR and X-factors for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
ARR ('unsmoothed' building block costs) ($m)	249.23	250.73	270.98	264.26	272.27	**1,307.46**
MAR ('smoothed' revenue) ($m)	256.94	259.68	258.84	263.14	267.51	**1,306.12**
X-factors (%)[107]	-0.29	-1.06	0.32	-1.66	-1.66	**n/a**
Implied average price changes (%)[108]	-	-	-1.90	-	-	**n/a**

Table 6–3: Proposed ARR, MAR and X-factors for metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
ARR ('unsmoothed' building block costs) ($m)	42.10	31.13	31.62	27.39	25.58	**157.82**
MAR ('smoothed' revenue) ($m)	31.15	31.54	31.92	32.31	32.71	**159.64**
X-factors (%)[109]	58.84	1.22	1.23	1.23	1.23	**n/a**
Implied average price changes (%)[110]	-59.39	-	-	-	-	**n/a**

6.2 PROPOSED ANNUAL REVENUE REQUIREMENT

181. The ARR represents the amount of revenue we need to generate over the 2016 regulatory period to allow us to invest in, operate and maintain our network efficiently and earn a reasonable return on our investment in providing the distribution and metering services our customers value over this period.

182. To calculate our proposed ARR, we used a building block approach.[111] This involved calculating and summing the following building block costs: return on capital (or funding costs); return of capital (depreciation); forecast operating expenditure; forecast tax costs; and other revenue adjustments (see Box 6–1).

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107 A negative X-factor represents a positive change in our revenue (excluding the impact of inflation).

108 A negative number corresponds to a price decrease.

109 A negative X-factor represents a positive change in our revenue (excluding the impact of inflation).

110 A negative number corresponds to a price decrease.

183. Table 6–5 and Table 6–6 sets out our proposed ARR and building block costs for distribution and metering services over the 2016 regulatory period (combined and separately).

184. Table 6–4 compares the proposed building block costs for the 2016 regulatory period with those approved by the AER for the 2011 regulatory period on a cost per customer basis.[112]

185. The following section outlines each of our proposed building block costs in more detail, including the approaches we used to calculate them.

Box 6–1: Calculating the ARR using a building block method

In line with the requirements of the NER, we calculated our proposed ARR using a building block method. This involved calculating and adding together the following allowances using the AER's PTRM:

- **Return on capital**. This allowance represents the efficient costs of funding our investment in the assets used to provide our distribution and metering services—including our past and forecast capital expenditure—over the regulatory period. To calculate this allowance we used three key inputs: the opening value of our asset base (see section 6.2.1.1); our forecast capital expenditure over the period (see chapter 7); and our proposed rate of return (see chapter 9).
- **Return of capital.** This allowance represents the depreciation of our assets over the regulatory period (the decrease in their value due to usage and aging).[113] To derive this allowance, we used three key inputs: the opening value of our asset base (see section 6.2.1.1); the remaining lives of our assets; and our forecast capital expenditure over the period (see chapter 7).[114]
- **Forecast operating expenditure.** This allowance represents our forecast operating expenditure over the regulatory period. These are the costs we expect to incur to operate and maintain our assets, and to administer and manage our business. To calculate this allowance we used three key inputs: our revealed efficient 2014 base year costs; forecast step changes for new activities; and forecast expected rate of change in operating costs (see chapter 8).
- **Tax costs.** This allowance represents our forecast income tax liabilities over the regulatory period. To calculate this allowance we used two key inputs: the corporate tax rate; and the value of imputation credits to reflect the value of 'franking credits' to investors[115] (see section 6.2.4).
- **Other revenue adjustments.** This allowance takes account of any rewards or penalties we earned under the incentive schemes[116] in the 2011 regulatory period, and to reflect assets that are shared in providing both regulated and unregulated services (see section 6.2.5).

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111 Our approach for calculating the ARR complies with NER cl 6.4.3 and the AER's PTRM.

112 These per customer costs were derived by dividing the building block costs by actual and forecast customer numbers.

113 While we generally recover our operating costs and tax costs in prices in the same period that we incur them, we recover our capital costs over the lifetime of our assets.

114 The AER offsets changes in indexation of the regulatory asset base (**RAB**) through the calculation of depreciation and refers to this as 'regulatory depreciation'.

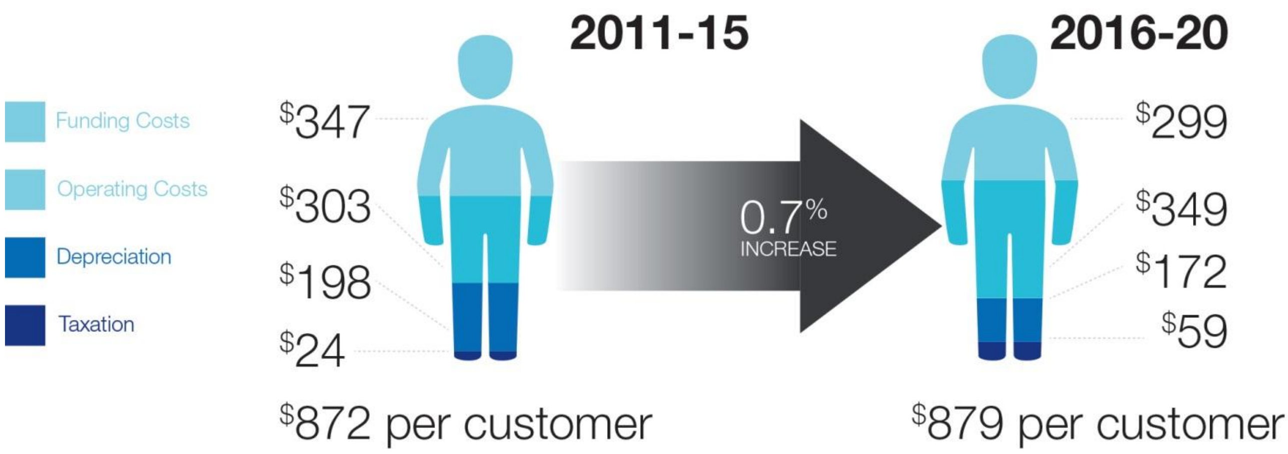
115 Australia has had an imputation tax system since 1 July 1987. It exists to avoid investors' corporate profits being taxed twice. These franking credits—or imputation credits—are provided to investors for tax paid at the corporate level to off-set against an investors' personal income tax.

116 See section 5.3 for more detail on the incentive schemes for the 2016 regulatory period.

Table 6–4: Proposed ARR for distribution and metering services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
Return on capital (funding costs)	91.79	94.82	99.64	103.88	108.34	**498.47**
Return of capital (depreciation)	64.77	61.82	60.26	47.69	52.30	**286.83**
Forecast operating expenditure	106.05	106.33	109.82	114.88	118.67	**555.74**
Tax costs	18.63	19.23	22.69	18.29	18.87	**97.71**
Other revenue adjustments[117]	10.11	-0.34	10.19	6.91	-0.33	**26.53**
Total annual revenue requirement	**291.33**	**281.86**	**302.59**	**291.65**	**297.85**	**1,465.28**

Figure 6–1: ARR for distribution and metering services per customer – proposed for 2016 regulatory period compared with approved for 2011 regulatory period ($2015)[118]



117 These adjustments relate to (1) rewards under the EBSS for our performance in the 2011 regulatory period, (2) trueing–up actual s-factor performance from 2010 and (3) use of assets that are to be shared in providing both regulated and unregulated services in the 2016 regulatory period. One of the shared assets principles is that a shared asset cost reduction should be applied where the use of the assets other than for SCS is material.

118 Other revenue adjustments are captured in the operating expenditure category.

Table 6–5: Proposed ARR for distribution services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
Return on capital (funding costs)	83.40	87.98	93.65	98.67	103.63	**467.33**
Return of capital (depreciation)	43.07	49.63	48.40	39.24	45.36	**225.70**
Forecast operating expenditure	95.37	95.36	98.51	103.18	106.60	**499.01**
Tax costs	18.63	18.10	20.23	16.26	17.01	**90.23**
Other revenue adjustments[119]	8.76	-0.34	10.19	6.91	-0.33	**25.19**
Total annual revenue requirement	**249.23**	**250.73**	**270.98**	**264.26**	**272.27**	**1,307.46**

Table 6–6: Proposed ARR for metering services ($2015, $millions)

Building block cost	2016	2017	2018	2019	2020	Total
Return on capital (funding costs)	8.39	6.83	5.99	5.22	4.71	**31.14**
Return of capital (depreciation)	21.70	12.19	11.85	8.45	6.94	**61.13**
Forecast operating expenditure	10.68	10.97	11.31	11.70	12.07	**56.73**
Tax costs	-	1.13	2.46	2.03	1.86	**7.48]**
Other revenue adjustments	1.34	-	-	-	-	**1.34**
Total annual revenue requirement	**42.10**	**31.13**	**31.62**	**27.39**	**25.58**	**157.82**

6.2.1 RETURN ON CAPITAL

186. The return on capital allowance reflects the benchmark efficient costs of funding our investments in the assets we use to provide our distribution and metering services over the regulatory period. We fund these investments through borrowings from the debt market and investments from equity holders, which we pay back over the long term. This approach minimises spikes in our costs (and therefore our prices), and ensures both the current and future customers who benefit from these investments contribute to their costs.

187. Our proposed return on capital allowance is the largest of the building block costs, representing around 34.0% of our total distribution and metering services building block costs. We calculated this allowance using three key inputs: our proposed opening value of the asset base; forecast capital expenditure; and proposed rate of return. Each of these inputs is outlined in Table 6–9, and detailed in Attachment 6-1 and Attachment 6–2.[120]

119 These adjustments relate to (1) rewards under the EBSS for our performance in the 2011 regulatory period, (2) trueing–up actual s-factor performance in 2010 and (3) use of assets that are to be shared in providing both regulated and unregulated services in the 2016 regulatory period. One of the shared assets principles is that a shared asset cost reduction should be applied where the use of the assets other than for distribution services (or SCS) is material.

120 We have calculated our proposed return on capital allowance consistent with NER cl 6.5.2 and the AER's PTRM.

6.2.1.1 Proposed opening value of the asset base

188. The value of the assets we use in providing regulated distribution and metering services is known as the RAB. This value represents the (as yet) unrecovered past capital investments we have made to provide services to our customers.[121]

189. The value of the RAB changes over time. As we invest in new assets, this expenditure is added to the RAB. As our assets depreciate, this value is subtracted from the RAB. And as customers make capital contributions or we dispose of assets, these proceeds are subtracted from the RAB.

190. To calculate the opening value of the RAB for the 2016 regulatory period, we used an approach consistent with the NER[122] and the AER's RAB roll-forward models.[123] This involved taking the opening RAB for the 2011 regulatory period, and adjusting this value to take account of our actual and expected capital expenditure over that period, as well as the depreciation of our assets over that period and several other factors (see Box 6–2).

Box 6–2: Calculating the opening RAB for the 2016 regulatory period

To calculate the opening RAB for the 2016 regulatory period, we:

- Take the opening RAB for the 2011 regulatory period
- Indexed this RAB to account for inflation over that period
- Added the value of our actual and expected capital expenditure over that period
- Deducted the value of depreciation over that period (calculated using the AER's approved standard asset lives)
- Made adjustments for any assets that have been reclassified during that period.

191. Our proposed opening value of the RAB is set out in Table 6–7. More detail on our approach and our populated AER models are provided as Attachment 6-1 and Attachment 6-2.

Table 6–7: Proposed opening value of RAB for distribution and metering services ($2015, $millions)

RAB	As at 1 Jan 2016
Distribution services	1,190.84
Metering services	119.75

6.2.1.2 Forecast capital expenditure

192. Our capital expenditure includes the investments we make to buy and build the physical assets necessary to deliver our required safety and service levels now and into the future. Our capital works range from small standard projects (such as connecting a new customer to the existing network) to large multi-million-dollar projects (like extending the network and installing multiple meters to connect a new town or housing estate). These assets are typically long-lived and will benefit our customers into the future.

121 NER cl 6.5.1(a) states that the regulatory asset base "is the value of those assets that are used by the Distribution Network Service Provider to provide standard control services, but only to the extent that they are used to provide such services."

122 NER cl 6.5.1 and NER cl S6.2.

123 On 26 June 2008, in accordance with cl 6.5.1 of the NER, the AER published a Roll forward model, an associated handbook and final decision document (https://www.aer.gov.au/node/6908).

193. Our forecast capital expenditure for distribution and metering services over the 2016 regulatory period is set out in Table 6–8. More information on this expenditure—including how the proposed capital program represents the efficient level of expenditure required to provide the distribution and metering services that our customers value—is provided in chapter 7.

Table 6–8: Proposed capital expenditure for distribution and metering services ($2015, $millions)

Gross capital expenditure	2016	2017	2018	2019	2020
Distribution services	161.46	183.64	177.13	167.60	154.56
Metering services	2.41	2.54	2.80	2.94	4.60

(1) Gross capex includes equity raising costs.

6.2.1.1 Capital contributions

194. It is important that our customers pay their way when using our network. This supports efficient utilisation of the network and is in all customers' long-term interests. To support this efficient outcome, in some cases, we need to ask a new customer to provide an upfront contribution to support the services we provide them.

195. We have therefore forecast an amount of capital contributions to offset against the capital expenditure we recover through network charges. Our forecasting method is to apply a historical percentage rate of contributions and adjust the incremental revenue calculations—caused by changes in the x-factor in the final year of the 2016 regulator period—to forecast capital expenditure.

6.2.1.2 Proposed rate of return

196. As noted, we fund investments in our network through borrowings from the debt market and investments from equity holders that are paid back over the long term. The rate of return reflects the cost of funding these borrowings. Essentially, it reflects the weighted average of the interest we pay on our loans and the return our shareholders expect for committing their money to our operations (or the weighted average cost of capital (**WACC**)).

197. Our proposed rate of return for the 2016 regulatory period is set out in Table 6–9. We calculated this rate of return using an approach consistent with the requirements in the NER.[124] We have expressed the rate of return as a 'nominal vanilla WACC' consistent with the AER's rate of return guideline;[125] however, we have departed from the guideline in several areas (see chapter 9).

124 NER cl 6.5.2 (b) – (q)

125 AER, *Better regulation, Rate of return guideline*, December 2013

Table 6–9: Proposed rate of return ('nominal vanilla WACC') (per cent)

Parameters	JEN proposal
Return on equity	9.87
Return on debt	5.39
Inflation	2.52
Leverage	60.00
Gamma	25.00
Corporate tax rate	30.00
Nominal vanilla WACC	**7.18**

(1) Return on debt, return on equity, and nominal WACC are estimated using data from the sample averaging period of the 20 business days to 30 January 2015 (inclusive).

(2) Our gamma proposal is outlined in section 9.2.1.3, and supported by Attachments 6–4, 6–7 and 6–8.

198. Our proposed rate of return is lower than the rate allowed by the AER for the 2011 regulatory period. This reflects the easing in current market conditions following the heightened perceptions of risk in global and domestic financial markets during the Global Financial Crisis (**GFC**) from 2008–2010. This passes the benefits of reduced interest rates on to our customers.

199. Chapter 9 provides more details on our proposed rate of return, including how it ensures we will be able to attract the funds necessary to provide the distribution and metering services our customers' value, and how our approach and assumptions for calculating it differ from the AER's guidelines. Attachment 6–9 and 9–1 to 9–17 provide additional detail and expert analysis.

6.2.2 RETURN OF CAPITAL (DEPRECIATION)

200. The return of capital allowance reflects the depreciation of our assets over the regulatory period—that is, the decrease in their value due to usage and aging.

201. Our proposed return of capital allowance for distribution and metering services (shown in Table 6–4) represents around 19.6% of our total distribution and metering services building block costs. We calculated this allowance using an approach consistent with the NER[126] and the AER's PTRM (see Box 6–3). The model we used is provided as Attachment 6-1, including our nominated depreciation schedule.

[126] NER cl 6.5.5

Box 6–3: Calculating the return of capital (or regulatory depreciation)[127] allowance for the 2016 regulatory period

To calculate our proposed return of capital allowance, we:

- Applied the real straight line depreciation method, which involves:
  - For existing assets, dividing the amount of the opening RAB as at 1 January 2016 for each asset class, by the relevant weighted remaining asset lives (calculated using the AER's preferred approach)
  - For new assets, dividing the real net capital expenditure over the 2016 regulatory period, by our proposed standard asset lives, and
- Applied a forecast inflation of 2.52% to index the RAB.

6.2.3 FORECAST OPERATING EXPENDITURE

202. Our operating expenditure includes the costs of operating and maintaining our physical assets (for example, poles, meters and computer systems), responding to emergencies (such as fallen trees on our lines) and performing related functions like collecting meter information and providing billing information to retailers.

Our proposed forecast operating expenditure for distribution and metering services (shown in Table 6–4) represents 37.9% of our total distribution and metering services building block costs. Chapter 8 provides more details of this expenditure, including how it represents the efficient level of expenditure required to operate and maintain our network.

6.2.4 TAX COSTS

203. Like other businesses, we must pay income tax to the Australian Taxation Office. The allowance for tax costs reflects our expected tax liabilities over the regulatory period.

204. Our proposed tax cost allowance for distribution and metering services over the 2016 regulatory period (shown in Table 6–5 and Table 6–6) represents 6.7% of our total distribution and metering services building block costs. We calculated this allowance using an approach consistent with the NER[128] and the AER's PTRM (see Box 6–4).

205. Key inputs for this approach include the corporate tax rate and the value of imputation credits to reflect the value of 'franking credits' to investors.[129] The methods we used to derive these inputs and the values we adopted are set out in Attachment 6–4. Our model is provided as Attachment 6–1.

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127 The net total of the indexation of the RAB to account for inflation and the amount of depreciation is referred to as 'regulatory depreciation'.

128 NER cl 6.5.3

129 Australia has had an imputation tax system since 1 July 1987. It exists to avoid investors' corporate profits being taxed twice. These franking credits—or imputation credits—are provided to investors for tax paid at the corporate level to off-set against an investor's personal income tax.

Box 6–4: Calculating the cost of corporate income tax for the 2016 regulatory period

We calculated the tax cost component of the building blocks for the 2016 regulatory period by:

- Determining the opening tax asset base for the 2016 regulatory period, using the diminishing value tax depreciation method
- 'Rolling forward' the tax base over this period:
  - Using forecast inflation of 2.52% (see chapter 9) to index the tax asset base
- Using the legislated income tax rate of 30%, and
- Assuming the value of imputation credits is 0.25[130] (see chapter 9).

6.2.5 OTHER REVENUE ADJUSTMENTS

206. We have proposed an allowance to cover all relevant revenue adjustments. It accounts for 1.8% of our total distribution and metering services building block costs. These revenue adjustments relate to:

- The EBSS – As chapter 5 outlines, the incentive framework for the 2011 regulatory period contains a number of incentive schemes to encourage us to make continued improvements in our cost efficiency, service standards and demand management. Rewards and penalties under these schemes are added to or subtracted from the ARR as a separate building block in the 2016 regulatory period. The model we used for the EBSS and share assets calculations (see Attachment 6–1 and Attachment 6–2). The adjustment for the EBSS reflects the benefit we expect to receive under this scheme.
- The close out of the 2010 s-factor performance scheme – We have included an adjustment to revenue for the close out of the s-factor scheme that was in operation for the 2006 regulatory period. In its 2011 EDPR determination, the AER decided not to account for s-factor performance in the final year of the 2006 regulatory period, instead preferring to close out the scheme in the 2016 regulatory period (see Attachment 5–3). To this end, a revenue adjustment is included which also accounts for the time value of money (see Attachment 6–5)
- Shared asset revenue – If our assets are to be shared in providing both regulated and unregulated services in the 2016 regulatory period (then a shared asset cost reduction should be applied). The adjustment for shared asset revenue reflects the benefits we and our customers receive from distribution assets being shared in providing both regulated and unregulated services in the 2016 regulatory period. We calculated this revenue in line with the AER's shared asset guidelines[131] and PTRM (see Attachment 6–6).

207. Table 6–10 sets out our proposed other revenue adjustments for distribution services.

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130 This assumption reflects our interpretation of the NER, the 2011 decision of the Australian Competition Tribunal, and current expert advice.

131 AER, *Better Regulation, Shared asset guideline*, November 2013.

Table 6–10: Proposed other revenue adjustments for distribution services ($2015, $millions)

Revenue adjustments	2016	2017	2018	2019	2020	Total
EBSS	5.29	-0.01	10.52	7.24	-	**23.05**
Close out of 2010 s-factor scheme	3.81	-	-	-	-	**3.81**
Shared asset revenue	-0.34	-0.34	-0.34	-0.33	-0.33	**-1.68**
Total revenue	**8.76**	**-0.34**	**10.19**	**6.91**	**-0.33**	**25.19**

Other adjustments, such as trueing up revenue from year-to-year under a revenue cap mechanism or STPIS performance benefits are managed through the price control formulae rather than an adjustment to the building block model (see section 5.3).

6.3 PROPOSED MAXIMUM ALLOWED REVENUES

208. We 'smoothed' our proposed ARR to derive our proposed MAR for each year of the 2016 regulatory period using an approach consistent with NER requirements and the AER's PTRM. We ensured the MAR is equal to the ARR in net present value terms, subject to minimising the variance between the expected revenue and the ARR in 2020.

209. Our proposed MAR for our distribution services (Table 6–11) reflect:

- Our customers' preference for us to pass on our cost savings over the 2016 regulatory period in a way that introduces our proposed changes to our network tariff structure as soon as practical, but also minimises the impact of these changes on specific groups of customers (as a result of a decrease in the MAR in 2018)[132] and provides an opportunity for customers to change their behaviour to minimise their bills (see chapter 10 and Attachment 4-1)
- Our intention to minimise the potential for price shocks between the 2016 regulatory period and the subsequent regulatory period[133]
- The modest increases in forecast energy consumption over the period.

Table 6–11: Proposed MAR for distribution services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
ARR (building block costs)	249.23	250.73	270.98	264.26	272.27	**1,307.46**	1,144.49
MAR ('smoothed' revenue)	256.94	259.68	258.84	263.14	267.51	**1,306.12**	1,144.49

(1) The Net Present Value (**NPV**) is calculated by discounting the ARR and MAR cash flows, using the nominal vanilla WACC.

210. Our proposed MAR for our metering services (Table 6–12) reflects our intention to pass on the reductions in our costs following the completion of the roll-out of AMI to customers as soon as possible.

132 A decrease in the MAR in 2018 for our distribution services will allow us to decrease the fixed and consumption charges to offset the introduction of a new maximum demand charge for residential and small business customers.

133 For example, if we smoothed the revenue over the 2016 regulatory period in a way that the ARR or smoothed revenue in 2020 was significantly less than the building block costs or unsmoothed revenue in 2020, then prices may need to increase in the following regulatory period to meet the required revenues.

Table 6–12: Proposed MAR for our metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total	NPV
ARR (building block costs)	42.10	31.13	31.62	27.39	25.58	**157.82**	139.85
MAR ('smoothed' revenue)	31.15	31.54	31.92	32.31	32.71	**159.64**	139.85

6.4 PROPOSED X-FACTORS

211. As section 5.2.2 outlines, our distribution and metering services will be regulated through a revenue cap in the 2016 regulatory period, with the form of control being CPI-X. The X-factors for the 2016 regulatory period need to reflect the change in our revenue (on top of CPI) necessary to allows us to recover our MAR in each year of the period.

212. Our proposed X-factors are shown in Table 6–13. We calculated these X-factors consistent with the NER[134] and the AER's PTRM (our model is provided as Attachment 6–1 and Attachment 6–2).

Table 6–13: Proposed X-factors for distribution and metering services (per cent)

	2016	2017	2018	2019	2020
Distribution services	-0.29	-1.06	0.32	-1.66	-1.66
Metering services	-58.84	1.22	1.23	1.23	1.23

213. Note that the proposed X-factors do not necessarily determine the actual movements in our individual network tariffs or the actual customer bill outcomes. This is because:

- The X-factors are those under a revenue cap and therefore relate to the annual change in revenues. Prices necessary to recover the allowed revenues will depend on the demand forecast in each year, and
- Under the form of control determined by the AER in its framework and approach paper, the X-factors will be updated annually to account for unforseen changes in energy consumption[135] and annual movements in the return on debt.[136]

214. Actual movements in customers' bills will also depend on their specific circumstances, including which of our network tariffs they are on, and the amount of electricity they consume (including how they respond to our proposed changes in tariff structures).

215. Also note that the proposed X-factor for distribution services in 2018 indicates a reduction in our revenue that is intended to coincide and assist with the transition to the proposed changes to our tariff structures for residential and small business customers (see chapter 10 and Attachment 4-1). We have proposed this reduction,

134 NER cl 6.5.9

135 The proposed X-factors have been determined based on our independent expert forecasts of demand for our distribution and metering services for each year of the 2016 regulatory period. Under a revenue cap the X-factors will be adjusted annually if actual energy consumption is over or under our forecast, to ensure we recover the approved ARR over the 2016 regulatory period.

136 The AER developed a rate of return guideline in 2013 (AER, *Better regulation, Rate of return guideline*, December 2013.). This guideline allows the return on capital component of the building blocks to be updated annually to account for annual movements in the cost of debt (see section 9.3 for detail on the cost of debt). This was developed following changes to the NER in 2012 (see section 2.4). As a result of these annual updates to the return on capital component of the building blocks, the X-factors will be updated annually. (AER, *Proposed amendments to the electricity transmission and distribution network service providers' post-tax revenue models—Explanatory statement*, October 2014, p14.)

consistent with the NER and customer feedback, to mitigate the impact of transitioning to more cost-reflective tariff structures.[137]

216. The price control mechanism for updating the X-factors is provided as Attachment 5–2. Our proposed network tariffs—including the proposed changes in tariff structures and potential customer bill outcomes—are outlined in chapter 10 and our Tariff Structures Statement (Attachment 10–1).

137 A positive X factor for our distribution services in 2018 will allow us to decrease the fixed and consumption charges to offset the introduction of a new maximum demand charge for residential and small business customers.

