Jemena Electricity Networks (Vic) Ltd

Tariff Structure Statement

Public

25 September 2015

TABLE OF CONTENTS

Glossary v

1. Introduction 1

2. Making sense of our network tariffs 5

2.1 Elements included in the network tariff 7

2.2 A few additional concepts 8

2.2.1 Tariff classes 8

2.2.2 Tariffs 9

2.2.3 Tariff structures, tariff components and charging parameters 9

2.2.4 Price levels 9

2.2.5 Tariff class simple example 9

3. How we set our tariff schedule 11

3.1 stage 1—Establishing our services and costs 11

3.2 stage 2—Establishing the timing for recovery of these costs 12

3.3 stage 3—Setting our network tariffs to recover these costs 12

4. Our pricing goals 13

4.1 What are our pricing goals? 13

4.2 Pricing goals in detail 14

4.2.1 Recover our efficient costs of providing services/operation 14

4.2.2 Drive economic efficiency 15

4.2.3 Treat customers equitably 16

4.2.4 Facilitate simplicity and transparency 17

4.2.5 Provide predictability 17

4.3 We have to balance competing pricing goals 18

5. Responding to market changes 20

5.1 Changes in the electricity market 20

5.1.1 Customers are increasingly taking control of their energy decisions 20

5.1.2 Investment in smart meters facilitates informed customer decisions 21

5.1.3 New technologies and emerging market players 22

5.1.4 Changing policy and regulatory environment 23

6. Proposed tariff classes 26

6.1 Our distribution services tariff classes 26

6.1.1 Economically efficient customer groupings 28

6.2 User-requested services and metering services tariff class 28

7. Proposed tariff structures 30

7.1 Our tariff structures 30

7.1.1 Distribution services tariff structures 30

7.1.2 User-requested Services and metering services tariff structures 33

7.2 Explanation of our proposed tariffs and tariff structures 34

7.2.1 Proposed tariffs 34

7.2.2 Tariff structures 36

7.3 Transition to our proposed new tariff structures 42

7.4 Compliance—our assessment of our tariffs, tariff structures and tariff levels against the pricing principles 44

7.4.1 Meeting the network pricing objective 45

7.4.2 Stand alone and avoidable cost efficiency test 50

7.4.3 Estimating long run marginal cost 51

8. Updating our tariff classes, structures and levels 53

8.1 Annual changes to the tariff schedule 53

9. How a new tariff schedule takes effect 55
10. Indicative prices 56
10.1 Average price changes 56
10.1.1 Combined distribution and metering price changes 57
10.1.2 Distribution services price changes 58
10.1.3 Metering services price changes 59
10.2 User-requested services price changes 59

List of tables

Table 1–1: Navigating this document 3
Table 1–2: Where to find how we address the TSS Rule requirements 4
Table 6–1: Tariff classes for distribution services 26
Table 6–2: User-requested and metering services 28
Table 7–1: Overview of proposed changes to our network tariffs for the 2016 regulatory period 32
Table 7–2: Transitioning to new tariff structures for our distribution services 43
Table 7–3: Efficient bounds for expected revenues 51
Table 8–1: JEN annual pricing proposal and approval process 54
Table 10–1: X factors for distribution services ($2015) 58
Table 10–2: X factors for metering services ($2015) 59
Table 10–3: Metering service charges, ($2015, per meter per year) 59

List of figures

Figure 1–1: JEN distribution area 1
Figure 2–1: Proposed classification of our services for the 2016 regulatory period 5
Figure 2–2: Costs included in an electricity bill 7
Figure 2–3: Example of tariffs 10
Figure 3–1: Process of creating and updating our tariff schedule 11
Figure 5–1: Comparing usage to maximum demand 22
Figure 6–1: Our tariff classes 27
Figure 7–1: Save by spreading out usage 40
Figure 7–2: Network tariff component options for signalling the cost of using our network 42
Figure 7–3: Proportion of bill from each tariff component (median residential customer example) 43
Figure 10–1: The impact of our 2016 Plan for typical customers (excluding inflation) 58

List of appendices

Appendix A JEN tariff structures for distribution services 2016-20
Appendix B Selecting the demand charging window
Appendix C Pricing principles of the National Electricity Rules
Appendix D Stand alone and avoidable cost
Appendix E Price setting description
Appendix F Indicative NUOS tariff schedule
Appendix G Assignment and reassignment policies and procedures
Appendix H User-requested services indicative prices

GLOSSARY

2011 regulatory period	1 January 2011 to 31 December 2015
2016 Plan	2016-20 Electricity Distribution Price Review Proposal
2016 regulatory period	1 January 2016 to 31 December 2020
AEMC	Australian Energy Market Commission
AER or regulator	Australian Energy Regulator
AIC	Average Incremental Cost
CROIC	Cost Recovery Order In Council
DUOS	Distribution Use of System
EDPR	Electricity Distribution Price Review
EV	Electric Vehicles
GWh	Gigawatt hour
JEN	Jemena Electricity Networks
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt hour
NEL	National Electricity Law
NEO	National Electricity Objective
NER or the Rules	National Electricity Rules
NMI	National Meter Identifier
NUOS	Network Use of System
O&M	Operation and Maintenance
OM&R	Operation, maintenance and replacement
PV	Photovoltaic
Tariff schedule	The list of prices and tariff structures for each of our tariffs
TSS	Tariff Structures Statement
TUOS	Transmission Use of System
WACC	Weighted average cost of capital

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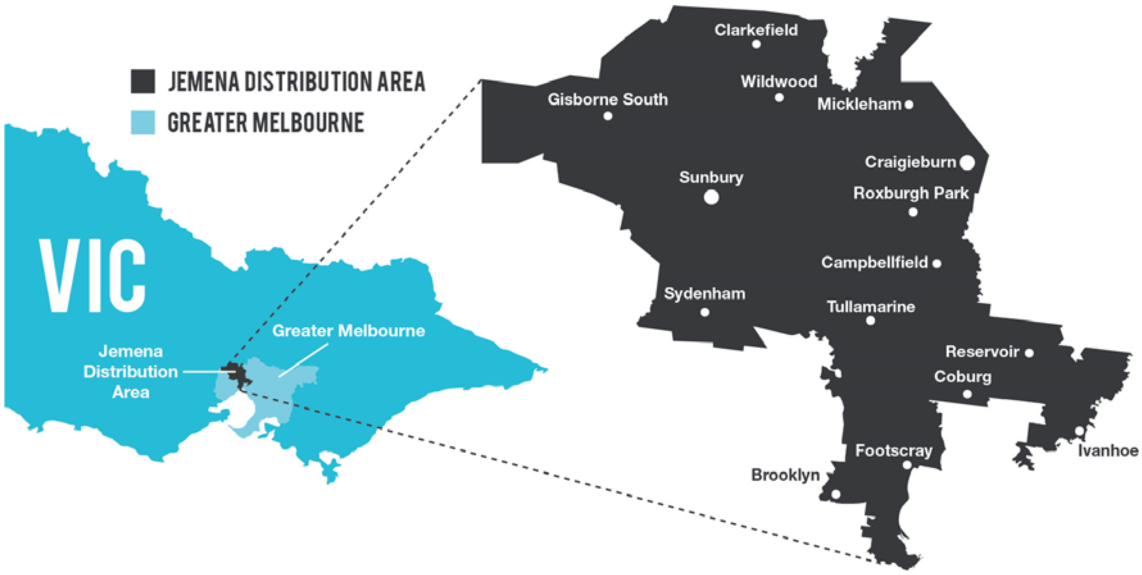
1. INTRODUCTION

1. Jemena Electricity Networks (**JEN**) is responsible for delivering electricity to approximately 320,000 residential and business customers across north-west greater Melbourne.[1] Figure 1–1 shows JEN's distribution area.

Figure 1–1: JEN distribution area



2. The Australian Energy Regulator (**AER or 'regulator'**)[2] regulates the tariffs we are allowed to charge for delivering electricity to our customers. Every 5 years, we submit a proposed plan to the AER, explaining the services we will offer, the costs we are likely to incur, and the tariffs we propose to charge over the next regulatory period. The AER only approves our plan if our proposal complies with legislation and promotes the long-term interests of our customers.[3]

3. The next five year regulatory control period commences 1 January 2016 and ends 30 December 2020 (**2016 regulatory period**). We call our plan for this period the '2016 Plan'. When developing our 2016 Plan, we engaged with customers, stakeholders and the community to better understand what they want and value from their electricity service to help us make decisions that reflect their priorities and long-term interests.[4]

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[1] JEN owns, operates and maintains over 6,000 kilometres of overhead and underground distribution network system over 950 square kilometres of north-west greater Melbourne.

[2] The AER is a Commonwealth Government agency that regulates the prices we charge and the services we offer. They do this via being cognisant of the long term interests of customers.

[3] The National Electricity Law (NEL) includes the National Electricity Objective (**NEO**), which is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

[4] Information about how we've engaged with our customers, stakeholders and the broader community is contained in Attachments 4–1, 4–2 of our 2016 Plan and on our website at http://jemena.com.au/home-and-business/price-reviews/electricity/our-engagement-approach

1 — INTRODUCTION

4. This tariff structure statement (**TSS**) seeks to provide clear and accessible information on our network tariffs and how these may change in the future. This document:

   - Provides a simple explanation of network tariffs and other key concepts discussed in this document
   - Outlines our proposed tariff structures for the 2016 regulatory period, the approach we used to develop our tariff schedule and the approach we will use to update tariffs
   - Discusses some of the key steps in our approach in more detail
   - Outlines how our network tariffs are expected to change in 2016 and over the remainder of the period (both the tariff structure and prices).

5. We provided a draft TSS as part of our 2016 Plan in April 2015 and listened to customer and stakeholder feedback in producing this TSS. As we are always looking to improve, we welcome feedback from our customers, stakeholders and the community on this TSS. To have your say you can contact us at haveyoursay@jemena.com.au

6. To help navigate this TSS, Table 1–1 provides answers to some common questions about pricing and tariffs and indicates where in this TSS you can find more information on each topic.

7. The resulting prices presented in this TSS are based on the inputs from the 30 April 2015 version of our 2016 plan (ie. our initial 2016-20 regulatory proposal).

Table 1–1: Navigating this document

Question	Answer	See section
What are network tariffs?	Network tariffs recover the costs of the services JEN provides to its customers. We provide an example to demonstrate the elements that make up your network tariffs and bill	Section 2—making sense of our network tariffs
How does JEN create a tariff schedule?	We provide a high-level overview of the process from establishing our costs, getting them approved, to creating a tariff schedule	Section 3—how we set our tariff schedule
How are JEN's costs established?	The regulator determines our costs following our consultation and our proposal to the regulator	Section 3—how we set our tariff schedule
What are JEN's tariffs trying to achieve?	Our prices are the result of us balancing a number of goals	Section 4—our pricing goals
What external factors must JEN consider?	We consider a number of changes which are occurring in our electricity market	Section 5—responding to market changes
How does JEN implement its pricing principles?	We carefully construct our tariff schedule in accordance with our pricing goals (that incorporate the pricing principles and network objective in the Rules), and taking into account the changing market environment	Section 6—tariff classes Section 7—tariff structures
How does JEN check its prices are appropriate?	We undertake robust economic analysis to assess the cost-reflectivity of our tariff classes and levels. We engage customers and stakeholders to understand their preferences. Our prices and tariff structures are also checked by the AER	Section 7— tariff structures
How does JEN engage with customers, stakeholders and the community for annual price changes?	We consult with a range of customers and stakeholders on any changes to tariff structures	Section 8—updating our tariff classes, structures and levels
How does JEN adjust prices over time?	We have processes for setting an initial tariff schedule, engaging with our customers on potential tariff schedule variations and seeking AER approval	Section 8—updating our tariff classes, structures and levels
When do JEN's prices take effect?	Our prices take effect from 1 January each year.	Section 9—how a new tariff schedule takes effect
How might JEN's prices change over the next 5 years?	We have estimated how we see prices trending until 2020	Section 10—expected network tariff trends

8. This TSS is a requirement of the National Electricity Rules (**NER** or **Rules**). Table 1–2 provides where to find how we addressed these rule requirements.

Table 1–2: Where to find how we address the TSS Rule requirements

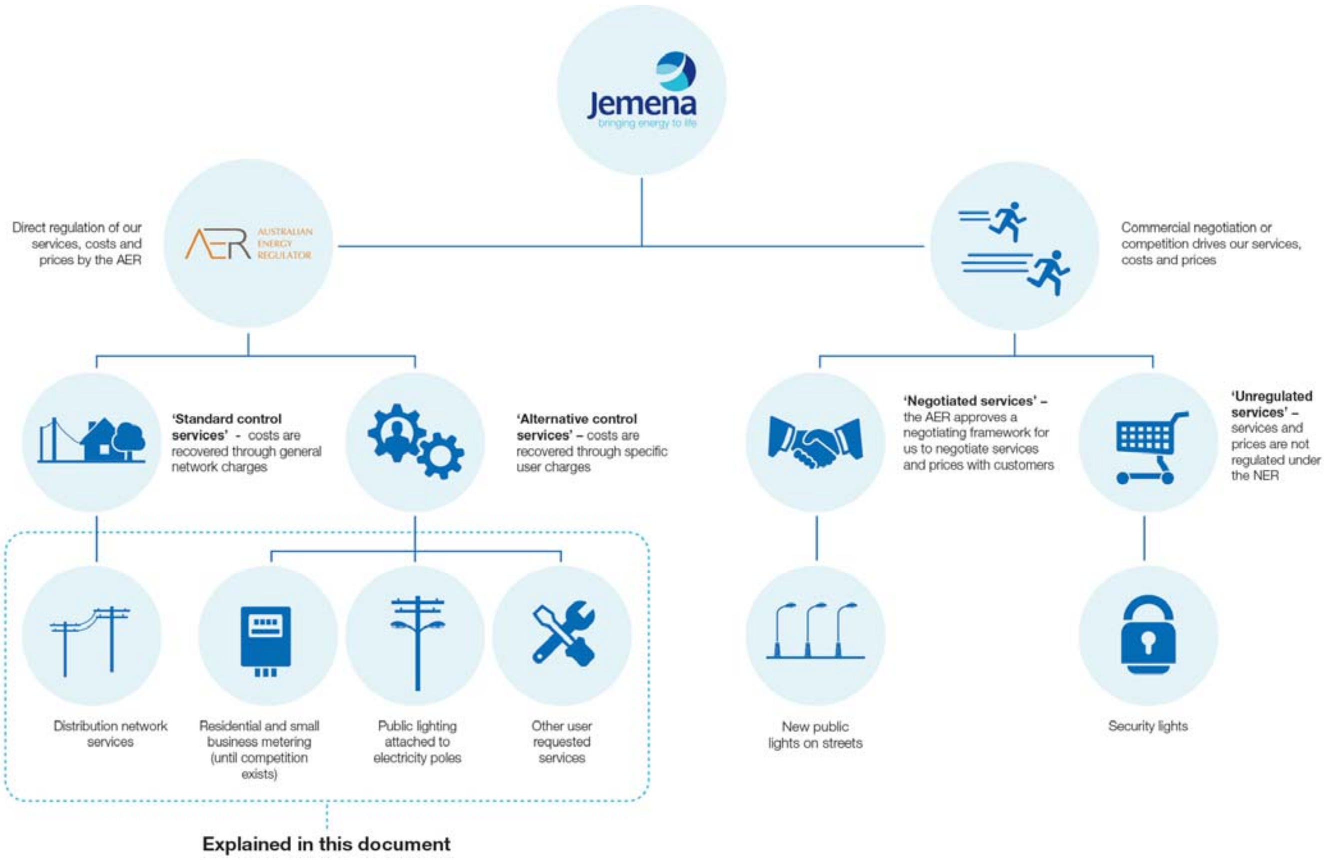
Requirement	Rule	Location
A description of how the proposed TSS complies with the pricing principles	6.8.2(c)(7), 6.8.2(d2) & 6.18.1A(b) Note that transitional rules mean this requirement is to be met by 25 September 2015	Section 7.4
The TSS must be accompanied by an indicative pricing schedule	6.8.2(d1) & 6.18.1A(e)	The schedule is attached in Appendix F and discussed in section 10
The TSS must include **tariff classes**	6.18.1A(a)(1)	Section 6
The TSS must include the **policies and procedures for assigning customers to tariffs** and reassigning from one tariff to another	6.18.1A(a)(2)	Appendix G
The TSS must include the **structures** for each tariff	6.18.1A(a)(3)	The structures are included at Appendix A and discussed in Section 7
The TSS must include **the charging parameters** for each tariff	6.18.1A(a)(4)	The charging parameters are included with the tariff structures at Appendix A and discussed in Section 7
The TSS must include a **description of the approach** we will take in setting each tariff in each pricing proposal during the regulatory period	6.18.1A(a)(5)	Section 7 and Appendix E
We must describe our engagement with customers, retailers and stakeholders in developing the TSS	6.8.2(c1a) & 11.76.2	We have provided how we have engaged on the TSS in a separate overview of how we engaged with our customers and stakeholders in developing our TSS.[5] Customer feedback and how we incorporate this is also reflected in this TSS.

5 JEN, '*How we engaged with our customers and stakeholders in developing our tariff structure statement*', 25 September 2015.

2. MAKING SENSE OF OUR NETWORK TARIFFS

9. Like most businesses, we need to recover the costs of providing our network services from the customers who use them. We do this by charging network tariffs. This TSS describes network tariffs for the services highlighted in Figure 2–1.

Figure 2–1: Proposed classification of our services for the 2016 regulatory period



Source: Jemena Electricity Networks

10. We classify our services into one of the following types:[6]

- *Distribution services*—core network and connection services associated with the access to and supply of electricity to customers (examples include: network maintenance; load control equipment, and transporting electricity from high-voltage transmission lines to customers' premises in a safe, reliable and responsive way, network maintenance and load control equipment). We recover our costs of providing distribution services through distribution network tariffs which we bill retailers.
- *Metering services*—including installing, maintaining and reading electricity meters—we recover our costs of metering through an annual fixed charge to retailers

[6] Note that the Rules refer to standard control services and alternative control services. Figure 2-1 shows how we have further divided and described these into services that are meaningful to customers. Under the Rules, standard control services and alternative control services are collectively as 'direct control services'.

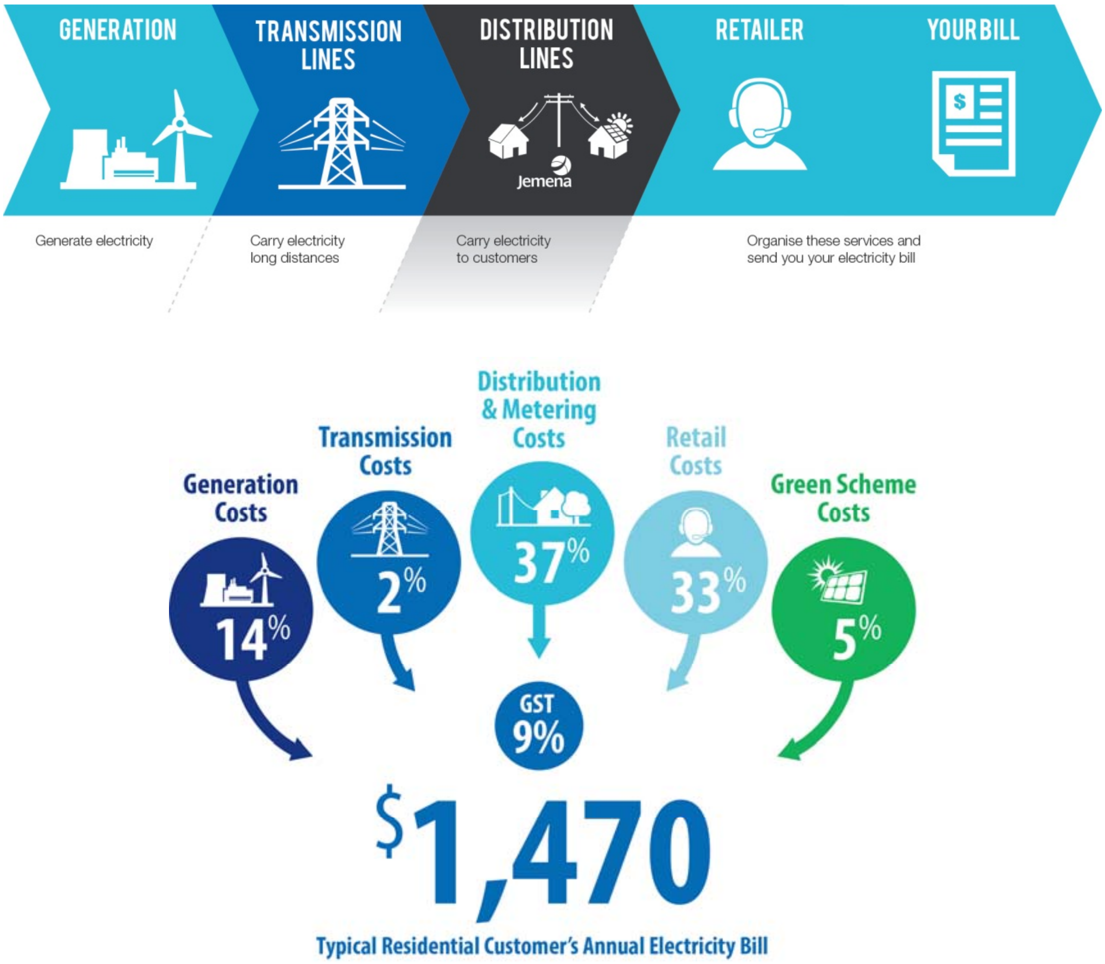
- *User requested services*—these are services we provide to customers and charge retailers based upon request of these services. They are divided into:
  - Fee-based services—services for which costs are generally discernible prior to undertaking the service and do not vary significantly among customers—these include:[7]
    - Services such as connection, truck visits, fault response
    - Public lighting services—related to the operation, maintenance and replacement of public lights
  - Quoted services—which vary depending on the particulars and scope of the service we provide on a case-by-case basis.

11. Customers may not see their network tariff itemised on their electricity bill. For smaller customers, including households, electricity retailers incorporate our network tariffs in their retail prices and charges, along with the other costs of producing and supplying electricity.

12. Figure 2–2 shows the range of costs currently included in a customer's electricity bill. In 2014, our network tariffs made up around 37 per cent of a typical residential customer's retail electricity bill. We expect this percentage to fall over the 2016 regulatory period because we are proposing average network tariff decreases.

[7] See section 10.2 for a full list of user requested services.

Figure 2–2: Costs included in an electricity bill



Source: Based on analysis by Oakley Greenwood, *Causes of residential electricity bill changes in the JEN service area*, 1995 to 2014, December 2014.

13. We publish our network tariffs in our **tariff schedule**—which is like a price list. This tariff schedule is approved by the AER annually as part of our pricing proposal.[8] We publish a new tariff schedule each year, which applies from 1 January to 31 December. Our pricing proposal is informed by the revenue requirement determined by the AER which is set over the five year 2016 plan period.

2.1 ELEMENTS INCLUDED IN THE NETWORK TARIFF

14. The total network tariff incorporated by retailers into customers' electricity bills is typically made up of one or more of the following tariff components:

- *A fixed (or 'standing') charge tariff component*—an annual supply charge that applies to each premises that electricity is delivered to (in dollars per annum), charged on a pro-rata basis depending on how frequently each customer is billed (usually monthly or quarterly).

[8] This is a requirement under NER, cl. 6.18.2

- *A usage charge tariff component*—a charge that applies to the volume of electricity consumed (in cents per kilowatt hour (**kWh**)).[9] For some customers, this charge may also depend on the time of the day the electricity is consumed
- *A demand charge tariff component*—a charge that applies to either a customer's electricity capacity requirement (in dollars per kilovolt-ampere (**kVA**)) or their maximum demand level (in dollars per kilowatt (**kW**)) depending on the type of customer.[10]

15. In addition, there may be a metering charge, which is an annual fixed amount. Most of our residential and small business customers currently pay a fixed (including metering charge) and a usage charge tariff component, but the price levels they pay vary to reflect their different characteristics. Most large business customers pay all three tariff components.[11] Some of our customers may also pay other charges ('user requested charges') if they request other services.[12]

2.2 A FEW ADDITIONAL CONCEPTS

16. To make sense of our network tariffs, it is helpful to be familiar with a few additional concepts—including tariff classes, tariffs, tariff structures, tariff components, charging parameters and price levels. The sections below provide a brief explanation of these concepts. Figure 2–3 provides a simple example of how these can fit together for a single tariff class.

2.2.1 TARIFF CLASSES

17. We have approximately 320,000 residential and business customers, with a range of different characteristics such as usage patterns and the voltage level of the lines they are connected to our network at. We group customers that have similar characteristics together so that similar customers pay similar prices. These groupings are known as our 'tariff classes'. We have five tariff classes that differentiate between:

- Residential customers
- Small business customers[13]
- Large business customers connected at low voltages (<1000 volts)
- Large business customers connected at high voltages (≥1000 volts and ≥ 22,000 volts)
- Large business connected at sub-transmission levels (> 22,000 volts).

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9 Consumption refers to the quantity of energy used over a period of time. Consumption is commonly reported on a monthly, quarterly and annual basis, though any time period is possible subject to measurement constraints. Consumption is measured in a multiple of watt hours (at the network level, usually kilowatt hours). Mathematically, consumption is equal to average demand over time.

10 Demand refers to the quantity of electricity that passes through a given element of a network at a given instant in time. Demand changes instantaneously. In practice, demand is usually reported once for each half hour interval and is the average of instantaneous recordings over the half hour period. Demand is measured in a multiple of watts (at the network level usually kilowatts).

11 Metering is contestable for large business customers, meaning this charge may be set by and paid to a metering provider other than JEN.

12 User requested and metering charges fall under the term 'alternative control service' in the Rules.

13 A small business customer has annual consumption less than 0.4 gigawatt hours (**GWh**) and maximum demand less than 150 kVA (120kW). Additionally, supply must not be taken from an on-site or dedicated substation.

2.2.2 TARIFFS

18. Each tariff class is made up of a number of tariffs. In most cases, a single customer will only be subject to one tariff.[14] A tariff is made up of a number of tariff components which together give the tariff structure.

2.2.3 TARIFF STRUCTURES, TARIFF COMPONENTS AND CHARGING PARAMETERS

19. Once we've grouped our customers into tariff classes and further assigned them to tariffs[15], we determine the tariff structure for each tariff. Tariff structures represent how we charge customers for using our network. We need to have tariff structures that allow us to send customers appropriate signals about how their usage impacts our costs. The individual charges within a given tariff structure are known as the tariff components. For example, these can include one or more of a fixed charge, usage charge and a demand charge tariff component.

20. We also define specific characteristics to those components, such as the time periods that apply or minimum charge levels—these are referred to as 'charging parameters'.

21. We don't update our tariff structures often, and will only do so after consulting with customers (see section 8). When we are considering making changes to our tariff structures, they are generally to reflect changes in the electricity market and are needed to improve the signals to encourage customer behaviour consistent with keeping our costs down or to reflect customer preferences.

2.2.4 PRICE LEVELS

22. Once we have a tariff structure—with its tariff components and charging parameters—we set the level of each tariff component (the number of dollars per annum, per kilowatt, per kilowatt hour or per kilovolt-ampere as is appropriate for that component). We call these the "price levels".

23. Our overall aim is to set these levels so that we send customers appropriate signals about how their usage impacts our costs and so that our overall revenues recover our forecast efficient costs for the 2016 regulatory period. This is a complex process that involves considering a range of factors, including our pricing goals (see section 4), making appropriate trade-offs where these conflict (see section 4.3) and meeting the requirements set out in the Rules.

2.2.5 TARIFF CLASS SIMPLE EXAMPLE

24. Figure 2–3 shows how these tariff concepts fit together within a tariff class.[16] Within the simplified example:

- There is only one **tariff class**—residential—with customers assigned to this tariff class based on their characteristics
- There are two **tariffs—**a 'flat' tariff and a 'time of use' tariff
- The **tariff structures** differ for each tariff—the flat tariff has for **tariff component**s (fixed, anytime usage summer demand and non-summer demand) and the time of use tariff has five **tariff components** (fixed, peak usage, off-peak usage, summer demand and non-summer demand)

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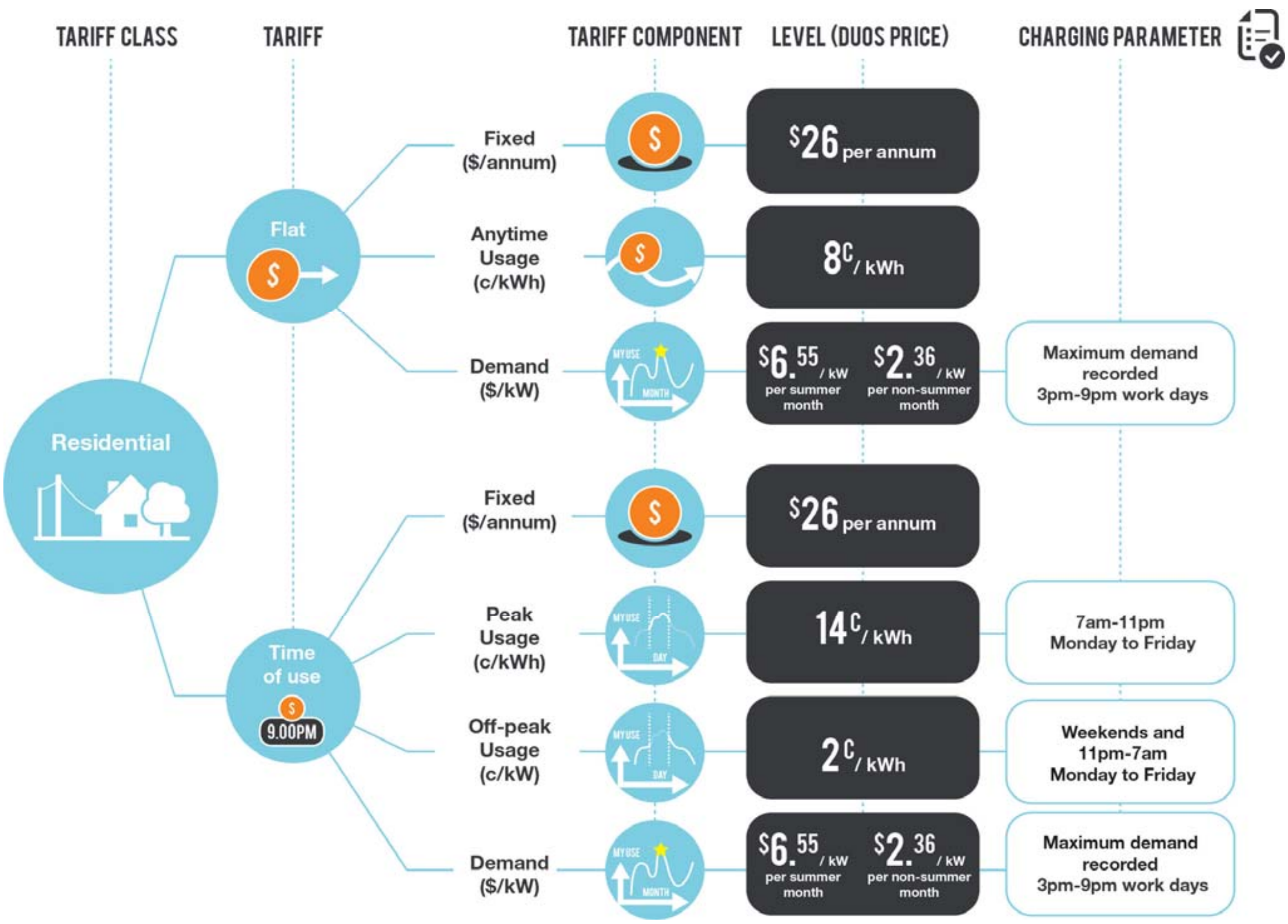
[14] Those customers with a dedicated circuit for our off-peak hot water heating only tariff would also be on another residential tariff for their remaining consumption.

[15] Customers are assigned in accordance with the tariff assignment and reassignment policy (see appendix G).

[16] Note that Figure 2-3 is a simplified example for illustrative purposes only and does not represent actual tariff classes, structures or levels, which are provided from Section 6 and in Appendix A.

- The **price levels** happen to be the same for the fixed and demand tariff components in each tariff, but different for the usage components
- The **charging parameters** provide additional information about how the tariff component is applied—for example, the summer and non-summer demand charge for both the flat and time of use tariffs only applies to the maximum demand recorded between 3pm and 9pm on work days.

Figure 2–3: Example of tariffs



Source: Jemena Electricity Networks

3. HOW WE SET OUR TARIFF SCHEDULE

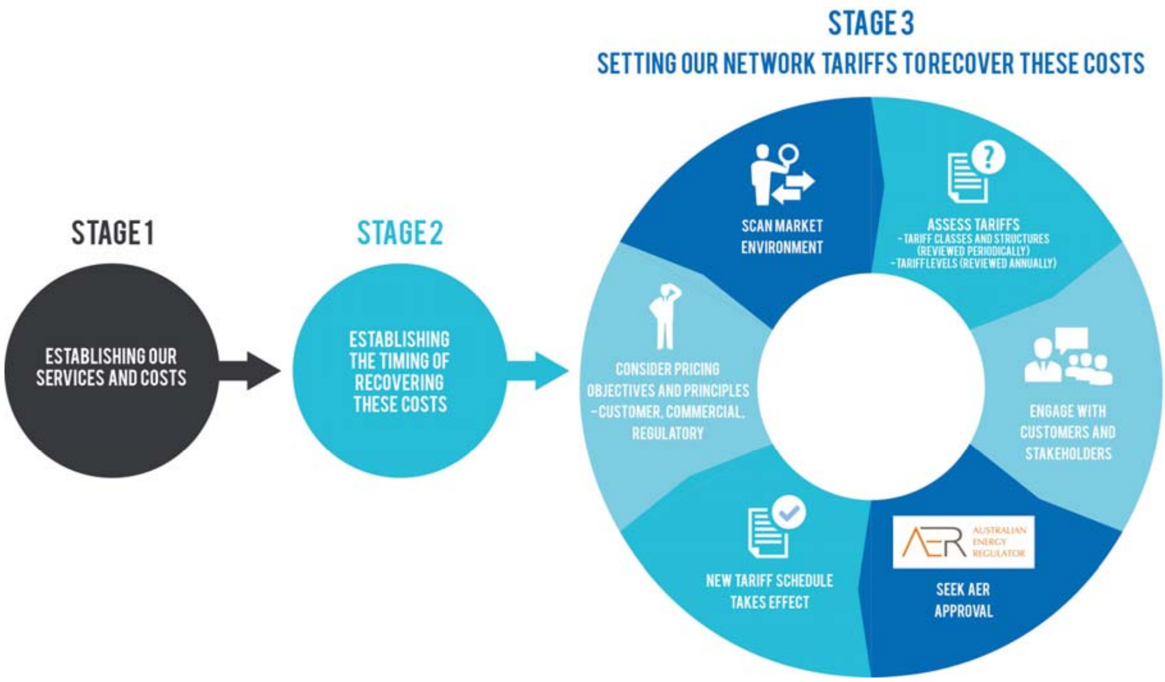
25. In general, the approach we use to set our tariff schedule involves three key stages:

1. **Establishing our services and costs**—taking into account customer feedback, we make decisions about the safety and service levels we will provide over the 2016 regulatory period, forecast the efficient costs of doing so, and therefore forecast the total revenue we will need to recover to meet our customers' expectations
2. **Establishing the timing for recovery of these costs**—deciding when to recover these costs over the 2016 regulatory period
3. **Setting our network tariffs to recover these costs**—we then make more detailed decisions, including establishing our tariff classes and tariffs, and deciding on the tariff structures, components, parameters and price levels for each of those tariffs to recover these costs.

26. The first two stages occur as part of developing the 2016 Plan. During the development of the 2016 Plan, we also go through the third stage for network tariffs that will apply in the first year of the 2016 regulatory period (that is, calendar year 2016).

27. The three stages are summarised in Figure 3–1. The sections below provide more information on the three stages.

Figure 3–1: Process of creating and updating our tariff schedule



Source: Jemena Electricity Networks

3.1 STAGE 1—ESTABLISHING OUR SERVICES AND COSTS

28. Establishing our services and costs for the 2016 regulatory period is the primary purpose of our 2016 Plan. We propose to the AER—for the AER's consideration and approval—our forecast of the minimum efficient costs

necessary to deliver a safe, reliable and responsive electricity service, in line with our customers' preferences, and in a manner that best promotes their long-term interests. The AER reviews our proposal against electricity legislation and makes a final decision on our services and costs for the 2016 regulatory period.

3.2 STAGE 2—ESTABLISHING THE TIMING FOR RECOVERY OF THESE COSTS

29. As part of our 2016 Plan, we also make decisions about the amount of costs we need to recover in each year of the period. This is known as a 'revenue path'.[17] The key steps in determining these are:

1. Considering the pricing goals we should meet and the NER requirements
2. Considering any emerging changes in the electricity market, including customer preferences
3. Developing a proposed revenue path that takes into account 1 and 2 above, and is based on recovering the cost required to provide our services in stage 1
4. Engaging with customers, stakeholders and the community on our proposed revenue path (and price path)
5. Finalising and seeking AER approval on the proposed revenue path (as part of our 2016 Plan).

30. See Table 10–1 for our proposed 2016 regulatory period indicative price path for our distribution services.

3.3 STAGE 3—SETTING OUR NETWORK TARIFFS TO RECOVER THESE COSTS

31. Once we have made broad decisions on our safety and service levels, forecast costs, and our revenue and price paths, we need to decide on how we set our network tariffs to recover these costs over the 2016 regulatory period. This is a complex and iterative process. The key steps are:

1. Considering the pricing goals we should meet and the NER requirements
2. Considering any emerging changes in the electricity market, including customer preferences
3. Forming a proposed tariff schedule that takes into account 1 and 2 above, and is based on recovering the cost required to provide our services in stage 1 and the timing established in stage 2
4. Engaging with customers, stakeholders and the community on our proposed tariff schedule
5. Finalising and seeking AER approval on the proposed tariff schedule
6. Implementing the approved tariff schedule.

32. Each year we, and the AER, revisit stage 3 to ensure the tariff schedule in the forthcoming year complies with the revenue allowed in the first two stages plus any allowed pass throughs under the rules. As we are regulated under a revenue cap, this means in any year, we need to refund any over-recovered, or collect any under-recovered, revenue from the previous year. Price level adjustments reflect changes approved by the AER (see to section 8).

33. The remainder of this document follows the structure of stage 3 (see Figure 3–1). We start by considering our pricing goals in section 4, and then move clockwise until a new tariff schedule takes effect (see section 9).

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[17] The revenue path also has an associated 'price path'. The revenue path sets out the timing for recovery of our forecast costs and the price path provides the annual price changes to enable this revenue recovery.

4. OUR PRICING GOALS

4.1 WHAT ARE OUR PRICING GOALS?

34. Our pricing goals are our first consideration when forming our tariffs for the 2016 regulatory period.

35. We have tested the following pricing goals with our customers and stakeholders:[18]

- *Recover efficient costs of operation*—that we have sufficient funding to provide a safe and reliable electricity network service now and into the future
- *Drive economic efficiency*—set prices that are cost reflective and empower customers to make efficient electricity consumption decisions
- *Treat customers equitably*—our tariff classes and tariffs ensure similar customers pay similar prices
- *Facilitate simplicity and transparency*—our customers can understand our tariffs and respond to price signals
- *Provide predictability*—our prices remain relatively stable over time to support customers' ability to make long-term decisions.

36. These goals reflect the requirements of the National Electricity Law (**NEL**) and the Rules (that includes the 'network pricing objective'[19] and pricing principles[20])—including the requirement that our 2016 Plan should promote the long-term interests of customers (see Box 4-1). They reflect our understanding of what customers want from their electricity service, as well as supporting our ability to deliver on these expectations over the long-term.

37. Our customers and stakeholders have expressed support for these goals[21], and we consider they are consistent with the network pricing objective and pricing principles (see section 4.2).

38. The remainder of this section 4 explains each of these goals in more detail and highlights how we consider they are consistent with the Rules. It also explains how we balance competing goals, consistent with the Rules.

Box 4-1: What do we mean by the long-term interests 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 2016 Plan 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

[18] These were tested at our 30 May 2014 and 2 October 2014 pricing workshops.

[19] The network pricing objective is 'that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer. See NER, cl 6.18.5(a).

[20] NER, cl 6.18.5(e)-(j).

[21] These were discussed at our 30 May 2014 pricing workshop. Our engagement is detailed in Attachment 4–1 to our 2016 Plan.

levels (and are not higher than they need to be because of inefficient operations or poor investments). This is referred to as promoting ‘productive efficiency’.

- Our service levels reflect what our customers want and are willing to pay for. This is referred to as promoting ‘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 is referred to as promoting 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 is referred to as promoting dynamic efficiency.

4.2 PRICING GOALS IN DETAIL

4.2.1 RECOVER OUR EFFICIENT COSTS OF PROVIDING SERVICES/OPERATION

Box 4-2: Pricing goal—recover efficient costs of operation

We will aim to set our tariffs to recover our efficient costs—and in a manner consistent with our other pricing goals.

39. Like most businesses, we need to recover our costs if we are to be a sustainable business that provides a safe, reliable and affordable electricity service over the long-term.

40. The AER reviews our costs every five years and we are not able to recover unnecessary or overstated costs. For expenditure requirements that are too difficult to forecast 5 years in advance, the AER will assess these more frequently, or as they arise. An example would be costs resulting of a major natural disaster, like an earthquake.

41. Ultimately, we must ensure that our prices provide adequate revenue to recover our efficient costs of operation. We need to recover our efficient costs so that we can continue to provide value for money electricity services in the long-term interests of our customers. Legislation governing the electricity market recognises the importance of this goal.[22] This goal is also consistent with the NER pricing principle to recover expected revenue.[23]

[22] National Electricity Law, s 7A.

[23] NER, cl 6.18.5(g).

4.2.2 DRIVE ECONOMIC EFFICIENCY

Box 4-3: Pricing goal—driving economic efficiency

We will set prices that are cost reflective and empower customers to make informed electricity usage decisions.

To promote this goal, we will:

- Set our tariffs to recover our efficient costs—and in a manner consistent with our other pricing goals
- Introduce demand tariffs to all tariff classes to provide a signal to reflect the cost of consumption during peak periods
- Recover residual revenue in a way that least distorts efficient price signals.[24]

42. We are required to create our tariff schedule in accordance with the Rules, which requires that our tariff classes and tariff components meet specific economic efficiency requirements consistent with the National Electricity Objective (**NEO**) (see section 7), including the network pricing objective. In general, the Rules are designed to ensure that tariffs and price levels are set to best encourage efficient use of, and investment in,[25] our electricity network.[26]

43. Meeting demand at peak times is the predominant driver of our costs to expand the network.[27] We need a network that can accommodate the moment when total demand is highest on our network. This moment generally occurs on a hot afternoon in summer, when many of our customers are using air conditioners to cool their homes and businesses. This peaking capacity will be unused for the remainder of the year.

44. It's in everyone's interests that we try and reduce or flatten this peak. The flatter the peak, the lower the need to augment our network. This more efficient use of the network will facilitate more efficient investment in the network. One way of achieving this (and, therefore, the efficiencies referred to in Box 4.1) is to provide price signals to encourage customers to spread out their usage.

45. We want our tariffs to allow customers to make informed decisions about when, and how much, they consume electricity. We can incentivise customers to make efficient consumption decisions by offering savings to those who spread out their usage and reduce their maximum demand.

46. This goal is consistent with the network pricing objective, and the pricing principle that requires tariffs to be based on long run marginal cost (and in particular, the requirement to have regard to the additional costs associated with meeting demand at times of greatest utilisation).[28]

47. The introduction of over 315,000 smart meters across our network means we can provide such pricing signals through our tariffs, as smart meters allow us to measure each customer's maximum demand.

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[24] Residual revenue is the revenue required to recover our efficient costs of operation less the revenue we will obtain from our demand tariffs.

[25] Often known as the 'stand-alone cost' and 'avoidable cost' tests (see NER cl 6.18.5(e)).

[26] The rules require us to base our tariffs on the long run marginal cost of transporting electricity (see NER 6.18.5(f). The long run marginal cost is the incremental cost associated with supplying additional volumes of capacity or electricity to customers over a period of time when all inputs to the production of the service can be changed.

[27] See section 7.2.2.3 and Appendix B for additional detail on our demand peaks.

[28] NER, cl 6.18.5(f).

4.2.3 TREAT CUSTOMERS EQUITABLY

Box 4-4: Pricing goal—treat customers equitably

We will treat customers equitably.

To promote this goal, we will:

- Group our customers together to ensure that similar customers pay similar prices
- Set tariffs mindful of current and future technologies and their potential uptake to ensure that our tariffs relate to the costs a customer imposes on the network and support efficient investments
- Consider customer impacts when developing our tariffs, tariff structures, price path and transition to cost-reflective prices.

48. Our tariff classes and tariffs are designed to ensure that customers are grouped together in an equitable way. For example, a residential tariff class ensures residential customers with similar load characteristics are grouped together (see Figure 6–1).

49. We expect the prevalence of new technologies, such as solar photovoltaics (**PV**), battery storage and electrical vehicles to increase over time. Each of these will have different impacts on our network. 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. We need to ensure that our tariffs are designed to provide appropriate price signals to these customers so that they are 'paying their way' and also that they face appropriately targeted bill saving signals to inform how they integrate these technologies into their total energy sourcing and usage decisions.

50. We also understand that moving customers onto new tariffs with different tariff structures and price levels will impact different customers in different ways. We think a measured and responsible transition to new tariffs will help mitigate the potential for unexpected sudden changes in customers' bills.

51. This goal is consistent with the rules for setting tariff classes[29] and the 'customer impact' principle.[30]

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29 NER, cl 6.18.3.

30 NER, cl 6.18.5(h) & (i).

Box 4-5: Pricing goal—facilitate simplicity and transparency

We will avoid unnecessary complexity in our tariff schedule.

To promote this goal, we will:

- Incorporate a demand charge into all tariffs rather than having separate tariffs with and without demand charges
- Continue to engage with our customers on pricing—for example, we welcome feedback on this TSS, which is a new document that facilitates customer and stakeholder understanding and engagement on our network tariffs
- Consult with customers and stakeholders before making changes to the TSS
- Provide indicative prices on our website (see section 10)
- Publish changes to annual prices earlier.[31]

4.2.4 FACILITATE SIMPLICITY AND TRANSPARENCY

52. Customers have told us that they can find it difficult to understand electricity pricing. Overly complex tariffs can:

- Make it difficult for customers and retailers to respond to the signals we provide to promote efficient consumption decisions
- Make it difficult for customers to engage with us as we develop our tariff structures
- Be a barrier to customer participation and retail competition in the energy market
- Be costly for us, retailers and the AER to implement and administer.

53. Therefore, we will avoid unnecessary complexity in our tariff schedule. This goal is consistent with the pricing principle that requires that customers must be reasonably capable of understanding the tariff structures.[32]

4.2.5 PROVIDE PREDICTABILITY

54. We understand that tariff volatility is undesirable for our customers. Stable and predictable tariffs allow customers to understand and respond to price signals and conduct long-term planning and budgeting. This will become even more important in the future for small/household customers, as they're increasingly faced with choices about whether to invest in new technologies and appliances. Long-term planning based on appropriate price signals will likely result in efficient electricity market outcomes.

55. We want our customers to be able to understand medium to long-term trends in tariffs so they can confidently make short and medium-term decisions about future energy consumption and technology investments. This

[31] We will submit our annual pricing proposals to the AER by 30 September for each year of the 2016 regulatory period. This had previously been 30 October.

[32] NER, cl 6.18.5(i).

goal is consistent with the pricing principle that we must seek to minimise the impact on customers of change in tariffs from the previous year.[33]

Box 4-6: Pricing goal—provide predictability

We will aim to minimise disturbance to our tariff structures and price levels.

To promote this goal, we will:

- Outline a clear transition to tariffs that include a demand based charge for all customers. This will be a move toward a proportion of residential and small customer network bills being recovered from the demand charge—the final proportion based on the goal of achieving cost-reflective prices (see section 7)
- Seek to mitigate customer impacts of any transition via the tools available to us, including speed of transition and price path considerations
- Provide, and regularly update, information on our intended strategy and tariff trends as part of our TSS and our annual pricing proposals.

4.3 WE HAVE TO BALANCE COMPETING PRICING GOALS

56. In some cases, our pricing goals conflict or compete with each other. Where this occurs, we aim to set tariffs in a way that balances the competing goals transparently and that ultimately best promotes the long-term interests of our customers.

57. The Rules allow for such balancing of objectives by allowing us to depart from the efficiency principles, to the extent necessary to meet either the consumer impact or jurisdictional pricing obligation principles.[34] We explain these departures in section 7.4.

58. For example, we need to make trade-offs between:

- **Cost-reflectivity and simplicity**—a purely cost-reflective approach would have approximately 320,000 tariffs on our tariff schedule—one for every customer that reflects on the costs that customer creates
  - However, this is impractical, would be confusing for customers, retailers and new market players, and would expensive to design and administer
  - We, therefore, make an on-balance decision about the number of tariff classes and tariffs we include on our tariff schedule.
- **Timely transition to cost-reflective prices and customer impacts**—when we update our calculations for cost-reflective prices, these can sometimes vary from our current tariff structures and levels
  - However, an immediate implementation of new cost-reflective prices could result in bill shock for some individual customers

[33] NER, cl 6.18.5(h).

[34] NER cl 6.8.15(c).

  - We, therefore, consider—and engage with our customers and stakeholders—on the speed at which we implement any changes to our tariff structures and other means to mitigate customer impacts, such as focusing our overall price decrease in the year we are introducing our new cost-reflective tariff structures (see section 7).

- **Price stability and economic efficiency**—the energy market is dynamic meaning the cost of supplying customers can vary over time

  - However, updating our network tariffs to ensure they are purely cost-reflective might incorporate a degree of volatility inconsistent with the value customers place on price stability and certainty

  - We, therefore, are cognisant of the potential for changing calculations of cost-reflective price levels, and make on-balance decisions of how often to update these.

5. RESPONDING TO MARKET CHANGES

59. 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. How we respond to these changes will influence how successful we will be in meeting our pricing goals.

60. Some of the key factors influencing the Victorian market include the mass introduction of advanced metering infrastructure (known as "AMI" or "smart meters") and changes to the way customers use our network as a result of rapidly developing technology, regulatory changes and the improving economics of alternative energy sources.

61. To understand the impact of these market changes, we engaged independent experts ACIL Allen to assist us in forecasting how customers are likely to use our network over the next five 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 our network will need to meet.

62. 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,[35] and the level of peak demand will grow at 1.4% per annum over the 2016 regulatory period.

63. The sections below provide more information on the emerging changes in the Victorian electricity market that we considered in setting our network tariffs for the 2016 regulatory period.

5.1 CHANGES IN THE ELECTRICITY MARKET

5.1.1 CUSTOMERS ARE INCREASINGLY TAKING CONTROL OF THEIR ENERGY DECISIONS

64. 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. This is demonstrated by the continued growth in the installation of small distributed generation units (such as solar PV units) at our customers' homes and businesses.

65. 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 smart meters, which make it possible for customers to access information on their energy usage in real time. This information allows customers to assess their technology investment decisions, including whether it is cost effective to go 'off-grid'.

66. Customers 'being off-grid' refers to customers whose home or business is within our network area, but is no longer connected to our network.[36] For a customer to be 'off-grid' requires them to have alternative energy sources, such as solar PV in combination with battery storage. Customers can also be 'partially' off-grid, whereby they are still connected to the network, but only rely on the network for electricity as a contingency or during abnormal consumption periods. While being off-grid is currently not economically competitive with being on-grid, future technological advances will challenge this paradigm for some customers.

[35] ACIL Allen is forecasting growth of 1.8 per cent 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 cent per annum in business consumption, primarily driven by the need to supply over 2,000 new business customers over the 2016 regulatory period.

[36] Where our network remains connected for back-up, or for the purposes of exporting energy into the network, we consider this as being partially 'off-grid'.

67. Many of our customers have already made significant investments in solar PV. For example, in 2001, we had almost no installed solar PV capacity on our network. At the end of 2013, this was over 43,000kW. Most of this increase has been since 2010, with customers taking advantage of government incentives. The number of installations decreased in 2013, in line with a reduction in these incentives. This amount of installed PV has changed the dynamics of our network.

68. Over the medium to longer term, we expect off-grid options to become a serious competitor to network-delivered electricity. This drives us to continually improve our price and service offerings in order to retain existing customers, and in the longer term also attract new customers.

5.1.2 INVESTMENT IN SMART METERS FACILITATES INFORMED CUSTOMER DECISIONS

69. Smart meters provide customers with real-time electricity usage data that enables them to make choices about how much electricity they use. Smart meters are now the standard electricity meter in Victoria. The roll out of smart meters is now complete, with almost 2.8 million smart meters installed across the state. As of August 2015, we have installed 322,000 smart meters operating on the Jemena electricity network.[37] This means over 98 per cent of our customers can access the benefits of the new technology and be more informed about their electricity choices and use.[38]

70. The Jemena Electricity Outlook portal (https://electricityoutlook.jemena.com.au/) is a tool that uses information from customers' smart meters. It provides customers with their usage data on a daily basis and the power to take greater control of their electricity bills. Customers are also able to use their consumption data to compare electricity retail offers on one of the government or commercially provided comparator websites. The portal also allows customers to use their own consumption data to compare electricity retail offers.

71. Smart meter data also allows us to gain a better understanding of how our customers use electricity. As a result, we are able to offer tariffs and tariff structures that reward customers whose consumption patterns help to minimise our costs.

72. Some of this data is plotted in Figure 5–1. This shows that low usage customers can have similar or even higher maximum/peak demand than large customers.[39] This data illustrates how usage-based charges (measured in c/kWh) are an imperfect signal of the cost of using electricity at peak times.

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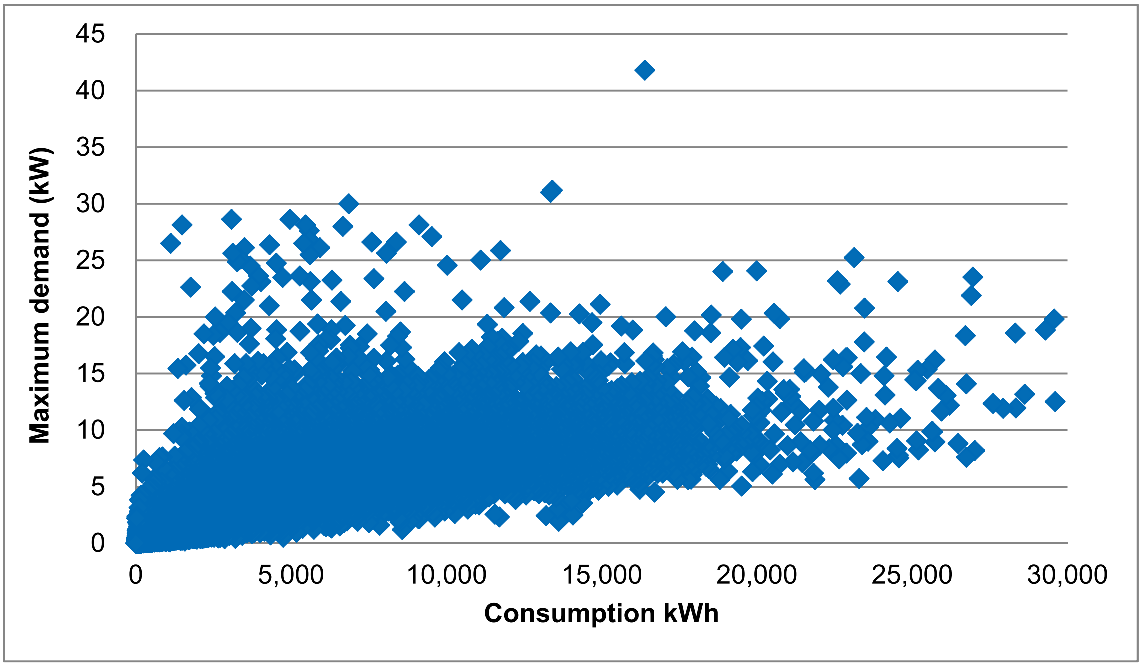
[37] Note that we have more meters than customers as some customers have more than one meter per national metering identifier. This is most common where a customer has three phase and an off peak load and the tariffs cannot be supported by a single physical meter.

[38] We are continuing to engage with customers to carry out the few remaining meter exchanges.

[39] Maximum demand is the point of highest demand from a customer. This will either be measured in a half hour or a 15-minute period.

Figure 5–1: Comparing usage to maximum demand



Source: Jemena Electricity Networks

(1) Sample size is 129,800 non-solar and 8,900 solar smart meter residential customers

5.1.3 NEW TECHNOLOGIES AND EMERGING MARKET PLAYERS

73. As technology advances, so does the impact of these technologies on our network.

74. For example, the increasing take-up of solar PV and other small distributed generators have changed the way customers use our network. We expect further changes to the way our network is used, as new technologies (for example, battery storage, electric vehicles and smart grids) and new market players (for example, aggregators and energy advisors) emerge and develop.[40]

75. 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 economic and demographic uncertainties will make it even more challenging to forecast electricity demand in the future.[41] Box 5-1 explains this further using the example of electric vehicles (**EV**).

76. Market 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.

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[40] Currently, 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, such as during peak periods.

[41] 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

Box 5-1 Electric Vehicles impact on demand and tariffs

EV uptake is an example of how economic and demographic factors can complicate forecasting electricity demand in relation to new and emerging technologies.

There are only a small number of EVs on Australia's roads at the moment (estimated 0.01 per cent of all passenger vehicles), due to supply constraints and relatively high purchase prices. Range anxiety—which is the concern that an EV's battery will run out of power before the driver's journey is complete—is also a major barrier that is preventing EV uptake.[42]

However, even the initial stages of EV adoption could pose the risk of exacerbating peak load in localised areas of the network because:

- Early EV adopters are expected to have above-average levels of income, education and vehicle ownership—this means that early adoption will occur in spatial clusters and not evenly across a given geographical area
- EV charging at home is the preferred option for EV owners, many of whom tend to begin charging immediately after they arrive home from work in the evening, which falls within the peak period on our network
- While EVs can be charged using general purpose outlets, consumer demand for larger battery sizes and faster charging rates means that the installation of rapid charging equipment, with higher instantaneous demand levels, could become commonplace in EV households.

This means forecasting electricity demand from EV charging requires more detailed analysis of uptake patterns. This is important because, as EV uptake increases, we need to consider efficient price signals that encourage load shifting to off-peak periods (for example, overnight) to prevent exacerbating peak load and encourage customers to spread out their usage.

Getting these price signals right ensures that we only need to augment our network where it is efficient to do so, allowing us to defer network augmentation and increase network utilisation during off-peak periods. Changing technology therefore needs to be a key consideration as we develop our tariff structures, as both these outcomes would have long-term benefits for our customers.

5.1.4 CHANGING POLICY AND REGULATORY ENVIRONMENT

77. There are three key regulatory factors that impact how we set our tariffs:

- The AER's changing approach to regulating our revenues and prices
- The requirements of the Rules regarding tariff-setting
- Victorian specific legislation that sets out tariff requirements for smart meter customers.[43]

5.1.4.1 AER approach to regulating our services

78. Section 2 outlined how we classify our various electricity services. For each service type, in simple terms, the AER can decide to control the revenues we are allowed to recover for customers, or the tariffs we are allowed to

[42] 'Range anxiety' does not refer to the physical limitation of EVs, but rather an issue that exists in the minds of potential consumers. Many EVs now have a range of around 160 km per full charge, which is higher than the average daily driving distance of many residents in the Melbourne metropolitan area, where 70 per cent of vehicles travel 40km or less on a daily basis. However, as EVs become more prevalent on the road and their technology develops further, range anxiety is likely to become less of a barrier to mass-market EV adoption.

[43] Victorian AMI Tariffs order in council for AMI customers.

charge our customers. For our distribution services, the AER will regulate annual changes in our allowed revenue by a revenue cap over the 2016 regulatory period.[44]

79. A key benefit of a revenue cap is that it incentivises us to minimise our costs. It drives us to seek ways to reduce demand peaks in order to minimise the cost of augmenting our network.

80. Our pricing strategy is therefore particularly important, as it should influence and incentivise customer usage behaviour in a way that reduces costs. This results in cost reductions that are ultimately passed through to our customers.