7. FORECAST CAPITAL EXPENDITURE

Key messages

- We have developed our capital expenditure forecasts for the 2016 regulatory period consistent with the NER requirements, and to reflect our customers' stated preference for us to maintain our current safety and service levels.
- We have followed our PAS-55, internationally recognised asset management governance standard for which JEN is accredited, thus ensuring that our capital program is planned, managed and delivered prudently and efficiently, as required by the NER and for the benefit of our customers.
- We have forecast total capital expenditure for distribution services of $841m, which is 20% higher than we expect to spend in the 2011 regulatory period. This increase is largely due to increases in our replacement program with targeted investments to replace our oldest failure-prone assets to ensure they don't cost our customers more in the future or jeopardise our safety and service levels.

  Other drivers include:

  – forecast growth in customer-initiated connections in new housing developments

  – forecast growth in residential and business customer demand in parts of our network identified by the Victorian Government as key growth areas

  – forecast real increases in key input costs.
- We have forecast total capital expenditure for metering services of $15m for the 2016 regulatory period, which is 89% lower than we expect to incur in the 2011 regulatory period, now that our smart meter rollout program is complete.
- We have thoroughly assessed how best to prudently deliver our proposed capital expenditure program to ensure that the cost of our investments is minimised and timing is optimised. We are confident the program represents the level of expenditure necessary to comply with requirements in the NER, efficiently meet our obligations and customers' expectations, and promote the long-term interests of our customers.

217. Forecast capital expenditure is a key input to the return on and of capital components of our revenue requirement (see chapter 6). The NER require[138] that we propose the total capital expenditure necessary to provide our distribution and metering services in each year of the 2016 regulatory period, and meet the capital expenditure objectives set out in the NER. These objectives include meeting or managing our customers' expected demand, and complying with all relevant regulatory obligations and requirements (including those related to our service levels).[139]

218. We provide an overview of our forecast capital expenditure for distribution and metering services in the 2016 regulatory period in section 7.1.[140] Subsequent sections provide further information about this expenditure as required by the NER and AER,[141] including:

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[138] NER cl 6.5.7(a)

[139] NER cl 6.5.7(a)

[140] We have also forecast capital expenditure for our metering services to complement the AMI roll-out which was governed by the cost recovery order in council (see Box 3–1)

[141] NER cl 6.5.7 and schedule s 6.1.1; AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, December 2013; and RIN cl 3.

- Our capital expenditure categories
- The approach we have used to develop our capital expenditure forecast to ensure it is consistent with the costs that would be incurred by a prudent service provider acting efficiently[142]
- Our proposed capital expenditure programs
- The difference between our forecast and actual capital expenditure over the 2011 regulatory period.

219. In developing our capital expenditure forecast, we are guided by the requirements in the NER, as well as the AER's guidelines and our customers' preferences. We also take into account anticipated changes occurring in the energy market over the 2016 regulatory period and beyond.

7.1 OVERVIEW OF FORECAST CAPITAL EXPENDITURE

Table 7–1: Forecast capital expenditure for distribution services and metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
Distribution services	158.24	183.64	177.13	167.60	154.56	**841.17**
Metering services	2.41	2.54	2.80	2.94	4.60	**15.29**

(1) Distribution services capital expenditure above is gross capital expenditure, inclusive of customer contributions

(2) Excludes equity raising costs

220. The forecast capital expenditure for distribution services shown in Table 7–1 is $138m or 20% more than we expect to spend over the 2011 regulatory period. The main drivers of this increase are:

- Additional projects and programs over the 2016 regulatory period to:
  - Address safety-related recommendations from the independent safety regulator, Energy Safe Victoria (**ESV**) by replacing the oldest and most failure-prone assets in our network and strengthening parts of the network exposed to higher bushfire risk
  - Meet the forecast increase in customer-initiated connections due to new housing developments and the redevelopment of some large industrial sites that have, or are expected to close
  - Provide the incremental network capacity required to safely and reliably meet forecast growth in residential and business electricity demand within growth corridors of our network
  - Replace some SCADA and billing IT systems that have come to the end of their useful or economic life, and retire applications and technologies that have become redundant as new systems replace their business and technical functions.
- Forecast real increases in our key input costs (labour and materials) of 0.96% per year.

221. To minimise our forecast capital expenditure and hence the long-term cost of providing our network services we have:

- Planned to maintain our current safety and service levels in line with our customers' expectations (see chapter 4 and Attachment 4–2)

142 In accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services, NER cl S6.2.2.

- Planned for the long-term and carefully prioritised our investments to maximise dynamic efficiency without compromising safety and service standards
- Revised our approach to sourcing non-network solutions to defer network augmentation which assists to ensure we maintain an allocative efficient approach to network planning
- Updated our procurement approach by establishing new competitive tenders, and refreshed our panel of preferred suppliers to provide us access to an external resource base with specialised expertise at best market rates to ensure we continue to be productively efficient. Further detail on how we derive unit rates and our cost estimation method is provided in Attachment 7-10.

222. In addition, our capital expenditure on Advanced Metering Infrastructure (**AMI**) will decrease significantly now that the smart meter rollout program is complete. We expect capital expenditure over the 2016 regulatory period to be $124m or 89% less than we expect to spend over the 2011 regulatory period.

223. Our forecast capital expenditure represents the amount we consider necessary to achieve the requirements in the NER,[143] efficiently meet our obligations and customers' expectations, and promote the long-term interests of our customers.

7.2 OUR CAPITAL EXPENDITURE CATEGORIES

224. To comply with the NER[144] we have forecast our capital expenditure using the capital expenditure categories outlined in the category analysis Regulatory Information Notice (**RIN**),[145] including:[146]

1. **Replacement** – expenditure associated with replacing aging assets to ensure we continue maintain the safety standards and service levels that our customers expect
2. **Augmentation** – expenditure associated with increasing the capacity of the distribution network to ensure we can meet our customer's requirements for growth and reliability
3. **Connections** – gross expenditure (inclusive of customer contributions) associated with planning and constructing new customer connections and upgrading existing customer connections. We undertake this work following requests by customers and developers.
4. **Non-network IT** – expenditure associated with maintaining the IT infrastructure, software and applications which support the operation of our network.
5. **Non-network other** – expenditure associated with maintaining property and buildings, the fleet of vehicles that support the operation of our network, our inventory of tools and equipment, and the communications system that supports our network and metering systems.
6. **Metering** – expenditure associated with meter provision and meter data services.

225. Figure 7–1 illustrates these capital expenditure categories.

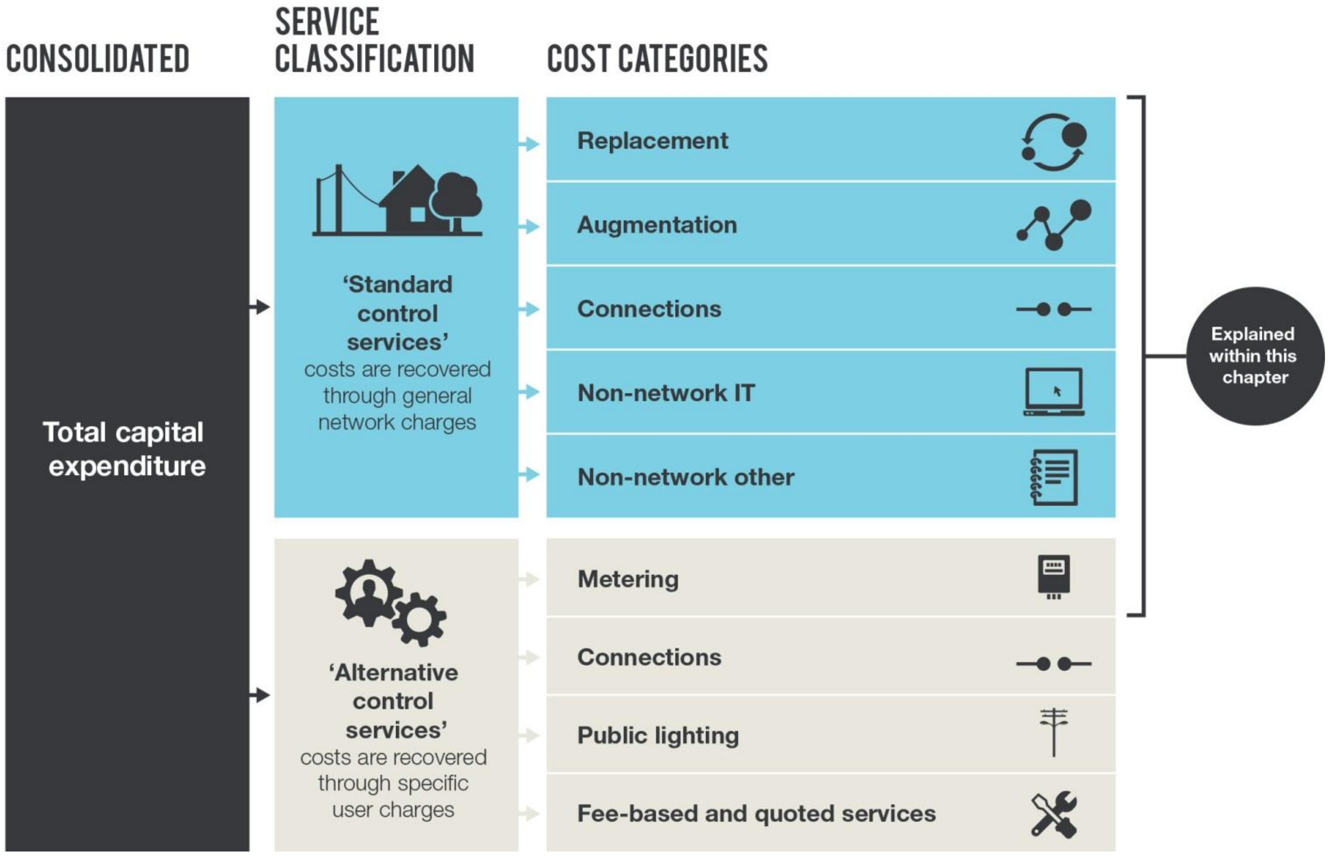
[143] Including the capital expenditure objectives in NER cl 6.5.7

[144] NER cl 6.5.7(b)(1) requires our forecast capital expenditure to comply with the requirements of any relevant regulatory information instrument. NER cl 6.5.7(b)(2) requires our forecast capital expenditure to be allocated in accordance with our cost allocation methodology.

[145] Preferred capital expenditure categories are set out in its guidelines. AER, *Better Regulation—Expenditure Forecast Assessment Guideline*, November 2013. These capital expenditure categories align to the category analysis RIN capital expenditure categories.

[146] The scope of capital expenditure categories explained in this chapter includes the standard control service capital expenditure categories in the AER's category analysis RIN and the alternate control metering services expenditure category. Other alternate control service expenditure categories are explained in chapter 11.

Figure 7–1: JEN's capital expenditure categories



7.3 APPROACH USED TO FORECAST CAPITAL EXPENDITURE

226. To forecast our capital expenditure for distribution services and metering services for the 2016 regulatory period, we take the following steps:

1. For each capital expenditure category, we forecast the necessary expenditure using fit for purpose methods that ensure we capture the relevant drivers of expenditure for the category and, where possible, remain consistent with the AER's preferred methods. In general, we used bottom-up forecasting methods, and complement them with top-down approaches for most projects and programs of work.

2. We sum the required expenditure for each category to provide a total forecast of capital expenditure consistent with the requirements of the NER.

227. In applying these steps we followed PAS-55, the internationally recognised standard for asset management governance for which JEN is accredited (see Box 7–1). This approach helps ensure that our capital program is planned, managed and delivered prudently and efficiently, as required by the NER and for the long-term benefit of our customers.

228. In section 7.3.1 we provide an overview of our forecasting process and further information on our governance processes for asset management planning, cost estimation and project management. Attachment 7–2 provides further detail on each step of our capital planning process and governance framework and Attachment 7–3 provides a detailed explanation of the resulting capital expenditure forecast for the 2016 regulatory period.

Box 7–1: Our governance systems and processes for asset management are internationally recognised as world's best practice

Our approach to asset management is driven by our vision to be recognised as a world-class manager of energy assets. In line with this and the expenditure forecast assessment guideline,[147] our governance systems and processes have been reviewed and are PAS-55 accredited under the British Standards Institution's (BSI) Publicly Available Specification for the optimised management of physical assets.

We achieved PAS 55 accreditation in August 2014, and are one of only three Australian businesses to have done so. The accreditation applies to our asset management system, which covers activities relating to the creation, acquisition, operation and maintenance of electricity distribution assets.

7.3.1 FORECASTING PROCESS WE USED

229. To develop our forecast expenditure for each capital expenditure category, we used the following broad process as outlined in our expenditure forecasting methodology document[148]:

- We consider the safety and service performance that our assets must deliver over the 2016 regulatory period, taking into account our safety obligations and our customers' service level preferences (see Box 7–2 which outlines how our customers' preferences have influenced our forecast capital plan)
- We consider the anticipated changes in the energy market and other factors that will influence the network's ability to deliver the required performance over the period. For example, forecast changes in peak demand, new growth areas, changes in how customers use our network, and the condition of our assets[149]
- We undertake engineering analysis of supply and demand side options for delivering the required performance[150]
- We determined our proposed capital expenditure program, balancing the service risks and costs involved and our ability to deliver the program. In relation to costs, we take account of the forecast real escalation in our capital costs,[151] as well as the interaction between capital and operating expenditure (see Box 7–3)
- We develop a detailed delivery strategy that demonstrates how we will deliver a greater volume of capital work over the 2016 regulatory period than in the 2011 regulatory period, and described how the recommended resource mix will deliver the lowest sustainable cost to our customers and business (see Attachment 7–8).

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147 The guideline states that "a [favourable] governance review may, however, indicate a DNSP's likely overall efficiency", AER, *expenditure forecast assessment guideline – distribution* – November 2013 p19-20.

148 Jemena Electricity Networks (VIC) Ltd, *Expenditure forecasting methodology for the 2016-20 regulatory period*, 30 May 2014

149 Typically, to consider our asset condition, we use a bottom-up approach, which involves collecting asset condition data and age-based data to generate life-cycle management plans for classes of assets that will meet our safety obligations and deliver our customers' preferred service levels, as well as top-down modelling. We also use an approach called Condition Based Risk Management (CBRM) which complements the bottom-up approach by applying asset information to generate a health index and forecast failure rate for asset classes.

150 Options are evaluated using economic cost benefit analysis to consider broader costs and benefits of various options. Key inputs to this analysis are our customers' expected unserved energy and the value of customer reliability (VCR). In determining our engineering requirements we have applied the VCR as determined by the Australian Energy Market Operator (AEMO), *Value of Customer Reliability Review Final Report*, September 2014.

151 We engaged independent market experts to forecast the real escalation in our capital costs, and then apply this escalation to our capital program, along with a share of the costs associated with our corporate functions like human resources, finance and legal.

230. The key variables and assumptions[152] that underpin our forecast capital expenditure are provided in Attachment 8-2. JEN's directors also certify the reasonableness of these assumptions (see Attachment 7-14) as required by the NER.[153]

Box 7–2: How our customers' preferences have influenced our proposed capital program

As chapter 4 outlines, we engaged extensively with our customers to understand their service level preferences. As part of this process, we tested their views on the trade-off we could make between safety and service levels and our costs and prices, and on the key attributes of the services we provide to customers—reliability, responsiveness, visual and public amenity and empowering customers.

We asked our customers whether they agree that the safety of our customers, the general public and our employees should be our number one priority. We also asked them whether they:

- Are satisfied with our current levels of service reliability and responsiveness, or would prefer to pay higher (or lower) prices for higher (or lower) service levels
- Are satisfied with the current visual impact of our network in local areas, or would prefer to pay more (or less) to manage this impact
- Support the investments we plan to make to maintain our current service levels across our network.

Our proposed forecast capital expenditure reflects the feedback we received (see Attachment 4–1).

152 NER cl S6.1.1(2) to cl S6.1.1(4)

153 NER cl S6.1.1(5)

Box 7–3 Interaction between forecast capital and operating expenditure

The NER require us to explore the possibility of substitution between operating expenditure and capital expenditure.[154] Demand Management (**DM**) presents an opportunity to make trade-off decisions between capital and operating expenditure. For example, we could incur augmentation capital expenditure to increase network capacity, or instead, we may incur operating expenditure by making payments to customers to curtail load during peak times thus avoiding augmenting the network.

We are currently in partnership with a provider of DM services and have already conducted trials at two zone substations to assess the potential for asset investment deferrals:

- This includes assessing the viability of deferring network capital expenditure and/or addressing customer supply risk in the Essendon and Braybrook area. An output of this work is expected to be a DM toolkit to assist us in conducting augmentation planning studies, and facilitate DM discussions relating to upcoming RIT-D[155] projects
- During the 2016 regulatory period, we plan to continue to test the DM market across our network, and implement DM solutions where it is to the long-term benefit of our customers.

This is an example of new DM technologies and our revised approach to sourcing DM products is helping us to better respond to our customers' expectations to maintain high levels of services and put downward pressure on our costs and prices.

Attachment 5-5 provides more detail of our proposed innovation and technology investment.

7.3.2 OUR GOVERNANCE PROCESS FOR ASSET MANAGEMENT PLANNING, COST ESTIMATION AND PROJECT MANAGEMENT

231. As noted, we forecast our capital expenditure for the 2016 regulatory period within the governance process for asset management. This process involves a range of robust tools that helps ensure that we achieve efficient and prudent investment. These include our:

- **Framework for monitoring capital expenditure works portfolio** governs the prioritisation of projects and guides us in managing issues, risks, variation and escalation across our whole capital works portfolio.
- **Seven-stage gating process** for managing projects from inception through to delivery and completion, which ensures that checks are undertaken at critical stages of the project and within Jemena's delegation of financial authority policy
- **Project Management Methodology (PMM)** improves and standardises the scoping, estimation and delivery management of network infrastructure programs and projects throughout their lifecycle.

232. The outputs of this process creates a number of strategy asset management plans which are used to guide the business investment and planning activities:

- **Seven-year asset management plan (AMP)** summarises our approaches for forecasting and governance, evaluating business cases and making investment decisions. The AMP, which is updated annually, also includes a rolling five year forecast of the capital work we need to undertake to maintain a safe, reliable network (The AMP is provided at Attachment 7–5)

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154 NER cl 6.5.6(e)(7) requires the AER to have regard to whether we have explored the substitution possibilities between operating and capital expenditure

155 Regulatory Investment Test-Distribution (**RIT-D**) projects include those developed in accordance with – AER, *Regulatory investment test for distribution* 23 August 2013.

- **IT asset management plan (IT AMP)** focusses on our information and communications technology assets, including metering and SCADA (see Attachment 7–7)
- **20-year strategic asset management plan (SAMP)** ensures we adapt over time to maintain the relevance of our services to our customers. The SAMP also indicates the effect that deferring expenditure into the subsequent regulatory periods is likely to have on prices and service levels (see Attachment 7–6.)

233. We continually update and improve our governance processes and tools to help ensure that only prudent, efficient expenditure is incurred, and that our capital program accords with the capital expenditure objective, criteria and factors of the NER.[156]

7.4 PROPOSED CAPITAL EXPENDITURE PROGRAMS

234. Our proposed capital expenditure programs for distribution services and metering services are outlined in Table 7–2 which represents a prudent and efficient level of expenditure required to meet our obligations and requirements, maintain existing service levels and to reflect our customers' preferences for the 2016 regulatory period.

Table 7–2: Forecast capital expenditure by cost category ($2015, $millions)

Gross forecast capex	2016	2017	2018	2019	2020	Total
Replacement expenditure	49.26	51.76	50.30	69.00	73.16	**293.48**
Augmentation expenditure	25.44	60.64	52.40	30.64	13.58	**182.69**
Connections expenditure	45.07	44.24	48.07	43.60	46.83	**227.80**
Non-network IT	21.36	22.98	22.28	18.44	16.84	**101.90**
Non-network other expenditure	17.12	4.03	4.07	5.93	4.15	**35.29**
Distribution services expenditure[157]	**158.24**	**183.64**	**177.13**	**167.60**	**154.56**	**841.17**
Metering services expenditure	2.41	2.54	2.80	2.94	4.60	**15.29**

(1) Connections expenditure is gross capital expenditure, inclusive of customer contributions

(2) Excludes equity raising costs.

7.5 DIFFERENCES BETWEEN CAPITAL EXPENDITURE IN 2011 AND 2016 REGULATORY PERIODS

235. We analysed the differences between our actual capital expenditure and allowed capital expenditure for the 2011 regulatory proposal[158] and our forecast capital expenditure for the 2016 regulatory period.

236. Our actual capital expenditure for distribution services over the 2011 regulatory period is expected to be $151m or 27% higher in real terms than the regulatory allowance. Figure 7–2 also highlights, our forecast capital

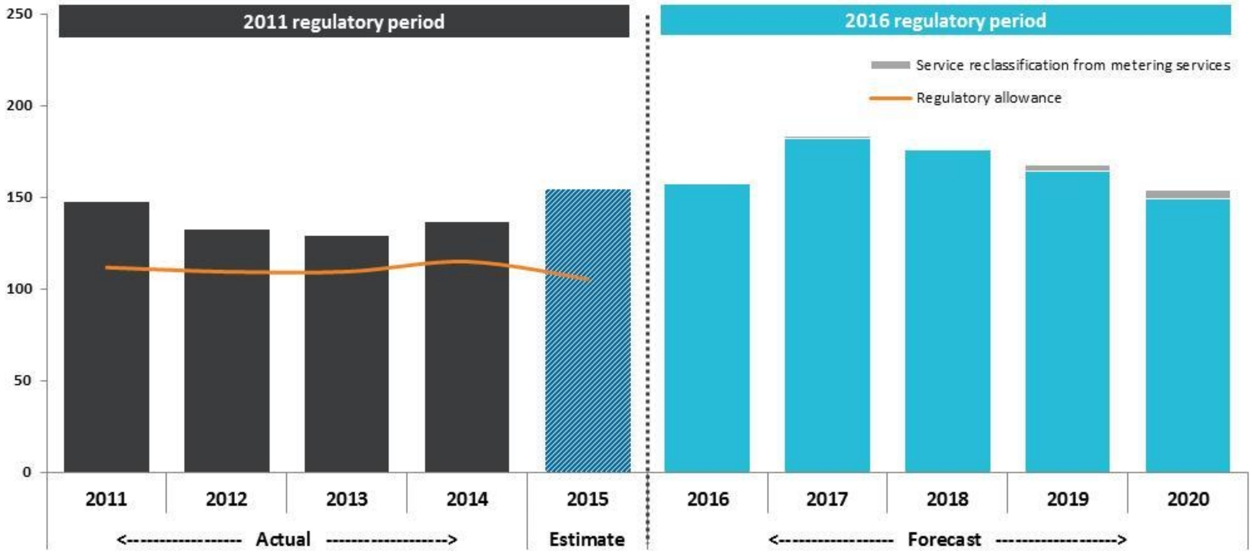
[156] NER cl 6.5.1

[157] The forecast distribution services expenditure includes a portion of costs that were previously recovered through metering expenditure.

[158] We did not conduct the same analysis in this proposal for historical metering services as they were governed under the Victorian Government's CROIC (see Box 3–1)

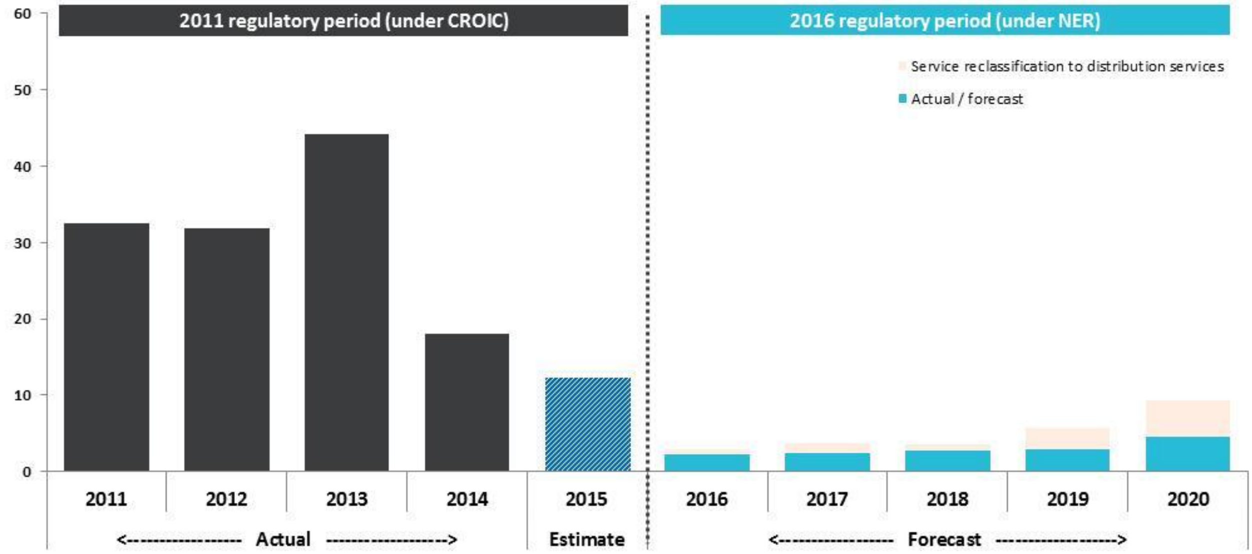
expenditure for distribution services in the 2016 regulatory period is higher than our actual expenditure in the 2011 regulatory period.

Figure 7–2: Comparison of actual and forecast capital expenditure for distribution services over the 2011 and 2016 regulatory periods ($2015, $millions)



237. In contrast to distribution services, our forecast capital expenditure for metering services over the 2016 regulatory period is significantly lower than our actual expenditure in the 2011 (see Figure 7–3). This is because we have completed the AMI rollout, and no longer incur the same magnitude of capital expenditure on new meters, communication and IT infrastructure to facilitate this program.

Figure 7–3: Comparison of actual and forecast capital expenditure for metering services over the 2011 and 2016 regulatory periods ($2015, $millions)



(1) From 1 January 2016, the cost recovery of JEN's AMI assets will transition from the Victorian Government's CROIC (see Box 3–1) to the provisions of chapter 6 of the NER.

(2) In Figure 7–3, capital expenditure over the 2011 regulatory period includes the cost of new AMI meters, IT and communications infrastructure.

238. Section 7.5.1 outlines the key factors that led to our higher than allowed capital expenditure for distribution services in the 2011 regulatory period. Section 7.5.2 outlines the factors impacting our forecast for the 2016 regulatory period.

7.5.1 FACTORS THAT LED TO HIGHER THAN ALLOWED CAPITAL EXPENDITURE FOR DISTRIBUTION SERVICES IN THE 2011 REGULATORY PERIOD

239. As noted, our expected actual capital expenditure for distribution services in the 2011 regulatory period was higher than the regulatory allowance. We note that the allowed expenditure was materially less than our revised proposal for the 2011 regulatory period, and that our actual delivered volumes of work—particularly for replacement expenditure—were consistent with our revised proposal.

240. As chapter 2 outlines, our private ownership, our customers' expectations and the regulatory framework[159] provide us with strong incentives to invest in and operate our network business efficiently, and to respond to changing energy market conditions. We responded to those incentives in the 2011 regulatory period and incurred the efficient capital expenditure necessary to meet our safety obligations (see Box 7–4), provide the service levels our customers expect and minimise the long-term cost of providing network services (see Box 7–5).

241. We had to address a range of regulatory and market challenges during the 2011 regulatory period, which led to our higher than allowed capital expenditure. In some cases, we foresaw the challenges in developing our initial proposal, and accounted for them in our initial forecast capital programs. In other cases, the challenges could not have been reasonably foreseen when we were developing our proposal for the 2011 regulatory period.

242. We sought to reduce our capital expenditure over the 2011 regulatory period where possible—including by:

- Transferring load from capacity-constrained zone substations to nearby substations that had spare capacity, and
- Deferring some major augmentation projects until the 2016 regulatory period (for example, see Box 7–5).

243. We also experienced slightly lower peak demand relative to our forecast, which contributed to our decision to defer some demand-driven projects, and also meant we could replace a greater volume of the failure-prone and oldest assets in our network in the 2011 regulatory period.

244. To ensure our stakeholders understand why we spent more than our capital expenditure allowance in the 2011 regulatory period, we have prepared a detailed year-on-year explanation (see Attachment 7–1).

[159] Spending over the allowance is uncommercial and expensive, as in circumstances where actual depreciation is applied when rolling forward the asset base to the beginning of the next regulatory period (NER cl. S6.2.2A) the business bears the financing costs and depreciation penalty for doing so—an incentive strong enough to encourage all privately funded electricity distribution businesses to maintain expenditure within the allowance where possible. Spending in excess of allowance is not commercially sustainable over successive regulatory periods.

Box 7–4: Investing in our network to meet our safety obligations and customer expectations

At the time of the AER's review of our proposed capital expenditure for the 2011 regulatory period, we forecast capital expenditure relating to the Pascoe Vale transformer upgrade project. We originally proposed that this project be implemented in 2011. The final decision assumed that the project was not required until 2013.

We considered the potential to defer the project until 2013. However to meet safety obligations, and provide the service levels our customers expect, we decided to proceed with this major reinforcement project in 2012. In our view, we could not defer this project any longer than this without compromising security of supply and safety.

Box 7–5: Responding to incentives and the changing energy market by deferring capital expenditure

Our capital expenditure proposal for the 2011 regulatory period included a proposal for a large augmentation project to address the capacity limitations at Flemington zone substation.

During the period, we updated our project assessment, taking account of the most recent market influences to the scope and timing of the required capital expenditure. In this case, we were able to defer the project until 2016 by substituting the proposed large zone substation augmentation work with an alternative, lower cost interim solution—a new feeder at a neighbouring zone substation.

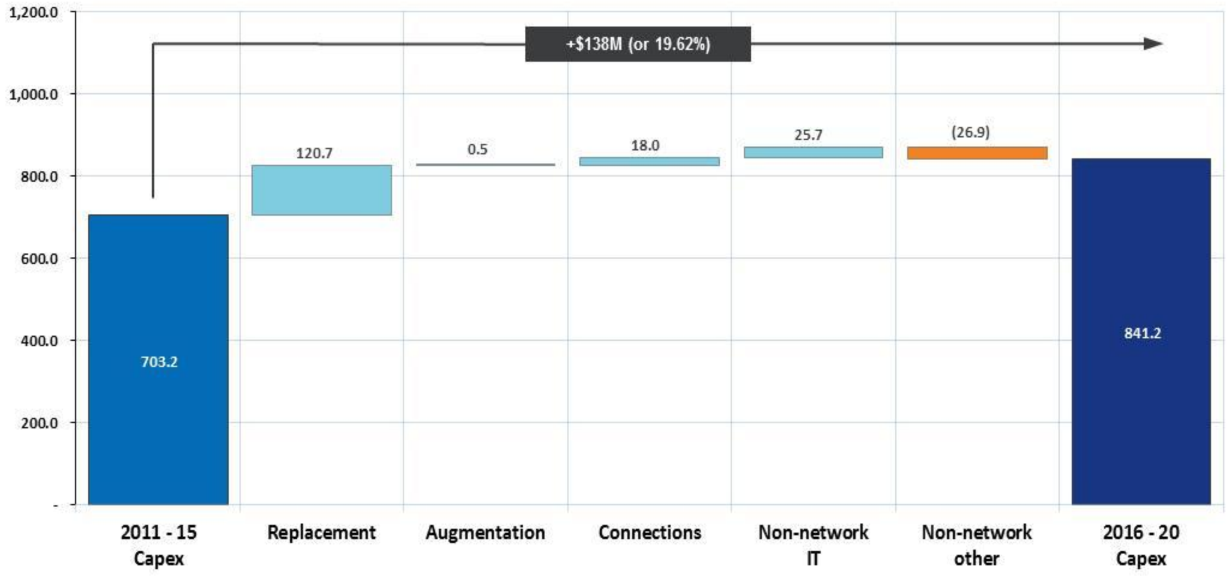
The project is now planned to be completed by November 2017 and will be a combination of asset replacement and network augmentation works.

This example demonstrates our dynamic responsiveness to changes in our circumstances. We regularly review our capital program to ensure we optimise the timing and delivery of our capital program and minimise the long-term cost of providing network services.

7.5.2 FACTORS LIKELY TO IMPACT OUR CAPITAL EXPENDITURE IN 2016 REGULATORY PERIOD

245. Our forecast capital expenditure for distribution services for the 2016 regulatory period is $841m which is $138m or 20% more than we expect to spend over the 2011 regulatory period. The higher expenditure associated with each expenditure category is shown on Figure 7–4.

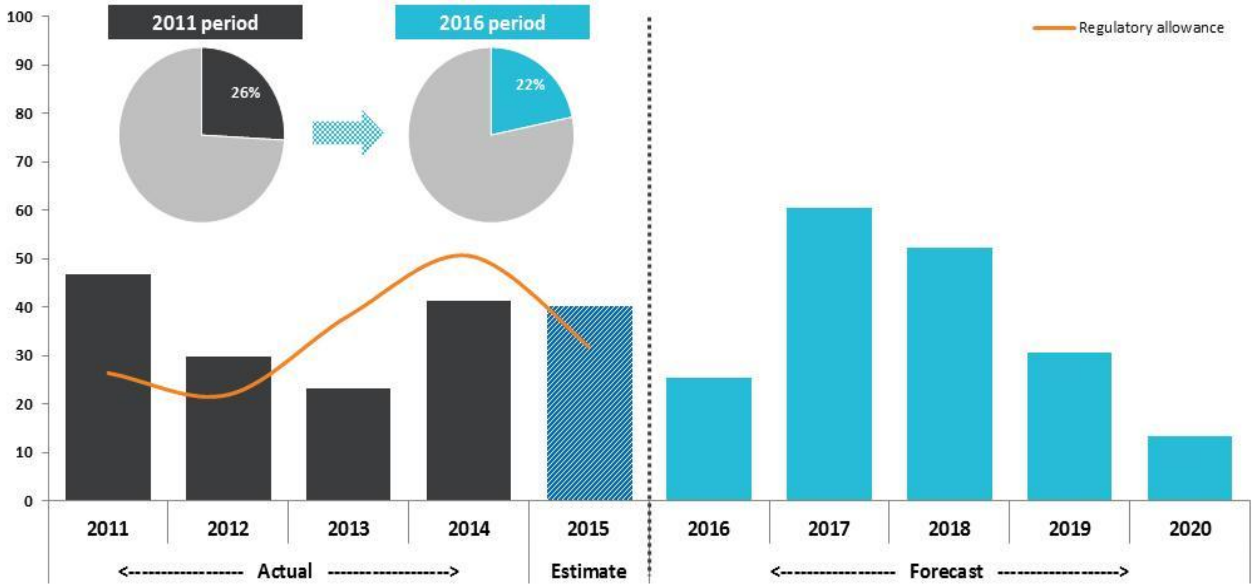
Figure 7–4: Increase in forecast capital expenditure for distribution services over the 2016 regulatory period by expenditure category ($2015, $millions)



7.5.2.1 Forecast augmentation expenditure

246. Our forecast augmentation expenditure is in line with what we expect to spend over the 2011 regulatory period (see Figure 7–5), being only $0.5m or 0.3% higher.

Figure 7–5: Comparison of actual and forecast augmentation capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)



247. Similar levels of augmentation expenditure are forecast in the 2016 regulatory period, relative to the 2011 regulatory period, to service the growing residential and small business population in three growth corridors:

- The Northern growth corridor, encompassing Craigieburn and the Somerton supply region
- The Sunbury growth corridor, covering the region around Sunbury and Diggers Rest
- The Western growth corridor, including some of the Western perimeter of our network around Sydenham.

248. Peak demand is expected to grow annually by over three per cent in these areas over the 2016 regulatory period. Further detail is provided in Box 7–6 and our forecast capital expenditure report (see Attachment 7–3).

Box 7–6: Investing to meet forecast peak demand growth in Craigieburn

Our network must be built and maintained to meet our customers' total maximum demand for electricity from the network at any moment in time. Daily peaks in demand occur between 10am and 8pm on weekdays. The highest peaks occur on just a few days per year—when weather conditions are extreme, and many people are using air conditioners. As these peaks increase, we must invest in the network to maintain the reliability of our services.

Over the 2016 regulatory period, we forecast growth in peak demand of 4.2% around Craigieburn – significantly higher than the forecast aggregate growth of 1.35% for the entire network.

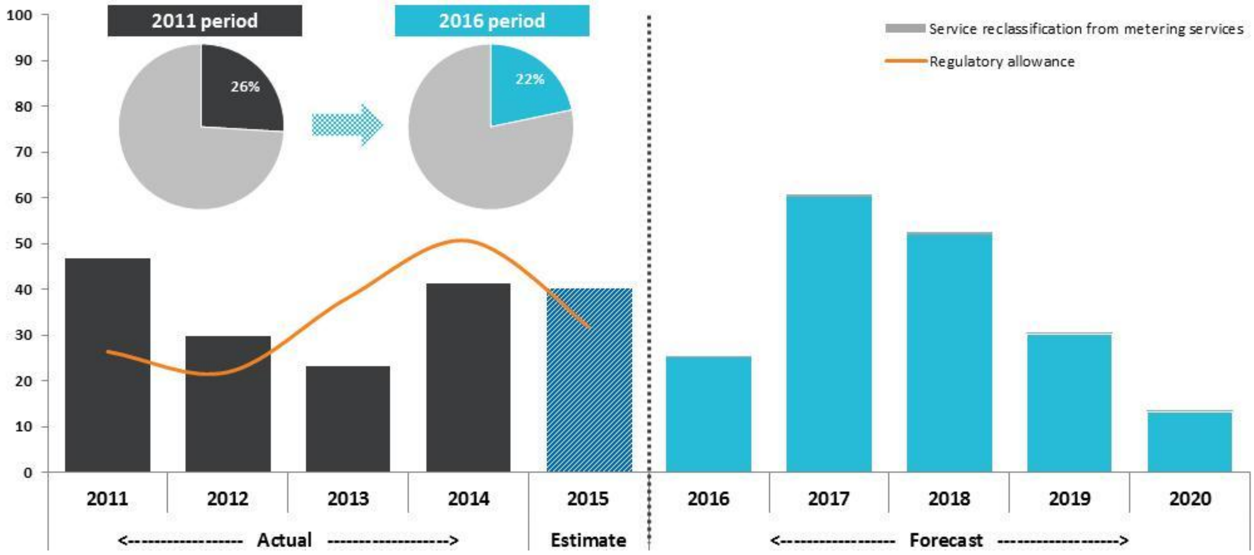
As a result, significant limitations are emerging on a number of feeders from the surrounding Somerton and Coolaroo zone substations. These feeders supply the rapidly developing residential area to the north-west of Somerton in the Craigieburn, Roxburgh Park and Greenvale areas. We expect that by summer 2020, these feeders will have an average utilisation of around 120%.

We have identified a preferred solution to alleviate the zone substation limitations, which involves establishing a new zone substation to be built by November 2019.

7.5.2.2 Forecast replacement capital expenditure

249. Our forecast replacement capital expenditure is $121m or 70% higher than we expect to spend over the 2011 regulatory period (Figure 7–6).

Figure 7–6: Comparison of actual and forecast replacement capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)



250. The principle drivers of this increase in replacement expenditure are:

- **Aging assets** – Our network is aging and we are still in the initial phase of a replacement cycle for many assets. This means we will need to increase replacement expenditure to ensure that reliability, security and safety do not degrade over the next period (see Box 7–7 for more information)
- **Safety issues** – There are a number of areas where safety has deteriorated during the 2011 regulatory period. We need to increase replacements in these areas to arrest this degradation and address concerns raised by the independent safety regulator, ESV.[160]

251. Changes in our operating environment will continue to place upward pressure on our safety driven replacement expenditure over the 2016 regulatory period and beyond. In particular, changing climate conditions are increasingly affecting our network's performance, lengthening and intensifying the bushfire season,[161] and creating conditions conducive to pole fires. In addition, increasingly frequent severe weather events (including wind storms and heat waves) mean we need to undertake programs to minimise the fire risk associated with our assets. Our proposed safety replacement programs in the 2016 regulatory period will ensure we continue to maintain the safety of our customers, community and staff (see Attachment 7-3 for further detail).

160 Energy Safe Victoria, *Safety Performance Report on Victorian Electricity Networks 2013*, June 2014

161 Climate Council , *Be prepared: Climate change and the Victorian bushfire threat* , 2014

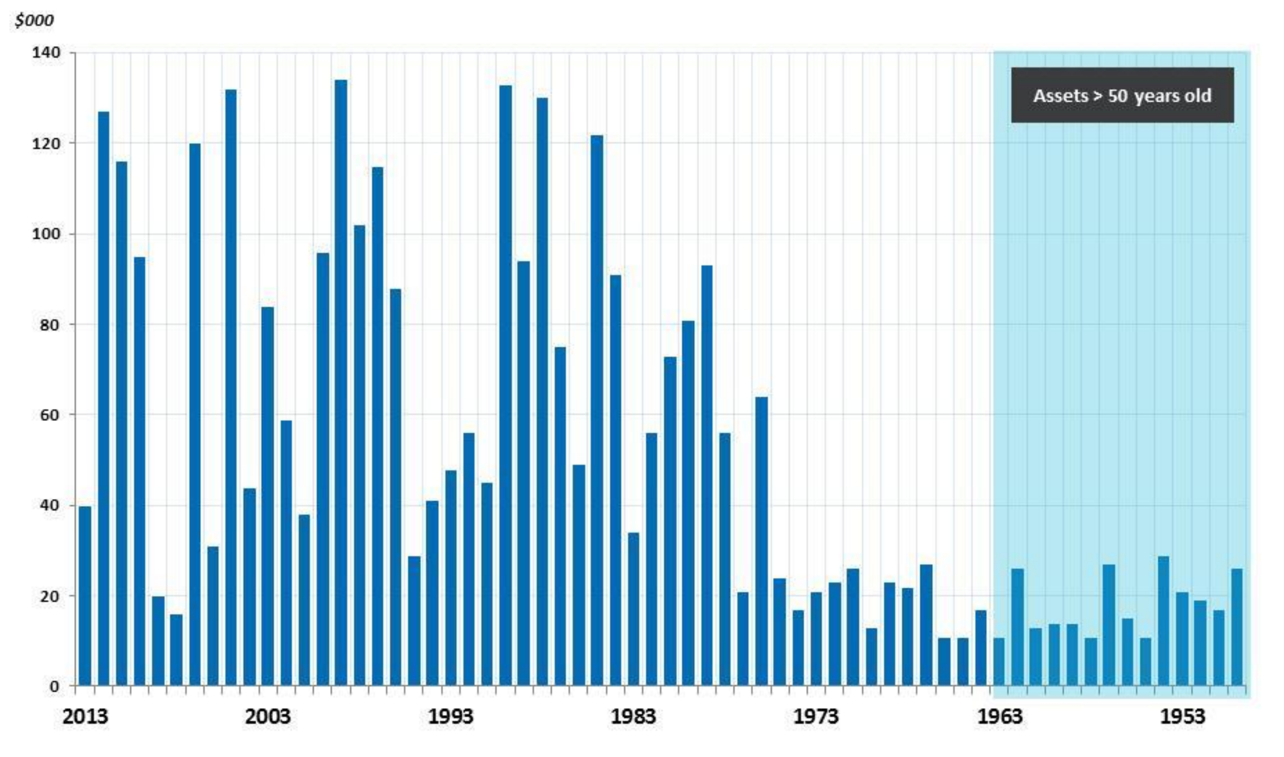
Box 7–7: Investing to manage aging assets across our network

Many of our network assets were built 50 or more years ago, and the underlying assets are nearing the end of their life. These aging assets need replacement, and we expect to incur increased capital and operating expenditure in the aging parts of the network to meet safety requirements and provide the service levels our customers expect.

Compounding the aging issue, a number of asset classes have exhibited deteriorating safety performance in the 2011 regulatory period, requiring us to increase replacement to arrest the degradation and address the concerns raised by the ESV.

Figure 7–7 provides a profile of the asset age and forecast replacement cost which reveals that we have a large proportion of assets that will reach 50 years old during the 2016 regulatory period—including some transformer replacements.

Figure 7–7: JEN asset age v replacement cost



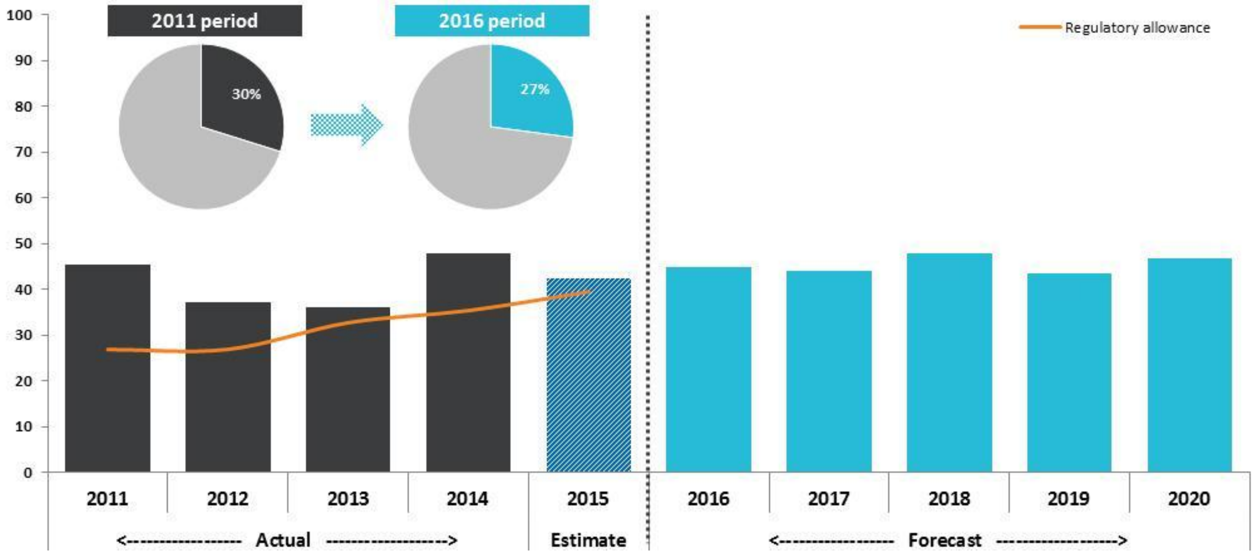
Source: JEN analysis

If the condition of an asset outperforms its asset age and life, the asset doesn't simply qualify for replacement. In fact, we manage and maintain our assets so that outperformance is very common. We only replace those assets that are failing, or their actual condition has deteriorated such that it will likely fail in the near future and so it poses a safety concerns and/or reliability concern to our customers, as required under NER 6.5.7(e)(7).

7.5.2.3 Forecast connections capital expenditure

252. Our forecast connections capital expenditure is $18m or 9% more than we expect to spend over the 2011 regulatory period (Figure 7–8).

Figure 7–8: Comparison of actual and forecast connections capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)



253. This higher connections expenditure is driven largely by our forecast of 0.58% year-on-year growth in customer numbers. Some of the projects identified by our customers as connection activities over the 2016 regulatory period include:

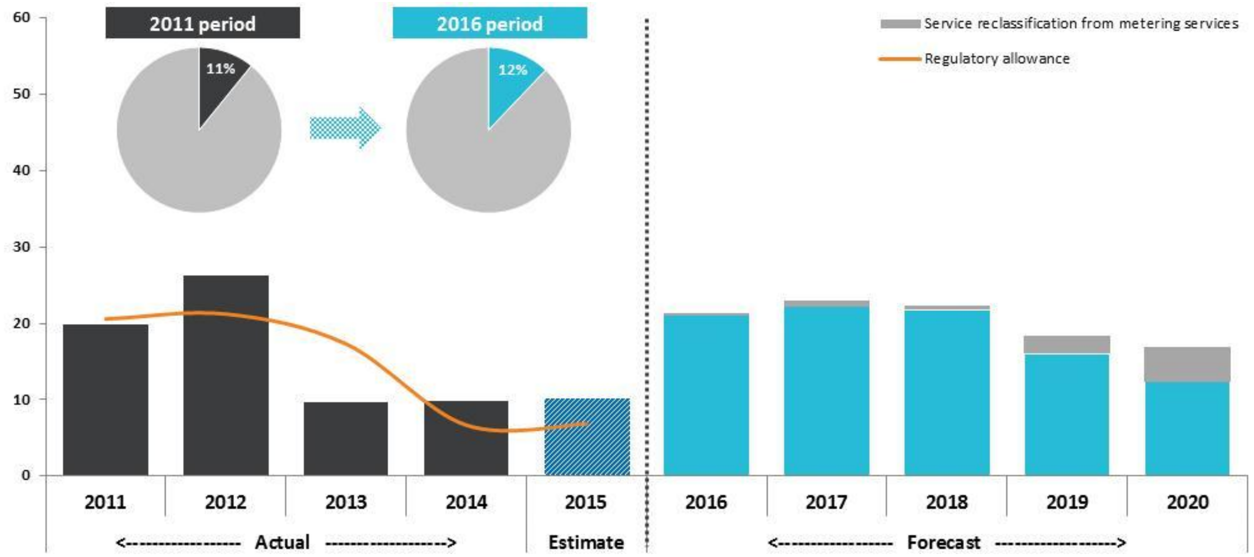
- Expanding the commercial precinct in and around Melbourne Airport
- Redeveloping the decommissioned paper mill site in Fairfield with a new residential and small business precinct
- Redeveloping a number of former industrial sites as new suburbs or high-rise apartments.

254. More detail is provided in section 4.3 of our forecast capital expenditure report at Attachment 7–3.

7.5.2.4 Forecast non network IT capital expenditure

255. Our forecast non-network IT capital expenditure is $26m or 34% more than we expect to spend over the 2011 regulatory period (Figure 7–9).

Figure 7–9: Comparison of actual and forecast non-network IT capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)



256. The main drivers of this increase in non-network IT expenditure are the need to:

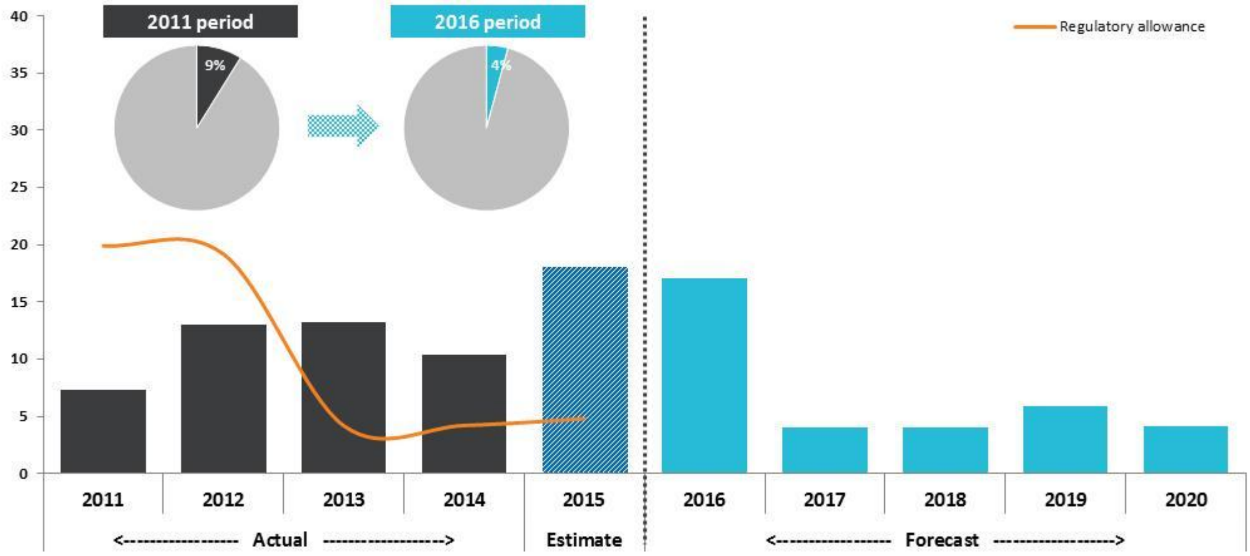
- Sustain the IT asset functionality through upgrades, to optimise asset performance and provide for growth
- Replace systems that have come to the end of their useful or economic life, and retire applications and technologies that have become redundant as new systems replace their business and technical purpose
- Add new systems and technologies and extend the use or functionality of existing systems to modernise our IT capability in areas where benchmarking against comparable businesses has identified we have gaps

257. These targeted investments will also assist us to better collect the information, in the form requested by the AER, in Regulatory Information Notices (**RINs**) by providing the systems in which to capture this data. More detail of our forecast IT expenditure is provided in our IT AMP at Attachment 7–7.