81. A consequence for customers of a revenue cap is the potential for increased year-on-year price fluctuations. This will occur if we do not recover our exact allowable revenue in a particular year, because any over or under recoveries result in an adjustment to the revenue cap for the following year. We will take this impact into account when setting annual prices to try and minimise annual price volatility.[45]

5.1.4.2 Changing policy environment

Network pricing rule change

82. On 27 November 2014, the AEMC changed the network pricing rules.[46]

83. The new Rule ensures network prices better reflect the costs of providing network services to individual customers. The Rules now requires network prices to reflect the efficient costs of providing network services to each customer, and sets out new pricing principles that we must comply with in setting the structure and level of our network prices. It also requires network businesses to engage in meaningful consultation with customers and other stakeholders when developing network prices.

84. These new requirements align more closely with our pricing goals. We are driven toward cost reflective prices (that reflect the efficient costs of providing the services to customers) to encourage efficient consumption patterns. This is facilitated by smart meters, which collect usage and demand data that will help us set and administer cost reflective tariffs.

85. This rule change also implemented new compliance requirements for tariffs, including those detailed in Table 1–2. Future rule changes, including those arising from the AEMC's 'Power of Choice' review, may also impact our future tariffs.[47]

Continuing tariff reform agenda

86. Following the AEMC's network pricing rule change, industry, governments and consumer bodies are working together on how to implement tariff reform in the most appropriate way.[48] While we have made significant progress on tariff reform via our engagement, data analysis and this TSS, we are aware that other stakeholders are still investigating how to approach tariff reform and the potential impacts it may have.

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44 AER, *Final framework and approach for the Victorian Electricity Distributors,* 24 October 2014.

45 We will also need to balance this against other impacts such as minimising distortions to the price signals, which are meant to encourage efficient usage.

46 AEMC, *Distribution network pricing arrangements,* Final determination, 27 November 2014.

47 See http://www.aemc.gov.au/Major-Pages/Power-of-choice

48 For example, the Federal Government released its final Energy White Paper on 8 April 2015. This included statements that 'Cost-reflective electricity tariffs give consumers better price signals about how they use energy. Consumers will increasingly be charged according to what it costs to supply energy at the time they use it' and 'Price signals discourage use during peak times, when energy is most costly to deliver, taking pressure off the network and reducing network costs, which are around half of the total electricity bill.

87. The outcomes of these stakeholder's investigations, including any Government policy, could impact our optimal response or what we are required to do with our tariffs. We will keep our customers informed of new developments as they occur.

5.1.4.3 Victorian legislation

88. Existing legislation made by the Victorian Government by way of an 'order in council' sets out certain requirements for network tariffs. The Government is currently considering the appropriate regulatory arrangements going forward. Our tariffs will comply with all relevant legislation.[49]

[49] This is also required by Rule 6.18.5(i)—the jurisdictional obligations principle that requires tariffs comply with the Rules and all applicable regulatory instruments.

6. PROPOSED TARIFF CLASSES

89. In developing our proposed tariff schedule, we aim to meet our pricing goals (discussed in section 4) and respond to the emerging market changes (discussed in section 5). We also need to ensure that our tariff classes meet the requirements of the Rules.

90. This section explains the tariff classes we propose to include in our tariff schedule for the 2016 regulatory period and how they reflect our pricing goals and the requirements of the Rules. Box 6-1 sets out the Rules relevant to setting tariff classes.

Box 6–1: Rule 6.18.3(d) of the National Electricity Rules

A tariff class must be constituted with regard to:

(1) *the need to group retail customers together on an economically efficient basis; and*

(2) *the need to avoid unnecessary transaction costs.*

91. As we have approximately 320,000 residential and business customers with a range of different load and connection characteristics, we group customers that have similar characteristics together. This ensures that the number of individual tariffs we have is sensible and avoids unnecessary administrative (or transaction) costs and confusion of having different tariffs for each customer. It also ensures that similar customers pay similar prices.

6.1 OUR DISTRIBUTION SERVICES TARIFF CLASSES

92. Distribution services are the core distribution network services and new connection services requiring augmentation (including customer initiated connections requiring augmentation).[50]

93. To support our pricing goals, we propose to continue offering five tariff classes for distribution services. Stakeholders supported this set of tariff classes.[51] Table 6–1 sets out the tariff classes and the customers that will be assigned to each.

Table 6–1: Tariff classes for distribution services

Tariff class	Class definition
Residential	Only available to residential customers
Small business	Only available to customers: 1. with annual usage less than 0.4 GWh and maximum demand less than 150 kVA (120kW); and 2. where supply is not taken from an on-site or dedicated substation.

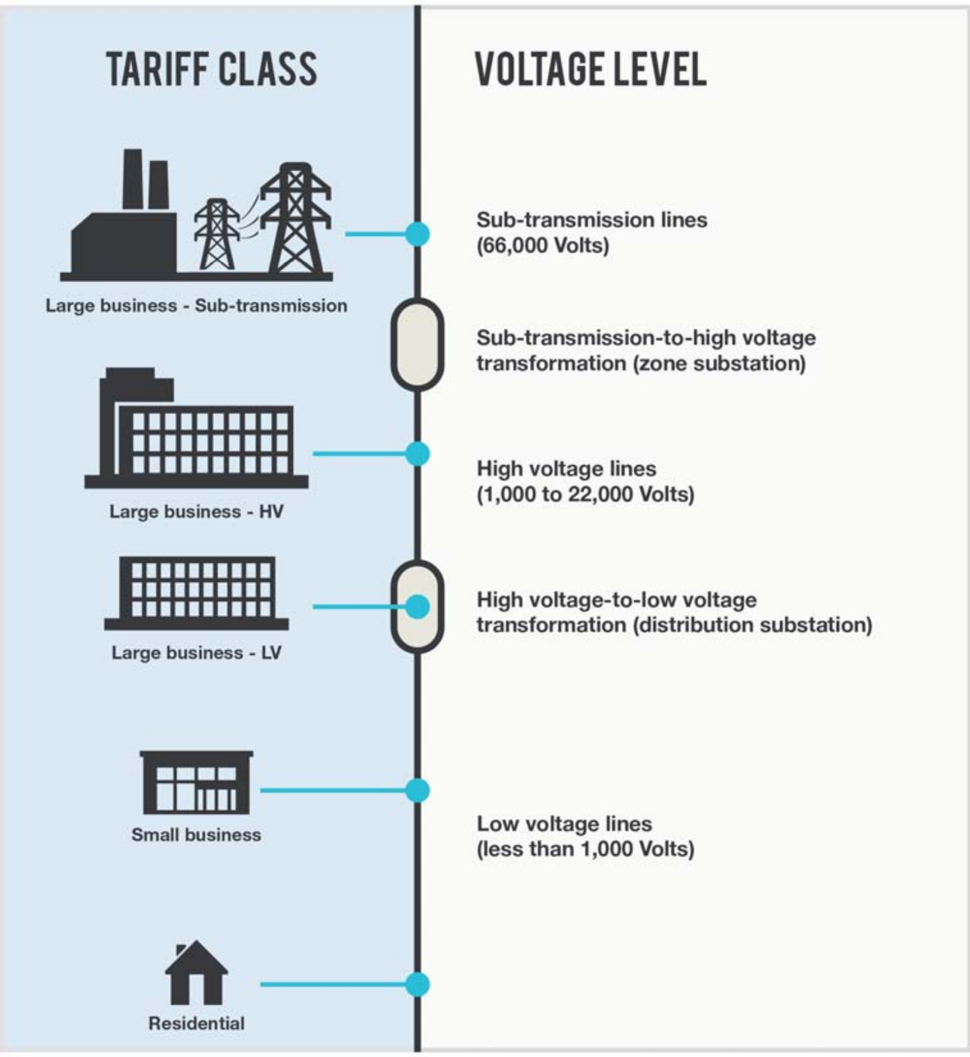
[50] Including new connections requiring augmentation of our shared network. Our distribution services are referred to as 'standard control services' in the AER's Framework and Approach paper. AER, Final Framework and Approach for the Victorian Electricity Distributors—October 2014.

[51] This set of tariff classes was discussed with stakeholders at our 2 October 2014 pricing workshop.

Tariff class	Class definition
Large business – low voltage	Low voltage tariffs (nominal voltage is less than 1000 volts) Only available to customers: 1. with annual usage 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)

94. Figure 6–1 shows how our tariff classes are aligned to our customer segments and physical characteristics of our network assets. Each of our customers will be assigned to a tariff within a tariff class.[52]

Figure 6–1: Our tariff classes



Source: Jemena Electricity Networks

52 In some limited circumstances, a customer will have more than one tariff such as customers with electric hot water or slab heating.

6.1.1 ECONOMICALLY EFFICIENT CUSTOMER GROUPINGS

95. 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.

96. Our set of tariff classes enables us to design tariffs that encourage efficient usage decisions by not including the cost of all network assets across customers who only use some. For example, large business customers who connect as high voltage levels do not use the low voltage network.

97. In some cases further, more subtle, pricing differentiation is desirable within our customer segments. We achieve this via pricing flexibility within tariff classes allowed under the Rules. For example, within the residential tariff class we offer both time of use and flat rate (called 'general purpose') tariffs to customers.[53]

98. This approach supports the goals of transparency and predictability and allows customers a better chance to understand the tariff structures that apply to them.

99. Section 7 contains further information on the efficiency of our tariffs.

6.2 USER-REQUESTED SERVICES AND METERING SERVICES TARIFF CLASS

100. We allocate the costs of providing user-requested 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. Our metering services include our services for smart and accumulation meters for 'small customers'.[54]

101. There are multiple tariffs (see Appendix H) for which the services are described in Table 6–2.

Table 6–2: User-requested and metering services

Service	Class definition
Fee based services	Includes: • user-pays services for which the AER has applied a cap on prices, for example, services such as connection, truck visits, fault response • metering for 'small customers' (Type 5 and 6 metering), Type 7 metering[55] and user-requested metering services

[53] This is possible through rule 6.18.6 that allows tariff rebalancing within the total revenue constraint on a given tariff class.

[54] This includes type 5 and 6 metering with annual consumption under 160MWh per year and type 7 metering. Our user requested services and metering services are classified by the AER as part of 'alternative control services'. AER, *Final Framework and Approach for the Victorian Electricity Distributors*, October 2014.

[55] Definitions of the different types of meters can be found here: AER, *Final framework and approach for the Victorian Electricity Distributors,* 24 October 2014, p. 47.

Service	Class definition
Public lighting (a subset of fee based services)	The operation, maintenance and replacement (**OM&R**) Services for public lighting, which the AER has applied a cap on the price per lighting type[56]
Quoted services	Services for which the AER has placed a cap on the applicable labour rates (inclusive of margins and all overheads)

102. These service offerings have not changed from those that applied during the 2011-2015 regulatory control period (**2011 regulatory period**). We tested, and received support for, these with stakeholders at our 2 October 2014 pricing workshop. As a result of this engagement we consider that there is no efficiency gain or other benefit to be made from altering this approach.

103. There is only a single tariff class for these services—the ‘alternative control services tariff class’. 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.

56 In the framework and approach paper, (October 2014) the AER sought to classify public lighting OM&R service for lights attached to shared poles as ACS and public lighting OM&R service attached to a dedicated pole as a negotiated service. Since this date—and following extensive public consultation—the AER has dedicated to classifying all public lighting OM&R services as ACS; this is consistent with the service classification in the 2011 regulatory period. JEN proposes to apply the service classification consistent with the AER’s revised approach.

7. PROPOSED TARIFF STRUCTURES

104. This section sets out our proposed tariff structures for the 2016 regulatory period. It is split into:

- **Our tariff structures**—the Rules require us to outline our tariff structures for both standard control services (the charges customers pay for using our network) and alternative control services (**ACS**) (the charges customers pay only if they request a specific service)[57]
- **Explanation of our proposed tariff structures**—as we are changing the tariff structures, we provide an explanation of what the new structures mean and why we have chosen them
- **Transition**—we are introducing a demand component to our tariff structures (and reducing our usage and fixed charges), and will do this in a way to minimise adverse customer impacts
- **Compliance**—we set out how we consider our proposed tariff structures meet the pricing principles set out in the Rules, including a description of how we have set prices and met the efficiency tests.

105. We have engaged with our customers and stakeholders to establish this set of proposed tariff structures. We highlight the areas where engagement has helped shape our prices. We have outlined our engagement on our prices in our overview of how we engaged with our customers and stakeholders in developing our TSS[58] as wend in an attachment to our regulatory proposal.

7.1 OUR TARIFF STRUCTURES

7.1.1 DISTRIBUTION SERVICES TARIFF STRUCTURES

106. The charges for distribution services make up the bulk of the network component of a customers' bill. All of the five tariff classes for distribution services (discussed in section 6) contain tariffs with specific structures that reflect our pricing goals and support the network pricing objective.

107. The term 'tariff structure' is the combination of the tariff components within a specific tariff. These components will be one or more of:

- A fixed (or 'standing') charge—an annual supply charge that applies at each premises electricity is delivered to ($ per annum) and paid on a pro-rated basis depending on the number of days in the billing period
- A usage charge[59]—a charge that applies to the volume of electricity consumed (in c/kWh), which could be a:
  - — Flat unit rate (applicable to all times of the day)
  - — Peak unit rate
  - — Shoulder unit rate
  - — Off peak unit rate

57 NER, cl 6.18.3(c).

58 JEN, '*How we engaged with our customers and stakeholders in developing our tariff structure statement*', 25 September 2015. Our approach to engagement across all elements of our 2016 Plan can be found in Attachment 4-1 of our 2016 Plan.

59 Note that 'energy' reflects that the amount charged is dependent on the energy delivered (and hence might be considered a variable charge). However, the unit price associated with each component is set each year and is not variable in any other way.

- A demand (or capacity) charge[60]—a charge that applies to a customer's capacity (either dollars per kilowatt $/kW or dollars per kilovolt-ampere $/kVA). Specifically for:
  - — Residential customers—this charge is based on the maximum demand (kW) in each month that is recorded between 3pm and 9pm work days with no minimum chargeable demand level. As peaks occur in summer months, the demand charge will be discounted in non-summer[61] months.
  - — Small business[62]—this charge is based on the maximum demand (kW) in that is recorded by the business between 10am and 8pm work days[63] and may be subject to a minimum chargeable demand level.[64]
  - — Large business[65]—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.

108. After engaging with our customers and stakeholders, we are proposing to make amendments to improve our structures for our standard control services over the 2016 regulatory period. This includes ensuring we have a demand charge tariff component within each tariff[66] (by adding the maximum demand charge for residential and small business customers), and providing appropriate incentives for power factor correction (by charging large business customers based on kVA). Our customers told us that including a demand charge tariff component within each tariff is preferable to an 'opt-in' basis. An opt-in approach would likely delay the realisation of benefits by all customers.

109. Our proposed changes are required to improve cost-reflective signals for customers so that they can make more informed electricity usage decisions in line with Rule requirements.[67] This approach facilitates efficiency and supports the long-term interests of all customers. Customers told us they understood the benefits of moving towards cost-reflective prices and supported the reasons and goals of doing so. They told us they strongly preferred incentivising customers to reduce their peak usage rather than just continuing to build network capacity to meet growing peak demand. They told us that cost-reflective prices represent a fair way of charging.

110. We are able to make these tariff improvements now because of the introduction of smart meters for residential and small business customers, which have provided us the necessary data to charge in new ways.

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60 Note that the amount charged is dependent on the capacity or maximum demand (the variable element). The unit price associated with each component is set each year and is not variable.

61 Summer months are December to March. Non-summer months are April to November.

62 The maximum demand is calculated as the highest of the maximum demand recorded for the current month and the maximum demand recorded in the previous month. For new customers it is determined as the highest between the maximum demand recorded for the current month, contract demand (if there is a contract is in place) and the minimum demand charge applicable to the tariff (if a minimum chargeable demand applies to the tariff).

63 This is the demand charging window for small business customers who were not already subject to a demand charge prior to 2017. That is, it excludes the 'time of use weekdays -demand' and 'time of use extended – demand' small business tariffs.

64 The full tariff schedule is provided at Appendix A, where a small business customer can find whether the tariff is subject to a minimum chargeable demand.

65 The maximum demand is calculated as the highest of the maximum demand recorded for the current month and the maximum demand recorded in the previous month. For new customers it is determined as the highest between the maximum demand recorded for the current month, contract demand (if there is a contract is in place) and the minimum demand charge applicable to the tariff (if a minimum chargeable demand applies to the tariff).

66 This excludes the off-peak hot water heating only tariff for the residential tariff class as this by definition should not be subject to a peak demand signal. It also excludes the 'unmetered supply' tariff for the small business tariff class for which a demand charge is not appropriate given the metered value must be estimated by definition.

67 NER, cl 6.18.5.

111. As shown in Table 7–1, the key differences between this proposal and our current tariff structures are that:

- For the residential tariff class, we are introducing a monthly maximum demand tariff component into the tariff structure in 2017 and transitioning this charge towards cost-reflective levels from 2018. Customers will be able to opt out of a tariff with a demand charge tariff component in 2017.[68]
- 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 towards cost-reflective levels from 2018.
- For all large business tariff classes, we are changing the basis on which the existing maximum demand charges are determined from kW to kVA charges from 2017 to better reflect the additional costs a poor power factor has on the system.

112. Introducing the new charges will not enable us to earn additional revenue, as we will be regulated under a revenue cap. This means we have no scope to recover more or less revenue from our tariffs than the total revenue allowed by the AER. Where the tariff levels do happen to over-or under-recover revenue in any one year (due to actual demand levels being different to forecast), we must adjust a near future year's tariffs to correct this.[69]

113. Appendix A sets out our full suite of proposed tariffs and tariff structures for each tariff within each tariff class.

114. Appendix A also indicates what has changed from our current tariff structures. We understand that, despite being revenue neutral, these changes represent a change to how customers are charged for our services.

115. When we consulted on this new approach with our customers, we suggested an extended and smooth transition to minimise the impact on customers and provide time and transparency to enable them to respond to the signals provided by the tariff structures.[70] However, our customers responded by telling us that they wanted these changes—seen as more equitable—to be made as soon as possible, where this can be done in a way that minimises individual customer impacts.[71]

Table 7–1: Overview of proposed changes to our network tariffs for the 2016 regulatory period

Tariff class	Tariff structures change	Transition path
Residential	Introduce maximum demand-based prices to the existing tariff structure—measured as monthly maximum demand recorded between 3pm and 9pm work days (the 'residential demand charging window')	• Systems introduction[72]—new tariff structure introduced on 1 January 2017 with demand charge at $0/kW to allow changes to market billing systems and customers to understand the demand component and adjust their behaviour—customers will be able to opt out of the new tariff structure in 2017 • Charging introduction—demand charges

[68] Opting out of a tariff with a demand charge tariff component will necessarily involve higher usage and/or fixed charge components to ensure these tariffs remain cost reflective.

[69] This is currently set to occur on a two year lag to ensure a full year's data is available when prices are set.

[70] Our extended transition was to set the demand charge at 5 per cent of cost reflective levels in 2018 and move in 5 per cent increments to 2020, with a plan to be at fully cost-reflective levels by 2030.

[71] Feedback from our residential and small business customers deliberative forum was that 73 per cent of customers asked encouraged us to transition to demand tariffs as soon as practicable, with another 23 per cent considering it should be phased in over 5 years. We heard the same from our customers and stakeholders at our 2 October 2014 Pricing Workshop and 16 February 2015 customer council meeting.

[72] A systems launch in 2017 with prices set to zero enables retailers an opportunity to make the required system changes.

Tariff class	Tariff structures change	Transition path
		phased in towards cost-reflective levels from 2018 (see Table 7–2)
Small business	Introduce maximum demand-based prices to the existing tariff structure[73]—measured as the highest demand recorded between 10am and 8pm work days in any month and may be subject to a minimum chargeable demand	• 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 7–2). Customers already subject to a demand-based tariff at 1 Jan 2016 will have a different transition (see Table 7–2)
Large business – low voltage	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		
Large business – sub transmission		

7.1.2 USER-REQUESTED SERVICES AND METERING SERVICES TARIFF STRUCTURES

116. Our charges for user-requested services and metering services are set out in the tariff schedule as a price list for specific services. The tariff structure is simple, as we list the services with the prices for providing these services during business hours and after hours, or we set out where the customer should request a quote.

117. We have made a small number of changes to these services as outlined in Box 7-1.

Box 7-1 2016 regulatory period changes to user requested and metering services

- *Supply enhancement at customer request*—this service was classified as an alternative control service for the 2011 regulatory period, although the service was not required, with the activities instead being provided as a routine connection or a new connection requiring augmentation. Continuing this practice means we have not provided a separate price for this service for the 2016 regulatory period
- *Supply abolishment*—the AER has reclassified supply abolishment (<100 amps) as a standard control service
- *Metering services*—metering services were regulated under Victorian legislation[74] in the 2011 regulatory period, but are now an alternative control service
- *Reserve feeder construction*—the AER has moved this out of alternative control services to a negotiated service[75]
- *Reserve feeder maintenance*—the AER has moved this from fee-based to quoted services

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73 Where one does not already exist.

74 The AMI cost recovery order in council (CROIC).

75 AER, *Final framework and approach for the Victorian Electricity Distributors,* 24 October 2014. A negotiated service allows JEN and a customer to negotiate the price and service under a negotiating framework provided by the AER.

- *Emergency recoverable works*—this will be unclassified and therefore not regulated by the AER[76]
- *Public lighting services*—operation, maintenance, repair and replacement activities of all public lighting assets are classified as fee based in the 2011 regulatory period. For the 2016 regulatory period, the same classification will apply.[77]

7.2 EXPLANATION OF OUR PROPOSED TARIFFS AND TARIFF STRUCTURES

118. In this section we outline our proposed changes to our tariffs and tariff structures.

7.2.1 PROPOSED TARIFFS

119. For the 2016 regulatory period, we will:

- Retain all tariffs[78] available at the close of 2015[79] (see Appendix A for a full set of tariffs)
- Add a special supply arrangements tariff
- Consider adding a new traction supply tariff, a preferential service tariff, a battery tariff, and/or a trial critical peak rebate tariff.

120. We are conscious that our customers are becoming more informed decision-makers with regard to their electricity usage and that this is likely to continue into the 2016 regulatory period. We are also on a path toward greater cost-reflectivity of our tariffs. As such, we will only add or remove tariffs within the 2016 regulatory period under the circumstances discussed below.

7.2.1.1 New tariff—special supply arrangements tariff

121. Under our proposed tariff structures, all business customers are subject to a ratcheting demand mechanism. However, some supply points are primarily used as a reserve in case of failure of a customers' primary supply. These supply points are used infrequently and, when in use, offset usage that would otherwise be consumed from the primary supply point. Current arrangements result in the customer's annual charges for the reserve supply point being set on the basis of the demand achieved as a result of a (very rare) primary supply failure. Therefore, we are planning to introduce a special arrangements tariff that will not be subject to the demand ratcheting mechanism. This tariff will be introduced in 2017 in line with the introduction of the new tariff structures.

122. The special supply arrangements tariff would be specifically for customers with special arrangements for reserve supply. It would apply only to the supply points with reserve as a primary purpose and where market

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76 AER, *Final framework and approach for the Victorian Electricity Distributors,* 24 October 2014.

77 In the framework and approach paper, (October 2014) the AER sought to classify public lighting OM&R service for lights attached to shared poles as ACS and public lighting OM&R service attached to a dedicated pole as a negotiated service. Since this date—and following extensive public consultation—the AER has dedicated to classifying all public lighting OM&R services as ACS; this is consistent with the service classification in the 2011 regulatory period. JEN proposes to apply the service classification consistent with the AER's revised approach.

78 As shown in Appendix A, the tariff refers to the combination of tariff components that apply to a customer. It does not refer to price level.

79 We are adjusting some tariff names to indicate those that now include a demand component.

arrangements require a separate national meter identifier (**NMI**).[80] Standard reserve feeder arrangements (which do not require a NMI) will be unaffected.

7.2.1.2 Potential tariff—traction supplies[81]

123. During our customer consultation we discussed with Metro Trains the cost reflectivity of their tariff.

124. As a result of this consultation, we are considering the introduction of a traction supply tariff in the 2016 regulatory period.

125. Before introducing this tariff, we would:

- Require information from Metro Trains that explains how Metro Trains' contribution to driving JEN's costs is different from other large customers
- Undertake analysis to determine:
  - Whether Metro Trains' current tariffs (or other existing tariffs on our network) result in charges that are materially different from cost-reflective levels
  - Any costs and benefits (including the introduction or mitigation of potential cross-subsidies) of the new tariff to the network and our customers' long-term interests
  - That the new tariff does not create cross subsidies.
- Undertake, and take into account, customer and stakeholder engagement on the potential tariff and any consequences of its inclusion.

126. If, as a result of this process, we determine it appropriate to introduce a new tariff for Metro Trains, we would take the approach of introducing the new tariff via the annual pricing proposal process (see section 8).

7.2.1.3 Potential tariff—preferential services

127. During our engagement with large customers, some of those customers requested that we investigate providing preferential services—that is, distribution services provided to a higher service level. For example, this could mean better expected reliability through higher levels of security and better response times for the part of the network that the relevant customer is connected to. As preferential services would drive higher costs, we would need to ensure that the customers requesting the preferential service would fully fund the additional costs of providing such a service through higher tariffs than the rest of our customer base.

128. Before introducing this tariff, we would:

- Investigate and define the various types of preferential services that we could offer
- Undertake analysis to determine:
  - Whether our existing tariffs would result in charges that are materially different from cost-reflective levels for preferential services
  - Any costs and benefits (including the introduction or mitigation of potential cross subsidies) of the new tariff to the network and our customers' long-term interests

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80 Australian Energy Market Operator, *National metering identifier procedure,* August 2009.

81 Traction supplies relates to power supply systems that are used for tramway and/or railway electrification systems.

  - That new tariff does not create cross subsidies.
- Undertake, and take into account, customer and stakeholder engagement on the tariff(s) and any consequences of its inclusion.

129. If, as a result of this process, we determine it appropriate to introduce a preferential services tariff, we would take the approach of introducing the new tariff via the annual pricing proposal process (see section 8).

7.2.1.4 Potential tariff—network benefit tariff

130. Box 5-1 detailed the potential impact of EVs on our network. There is also the potential that customers may invest in other battery options, for example a battery and solar PV combination. These technologies may be metered separately from customers' primary supply and therefore may enable characteristics such as a different reliability levels or be capable of interruption that have benefits for the distribution network.

131. We want to facilitate the efficient deployment of new technologies in our network. This requires ensuring that we have tariffs available that reflect the costs of supplying customers using these technologies.

132. Before introducing a network benefit tariff, we would:

- Understand the consumption profile or usage characteristics of customers with new technologies, including storage
- Understand the costs (and any potential benefits) of supplying those customers
- Assess whether existing tariffs would recover the costs and provide efficient price signals to those customers
- Understand any costs and benefits (including the introduction or mitigation of potential cross subsidies) of any new tariff to the network and our customers' long-term interests
- Undertake, and take into account, customer and stakeholder engagement on the tariff and any consequences of its inclusion.

133. If, as a result of this process, we determine it appropriate to introduce a new network benefit tariff, we would take the efficient approach of introducing the new tariff via the annual pricing proposal process (see section 8).

7.2.1.5 Potential tariffs–trial tariffs

134. We may undertake trials of critical peak rebates over the 2016 regulatory period. These trials can have potential benefits of obtaining targeted response in certain locations.

7.2.2 TARIFF STRUCTURES

7.2.2.1 Fixed charge tariff component

135. Our fixed (standing) charges are specific to each tariff. We have not changed any structure or charging parameter of our fixed charges. We set our fixed charges to signal to the customer:

- The largely fixed cost nature of distributing electricity to their premises
- The cost to connect customers to the network having regard to the size, location and type of customer.

7.2.2.2 Usage charge tariff components

136. Our usage charges are specific to each tariff. We have not changed the structure or charging parameters of any of our usage charges. We set our usage charges to:

- Complement the price signal provided by our demand charges
- Provide incentives to customers to make efficient energy usage decisions.[82]

137. Our tariff schedule sets out our usage charges. There will be an overall price decrease for our residential and small business customers over the 2016 regulatory period (see section 10). The decrease in usage charges will be relatively significant because we are increasing the price level of the demand charges, under transitional arrangements, to cost reflective levels and we must remain revenue neutral. Residential customers who choose to opt out of the demand charge in 2017 will not be subject to these decreases (given they will not face the demand charge).

7.2.2.3 Demand charge tariff components

138. As noted in section 7.1, we are seeking to make improvements to our tariff components. To achieve this we are:

- Introducing a demand charge within each residential and small business customer tariff
- Changing how we measure demand for large business customers from kW to kVA.

Residential and small business customers demand component

Adding a demand charge improves the cost-reflectivity of tariffs

139. Introducing a demand charge will result in a fairer way of charging that will enable signals to be provided to customers that better reflect our costs of serving them.

140. A demand charge will empower customers to take control of their electricity usage and electricity bills. In the changing market environment section (see section 5), we noted how it is important we ensure that the tariffs we charge more closely reflect our cost of providing network services to our customers. This is also required by the network pricing objective.

141. Currently, some customers who use a lot of electricity at once (e.g. by running several large air conditioners at once), at a time when the network is most under strain, are not paying enough to cover their share of building a network to accommodate peak demand. This means that other customers—who don't use the network in this way—have to pay more than their fair share.

142. We have to build our network so that it copes with the maximum amount of electricity used by all customers on a very hot day. Our variable costs are driven by the need to meet peak demand on our network (when everyone is using electricity at the same time). Section 5.1.2 demonstrates that a customer's total demand (measured in kWh) is not a good proxy for a customer's maximum demand (measured in kW). Therefore, reliance on usage-based charges may not send efficient price signals and therefore not meet the pricing principles where there is capability to measure demand in kW.[83]

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82 Flat rate tariffs allow customers to save by reducing total consumption, or, for those tariffs with peak and off-peak components, customers can also save by consuming a greater proportion of their total consumption during off peak time.

83 NER, cl 6.18.5.

143. The installation of smart meters across the majority of our network means that we will have information on customer's maximum demand level (the moment in a day when the customer is using the most electricity). This enables us to charge on a maximum demand basis.

144. Over time, as some customers respond to price signals by reducing their maximum demand, these changes will also mean we won't have to spend as much money on building the network to meet maximum demand. We will ensure these savings are passed on to our customers through lower bills.

145. We will be regulated under a revenue cap over the 2016 regulatory period. We, therefore, have no scope to recover more or less from our tariffs than the total revenue allowed by the AER. Our incentive is to provide cost-reflective price signals, such that customers make informed energy usage decisions.