7.5.2.5 Forecast non-network other expenditure

258. Our forecast non-network other capital expenditure is $27m or 43% lower than we expect to spend over the 2011 regulatory period (see Figure 7–10).

Figure 7–10: Comparison of actual and forecast non-network other capital expenditure over the 2011 and 2016 regulatory periods ($2015, $millions)



259. Our capital expenditure in the non-network other category mostly comprises expenditure in these sub-categories:

- Vehicles
- Property, buildings tools and equipment.

260. Our lower non-network other expenditure is driven by a reduction in property and buildings expenditure. The most significant proposed property development in the 2016 regulatory period is a project to redevelop our Broadmeadows depot in 2016.

261. More detail is provided in section 4.4 of our forecast capital expenditure report at Attachment 7–3.

8. FORECAST OPERATING EXPENDITURE

Key messages

- We developed our operating expenditure forecasts for the 2016 regulatory period using an approach consistent with the requirements and guidance in the NER and provided by the AER. We also took account of our customers' preference for us to maintain our current safety and service levels and the changes occurring in our energy market.
- Our forecast operating expenditure for distribution services is $499m, which is around 32% more than our expected expenditure in the 2011 regulatory period (see Figure 8–3 for details).
- The increase is due to unavoidable upward pressure on this expenditure, including forecast real increases in our key input costs, forecast growth in key network assets and customer numbers and additional programs to ensure we continue to meet safety requirements and our customers' expectations.
- Service reclassification, where a portion of costs for activities such as metering and supply abolishment is now included in the distribution services costs, gives the appearance of cost increases.
- Our forecast operating expenditure also includes a productivity improvement target of 4.5%, in line with expert advice on the productivity improvements attainable over the 2016 regulatory period and the AER's guideline method.

262. Forecast operating expenditure is one of the building block costs used to calculate the annual revenue requirement (chapter 6). We must propose the total operating expenditure we will require to provide our distribution and metering services in each year of the 2016 regulatory period (see Table 8–1), and meet the operating expenditure objectives set out in the NER and Victorian metering obligations. These objectives include meeting or managing our customers' expected demand, and complying with all relevant regulatory obligations and requirements (including those related to our service levels).[162]

263. Section 8.3 provides an overview of our forecast operating expenditure for distribution and metering services. The subsequent sections and relevant attachments provide further information about this expenditure as required by the NER and AER,[163] including:

- Our operating expenditure categories
- The approach we used to forecast operating expenditure for the 2016 regulatory period and ensure it is consistent with the costs incurred by a prudent service provider acting efficiently[164]
- Our proposed operating expenditure programs for the period
- The difference between our forecast operating expenditure for the 2016 regulatory period and actual operating expenditure for the 2011 regulatory period.

264. Along with the NER requirement and the AER's guideline, we were guided by our customers' preferences. We also took account of the changes expected to occur in our energy market over the 2016 regulatory period and beyond.

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162 NER cl 6.5.6.

163 AER, *Expenditure Forecast Assessment Guideline for Electricity Distribution*, December 2013.

164 NER cl S6.1.2(2) to S6.1.2(5).

8.1 OVERVIEW OF FORECAST OPERATING EXPENDITURE

Table 8–1: Proposed forecast operating expenditure for distribution and metering services ($2015, $millions)

	2016	2017	2018	2019	2020	Total
Distribution services	95.37	95.36	98.51	103.18	106.60	499.01
Metering services	10.81	11.08	11.40	11.78	12.14	57.21
Total operating expenditure	**106.17**	**106.43**	**109.91**	**114.96**	**118.74**	**556.22**

(1) Operating expenditure includes debt raising costs.

265. Our forecast operating expenditure for distribution services is approximately 32% or $120m more than our actual (expected) expenditure over the 2011 regulatory period. This increase is due to unavoidable upward pressure on this expenditure over the 2016 regulatory period, including:

- Service reclassification, where a portion of costs for activities such as metering and supply abolishment is now included in the distribution services costs
- Additional inspection, maintenance, customer engagement and vulnerable customer assistance programs to ensure we continue to meet safety and other regulatory requirements and provide the service levels our customers have told us they value
- Forecast real increases of 0.98% per year in our key input costs (labour and materials)
- Forecast growth of 2.24% per year in our network's system physical capacity and the number of customers we will serve
- Other costs such as debt raising costs required to finance a capital program.

266. Our proposed forecast operating expenditure also includes a productivity improvement target of 4.5%, in line with expert advice on the productivity improvements attainable over the 2016 regulatory period and the AER's guideline method.

267. We have undertaken a thorough assessment to determine that our forecast operating expenditure represents the expenditure that would be required to achieve the requirements in the NER,[165] to efficiently meet our obligations and customers' expectations and to promote the long-term interests of our customers.

8.2 OUR OPERATING EXPENDITURE CATEGORIES

268. Our operating expenditure for distribution and metering services includes the costs of operating and maintaining our physical assets (for example, poles, wires, meters and computer systems), responding to emergencies (such as fallen trees on our lines) and performing related customer functions like collecting meter information and providing billing information to retailers.

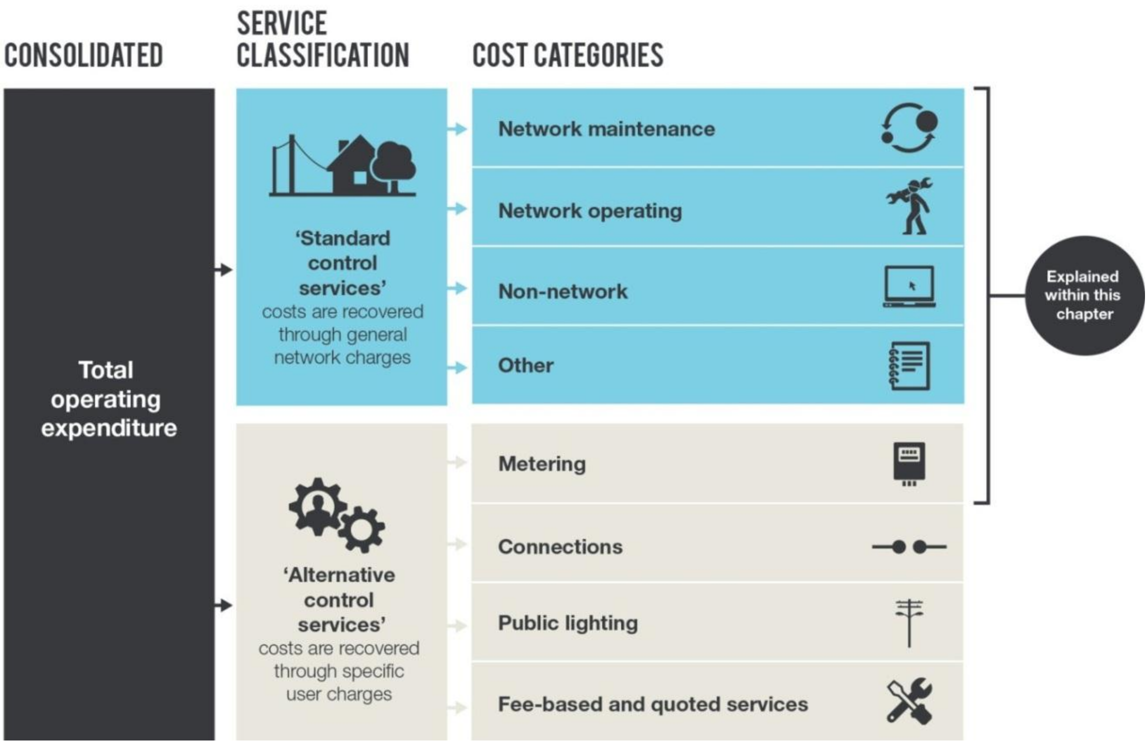
269. To comply with the NER[166] and to assist the AER in assessing our forecast operating expenditure, we have captured our costs to these categories, and allocated these to the relevant services using our approved cost allocation methodology (**CAM**).[167] The categories are:[168]

165 Including the operating expenditure objectives in NER cl 6.5.6(a).

1. **Network maintenance** - expenditure associated with conducting routine, non-routine and vegetation maintenance of and around our network, and responding to emergencies (such as outages caused by storms) to ensure we can meet our safety and service obligations and provide the level of service our customers expect
2. **Network operating** - expenditure associated with managing the design, planning and operations of the network, and providing training, safety and corporate support
3. **Non-network** - expenditure associated with the operation, maintenance and leasing costs of our IT systems, vehicles and property
4. **Other** - expenditure including levies and land taxes, insurance costs to manage specific risks and the debt-raising costs required to finance our capital program.

270. Figure 8–1 illustrates these expenditure categories.

Figure 8–1: JEN's operating expenditure categories



(1) Metering services operating expenditure are reported using consistent cost categories as distribution services.
(2) Operating expenditure relating to connections, public lighting and fee-based and quoted services are explained in other chapters of this regulatory proposal.

166 NER cl 6.5.6(b)(1) requires our forecast operating expenditure to comply with the requirements of any relevant regulatory information instrument

167 See Attachment 7-10

168 These operating expenditure categories align to the RIN operating expenditure categories. However these expenditure categories are different to those approved by the AER for the 2011 regulatory period. Attachment 8.3 explains how our forecast operating expenditure would be allocated into the previously approved expenditure categories consistent with the 2011 regulatory period.

8.3 APPROACH TO FORECASTING OPERATING EXPENDITURE

271. Once we capture our operating costs to the categories, we take the following steps to forecast our operating expenditure for the 2016 regulatory period:

1. For each expenditure category, we forecast this expenditure using a 'fit for purpose' method that ensures we identify the relevant drivers of each expenditure category and, where possible, are consistent with the AER's preferred methods
2. The forecast operating expenditure for each category to obtain our total forecast operating expenditure, consistent with the requirements in the NER

272. Section 8.3.1 explains the methods we used in step one—including the base, step and trend method and the specific year-on-year method—and the key variables and assumptions we used in applying each of these methods. Attachment 8–6 provides further details on each step change.

8.3.1 METHODS USED TO FORECAST COSTS FOR EACH EXPENDITURE CATEGORY

273. To develop our forecast operating expenditure for each expenditure category, we used two methods:

- **Base, step and trend method**—this uses a base year that reflects recurrent operating expenditure, and adjusts this to account for future changes in our circumstances and operating environment and changes in demand and other cost inputs over the regulatory period. To apply this method we:
  - Used 2014 as our base year, which is the most recent year for which full-year actual costs are available (or will become available) prior to the AER's final decision being made, and subtracted costs relating to non-recurrent events and circumstances that are not expected to endure
  - Trended the adjusted base year costs forward, escalating or de-escalating the forecast to reflect changes in key cost inputs, productivity improvements and output growth
  - Added or subtracted step changes in operating expenditure not captured by the base year expenditure or trend escalation, to reflect other expected events or programs over the 2016 regulatory period, such as changes to regulatory obligations, our operating environment or customer preferences identified through our engagement with them
- **Specific year-on-year method**—for items where base year costs are not representative of future costs, we estimated the forecast incremental costs for each year of the 2016 regulatory period, and added them to the output of the base, step, trend method.[169]

274. Table 8–2 shows the method we used to forecast each cost item within the expenditure categories. As it indicates, we used the AER's preferred base, step and trend method to forecast the majority of our operating costs. We used the specific year-on-year method to forecast the remainder of this expenditure.[170]

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169 These items include GSL payments, demand side management costs, self-insurance and the debt raising costs to finance our capital program (see Attachment 8–7)

170 We have used specific year-on-year forecasts for our step change forecasts.

Table 8–2: Methods use for each operating expenditure category

Cost categories	Base, step and trend method	Specific year-on-year method
Network maintenance	•	
Routine maintenance	•	
Non-routine maintenance	•	
Emergency response	•	
Vegetation management		
Network operating	•	
Management	•	
Network planning	•	
Network control and operational switching	•	
Project governance and related functions	•	
Quality and standard functions	•	
Other	•	
Corporate overheads (excluding IT)		
Non-network	•	
Information technology (IT)	•	
Motor vehicles	•	
Buildings and property		
Other	•	
Levies (incl. license fees)		•
GSL payments		•
Demand side management		•
Self-insurance		•
Debt raising costs	•	

8.3.2 KEY VARIABLES AND ASSUMPTIONS USED IN APPLYING BASE, STEP AND TREND METHOD

275. The NER require us to set out the forecasts of the key variables we relied on in applying the base, step and trend method to forecast our operating expenditure, as well as the methods and assumptions we used to forecast these variables.[171] We have identified six variables, which account for the majority of the difference between our historical (expected) operating expenditure and our forecast operating expenditure for the 2016 regulatory period:

- The base year operating expenditure that reflects recurrent operating costs incurred by a prudent service provider acting efficiently (see section 8.3.2.1)

171 NER cl S6.1.2(3)

- Real cost escalators to reflect changes in key cost inputs across the economy over time
- Expected productivity improvement over time
- The interaction between forecast operating expenditure and capital expenditure
- The expected increase in network size, and
- Other change factors (or step changes), including those not captured by the base year expenditure or trend escalation relating to events or programs that are expected to incur over the 2016 regulatory period.

276. Table 8–3 summarises the key variables and our assumptions. The following sections outline each variable in more detail. Attachment 8–2 provides more detail.

Table 8–3: Key variables and assumptions used in applying base, step, trend method

Key variable	Our assumption
Base operating expenditure	We propose to use 2014 as the base year—this is the most recent year for which full-year actual costs are available prior to the AER's final decision being made. We have subtracted costs relating to non-recurrent events and circumstances that are not expected to endure
Real cost input changes	Weighted average change of 0.98% per year based on expert advice from external economic forecaster BIS Shrapnel (see Attachment 8–8)
Expected productivity improvement	0.89% per year based on expert advice from our external consultant Huegin (see Attachment 8-5)
The interaction between forecast operating expenditure and capital expenditure	We actively manage trade-offs between our capital expenditure and operating expenditure.[172] For example, we actively pursue demand management solutions through our Distribution Annual Planning Report (**DAPR**) and programs that seek to defer capital intensive network augmentation (see Box 7–3). We also seek to expand the allowances in the DMEGCIS, to pursue further opportunities (see Attachment 5–3 and Attachment 5–5). The new CESS also provides powerful incentives for us to seek out new opportunities to make efficient capital expenditure and operating expenditure trade-offs.
Expected growth in our network	Weighted average change of 2.24% per year based on internal forecasts of growth in our network's system physical capacity and expert advice from ACIL Allen (**ACIL**) on growth in our customer numbers over the 2016 regulatory period (see Attachment 3–3)
Other change factors (or step changes)	An increase of $30.3m ($2015) in the 2016 regulatory period to meet new regulatory obligations and respond to changes in our operating environment and customers' preferences (see Table 8–5 and Attachment 8–6)

8.3.2.1 Base year operating expenditure

277. We used actual operating expenditure incurred in 2014 as the base year for developing our forecast operating expenditure. We consider 2014 to be an appropriate base year and consistent with the NER[173] because it is:

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172 See Box 7–3 for capex / opex trade-offs

173 NER cl 6.5.6(a) requires our forecast operating expenditure to achieve the 'operating expenditure objectives'.

- The latest information available at the time of preparing the forecast, consistent with the AER's expenditure forecast assessment guideline[174]
- Representative of our recurrent operating expenditure (including the future level of activity in vegetation management, emergency response or maintenance) once adjusting for one-off costs (including those of preparing this regulatory proposal)
- Consistent with the costs incurred by prudent service provider acting efficiently (see Box 8–1 and Attachment 8–2 for further information and expert analysis on the efficiency of the base year).

Box 8–1: Our base year operating expenditure is prudent and efficient[175]

Our base year operating expenditure is consistent with the costs incurred by prudent service provider acting efficiently for two reasons:

1. **We have a strong governance framework and set of internal policies** that ensure we incur operating expenditure only where it is necessary, examples include:
   - PAS-55—this world-class accreditation—indicates we have sound processes in place to facilitate compliance with relevant governance frameworks (see chapter 7 and Attachment 7–2 for more information)
   - Sound budgeting and forecasting processes—these processes facilitate proper cost control and management as well as timely management and statutory reporting consistent with accounting standards
   - Delegation of financial authority—effective controls are in place to ensure only personnel with appropriate delegated financial authority approve expenditure
   - An efficient procurement policy and leading procurement practices—we use outsourcing and competitive tendering with strict evaluation criteria to ensure high-quality services and market-tested prices
   - Sound recruitment policies—including a well-documented process and a dedicated committee to approve all new employee positions
   - Step changes—we assessed our current compliance and identified additional new obligations (and associated step changes) and consider alternatives available before choosing the most appropriate option to ensure we can meet our obligations and customer expectations.
2. **Our analysis and expert advice indicates that we are efficient:**
   - Despite being the smallest distribution network service provider in Victoria our efficiency (productive, allocative or dynamic) is comparable with our network peers
   - The AER's latest annual benchmarking report ranks JEN as an efficient electricity distribution business[176] across the NEM (see Attachment 2-1).

174 The AER notes (on page 92 its forecast expenditure assessment guideline) that "*Typically, we use the revealed costs of the second or third last year in a regulatory control period as the base year. The second last year is the most recent available data at the time of the determination and likely to best reflect the forecast period. Sometimes, we use the third last year, being the most recent year of available data when the NSP submitted its regulatory proposal).*"

175 The AER notes (on page 43 of its forecast expenditure assessment guideline) that "*Prudent expenditure is that which reflects the best course of action, considering available alternatives. Efficient expenditure results in the lowest cost to consumers over the long term. That is, prudent and efficient expenditure reflects the lowest long term cost to consumers for the most appropriate investment or activity required to achieve the expenditure objectives.*"

176 AER *Electricity distribution network service providers, Annual benchmarking report*, November 2014

8.3.2.2 Real cost input changes

278. The base year operating expenditure reflects the current prices of our cost inputs. To adjust this base to account of real changes in these input costs likely over the 2016 regulatory period, we:

- Mapped the base year expenditure into cost type (for example, internal labour, contracted services, materials)
- Assigned weights to each cost type, based on historical data
- Identified an appropriate cost escalator index or measure of input costs for each cost type
- Commissioned expert advice on movements real cost input changes (or cost escalators) over the 2016 regulatory period
- Applied a 'blended' weighted forecast cost escalator[177] to each of the operating expenditure categories.

279. Table 8–4 lists the real cost escalator we applied to each cost type and the resulting average annual change in cost. Attachment 8–8 provides expert analysis of the cost escalators, including the method and assumptions used to develop these escalators.[178]

Table 8–4: Escalators used to account for real input cost changes (per cent)

Cost type	Nature of the cost	Real cost escalator applied	Average annual change
Labour	Cost of internal labour	Victorian wage price index for utilities industry	1.58
External labour	Cost of external labour	Victorian wage price index for construction sector	1.57
Materials	Cost of materials used	A simple average of raw commodities escalators	-0.11

(1) For materials, BIS Shrapnel forecasts real cost escalators by composite material (e.g. aluminium, copper, wood, etc.). For our operating expenditure forecasts, we applied a 'general' material cost escalator, using a simple average of all composite material escalators.

(2) Averages annual changes shown are arithmetic.

8.3.2.3 Expected productivity improvement

280. The base year operating expenditure reflects the current efficiency in our operations. As section 8.3.2.1 outlines, we are satisfied that our base year operating expenditure is consistent with the costs incurred by prudent service provider acting efficiently.

281. Additionally, our private ownership, our customers' expectations and the regulatory framework provide us with strong incentives to continue to make further improvements in our productivity. The AER's Expenditure Forecast Guideline also requires that our forecast operating expenditure reflect the expected improvements in productivity across our industry.[179]

282. In response to these incentives, we sought expert analysis on the productivity improvements attainable to us over the 2016 regulatory period. This analysis—from Huegin—indicates that we can achieve productivity improvements averaging 4.5% over the period (see Attachment 8–5).

[177] The 'blended' weighted forecast cost escalator = ∑(Wi x Ei), where Wi = relative weight of each opex cost type (for example. labour versus. materials) and Ei = cost escalator index or measure for that cost type.

[178] NER cl S6.1.2(3)

[179] NER cl 4.2.3, "Expenditure Forecast Assessment Guideline for Electricity Distribution" (Nov, 2013), AER

283. In line with this analysis, we have applied these expected productivity improvements to the forecast operating expenditure. These forecast productivity gains will be passed directly through to our customers and reflect our commitment to efficiently managing our business at lowest sustainable costs over the 2016 regulatory period.

8.3.2.4 Interaction between forecast operating expenditure and capital expenditure

284. The NER require us to identify and explain any significant interaction between our forecast operating expenditure and forecast capital expenditure programs.[180,181] In developing our forecast operating expenditure for the 2016 regulatory period, we considered this interaction. We note that as a proportion of our total expenditure, operating expenditure has declined materially—from more than 50% of our total forecast expenditure over 1996 to 2000 to approximately 40% in the 2016 regulatory period.

285. Additionally, the incentive schemes in the regulatory framework (including the EBSS and CESS) encourage us to optimise our forecast operating expenditure and capital expenditure in a way that lowers our total expenditure, and improves our total productivity or productive efficiency. That is, they ensure we do not aim to simply minimise operating expenditure at the expense of capital expenditure.

286. Our approach to optimising the balance between operating and capital expenditure includes:

- Emphasising an active risk management process that targets a combination of asset replacements (capital expenditure) and enhanced asset inspections (operating expenditure) to address asset aging
- Ongoing improvements to the way we capture employee time-writing data[182] to better understand our costs (that is, whether our employees are working on capital projects or operating activities)
- Ongoing assessment of operating and capital expenditure trade-offs through robust economic cost-benefit analysis of whether we should invest further in our IT systems (capital expenditure) to deliver operating expenditure savings over time.

8.3.2.5 Expected growth in our network

287. Many of our operating activities, and expenditure, grow in line with the number of assets we need to operate and maintain and the number of customers we serve.

288. We examined two key factors that contribute to our operating costs including the network's system physical capacity, and forecast growth in the number of customers we will need to serve.

289. We then forecast the growth in these factors (with expert advice from ACIL on the expected growth in customer numbers),[183] and weighted these factors (based on regression estimates from ACIL) to provide an overall forecast growth of 2.24% per year. Attachment 8–3 provides further detail on internal estimates and how we forecast the annual output growth rates (see Attachment 3–2 for ACIL's expert analysis).

8.3.2.6 Other change factors (or step changes)

290. Other change factors (or step changes) include increases or decreases in our operating expenditure associated with meeting new regulatory obligations, or responding to changes in our operating environment and customers'

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180 NER cl S6.1.3(1)

181 NER cl 6.5.6(e)(7) requires the AER must have regard to whether we have explored the substitution possibilities between operating and capital expenditure

182 Employee time recording

183 ACIL advised that our customer base is expected to grow by 1.29% per year in the 2016 regulatory period.

preferences.[184] These factors represent forecast required operating expenditure not captured by the base year expenditure or trend escalation, and therefore they are added to the trend adjusted base year.

291. Our forecast operating expenditure includes 12 other change factors that together account for $30.34m or 6.1% of our forecast operating expenditure for distribution services in the 2016 regulatory period. The most significant of these factors are:

- Additional inspection and maintenance programs required to ensure we meet new safety and technical standards to maintain our safety and service levels
- Continuation of the successful customer, stakeholder and community engagement activities we undertake during 2014 required to respond to customer preferences and meet new regulatory requirements
- New expenditure to assist vulnerable customers in response to customers' preferences
- New expenditure for new or significant improvements in relation to security or our proposal to meet new regulatory requirements to better manage and serve our customers.

292. We do not foresee any other significant change factors (or step changes) that will affect our operating expenditure for metering services over the 2016 regulatory period.

293. Table 8–5 summarises the step changes in our operating expenditure and incremental costs we are proposing to include in our forecast operating expenditure. Attachment 8–6 provides additional detail on these step changes.

Table 8–5: Step changes included in forecast operating expenditure ($2015, $millions)

Change factor	Reason	Total over 2016 regulatory period
Enhanced inspection and maintenance program of aging assets	To meet new safety and technical standards, and target assets that are in need of replacement to maintain our safety and service	11.41
Regulatory proposal	To meet the requirements of running the 2021-25 price review (including drafting the relevant regulatory proposal documents)	8.03
Vulnerable customer assistance	To assist vulnerable customers in response to customer preferences	1.01
Vegetation Management	To comply with changes in Electricity Safety Amendment (Bushfire Mitigation) Act 2014 and proposed Electricity Safety (Electric Line Clearance) Regulations 2015	5.63
Targeted Demand Response	Implementing a demand response (DR) programme to mitigate network constraints and limit potential risk of supply interruption to customers	0.71
Insurance premiums	To prudently and effectively manage the emerging risks posed to our business	0.17

184 NER cl 6.5.6(e)(5A) requires us to outline the extent to which our operating expenditure forecast includes expenditure to address the concerns of electricity consumers that we identified in the course of its engagement with electricity consumers

Change factor	Reason	Total over 2016 regulatory period
Customer, stakeholder and community engagement	To design and deliver customer engagement with respect to best practice principles and identification of relevant concerns in preparing the 2016 regulatory proposal	0.93
Implementing new tariffs	On 27 November 2014, the AEMC made a rule that introduced new pricing arrangements to the NER. The intent of the rule change is to drive cost-reflective network prices and improve the transparency of distributors pricing information. This has created new obligations on distribution businesses, including JEN.	2.46
Total step changes		**30.34**

8.3.3 KEY VARIABLES AND ASSUMPTIONS FOR SPECIFIC YEAR-ON-YEAR FORECASTS

294. The NER require us to set out the forecasts of key variables we used in applying the year-on-year approach to forecast operating expenditure, as well as the forecasting methods and assumptions we applied.[185]

295. We used the specific year-on-year method to forecast only a small portion (less than 10%) of our total forecast operating expenditure. This expenditure relates to cost items such as GSL payments, demand side management, self-insurance and debt raising costs. In developing specific year-on-year forecasts for these cost items, we were guided by internal historical trend analysis or relevant AER-preferred estimation techniques.