How do we introduce the demand component for residential and small business customers?

146. We will introduce a demand tariff component to residential and small business tariffs as follows:

a) Calculate a cost-reflective maximum demand charge level (kW) for each residential and small business tariff and set this as the approximate level that we want to reach following a period of transition (see section 7.3)

b) Introduce a maximum demand charge in two phases[84]:

   i) a 'systems introduction' from 1 January 2017, where we implement the demand tariff as part of each customer's tariff, but set the prices to zero—this enables billing systems to be ready for the change

   ii) a 'charging introduction' from 1 January 2018 with positive prices that will start below cost-reflective levels (as calculated in (a)) and then increase over time towards the cost-reflective levels in line with the transition outlined in 7.3

c) As we increase the price level of the demand charge tariff component through the transition, we would reduce our usage and/or fixed tariff components to ensure the total revenue we collect remains within the allowance set by the AER

d) A residential customer's maximum demand is calculated as the customer's highest half-hour demand level (in kW) in each month that falls between 3pm and 9pm work days (the 'residential demand charging window'). Appendix B demonstrates how we chose the 3pm to 9pm window

e) Residential customers would be billed on the actual maximum demand that occurs within the residential demand charging window in each month (with the measured demand reset each month).[85] We explain this further with an example in box 7-1

f) The price associated with the demand charge will be discounted for residential customers in non-summer months[86]

g) Residential customers would be able to opt out of the tariff that includes a demand charge component in 2017

h) Small businesses customers would be billed on the highest maximum demand level recorded between 10am and 8pm work days[87]

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84 We consider such a transition would be necessary to meet our predictability goal and ensure customers can react to the new price signal provided.

85 After testing with our pricing workshop, we consider resetting the demand level each month us appropriate given residential customers consumption patterns can vary substantially across the year and we need to maintain incentives to use electricity efficiently on an ongoing basis.

86 Summer months are December to March inclusive, non-summer months are April to November inclusive.

i) All other current tariff components for residential and small business customers would remain unchanged—noting that the associated pricing levels of these components would be lower than they would have been without the demand charge (see Appendix A).

147. A majority of customers we spoke to told us they thought demand charges were fair and that they were likely to respond to our price signals by reducing their maximum demand during peak times.[88]

Box 7-1 What is our monthly maximum demand tariff for residential customers?

Example of how the demand charge works

Suppose the summer monthly maximum demand (**MD**) charge is set at $6/kW per month and the non-summer monthly maximum demand is set at $2/kW per month, then for a customer who:

- In January, the MD is recorded as 5kW at 7:00pm on a work day—the related monthly maximum demand charge for January would be $30
- In February, the MD is recorded as 3kW at 4:00pm on a work day—the related monthly maximum demand charge for January would be $18
- In March, the MD is recorded as 4kW at 6:00pm on a Thursday. The customer also happened to record 6kW at 3:00pm on a weekend—the related monthly maximum demand charge for March would be based on the 4kW MD during 3:00pm and 9:00pm on a weekday and would be $24
- In April, the MD is recorded as 5kW at 5:30pm on a work day—the related monthly maximum demand charge for January would be $10.

How can customers save?

Under our proposed tariff structure, residential customers could reduce their electricity bill in a new way—by reducing their maximum demand—that is, by spreading out when electricity is consumed during 3:00pm to 9:00pm weekdays ('the residential demand charging window'). Retaining a usage charge means customers can also save by reducing their total usage over the billing period.

As shown in

Figure 7–1, customers do not necessarily have to move usage out of this residential demand charging window to save. Assuming the monthly maximum demand price is set at $6/kW per month, then the customer in the example would save around $6 in each month they are able to reduce their maximum demand from 5kW to 4kW.

Our free Electricity Outlook portal allows customers to view their daily energy usage – see electricityoutlook.jemena.com.au. Customers can also use an in-home energy display to see details about your electricity usage in real-time.

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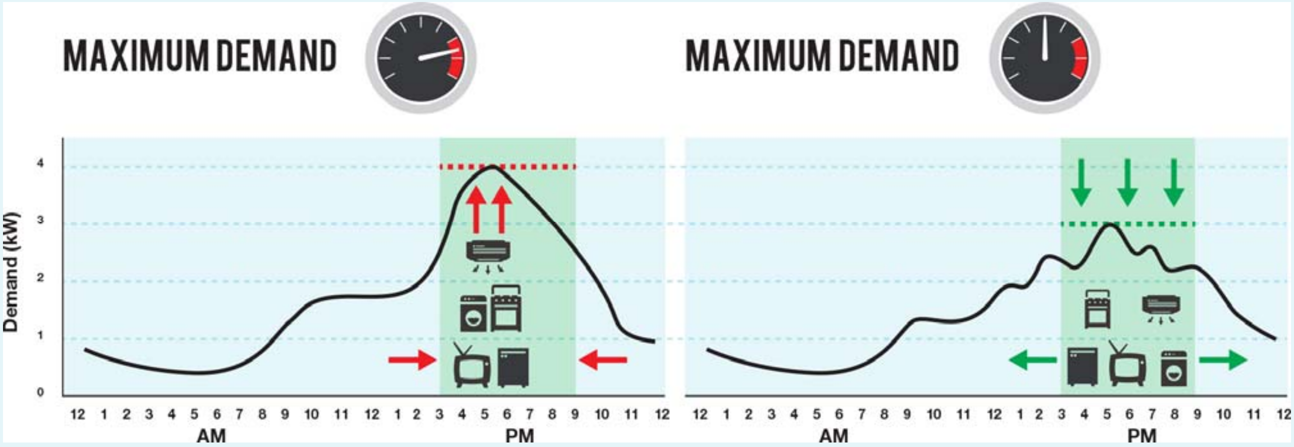
87 This is the customer's highest half-hour demand level (in kW) recorded between 10am and 8pm weekdays. The billed maximum demand in any month is determined as the highest of the maximum demand recorded for a month and the sum of maximum demand for previous month (with demand reset in accordance with demand reset policy). After testing with our pricing workshop, we consider this approach is appropriate as small business customers consumption patterns are closer to large businesses (that is, they are more stable across the year) and we need to maintain incentives to not exceed their previous maximum demand levels.

88 79% of attendees at our deliberative forum thought that charging households according to maximum demand used at peak times was fairer and 87% said they were at least somewhat likely to reduce their maximum demand during peak periods if demand-based charging was introduced. See Attachment 4-1 to our 2016 Plan for our detailed engagement process and feedback.

Figure 7–1: Save by spreading out usage



In 2017, residential customers can opt out of demand tariff until 2020

148. We understand that a move to a new way of charging creates uncertainty for some customers and that some customers might prefer choice. To facilitate this, customers will be able to elect to opt out of the demand tariff in 2017. To enable this choice, an opt out tariff will be introduced with no demand charging component (in line with the existing flat rate tariff structure). Customers who choose to opt out in 2017 will be able to remain on the opt out tariff for the remainder of the period (up until 31 December 2020). Customers could do this by contacting their retailer in 2017 to request to be allocated to the opt out tariff.[89]

149. We do not anticipate many customers would benefit by opting out from the cost reflective demand tariffs. This is because:

- An opted-out customer would only face fixed and usage tariff components.
- In order to ensure these are cost reflective tariffs, the price of each of these components would need to be higher than in the tariff that has a maximum demand component
- The decision to opt out would not enable a customer to save from reducing their maximum demand.

Residential and small business customers without AMI meters

150. We have installed smart meters for around 97.8 per cent of our residential and small business customers.[90] We need a mechanism to charge non-smart meter customers for their maximum demand. This needs to be set in an equitable manner to ensure fair treatment of all customers and using a method which does not provide an ongoing incentive to refuse installation of a smart meter.

151. Our approach is to move these customers to the opt out tariff in 2017. These customers will remain on the opt out tariff until the end of the regulatory period or they install a smart meter. This approach will mean that non-

[89] This must be customer instigated.

[90] We were not able to access all customer premises to upgrade their meter.

smart meter customers, who want to be able to realise savings from taking control of their demand, have an added incentive to install a smart meter.

152. We consider this approach is preferable to alternatives such as:

- Charging those customers the usage components only of the new cost reflective tariffs—this is not equitable as the discount received would result in an inefficient cross subsidy
- Applying the new demand-based tariffs using an estimated demand level for the customer—this may provide high demand customers (or those that suspect they are high demand customers) incentive to continue refusing the installation of an smart meter.

Tariff structure options considered, but not proposed

153. There is a spectrum of potential tariff components that can signal the cost of using our network (see Figure 7–2).

154. At one end, there are the traditional tariffs with which most residential and small business customers are familiar. These are simple to understand, however, they do not send signals to customers about the cost of using our network, particularly during peak periods.[91]

155. For example, a flat rate for energy supply does not signal to customers the higher cost of supplying electricity during peak periods. Therefore, customers may not consider this cost when deciding to turn on (or off) their appliances. As a result, peak demand is likely to be higher than it might otherwise be which imposes higher costs on all customers. The traditional pricing structure also means that customers who consume a significant proportion of the electricity from our network during peak periods are not contributing their fair share. These customers may include those with distributed generation units (such as solar PV), as these reduce a customer's total consumption from our network but may not reduce their usage during peak periods.

156. 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 parts of our network. While most of our large business customers are familiar with these capacity tariffs structures, they are more complex to administer and for customers to understand and for them to respond.

157. In particular, we do not consider that a locational critical peak demand[92] 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 Rules.[93] 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.

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[91] Section 5.1.1 shows that energy charges (c/kWh) are imperfect at targeting costs on peak users and are therefore poor at sending cost-reflective signals and enabling customers to make informed energy consumption decisions.

[92] Critical peak is the time on our network when customers collective demand level in kW or kVA is at its highest (or peak) point. A customer's coincident peak is their demand level in kW or kVA at the critical peak.

[93] See customer impact principle, NER, cl 6.18.5(i).

Figure 7–2: Network tariff component options for signalling the cost of using our network

Source: Jemena Electricity Networks

Large business customers demand component

158. The proposed approach for large business customers is to change how we measure demand for the demand charge tariff component from $kW to $/kVA from 2017. We propose to make this change, as it is the quality of customers' power factor that imposes additional costs or creates savings on our system. While kW provides a maximum demand level, it does not provide an indication of a customer's power factor.

159. We will provide an information paper to our large business customers at least six months prior to the change. This allows our large business customers a chance to consider their circumstances and invest in means to improve their power factor if they wish.

160. Many large business customers considered kVA charging is a fairer way of charging, and will be looking at opportunities to improve their power factor. Some of our large business customers told us they were unsure about what the introduction of kVA-based charges would mean for them, and would value more information, including on future tariff levels to assist them in managing their businesses. We have committed to continue to meet individually with our large customers to provide them with more information about our proposed kVA charges and outline options available to them to improve their power factor.

7.3 TRANSITION TO OUR PROPOSED NEW TARIFF STRUCTURES

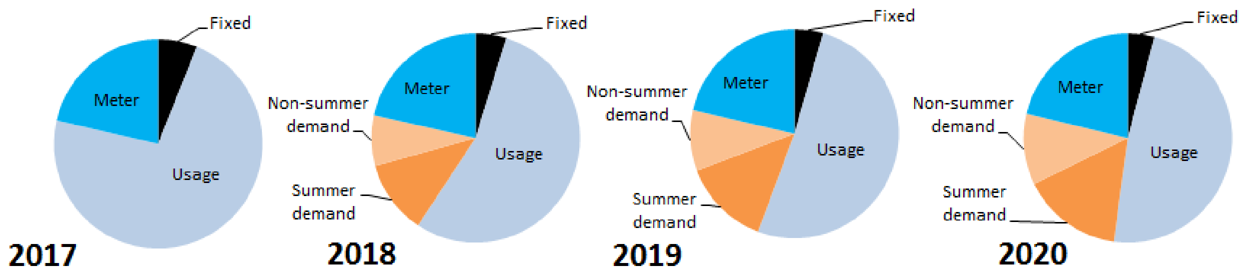
161. We understand that a move to new tariff structures and cost-reflective prices under the Rules will impact different customers in different ways. To enable time for customers and stakeholders to understand and adapt to the changes, we are:

- Introducing a positive charge in 2018 for the maximum demand tariff component for our residential and small business tariffs
- Transitioning the price of the demand tariff component over a number of years.

162. The effect is that, assuming no behaviour change, the contribution to a customers' bill of the demand tariff component will increase over time while the contribution of other components decreases (see Figure 7–3). We expect this will reach approximately 27% of a customer's distribution bill by 2020, which works out to be around

10% of their final retail bill. We would recover around 60% of a customer's total annual demand charge amount over summer months.

Figure 7–3: Proportion of bill from each tariff component (median residential customer example)



Source: Jemena Electricity Networks

163. Table 7–2 outlines our proposed transition to our proposed tariff structures over the 2016 regulatory period. Our current expectation is that all our maximum demand charges will reach fully cost-reflective levels by 2025, but we will consult with customers and stakeholders on this further over the 2016 regulatory period and in preparation for our 2021 regulatory proposal. We will determine cost-reflective demand charges based on the long run marginal cost (**LRMC**) of providing network services to the relevant tariff class.[94]

164. In developing our proposed transition, we engaged with our customers and stakeholders. We consider this transition, combined with our proposed price path (see section 10), reflects our customers' and stakeholders' preference for a quicker transition that minimises impacts on individual customers.

165. We are able to transition to 50 per cent of cost-reflective price levels in 2018 whilst minimising customer impacts by focusing our overall price decrease in 2018. This is because:

- Our 2016 Plan results in an overall real price decrease in our distribution network charges over the 2016 regulatory period
- Our 2016 Plan includes a price path,[95] with an overall price decrease in 2018, which puts downward pressure on all our customer's prices
- Customers who would have had bill increases in 2018 due to the new tariff structures (i.e. those with relatively higher demand levels), will have these increases mitigated by the average decrease.

Table 7–2: Transitioning to new tariff structures for our distribution services

Tariff	Maximum demand charging parameter	2016	2017	2018	2019	2020
All residential[96]	$/kW pa	×	Opportunity for customers to opt out	✓ (50 per cent of scaled LRMC	✓ (60 per cent of scaled LRMC	✓ (70 per cent of scaled LRMC

94 As required by NER cl 6.18.5(f).

95 See section 10 and Attachment 4.1 to our 2016 Plan for further detail on our price path and how we worked with our customers and stakeholders to determine it.

96 Excludes the 'off-peak hot water heating only' tariff which will not have a maximum demand charge.

				level)	level)	level)
				Opt out tariff for customers who opted out	Opt out tariff for customers who opted out	Opt out tariff for customers who opted out
Small business without demand tariff prior to 2015[97]		×		✓ (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 Appendix E 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').

7.4 COMPLIANCE—OUR ASSESSMENT OF OUR TARIFFS, TARIFF STRUCTURES AND TARIFF LEVELS AGAINST THE PRICING PRINCIPLES

166. This section provides information on how we set our network tariffs and how we have arrived at specific tariff levels. It describes how each of our steps in the process have been instructed by the pricing principles, including efficiency requirements, in the Rules.

167. Appendix C provides the relevant requirements from Rule 6.18.5.

168. We have made sure that our tariff levels meet the efficiency requirements within the rules. This includes:

- **Meeting the network pricing objective** that tariffs for a customer should reflect our efficient costs of providing services to those customers:
  - Ensuring the revenue for each tariff class sits between the **avoidable and stand alone cost** of supplying these customers (see Appendix C for relevant rule requirements)[98]
  - Basing our tariffs on our estimates of the **LRMC**.[99]

169. These tests seek to ensure there are no inefficient cross subsidies between customers.

[97] Excluding the 'unmetered supply' small business tariff, which will not have a demand tariff added.

[98] NER, cl 6.18.5(e).

[99] NER, cl 6.18.5(f).

7.4.1 MEETING THE NETWORK PRICING OBJECTIVE

170. The network pricing objective (see Appendix C) requires that our tariffs for each of our customers should reflect the costs of providing services to those customers. Our tariffs only move from these efficient levels to mitigate the effects on customers (the customer impact principles) and to meet jurisdictional legislation or orders in council (the jurisdictional obligation principle).

7.4.1.1 How our tariffs meet network pricing objective and pricing principles

171. The Rules require us to show how we have 'based' our tariffs on LRMC estimates, that we will recover our efficient costs, and only diverge from this to give effect to the customer impact principles and the jurisdictional obligation principle. We note that a final tariff level is set by balancing all of our pricing goals, which might involve certain qualitative judgements.

172. Our tariff levels have a primary function of recovering our costs as determined by the AER every five years. Our costs are made up of more than just expenditure to accommodate growth. It includes our funding costs on our previous investments, tax and reinforcement and renewal expenditure as well as fixed overhead costs. This is why the combination of our charges will exceed those set solely at LRMC values.

173. This section describes how we consider we have balanced the pricing principles in Rule 6.18.5 to meet the network pricing objective and best meet customer's long-term interests.

174. We describe how we have set our prices, including our LRMC methodology in Appendix E. The remainder of this section describes how this approach meets the pricing principles.

Our tariffs are based on LRMC

175. Rule 6.18.5(f) requires our tariffs are to be based on LRMC. All our tariffs under our proposed tariff structures[100] would have a demand component included and we can set that demand charge (after a period of transition) based on the LRMC level we have calculated for each of our tariffs as in Table 7–2. This provides a direct link between the LRMC levels and our tariff levels (or prices).

176. Based on stakeholder feedback to mitigate customer impact by providing customer choice during transition, we have included an option for customers to opt out of a tariff that contains a demand component. The opt out tariff will depart from our preferred approach to base our tariffs on the demand (kW) LRMC. However, the tariffs (and the prices for the usage and fixed components) will still be set to best reflect the LRMC values and revenue we would obtain had a demand charge applied. Appendix E describes the methodology we will use to set up prices for the opt out tariff.

Demand charges signal cost of meeting demand at times of greatest utilisation

177. Rule 6.18.5(f)(2) requires we have regard to the costs of meeting demand at times of greatest utilisation. By applying the LRMC to the demand charge and measuring the demand level as the individual customers maximum demand (kW) for residential and small business customers and power factor for large business (kVA), we are focusing this price signal to periods of greatest utilisation. Appendix B describes how we chose the residential and small business demand charging windows we will use to record residential and small business maximum demand.

178. Signalling the cost at times of greatest utilisation is simplest with the demand charge tariff component. For customers who choose to opt out of the demand tariff during 2017, we are less able to provide that signal for the

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[100] Other than the off peak heating only tariff for residential customers and unmetered supply tariff for small business customers, which by definition are not driving peak demand.

remainder of the 2016 regulatory period. However, opt out is the customer tariff choice mechanism that maintains the signal for the largest proportion of customers.

We need to consider administrative costs when choosing the method to calculate LRMC

179. We considered both the Average Incremental Cost (**AIC**) approach and Turvey (perturbation) approach to calculating LRMC and the costs and benefits associated with calculating, implementing and applying the methods (Rule 6.18.5(f)(1)). We consider that, on balance, the administrative cost of undertaking the Turvey approach would exceed any benefits. This is because the Turvey method is complex and requires multiple demand permutations and engineering assessments of capex to provide robust results. We do not consider the cost of obtaining robust results would provide any potential additional benefit that would outweigh what we can obtain from LRMC estimates from the AIC approach.[101]

Not pricing by location at this time

180. As shown in Figure 7–2, the potential ways to charge fall on a spectrum. An important part of tariff reform is that we are taking steps toward more cost-reflective prices that are consistent with available technology and customer understanding. We consider that introducing a demand charge to all our tariffs, with the option for opt out, will achieve this.

181. We consider that the benefit of signalling locational differentiation (as required under Rule 6.18.5(f)(3)) needs to be balanced against the administrative costs of doing so (Rule 6.18.5(f)(3)) and customer's ability to understand our tariffs (Rule 6.18.5(i)) and mitigate the impact of year on year changes in our tariffs (Rule 6.18.5(h)(3)).

182. We also would want to consider the benefits of critical peak rebates from first conducting a trial (see section 7.2.1.5). We would reconsider locational differentiation once we have trial results and our customers have had a period of time to understand our new way of charging.

We recover our efficient costs (allowed revenue)

183. We set our tariff levels to ensure we recover our required revenue set out as part of our 2016 Plan. This relies on our demand forecasts as we need to know demand and prices to obtain our required revenue. To meet the requirement under Rule 6.18.5(g)(2), we demonstrate we have recovered only our efficient costs in our annual pricing proposals (see section 8). These must demonstrate our total forecast revenue for each year is equal to our allowed revenue (plus any allowed adjustments).

184. Further, to ensure we align our LRMC calculation with our method for recording residential and small business customers demand levels (as maximum demand occurring between 10am and 8pm weekdays), we have scaled our LRMC estimates to establish a 'cost-reflective level'.[102]

185. Section 7.4.2 describes how we meet the stand alone and avoidable cost tests. This demonstrates how the revenue for each tariff reflects the total efficient costs of serving the customers in that tariff (Rule 6.18.5(g)(1)).

We recover our efficient costs in a way that minimises distortions to price signals for efficient usage

186. Rule 6.18.5(g)(3) requires that we recover our efficient costs in a way that minimises distortions to price signals. For each tariff, we do this by:

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[101] In particular, because there is little evidence as to which method produces more accurate and appropriate results for distribution network pricing.

[102] Our LRMC estimates in Appendix E are calculated with reference on the annual coincident peak, but JEN's prices will apply to individual residential and small business customer maximum demand that occurs over a wider peak period (10am to 8pm weekdays). Therefore, we need to scale the LRMC to derive a $/kW demand charge that is cost-reflective of how we are measuring demand. See Appendix E for further explanation.

- Using our estimates of LRMC to establish the basis of our prices—we establish our 'raw' demand component tariffs levels for each tariff to these prices (see to our price setting description in Appendix E)
- We use the 'raw' demand component tariffs levels with our forecast demand levels to provide the expected revenue collected from the 'raw' demand tariff component
- Working out residual revenue to be recovered from each tariff class and tariff[103]
- Collecting residual revenue from our fixed, usage and demand charges to minimise any distortions to the signals provided by our raw demand component levels (Rule 6.18.5(g)(3)) and minimises customer impacts (Rule 6.18.5(h)).

187. For our residential customers, and majority of our small business customers for whom demand charging is new, this means we will not adjust the demand charge from the 'raw' demand component tariffs levels.[104] We then apportion residual revenue to the usage and fixed charges in a manner consistent with the costs of serving that tariff. This enables the price signal, which is new for these customers.

188. For our large business customers and those small business customers on a demand tariff prior to 2017 for whom demand charging is well established, this means we need to adjust the 'raw' demand component tariffs levels to minimise the customer impact of any change. We consider this is a prudent approach, consistent with the Rules, because:

- We will seek to better align our demand component tariff level to our calculated cost-reflective levels over time (Rule 6.18.5(h)(1)).
- However, we will not make significant year on year changes—while we have undertaken significant work to establish our LRMC estimates, these are subject to a number of assumptions, the quality and availability of the data inputs and the exact methodology. There can be different LRMC outcomes under different assumptions/methodologies and depending on when we run the model run. We are seeking to provide predictability and avoid any volatility in our prices.
- Any material decreases to the demand charge would provide a perverse incentive for these customers to allow their power factor to deteriorate and result in additional network costs that are unlikely to be in customers' long-term interests—we need to make the adjustment to ensure a rational long-term price signal is maintained.

189. Our approach for setting our tariff levels for each tariff is provided in our price setting description at Appendix E.

We estimated customer impacts and listened to customers about what transition and price path makes sense

190. Rule 6.18.5(h) is one of the customer impact principles. It requires us to minimise the impact on customers of year-on-year changes in tariffs. This allows for us to balance how we transition, the extent customers can choose their tariff and customers' ability to mitigate the impact through their consumption decisions.

191. Our proposed approach does not enable customers to initially choose whether their tariff has a demand component as all tariffs will initially have a demand component added. However, we consider our approach to transition, the option to opt out of the demand tariff component in 2017, and the ability for changes in customer behaviour to directly relate to savings on their electricity bills means we have struck a sensible balance for this customer impact principle. Additionally, our customers told us that including a demand charge tariff component within each tariff is preferable to an 'opt-in' basis. They considered that an opt-in approach would likely delay the realisation of benefits by all customers.

[103] To the extent possible, we are seeking to maintain the proportion of revenue obtained from each tariff class and tariff as currently. We have not found any evidence these are not currently cost-reflective.

[104] Other than to reflect the transition described in section 7.3.

192. We undertook residential customer analysis of four potential transitions to our proposed new tariff structures:

1. Implementation of fully cost-reflective prices in 2018—the analysis showed this would have the greatest impact on individual customers—especially those with relatively higher demand than usage levels—with around 5 per cent of our customers having network bill increases of over $100 in 2018.
2. A 'restrained transition'[105]—this severely restricts customers receiving any price signal. Our customers also considered a restrained transition was too slow for customer benefits realisation, so we accelerated the transition.
3. Our proposed 'accelerated' transition (see section 7.3)—this enables a swift move to cost-reflective prices and, by applying a price path that focuses distribution services price decreases in 2018, this enables individual customer impact to be mitigated.[106]
4. Beginning the transition with a positive charge in 2017—we presented this option with our customers and stakeholders at our 12 August 2015 workshop to gather feedback on whether an aligned Victorian distributor 2017 charging introduction would be preferable. Feedback suggested a general preference for alignment, with customers preferring 2018 as a first choice and a retailer preference for 2018 to allow necessary updates to systems to be in place and tested.

193. We consider that our proposed transition clearly mitigates the potential for adverse individual customer impacts. The construction of our monthly maximum demand charge also allows customers to save by spreading out their usage as described in Box 7-1. Hence, they have ability to mitigate the impact through their usage decisions.[107] Our customer council considered our approach and how we balance the customer impacts principles sensible.[108]

194. We also heard from stakeholders that customer choice of tariffs is important as part of the transition to fully cost reflective prices for all customers. We have, therefore, included the ability for customers to opt out of a tariff that contains a demand component. This will allow customers to consider if the opt out tariffs would help them mitigate their own bill impacts. A customer who has opted out, would be able to opt back in to the demand tariff.

195. We consider that, on balance, these departures from cost reflective tariffs are appropriate to give effect to Rule 6.18.5(h).

We have made our messages simple

To support customer's ability to understand (Rule 6.18.5(i)), we have kept things simple. This includes:

1. Adding the demand component to all (non-peak specific) tariffs, but allowing customers to choose to opt out
2. Providing simple messages to customers to spread out their usage during peak periods, allowing them to save on their bills should they have an appropriate retail tariff that passes through the benefit
3. Targeted communications (including through published fact sheets, energy forums and partnering with other stakeholders).

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105 Our restrained transition was 5 per cent of cost reflective levels in 2018, with 5 per cent increments to 2020, and fully cost-reflective by 2030.

106 Our analysis showed that in 2018, approximately 87 per cent of customers would have a price decrease under our proposed 'accelerated' transition and price path approach. An individual customer's impact would depend on their consumption and demand levels, with those with lower relative demand (compared to consumption) having savings of up to $80. It also showed the greatest negative impact would be on a low consumption (2233kWh), high demand (4.27kW) customer archetype (who make up around 1 per cent of our customers) who would pay an extra $56 in 2018. This is mitigated from $75 by our price path approach to focus price decreases in 2018.

107 A consideration under NER, cl 6.18.5(h)(3).

108 See Attachment 4.1 of our 2016 Plan.

We have heard our stakeholder and customer feedback and sought to align with other Victorian distributors

196. Throughout our customer and stakeholder engagement, a key and strong theme was to align with other Victorian distributors on key design elements. Our stakeholders and customers considered this essential to gain customer understanding and to facilitate mass market communications (to inform of the demand charge tariff component introduction and for retailer call centres to respond to customer enquiries). Aligning our approach has clear benefit to support customers' ability to understand (Rule 6.18.5(i)).

197. At this stage, where we are introducing the new way of paying for electricity, we consider customer acceptance and understanding is a primary driver over pure cost reflectivity. To this extent we have ensured we aligned with other Victorian distributors on the following key areas:

- The design of the demand tariff (monthly maximum demand)—no change to our draft TSS.
- No locational pricing at this time—no change to our draft TSS.
- The time period for the residential demand charging window—we moved this window to 3pm-9pm work days from 10am-8pm weekdays to allow one state-wide residential demand charging window for residential customers. Refer to Appendix B that outlines why we think this will not have any perverse impact for the 2016 regulatory period.
- The use of a discount for non-summer demand charge (with the same definitions of summer and non-summer)—as we have summer demand peaks, this alignment also moves us closer toward cost reflectivity.

198. Based on our customer and stakeholder feedback, we consider there is benefit to align with other Victorian distributors and that on balance, this benefit accrued under Rule 6.18.5(i) outweighs the current detrimental impact under Rule 6.18.5(f) of moving away from what we consider is cost reflective for our network. We will reassess this balance as we approach our 2020 regulatory period, once customers would have had some experience of the new demand tariffs.

199. We also received strong stakeholder and customer preference for the residential demand charging window to exclude weekends and public holidays (i.e. work days only).[109] For our network we sought to understand the systems costs to achieve this change from our original position of weekdays. We anticipate that moving to work days will have a small systems cost implication. We consider that the feedback we received supporting a work day approach would justify the additional systems spend.

200. We also understand that, for other Victorian distributors, weekend peaks are possible in certain parts of their network now, and which may increase in future as a result of this position. This is, therefore, an area that all distributors will need to monitor going forward and revise on an individual basis where residential customers' consumption patterns suggest this is required.

201. It has been indicated that some Victorian distributors are planning to transition to cost reflective prices starting from 2017. Our preference is not to introduce positive demand prices in 2017, to allow time to implement changes to market billing systems. Also, a $0kW demand charge will allow customers time to understand the demand concept and to potentially adjust their behaviour in 2017 to minimise bill impacts by the time the positive price is introduced.

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109 We presented the issue of any day vs weekday at our 12 August 2015 pricing workshop (made up of consumer representatives, energy retailers, Victorian Government and statutory authorities and large customers) and received overwhelming feedback supporting a work day approach. We also received two letters co-signed by Alternative Technology Association, St Vincent de Paul Society, Consumer Utilities Advocacy Centre, Victorian Council of Social Services, Consumer Action Law Centre, Kildonan, Brotherhood of St Laurence, Community Information & Support Victoria, Rights, Information and Advocacy Centre, Ethnic Communities Council of Victoria, The Country Women's Association Vic, COTA Victoria, Financial and Consumer Rights Council, Good Shepherd Australia New Zealand. These letters supported demand charging that excluded weekends and public holidays.

202. However, if JEN had to introduce a positive demand charge in 2017 for the benefits of alignment with other Victorian distributors, we would introduce the minimum sufficient positive price. We would then transition in line with the proposed approach described in Table 7–2 in 2018–2020.

Our customers support our approach

203. We have set out why we consider our approach meets the pricing principles and network pricing objective in the Rules. By design, meeting these criteria should facilitate the NEO by promoting customers long-terms interests. We also need to understand customer preferences to ensure our approach will best promote the NEO.

204. Box 7-2 summarises key customer feedback.

Box 7-2: Feedback from residential and small business customers and other stakeholders on tariff structures for the 2016 regulatory period

- 90 per cent of our customers asked understood and accepted a maximum demand charge on their network bills as fair and equitable[110]
- 71 per cent of customers asked indicated that they would respond to a maximum demand charge[111]
- 73 per cent of customers asked encouraged us to transition to these tariffs as soon as practicable, with 23 per cent considering it should be phased in over 5 years
- 74 per cent of retailers we asked indicated that they would incorporate a maximum demand charge in their retail prices for residential and small business customers[112]
- Upon being provided analysis, our customers and stakeholders supported:
  - (a) our proposed transition to cost-reflective maximum demand charges (see section 7.3)
  - (b) tariff design aligning with other Victorian distributors
  - (c) a price path that targets price decreases in 2018 when we introduce the maximum demand charge to mitigate individual customer impacts.

We will comply with jurisdictional requirements

205. Rule 6.18.5(i) is the jurisdictional obligations principle that requires tariffs comply with the Rules and all applicable regulatory instruments. We understand that the Victorian government is considering a policy response on tariff reform and we will comply with all jurisdictional schemes as required.

7.4.2 STAND ALONE AND AVOIDABLE COST EFFICIENCY TEST

206. This test is designed to ensure our customers ‘pay their way’ without ‘paying too much’.

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110 Asked the question “How well do you understand the concept of capacity pricing?”, 15 per cent indicated ‘completely’, 35 per cent indicated ‘very’ and 40 per cent indicated ‘moderately’.

111 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’.

112 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’).

207. The avoidable costs for a tariff class are the theoretical cost savings that would be made if the customers in that tariff class were to cease to exist whilst all other customers in other tariff classes remained the same. This is often a relatively low value as it would generally only include assets specifically dedicated to those customers and a portion of operating expenses reflecting the incremental costs of supplying each customer.

208. Requiring that revenue from a tariff class is above avoidable cost ensures our customers ‘pay their way’. This makes sense because if the revenue from these customers was less, then revenues from customers in other tariff classes would be ‘too high’, meaning other customers may be inefficiently cross-subsidising that tariff class.

209. The stand alone cost for a tariff class is the theoretical cost of building and operating a network designed solely for that tariff class. This is often relatively high because, by definition, there are no economies of scale from using shared assets to supply multiple tariff classes.

210. By requiring revenue from a tariff class to be below stand alone cost we ensure customers don’t ‘pay too much’. This makes sense as we don’t want to incentivise inefficient behaviour by encouraging customers to duplicate our assets and build their own network as this would mean these customers would not be able to share any of the efficiency benefits from using a shared network.

211. Table 7–3 shows that we expect all our revenue from each tariff class to fall between the stand alone and avoidable cost estimates. Further information on our methodology for calculating these values can be found in Appendix D.

Table 7–3: Efficient bounds for expected revenues[113]

Tariff class	Avoidable cost ($)	2016 Revenue ($)	Stand alone cost ($)	Compliance check
Residential	19,858,164	114,602,888	297,053,247	✓
Small business	6,154,420	60,818,333	169,349,770	✓
Large business – low voltage	3,186,575	66,175,777	78,547,904	✓
Large business – high voltage	1,326,490	20,169,858	46,287,606	✓
Large business – sub-transmission	c-i-c	c-i-c	c-i-c	✓

(1) Costs are annualised stand alone and avoidable costs.

7.4.3 ESTIMATING LONG RUN MARGINAL COST

212. To enable customers to make informed decisions, we need to provide price signals of the costs associated with those decisions. Prices set on the basis of marginal costs provide a signalling function to ensure customers make efficient usage decisions at the margin. LRMC measures how long run operating and capital costs change as a result on an ‘incremental’ demand change. We use estimates of the LRMC as the basis for these price signals.

213. LRMC differs from an estimate of short-run marginal costs as it assumes that all inputs can feasibly be altered so as to capture the cost of building additional capacity.

113 Stand alone and avoidable costs are annualised to make them comparable to a single years revenue.

214. The Rules require us to estimate LRMC and to base our tariffs around these estimates. This does not mean setting every tariff level at an LRMC estimate as we must also give consideration to the remaining pricing principles in rule 6.18.5 (see section 7.4.1.1). The Rules defines LRMC as[114]:

> *…the cost of an incremental change in demand for direct control services provided by a Distribution Network Service Provider over a period of time in which all factors of production required to provide those direct control services can be varied*

215. Meeting demand at peak times is the predominant driver for us to expand and augment our network. Therefore, in order for our customers' usage decisions to take into account costs associated with peak demand, the LRMC should signal the expected additional costs arising from increases in peak demand levels. This means we should provide our LRMC estimates for each tariff expressed as demand and/or capacity components; that is, $/kW or $/kVA.

216. Accordingly, we have calculated $/kW and $/kVA LRMC estimates (as appropriate) for each of our tariff classes and tariffs using an approach known as the average incremental approach. Like any approach to estimating LRMC, the outputs of this method are subject to:

- The assumptions made
- The quality and availability of the data inputs.

217. Our LRMC estimates for our tariff classes and tariffs, including our methodology for calculating LRMC is in Appendix E.

7.4.3.1 Metering services and user-requested services

218. We have not calculated a LRMC for user-requested services (including metering services) as these are effectively charged on a ring-fenced cost-recovery basis.

219. For metering services, and public lighting services, the costs (and their recovery) are ring-fenced from the costs of all other services through separate regulatory reporting and price-setting models. The primary cost-drivers for providing metering and public lighting services are the capital costs of each meter type and light type. To reflect this, our tariffs for different meter types and light types are weighted by the relative capital costs of the relevant meters and lights.

220. For fee-based and quoted services user-pays fees recover the full costs of providing the service, almost all of which are incremental and specific to the customer requesting the service.

[114] NER, Definitions, Chapter 10.

8. UPDATING OUR TARIFF CLASSES, STRUCTURES AND LEVELS

221. As discussed in section 3, we may make adjustments to the tariff schedule for each of the last 4 years of our 5 year regulatory period, subject to consulting with our customers and stakeholders and the obtaining the AER's approval.

222. In each of these four years, we will engage with customers and submit a revised version of our TSS only if we wish to revise our tariff structures.

223. In addition, in each of these four years, we will submit a document—the annual pricing proposal—to the AER for assessment and approval. The annual pricing proposal will explain:

- How we propose to vary tariffs levels from the start of the next financial year (1 January)
- Any material differences between the pricing proposal and the information on tariffs and tariff structures in our TSS, including material differences between our annual pricing proposal and the previous indicative price schedule.[115]

224. The sections below provide more detail on the annual process for updating the tariff schedule following the first year of the 2016 regulatory period, and on making changes outside of these annual adjustments.

8.1 ANNUAL CHANGES TO THE TARIFF SCHEDULE

225. Like most businesses operating in a competitive environment, we update our tariffs and charges each year. This enables us to respond to changing market conditions and recover our costs in a way that continues to be consistent with our long-term pricing goals.

226. Given that we want to involve customers and stakeholders in our decision-making, we will engage with our customers and stakeholders on these annual changes. In addition to preparing a TSS we will:

- Inform customers and stakeholders of the annual changes in the tariff levels through the Customer Council, the JEN website and email notification to registered subscribers
- Consult with customers and stakeholders on any proposed changes to tariffs structures we have flagged in section 7.2.1 through the JEN Customer Council, retailer forums, and potentially focus groups with residential and business customers. This consultation would occur around November in any year.

227. The process for annual changes to our network tariffs taking effect from 1 January each year is contained within chapter 6 of the Rules. We have summarised these steps in Table 8–1.

[115] Rule 6.18.2(b)(7A) of the NER requires that we 'demonstrate how each proposed tariff is consistent with the corresponding indicative pricing levels for the relevant regulatory year as set out in the relevant indicative pricing schedule, or explain any material differences between them'.

Table 8–1: JEN annual pricing proposal and approval process

Timing	Process
November-February	JEN consults on any proposed revisions to the TSS if these are required
End of March	JEN submits revised TSS to AER (if required) and publishes it on its website
July 20 (approximately)	June CPI becomes available
End of August	AER decision on revised TSS
August-September	JEN prepares the annual pricing proposal and revised indicative network use of system (**NUOS**) prices
End of September	JEN submits its annual pricing proposal to the AER for approval
Mid November (6 weeks after JEN submits its annual pricing proposal to the AER)	AER decision on annual pricing proposal
1 January[116]	New tariffs and any new tariff structures to take effect.

228. The annual pricing proposal will contain a description of all the elements that makes up the change including:

- The inflation[117] figures
- The X factor[118] approved in the AER's final determination
- All annual adjustments[119] where actual costs have been different to those allowed by the AER
- All proposed pass through amounts[120] which have a significant positive or negative impact on our costs
- A comparison of the indicative NUOS pricing schedule and the outturn tariffs in the annual pricing proposal and an explanation of all material differences[121]
- An updated indicative NUOS pricing schedule
- Any relevant outcomes from our customer engagement.

116 For the 2016 regulatory period, prices for the period ending 31 December 16 are set by the AER's first final determination of JEN's EDPR. The first year that there will be an annual pricing proposal will be 2016 (for prices for the year ending 31 December 17). The first year that a TSS applies is 2017. Once approved by the AER, the first year the TSS might be revised (if required) is during 2017 (for tariff structures to apply for the year ending 31 December 18).

117 We use the Australian Consumer Price Index (**CPI**) as the measure of inflation per the methodology outlined in the EDPR.

118 The X factor is a nominal price change. The distribution X factors form part of an AER's determination of the 2015 Plan, and drive annual price increases or decreases.

119 The form of price control requires truing up the actual revenue as it varies to forecast for standard control services, Type 5 and 6 regulated metering services, designated pricing proposal charges and jurisdictional scheme amounts (see Attachment 5.2 of our 2016 Plan).

120 Pass-through events are for specific unforseen events. Our pass through events include natural disaster events, terrorism events, insurance credit risk events, insurance cap events and carbon cost event, National Energy Customer Framework Event and Rapid Earth Fault Current Limiter event (see Attachment 5.4 of our 2016 Plan).

121 NER cl 6.18.2(b)(7A)

9. HOW A NEW TARIFF SCHEDULE TAKES EFFECT

229. Section 8 outlined that a new tariff schedule will take effect annually (as at 1 January). This section outlines how our tariff schedule updates make their way into customer bills.

230. The bill that a customer faces comes from their electricity retailer. Our network charges are paid by the retailer. Therefore, the retailer designs the actual prices customers pay and these may vary depending on the offer customers signed up for.

231. Following the AER's approval of our network tariffs in November of each year, retailers need time to incorporate our network tariffs, estimates of their costs and their competitive strategy, into their retail prices.

232. The retail market in Victoria has been deregulated, which means there are a number of different retailers who compete for customers and the government is satisfied that this competitive pressure does not require them to apply close scrutiny to retail prices.

233. Once retailers have set their prices, customers are able to use comparison tools to help compare the price of different energy offers and to make an informed decision about which offer best suits their needs. Customers can shop around for a retailer who offers a deal that best suits their needs. A customer who wants to actively manage their usage to save from our new tariff structures should seek a retail deal that will pass these savings on to them.

234. There are a number of comparator websites including commercial switching sites or the Victorian government provided comparison site www.switchon.vic.gov.au. The AER also has the Energy Made Easy website (www.energymadeeasy.gov.au).

10. INDICATIVE PRICES

235. Our final network tariffs we charge (sometimes referred to as network use of system charges or '**NUOS**') include the costs associated with both our distribution network (distribution use of system charges or '**DUOS**') and a number of other costs that we pass through[122], including transmission costs (transmission use of system charges or '**TUOS**'). They must also incorporate the outcome of some incentive schemes we operate under and to balance any under- or over-recovery of revenue in any one year.[123]

236. Our charges for distribution network and metering services make up around 37 per cent of a typical residential customer bill.[124] Transmission services make up around 6 per cent of a typical customer bill.

237. This TSS has focused on the tariff structures and price setting process for our distribution services (standard control services) and the metering and user requested services (alternative control services) as this is the part that we manage.

238. However, the rules require us to publish a full schedule of indicative NUOS prices for the remaining years of a regulatory period.[125] We have provided price information on both.

239. There are many elements that we have to forecast to provide the indicative NUOS prices. The indicative NUOS prices that accompany this TSS will prove to be different to the actual outturn NUOS prices. This is because TUOS can be volatile and there will be other elements that are difficult to forecast such as pass through amounts, incentive scheme outcomes and adjustments to take into account for the previous year's under- or over-recovery of revenue.

240. Customers relying on this information to make business or investment decisions should consider the potential volatility between an indicative NUOS price and final outturn price and the risks inherent with relying on them.

241. The remainder of this section summarises expected price and customer impacts of our charges for distribution network and metering services. Our indicative NUOS pricing schedule accompanies this TSS and for ease is included at Appendix F.

10.1 AVERAGE PRICE CHANGES

242. Our customers told us they value information that clearly outlines what our X-factors are and indicative customer impacts.

243. This section includes our proposed revenue (represented by X-factors) and price paths (represented by implied average price changes). We provide indicative prices/forecasts for:

[122] The Rules refers to these as: 'designated pricing proposal charges', which include TUOS charges, inter-distribution charges and avoided TUOS and 'Jurisdictional scheme cost recovery', which include rebates paid for premium feed in tariffs and transitional feed-in tariffs.

[123] As we are regulated under a revenue cap, the AER sets the maximum revenue we can receive in any year. Because revenue depends on actual demand levels and prices are set in advance, we will collect a different level of revenue to our allowance in any year. This is corrected by adjusting a following years' prices to pay back any over-recovery or collect any under-recovery. To allow data to become available for the annual price setting process, this has to be done with a two year lag.

[124] Based on analysis by Oakley Greenwood, *Causes of residential electricity bill changes in the Jemena service area, 1995 to 2014*, December 2014.

[125] 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.

- Combined distribution and metering services
- Distribution services
- Metering services.

We also provided expected price changes for our user-requested services.

10.1.1 COMBINED DISTRIBUTION AND METERING PRICE CHANGES

244. Figure 10–1 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 and takes into account our proposed changes to tariff structures in section 7. 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.

245. More detailed customers impacts can be found in Attachment 10-2 to our regulatory proposal. This has our current expected distribution and metering tariff levels for each tariff and enables those interested customers to enter their own usage and demand levels to estimate their individual impact.

246. 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[126]
- 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[127], allowed pass throughs and the adjustments to take into account for the previous year's under- or over-recovery of revenue.

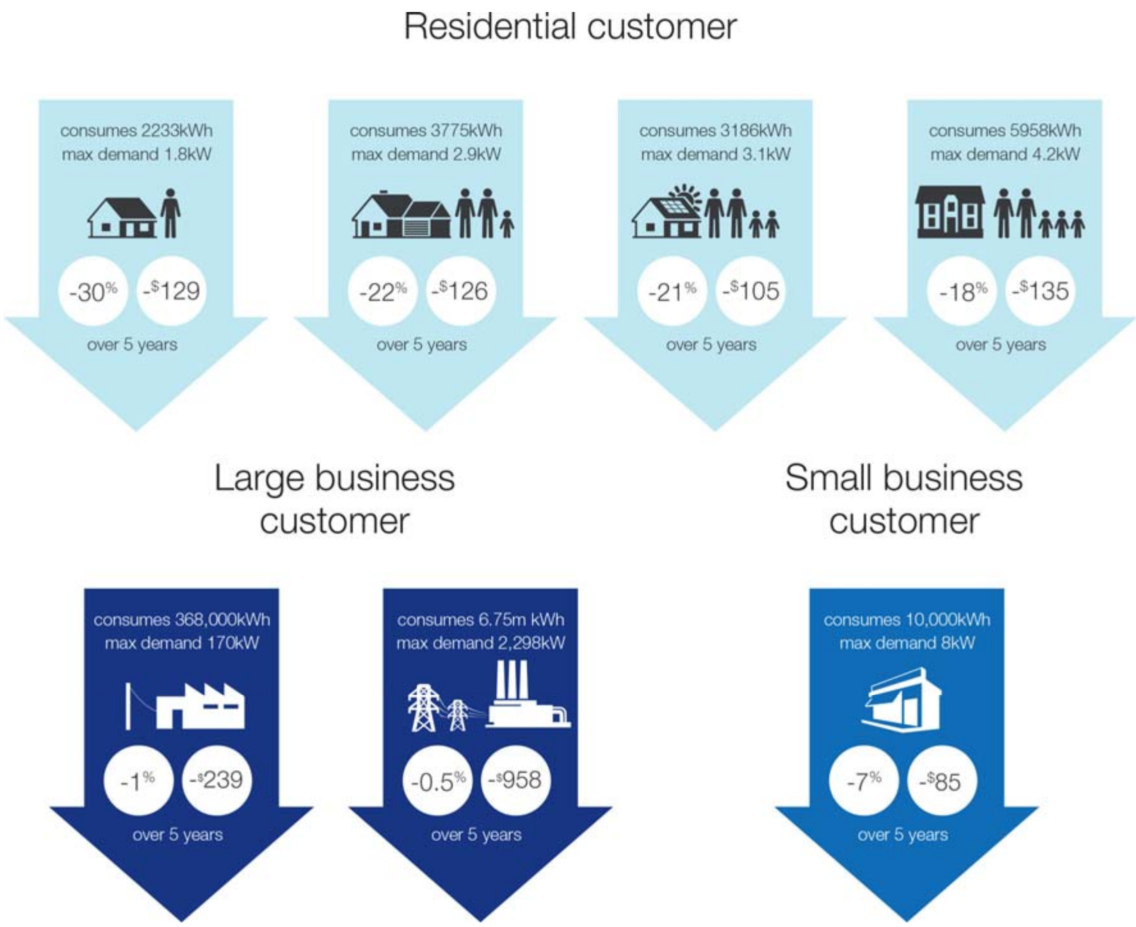
247. The impacts in Figure 10–1 include our DUOS and metering charges, but exclude TUOS.[128]

[126] 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.

[127] Resulting from factors such as unforseen changes in energy consumption and annual movements in the cost of debt (see section 6.4).

[128] We outlined at the beginning of the section that transmission charges make up part of our final network tariffs, but are not within our control.

Figure 10–1: The impact of our 2016 Plan for typical customers (excluding inflation)



Source: Jemena Electricity Networks

248. Attachment 10-2 to our 2016 Plan provides the full set of our expected distribution services prices for each tariff and tariff component (as well as our prices for metering services) used for the calculation of these customer impacts.

10.1.2 DISTRIBUTION SERVICES PRICE CHANGES

249. Table 10–1 provides the average tariff level changes solely for our distribution services for the 2016 regulatory period.[129]

Table 10–1: X factors for distribution services ($2015)

	2016	2017	2018	2019	2020
X-factors (%)[130]	-0.29	-1.06	0.32	-1.66	-1.66
Implied average price changes (%)[131]	0.00	0.00	-1.90	0.00	0.00

129 These will be replaced with AER approved values once available.

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

131 A negative number corresponds to a price decrease.

250. As can be seen in Table 10–1 we have focused our real price decrease in 2018—the year we are introducing our demand charges for residential and small business customers. We engaged with our customers and stakeholders on this approach, which they unanimously considered to be sensible.

10.1.3 METERING SERVICES PRICE CHANGES

251. Table 10–2 provides the average tariff level changes for our metering services for the 2016 regulatory period.[132]

Table 10–2: X factors for metering services ($2015)

	2016	2017	2018	2019	2020
X-factors (%)[133]	58.84	-1.22	-1.23	-1.23	-1.23
Implied average price changes (%)[134]	-59.39	0.00	0.00	0.00	0.00

252. Table 10–3 outlines the movements in our metering service charges that result from the X-factors in Table 10–2.

Table 10–3: Metering service charges, ($2015, 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)

10.2 USER-REQUESTED SERVICES PRICE CHANGES

253. Our user-requested services are set to recover our costs to undertake the required activity. The forecast price changes over the 2016 regulatory period reflect changes in CPI and in the real cost of the inputs (labour and materials) used to provide the services.

254. Appendix H1 provides the forecast schedule of user-requested services fee-based charges and charges for OM&R public lighting services.

132 Table 10–2 relates to meter provision and meter data services. These will be replaced with AER approved values once available. 2016 regulatory period prices for user requested meter services are provided in Appendix H.

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

134 A negative number corresponds to a price decrease.

Appendix A
JEN tariff structures for distribution services 2016-20

A1. TARIFF STRUCTURES FOR DISTRIBUTION SERVICES

255. Table A1-1 sets out our proposed tariff structures for distribution services (standard control services). It provides each tariff under each tariff class, with the structure of each tariff made up of the components and charging parameters for each tariff.

Table A1–1: Tariff structures for distribution services

Tariff class	Tariff	Components	Unit	Charging parameter
Residential	General purpose - demand	Standing charge	$ pa	
		Unit rate	c/kWh	
		Demand charge	$/kW pa	Maximum demand set 3pm-9pm work days and reset monthly Prices will be set separately for summer months and non-summer months[135]
	Flexible - demand[136]	Standing charge	$ pa	
		Peak unit rate	c/kWh	3pm-9pm weekdays
		Shoulder unit rate	c/kWh	7am-3pm and 9pm-10pm weekdays and 7am-10pm weekends
		Off peak unit rate	c/kWh	10pm-7am daily
		Demand charge	$/kW pa	Maximum demand set 3pm-9pm work days and reset monthly Prices will be set separately for summer months and non-summer months
	Time of use interval meter - demand[137]	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm weekdays
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set 3pm-9pm work

135 Summer months are December to March inclusive, non-summer months are April to November inclusive.

136 Unit rates can vary also vary by summer (daylight savings period) and non-summer (all other times).

137 Closed to new entrants.

Tariff class	Tariff	Components	Unit	Charging parameter
				days and reset monthly Prices will be set separately for summer months and non-summer months
	Time of use - demand[138]	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm weekdays
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set 3pm-9pm work days and reset monthly Prices will be set separately for summer months and non-summer months
	General purpose – opt out	Standing charge	$ pa	
		Unit rate	c/kWh	
	Off peak hot water heating only (dedicated circuit)	Standing charge	$ pa	
		Off peak unit rate	c/kWh	10pm-7am daily
Small business	General purpose - demand	Standing charge	$ pa	
		Unit rate	c/kWh	
		Demand charge	$/kW pa	Maximum demand set 10am-8pm work days (see note 8).
	Time of use weekdays (from 1 Jan 17 to be renamed 'Time of use weekdays low user – demand')	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm weekdays
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set 10am-8pm work days (see note 8).
	Time of use weekdays – demand	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm weekdays
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set at any time (see

[138] Closed to new entrants.

Tariff class	Tariff	Components	Unit	Charging parameter
				note 8). Subject to minimum chargeable demand of 60kW
	Time of use extended (from 1 Jan 17 to be renamed 'Time of use extended low user – demand')[139]	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm daily
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set 10am-8pm work days (see note 8).
	Time of use extended – demand[140]	Standing charge	$ pa	
		Peak unit rate	c/kWh	7am-11pm daily
		Off peak unit rate	c/kWh	All other times
		Demand charge	$/kW pa	Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 60kW
	Unmetered supply	Peak unit rate	c/kWh	7am-11pm weekdays
		Off peak unit rate	c/kWh	All other times
Large business – low voltage	LV 0.4 - 0.8 GWh	Each contains a: • Standing charge • Peak unit rate[141] • Off peak unit rate • Demand charge	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017	Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 120kW
	LV_{EN} Annual Consumption - <=0.8 GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 120kW
	LV 0.8+ - 2.2 GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 250kW
	LV_{EN} 0.8+ - 2.2 GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 250kW
	LV 2.2+ - 6.0 GWh			Maximum demand

139 Closed to new entrants.

140 Closed to new entrants.

141 Peak is 7am-11pm weekdays. Off peak is all other times

Tariff class	Tariff	Components	Unit	Charging parameter
				set at any time (see note 8). Subject to minimum chargeable demand of 250kW
	LV_{EN} 2.2+ GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 250kW
	LV_{MS} 2.2+ - 6.0 GWh[142]			Maximum demand set at any time (see note 7). Subject to minimum chargeable demand of 250kW
	LV 6.0+ GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 450kW
	LV_{MS} 6.0+ GWh[142]			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 450kW
	Special supply arrangements	Standing charge	$ pa	
		Unit rate	c/kWh	
		Demand charge	$/kW pa	Maximum monthly demand set at any time (note 8 does not apply)
Large business – high voltage	HV	Each contains a: • Standing charge • Peak unit rate[143] • Off peak unit rate • Demand charge	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017	Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 1,000kW
	HV_{EN}			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 1,000kW
	HV_{RF}[142]			Maximum demand set at any time (see note 8). Subject to minimum chargeable

142 Closed to new entrants.

143 Peak is 7am-11pm weekdays. Off peak is all other times

Tariff class	Tariff	Components	Unit	Charging parameter
				demand of 1,000kW
	HV - Annual Consumption >= 55 GWh			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 10,000kW
Large business – sub transmission	Sub-transmission	Each contains a: • Standing charge • Peak unit rate[144] • Off peak unit rate • Demand charge	Unit is: • $ pa • c/kWh • c/kWh • $/kW pa for 2016 and $/kVA pa from 2017	Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 15,000kW
	Sub-transmission MA			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 15,000kW
	Sub-transmission EG			Maximum demand set at any time (see note 8). Subject to minimum chargeable demand of 15,000kW

(1) A clear cell indicates the component currently exists in our current tariff schedule, a light blue cell or grey highlight indicates a change that would occur from 1 January 2017.
(1) LV and HV are low voltage and high voltage respectively.
(2) EN is 'embedded network' representing the tariff is only available to embedded network customers. (Additional criteria may apply as outlined in our tariff schedule).
(3) Large business customer minimum chargeable demand levels will convert to an appropriate corresponding kVA value from 2017.
(4) MS is 'multiple supply' 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.
(8) 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).

[144] Peak is 7am-11pm weekdays. Off peak is all other times

Appendix B
Selecting the demand charging window

B1. SELECTING THE DEMAND CHARGING WINDOWS

256. Our process to select the demand charging window is an example of how our engagement has influenced our TSS proposal. The sections below set out our:

- Proposed demand charging windows for residential and relevant small business customers
- Process for selecting the window

B1.1 OUR DEMAND CHARGING WINDOWS

257. The demand charging windows cover the period for which residential and small business customers can set their maximum demand levels.[145] We have selected our demand charging window of:

- 3pm to 9pm work days for residential customers
- 10am to 8pm work days for small business customers[146].

258. The residential customer demand charging window is currently aligned across all Victorian distributors.

B1.2 PROCESS FOR SELECTING THE DEMAND CHARGING WINDOWS

259. JEN's original position, outlined in our 30 April 2015 draft TSS, was to introduce for our residential and small business customers:

- a 'weekday' monthly maximum demand charge
- a 'window' for measuring maximum demand of between 10am and 8pm.

260. This reflected the characteristics of our network, which does not have weekend demand peaks, but does have peaks in earlier times in the day, largely driven by commercial loads.

261. Figure B1-1 shows the average of the five highest peaks in the 2014 summer. This shows the demand profile of our residential, small business and the sum of our three large business tariff classes. As can be seen in the graph, each tariff class has its demand peak at slightly different times. The 'terminal station' demand is the sum across all tariff classes on our network.

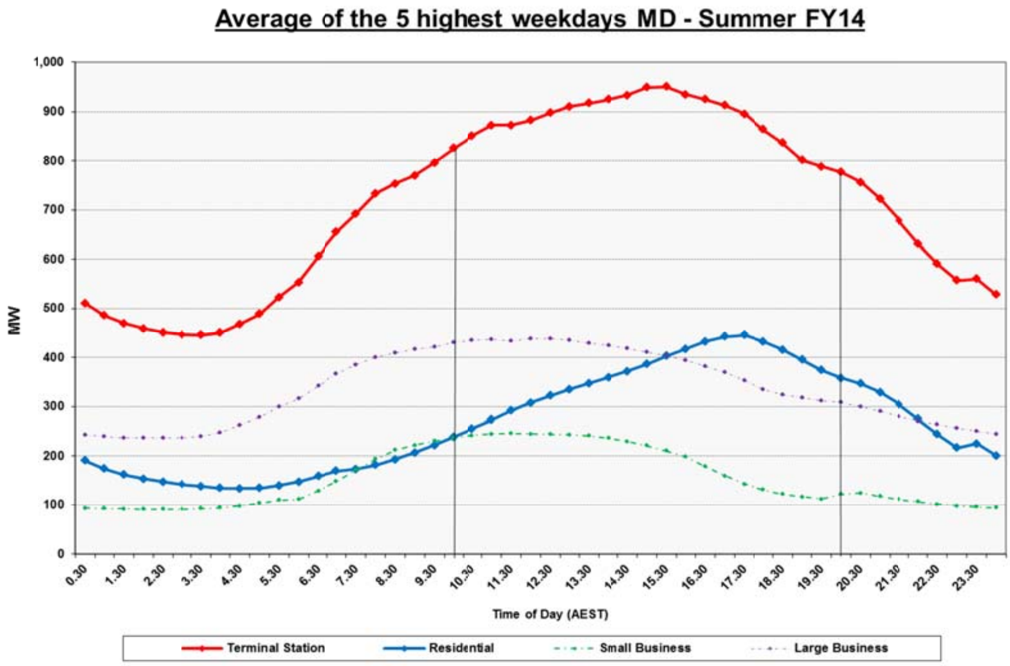
262. This shows that 10am to 8pm will cover the 95% probability interval of times a peak will likely occur.[147]

[145] In terms of a customers' bill, these maximum demand levels are applied to our demand tariff price level, to give their monthly demand charge. The demand charging window is not a period in which all energy consumed is subject to a higher price.

[146] This is the demand charging window for small business customers who were not already subject to a demand charge prior to 2017. That is, it excludes the 'time of use weekdays -demand' and 'time of use extended – demand' small business tariffs.