8.4 PROPOSED OPERATING EXPENDITURE FORECASTS

296. Table 8–6 and Table 8–7 set out our forecast operating expenditure for distribution services and metering services by expenditure category. These expenditure programs represent a prudent and efficient level of expenditure required to meet our obligations and requirements, maintain existing service levels and to reflect our customers' preferences for the 2016 regulatory period.

Table 8–6: Forecast operating expenditure for distribution services[186] ($2015, $millions)

Distribution services	2016	2017	2018	2019	2020	Total
Network maintenance	**19.31**	**19.64**	**20.07**	**20.50**	**20.94**	**100.46**
Routine maintenance	6.17	6.28	6.40	6.51	6.63	**31.98**
Non-routine maintenance	3.92	4.02	4.12	4.22	4.32	**20.62**
Emergency response	3.84	3.94	4.05	4.15	4.25	**20.24**
Vegetation management	5.38	5.39	5.51	5.62	5.73	**27.62**
Network operating	**56.36**	**55.40**	**57.50**	**61.11**	**63.47**	**293.84**
Network overheads	34.28	32.73	34.22	37.23	38.98	**177.43**

185 NER cl S6.1.2(3)

186 Forecast distribution operating expenditure includes a portion of costs for activities such as metering and supply abolishment. The metering costs (now included in distribution services) were previously recovered through the CROIC mandate (see Box 3–1).

Distribution services	2016	2017	2018	2019	2020	Total
Corporate overheads (excluding IT)	22.08	22.67	23.28	23.88	24.49	**116.41**
Non-network	**16.62**	**17.08**	**17.57**	**18.08**	**18.59**	**87.95**
Information technology (IT)	11.75	12.08	12.44	12.82	13.19	**62.28**
Motor vehicles	0.57	0.59	0.60	0.62	0.63	**3.01**
Buildings and property	4.30	4.42	4.53	4.65	4.76	**22.66**
Other	**3.08**	**3.23**	**3.36**	**3.48**	**3.60**	**16.76**
Levies (incl. licence fees)	1.56	1.60	1.65	1.69	1.73	**8.24**
GSL payments	0.07	0.07	0.07	0.07	0.07	**0.35**
Demand side management	0.17	0.22	0.22	0.22	0.22	**1.04**
Self-insurance	-	-	-	-	-	**-**
Debt raising costs	1.27	1.34	1.43	1.50	1.58	**7.13**
Total forecast operating expenditure	**95.37**	**95.36**	**98.51**	**103.18**	**106.60**	**499.01**

Table 8–7: Forecast operating expenditure for metering services[187] ($2015, $millions)

Metering services	2016	2017	2018	2019	2020	Total
Network maintenance	**1.03**	**1.06**	**1.09**	**1.13**	**1.17**	**5.47**
Routine maintenance	1.03	1.06	1.09	1.13	1.17	**5.47**
Non-routine maintenance	-	-	-	-	-	**-**
Emergency response	-	-	-	-	-	**-**
Vegetation management	-	-	-	-	-	**-**
Network operating	**4.65**	**4.79**	**4.94**	**5.12**	**5.29**	**24.79**
Network overheads	3.80	3.92	4.04	4.19	4.32	**20.27**
Corporate overheads (excluding IT)	0.85	0.87	0.90	0.93	0.96	**4.52**
Non-network	**4.87**	**5.02**	**5.18**	**5.37**	**5.54**	**25.99**
Information technology (IT)	4.87	5.02	5.18	5.37	5.54	**25.99**
Motor vehicles	-	-	-	-	-	**-**
Buildings and property	-	-	-	-	-	**-**
Other	**0.26**	**0.21**	**0.18**	**0.16**	**0.14**	**0.95**
Levies (incl. licence fees)	-	-	-	-	-	**-**
GSL payments	-	-	-	-	-	**-**
Demand-side management	-	-	-	-	-	**-**
Self-insurance	-	-	-	-	-	**-**

187 Forecast metering operating expenditure excludes a portion of costs that were previously recovered through the CROIC mandate (see Box 3–1).

Metering services	2016	2017	2018	2019	2020	Total
Debt raising costs	0.26	0.21	0.18	0.16	0.14	**0.95**
Total forecast operating expenditure	**10.81**	**11.08**	**11.40**	**11.78**	**12.14**	**57.21**

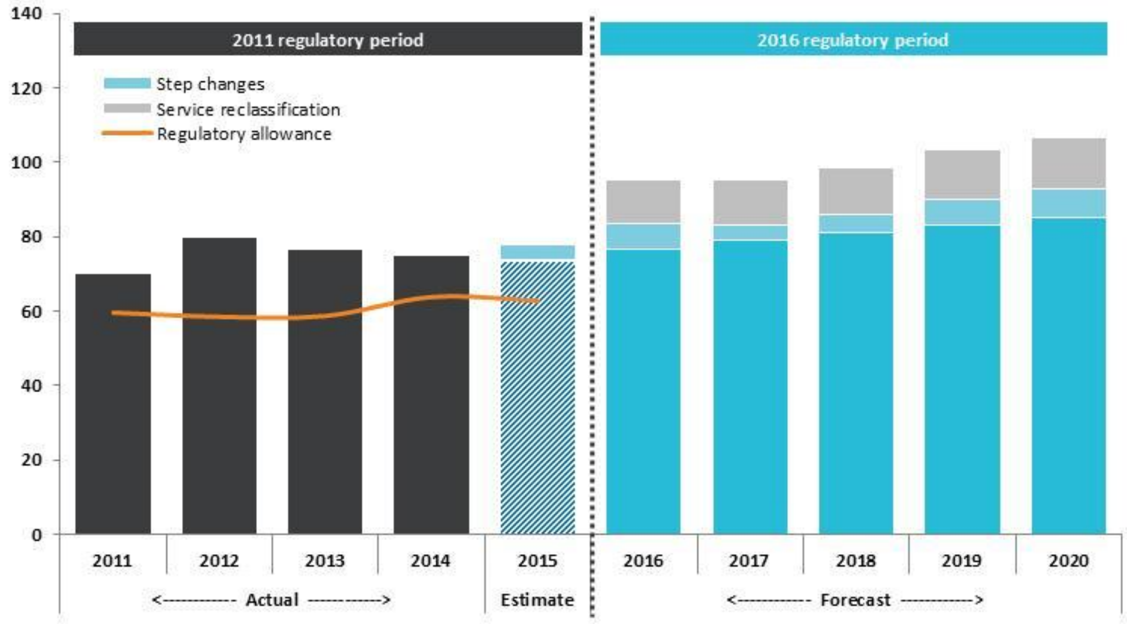
8.5 DIFFERENCE BETWEEN ACTUAL AND FORECAST OPERATING EXPENDITURE IN THE 2011 AND 2016 REGULATORY PERIODS

297. In forecasting our operating expenditure for the 2016 regulatory period, we analysed the differences between our actual (expected) operating expenditure for distribution services over the 2011 regulatory period and the allowance for this expenditure approved by the AER for this period.

298. Our total actual operating expenditure in providing our distribution services in the 2011 regulatory period is expected to be $379m. This is $43m or 13% higher than the total allowance approved by the AER. As Figure 8–2 highlights, our forecast operating expenditure for the 2016 regulatory period is higher than our actual expenditure in the 2011 regulatory period.

299. Section 8.5.1 outlines the key factors that led to the higher operating expenditure in the 2011 regulatory period, and are likely to impact our operating expenditure in the 2016 regulatory period (see Attachment 8–1 for more details).

Figure 8–2: Comparison of actual and forecast operating expenditure for our distribution services over the 2011 and 2016 regulatory periods ($2015, $millions)



8.5.1 FACTORS THAT LED TO HIGHER THAN ALLOWED OPERATING EXPENDITURE FOR DISTRIBUTION SERVICES IN THE 2011 REGULATORY PERIOD

300. As chapter 2 outlines, for the past two decades, our private ownership together with our customers' expectations and the regulatory framework have provided us with strong incentives to invest in and operate our network business efficiently. In addition, we have been subject to an EBSS for the past four price determination

periods (commencing in 1995). This scheme creates specific incentives for us to continuously improve our operating efficiency and minimise our operating expenditure—through a fair sharing of efficiency gains and losses between our shareholders and our customers.[188]

301. In response to these incentives, we actively review our strategies, policies and businesses processes to identify opportunities to minimise our operating expenditure over the 1995, 2000, 2005 and 2011 regulatory periods. As a result, we have delivered continued expenditure efficiencies and service performance improvements across our network.[189]

302. However, our energy market is changing and we faced a range of unforseen regulatory, market and commercial challenges over the 2011 regulatory period. These include new regulatory obligations and requirements, less predictable demand and peak demand outlooks and the loss of some of the commercial efficiencies or synergies in asset management we had previously benefited from.[190] Some of these changes could not have been reasonably foreseen when we were developing our proposal for the 2011 regulatory period, nor when the AER was making its final decision on our proposal.[191] Box 8–2 and Attachment 8–1 provide further detail on these factors.

303. Despite these challenges, we were able to achieve estimated efficiency gains of $23.1m ($2015). Consistent with the EBSS, these gains will be shared with our customers in the 2016 regulatory period.

Box 8–2: Key differences between our actual and allowed operating expenditure for distribution services in 2011 regulatory period

The difference between our actual (expected) operating expenditure in providing distribution services in the 2011 regulatory period and the AER-approved allowances is evident across the four broad categories of operating expenditure:

- **Network maintenance**. We expect to be spend approximately $41m ($2015) above the AER's assessed allowance due to:
  - Unforeseen (or uncontrollable) major network events such as storm damage to our Broadmeadows field depot (in late 2011), separate pole fire events and significant wind storm events
  - New compliance obligations from ESV and recommendations arising from the Royal Commission into the 2009 bushfire incidents
  - Additional safety and regulatory compliance tasks, including bushfire mitigation and electric line clearance planning, fire-factor (**F-factor**) monitoring and ESV auditing and investigations.[192]
  - Our commitment to improve our response times in the field as well as improvements to our coordination centre through the realignment of our emergency management system (**EMS**).
- **Network operating.** We expect to be on par (overspend of approximately $2m ($2015)) with what the AER's regulatory allowance:

188 Chapter 5 provides more information on the EBSS.

189 For example, in the 2006 regulatory period we responded to the incentive mechanisms by achieving efficiency benefits or synergies from the provision of a large range of services to other businesses, including United Energy. These synergies supported us achieving a 16.9% saving in operating expenditure relative to the approved allowance, with these savings being shared with our customers in the 2011 regulatory period.

190 From 1 July 2011 Jemena Asset Management—JEN's asset manager—lost a large share of its business with UED

191 The AER made its Final Decision on our proposal for the 2011 regulatory period on 29 Oct 2010.

192 JEN responded to the AER's queries on the actual compliance costs associated with these new obligations—see (JEN's) "*Response to questions concerning bushfire regulations and productivity, 3 February 2015*".

- Our commitment to proactively respond to the EBSS incentives and reduced our opex on a sustainable basis
- Initiatives to offset the increases in network operating costs caused by factors, such as:
  - Lost synergies resulting from changes in the regulatory regime
  - Management decisions to improve aspects of our service performance and reporting—including control centre monitoring, customer service, asset regulatory technical compliance, and operational activity cost reporting
  - Regulatory obligations—particularly related to regulatory reporting requirements, through four additional RINs—requiring significant additional resourcing efforts, audits and costs
- Understated cost considerations by the AER in assessing allowances in the 2011–15 EDPR period, including no provision made by the AER for the payment of a management fee—to compensate our shareholders for overseeing and providing strategic guidance on the overall operation of our network—and related party margins.

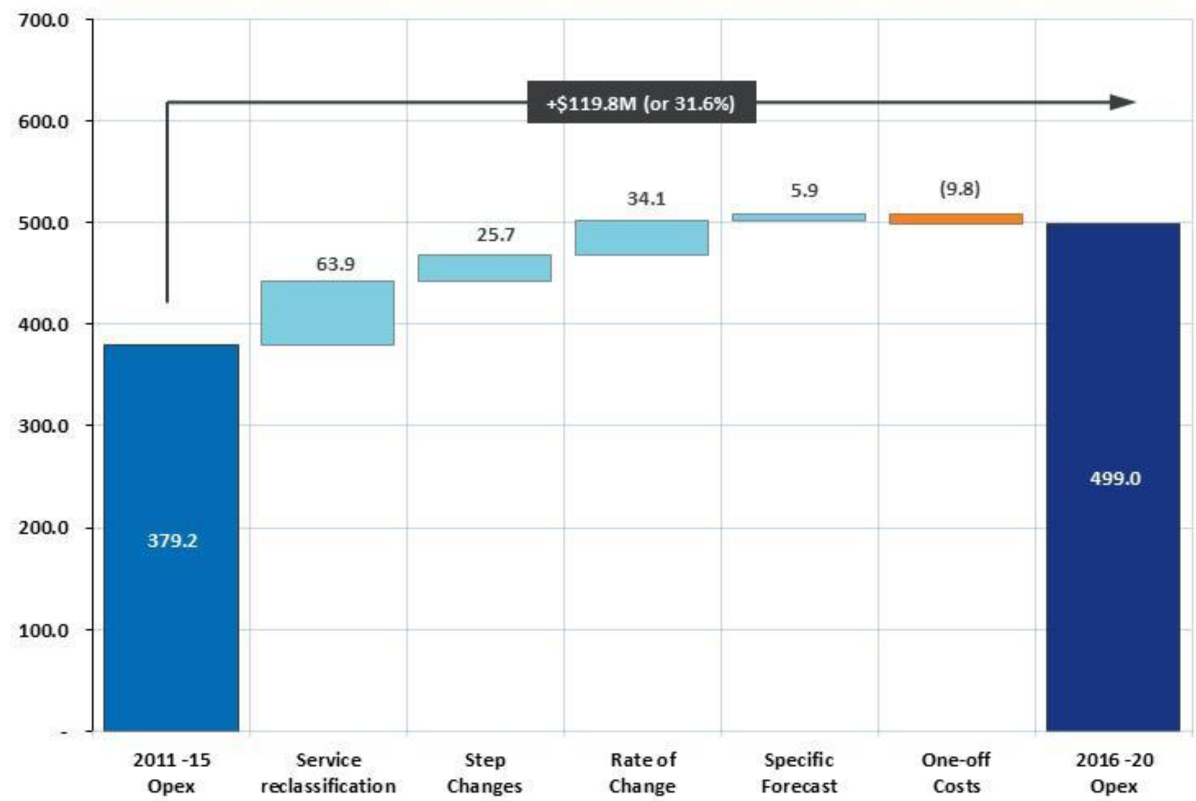
8.5.2 FACTORS LIKELY TO IMPACT OUR OPERATING EXPENDITURE IN 2016 REGULATORY PERIOD

304. As our energy market continues to change, a number of factors are likely to drive increases in our forecast operating expenditure for the 2016 regulatory period, including service reclassification[193] between our distribution and metering services, higher uncontrollable costs (through debt raising costs to fund our capital program), and increased real costs.

305. Figure 8–3 summarises of the key factors and their contribution to the increase in our forecast operating expenditure for the 2016 regulatory period.

[193] In the 2011 regulatory period the process for allocating costs was outlined under the CROIC (see Box 3–1) and the NER. During the 2016 regulatory period costs are allocated by the NER only. Service reclassification is simply the process of ensuring costs are allocated to the appropriate service under this new regime.

Figure 8–3: Contribution of key factors to our forecast operating expenditure for our distribution services[194] for the 2016 regulatory period ($2015, $millions)



(1) One-off costs relate to items that are non-recurrent in nature and are removed off the actual base year (2014) expenditure. The total amounts relates to the 'trended' amount of these one-off costs, if they were included in the base year (used for trending).

194 Excludes ACS metering services (see section 11.7)

9. PROPOSED RATE OF RETURN

Key messages

- We need to be able to earn a fair rate of return on capital to continue investing in our network in a manner that best promotes our customers' long-term interests.
- We propose a rate of return of 7.18% in the first year of the 2016 regulatory period—which is significantly lower than our allowed rate of return for the current regulatory period (10.33% per annum). This reflects the easing in market conditions after heightened perceptions of risk during the global financial crisis.
- We also propose that our rate of return be updated in each of the remaining years to account for movements in the return on debt and ensure the benefits of further reductions in interest rates and perceptions of risk are passed on to our customers.
- Our proposed rate of return complies with all requirements in the NER, and was calculated using an approach consistent with many elements of the AER's rate of return guideline. However, we departed from this guideline in some ways, particularly when estimating the return on equity component, where we consider an alternative approach is more prudent and better reflects the risks we face and investor practice.
- We are confident our proposed rate of return reflects the efficient costs associated with borrowing in debt markets and providing returns to investors in equity markets, and reflects the risks associated with providing distribution and metering services to our customers over the 2016 regulatory period—and therefore is likely to promote the long-term interests of our customers.

306. The rate of return is a key input used to calculate the return on capital allowance – the largest 'building block cost' in our proposed annual revenue requirement (see chapter 6). The rate of return represents the costs of funding investments in our network through borrowings from debt markets investments from equity holders. Both of these funding costs are influenced by financial market conditions – and like all businesses, we must pay the going rate for debt and equity capital.

307. The NER[195] require us to propose a benchmark rate of return that (among other things) reflects the funding costs for a benchmark efficient entity providing distribution and metering services to our customers over the 2016 regulatory period. Using a benchmark rate of return (rather than JEN's actual funding costs) means:

- We have an incentive to 'beat the benchmark' by continually improving the efficiency of our funding costs, much like we have for other costs such as capex and opex, and
- We do not need to disclose commercially sensitive information in our proposal (such as the actual interest rate we have agreed to pay for our debt over the 2016 regulatory period).

308. The AER also publishes a rate of return guideline that sets out the methodologies, financial models and market data it intends to use in assessing our proposed rate of return.[196] We are required to explain any areas where we agree and disagree with the rate of return guideline.[197]

195 NER cl 6.5.2 (b) – (l)

196 AER, *Better regulation, Rate of return guideline*, December 2013

197 NER cl S6.1.3 (9) requires us to outline where we have departed from the methodologies set out in the Rate of Return Guideline and the reasons for that departure.

309. In developing our proposed rate of return, we were guided by the requirements in the NER and the rate of return guideline. We also analysed financial market conditions for debt and equity capital over the 2016 regulatory period, and the changes occurring in our energy market in this period and beyond.

310. Section 9.1 provides an overview of our proposed rate of return. The following sections outline the approach we used to calculate this rate of return, and explain how we calculated the return on equity and return on debt components in more detail, including where and why our approach differs from the rate of return guideline.

9.1 OVERVIEW OF PROPOSED RATE OF RETURN

311. Our proposed rate of return for distribution and metering services over the 2016 regulatory period (shown in Table 9–1) is lower than our allowed rate of return for the 2011 regulatory period. This reflects the easing in market conditions following the heightened perceptions of risk in global and domestic financial markets during the global financial crisis from 2008 to 2010. Our proposed rate of return, which will be updated annually to account for movements in the return on debt, ensures that the benefits of reduced interest rates and some reduced perceptions of risk are passed on to our customers.[198]

Table 9–1: Proposed rate of return ('nominal vanilla WACC') for distribution and metering services (per cent)

Parameter	Proposed value
Return on equity	9.87
Return on debt	5.39
Inflation	2.52
Leverage	60.00
Gamma[199]	25.00
Corporate tax rate	30.00
Nominal vanilla WACC[200]	**7.18**

(1) Return on debt, return on equity, and nominal WACC estimated using data from the sample averaging period of the 20 business days to 31 January 2015 (inclusive).

(2) Further detail on the proposed averaging period is provided in Attachment 9–3.

312. This proposed rate of return complies with all requirements in the NER.[201] In particular, it:

- Reflects the financing costs of a benchmark firm with a similar degree of risk (the 'allowed rate of return objective')
- Has been calculated using a weighted average of the return on equity and the return on debt
- Is determined on a nominal vanilla basis
- Incorporates an estimate of the value of imputation credits ('gamma') consistent with the market's valuation

198 The proposed rate of return will also be used to determine the building block costs and revenue requirements for our public lighting services (see chapter 11).

199 See section 9.2.1.3

200 This rises to 7.19 per cent when the return on equity is rounded to one decimal place (i.e. 9.9 per cent) in the AER's PTRM.

201 NER cl 6.5.2 (b) – (l)

- Reflects prevailing market conditions for equity funding and a combination of prevailing and historical market conditions for debt funding.

313. In addition, the proposed rate of return is consistent with some (but not all) areas of the rate of return guideline (see Table 9–2). The key differences between the approach and assumptions we used to calculate the rate of return and the rate of return guideline relate to the return on equity component. In particular, we:

- Based our estimate on the outputs of a range of equity models as we consider this is a more prudent approach given no one model captures all relevant information or reflects reality perfectly
- Used a higher value for the equity beta to reflect the risks facing a benchmark efficient firm providing distribution and metering services to our customers over the 2016 regulatory period
- Used a lower value for gamma that better reflects how investors value imputation credits.

314. We are confident the proposed rate of return reflects the efficient costs associated with borrowing in debt markets and providing returns to investors in equity markets—and reflects the risks associated with providing distribution and metering services to our customers over the 2016 regulatory period. Therefore, we consider that using the proposed rate of return to calculate the return on capital allowance of the ARR is likely to promote the long-term interests of our customers.

Table 9–2: Our proposed rate of return for the 2016 regulatory period compared with the rate of return guideline

Approach or parameter	AER rate of return guideline	JEN proposal
Return on equity		
Models	Continue to use the Sharpe–Lintner CAPM to estimate a starting point and a range for the expected return on equity, but have regard to other information by either informing the parameter estimates or using it as a crosscheck on the overall return on equity	Use weighted average of four relevant models: • SL-CAPM • Black CAPM • Fama-French three-factor model • Dividend discount model
Equity beta	0.70	0.89
Market Risk Premium (**MRP**)	6.50%	8.17%
Gamma	0.50, although the AER's recent draft decisions for the NSW and ACT electricity networks proposes revising this down to 0.40	0.25
Nominal risk free rate	Annualised yields on 10-year Commonwealth Government securities over 20-day sampling period, sourced from the Reserve Bank of Australia (**RBA**)	Consistent with rate of return guideline
Return on debt		
Term to maturity	10-year term	Consistent with rate of return guideline
Credit rating	BBB+	BBB
Data source	Use a third-party data source. The AER's recent draft decisions for the NSW and ACT electricity networks propose taking an average of Bloomberg and RBA data	For the first averaging period, select the independent third-party estimate or combination of estimates that best fits observed bond data (consistent with Australian Competition Tribunal

Approach or parameter	AER rate of return guideline	JEN proposal
		decisions on the debt risk premium). For subsequent averaging periods, use the approach from the recent draft decisions, unless there is a material divergence between estimates from the two sources – in which case automatically select the independent third-party estimate or combination of estimates that best fits observed bond data
Measurement approach	Trailing average portfolio approach with the length of the trailing average to be 10 years	Consistent with rate of return guideline
Implementation	10-year trailing average approach with transition over 10 years	Consistent with rate of return guideline, except with a transition from the hybrid approach rather than the rate on the day approach
Annual update	Tariffs update each year to reflect the new return on debt estimated using the trailing average portfolio approach	Consistent with rate of return guideline, except with a one-year lag so that all relevant data can be reflected in tariffs
Inflation	N/A	Geometric average of forecast annual inflation, but subject to review if current market conditions remain
Leverage	60.00%	Consistent with rate of return guideline
Corporate tax rate	N/A	30.00%
Nominal vanilla WACC[202]		**7.18%**

9.2 PROPOSED RETURN ON EQUITY

315. Our proposed return on equity for the 2016 regulatory period is 9.87% (compared with 11.1% for the 2011 regulatory period).[203] This component accounts for 40% of the proposed rate of return.

9.2.1 EQUITY MODELS AND ESTIMATION APPROACH WE USED

316. As it is not possible to directly observe the return investors expect for committing their money to a benchmark firm, we have used a range of models and other evidence to estimate a benchmark return on equity. We considered the risk associated with investments in services such as ours.

317. Consistent with the AEMC's guidance, we consider it prudent to use a range of models and evidence in estimating the benchmark return on equity. This is consistent with real-world practice in financial markets that recognises that all models are a simplification of the real world and that some approaches provide greater insight than others.[204]

202 This rises to 7.19 per cent when the return on equity is rounded to one decimal place (i.e. 9.9 per cent) in the AER's PTRM.

203 This value rounds to 9.9 per cent when input into the AER's PTRM.

204 AER, *Better regulation, Rate of return guideline – Explanatory Statement,* December 2013, p64.

318. In particular, we estimated the return on equity using four relevant models (see Box 9–1):

- Sharpe-Lintner capital asset pricing model (**SL-CAPM**), which the rate of return guideline suggests should be the starting point for estimating the return on equity
- Black CAPM
- Fama-French three factor model
- Dividend discount model.

319. We then calculated the simple average of these estimates to derive a single point estimate for the return on equity (see Table 9–3).

Table 9–3: Estimated return on equity by model and weighted average (per cent)

Model	Estimated return on equity	Weighting
SL-CAPM	9.32	25.00
Black CAPM	9.93	25.00
Fama-French model	9.93	25.00
Dividend discount model	10.32	25.00
Simple average	**9.87**	**100.00**

320. We consider using a simple average is appropriate given that no one model is perfect or provides all information relevant to estimating the return on equity. For instance, as explained in Attachment 9–2, there are material concerns with the accuracy of the SL-CAPM, which, if adopted without adjustment, would materially understate the return on equity required by investors in the benchmark entity. A simple average helps overcome (or minimise the impact of) such shortcomings.

321. In estimating our proposed return on equity, we sought to use an approach that:

- Is transparent and relatively simple to apply
- Uses a range of publicly available information
- Is likely to provide sustainable, stable and robust 'consensus' forecasts that provide stability in funding costs and reduce unnecessary volatility in our network prices.