[147] By way of comparison the peak period AEMO uses for their Victorian transmission use of system charges is 7am to 11pm, which is wider than our proposed demand charging window.

Figure B1–1: JEN peak demand



263. We initially had a wide range of views from our customers and stakeholders on this demand charging window. Some felt a wider window would allow simpler mass market messaging and others considered that a more defined window would enable a sharper and more cost reflective signal.

264. However, customers and stakeholders were clear, and provided strong guidance, for Victorian distributors to align on the window and days that it applies to for residential customers. We heard that this has a number of benefits in terms of communicating tariff reform, such as common communications (and therefore customers' ability to understand the tariffs) and simplifying call centre training.

B1.2.1 MOVING TO A 3PM TO 9PM WINDOW

265. In our draft TSS, we noted that we will be able to refine our approach to setting the demand charging window as we obtain more data and customer feedback. Since then we have heard our customers and undertook further analysis of our residential customer base to enable us to move to a 3pm-9pm demand charging window, which would align us with other Victorian distributors.

266. We consider Figure B1-1 demonstrates that 3pm-9pm is not our ideal window. A shorter demand charging window could risk future peaks falling outside the selected window. In particular, it risks residential customers moving load to earlier in the day (before 3pm), when our business demands are peaking this could create the potential for demand shifts to result in incremental investment, or to bring forward planned investment. This would be a perverse outcome of shifting our demand charging window.

We were able to move to 3pm-9pm common demand charging window by focusing our analysis on the next 10 year period, with the greatest attention on the 2020—2025 regulatory period because:

- We have committed to 2016-2020 investments as part of our 2016 regulatory proposal—given the proposed timing of our transition (see section 7.3), these investments are unlikely to be impacted

- We assume we will be able to adjust the demand charging window in future, if a change in behaviour occurs and is likely to cause perverse impacts.

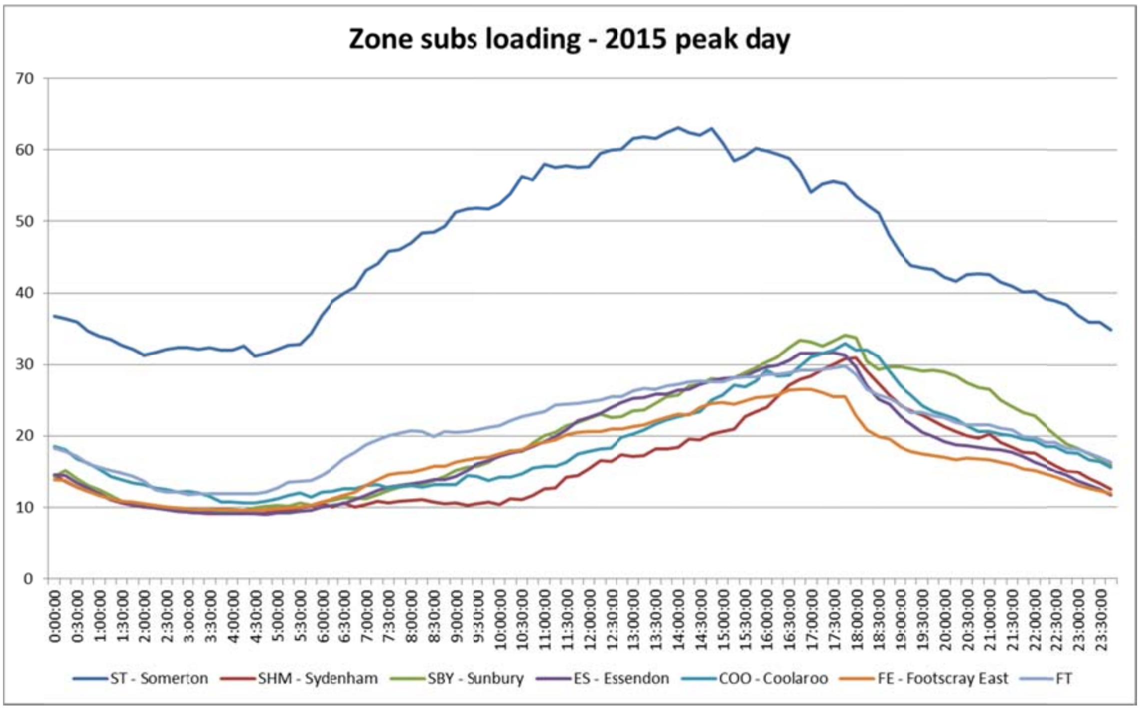
267. Our analysis indicates that the risk of perverse impacts occurring over the next 10 years is low.

268. We looked at our individual zone substations not planned for upgrade in the 2016 regulatory period, but which are likely to require upgrades in 2021-25, and whether providing incentives to shift residential demand to before 3pm could bring forward those upgrades into the 2016 regulatory period.

269. Figure B1-2 shows the load profile of the zone substations we currently think will require upgrades in the 2021-26 regulatory period. This shows that six out of seven of the substations peaks are between 3pm and 9pm, and thus present a low risk of perverse outcomes from moving to this window. We looked further at the Somerton substation that peaks before 3pm and the customers it supplies.

270. We could see that the Somerton peak was driven primarily by commercial customers. These customers already pay a cost reflective demand price and are subject to a wider demand charge window. Again, this presents a low risk of perverse outcomes from setting the residential demand charging window to 3pm-9pm for the 2016 regulatory period.

Figure B1–2: Load profiles of zone substations currently planned for 2021-26 upgrade



Source: Jemena Electricity Networks

271. On balance, we considered the benefits of alignment[148] justified a shift in our position to a 3pm-9pm demand charging window.

272. It is important to highlight here that, while we are comfortable to align to the common demand charging window for the 2016 regulatory period, we will need to review the window going forward. JEN has a substantial proportion of the zone substations (53%) peaking earlier in the day than the 3pm-9pm demand charging

148 In particular having regard to customer impacts of this transition and customer's ability to understand our tariffs.

window. Therefore, if customers choose to move their load to earlier than 3pm, the shift will result in higher peak demand on the zone substations peaking outside 3pm-9pm period. When those substations begin to face capacity constraints, we will need to change the demand charging window going forward.

B1.2.2 MOVING FROM WEEKDAY TO WORK DAY

273. To align with other Victorian distributors who do have weekend demand peaks in parts of their networks, we also considered changing our position to introduce an ‘any day’ demand.

274. JEN took this consideration to customers and stakeholders at our pricing workshop on 12 August 2015. The clear feedback from consumer representatives present was that they welcomed our effort to align with other distributors, but there was strong preference for the aligned position to exclude weekends and public holidays from a demand charge.

275. As we do not currently have peaks on weekends or public holidays, we sought to understand the systems costs to achieve this change from our original position of weekdays. Moving to work days will have a small systems cost implication. We consider that the feedback we received supporting a work day approach would justify the additional systems spend.

276. Upon further engagement with other Victorian distributors, we understand there will be an aligned position of work days for the 2016 regulatory period. We understand that, for other Victorian distributors, weekend peaks are possible in certain parts of their network now, and which may increase in future as a result of this position. This is, therefore, an area that all distributors will need to monitor going forward and revise on an individual basis where residential customers’ consumption patterns suggest this is required.

Appendix C
Pricing principles of the National Electricity Rules

C1. PRICING PRINCIPLES OF THE NATIONAL ELECTRICITY RULES

Box C1-1 provides the distribution pricing principles.

Box C1-1: Rule 6.18.5 'Pricing principles' of the National Electricity Rules

Rule 6.18.5(a) outlines the network pricing objective. Rule 6.18.5(a) outlines how the pricing principles should be applied:

6.18.5 Pricing principles

Network pricing objective

(a) The network pricing objective is that the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer.

Application of the pricing principles

(b) Subject to paragraph (c), a Distribution Network Service Provider's tariffs must comply with the pricing principles set out in paragraphs (e) to (j).

(c) A Distribution Network Service Provider's tariffs may vary from tariffs which would result from complying with the pricing principles set out in paragraphs (e) to (g) only:

(1) to the extent permitted under paragraph (h); and

(2) to the extent necessary to give effect to the pricing principles set out in paragraphs (i) to (j).

(d) A Distribution Network Service Provider must comply with paragraph (b) in a manner that will contribute to the achievement of the network pricing objective.

Rule 6.18.5(e) requires that revenues from each tariff class for standard control distribution services must lie between economically efficient bounds, specifically:

Pricing principles

(e) For each tariff class, the revenue expected to be recovered should lie on or between:

(1) an upper bound representing the stand alone cost of serving the retail customers who belong to that class; and

(2) a lower bound representing the avoidable cost of not serving those retail customers.

Rule 6.18.5(f) contains the principle that requires tariffs are based on LRMC:

(f) Each tariff must be based on the long run marginal cost of providing the service to which it relates to the retail customers assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

(1) the costs and benefits associated with calculating, implementing and applying that method as

proposed;

(2) *the additional costs likely to be associated with meeting demand from retail customers that are assigned to that tariff at times of greatest utilisation of the relevant part of the distribution network; and*

(3) *the location of retail customers that are assigned to that tariff and the extent to which costs vary between different locations in the distribution network.*

Rule 6.18.5(g) contains the principle that we recover our efficient costs

(g) *The revenue expected to be recovered from each tariff must:*

(1) *reflect the Distribution Network Service Provider's total efficient costs of serving the retail customers that are assigned to that tariff;*

(2) *when summed with the revenue expected to be received from all other tariffs, permit the Distribution Network Service Provider to recover the expected revenue for the relevant services in accordance with the applicable distribution determination for the Distribution Network Service Provider; and*

(3) *comply with sub-paragraphs (1) and (2) in a way that minimises distortions to the price signals for efficient usage that would result from tariffs that comply with the pricing principle set out in paragraph (f).*

Rule 6.18.5(h) and 6.18.5(i) contains the customer impact principles

(h) *A Distribution Network Service Provider must consider the impact on retail customers of changes in tariffs from the previous regulatory year and may vary tariffs from those that comply with paragraphs (e) to (g) to the extent the Distribution Network Service Provider considers reasonably necessary having regard to:*

(1) *the desirability for tariffs to comply with the pricing principles referred to in paragraphs (f) and (g), albeit after a reasonable period of transition (which may extend over more than one regulatory control period);*

(2) *the extent to which retail customers can choose the tariff to which they are assigned; and*

(3) *the extent to which retail customers are able to mitigate the impact of changes in tariffs through their usage decisions.*

(i) *The structure of each tariff must be reasonably capable of being understood by retail customers that are assigned to that tariff, having regard to:*

(1) *the type and nature of those retail customers; and*

(2) *the information provided to, and the consultation undertaken with, those retail customers.*

Rule 6.18.5(j) contains the jurisdictional obligation principle

(j) *A tariff must comply with the Rules and all applicable regulatory instruments.*

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Appendix D
Stand alone and avoidable cost

Jemena

D1. ESTIMATING STAND ALONE AND AVOIDABLE COST

277. This appendix describes our methodology for calculating stand alone and avoidable cost estimates for the purposes of complying with rule 6.18.5(a).

278. To estimate the stand-alone and avoidable cost for each tariff class, we have, where possible, linked each asset to one or more tariff classes. The linkage depends on an engineering assessment of whether that tariff class would require the asset in a stand-alone network that served only that tariff class.

279. Prior to performing the stand alone and avoidable cost calculations, we developed a set of hypothetical optimised electricity distribution networks for our distribution area based on engineering estimates for each tariff class.

280. The hypothetical network approach adequately addresses the concept of stand alone cost as it represents the likely infrastructure that a hypothetical new entrant would construct in order to supply the same electricity distribution services to each tariff class. It also allows us to readily identify dedicated assets for the purposes of calculating the avoidable cost for each tariff class.

281. The steps used to create the hypothetical stand alone networks for each tariff class are outlined below:

- Determine the asset classes required to supply each of JEN's tariff classes
- Determine the network topology linking the asset classes for each tariff class
- For Distribution line assets, the optimised length of each distribution line asset required to serve that tariff class was determined. JEN classified the following assets as "Distribution line assets":
  - Overhead low voltage distribution
  - Overhead 6.6 kV
  - Overhead 11 kV
  - Overhead SWER
  - Overhead 22 kV
  - Overhead 33 kV
  - Overhead 66 kV
  - Overhead 132 kV
  - Overhead Low voltage services
  - Underground low voltage distribution
  - Underground 6.6 kV
  - Underground 11 kV
  - Underground SWER
  - Underground 22 kV
  - Underground 33 kV
  - Underground 66 kV

  - Underground 132 kV
  - Underground low voltage services
- For non-distribution line assets, the optimised number of assets required to serve that tariff class was determined. JEN classified the following assets as "non-distribution line assets":
  - Distribution substations—residential and small business tariff classes
  - Distribution substations—large business tariff classes
  - Zone substations.

D2. STAND ALONE COSTS

282. The stand alone cost for each tariff class is calculated based on the assumption that network assets utilised by each tariff class only serve customers in that particular tariff class and that no other customers (in other tariff classes) share the same network assets with customers in that tariff class.

283. In estimating the stand alone cost for each tariff class, we developed the hypothetical optimised networks for each tariff class and determined the replacement cost of all the assets that would comprise these hypothetical networks. This includes the replacement cost of:

- All dedicated assets associated with the tariff class
- All shared assets (optimised in quantities where appropriate) associated with the tariff class
- All non-system assets (for example, SCADA/network control, non-network IT, fleet, buildings, land and easements and equipment)

284. The stand alone costs also include the operation and maintenance (**O&M**) cost associated with maintaining the dedicated and shared assets for the tariff class and other opex costs.

285. This is depicted in Box A2-1.

Box A2–1 Stand-alone cost calculation

SC = DA + SA + OA + NA

Where

- SC is the stand-alone cost
- DA is the annualised dedicated asset cost
- SA is the annualised shared asset costs
- NA is the annualised non-system asset costs
- OA is the annual O&M and other opex associated with the assets

286. The calculations of each of the cost calculation components are detailed below.

D2.1 DEDICATED ASSETS

287. The value of dedicated assets for each tariff class is calculated as the sum of the annualised replacement costs of all dedicated assets associated with that tariff class.

288. The replacement costs for services and substations are calculated as follows:

- For each type of services associated with the tariff class, the unit cost (dollars per service) multiplied by optimised number of services, and
- For each type of substations associated with the tariff class, the unit cost (dollars per substation) multiplied by the optimised number of services (which is in turn based on the number of customers in that tariff class).

D2.2 SHARED ASSETS

289. We calculated the replacement cost of the shared assets for each tariff class by:

  - Multiplying the replacement cost (in dollars per asset) by the optimised number of assets (for non-distribution line assets)
  - Multiplying the replacement cost (in dollars per kilometre) by the optimised number of kilometres of distribution line for each distribution line asset.
  - Summing the replacement costs for all distribution line and non-distribution line asset classes.

290. Note that we optimised the length of distribution line required to service the tariff class to remove distribution line routes that only serve customers in other tariff classes. For customers served by the tariff class in question, we did not further optimise of the length of distribution line assets. This is because we assumed that the location of the customer connection points, the connection route through the electricity distribution network and the location of the electricity transmission connection points would not change from what is currently in place if a hypothetical network provider were to supply the tariff class customers.

D2.3 NON-SYSTEM ASSETS

291. We calculated the replacement cost of non-system assets for each tariff class as the sum of the replacement value of all non-system assets associated with that tariff class following the steps:

- Calculate the inflated total non-system assets value[149]
- Allocate the total non-system assets value (by non-system asset class) to each tariff class based on the following allocators:
  - SCADA/network control: asset value
  - Non-network IT: asset value

[149] We note that for each tariff class, the sum of the asset values of each stand alone hypothetical network for each tariff class will be greater than the asset value of the existing network due to some overlap between different asset classes. In order to account for this overlap in the system assets, and have a consistent approach for the non-system assets, we used an inflated total non-system asset value to derive the non-system asset values for each asset class. The inflation factor is the ratio of the total of the asset value of all stand alone networks put together versus asset value of the existing network.

- Fleet: asset value
- Building: evenly allocated
- Land and easements: customer numbers
- Equipment: asset value
- Non-network other: customer numbers.

D2.4 O&M ASSOCIATED WITH THE ASSETS

292. The value of the O&M and other opex costs associated with each tariff class is calculated as the sum of:

- The O&M cost (which includes vegetation management, maintenance and emergency response) allocations to the tariff class
- Corporate overhead allocations to the tariff class.

293. The allocator for the O&M cost is customer numbers.

294. This approach relies on estimates for:

- Optimised length of each distribution line asset by asset class
- Optimised conductor size of each distribution line asset by asset class
- Optimised number of each non-distribution line asset
- Unit rates representing the full replacement cost for each asset class—these are in dollars per kilometre for distribution line assets and dollar per asset for non-distribution line assets and are inclusive of overheads.

D3. AVOIDABLE COSTS

295. The avoidable cost for each tariff class is derived from the capital cost of all dedicated assets (e.g. low voltage services and substations) associated with that tariff class, along with the incremental operating and maintenance costs associated with those dedicated assets.

296. The avoidable cost for each tariff class comprises both capex and opex as follows:

- Capex includes the replacement value of dedicated connection assets such as meters and services
- Opex includes the costs associated with operating and maintaining the dedicated connection assets.

297. Box A3-1 shows the avoidable cost for each tariff class.

Box A3–1 Avoidable cost calculation

AC = DA + OD

Where

- AC is the avoidable cost
- DA is the annualised dedicated asset cost
- OD is the annual O&M cost associated with dedicated assets

D4. ANNUALISATION

298. To allow for comparison with the revenue recovered from each tariff class (as required under the Rules), we annualise the replacement costs for the avoidable and stand alone cost calculations.

299. These are annualised by adding the annual depreciation of the replacement cost (using the economic life of the asset) to the annual return on asset of the replacement cost (using the weighted average cost of capital).

Appendix E
Price setting description

E1. DESCRIPTION OF APPROACH TO SETTING TARIFF LEVELS

300. This appendix describes our approach to how we estimate long run marginal cost (**LRMC**) for each tariff and subsequently set tariff levels.

E1.1 ESTIMATING LRMC

E1.1.1 HIGH-LEVEL APPROACH

301. We are required to calculate a LRMC estimate for each of our tariffs. As each tariff has a number of tariff components, the LRMC can be estimated in units of dollars per annum ($ pa), cents per kilowatt hour (c/kWh), dollars per kilowatt ($/kW) or dollars per kilovolt-ampere ($/kVA).

302. Meeting demand at peak times is the predominant driver for us to expand and augment our network. Therefore, in order for our customers' usage decisions to take into account costs associated with peak demand, the LRMC should signal the expected additional costs arising from increases in peak demand levels. This means we should provide our LRMC estimates for each tariff expressed as demand and/or capacity components; that is, $/kW or $/kVA.

303. Accordingly, we have calculated $/kW and $/kVA LRMC estimates (as appropriate) for each of our tariff classes and tariffs.

304. To ensure a robust approach to calculating LRMC, we considered both the Turvey approach and the average incremental cost (**AIC**). The Turvey approach aims to capture the direct change in expenditure resulting from multiple scenarios of changes in demand whereas the AIC approach captures the average change in expenditure. For this reason the AIC approach is more readily applied.[150]

305. We have therefore used the AIC approach in order to estimate the LRMC for each tariff and each tariff parameter. In opting for an AIC approach, we considered the approved approaches of other electricity distributors for which an AIC approach is common.

306. The AIC approach examines a forecast demand profile and the portion of demand that is beyond the current supply capacity. A cost minimising quantity of capex and opex necessary to supply the incremental demand is then calculated. The present value (**PV**) of the total expenditure necessary to supply the incremental demand is then divided by the present value of the additional demand, to provide an estimate of the LRMC on a dollars per unit (of demand) basis. We outline the steps in Table E1–1.

150 This is a factor in considering the costs and benefits associated with calculating, implementing and applying the proposed method for calculating LRMC as required under Rule 6.18.5(f)(1).

Table E1–1: AIC implementation approach

Step	Description
1. Define forecast incremental annual capacity related to network expansion	This is drawn from the capacity forecasts
2. Define a forecast capex program to 2035	Define a program of expansion capex (as opposed to network re-enforcement) over the long run[151]
3. Define a forecast opex program to 2035	Define an opex profile associated with the defined capex program.
4. Allocate these total costs to tariffs and charging parameters	Allocate these costs to tariffs and charging parameters in a meaningful way (i.e. take into account which users are creating peak demand and allocate costs in a sensible way)
5. Calculate average incremental cost	Calculate the average for each tariff or charging parameter by dividing the PV of the capex and opex programme cost by the PV of the forecast annual incremental capacity.

E1.1.2 STEPS FOR CALCULATING LRMC FOR TARIFFS

307. In accordance with rule 6.18.5(f), JEN is required to calculate LRMC for each tariff.

308. We estimated LRMC for each tariff based on demand charge ($/kW and $/kVA). The steps for calculating the LRMC for each tariff are:

1. Determine the present value (**PV**) of the annual change in demand for each tariff using the annual change in demand and the forecast weighted average cost of capital **(WACC**) value.[152] The annual change in demand (kVA and KW) for each tariff is pro-rated based on energy usage of each constituent tariff within each tariff class.
2. Annual future growth capex (including customer-initiated capex) is broken down by asset class for each tariff class and allocated to the constituent tariffs based on each tariff's relative proportion to the total kW demand or kVA demand of the tariff class (depending on the tariff component being calculated).
3. Determine the PV of the annual future growth capex for each tariff using the annual future growth capex allocated to each tariff charging parameter and the forecast WACC value.[153]
4. Annual future growth-related opex by tariff is allocated to tariff charging parameters in the same manner as annual future growth-related capex.

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151 We have assumed augmentation capex (and associated opex) to mean the addition of new assets and 'upgrade / replacement' of existing assets where these add capacity to the network.

152 The annual change in KW capacity is calculated by dividing the annual capex for each tariff class by an estimated $/KW value. The annual change in kVA capacity is calculated by dividing the annual capex for each tariff class by an estimated $/kVA. We use the WACC value applicable for the 2011 regulatory period.

153 Annual future growth-related opex comprises two components, being general O&M (i.e. additional O&M costs associated with operating the whole network as a result of the additional network investment) and project specific operating costs (i.e. additional operating costs associated with maintaining the new network assets). General firm-wide O&M costs are allocated to each tariff class based on the relative proportion of each tariff class' consumption to whole of network consumption. Project specific opex associated with the future growth capex for each tariff class are entered either as a percentage of the annual future growth capex, or as an absolute amount for each year. Project specific opex is currently estimated to be 0.93 per cent of the annual growth capex for all of the tariff classes.

5. Determine the PV of the annual future growth-related opex using the annual opex costs and the forecast WACC value.

The average incremental cost LRMC value is calculated for the tariff by dividing the PV of the annual growth related capital and operating costs by the PV of the annual change in demand for the tariff.

E1.1.3 OUR LRMC ESTIMATES

309. Table E1-2 provides LRMC estimates by tariff.

Table E1-2: LRMC for each tariff class by tariff ($2015)

Tariff Class	Tariff	LRMC	
		Demand $/kW	Demand $/kVA
Residential	General Purpose Residential	119	-
	Flexible	112	-
	Time of Use Interval Meter	115	-
	Time of Use	120	-
	Off Peak Hot Water Heating Only	NA	-
Small business	General Purpose Business	105	-
	Time of Use Weekdays	105	-
	Time of Use Weekdays - Demand	102	-
	Time of Use Extended	106	-
	Time of Use Extended - Demand	105	-
	Unmetered Supply	NA	-
Large business – low voltage	LV 0.4 - 0.8 GWh	104	90
	LVEN Annual Consumption <= 0.8 GWh	98	85
	LV_{EN} 0.8+ - 2.2 GWh	109	94
	LV 0.8+ - 2.2 GWh	98	85
	LV 2.2+ - 6.0 GWh	98	85
	LV_{EN} 2.2+ GWh	94	81
	LV_{MS} 2.2+ - 6.0 GWh	99	86
	LV 6.0+ GWh	96	84
	LV_{MS} 6.0+ GWh	97	84
Large business – high voltage	HV	50	47
	HV_{EN}	50	46
	HV_{RF}	51	47
	HV - Annual Consumption >= 55GWh	51	47

Large business – sub transmission	Sub-transmission	50	46
	Sub-transmission MA	49	46
	Sub-transmission EG	49	46

E2. DESCRIPTION OF APPROACH FOR SETTING TARIFF LEVELS FOR DISTRIBUTION SERVICES

310. In summary, our approach to setting our prices for each tariff is described in the following 5 steps:

311. For each tariff, we do this by:

1. Using our estimates of LRMC to establish the basis of our prices—we establish our 'raw' demand component tariffs levels for each tariff to these prices (Rule 6.18.5(f))
2. Using the 'raw' demand component tariffs levels with our forecast demand levels to provide the expected revenue collected from the 'raw' demand tariff component
3. Working out residual revenue to be recovered from each tariff class and tariff
4. Collect residual revenue from our fixed, usage and demand charges to minimise any distortions to the signals provided by our raw demand component levels (Rule 6.18.5(g)(3)) and minimises customer impacts (Rule 6.18.5(h)).

312. Section E2.1 to E2.4 describe each step in more detail for each of our tariffs. Our approach to setting our tariffs will only vary in each year the TSS applies (2017-20) to give effect to the transition proposed in Section 7.

E2.1 ESTABLISH COST-REFLECTIVE DEMAND TARIFFS

313. Our approach for all our tariffs is to translate our LRMC estimates into cost-reflective levels. We need to do this because our LRMC estimates are calculated to apply at the annual critical peak, but we will apply these prices to a wider peak period. Therefore, we need to scale the LRMC estimates down to derive a $/kW demand component tariff level. We call this the 'raw' level as it includes no adjustments from the cost-reflective level.

E2.1.1 OUR APPROACH TO SCALING LRMC TO RAW DEMAND COMPONENT LEVEL

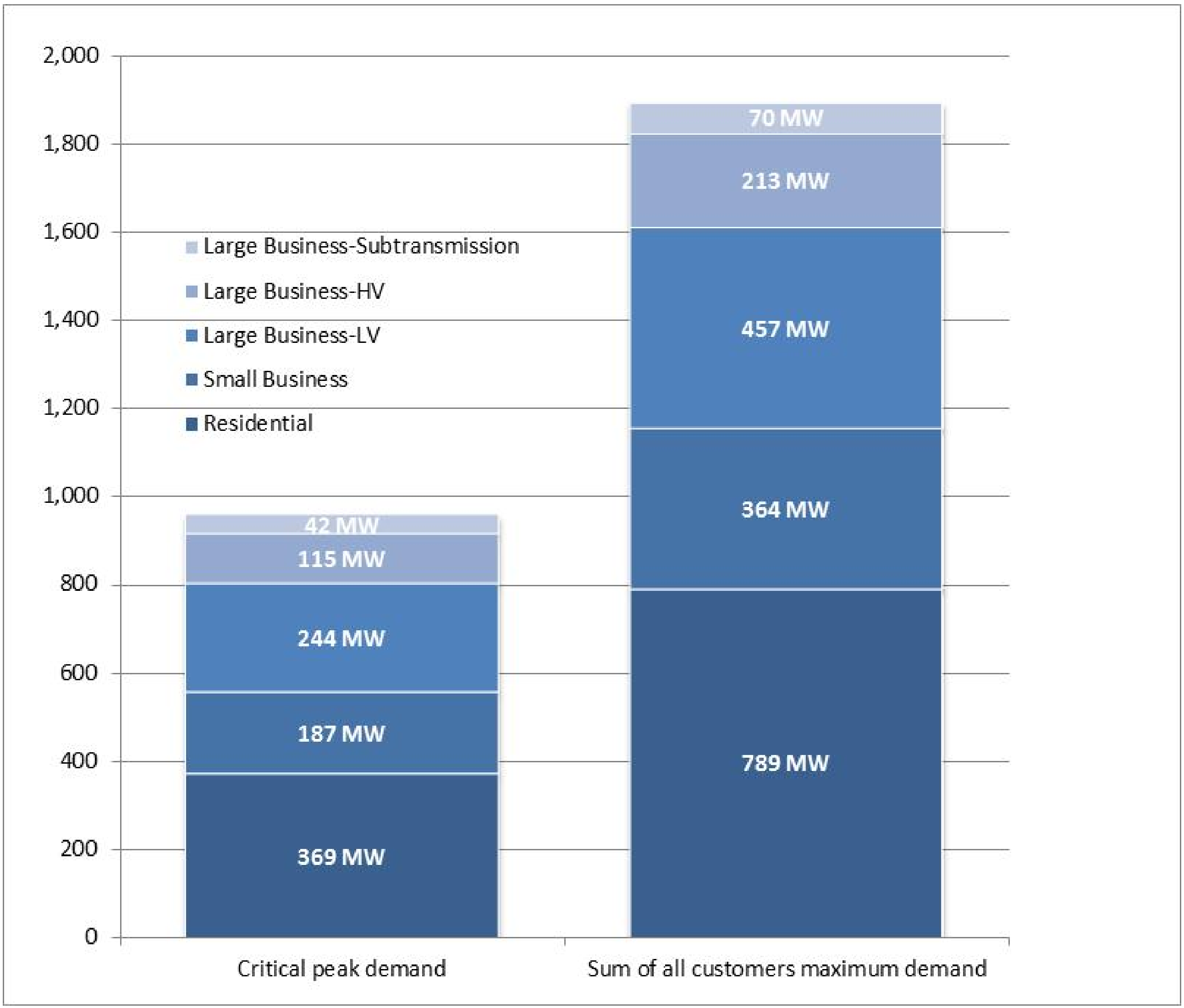
314. Figure E2–1 shows the critical peak demand on our network is approximately 950kW. However, the sum of the maximum demand of our customers (that is, the measure by which we charge) is around 1,900kW. This occurs because individual customer peaks can occur outside our critical peak.[154] Our scaling approach is to:

1. Determine the average contribution of each tariff class to the system peak demand (in kW) for the 5 hottest days during the year

[154] Note that we discuss why our approach to measuring demand meets the Rule requirements and why a critical peak price is not appropriate in section 7 of the TSS.

2. For each tariff class, determine the revenue that the LRMC tariff estimates would collect. This is equivalent to the LRMC value for the tariff class multiplied by the average (in kW) that tariff class contributes to the system peak (from 1 above)
3. For each tariff class, determine the raw demand tariff component level (in $/kW) as the revenue that the LRMC tariff estimates would collect (from 2 above) divided by the total maximum demand for this tariff class.[155]

Figure E2–1: Comparing critical peak against the sum of customer's maximum demand



Source: Jemena Electricity Networks

315. This approach to scaling down our LRMC estimates results in the raw demand component levels shown in Table E2-3.

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155 This scaling is applied at a tariff class level, thus providing one raw demand component level per tariff class.