322. Attachment 9–2 provides further details on our proposed return on equity and is supported by Attachments 9–3 to 9–13.

Box 9–1: Overview of the models used to estimate the return on equity

We used four relevant models to estimate our proposed return on equity:

1. **The SL-CAPM.** This model relies on the principle that rational investors will seek to minimise their level of risk for a given return. It requires the estimation of:
   - The risk free rate, which is the return investors would expect for committing their money to operations with no risk
   - The equity beta, which measures the relationship between the returns on an individual asset or firm with that

of the overall market, and

- The MRP, which is the additional return (over the risk free rate) that investors require for committing their money to the market portfolio of assets (or the risk equivalent to an ‘average firm’).

2. **The Black CAPM.** This model relaxes a key assumption underpinning the SL-CAPM—that investors can borrow and lend at the risk-free rate—which, in reality does not hold. Instead, it assumes that investors can short-sell (that is, borrow) assets. In addition to the parameters required for the SL-CAPM, the Black CAPM also requires an estimate of:

   - The zero-beta premium, which is the difference between the return on the risk-free asset and an asset that does not correlate with the overall market.

3. **The Fama-French model.** This three-factor model builds on the SL-CAPM by adding two further factors that investors consider relevant in practice:

   - The small minus big risk premia and beta exposure, which together measure how much extra return an investor requires from investing in assets with prices that act like small stocks rather than big stocks

   - The high minus low risk premia and beta exposure, which together measure how much extra return an investor requires from investing in assets with prices that act like value stocks rather than growth stocks.

4. **The dividend discount model.** This model takes a different approach to the three asset pricing models over by inferring the required return on equity from share prices. It starts with the assumption that share prices accurately reflect investor requirements by determining the discount rate needed to set the present value of all forecast dividends equal to the share price. It requires two inputs:

   - Current dividend yield, which is simply the value of dividends per share divided by the current share price

   - Forecast dividend growth, which is a forecast of how dividends will grow over time, including for inflation.

9.2.1.1 Nominal risk free rate

323. The risk free rate represents the return investors are likely to expect for committing their money to operations with no default risk. Three of the models we used (SL-CAPM, Black CAPM and Fama-French) require an estimate of the risk free rate.

324. The rate of return guideline suggests estimating the risk free rate using 10-year Commonwealth government securities (**CGS**) averaged over a short period of time close to the commencement of the regulatory period.

325. Consistent with this guideline, we have calculated the nominal risk free rate as 2.64%, using the annualised yield on 10-year CGS over the 20 business days to 30 January 2015 inclusive.[205]

326. Attachment 9–1 details our calculations of the risk free rate.

9.2.1.2 Market risk premium

327. While the risk free rate represents the returns investors expect for committing their money to operations with no default risk, in reality most investments involve risk.

328. The MRP represents the additional returns (over the risk free rate) that investors are likely to expect for committing money to firms in the market (or the risk equivalent to an ‘average firm’). As a result, it compensates an investor for the *systematic risk* of investing in the market.[206]

[205] These yields were the indicative mid rates published by the RBA.

329. Three of the models we used (SL-CAPM, Black CAPM and Fama-French) require an estimate of the MRP. The guidelines assume a point-estimate of the MRP of 6.5% derived from historical excess returns, survey evidence and estimates from the DDM applied to the market portfolio.

330. In contrast, we propose a value of 8.17%, derived by also considering historical returns to the market and estimates from independent expert reports. Attachment 9–2 details our MRP proposal.

9.2.1.3 Gamma

331. Gamma represents the value of imputation credits or 'franking credits' to investors. These credits are provided to investors for tax paid at the corporate level to off-set against their personal income tax.[207] If these credits are highly valued, the return investors expect by way of dividends and capital gains is lower than it might otherwise be.

332. Gamma is a function of the extent to which imputation credits created when companies pay tax are distributed to investors ('distribution rate') and the value of distributed imputation credits to investors who receive them ('theta').

333. Consistent with the rate of return guideline, we have calculated gamma using a distribution rate of 0.7. However, we have used a theta value of 0.35 which is lower than that favoured by the AER in its rate of return guideline. Consistent with recent independent reviews (including by the Australian Competition Tribunal)[208] and previous regulatory practice, our proposed value for theta represents the actual value of imputation credits to investors, rather than their notional face value or potential value. As a result, our value for gamma places a lower value on these credits than that favoured by the AER in its rate of return guideline.

334. We consider it is in our customers' long-term interests for investors to be sufficiently compensated for the costs of investing in the benchmark efficient firm (including for tax net of the value they ascribe to imputation credits). If they are undercompensated, we may not be able to fund the investments required to provide services that our customers value.

335. Attachment 6–4 provides further detail on our calculation of gamma and is supported by Attachments 6–7 and 6–8.

9.2.1.4 Equity beta

336. Like our interest costs, our proposed return on equity reflects the risk of investing in our industry because investors will expect a return that reflects the risk of their investment.

337. Assessing the riskiness of an industry can be a complex task – and is often the subject of significant debate. This risk can be estimated using a variety of models and market information, and is known as the 'equity beta'. The equity beta measures the riskiness of a business' returns relative to the market as a whole by analysing the correlation between the returns on an individual asset or firm with that of the overall market.[209]

338. The rate of return guideline assumes that shareholders investing in an energy network business expect lower returns than in the Australian market as a whole. In line with this view, the guideline suggests an equity beta of 0.70.

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206 Systematic risk is that which affects all firms in the market (such as macroeconomic conditions and interest rate risk) and cannot be eliminated or diversified away through investing in a wide pool of firms.

207 Australia has had an imputation tax system since 1 July 1987. It exists to avoid investors' corporate profits being taxed twice.

208 See discussion of these reviews and our gamma proposal in Attachment 6-4.

209 AER, *Better regulation, Rate of return guideline – Explanatory Statement*, December 2013, p73. In practice, equity beta is estimated relative to only the listed equity market, which may differ from that measured relative to the overall market.

339. However, we propose a higher equity beta of 0.82 because:

- We consider that an electricity utility – particularly in Victoria where our investment in smart meters is likely to facilitate the introduction of new energy market players and technologies – faces material additional risks that are relevant to investors when considering where to invest their money, including risks associated with the changes in the energy market and our role (see chapter 3 and Attachment 9–2)
- There is limited Australian data available to derive a reliable estimate, and to increase the sample size we have looked at international evidence
- The limited Australian data that is used to derive the AER's estimate is for a sub-sample of listed energy networks (now only four) that may not reflect the benchmark firm
- We consider that it is in our customers' long-term interests for investors to be sufficiently compensated for the risks of investing in the benchmark efficient firm – if they are undercompensated, we may not be able to fund the investments required to provide the services our customers value.

340. Our proposed equity beta is supported by expert advice from SFG Consulting, which is provided as Attachment 9–4.

9.3 PROPOSED RETURN ON DEBT

341. Our proposed return on debt for the 2016 regulatory period is 5.39% (compared to 9.99% for the 2011 regulatory period) and accounts for 60% of our proposed rate of return.

9.3.1 APPROACH WE USED TO CALCULATE PROPOSED RETURN ON DEBT

342. To estimate our proposed return on debt, we considered the riskiness of investments in our distribution and metering services, and then observed the price and promised payments on observed bonds for firms with similar levels of risk.

343. Historically, the AER has estimated the benchmark return on debt by observing the current price and promised payments on observed bonds 'on the day'.[210] The rate of return guideline proposes implementing a new approach that involves:

- Observing historical prices and promised payments for up to 10 years (a 'trailing average' portfolio approach)
- Updating this annually using the 10 most recent years of observations
- Using yield estimates from an independent third-party service provider for a 10-year debt term with a BBB+ credit rating, and
- Transitioning to this approach from the hybrid approach over a 10-year period.

344. We support the AEMC's changes to the NER and many elements of the AER's proposed approach to calculating the return on debt. Consistent with this approach, we used a 10-year 'trailing average' to calculate our proposed return on debt, and propose that this calculation be updated annually.[211] In our view, this provides greater stability in network prices (which our customers prefer) and better aligns the calculation of the return on

210 AER, *Rate of return guideline*, December 2013, p. 4.

211 This would result in changes to the X-factors and changes to the levels of our network tariffs (see section 10.6). Although we prefer the hybrid approach, we adopt the trailing average approach in our proposal (consistent with the rate of return guideline).

debt with efficient debt procurement practices of benchmark firms. Therefore, we consider this approach is in the long-term interests of our customers.

345. However, we have departed from the rate of return guideline in four key areas, including the credit rating of the benchmark firm, the data source, the processes for the annual update and the transition to the trailing average approach.

346. Attachment 9–2 provides further details on our proposed return on debt and is supported by Attachments 6–9, 9–14, 9–15, 9–16 and 9–17.

9.3.1.1 Benchmark credit rating

347. To ensure that we can continue attracting necessary funds, we have departed from the rate of return guideline by estimating the return on debt using a lower benchmark credit rating (BBB) than the AER's preference of BBB+.

348. The current regulatory framework allows network businesses to recover their investments over the life of the asset (in many cases over 50 years). This has been an effective model in a world with little change and where we could reasonably expect customers to continue to connect to and use our network.

349. However, as chapter 3 outlines, our energy market is changing, and we expect increasing customer choice about meeting and managing their electricity needs will lead to new industry players, as well as changes in the services we provide. We will increasingly compete against a range of other technologies and energy market players over the 2016 regulatory period and beyond. These changes in our energy market present challenges to the current model for recovering our investments, and heighten investor perceptions of risk.

350. We consider it is appropriate to use a lower benchmark credit rating (BBB) to reflect new risks and heightened perceptions of risk a benchmark firm would face in providing our distribution and metering services over the 2016 regulatory period.

9.3.1.2 Data source

351. There are several methods and data sources available for estimating the return on debt. The rate of return guideline suggests using a third-party data source, and the AER's draft decisions for the NSW and ACT electricity networks propose using an average of Bloomberg and RBA data.

352. Consistent with the guideline, we propose using published yields from an independent third-party data service provider to estimate the return on debt for each of the averaging periods. However, given that we cannot assume that any one data series will be superior (or inferior) to all others in all circumstances, we have departed from the guideline by proposing to use:

1. For the first averaging period, a process that selects the independent third-party estimate that best fits observed bond data for future averaging periods (consistent with Australian Competition Tribunal decisions on the debt risk premium)
2. For subsequent averaging periods, the average proposed by the AER in the draft decisions unless there is a material (60 basis point) departure between the estimates from the two sources – in which case an automatically application of the process in (1) is used to select the best estimate.[212]

[212] The 60 basis point value is set to align with the one per cent revenue threshold set out in the NEL. A 60 basis point difference between the two curves means that each curve is either 30 basis points higher or lower than the average of those two curves. Moving from that average to either curve corresponds to a $2.5M annual revenue impact—which is about one per cent of JEN's forecast building blocks revenue. The $2.5M is calculated as: $2.5M = 30 basis points x $1.4B RAB x 60 per cent.

9.3.1.3 Annual update to the return on debt

353. Consistent with the AEMC's changes to the NER, we propose an annual update to the return on debt over the 2016 regulatory period. This will result in updates to the proposed X-factors (see Table 6–2 and Table 6–3.) and the levels of our network tariffs (see section 10.6).

354. The AER's guideline suggests a process for updating the return on debt annually that involves estimating the trailing average return on debt each year using the new return on debt observed for a given averaging period, and then reflecting this in tariffs by updating the X-factors. In its recent draft decisions for the NSW and ACT electricity networks,[213] the AER proposed estimating the observed return on debt as a simple average of Bloomberg and RBA data.

355. We propose an annual update to the return on debt that is very similar to the AER's, except that we propose:

- Having a one-year lag between observing the return on debt for a given averaging period and reflecting this in tariffs. This will ensure that that period can fall as close as possible to the start of the regulatory year to which it applies, and still leave sufficient time for us to engage with retailers and other stakeholders on the annual tariff proposal before the update is reflected in tariffs.
- Having a two part approach for each year within the 2016 regulatory period:
  - As the default estimate, the simple average of estimates from the Bloomberg and RBA data sources is used as the return on debt observation for that year
  - If these estimates depart by 60 basis or more, then a mechanism is used that automatically selects the data source or combination of data sources that gives the best estimate of the return on debt observation for a given averaging period. This estimate replaces the default estimate and will minimise the risk that consumers over or under pay for the return on debt financing by using pre-specified data to estimate the return on debt that may be inaccurate for a given period, without unnecessarily complicating the update process.

356. Attachment 9–2 provides more detail on this annual update to the return on debt.

213 AER Draft Decision: Ausgrid distribution determination 2015–16 to 2018–19, November 2014.

10. OUR NETWORK TARIFFS

Key messages

- We propose to update our network tariff structures to encourage more informed customer decision making and to put downward pressure on our costs and average prices over the long-term by:
  - Introducing a new 'maximum demand charge' for all residential and small business customers to more clearly signal the higher costs of using our network during periods of peak demand, and thus encourage these customers to reduce or spread out consumption
  - Changing the existing demand charges for all large business customers to improve their cost-reflectivity.
- We will continue to have a fixed standing charge and consumption charges, and on average these charges will be reduced so we do not recover more revenue from customers due to our changes to tariffs.
- Overall, our proposed network tariffs will result in lower average prices over the 2016 regulatory period. However, the impact on individual customers' bills will depend on how and when they use our network, and how they respond to the new price signals.
- To manage any potential adverse impacts of the new maximum demand charge for residential and small business customers, we propose to:
  - introduce the new charge as soon as practical (in 2018), but transition it to cost-reflective levels over a number of years
  - reduce our average prices in 2018 (including our fixed and consumption charges) to offset the introduction of the maximum demand charge
  - empower our customers with information and other tools to help them respond to the new maximum demand charge and take control of their electricity bills.
- We are confident our proposed network tariffs and transition arrangements are consistent with our pricing goals and the NER requirements, and reflect our customers' priorities and preferences. They strike an appropriate balance between efficiency and simplicity, stability and predictability.

357. Our network tariffs include the charges for our distribution services and metering services, as well as the charges we pay for transmission services.[214] While we charge different customer groups (or tariff classes) different amounts for using our network, our charges for distribution network and metering services make up around 37% of a typical residential customer bill (see Figure 2–3).

358. For the 2016 regulatory period, the NER require us to:

- Propose tariff structures[215] that comply with the pricing principles set out in the NER,[216] including the need to calculate and send efficient price signals to customers reflecting the cost of using our network[217]

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214 Our proposed network tariffs are sometimes referred to as network use of system (**NUOS**) charges. These charges include the costs associated with both our distribution network (distribution use of system (**DUOS)** charges), designated pricing proposal charges which include a portion of AusNet Services' and AEMO costs for transporting electricity over AusNet Services' high voltage transmission network (transmission use of system (**TUOS)** charges), costs associated with any NER allowed pass-through events and jurisdictional scheme costs.

215 NER cl 6.18.1A(a) requires us to propose the tariff structures as part of the tariff structure statement. NER cl 11.76.2 requires us to submit our first TSS by 25 September 2015. We have chosen to submit it earlier with this 2016 regulatory proposal.

216 NER cl 6.18.5.

- Provide a description of our approach to setting each tariff in each year of the period that enables us to recover the allowable revenues from our individual network tariffs[218]
- Provide indicative network tariff levels or an 'indicative price schedule'[219]
- describe our engagement with our customers, stakeholders and the community in developing our TSS.[220]

359. In developing our proposed network tariffs, including proposed structures of our tariffs, we were guided by the requirements in the NER,[221] our proposed price control mechanism,[222] (see 5.2.2 and Attachment 5–2) and our customers' priorities and preferences (see chapter 4 and Attachment 4–1).

360. Section 10.1 provides an overview of our proposed network tariffs. We then outline our pricing goals (section 10.2) and approach to setting network prices (section 10.3), our proposed tariff classes (section 10.4) and tariff structures (section 10.5), and outcomes for customers (see section 10.6).

361. Attachment 10–1 provides our draft TSS, which includes further detail on our proposed network tariffs and tariff structures for each year of the 2016 regulatory period.

362. Attachment 10–2 provides our estimated customer bill outcomes. Attachment 4-1 provides an overview of our customer engagement in developing the TSS.

10.1 OVERVIEW OF OUR PROPOSED NETWORK TARIFFS

363. Our proposed network tariffs include changes to the structure of these tariffs (see Table 10–1) that are designed to send clearer price signals, share our costs between customers in the most fair and equitable way, and put downward pressure on our costs and average prices over the long term.

364. In particular, we propose to introduce a new 'maximum demand charge' for all residential and small business customers. The amount customers will pay for this bill component will depend on the maximum amount of electricity they draw from the network during the specified 'demand charging window'. This window is from 10am to 8pm on weekdays[223], when peaks on our network are most likely to occur. Building and maintaining the network to meet peak demand is relatively costly, and so has a significant influence on our capital expenditure program and ultimately on our network prices..

365. We also propose to change the existing demand tariff component of our charges for all large business customers—from $ per kilowatt (**kW**) per annum to $ per kilovolt-amps (**kVA**) per annum. We consider this change will improve the cost-reflectivity for this charge.

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217 NER cl 6.18.5(f) requires us to calculate the long run marginal cost for each tariff and base our tariffs on these.

218 NER cl 6.18.1A(a).

219 NER cl 6.18.1A(e).

220 NER cl 6.8.2(c1a) read with the transitional arrangements in NER cl 11.76.2.

221 NER cl 6.18 sets out the distribution pricing rules

222 The price control mechanism, including the X-factors, are set to allow us to recover the revenue required to invest, operate and maintain our network and to provide a reasonable return on our investment in providing the distribution and metering services our customers value for the 2016 regulatory period.

223 Due to system constraints, this currently includes all weekdays, whether a public holiday or not.

Table 10–1: Overview of proposed changes to our network tariffs for the 2016 regulatory period

Tariff class	Tariff structure	Transition tariff levels to new tariff structure
Residential	Introduce maximum demand-based prices to the existing tariff structure—measured as monthly maximum demand recorded between 10am and 8pm weekdays (the 'demand charging window')	• Systems introduction[224]—new tariff structure introduced on 1 January 2017 with demand charge at $0/kW to allow changes to market billing systems • Charging introduction—demand charges phased in to cost-reflective levels from 2018 (see Table 10–5)
Small business	Introduce demand-based prices to the existing tariff structure[225]—measured as the highest demand recorded in the demand charging window in any month and may be subject to a minimum chargeable demand[226]	• Systems introduction—new tariff structure introduced on 1 January 2017 with demand charge at $0/kW to allow changes to market billing systems • Charging introduction—demand charges phased in to cost-reflective levels from 2018 (see Table 10–5). Customers already subject to a demand-based tariff at 1 January 2016 will have a different transition (see Table 10–5)
Large business – low voltage (LV)	Change in how large business capacity charges are set by moving the demand tariff component from kW to kVA charges	• Effective 1 January 2017
Large business – high voltage (HV)		
Large business – sub transmission		

366. The new maximum demand charge for residential and small business customers will encourage these customers to make more informed decisions about how they use our network, which in turn should drive continued technological and market innovation and reduce network costs and average prices in the long-term. The new charge will not mean we recover more costs from these customers in total—rather, it will change the way we recover money from them. We will continue to have a fixed standing charge and variable usage charges, and we will reduce these tariffs on average.

367. As Table 10–1 indicates, we propose to introduce the new tariff structures from 1 January 2017. However, we propose to transition the new demand-based charges for residential and small business customers to cost-reflective levels over a number of years, starting from 1 January 2018.

368. In developing our proposed network tariffs, we took account of our customers' feedback. Customers supported us updating our individual network charges to reflect changes in how they use our network. They also told us they would prefer us to transition to the updated charges as soon as practicable and in a manner that minimises

224 A systems introduction in 2017 with prices set to zero enables retailers an opportunity to make the required system changes.

225 Where one does not already exist.

226 Maximum demand is set within the demand charging window and is determined as the highest of the maximum demand recorded for a month and the billed demand for previous month (with demand reset in accordance with demand reset policy).

individual customer impacts.[227] In our view, our proposal strikes an appropriate balance between efficiency—providing signals to encourage informed customer decision making—and simplicity, as well as between stability and predictability—customers having adequate understanding and notification to respond to price signals and ability to mitigate the impact on their bill.

369. To complement the proposed tariff changes and facilitate more informed decision making, we will publish information on our website and continue to engage with customers to help them understand how they can respond to the new maximum demand charge and take control of their electricity bills. We will also encourage our customers to make use of Jemena's Electricity Outlook portal (see section 3.4.3), which provides customers with easy-to-access to information on their electricity usage. This tool—together with our smart meters—will enable our customers to see how much electricity they are using and when they are using it, to set savings targets and track their progress, and to use their usage information to compare retail market offers. Ultimately, this will encourage more efficient use of our network, improving allocative efficiency.

370. Overall, our proposed network tariffs result in lower average prices over the 2016 regulatory period. However, the impact on individual customers' bills will depend on how and when they use our network, and how they respond to these new price signals. It will also depend on how retailers incorporate our proposed network tariffs into their retail prices.[228]

10.2 OUR GOALS IN SETTING OUR NETWORK TARIFFS

371. To assist us in setting our network tariffs, we developed, consulted on, and refined our pricing goals, consistent with the pricing principles in the NER. These objectives are shown in Box 10–1.

Box 10–1: Our goals in setting our network tariffs

- *To recover efficient costs of operation*—we need to ensure that we have sufficient funding to provide a safe and reliable electricity network services now and into the future.[229]
- *To drive economic efficiency*—we set prices that are cost-reflective and empower customers to make efficient consumption decisions.[230]
- *To treat customers equitably*—our tariffs and tariff classes ensure that similar customers pay similar prices.[231]
- *To provide simple and transparent tariffs*—our customers can understand our tariffs and respond to price signals.[232]
- *To provide predictability*—our prices remain relatively stable over time to support customers' ability to make long-term decisions.[233]

Our draft TSS (see Attachment 10–1) provides more detail on our pricing goals and our considerations in balancing these goals in setting our network tariffs.

227 See our customer engagement Attachment 10.

228 Customers may not see their network tariff itemised on their electricity bill as retailers incorporate our tariffs in their end prices and charges, along with the other costs of producing and supplying electricity.

229 This is consistent with the pricing principle in NER cl 6.18.5(g).

230 This is consistent with the network pricing objective in NER cl 6.18.5(a) and the pricing principle in NER cl 6.18.5(f).

231 This is consistent with the rules for setting tariff classes in NER cl 6.18.3.

232 This is consistent with the customer impact pricing principles in NER cl 6.18.5(h) and cl 6.18.5(j).

233 This is consistent with the pricing principle in NER cl 6.18.5(h).

10.3 OUR APPROACH TO SETTING NETWORK TARIFFS

372. Our approach to setting our network tariffs involves three key stages:

1. Establishing our services and costs to determine our ARR for the 2016 regulatory period
2. Establishing the timing of recovering these costs to determine our MAR (or 'smoothed revenues') and the average annual change in prices or X-factors required to recover these revenues in each year of the 2016 regulatory period
3. Setting individual network tariffs in line with the X-factors and our pricing goals (Box 10–1).

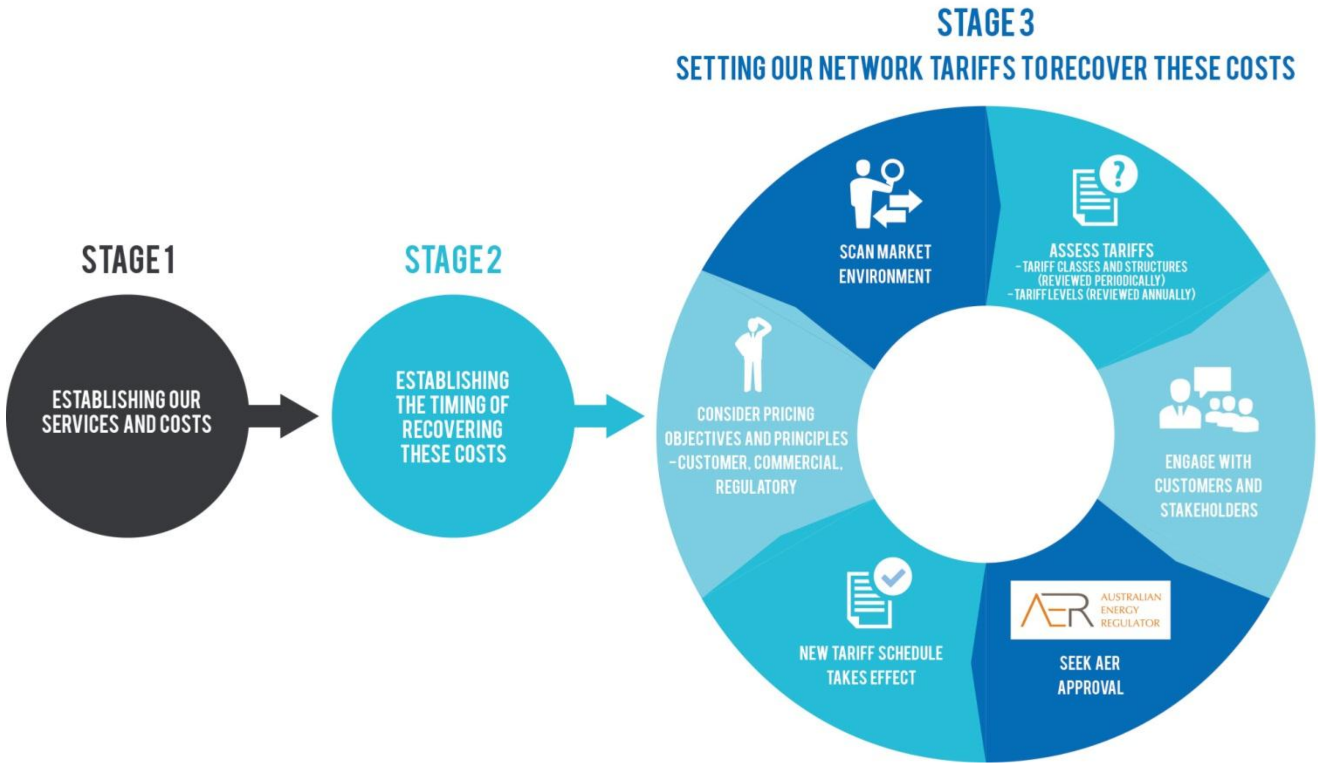
373. Stages 1 and 2 are outlined in detail in earlier chapters of this proposal (see chapters 5 to 9). Stage 3 (see Figure 10–1) involves making more detailed decisions on:

- Grouping similar customers together into tariff classes to ensure similar customers pay similar prices (see section 10.4)
- Structuring the tariffs in each tariff class to ensure we send signals to customers about the cost of using our network to encourage informed customer decision making about how they use our network (see section 10.5)
- Setting the level of each tariff to allow us to balance our pricing goals—including recovering our revenue, encouraging efficient use of our network, providing price stability and predictability—and promote the long-term interests of our customers.