Table E2-3: LRMC estimates and 'raw' demand component level ($2015)

Tariff Class	Tariff	Cost-reflective pricing	
		LRMC estimate ($/kW)	Raw demand component level ($/kW)
Residential	General Purpose Residential	119	57.630
	Flexible	112	57.630
	Time of Use Interval Meter	115	57.630
	Time of Use	120	57.630
	Off Peak Hot Water Heating Only	NA	NA
Small business	General Purpose Business	105	55.860
	Time of Use Weekdays	105	55.860
	Time of Use Weekdays - Demand	102	55.860
	Time of Use Extended	106	55.860
	Time of Use Extended - Demand	105	55.860
	Unmetered Supply	NA	NA
		LRMC estimate ($/kVA)	**Raw demand component level ($/kVA)**
Large business – low voltage	LV 0.4 - 0.8 GWh	90	54.620
	LVEN Annual Consumption <= 0.8 GWh	85	54.620
	LV_{EN} 0.8+ - 2.2 GWh	94	54.620
	LV 0.8+ - 2.2 GWh	85	54.620
	LV 2.2+ - 6.0 GWh	85	54.620
	LV_{EN} 2.2+ GWh	81	54.620
	LV_{MS} 2.2+ - 6.0 GWh	86	54.620
	LV 6.0+ GWh	84	54.620
	LV_{MS} 6.0+ GWh	84	54.620
Large business – high voltage	HV	47	27.970
	HV_{EN}	46	27.970
	HV_{RF}	47	27.970
	HV - Annual Consumption >= 55GWh	47	27.970
Large business – sub transmission	Sub-transmission	46	30.970
	Sub-transmission MA	46	30.970
	Sub-transmission EG	46	30.970

(1) NA is 'not applicable'.

E2.1.2 ALL RESIDENTIAL DEMAND TARIFFS

316. We will use the transition described in section 7 of the TSS to set our demand tariff component for each of our residential tariffs. Once fully transitioned, this will equal to the raw demand tariff component level after a period of transition (adjusted for inflation).

E2.1.3 SMALL BUSINESS DEMAND TARIFFS WITHOUT A DEMAND CHARGE PRIOR TO 2017

317. We will use the transition described in section 7 of the TSS to set our demand tariff component of each of our small business tariff currently without a demand charge. Once fully transitioned, this will equal to the raw demand tariff component level after a period of transition (adjusted for inflation).

E2.1.4 SMALL BUSINESS DEMAND TARIFFS WITH A DEMAND CHARGE PRIOR TO 2017

318. We will use the raw demand tariff component level as the basis for the demand price.

E2.1.5 ALL LARGE BUSINESS DEMAND TARIFFS

319. We will use the raw demand tariff component level as the basis for the demand price. For 2016, this will be the value in dollars per kilowatt ($/kW) and from 2017, will be the value in dollars per kilovolt ampere (kVA).

E2.2 ESTABLISH EXPECTED REVENUE FROM 'RAW' DEMAND TARIFF COMPONENTS

320. We establish the residual revenue we need to collect after we set our tariffs at the 'raw' demand component tariffs levels. We do this by multiplying the 'raw' demand component tariffs levels by our forecast demand levels.

E2.3 ESTABLISH RESIDUAL REVENUES

321. Residual revenue is our total allowed revenue from the AER less the revenue collected from the expected revenue from the raw demand tariff components (established in section E2.2). We allocate this residual revenue to individual tariffs based on that tariff's current contribution to our total revenue.

322. This is because we consider that the proportions of revenue we currently collect from each tariff are cost-reflective. We, therefore, establish the residual revenue to be collected from each tariff individually by:

- Calculating the current proportion of allowed revenue obtained from the customers in each tariff
- Applying that proportion to our required revenue as established in our 2016 Plan to give the revenue required from each tariff in the 2016 regulatory period
- Establishing each tariff's residual revenue as the revenue required from each tariff (calculated in the bullet above) less the expected revenue from the tariff's raw demand tariff component.

E2.4 ALLOCATE RESIDUAL REVENUES TO TARIFF COMPONENTS

323. We collect the residual revenue from our fixed, usage and demand tariff components as set out below.

E2.4.1 ALL RESIDENTIAL AND SMALL BUSINESS TARIFFS WITHOUT A DEMAND CHARGE PRIOR TO 2017

324. We will set our fixed charge to signal the fixed cost nature of electricity distribution, but also take into account the desirability and cost for customers to connect and remain connected. The remainder of revenue for each tariff will then be collected from our usage charges in a manner that:

- Maintains a signal to reduce total usage
- Focuses price reductions on peak usage charges (where these exist) as the price signal is being predominantly provided by the new demand charges.

E2.4.2 SMALL BUSINESS TARIFFS WITH A DEMAND CHARGE PRIOR TO 2017 AND ALL LARGE BUSINESS TARIFFS

325. We will set our fixed charge to signal the fixed cost nature of electricity distribution, but also take into account the desirability and cost for customers to connect and remain connected.

326. The remainder of revenue for each tariff will then be collected from our usage and demand charges in a manner that:

- Moves toward raw demand component levels in a way that minimises the disturbance to current demand price signals[156]
- Maintains a signal to reduce total usage
- Focuses price reductions on peak usage charges (where these exist) as the price signal is being predominantly provided by the new demand charges.

E2.5 DESCRIPTION OF APPROACH FOR SETTING TARIFF LEVELS FOR OPT OUT TARIFF

327. The opt out tariff will only be available for customers who choose to opt out of the demand tariffs in 2017. They will be able to remain on the opt out tariff for the remainder of the regulatory period (up until 31 December 2020).

328. The opt out tariff will only have fixed and energy usage tariff components—in line with the existing tariff structure for the residential flat (or 'general purpose') tariff. No demand charge component will apply to the opt out tariff. We will set up fixed and energy usage charges at the cost reflective level.

329. In summary, our approach to setting our prices for each tariff is described in the following steps:

- Set the 2017 prices for the opt out tariff based on the 2016 flat tariff price and the AER approved X-factor for 2017
- Analyse the load profile of the customers who chose to opt out in 2017
- Determine the total cost reflective revenue that needs to be collected from the opt out tariff by multiplying the total implied maximum demand for the opt out tariff by the relevant LRMC costs

156 As noted in Section 7 of the TSS, we have taken this approach to maintain predictability and avoid the potential for introducing any perverse incentives for customers to allow power factor deterioration.

- Collect the cost reflective revenue from the customers assigned to the opt out tariff through the fixed and energy component starting from 2018.

330. When analysing the load profile of the opt out customers we will use the following data/methodology:

- *Smart meter customers*: use actual annual load profile data
- *Legacy meter customers*: convert the actual energy consumption data into a maximum demand value. We will be applying an average conversion factor based on the analysis of the energy consumption and demand data for our smart meter customers. We will use the most recent data to calculate the conversion factor.

E3. DESCRIPTION OF APPROACH FOR SETTING TARIFF LEVELS FOR ALTERNATIVE CONTROL SERVICES

331. All alternative control services are priced at cost. JEN has undertaken an exercise to identify its costs to provide all alternative control services and considers the prices to be fully cost-reflective.

Appendix F
Indicative NUOS tariff schedule

JEN tariffs and customer outcomes

Index

These indicative network use of system (NUOS) prices will prove to be different to the actual outturn NUOS prices. This is because NUOS prices are made up of a number of uncertain and potentially volatile inputs, including transmission use of system (TUOS) charges and other elements that are difficult to forecast such as pass through amounts, incentive scheme outcomes and adjustments to take into account for the previous year’s under- or over-recovery of revenue.

Customers relying on this information to make business or investment decisions should consider the potential volatility between an indicative NUOS price and final outturn price and the risks inherent with relying on them.

Model Index

Description of model This model estimates the customer outcomes from JEN's proposed tariffs

Sheet Name	Sheet Description
2016 indicative tariffs	*Inputs the JEN indicative NUOS tariffs for the 2016 year*
2017 indicative tariffs	*Inputs the JEN indicative NUOS tariffs for the 2017 year*
2018 indicative tariffs	*Inputs the JEN indicative NUOS tariffs for the 2018 year*
2019 indicative tariffs	*Inputs the JEN indicative NUOS tariffs for the 2019 year*
2020 indicative tariffs	*Inputs the JEN indicative NUOS tariffs for the 2020 year*

Version Control	Developer	Comments	Date
Version 1	*Jemena Electricity Networks*	EDPR submission data	30-Apr-15
Version 2	*Jemena Electricity Networks*	TSS submission data	25-Sep-15

End

JEN tariffs and customer outcomes

2016 indicative tariffs

Source *Basis* *Tariff code*

Input | Indicative NUOS tariffs

Tariff component	Source	Basis	Tariff code	Fixed (Standing charge)	Unit rate	Peak	Off peak	Summer peak	Summer shoulder	Summer off peak	Non-summer peak	Non-summer shoulder	Non-summer off peak	Demand (annual)	Demand (annual)	Summer demand (monthly)	Non-summer demand (monthly)
Unit				$ per customer pa	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	$/kW	$/kVA	$/kW	$/kW
Residential																	
Residential - General Purpose	*JEN*	*$nominal*	*A100*	28.208	9.380	-	-	-	-	-	-	-	-	-	-	-	-
Residential - Flexible	*JEN*	*$nominal*	*A10X*	28.208	-	15.022	4.412	15.022	9.392	4.410	15.018	9.392	4.412	-	-	-	-
Residential - Time of Use Interval Meter	*JEN*	*$nominal*	*A10I*	28.208	-	15.016	2.807	-	-	-	-	-	-	-	-	-	-
Residential - TOU	*JEN*	*$nominal*	*A140*	49.678	-	12.090	3.086	-	-	-	-	-	-	-	-	-	-
Residential - Off Peak Only	*JEN*	*$nominal*	*A180*	-	-	-	2.783	-	-	-	-	-	-	-	-	-	-
Small business																	
Small Business - General Purpose	*JEN*	*$nominal*	*A200*	77.367	-	11.074	-	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Weekdays	*JEN*	*$nominal*	*A210*	128.711	-	13.325	2.943	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Weekdays Demand	*JEN*	*$nominal*	*A230*	294.427	-	8.086	3.006	-	-	-	-	-	-	68.204	-	-	-
Small Business - TOU Extended	*JEN*	*$nominal*	*A250*	128.711	-	11.832	3.174	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Extended Demand	*JEN*	*$nominal*	*A270*	294.427	-	6.829	3.135	-	-	-	-	-	-	68.204	-	-	-
Small Business - Unmetered Supply	*JEN*	*$nominal*	*A290*	-	-	11.920	3.006	-	-	-	-	-	-	-	-	-	-
Large business - low voltage																	
Large Business - LV 0.4 - 0.8 GWh	*JEN*	*$nominal*	*A300*	2,410.647	-	4.802	2.038	-	-	-	-	-	-	112.291	-	-	-
Large Business – LVEN Annual Consumption <=	*JEN*	*$nominal*	*A30E*	2,410.647	-	4.744	2.038	-	-	-	-	-	-	116.845	-	-	-
Large Business - LV 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A320*	4,159.183	-	4.235	2.022	-	-	-	-	-	-	104.813	-	-	-
Large Business - LVEN 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A32E*	4,159.183	-	4.013	2.022	-	-	-	-	-	-	106.535	-	-	-
Large Business - LV 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A340*	7,181.715	-	4.193	1.876	-	-	-	-	-	-	103.794	-	-	-
Large Business - LVEN 2.2+ GWh	*JEN*	*$nominal*	*A34E*	7,181.715	-	3.745	1.872	-	-	-	-	-	-	105.313	-	-	-
Large Business - LVMS 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A34M*	5,016.803	-	4.387	1.869	-	-	-	-	-	-	73.405	-	-	-
Large Business - LV 6.0+ GWh	*JEN*	*$nominal*	*A370*	10,875.756	-	3.852	1.801	-	-	-	-	-	-	99.953	-	-	-
Large Business - LVMS 6.0+ GWh	*JEN*	*$nominal*	*A37M*	8,216.471	-	3.966	1.801	-	-	-	-	-	-	72.616	-		
Large business - high voltage																	
Large Business - HV	*JEN*	*$nominal*	*A400*	14,106.446	-	3.689	1.303	-	-	-	-	-	-	83.899	-	-	-
Large Business – HVEN	*JEN*	*$nominal*	*A40E*	14,106.446	-	3.426	1.303	-	-	-	-	-	-	83.539	-	-	-
Large Business - HVRF	*JEN*	*$nominal*	*A40R*	14,106.446	-	3.779	1.303	-	-	-	-	-	-	78.667	-	-	-
Large Business - HV Ann Cons >= 55GWh	*JEN*	*$nominal*	*A480*	14,498.243	-	3.433	1.213	-	-	-	-	-	-	78.070	-	-	-
Large business - sub-transmission																	
Large Business - Subtransmission	*JEN*	*$nominal*	*A500*	52,092.924	-	2.656	0.791	-	-	-	-	-	-	30.329	-	-	-
Large Business - Subtransmission MA	*JEN*	*$nominal*	*A50A*	52,092.924	-	2.656	0.791	-	-	-	-	-	-	30.329	-	-	-
Large Business - Subtransmission EG	*JEN*	*$nominal*	*A50E*	34,724.432	-	2.691	0.789	-	-	-	-	-	-	12.691	-	-	-

Input | Advanced Metering Infrastructure

Meter provision charge	**2016**
Single phase single element meter	94.22
Single phase single element meter with contactor	94.22
Three phase direct connected meter	115.78
Three phase Current transformer connected meter	128.50

JEN tariffs and customer outcomes

2017 indicative tariffs

Source ***Basis*** ***Tariff code***

Input | Indicative NUOS tariffs

Tariff component				Fixed (Standing charge)	Unit rate	Peak	Off peak	Summer peak	Summer shoulder	Summer off peak	Non-summer peak	Non-summer shoulder	Non-summer off peak	Demand (annual)	Demand (annual)	Summer demand (monthly)	Non-summer demand (monthly)
Unit				$ per customer pa	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	$/kW	$/kVA	$/kW	$/kW
Residential																	
Residential - General Purpose	*JEN*	*$nominal*	*A100*	28.858	9.591	-	-	-	-	-	-	-	-	-	-	-	-
Residential - Flexible	*JEN*	*$nominal*	*A10X*	28.858	-	15.380	4.519	15.380	9.622	4.519	15.380	9.622	4.519	-	-	-	-
Residential - Time of Use Interval Meter	*JEN*	*$nominal*	*A10I*	28.858	-	15.358	2.859	-	-	-	-	-	-	-	-	-	-
Residential - TOU	*JEN*	*$nominal*	*A140*	50.858	-	12.332	3.128	-	-	-	-	-	-	-	-	-	-
Residential - Off Peak Only	*JEN*	*$nominal*	*A180*	-	-	-	2.826	-	-	-	-	-	-	-	-	-	-
Residential - General purpose (opt out)	*JEN*	*$nominal*	*A10L*	28.858	9.591	-	-	-	-	-	-	-	-	-			-
Small business																	
Small Business - General Purpose	*JEN*	*$nominal*	*A200*	79.160	-	11.328	-	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Weekdays	*JEN*	*$nominal*	*A210*	131.340	-	13.626	2.990	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Weekdays Demand	*JEN*	*$nominal*	*A230*	296.016	-	8.267	3.051	-	-	-	-	-	-	68.204	-	-	-
Small Business - TOU Extended	*JEN*	*$nominal*	*A250*	131.340	-	12.088	3.216	-	-	-	-	-	-	-	-	-	-
Small Business - TOU Extended Demand	*JEN*	*$nominal*	*A270*	296.016	-	6.927	3.184	-	-	-	-	-	-	68.204	-	-	-
Small Business - Unmetered Supply	*JEN*	*$nominal*	*A290*	-	-	12.166	3.043	-	-	-	-	-	-	-	-	-	-
Large business - low voltage																	
Large Business - LV 0.4 - 0.8 GWh	*JEN*	*$nominal*	*A300*	2,456.191	-	4.804	1.966	-	-	-	-	-	-	-	98.901	-	-
Large Business – LVEN Annual Consumption <:	*JEN*	*$nominal*	*A30E*	2,456.191	-	4.757	1.966	-	-	-	-	-	-	-	98.718	-	-
Large Business - LV 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A320*	4,230.403	-	4.196	1.949	-	-	-	-	-	-	-	93.573	-	-
Large Business - LVEN 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A32E*	4,230.403	-	3.974	1.949	-	-	-	-	-	-	-	103.635	-	-
Large Business - LV 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A340*	7,208.842	-	4.148	1.793	-	-	-	-	-	-	-	93.000	-	-
Large Business - LVEN 2.2+ GWh	*JEN*	*$nominal*	*A34E*	7,208.842	-	3.700	1.789	-	-	-	-	-	-	-	91.967	-	-
Large Business - LVMS 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A34M*	4,980.366	-	4.345	1.786	-	-	-	-	-	-	-	71.610	-	-
Large Business - LV 6.0+ GWh	*JEN*	*$nominal*	*A370*	10,921.175	-	3.804	1.715	-	-	-	-	-	-	-	87.889	-	-
Large Business - LVMS 6.0+ GWh	*JEN*	*$nominal*	*A37M*	8,069.180	-	3.918	1.715	-	-	-	-	-	-	-	64.776	-	-
Special supply arrangements	*JEN*	*$nominal*	*A30S*	296.016	-	4.804	1.966	-	-	-	-	-	-	-	98.901	-	-
Large business - high voltage																	
Large Business - HV	*JEN*	*$nominal*	*A400*	13,894.692	-	3.621	1.204	-	-	-	-	-	-	-	77.400	-	-
Large Business – HVEN	*JEN*	*$nominal*	*A40E*	13,894.692	-	3.358	1.204	-	-	-	-	-	-	-	83.587	-	-
Large Business - HVRF	*JEN*	*$nominal*	*A40R*	13,894.692	-	3.621	1.204	-	-	-	-	-	-	-	71.289	-	-
Large Business - HV Ann Cons >= 55GWh	*JEN*	*$nominal*	*A480*	14,285.976	-	3.373	1.111	-	-	-	-	-	-	-	70.104	-	-
Large business - sub-transmission																	
Large Business - Subtransmission	*JEN*	*$nominal*	*A500*	51,692.924	-	2.338	0.681	-	-	-	-	-	-	-	25.891	-	-
Large Business - Subtransmission MA	*JEN*	*$nominal*	*A50A*	51,692.924	-	2.338	0.681	-	-	-	-	-	-	-	28.087	-	-
Large Business - Subtransmission EG	*JEN*	*$nominal*	*A50E*	34,226.432	-	2.362	0.689	-	-	-	-	-	-	-	11.231	-	-

Input | Advanced Metering Infrastructure

Meter provision charge	2017
Single phase single element meter	96.60
Single phase single element meter with contactor	96.60
Three phase direct connected meter	118.71
Three phase Current transformer connected meter	131.74

JEN tariffs and customer outcomes

2018 indicative tariffs

Source ***Basis*** ***Tariff code***

Input | Indicative NUOS tariffs

Tariff component	Source	Basis	Tariff code	Fixed (Standing charge)	Unit rate	Peak	Off peak	Summer peak	Summer shoulder	Summer off peak	Non-summer peak	Non-summer shoulder	Non-summer off peak	Demand (annual)	Demand (annual)	Summer demand (monthly)	Non-summer demand (monthly)
Unit				$ per customer pa	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	$/kW	$/kVA	$/kW	$/kW
Residential																	
Residential - General Purpose	*JEN*	*$nominal*	*A100*	23.062	7.513	-	-	-	-	-	-	-	-		-	4.495	1.579
Residential - Flexible	*JEN*	*$nominal*	*A10X*	23.062	-	10.349	2.522	10.349	6.955	2.522	10.379	6.955	2.522		-	4.495	1.579
Residential - Time of Use Interval Meter	*JEN*	*$nominal*	*A10I*	23.062	-	10.949	2.571	-	-	-	-	-	-		-	4.495	1.579
Residential - TOU	*JEN*	*$nominal*	*A140*	35.965	-	10.227	3.048	-	-	-	-	-	-		-	4.495	1.579
Residential - Off Peak Only	*JEN*	*$nominal*	*A180*	-	-	-	2.835	-	-	-	-	-	-		-	-	-
Residential - General purpose (opt out)	*JEN*	*$nominal*		30.301	9.646	-	-	-	-	-	-	-	-	-	-	-	-
Small business																	
Small Business - General Purpose	*JEN*	*$nominal*	*A200*	83.831	-	9.100	-	-	-	-	-	-	-	30.096	-	-	-
Small Business - TOU Weekdays	*JEN*	*$nominal*	*A210*	83.831	-	11.858	2.990	-	-	-	-	-	-	30.096	-	-	-
Small Business - TOU Weekdays Demand	*JEN*	*$nominal*	*A230*	83.831	-	7.848	3.051	-	-	-	-	-	-	68.204	-	-	-
Small Business - TOU Extended	*JEN*	*$nominal*	*A250*	83.831	-	10.515	3.216	-	-	-	-	-	-	30.096	-	-	-
Small Business - TOU Extended Demand	*JEN*	*$nominal*	*A270*	83.831	-	6.457	3.184	-	-	-	-	-	-	68.204	-	-	-
Small Business - Unmetered Supply	*JEN*	*$nominal*	*A290*	-	-	12.204	3.054	-	-	-	-	-	-	-	-	-	-
Large business - low voltage																	
Large Business - LV 0.4 - 0.8 GWh	*JEN*	*$nominal*	*A300*	2,456.191	-	4.871	1.976	-	-	-	-	-	-	-	98.901	-	-
Large Business – LVEN Annual Consumption <	*JEN*	*$nominal*	*A30E*	2,456.191	-	4.825	1.976	-	-	-	-	-	-	-	98.718	-	-
Large Business - LV 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A320*	4,230.403	-	4.241	1.958	-	-	-	-	-	-	-	93.573	-	-
Large Business - LVEN 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A32E*	4,230.403	-	4.019	1.958	-	-	-	-	-	-	-	103.635	-	-
Large Business - LV 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A340*	7,208.842	-	4.189	1.800	-	-	-	-	-	-	-	93.000	-	-
Large Business - LVEN 2.2+ GWh	*JEN*	*$nominal*	*A34E*	7,208.842	-	3.741	1.796	-	-	-	-	-	-	-	91.967	-	-
Large Business - LVMS 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A34M*	4,980.366	-	4.385	1.793	-	-	-	-	-	-	-	71.610	-	-
Large Business - LV 6.0+ GWh	*JEN*	*$nominal*	*A370*	10,921.175	-	3.844	1.721	-	-	-	-	-	-	-	87.889	-	-
Large Business - LVMS 6.0+ GWh	*JEN*	*$nominal*	*A37M*	8,069.180	-	3.958	1.721	-	-	-	-	-	-	-	64.776	-	-
Special supply arrangements	*JEN*	*$nominal*		303.470	-	4.871	1.976	-	-	-	-	-	-	-	98.901	-	-
Large business - high voltage																	
Large Business - HV	*JEN*	*$nominal*	*A400*	13,894.692	-	3.655	1.207	-	-	-	-	-	-	-	77.400	-	-
Large Business – HVEN	*JEN*	*$nominal*	*A40E*	13,768.059	-	3.296	1.191	-	-	-	-	-	-	-	83.587	-	-
Large Business - HVRF	*JEN*	*$nominal*	*A40R*	13,768.059	-	3.559	1.191	-	-	-	-	-	-	-	71.289	-	-
Large Business - HV Ann Cons >= 55GWh	*JEN*	*$nominal*	*A480*	14,160.079	-	3.314	1.101	-	-	-	-	-	-	-	70.104	-	-
Large business - sub-transmission																	
Large Business - Subtransmission	*JEN*	*$nominal*	*A500*	48,466.963	-	2.319	0.678	-	-	-	-	-	-	-	26.080	-	-
Large Business - Subtransmission MA	*JEN*	*$nominal*	*A50A*	48,466.963	-	2.319	0.678	-	-	-	-	-	-	-	28.298	-	-
Large Business - Subtransmission EG	*JEN*	*$nominal*	*A50E*	31,024.403	-	2.344	0.686	-	-	-	-	-	-	-	11.264	-	-

Input | Advanced Metering Infrastructure

Meter provision charge	**2018**
Single phase single element meter	99.03
Single phase single element meter with contactor	99.03
Three phase direct connected meter	121.70
Three phase Current transformer connected meter	135.07

JEN tariffs and customer outcomes

2019 indicative tariffs

Source *Basis* *Tariff code*

Input | Indicative NUOS tariffs

Tariff component	Source	Basis	Tariff code	Fixed (Standing charge)	Unit rate	Peak	Off peak	Summer peak	Summer shoulder	Summer off peak	Non-summer peak	Non-summer shoulder	Non-summer off peak	Demand (annual)	Demand (annual)	Summer demand (monthly)	Non-summer demand (monthly)
Unit				$ per customer pa	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	$/kW	$/kVA	$/kW	$/kW
Residential																	
Residential - General Purpose	*JEN*	*$nominal*	*A100*	21.905	7.288	-	-	-	-	-	-	-	-	-	-	5.520	1.948
Residential - Flexible	*JEN*	*$nominal*	*A10X*	21.905	-	10.120	2.119	10.120	6.743	2.127	10.160	6.743	2.119	-	-	5.520	1.948
Residential - Time of Use Interval Meter	*JEN*	*$nominal*	*A10I*	21.905	-	10.720	2.576	-	-	-	-	-	-	-	-	5.520	1.948
Residential - TOU	*JEN*	*$nominal*	*A140*	34.256	-	9.853	3.053	-	-	-	-	-	-	-	-	5.520	1.948
Residential - Off Peak Only	*JEN*	*$nominal*	*A180*	-	-	-	2.827	-	-	-	-	-	-	-	-	-	-
Residential - General purpose (opt out)	*JEN*	*$nominal*		31.816	9.889	-	-	-	-	-	-	-	-	-	-	-	-
Small business																	
Small Business - General Purpose	*JEN*	*$nominal*	*A200*	84.560	-	9.046	-	-	-	-	-	-	-	37.027	-	-	-
Small Business - TOU Weekdays	*JEN*	*$nominal*	*A210*	84.560	-	11.760	2.933	-	-	-	-	-	-	37.027	-	-	-
Small Business - TOU Weekdays Demand	*JEN*	*$nominal*	*A230*	84.560	-	7.767	2.985	-	-	-	-	-	-	68.004	-	-	-
Small Business - TOU Extended	*JEN*	*$nominal*	*A250*	84.560	-	10.428	3.154	-	-	-	-	-	-	37.027	-	-	-
Small Business - TOU Extended Demand	*JEN*	*$nominal*	*A270*	84.560	-	6.399	3.113	-	-	-	-	-	-	68.004	-	-	-
Small Business - Unmetered Supply	*JEN*	*$nominal*	*A290*	-	-	12.427	3.093	-	-	-	-	-	-	-	-	-	-
Large business - low voltage																	
Large Business - LV 0.4 - 0.8 GWh	*JEN*	*$nominal*	*A300*	2,508.728	-	5.020	2.011	-	-	-	-	-	-	-	99.663	-	-
Large Business – LVEN Annual Consumption <:	*JEN*	*$nominal*	*A30E*	2,508.728	-	4.976	2.011	-	-	-	-	-	-	-	99.474	-	-
Large Business - LV 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A320*	4,317.242	-	4.341	1.992	-	-	-	-	-	-	-	94.255	-	-
Large Business - LVEN 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A32E*	4,317.242	-	4.118	1.992	-	-	-	-	-	-	-	104.441	-	-
Large Business - LV 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A340*	7,341.498	-	4.280	1.825	-	-	-	-	-	-	-	93.673	-	-
Large Business - LVEN 2.2+ GWh	*JEN*	*$nominal*	*A34E*	7,341.498	-	3.832	1.821	-	-	-	-	-	-	-	92.609	-	-
Large Business - LVMS 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A34M*	5,046.694	-	4.475	1.818	-	-	-	-	-	-	-	71.997	-	-
Large Business - LV 6.0+ GWh	*JEN*	*$nominal*	*A370*	11,093.788	-	3.932	1.743	-	-	-	-	-	-	-	88.496	-	-
Large Business - LVMS 6.0+ GWh	*JEN*	*$nominal*	*A37M*	8,155.486	-	4.046	1.743	-	-	-	-	-	-	-	65.073	-	-
Special supply arrangements	*JEN*	*$nominal*		311.120	-	5.020	2.011	-	-	-	-	-	-	-	99.663	-	-
Large business - high voltage																	
Large Business - HV	*JEN*	*$nominal*	*A400*	13,988.400	-	3.714	1.217	-	-	-	-	-	-	-	78.161	-	-
Large Business – HVEN	*JEN*	*$nominal*	*A40E*	13,858.488	-	3.349	1.200	-	-	-	-	-	-	-	84.459	-	-
Large Business - HVRF	*JEN*	*$nominal*	*A40R*	13,858.488	-	3.612	1.200	-	-	-	-	-	-	-	71.891	-	-
Large Business - HV Ann Cons >= 55GWh	*JEN*	*$nominal*	*A480*	14,249.982	-	3.365	1.107	-	-	-	-	-	-	-	70.688	-	-
Large business - sub-transmission																	
Large Business - Subtransmission	*JEN*	*$nominal*	*A500*	48,461.235	-	2.318	0.678	-	-	-	-	-	-	-	26.681	-	-
Large Business - Subtransmission MA	*JEN*	*$nominal*	*A50A*	48,461.235	-	2.318	0.678	-	-	-	-	-	-	-	28.969	-	-
Large Business - Subtransmission EG	*JEN*	*$nominal*	*A50E*	31,003.705	-	2.344	0.686	-	-	-	-	-	-	-	11.370	-	-

Input | Advanced Metering Infrastructure

Meter provision charge	2019
Single phase single element meter	101.53
Single phase single element meter with contactor	101.53
Three phase direct connected meter	124.77
Three phase Current transformer connected meter	138.47