374. While we have undertaken stage 3 in developing our proposal, we will also undertake it as part of our annual price change process within the regulatory period. This process updates our prices to account for the X-factors (including annual changes to the return on debt), unforseen changes and annual pass-through amounts, and to correct any previous under- or over-recovery of revenue. In most circumstances, these annual updates will involve changes to the tariff levels only, not the tariff structure.[234] In addition, all updates to our network tariffs are subject to the AER's approval.

[234] There is a process, overseen by the AER, to allow for changes to the tariff structures within the regulatory period. This requires certain thresholds to be met (refer cl 6.18.1B of the NER) and requires us to engage and consult on the potential TSS changes before submitting to the AER for approval.

Figure 10–1: Our approach to setting our network tariffs



Source: Jemena Electricity Networks

10.4 PROPOSED TARIFF CLASSES

375. To determine our tariff classes for the 2016 regulatory period, we considered how best to group together similar customers to ensure similar customers pay similar prices.[235] The NER recognise the need to balance efficiency and simplicity in setting tariff classes to 'avoid unnecessary transaction costs', and require us to group customers together in an 'economically efficient manner' (see Box 10–2).[236]

[235] We have approximately320,000 residential and business customers, with a range of different characteristics. Given the diversity in how customers use our network, a single network tariff for all customers would not provide customers with signals about the cost of using our network and would be unlikely to encourage informed customer decision making about the way energy is used. However, developing different network tariffs for each of these customers would create significant administrative costs, and most likely create confusion for retailers, new market players and customers.

[236] NER cl 16.18.3(d).

Box 10–2: Determining the tariff classes for the 2016 regulatory period

The NER[237] requires our tariff classes to be determined such that:

- Each customer (for direct control services) must be a member of one or more tariff classes
- There must be separate tariff classes for standard control services and alternative control services
- A tariff class must be constituted having regard to grouping customers on an economically efficient basis and the need to avoid unnecessary transaction costs.

376. Table 10–2 sets out our proposed tariff classes for our distribution services. These tariff classes are consistent with the requirements in the NER, and reflect our customers' preference for similar customers to pay similar prices. Our draft TSS provides additional information on why we consider these tariff classes are currently economically efficient customer groupings (see Attachment 10–1).

377. We propose to retain our current procedures for assigning new retail customers to tariff classes and reassigning existing retail customers from one tariff class to another. These are provided with our draft TSS (see Attachment 10–1).

Table 10–2: Our proposed tariff classes for distribution services

Tariff class	Class definition
Residential	Only available to residential customers
Small business	Only available to customers: 1. With annual consumption less than 0.4 GWh and maximum demand less than 150 kVA (or 120kW), and 2. Where supply is not taken from an on-site or dedicated substation
Large business – low voltage	Low voltage tariffs (nominal voltage is less than 1000 volts) Only available to customers: 1. With annual consumption greater or equal to 0.4 GWh or maximum demand greater or equal to 150 kVA (120kW), or 2. Taking supply from an on-site or dedicated substation
Large business – high voltage	High voltage tariffs (nominal voltage greater or equal to 1000 volts and less than or equal to 22,000 volts)
Large business – sub transmission	Sub-transmission tariffs (nominal voltage greater than 22,000 volts)

378. The five tariff classes enable us to achieve an optimal balance between differentiated price signalling—taking into account customer load and connection characteristics—and the transaction costs of providing more customised tariffs. In other words, the five tariff classes:

- Correspond to our five major customer segments which have materially different costs to connect and serve
- Ensure we can avoid unnecessary costs to ourselves, retailers (for example IT and billing systems and processes changes) and customers.

237 NER cl 6.18.3.

379. Our proposed tariff classes for distribution services are the same as those that applied during the 2011 regulatory period. We consider that there are no efficiency gains or other benefits to be made from altering this approach.

380. The NER require us to demonstrate that the revenue we expect to receive from each tariff class should lie on or between the standalone cost of servicing the tariff class (upper bound) and the avoidable cost of not servicing that tariff class (lower bound).[238] We have provided our standalone and avoidable cost estimates for each tariff class and our approach to calculating these in our draft TSS (see Attachment 10–1). The draft TSS demonstrates that our expected revenue for each tariff class lies between the two efficiency measures.

381. We have a single tariff class for our metering services and user requested services. This is because there is no advantage in dividing customers into further groups as the price applies to a service and does not vary by the type of customer using the service.

10.5 PROPOSED TARIFF STRUCTURES

382. To decide how customers in each of our tariff classes will pay for their use of our network—including to what extent they pay on the basis of fixed, consumption, time-of-use and maximum demand (or capacity) charges—we considered how best to balance our pricing goals (see Box 10–1) and meet the requirements of the NER. For example, our tariff structures need to:

- Send effective signals about the different costs of using our network in different ways to encourage informed customer decision making and treat customers equitably
- Recover the fixed costs of investing, operating and maintaining our network (including the unrecovered past capital investments we have made to provide services to our customers) while minimising any disincentive to use our network
- Provide simplicity, transparency and price predictability for our customers.

383. The NER make it clear that our tariffs should send signals to customers about the cost of using our network at times of greatest utilisation[239] to encourage informed customer decision making about the way they use energy.[240] At the same time, they recognise that customers need to be able to understand and respond to the price signals, and require that we consider customer impacts when determining how to transition to new tariff structures and levels.[241]

384. There is a spectrum of potential tariff components we could use to compile a tariff structure that signals the cost of using our network to customers (see Figure 10–2). At one end, there are the traditional tariffs with which most residential and small business customers are familiar. These are simple to understand, but they do not send strong signals to customers about the cost of using our network, particularly during peak periods.[242]

385. For example, a flat rate for energy supply does not signal to customers the higher cost of supplying electricity during peak periods. Therefore, customers do not consider this cost when deciding to turn on (or off) their electric appliances. As a result, peak demand is likely to be higher than it might otherwise be, imposing higher costs on all customers. The traditional pricing structure also means that customers who consume a significant

238 NER cl 6.18.5(e)

239 NER cl 6.18.5(f).

240 Meeting demand (measured in kilowatts (kW)) at peak times is the predominant driver of our costs to augment the network.

241 NER cl 6.18.5(h) and 6.18.5(i) are collectively the new customer impacts principles.

242 Section 5.1 of the draft TSS in Attachment 10-1 shows that energy charges (c/kWh) are imperfect at targeting costs on peak users and is therefore poor at sending cost-reflective signals and enabling customers to make informed energy consumption decisions.

proportion of their electricity from our network during peak periods are not paying a price reflective of their contribution to the investment that is required to meet these demand peaks. These customers may include those with distributed generation (such as solar PV) units, as these reduce a customer's total consumption from our network but may not reduce their consumption during peak periods.

Figure 10–2: Network tariff component options for signalling the cost of using our network

Source: Jemena Electricity Networks

386. At the other end of the spectrum, there are tariffs that are more reflective of the costs of using our network, particularly during peak periods or across certain areas of our network. While most of our large business customers are familiar with these tariffs structures, they are more complex for us and retailers to administer and for customers to understand and respond to.[243]

387. For the 2016 regulatory period, we propose tariff structures that include a mixture of the following tariff components for our distribution services:

- A fixed (or 'standing') charge—an annual supply charge that applies to each premises electricity is delivered to ($ per annum) and paid on a pro-rata basis depending on how frequently each customer is billed.
- A consumption (or 'usage') charge—a charge that applies to the volume of electricity consumed (in cents per kilowatt hour (c/kWh)). This charge may also depend on the time of the day the electricity is consumed
- A demand (or capacity) charge—a charge that applies to a customer's capacity ($ per kilowatt ($/kW) or $ per kilovolt ($/kV) charge). Specifically:
  - A maximum demand charge—for residential customers, this charge is based on the maximum demand (kW) in each month that is recorded between 10am and 8pm weekdays with no minimum chargeable demand level

243 For example, we do not consider that a locational critical peak demand tariff is currently appropriate for our network due to practicalities involved in notifying in advance when this peak will be (to provide the signal to customers). This approach might cause difficulties in providing a price signal to all customers and to fulfil our goal to treat customers equitably and to provide tariffs that are reasonably capable of being understood by customers as required by the NER. Additionally, this might not have the desired impact to reduce peaks as it might simply shift the peak to a time outside that which we notified. This might not best meet our goal to drive economic efficiency.

- A maximum demand charge—for small business, this charge is based on the maximum demand (kW) recorded by the business and may be subject to a minimum chargeable demand level[244]
- A demand charge—for large business, this charge is based on the capacity requirements (kW up to and including 2016, and kVA from 2017) of the business and is subject to a minimum chargeable demand level.

388. Table 10–3 sets out our proposed tariff structures for each tariff within a tariff class. As section 10.1 outlines, the key differences between this proposal and our current tariff structures are that:

- For the residential tariff class, we are introducing a maximum demand charge into the tariff structure in 2017 and transitioning this charge to cost-reflective levels from 2018
- For the small business tariff class, we are introducing a maximum demand charge (for those who currently do not face one) into the tariff structure in 2017 and transitioning this charge to cost-reflective levels from 2018
- For all large business tariff classes, we are changing the basis on which the existing capacity charges are determined from kilowatt (kW) to kilovolt-amps (kVA) charges from 2017.

389. We consider that our proposed tariff structures and transitioning arrangements are consistent with our pricing goals, the requirements of the NER, and reflect our customers' priorities and preferences.

Table 10–3: Proposed tariff structures for our distribution services

Tariff class	Tariff	Components	Unit
Residential	General purpose—demand	Standing charge	$ pa
		Unit rate	c/kWh
		Demand charge	$/kW pa
	Flexible—demand[245]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Shoulder unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge	$/kW pa
	Time of use interval meter—demand[246]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge	$/kW pa
	Time of use—demand[246]	Standing charge	$ pa
		Peak unit rate	c/kWh

244 A minimum chargeable demand level means that there is a minimum demand charge irrespective of the actual level of demand.

245 For the flexible tariff, peak (3pm-9pm weekdays), shoulder (7am-3pm and 9pm-10pm weekdays and 7am-10pm weekends) and off peak (10pm-7am) unit rates can vary by summer (daylight savings period) and non-summer (all other times).

246 For time of use and time of use interval tariffs, peak is 7am-11pm Monday to Friday and off peak covers all other times. These tariffs are closed to new entrants.

Tariff class	Tariff	Components	Unit
		Off peak unit rate	c/kWh
		Demand charge	$/kW pa
	Off peak heating only	Standing charge	$ pa
		Off peak unit rate	c/kWh
Small business	General purpose—demand	Standing charge	$ pa
		Unit rate	c/kWh
		Demand charge	$/kW pa
	Time of use weekdays (from 1 Jan 17 to be renamed 'Time of use weekdays low user –demand')[247]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge	$/kW pa
	Time of use weekdays – demand[247]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge[248]	$/kW pa
	Time of use extended (from 1 Jan 17 to be renamed 'Time of use extended low user – demand')[249]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge	$/kW pa
	Time of use extended – demand[249]	Standing charge	$ pa
		Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
		Demand charge[250]	$/kW pa
	Unmetered supply[247]	Peak unit rate	c/kWh
		Off peak unit rate	c/kWh
Large business – low voltage[247]	LV 0.4 - 0.8 GWh	Each contains a: • Standing charge • Peak unit rate • Off peak unit rate • Demand charge • Minimum chargeable	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017
	LV_{EN} Annual Consumption <=0.8 GWh		
	LV 0.8+ - 2.2 GWh		
	LV_{EN} 0.8+ - 2.2 GWh		
	LV 2.2+ - 6.0 GWh		

247 Peak is 7am to 11pm Monday to Friday. Off-peak covers all other times.

248 Subject to a minimum chargeable demand.

249 Peak is 7am to 11pm, Monday to Sunday. Off-peak covers all other times. These tariffs are now closed to new entrants.

250 Subject to a minimum chargeable demand.

Tariff class	Tariff	Components	Unit
	LV_{EN} 2.2+ GWh LV_{MS} 2.2+ - 6.0 GWh[251] LV 6.0+ GWh LV_{MS} 6.0+ GWh[251]	demand	
Large business – high voltage[247]	HV HV_{EN} HV_{RF}[251] HV - Annual Consumption >= 55 GWh	Each contains a: • Standing charge • Peak unit rate • Off peak unit rate • Demand charge • Minimum chargeable demand	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017
Large business – sub transmission[247]	Sub-transmission Sub-transmission MA Sub-transmission EG	Each contains a: • Standing charge • Peak unit rate • Off peak unit rate • Demand charge • Minimum chargeable demand	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017

(1) A light blue cell or grey highlighted text indicates a new tariff component or change that would occur from 1 January 2017.
(2) **LV** and **HV** are low voltage and high voltage respectively
(3) EN is ‘embedded network’ representing the tariff is only available to embedded network customers. (Additional criteria may apply as outlined in our tariff schedule).
(4) MS is ‘multiple supplies’ representing the tariff is only available to a non-embedded network customer taking supply from multiple National Meter Identifiers (**NMI**s). (Additional criteria may apply as outlined in our tariff schedule). These tariffs are closed to new entrants.
(5) RF is for customers with a reserve feeder contract. The tariff is closed to new entrants.
(6) TR is ‘traction supplies’ representing the tariff is only available to customers with traction supplies.
(7) EG is embedded generator connected to a specified loop.

10.5.1 PROPOSED TARIFF STRUCTURES FOR RESIDENTIAL AND SMALL BUSINESS CUSTOMERS

10.5.1.1 Distribution services

390. The proposed changes to our tariff structures for residential and small business customers mean that these customers will begin to pay for energy based on their maximum demand on our network in peak periods (the demand charging window). However, as customers pay more for their maximum demand, they will pay less for the volume of energy they consume in total over the billing period. This is because we cannot recover any additional revenue from these changes. The maximum demand charge for a typical residential will reach approximately 27% of their distribution bill by 2020, which works out to be under 10% of their final retail bill.

391. We consulted with customers on how they should pay for their use of our network—that is, what portion of their network bills should be made up of fixed, usage and maximum demand charges—over the 2016 regulatory period and subsequent periods. The feedback we received is summarised in Box 10–3.

251 Closed to new entrants.

Box 10–3: Feedback from residential and small business customers and other stakeholders on tariff structures for the 2016 regulatory period

- 90% of our customers we asked understood and accepted a maximum demand charge on their network bills as fair and equitable[252]
- 71% of customers we asked indicated that they would respond to a maximum demand charge[253]
- 73% of customers we asked encouraged us to transition to these tariffs as soon as practicable, with 23% considering it should be phased in over 5 years
- 74% of retailers we asked indicated that they would incorporate a maximum demand charge in their retail prices for residential and small business customers[254]
- Through our analysis, our customers and stakeholders understand and supported:
  - Our proposed transition to cost-reflective maximum demand charges (see section 10.5.1)
  - A price path that targets price decreases in 2018 when we introduce the maximum demand charge to mitigate individual customer impacts.

See Attachment 4-2 and Attachment 10-1 for further detail.

392. After considering this feedback, we decided to:

- Utilise the benefits of our investments in AMI by introducing a maximum demand charge for residential and small business customers during periods where co-incident demand is highest on our network (the 'demand charging window' of 10am-8pm on weekdays). This will send a signal to these customers about the costs of using our network during peak periods
- Phase in the maximum demand charge in two phases:
  - A 'systems introduction' from 1 January 2017 with prices set at zero to enable billing systems to be ready for the change, and
  - A 'charging introduction' from 1 January 2018 with non-zero prices that will increase to cost-reflective levels in line with the transition outlined in section 10.5.3.
- Measure maximum demand for residential customers as the monthly maximum demand for each customer set, and reset, during the demand charging window each month[255]
- Measure maximum demand for small business customers as the maximum demand for each customer set, during the demand charging window and reset in same manner as for large business customers[256]

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[252] Asked the question "How well do you understand the concept of capacity pricing?", 15% indicated 'completely', 35% indicated 'very' and 40% indicated 'moderately'.

[253] Asked the question, 'What is the likelihood of making changes to reduce maximum electricity use during peak periods if capacity charging is introduced?", 31 per cent indicated they definitely would, 25 per cent indicated 'very likely', 15 per cent' quite likely and 17 per cent 'somewhat likely'.

[254] Asked the question 'How likely are you to reflect the tariff structures for residential customers we have discussed today in your retail prices?' 32 per cent indicated 'very likely', 37 per cent indicated 'very likely, 5 per cent indicated somewhat likely' and 26 per cent were 'other' (including quotes such as 'too early to say').

[255] The monthly maximum demand is a residential customers' highest electricity use (measured in kW) in any 30 minute block (starting on the hour and half hour) between 10am and 8pm weekdays. This is calculated and reset every month.

[256] Maximum demand for small business and large business customers is determined as the highest of the maximum demand recorded for a month and the billed demand for previous month (demand reset in accordance with demand reset policy).

- Propose a revenue path (and therefore a price path) that targets our price decrease in 2018 when we introduce the maximum demand charge for residential and small business customers (see section 6.4).

393. The proposed demand charge, in combination with the existing standing and consumption charges should ensure that our network prices keep up with the increasing diversity in how our residential and small business customers use our network and allow for more informed customer decision making about this use. In addition, this combination of charges should empower customers that have an appropriate retail contract to reduce their bills in two key ways:

- By reducing their total electricity consumption (for example, by using more efficient appliances or turning off surplus lights)
- By spreading out when they use electricity from our network (for example, avoiding running several appliances at one time during the peak demand period).

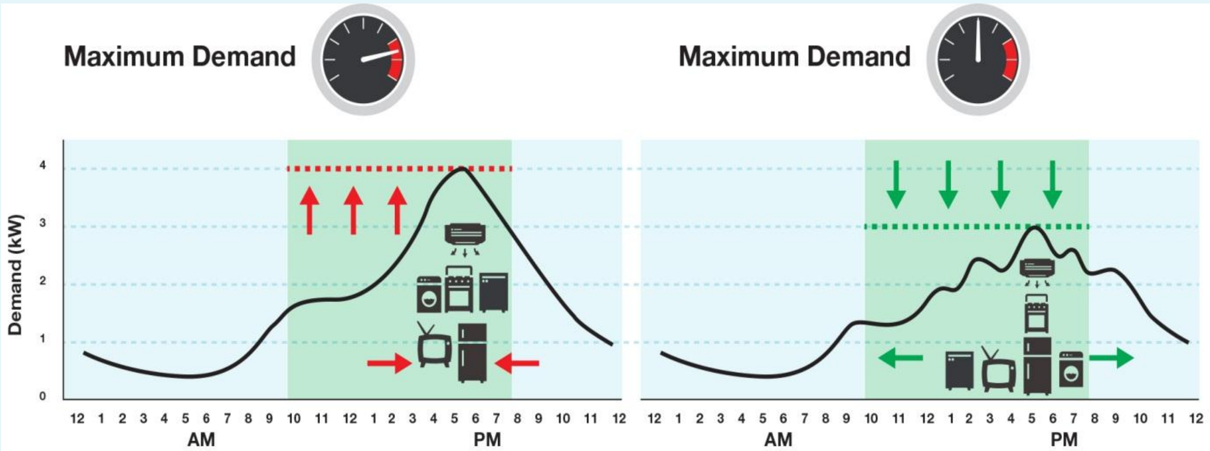
394. Box 10-4 outlines how residential customers can save under the maximum demand charge. Over time this should encourage continued innovation in new technologies and energy market players, more efficient use of our network, and greater equity between customers with large energy production sources or large air-conditioners.

Box 10-4: How residential customers can save with the maximum demand charge

Under our proposed tariff structure, residential customers could reduce their electricity bill by reducing their maximum demand—that is, by spreading out when electricity is consumed during 10:00am to 8:00pm weekdays ('the demand charging window').

This does not necessarily mean moving consumption out of this demand charging window as shown in Figure 10–3. Assuming the monthly maximum demand price is set at $5/kW per month then the customer in the example would save $5 in the month by reducing their maximum demand from 4kW to 3kW.

Figure 10–3: Save by spreading out consumption



395. We are confident that the proposed tariff structures for residential and small business meet the requirements of the NER and our customers' priorities and preferences, including the balance between allocative efficiency (providing signals to encourage informed customer decision making) and predictability (customers having adequate understanding and notification to respond to price signals).

10.5.1.2 Metering services

396. We need to recover the costs of the Victorian Government mandated rollout of AMI meters. We currently do this by separately charging for our AMI meters through prescribed metering service charges. We propose to continue a similar approach to charging these services over the 2016 regulatory period. The proposed tariff structures of our metering charges for residential and small business customers is shown Table 10–4.

Table 10–4: Proposed structure of our metering charges

AMI meter for customer consuming less than 160MWh	Charge
Single Phase Non-Off Peak	$ per annum per meter
Single Phase Off-Peak	$ per annum per meter
Multi-Phase Direct Connect	$ per annum per meter
Multi-Phase CT	$ per annum per meter

10.5.2 PROPOSED TARIFF STRUCTURES FOR LARGE BUSINESS CUSTOMERS

397. The proposed changes to our tariff structures for large business customers means that these customers will continue to pay for their use of our network through a combination of fixed standing charges, peak and off peak consumption charges, and capacity charges. However, on 1 January 2017 the capacity charges will be based on kVA rather than the current kW.

398. This proposed change is consistent with the network pricing objective and cost-reflective principles in the NER,[257] as it will provide a more cost-reflective signal to large customers. Poor power factor (effectively measured by kVA) is a key driver of the need for us to augment the network.

399. Many large business customers considered kVA charging is a fairer way of charging, and will be looking at opportunities to improve their power factor. We will provide an information paper to our large business customers at least six months prior to the 1 January 2017 change. This is consistent with the customer impact pricing principles in the NER,[258] and will give customers an opportunity to take corrective action on their power factor if they consider it is cost-effective for them to do so.

10.5.3 TRANSITION TO OUR PROPOSED TARIFF STRUCTURES

400. Table 10–5outlines our proposed transition to the proposed tariff structures over the 2016 regulatory period. Our current expectation is that all our maximum demand charges will reach fully cost-reflective levels prior to the end of the 2020 regulatory period. We will determine the cost-reflective demand charges based on the Long Run Marginal Cost (**LRMC**) of providing network services to the relevant tariff class.[259] Our approach to calculating LRMC, our LRMC estimates and how we used these to obtain cost reflective tariffs are set out in our draft TSS at Attachment 10-1.

401. In developing our proposed transition, we engaged with our customers and stakeholders and take their feedback into account. For example, we had originally planned (and began engaging on) a transition to our new cost-reflective tariffs over a 13 year period, however customers told us that they saw real value in providing price signals to customers to use the network more efficiently, and doing this sooner rather than later. We have

[257] NER cl 6.18.5(a) and 6.18.5(f)(2).

[258] NER cl 6.18.5(h).

[259] NER cl 6.18.5(f).

proposed a shorter, less gradual transition period as a direct result of this feedback.[260] We consider this transition, combined with our proposed price path (see section 6.4), reflects our customers' and stakeholders' preference for a quicker transition that minimises impacts on individual customers.

Table 10–5: Transitioning to new tariff structures for our distribution services

Tariff	Maximum demand charging parameter	2016	2017	2018	2019	2020
All residential[261]	$/kW pa	×		✓ (50 per cent of scaled LRMC level)	✓ (60 per cent of scaled LRMC level)	✓ (70 per cent of scaled LRMC level)
Small business without demand tariff prior to 2015[262]		×		✓ (50 per cent of scaled LRMC level)	✓ (60 per cent of scaled LRMC level)	✓ (70 per cent of scaled LRMC level)
Small business with demand tariff prior to 2015		✓ (based on $/kW pa i.e. previous method)	✓ (based on scaled $/kW pa LRMC estimates)			
All large business tariff classes	$/kVA pa	✓ (based on $/kW pa i.e. previous method)	✓ (based on scaled $/kVA pa LRMC estimates)			

(1) See our draft TSS at Attachment 10-1 for how and why we have scaled our LRMC estimates.

(2) For residential and small business customers, there is s systems introduction in 2017 with the demand charge added at $0/kW to enable systems to be ready and tested for the positive charge that begins in 2018 (the 'charging introduction').

10.6 CUSTOMER OUTCOMES AND INDICATIVE PRICE SCHEDULE

402. Figure OV–1 outlines the customer impacts for certain customer archetypes under our regulatory proposal for the 2016 regulatory period. This reflects changes to the distribution and metering charges have on customer bills. Individual customer bill outcomes will depend on the customer's specific circumstances, including which of our network tariffs they are on, the amount of electricity they consume, their maximum demand levels and how they respond to our proposed tariff structures.

403. More detailed customers impacts are provided at Attachment 10-2.

[260] We also recognised, undertook analysis on and then engaged with our Customer Council on the potential for this accelerated transition period to negatively impact some customers, and have proposed a solution (in the design of our price path to focus price decreases in 2018) to help mitigate any customer impacts of the proposed transition.

[261] Excludes the 'off-peak hot water heating only' tariff which will not have a maximum demand charge.

[262] Excluding the 'unmetered supply' small business tariff, which will not have a demand tariff added.

404. While overall, the proposed network tariffs result in lower average prices over the 2016 regulatory period, it may result in some customers paying less to use our network and others paying more. The key factors will be:

- How retailers incorporate our proposed network tariffs into their retail prices[263]
- How and when customers use our network, and how they respond to our new pricing schedule
- How the distribution component of our tariffs moves over the 2016 regulatory period, including to what extent our network tariffs are adjusted annually to account for movements in the X-factors[264] and allowed pass-through amounts.

405. The impacts in Figure OV–1 exclude transmission charges, which, as outlined at the beginning of the chapter, are part of our final network tariffs, but are not within our control. We have provided an indicative price schedule, that includes transmission charges as an accompaniment to our draft TSS at Attachment 10-1.[265]

406. Table 10–6 outlines the movements in our metering service charges under our proposal for the 2016 regulatory period.

Table 10–6: Metering service charges, (per meter per year)

Meter provision charge	2015	2016	2017	2018	2019	2020	Total change
Single phase single element meter	226.32	91.90	91.90	91.90	91.90	91.90	-134.42
Single phase single element meter with contactor	226.32	91.90	91.90	91.90	91.90	91.90	-134.42
Three phase direct connected meter	278.12	112.93	112.93	112.93	112.93	112.93	-165.19
Three phase current transformer connected meter	308.66	125.33	125.33	125.33	125.33	125.33	-183.33
Implied average nominal price change (%)	**n/a**	**-59.39**	**-**	**-**	**-**	**-**	**n/a**

407. Section 11 further outlines the movements in our metering service charges under our proposal for the 2016 regulatory period.

408. We have calculated our tariff levels and the resulting customer impacts:

- To recover the allowable revenues from our individual network tariffs
- Consistent with the requirements in the NER, including the network pricing objective and pricing principles,[266] and our description of our approach for setting tariff levels in our draft TSS[267]

263 Customers may not see their network tariff itemised on their electricity bill as retailers incorporate our tariffs in their end prices and charges, along with the other costs of producing and supplying electricity.

264 Resulting from factors such as unforseen changes in energy consumption and annual movements in the cost of debt (see section 6.4).

265 From 1 January 2017, NER cl 6.181A(e) will require us to outline indicative network tariff levels or an 'indicative price schedule', for each of our network tariffs over the 2016 regulatory period. The indicative price schedule is an indicative schedule of NUOS prices, which by their nature, must include a number of estimates for TUOS and costs/savings that will be passed through.

266 NER cl 6.18.5

267 NER cl 6.18.1A(a)(5)

- By balancing our pricing goals consistent with our customers' priorities and preferences and the changes occurring in the electricity market over the 2016 regulatory period.

409. Further detail on how we calculated these tariff levels are provided in our draft TSS at Attachment 10-1.

410. However, from 2017 our network tariffs will be updated annually to account for movements in the X-factors (see section 6.4), the AER-approved costs associated with pass-through events,[268] changes in transmission charges, and to correct any over- or under-recovery of revenues in the previous year.[269] We provide an updated set of indicative price schedule with our annual pricing proposals.

411. We intend to involve customers and stakeholders in our decision making and annual tariff update process. In particular, we will:

- Inform customers and stakeholders of the annual changes in the tariff levels through the JEN Customer Council, the JEN website and email notification to registered subscribers
- Consult with customers and stakeholders on any proposed changes to tariff structures through the JEN Customer Council, retailer forums, and potentially focus groups with residential and business customers
- Explain variations between our indicative price schedule and outturn tariff levels in our annual pricing proposals and provide an updated indicative price schedule.

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268 Resulting from factors such as unforseen changes in energy consumption and annual movements in the cost of debt (see section 6.4).

269 This is required under a revenue cap given the difference between forecast demand and consumption levels used to set allowed revenue and outturn demand and consumption levels.

11. OUR FEES AND CHARGES FOR USER REQUESTED SERVICES

Key messages

- Our proposed fees and charges for user-requested services are largely consistent with the existing pricing of those services
- In line with the NER, these prices reflect the costs of providing the relevant service to the customer that requested the service. They were calculated using the approach adopted by the AER for the 2011 regulatory period and the cost allocation methodology approved by the AER. They incorporate actual changes in key costs over the 2011 regulatory period and forecast changes in these over the 2016 regulatory period
- For negotiated services, our proposed negotiating framework is largely unchanged, except for some minor adjustments to ensure it covers only those services the AER has classified as negotiated services in its framework and approach paper
- Our proposal promotes the long-term interest of consumers by:
  - Ensuring, to the maximum extent possible, charges for user-requested services fully reflect the costs of providing the relevant services and only the customer benefitting from the service is charged for the service
  - Encouraging us to reduce the costs of providing the user-requested services over the 2016 regulatory period and to reveal those cost reductions through our RIN reporting, which in turn will enable us to pass on any savings to customers in future price resets

412. While we provide our distribution and metering services to all of our customers, we typically only provide user-requested services to a smaller group of our customers. For this reason, our user-requested services are treated differently. We allocate the costs of providing these services to those that request the services, and set our prices to recover these costs. This ensures that only those customers that benefit from a service pay for the service.

413. In addition, some of our user-requested services—such as providing operation, maintenance, repair and replacement of existing public lighting assets on shared electricity distribution poles—are provided solely by us,[270] while others are provided in more competitive markets:

- Those services provided solely by us are regulated by the AER through a cap on individual prices of the service ('fee based service') or the labour rates used to deliver the service ('quoted service'). The Victorian distribution price reset RIN requires us to set out the direct costs (tasks, labour rates, cost of materials), overheads used in calculating the individual prices and the approach used to determine the costs of providing the quoted services.
- Those services provided in more competitive markets do not require direct regulatory oversight by the AER. The NER require us to allocate our costs in providing these services using our approved cost allocation methodology, and to set out our process for negotiating price or non-price aspects of the service with customers ('negotiating framework').[271]

[270] These are classified as alternative control services. Refer Section 5.2.1

[271] NER cl 6.7.5(a)

11 — OUR FEES AND CHARGES FOR USER REQUESTED SERVICES

414. Section 11.1 provides an overview of our proposed price changes for user-requested services, and then outlines our approach to determining the proposed prices for these services over the 2016 regulatory period, and the proposed prices for each service in more detail. In developing the proposed prices we were guided by the requirements in the NER, the changes occurring in our energy market, and our customers' priorities and preferences for the 2016 regulatory period.

11.1 OVERVIEW OF PROPOSED CHANGES IN PRICES FOR USER-REQUESTED SERVICES

415. Our negotiating framework for construction of reserve feeder and certain public lighting services (see Attachment 11-1) remains largely unchanged, with minor updates to reflect only those services the AER has classified as negotiated services.

416. We do not propose to charge for remote special meter reads over the 2016 regulatory period. This is because the new functionality of our smart meters means the cost associated with this user-requested service is negligible.

11.2 OUR APPROACH TO DETERMINING PRICES FOR OUR USER-REQUESTED SERVICES

417. Consistent with the NER,[272] we have determined our proposed prices for user-requested services based on the costs of providing the relevant services to the customer. We have calculated the costs of providing the services by:

- Using the approach adopted by the AER for the 2011 regulatory period
- Using the cost allocation methodology approved by the AER (see Attachment 7-10)
- Incorporating actual changes in some of our key costs over the 2011 regulatory period and forecast changes over the 2016 regulatory period.

418. Table 11–1 provides more detail on our approach for estimating the cost of providing each service.

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[272] NER cl 6.8.2 (c) (3)

Table 11–1: Estimating the cost of providing user-requested services over the 2016 regulatory period

Service	Approach	Criteria	Further detail
Fee and quoted services	Bottom up build of labour and material inputs	• Cost of labour inputs, cost of material inputs and the mix and quantity of inputs used for those services that are provided in-house • Negotiated cost components used to set the contract charge for those services that are outsourced • Changes in our rates to capture movements in labour and material costs.	• Attachment 11–4 provides our charges model that supports these fees • Attachment 11–5 provides explanation supporting the charges consistent with the Victorian distribution reset RIN • Attachment 8–8 provides expert reports on movements in key input costs.
Existing public lighting	Building block approach	• Cost of labour inputs, cost of material inputs, light failure rates and the mix and quantity of inputs used for those services that are provided in-house • Proposed rate of return as set out in chapter 9.	• Attachment 11–2A outlines our cost that supports our proposed public lighting charges • Attachment 11–2B outlines the apportionment of public lighting regulatory base to alternative control services • Attachment 11–3 provides an explanation supporting the charges.
Metering services (exit fees)	Bottom up build of labour and material inputs and building block approach	• The basis for classifying and determining this charge is consistent with the requirements of the NER.[273]	• Attachment 11–6 details the rationale for a metering exit fee • Attachment 11–7 outlines our cost build-up model that supports these charges • Attachment 8–8 includes the expert reports on movements in key input costs.

11.3 PRICE DIFFERENCES BETWEEN FINAL AND SUBSTITUTE DETERMINATIONS

419. Our user-requested services consist of a mixture of services that can be subject to a true-up adjustment (public lighting services and metering services) and those that cannot (e.g. fee based services and quoted services). We propose that any price differences between the final and substitute determinations for public lighting services and metering services, be trued-up for one or more years in the 2017 to 2020 regulatory years.

420. For those alternative control services that cannot be trued-up, we propose adjusting standard control service charges for one or more years of the 2017 to 2020 regulatory years. We consider this approach is appropriate because the difference should be smeared across a wider base of network customers to minimise the price impact on prospective customers seeking those alternative control services. Moreover, such an adjustment may be simpler for the AER to manage.

421. These mechanisms should be made to adjust the net present value for alternative control services.[274]

[273] NER Cl. 11.17.6
[274] NER Cl. 11.60.4(d)(2)

11.4 USER-REQUESTED CONNECTION SERVICES

422. Our proposed classification of services includes a number of user-requested connection services (see Box 11–1).[275] Table 11–2 sets out our proposed fees for each of these services, and Table 11–3 sets out our proposed real price change at which labour for these services will change over the 2016 regulatory period.

423. Currently, we are the sole providers of metering services on our network for connections where the customer's energy consumption is below 160 KWh per annum, however, metering services are expected to be offered as competitive services commencing 1 July 2017[276]—-that is, customers (or retailers on behalf of the customers) can choose an accredited metering service provider other than JEN. Accordingly, we have proposed connection fees with and without metering services (see Table 11–2).

Box 11–1: User-requested connection services for the 2016 regulatory period

Our user-requested connection services for the 2016 regulatory period include:

- **Routine connection up to 100 amps** that involves minimal or no augmentation or extension of the distribution network
- **Routine connection over 100 amps** that involves minimal or no augmentation or extension of the distribution network even though this connection service is over the threshold of 100 amps three-phase and up to 415 Volts
- **Temporary supply connection** where supply is requested for a limited period, generally up to 12 months
- **Manual and remote energisation and de-energisation** which retailers may request on behalf of customers moving in or out of premises that has a connection
- **Reconnection after temporary disconnection for non-payment** which retailers may request
- **Supply abolishment greater than 100 amps** is typically non-standard and charge on a time and materials basis

11.4.1 FEE-BASED CONNECTION SERVICES

424. Because the jobs are relatively standard and costs to deliver the service do not vary significantly from site-to-site we propose a standard fee for this type of service. Our proposed fee based connection services are set out in Table 11–2 and Table 11–3 sets out our proposed real price increases at which labour and material costs for these services will change over the 2016 regulatory period.

275 As outlined in chapter 6, we have proposed new connections requiring augmentation as being classified as SCS (consistent with the AER's framework and approach decision paper). The costs of providing these services will be recovered through network prices and/or a capital contribution from customers.

276 AEMC, *Draft Rule Determination, Expanding competition in metering and related services*, 26 March 2015.

Table 11–2: Proposed fees for connection services for the 2016 regulatory period ($2015)

Connection services	Proposed 2016 fees	
	Normal Hours	After Hours
Connection services where Jemena is responsible for metering		
Routine single-phase connection to new premises	726.54	726.54
Routine three-phase connection to new premises	930.27	930.27
Temporary single-phase connection	711.56	711.56
Temporary three-phase connection	752.39	752.39
Connection services where Jemena is not responsible for metering		
Routine single-phase connection to new premises	726.54	726.54
Routine three-phase connection to new premises	930.27	930.27
Temporary single-phase connection	711.56	711.56
Temporary three-phase connection	752.39	752.39
Energisation and de-energisation services		
Reconnection after temporary disconnection for non-payment	65.59	73.19
Manual energisation (new and existing premises)	34.67	54.97
Manual energisation	34.67	54.97
Manual de-energisation	53.55	70.19
Remote energisation	9.33	-
Remote de-energisation	0.57	-

Table 11–3: Proposed real changes in our fees for connections services for the 2016 regulatory period (normal and after hours, per cent)

Connection services	2017	2018	2019	2020
Connection services where Jemena is responsible for metering				
Routine single-phase connection to new premises	1.52	1.20	0.20	0.79
Routine three-phase connection to new premises	1.85	1.22	-0.75	0.33
Temporary single-phase connection	1.48	1.19	0.32	0.85
Temporary three-phase connection	1.80	1.22	-0.59	0.40
Connection services where Jemena is not responsible for metering				
Routine single-phase connection to new premises	1.52	1.20	0.20	0.79
Routine three-phase connection to new premises	1.85	1.22	-0.75	0.33
Temporary single-phase connection	1.48	1.19	0.32	0.85
Temporary three-phase connection	1.80	1.22	-0.59	0.40
Energisation and de-energisation services				

Connection services	2017	2018	2019	2020
Reconnection after temporary disconnection for non-payment	1.61	1.51	1.65	1.91
Manual energisation (new and existing premises)	1.61	1.51	1.65	1.91
Manual energisation	1.61	1.51	1.65	1.91
Manual de-energisation	1.60	1.51	1.65	1.91
Remote energisation	1.62	1.50	1.62	1.91
Remote de-energisation	1.62	1.50	1.62	1.91

11.4.2 QUOTED CONNECTION SERVICES

425. It is not practical to establish individual fees for certain connection services as the cost varies significantly on a project to project basis. Therefore, we propose to provide individual quotes for those connection service requests. They will be based on the labour rates plus the costs of material, plant and contractors at cost to JEN. Our proposed labour rates are set out in Table 11–6.

426. Quoted connection services consist of:

- Routine connections over 100 amps
- Supply abolishment over 100 amps.

11.5 USER-REQUESTED ANCILLARY SERVICES

427. User-requested ancillary services include a large range of services—such as elective undergrounding, high load escorts and reserve feeder maintenance. The costs of these services can be identified and attributed to the individual customer who requested them. These ancillary services are either:

- **Fee-based services** where the cost variance of providing this service is relatively small between sites requested by different customers
- **Quoted services** where it is not practical to establish individual fees as the cost varies significantly on a project to project basis
- **Negotiated services** where the customer and Jemena negotiate the price and price or non-price aspects of the service.

11.5.1 FEE-BASED ANCILLARY SERVICES

428. Our proposed fees for these services are set out in Table 11–4, and the proposed rates at which these services will change over the 2016 regulatory period are set out in Table 11–5. Attachment 11–4 provides detail on the build-up of our proposed fees.

Table 11–4: Proposed fees for fee-based ancillary services for the 2016 regulatory period ($2015)

Ancillary services	Proposed 2016 fees	
	Normal Hours	After Hours
Service vehicle visit	449.09	583.72
Wasted service truck visit - not JEN's fault	418.01	583.71

Ancillary services	Proposed 2016 fees	
Fault response - not JEN's fault	449.09	583.72
Reserve feeder charge	14.74	-

Table 11–5: Proposed real changes in our fees for fee based ancillary services for the 2016 regulatory period (normal and after hours, per cent)

Ancillary services	2017	2018	2019	2020
Service vehicle visit	1.16	1.16	1.20	1.25
Wasted service truck visit - not JEN's fault	1.16	1.16	1.21	1.26
Fault response - not JEN's fault	1.16	1.16	1.20	1.25
Reserve feeder charge	3.82	1.42	-6.11	-2.41

11.5.2 QUOTED ANCILLARY SERVICES

429. The costs of some ancillary services vary significantly on a job-to-job basis, depending on the hours worked, and the type of plant and amount of materials used in providing the service. Given the nature of these services, it is not appropriate to set standard fees for these services.

430. For the 2011 regulatory period, we prepared quotes for these services by applying the AER's approved labour unit rates plus the cost of material, contractors and use of plant (equipment and machinery) at the same cost that we incur. We propose to maintain this approach for quoted ancillary services in the 2016 regulatory period (see Box 11–2).

Box 11–2: Our proposed user-requested quoted ancillary services for the 2016 regulatory period

- Elective undergrounding where over ground service currently exists
- Rearrangement of network assets at a customer's request (excluding alterations and relocation of public lighting assets).
- Damage to overhead service cables caused by high load vehicles
- High load escorts—lifting overhead lines
- Covering of low voltage lines for safety reasons
- After hours service truck by appointment
- Supply abolishment over 100 amps
- Reserve feeder maintenance
- Auditing design and construction
- Specification and design enquiry

431. We propose that, consistent with the current treatment of this service, the charges be controlled by way of a price cap on the labour unit rate per hour, with materials, plant (for example, vehicles, equipment and machinery) and contractor costs being passed onto customers at the same cost to us. The total charge to the customer would be quoted, prior to the service being provided.

432. We have used a top-down method to develop the labour rates for tasks performed by our back office, linesperson, technical officer and engineering personnel.

433. Table 11–6 sets out our proposed labour unit rates for quoted ancillary services, and Table 11–7 outlines the proposed rates at which labour costs for these services will change over the 2016 regulatory period.

Table 11–6: Proposed labour unit rates for quoted ancillary services in the 2016 regulatory period ($2015)

Type of labour workforce	Proposed 2015 labour rates	
	Normal hours	After hours
Back-office	82.33	n/a
Linesperson / Field worker	102.11	126.40
Technical Officer	141.30	165.35
Senior engineer	183.83	201.24

Table 11–7: Proposed real changes to the labour rates for quoted ancillary services for the 2016 regulatory period (per cent)

Ancillary services	2016	2017	2018	2019	2020
Back-office	0.88	1.35	1.76	2.11	1.81
Linesperson	0.88	1.35	1.76	2.11	1.81
Technical Officer	0.88	1.35	1.76	2.11	1.81
Senior engineer	0.88	1.35	1.76	2.11	1.81

11.5.3 NEGOTIATED ANCILLARY SERVICES

434. We propose the construction of reserve feeder ancillary service be provided as a negotiated service in accordance with the AER's framework and approach paper. Accordingly, we will construct reserve feeder services under our Negotiating Framework for Negotiated Distribution Services (see Attachment 11–1).

11.6 PUBLIC LIGHTING SERVICES

435. Public lighting services are provided to specific customers being local government councils and VicRoads. The provision of these services is governed by the Public Lighting Code.[277] The AER has classified public lighting services as either alternative control services or negotiated services.

11.6.1 OMR PUBLIC LIGHTING SERVICES

436. The AER has classified public lighting services which include operation, maintenance, repair and replacement (**OMR**) of shared public lighting assets—that is, those public lighting assets that are attached to electricity distribution poles—as alternative control services.

277 Essential Services Commission of Victoria, *Public Lighting Code*, , April 2005

437. We have proposed OMR charges for fewer light types over the 2016 regulatory period compared to the 2011 regulatory period. This is because a number of light types have since become obsolete and have been removed from service.

438. Our proposed charges are derived by rolling forward a variation of the AER's public lighting model for the 2011 regulatory period and making relevant changes to the inputs and assumptions to reflect different working conditions, cost of material and labour rates. We have also made adjustments to the public lighting regulatory asset base to reflect the changes to the public lighting services classification (see Attachment 11-2B).

439. We have estimated the cost of providing these services using the building block approach (outlined in chapter 6) which requires (among other things) estimates of forecast capital expenditure, forecast operating expenditure and a rate of return.

440. Table 11–8 sets out our proposed OMR charges, which were calculated using the public lighting model in Attachment 11–2A. These proposed charges are inclusive of X-factors.

Table 11–8: Proposed indicative public lighting OMR charges 2016-20 ($2015)

Light Type	OMR charge $ per year				
	2016	2017	2018	2019	2020
Mercury Vapour 80 watt	57.02	57.65	58.06	57.47	57.33
Mercury Vapour 125 watt	83.82	84.75	85.35	84.47	84.27
Mercury Vapour 250 watt	182.20	185.13	187.55	187.72	189.18
Mercury Vapour 400 watt	204.98	208.28	210.99	211.19	212.83
Sodium High Pressure 50 watt	235.13	238.92	242.05	242.27	244.16
Sodium High Pressure 100 watt	257.70	261.86	265.29	265.53	267.60
Sodium High Pressure 150 watt	188.11	191.14	193.64	193.82	195.33
Sodium High Pressure 250 watt	189.80	192.85	195.37	195.54	197.06
Sodium High Pressure 400 watt	252.43	256.49	259.84	260.07	262.09
Metal Halide 70 watt	146.55	148.16	149.23	147.69	147.33
Metal Halide 150 watt	417.59	424.33	429.88	430.27	433.63
Metal Halide 250 watt	408.06	414.62	420.04	420.42	423.68
T5 (2 x 14 W)	53.97	55.35	56.44	56.32	56.73
T5 (2 x 24 W)	60.78	62.33	63.56	63.43	63.89
Compact Fluoro 32W	46.55	47.74	48.68	48.58	48.93
Compact Fluoro 42W	52.50	53.84	54.90	54.78	55.18
LED 18W	20.99	21.52	21.95	21.90	22.06

(1) The charges are inclusive of labour and material escalators and forecast CPI.

11.6.2 PUBLIC LIGHTING SERVICES CLASSIFIED AS NEGOTIATED SERVICES

441. We propose classifying public lighting services attached to dedicated lighting poles as negotiated services (see section 5.2.1). They are:

- New public lights

- New lighting technologies not subject to a regulated charge
- Alteration and relocation of distribution network public lighting assets
- Operation, maintenance and repair services of dedicated public lighting assets
- Replacement of dedicated public lighting assets.

442. The charges for the provision of these services will be negotiated with the public lighting customer in accordance with our negotiating framework (see Attachment 11–1).

11.7 USER-REQUESTED METERING SERVICES

443. Metering services are provided for a range of activities, including complying with metrology procedures as outlined in chapter 7 of the NER. JEN proposed (see section 5.2.1) classifying metering into the following areas:

- Regulated metering services for type 5, 6 and smart meters including operation of type 7 metering installations
- Unregulated metering services for type 5, 6 and smart meters.

11.7.1 REGULATED METERING SERVICES FOR TYPE 5, 6 AND SMART METERS

444. Regulated metering services include those services that were previously governed by the CROIC (see Box 3–1) but now fall under chapter 6 of the NER:

- Installation, operation, repair and maintenance, and replacement of type 5 and 6 metering installations (including smart meters)
- Collection of meter data, processing and storage of meter data, and provision of access to meter data for type 5 and 6 metering installations (including smart meters)

445. Meter provision and meter data provision services for regulated metering services for type 5, 6 and smart meters are currently provided as a bundled service. We propose to continue this bundling of services in the 2016 regulatory period. The relevant charges for regulated metering for type 5 and 6 and smart meters are set out in Table 10–6.

446. In addition to meter provision and meter data provision services for regulated metering services for type 5, 6 and smart meters, JEN provides ancillary metering services on a user-requested basis. We can identify and allocate the costs of providing these services to those that request the services. Accordingly, we have proposed set prices to deliver these services. This ensures that only those customers that benefit from a service pay for the service. Ancillary metering services include:

- Manual special meter read
- Remote meter reconfiguration charge
- Re-test of type 5 and 6 metering installations (including smart meters) for customers with annual consumption less than 160 MWh
- Re-test of type 5 and 6 metering installations (including smart meters) for customers with annual consumption greater than 160 MWh
- Operation of type 7 metering installations.

447. Our proposed regulated metering prices are set out in Table 11–9 and Table 11–10 sets out our proposed real price change at which these services will change over the 2016 regulatory period

Table 11–9: Proposed fees for ancillary metering services for the 2016 regulatory period ($2015)

Metering services	Proposed 2016 fees	
	Normal hours	After Hours
Manual special meter reads	30.99	-
Re-test types 5, 6 and AMI smart metering installations	363.32	597.56
Remote meter re-configuration	48.75	-
Type 7 metering (meter data service)	0.57	-

Table 11–10: Proposed real changes in our fees for ancillary metering services for the 2016 regulatory period (normal and after hours, per cent)

Metering services	2017	2018	2019	2020
Manual special meter reads	1.60	1.52	1.67	1.90
Re-test types 5, 6 and AMI smart metering installations	1.62	1.49	1.61	1.91
Remote meter re-configuration	1.63	1.49	1.61	1.91
Type 7 metering (meter data service)	1.35	1.76	2.11	1.81

448. We also propose a metering exit fee to apply when metering services are no longer provided by JEN as a part of the CROIC service offering. We are making this application in in accordance with the CROIC requirements.[278] Details of the application and the proposed prices chargeable to an electricity retailer[279] are outlined in Attachment 11-6.

449. JEN is not applying for a metering restoration service fee as a part of this regulatory proposal.

11.7.2 UNREGULATED METERING SERVICES

450. Unregulated metering services are outside of the scope of this regulatory proposal. We propose to recover the costs of providing these services from those customers who have requested the services (see section 5.2.1). These services include:

- Installation, operation, repair and maintenance, and replacement of type 1-4 metering installations (excluding smart meters)
- Collection of meter data, processing and storage of meter data, and provision of access to meter data for type 1-4 metering installations (excluding smart meters)
- Smart metering services that are deemed to be competitive in nature—that is, those services where the derogation[280] has ceased to be in place.

[278] CROIC, cl. 7.1B

[279] CROIC, cl 7.1

[280] NER cl 9.9C.2

11.8 USER-REQUESTED UNREGULATED SERVICES

451. The NER recognise that there are varying levels of competition in providing the network services that customers' value. Therefore, direct regulation of services, costs and prices may only be required for those services where minimal competition exists.

452. We propose classifying the following services as unregulated services:

- Provision of installation, maintenance and repair of watchman (security) lights
- Provision of possum guards
- Emergency recoverable works that relate to the repair of the distribution network when an identifiable third party has caused damage.

453. We compete to provide these services (except for emergency recoverable works) to our customers, and thus direct regulatory oversight by the AER is not required. Emergency recoverable works are recoverable under common law from the identified parties responsible for causing the damage.

454. In setting our prices for these services, we propose to recover the costs of providing these from those customers who have requested the services.