JEN tariffs and customer outcomes

2020 indicative tariffs

Source	*Basis*	*Tariff code*

Input | Indicative NUOS tariffs

Tariff component	Source	Basis	Tariff code	Fixed (Standing charge)	Unit rate	Peak	Off peak	Summer peak	Summer shoulder	Summer off peak	Non-summer peak	Non-summer shoulder	Non-summer off peak	Demand (annual)	Demand (annual)	Summer demand (monthly)	Non-summer demand (monthly)
Unit				$ per customer pa	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	c/kWh	$/kW	$/kVA	$/kW	$/kW
Residential																	
Residential - General Purpose	*JEN*	*$nominal*	*A100*	20.271	7.074	-	-	-	-	-	-	-	-	-	-	6.546	2.360
Residential - Flexible	*JEN*	*$nominal*	*A10X*	20.271	-	9.865	2.102	9.865	6.529	2.110	9.819	6.529	2.102	-	-	6.546	2.360
Residential - Time of Use Interval Meter	*JEN*	*$nominal*	*A10I*	20.271	-	10.465	2.560	-	-	-	-	-	-	-	-	6.546	2.360
Residential - TOU	*JEN*	*$nominal*	*A140*	32.064	-	9.582	3.033	-	-	-	-	-	-	-	-	6.546	2.360
Residential - Off Peak Only	*JEN*	*$nominal*	*A180*	-	-	-	2.813	-	-	-	-	-	-	-	-	-	-
Residential - General purpose (opt out)	*JEN*	*$nominal*		33.407	10.138	-	-	-	-	-	-	-	-	-	-	-	-
Small business																	
Small Business - General Purpose	*JEN*	*$nominal*	*A200*	81.920	-	8.970	-	-	-	-	-	-	-	44.288	-	-	-
Small Business - TOU Weekdays	*JEN*	*$nominal*	*A210*	81.920	-	11.642	2.933	-	-	-	-	-	-	44.288	-	-	-
Small Business - TOU Weekdays Demand	*JEN*	*$nominal*	*A230*	81.920	-	7.671	2.985	-	-	-	-	-	-	68.004	-	-	-
Small Business - TOU Extended	*JEN*	*$nominal*	*A250*	81.920	-	10.324	3.154	-	-	-	-	-	-	44.288	-	-	-
Small Business - TOU Extended Demand	*JEN*	*$nominal*	*A270*	81.920	-	6.330	3.113	-	-	-	-	-	-	68.004	-	-	-
Small Business - Unmetered Supply	*JEN*	*$nominal*	*A290*	-	-	12.711	3.143	-	-	-	-	-	-	-	-	-	-
Large business - low voltage																	
Large Business - LV 0.4 - 0.8 GWh	*JEN*	*$nominal*	*A300*	2,561.548	-	5.164	2.041	-	-	-	-	-	-	-	100.828	-	-
Large Business – LVEN Annual Consumption <	*JEN*	*$nominal*	*A30E*	2,561.548	-	5.122	2.041	-	-	-	-	-	-	-	100.632	-	-
Large Business - LV 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A320*	4,404.217	-	4.437	2.021	-	-	-	-	-	-	-	95.327	-	-
Large Business - LVEN 0.8+ - 2.2 GWh	*JEN*	*$nominal*	*A32E*	4,404.217	-	4.214	2.021	-	-	-	-	-	-	-	105.658	-	-
Large Business - LV 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A340*	7,474.362	-	4.368	1.847	-	-	-	-	-	-	-	94.735	-	-
Large Business - LVEN 2.2+ GWh	*JEN*	*$nominal*	*A34E*	7,474.362	-	3.920	1.843	-	-	-	-	-	-	-	93.534	-	-
Large Business - LVMS 2.2+ - 6.0 GWh	*JEN*	*$nominal*	*A34M*	5,113.126	-	4.562	1.840	-	-	-	-	-	-	-	72.727	-	-
Large Business - LV 6.0+ GWh	*JEN*	*$nominal*	*A370*	11,266.671	-	4.017	1.762	-	-	-	-	-	-	-	89.481	-	-
Large Business - LVMS 6.0+ GWh	*JEN*	*$nominal*	*A37M*	8,241.927	-	4.131	1.762	-	-	-	-	-	-	-	64.999	-	-
Special supply arrangements	*JEN*	*$nominal*		318.960	-	5.164	2.041	-	-	-	-	-	-	-	100.828	-	-
Large business - high voltage																	
Large Business - HV	*JEN*	*$nominal*	*A400*	13,789.977	-	3.775	1.226	-	-	-	-	-	-	-	79.150	-	-
Large Business – HVEN	*JEN*	*$nominal*	*A40E*	13,657.349	-	3.404	1.208	-	-	-	-	-	-	-	85.683	-	-
Large Business - HVRF	*JEN*	*$nominal*	*A40R*	13,657.349	-	3.667	1.208	-	-	-	-	-	-	-	72.735	-	-
Large Business - HV Ann Cons >= 55GWh	*JEN*	*$nominal*	*A480*	13,824.408	-	3.417	1.113	-	-	-	-	-	-	-	71.513	-	-
Large business - sub-transmission																	
Large Business - Subtransmission	*JEN*	*$nominal*	*A500*	44,333.816	-	2.317	0.678	-	-	-	-	-	-	-	27.311	-	-
Large Business - Subtransmission MA	*JEN*	*$nominal*	*A50A*	44,333.816	-	2.317	0.678	-	-	-	-	-	-	-	29.672	-	-
Large Business - Subtransmission EG	*JEN*	*$nominal*	*A50E*	29,873.042	-	2.343	0.686	-	-	-	-	-	-	-	11.481	-	-

Input | Advanced Metering Infrastructure

Meter provision charge	**2020**
Single phase single element meter	104.10
Single phase single element meter with contactor	104.10
Three phase direct connected meter	127.92
Three phase Current transformer connected meter	141.97

Appendix G
Assignment and reassignment policies and procedures

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Jemena Electricity Networks (Vic) Ltd

Policy for Network Tariff Assignment and Reassignment

TABLE OF CONTENTS

1. DEFINITIONS ____ 3

2. INTRODUCTION ____ 6

3. TARIFF CLASSES ____ 6

4. SYSTEM OF ASSESSMENT ____ 7

5. TARIFF ASSIGNMENT ____ 7

6. TARIFF REASSIGNMENT ____ 9

7. FLEXIBLE TARIFF ASSIGNMENT AND REASSIGNMENT ____ 11

8. NOTIFICATION ____ 13

9. OBJECTION ____ 14

10. GENERAL CONDITIONS AND ADMINISTRATION PROCEDURES ____ 15

APPENDIX A –TARIFF CRITERIA ____ 16

APPENDIX B – JEN - TARIFF ASSIGNMENT REQUEST FORM – BUSINESS CUSTOMER ____ 18

APPENDIX C – JEN - TARIFF REASSIGNMENT REQUEST FORM – BUSINESS CUSTOMER ____ 21

APPENDIX D – JEN - TARIFF REASSIGNMENT OBJECTION FORM – BUSINESS AND RESIDENTIAL CUSTOMER ____ 24

1. DEFINITIONS

In this document, unless the context otherwise requires:

AER	means the Australian Energy Regulator (*AER*).
applicant	means the person lodging with JEN the Tariff Assignment/Tariff Reassignment Request form. The *applicant* could be the *customer* or the *customer's representative*.
appropriate tariff	means the *tariff* which matches the criterion applicable to the *customer's load, connection* and *metering characteristics*.
B2B service order	means the *business to business service order* the *customer's retailer* sends to JEN requesting specific service(s) on behalf of the *customer*.
business day	means the part of a day during which most businesses are operating, usually from 9am to 5pm Monday through to Friday (excludes gazetted public holidays in Melbourne).
connection characteristic	means: a) *supply* voltage level – *Low Voltage* (LV), *High Voltage* (HV) or *Subtransmission*; and b) in relation to *Low Voltage supply* whether the *supply* is taken from an on-site or dedicated substation OR directly from the street.
Common DB Process	refers to the "AMI Tariffs – Residential Customers: Tariff Application and Reversion Request Approach" developed by the Victorian Distributors in accordance with the requirements of the AMI Tariffs Order published 19 June 2013.
contract demand	means the *kW* (or *kVA*) demand used to calculate the demand charge component of the *demand tariff* applicable to the *customer* in each billing period. *Contract demand* is always greater than or equal to the *maximum demand*.
customer	means, in relation to the *retailer*, a person: a) who has a *supply point* in JEN's distribution area or is seeking to establish a *supply point* in JEN's distribution area; and b) either: • whose NMI is allocated to the *retailer* under the National Electricity Code; or • to whom the *retailer* agrees to sell electricity under a Retail Contract, or to whom the *retailer* is deemed under the Electricity Industry Act ("EI Act") to have a contract for the sale and *supply* of electricity (whether as a "default *retailer*" or a "supplier of last resort" or otherwise).
customer's representative	means the *retailer*, consultant, administrator, liquidator or third party contractor acting on the *customer's* behalf.
demand tariff	means a *tariff* approved by the *AER* which has a demand rate.
distribution licence	means a licence granted under section 19 of the EI Act to distribute and deliver electricity using a *distribution system*.

distribution system	means the system of electric lines (generally at nominal voltage levels of 66kV or below) which JEN is licensed to use to distribute electricity for delivery under its *distribution licence*.
DNSP	means distribution network service provider.
Flexible tariff	is the new 3-part residential tariff that JEN will introduce on 1 January 2013 (Tariff Code A10X).
GWh	is a unit of electrical energy consumption measurement (Gigawatt Hours). One *GWh* is equivalent to 1,000,000 *kWh*.
high voltage	nominal voltage levels of 1,000 volts or more but less than or equal to 22,000 volts.
JEN	means Jemena Electricity Networks (Vic) Ltd in its capacity as a *distribution licence* holder.
kVA	is a unit of electrical demand measurement (Kilo Volt-Amperes).
kW	is a unit of electrical demand measurement (Kilowatt).
kWh	is a unit of electrical energy consumption measurement (Kilowatt Hours).
load characteristic	means: a) annual electricity consumption in *kWh*; and b) *maximum demand* in *kW*.
low voltage	means a *supply* taken from a nominal voltage levels less than 1,000 volts.
maximum demand	in relation to a billing period, is the demand calculated as being: a) the highest energy consumption in *kWh* recorded over any 30-minute period multiplied by two (where the meter installed at the *customer's* premises measures 30 minutes interval data); or b) the highest energy consumption in *kWh* recorded over any 15-minute period multiplied by four (where the meter installed at the *customer's* premises measures 15 minutes interval data).
metering characteristics	means one of the four following types of meter: a) Interval meter manually or remotely read b) Two rate accumulation meter without demand meter c) Two rate accumulation meter with demand meter d) Single rate accumulation meter
MWh	is a unit of electrical energy consumption measurement (Megawatt Hours). One *MWh* is equivalent to 1,000 *kWh*.
NEL	means National Electricity Law.
NER	refers to the National Electricity Rules (NER) which governs the operation of the National Electricity Market. The Rules have the force of law, and are made under the *National Electricity Law.*
new customer	means a *customer* who has taken over an existing *supply point* (i.e. change of occupancy) or has commenced to consume electricity from a new *supply point* in JEN's distribution area (whether or not the *customer*

	has changed premises).
NMI	means "National Metering Identifier" as defined in the National Electricity Code.
PFIT	refers to Premium Feed In Tariff. JEN has replicated some of its network *tariffs*, using the prefix "F" to denote these *tariffs* attract the Premium Feed-in Tariff rebate. For example A230 becomes F230 which indicates the *tariff* attracts the PFIT rebate.
previous tariff	is the tariff the *customer* was on immediately prior to movement to the *Flexible tariff*.
qualifying customer	means a *customer* who qualifies for the *PFIT* or *TFIT tariff*. The *customer* must have the following characteristics: net interval metering, a photovoltaic generating facility which has an installed or name-plate generating capacity of 5 *kW* or less and annual consumption less than 100 *MWh* where the *customer* is a small business or community organisation.
retailer	means a person who holds a retail licence in Victoria to sell electricity to customers.
reversion	refers to the *customer's* right to move from and to the *Flexible Tariff* only.
reversion period	Is the period from 1 July 2013 to 31 March 2015.
subtransmission	nominal voltage levels greater than 22,000 volts.
supply	means the delivery of electricity.
supply point	in relation to a *customer*, means the point where a *supply* of electricity taken by the *customer* leaves a *supply* facility owned or operated by JEN before being *supplied* to the *customer* provided that where the *customer's* electrical installation is not directly connected to the *distribution system*, the *supply point* is the point at which the electricity last leaves the *supply* facility owned or operated by JEN before being *supplied* to the *customer*, whether or not the electricity passes through facilities owned or operated by any other person after leaving that point before being so *supplied*.
tariff	means the network *tariff* or *tariffs* charged by JEN to *retailers* in respect of their customers, for distributing electricity using the *distribution system* and the transmission system, as approved by the *AER* from time to time, in accordance with the Use of System Agreements between JEN and each *retailer*.
TFIT	refers to Transitional Feed In Tariff. JEN has replicated some of its network *tariffs*, using the prefix "T" to denote these *tariffs* attract the Transitional Feed-in Tariff rebate. For example A230 becomes T230 which indicates the *tariff* attracts the TFIT rebate.
written notice	means notice given via mail, e-mail.

2. INTRODUCTION

This document sets out JEN's policy on *tariff* assignments and *tariff* reassignments; and outlines how JEN will implement this policy. The policy describes the requirements which customers and their *representatives* must comply with when requesting a *tariff* assignment or reassignment and how JEN will respond to such requests. The policy is consistent with Appendix G, the Final Decision – Appendices of the Victorian electricity distribution network service providers Distribution Determination 2011–2015 (Final Decision), in particular the regulatory obligation that :

a) customers for Distribution Use of System (DUoS) services must be a member of a *tariff* class;

b) *tariff* assignment and reassignment must be based on an effective system of assessment, taking into account the *customer's load*, *connection* and *metering characteristics*; and

c) customers with similar *load* and *connection characteristics* are treated equally.

In determining the *tariff* class to which a *customer* or potential *customer* will be assigned or reassigned, JEN will take into account one or more of the following factors:

a) the nature and extent of the *customer's* usage

b) the nature of the *customer's connection* to the network

c) whether remotely-read interval metering or other similar metering technology has been installed at the *customer's* premises as a result of a regulatory obligation or requirement.

In addition to the above requirements, when assigning or reassigning a *customer* to a *tariff* class, JEN will ensure that:

a) customers with similar connection and usage profiles are treated equally

b) customers who have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

When developing this policy, JEN has endeavoured to balance JEN's rights to assign and reassign customers to the *appropriate tariffs* under the regulatory framework, the need to ensure that customers pay a fair amount for their use of the *distribution system* (so that one *customer* does not benefit to the detriment of all other customers) and the *customer's* need to change their *tariff* from time to time.

JEN reserves the right to amend this policy at any time without notice.

3. TARIFF CLASSES

JEN has grouped its *tariffs* into five *tariff* classes based on *customer's* type (residential or business), *customer's load* and *connection characteristics*. Each *tariff* class incorporates a number of *tariffs* sharing a common *tariff* code numbering convention. For example, Residential *tariff* class contains *tariffs* with *tariff* codes starting with A1XX, F1XX or T1XX whereas Small Business *tariff* class contains *tariff* codes starting with A2XX, F2XX or T2XX. The list of *tariffs* contained within each *tariff* class is detailed in Appendix A.

The five *tariff* classes are:

1) **Residential** – This *tariff* class contains all *tariffs* starting with *tariff* codes A1XX, F1XX or T1XX and applies to residential customers.

2) **Small Business** – This *tariff* class contains all *tariffs* starting with *tariff* codes A2XX, F2XX or T2XX and applies to *Low Voltage* business customers:

- consuming an annual amount of electricity less than 400 *MWh*; AND
- having a *maximum demand*[1] of less than 120 *kW*; AND
- where *supply* is not taken from an on-site or dedicated substation.

3) **Large Business Low Voltage** – This *tariff* class contains all *tariffs* starting with *tariff* codes A3XX, F3XX or T3XX and applies to *Low Voltage* business customers:

- consuming an annual amount of electricity greater than or equal to 400 *MWh*; OR
- having a *maximum demand*[2] greater than or equal to 120 *kW*; OR
- where *supply* is taken from an on-site or dedicated substation.

4) **Large Business High Voltage** – This *tariff* class contains all *tariffs* starting with *tariff* codes A4XX and applies to *High Voltage* customers.

5) **Large Business Subtransmission** – This *tariff* class contains all *tariffs* starting with *tariff* codes A5XX and applies to *Subtransmission* customers.

Note embedded networks are contained within the Large Business *tariff* classes (*Low Voltage* or *High Voltage* depending on the embedded network's *connection characteristics*).

4. SYSTEM OF ASSESSMENT

JEN uses the following system of assessment to assign or reassign customers to the *appropriate tariff*.

a) **Step 1 "Assigning the *customer* to a *tariff* class" –** The *customer* is assigned to the *appropriate tariff* class based on the *tariff* class criteria described in Section 3.

b) **Step 2 "Assigning the *customer* to the *appropriate tariff*" –** Once the *customer* is assigned to the *tariff* class, the *appropriate tariff* is determined based on *customer's* load and metering characteristics, specified against the criteria applicable to each *tariff* in the *tariff* class.

The criteria applicable to each *tariff* are described in Appendix A.

JEN's annual published *tariff* schedule also lists the criteria applicable to each *tariff* and *tariff* class. This policy and the *tariff* schedule provide the *customer* and *customer's representative* with the necessary information to select the *tariff* when applying for a *tariff* assignment or reassignment.

5. TARIFF ASSIGNMENT

Tariff assignment occurs when a *customer*:

a) Commences to consume electricity from a new *supply point* (i.e. New Connection); or

b) Takes over an existing *supply point* (i.e. Change of Occupancy)

[1] *maximum demand* is the greater of the *maximum demand* and the *contract demand* specified in the contractual arrangement between JEN and the *customer* (if it exists)
[2] ibid

Where a New Connection event occurs, JEN will use the estimated information collected from the *customer*, the *customer's representative* or the *retailer's B2B service order* to assign the *customer* to the *appropriate tariff*.

Where a Change of Occupancy event occurs for Business Customers, the *customer* or the *customer's representative* must notify JEN in writing of the change in occupancy, using the form in Appendix B to enable JEN to assign the *customer* to the *appropriate tariff*.

Where the completed request form is received within 20 *business days* from the date the change of occupancy occurred, the new *tariff* assignment (if approved) will take effect from the date the change of occupancy occurred. The new network *tariff* assignment will not take effect until JEN advises the *applicant* in writing of the approval and effective date of the new *tariff* assignment.

Where a Change of Occupancy event occurs for Residential Customers, the *retailer* must notify JEN using the *B2B service order* Meter Reconfiguration paperwork if a change in *tariff* is required.

In both circumstances, JEN will use the System of Assessment as described in Section 4 to assign the *customer* to the *appropriate tariff*.

As the *tariff* assignment will be based on estimated information obtained from the *customer* or *customer's representative*, it is the responsibility of the *customer* or *customer's representative* to monitor the suitability of the *tariff* applied and advise JEN if a *tariff* reassignment is required.

Note different rules apply for *tariff* assignment of residential customers to the *Flexible tariff* (A10X). These rules are described in Section 7 of this document.

Below are a few examples to illustrate how JEN uses its System of Assessment to determine the *appropriate tariff* to be assigned to the *customer*:

Example 1 - Business Customer A

Assumptions:

- Estimated annual consumption: 360 *MWh*
- Estimated *maximum demand*: 125 *kW*
- *Low voltage supply*

Assessment:

a) **Assignment to a *tariff* class**: The *customer's* estimated *maximum demand* is 125 *kW*, which is greater than 120 *kW*. As a result *Customer* A is assigned to *tariff* class *"Large Business - Low Voltage".*

b) **Assignment to the *appropriate tariff***: The estimated annual consumption is 360 *MWh*, which is less than or equal to 0.8 *GWh* (each *GWh* = 1,000 *MWh*). As a result *customer* A is assigned to *tariff* code A300 "*LV 0.4 – 0.8 GWh"*.

Example 2 - Business Customer B

Assumptions:

- Estimated annual consumption: 240 *MWh*
- Estimated *maximum demand*: 70 *kW*
- *Low voltage supply* not taken from an onsite or dedicated substation
- Interval meter

Assessment:

a) **Assignment to a *tariff* class**: The *customer* is not taking *supply* from an onsite or dedicated substation, the estimated *maximum demand* is less than 120 *kW* and the estimated annual consumption is less than 400 *MWh*. As a result *Customer* B is assigned to tariff class *"Small Business".*

b) **Assignment to the *appropriate tariff***: The estimated *maximum demand* is 70 *kW*, which is greater than 60 *kW* and the *customer* has an interval meter. As a result *Customer* B is assigned to *tariff* code A230 *"Time of use weekdays - Demand"*.

6. TARIFF REASSIGNMENT

When a *new customer* is assigned to a *tariff*, that *tariff* will continue to apply until such time as a result of a change in the *customer's load*, *connection* or *metering characteristics*, either:

a) The *customer* or the *customer's representative* applies for a *tariff* reassignment; or

b) JEN initiates the *tariff* reassignment after providing the *customer* notice prior to the reassignment

Where the *customer* or the *customer's representative* wants to make a request for a *tariff* reassignment, they must apply in writing by using the *Tariff* Reassignment Request Form in Appendix C for Business Customers.

For Residential Customers, the request for *tariff* reassignment must be made by the *customer's retailer* and must follow the *Common DB Process*.

JEN may become aware of the change in the *customer's load*, *connection* or *metering characteristics* through a number of means including but not limited to:

- A written application or correspondence received from the *customer* or the *customer's representative*, such as an application for a *tariff* reassignment, or a *contract demand* reset or the receipt of a *B2B service order* from the *customer's retailer*.

- The entering of a contractual arrangement between JEN and the *customer*

Whether the *customer*, the *customer's representative* or JEN initiates a *tariff* reassignment JEN will use the System of Assessment described in Section 4 to reassign the *customer* to the *appropriate tariff*.

Where a *customer* is on a *demand tariff*, the *tariff* reassignment does not trigger an automatic change in the *contract demand*. However, where the minimum chargeable demand applicable to the *tariff* to be reassigned to the *customer* is greater than the *contract demand* that applied to the existing *tariff,* the *contract demand* will increase to match the minimum chargeable demand applicable to the *tariff* to be reassigned to the *customer* (refer Example 3 below).

Further information on the application of *contract demand* can be found in JEN's Policy for Resetting Contract Demand which can be accessed via the link below:
http://jemena.com.au/what-we-do/assets/jemena-electricity-network/contract-demand-reset.aspx

Note different rules apply for *tariff* reassignment of residential customers to and from the *Flexible tariff* (A10X). These rules are described in Section 7 of this document.

Below are a few examples to illustrate how JEN uses its System of Assessment and review to determine the *appropriate tariff* to be reassigned to the *customer*:

Example 1 - Business Customer C

Assumptions:

- Annual consumption: Changed from 420 *MWh* to 830 *MWh* (changes in *load characteristics*)
- *Low voltage supply*
- Existing *tariff* Class: "Large Business – *Low Voltage*"
- Existing *tariff* code: A300
- Existing *contract demand* 280 *kW*
- *Customer* applied to be reassigned to *tariff* code A320

Assessment:

a) **Assignment to a *tariff* class**: The *customer's* annual consumption is 830 *MWh*, which is greater than or equal to 400 *MWh*. As a result *Customer* C will remain on *tariff* class *"Large Business - Low Voltage".*

b) **Assignment to the *appropriate tariff***: The annual consumption is 830 *MWh*, which is greater than 0.8 *GWh* but less than or equal to 2.2 *GWh*. As a result *Customer* C application is successful and will be reassigned to *tariff* code A320. The *contract demand* will not change as a result of *Customer* C switching to *tariff* code A320

Example 2 - Business Customer D

Assumptions:

- Annual consumption: Changed from 805 *MWh* to 380 *MWh* (changes in *load characteristics*)
- *Low voltage supply* taken from an onsite substation
- Existing *tariff* Class: "Large Business – *Low Voltage*"
- Existing *tariff* code: A320
- Existing *contract demand* 252 *kW*
- *Customer* applied to be reassigned to *tariff* code A230 under *tariff* class "Small Business"

Assessment:

a) **Assignment to a *tariff* class**: *The customer* is taking *supply* from an onsite substation. As a result *Customer* D is not eligible to be reassigned to *tariff* class "Small Business". The *customer* will remain on *tariff* class *"Large Business - Low Voltage"*. In this case *Customer* D application is unsuccessful.

b) **Assignment to the *appropriate tariff***: Despite the *customer*'s application being unsuccessful JEN will assess if the *customer* can remain on the existing *tariff* code A320. The annual consumption is 380 *MWh*, which is less than 0.8 *GWh*. As a result *Customer* D will be reassigned to *tariff* code A300. The *contract demand* will not change as a result of *Customer* D switching to *tariff* code A300.

Example 3 - Business Customer E

Assumptions:

- Annual consumption: Changed from 270 *MWh* to 405 *MWh* (changes in *load characteristics*)
- *Low voltage supply* not taken from an onsite or dedicated substation
- Existing *tariff* Class: "Small Business"
- Existing *tariff* code: A230

- Existing *contract demand* 105 *kW*
- *Customer* applied to be reassigned to *tariff* code A300 under *tariff* class "Large Business – *Low Voltage*"

Assessment:

a) **Assignment to a *tariff* class**: The *customer*'s annual consumption is 405 *MWh*, which is greater than or equal to 400 *MWh*. As a result *Customer* E will be reassigned to *tariff* class "Large Business – *Low Voltage*".

b) **Assignment to the *appropriate tariff***: The annual consumption is 405 *MWh*, which is less than or equal to 0.8 *GWh*. As a result *Customer* E application is successful and the *customer* will be reassigned to *tariff* code A300. The *contract demand* will increase to 120 *kW*, being the minimum chargeable demand under *tariff* code A300.

7. FLEXIBLE TARIFF ASSIGNMENT AND REASSIGNMENT

JEN has introduced a *Flexible tariff* on 1st Jan 2013 that will apply only to Residential Customers. The *tariff* code for the *Flexible tariff* is A10X.

The rules that will apply to the *tariff* assignment and reassignment of a Residential *Customer* to and from the *Flexible tariff* are as below,

- The *Flexible tariff* will only apply to Residential Customers with an AMI meter that is remotely read.

- All *tariff* change requests to and from the *Flexible tariff* must be made by the *customer's retailer* and follow the *Common DB Process*.

- Where a New Connection event occurs, the *retailer* must request JEN to apply the *Flexible tariff* via the *B2B service order* New Connections paperwork by specifying the *Flexible tariff* code in the "Proposed Tariff" field of the B2B paperwork. Where the "Proposed Tariff" field is left blank, the *customer* will be assigned to the General Purpose A100 *tariff*.

- Where a Change of Occupancy event occurs, the *tariff* that applied to the previous tenant or owner will continue to apply until such time the *retailer* notify JEN of the change of occupancy situation. The notification must be made to JEN via the *B2B service order* Meter Reconfiguration paperwork by specifying the required *tariff* code in the "Proposed Tariff" field of the B2B paperwork.

- Where the *retailer* wants to make a request for a *tariff* reassignment to or from the *Flexible tariff*, they must apply by using the *B2B service order* Meter Reconfiguration paperwork.

- During the *reversion period*, customers will have the right to revert from the *Flexible tariff* to their *previous tariff* with no restrictions except in the case where the *previous tariff* is a closed *tariff*. In this case customers will be allowed to revert back to their closed *previous tariff* provided the *retailer* who requested the *reversion* is the same *retailer* who initially applied the closed *previous tariff*.

- If a *customer* on the General Purpose and Off Peak Heating tariffs (A100/A180) switches to the *Flexible tariff* and then installs solar panels, the *customer* will be allowed to revert to the closed *tariff* Time of Use Interval Meter (A10I).

- Existing Solar Customers on *PFIT* or *TFIT tariff* -

  - Will be treated in a similar manner as all other non-solar customers. In particular in terms of their right to move to and from the *Flexible tariff*.

  - Will not lose their solar rebate eligibility if they move to and from the *Flexible tariff*.

- *Tariff* reassignment to and from the *Flexible tariff* will only be effective from the schedule date as indicated on the *B2B service order* Meter Reconfiguration paperwork, provided this date is equal to or greater than the date of receipt of the paperwork.

- Where a *retailer* transfer has occurred and the *tariff* reassignment to and from the *Flexible tariff* is required to align with the MSATS retail transfer date then the *tariff* change will be applied effective from the MSATS retail transfer date or where this is more than 10 *business days* prior, the schedule date as indicated on the *B2B Service Order* Meter Reconfiguration paperwork less 10 *business days*.

Below are a few examples to illustrate how JEN will review and apply the *Flexible tariff* and its reversion for residential customers:

Example 1 – Customer A (New Connection Customer)

Assumption:

- *Previous tariff* – Not applicable
- Current *retailer* – ABC
- Connection status – New Connection with supply start date 1st Aug 2013
- *Tariff* requested – A10X
- Request made using *B2B service order* for New Connection by specifying A10X *tariff* in the "proposed tariff" field of the B2B.

Assessment:

a) The *customer* will be assigned to the A10X *tariff* to be effective from the supply start date, i.e. 1st Aug 2013.

Example 2 – Customer B (Existing Customer)

Assumption:

- *Previous tariff* – A140 (closed tariff)
- Current *retailer* - ABC
- Connection status – Existing Customer
- Current *tariff* – A10X
- *Tariff* requested – A140 (closed tariff) with special instruction SAPPLY
- Request made via *B2B service order* Meter Reconfiguration paperwork with schedule date 15th October 2013.

Assessment:

a) The *customer* is with the ***same*** *retailer* being ABC.

b) The *customer* will be allowed to revert to the *previous tariff* (A140) to be effective from the schedule date, i.e. 15th October 2013.

Example 3 – Customer C (Existing Customer)

Assumption:

- *Previous tariff* – A10I (closed *tariff*)
- Current *retailer* – ABC
- New *retailer* – XYZ
- Connection status – Existing *customer*
- Current *tariff* – Moved to A10X *tariff* with ABC *retailer* prior to moving to XYZ *retailer*

- *Tariff* requested – A10I (closed *tariff*) with special instruction SAPPLY
- Request made via *B2B service order* Meter Reconfiguration paperwork with schedule date 15th October 2013.

Assessment:

a) The *customer* has changed to a ***different*** *retailer* being XYZ.

b) The *customer* ***cannot*** revert to his *previous tariff* (A10I) as the request is not from the *retailer* that originally applied the *previous tariff* (A10I).

Example 4 – Customer D (Existing Customer with new Solar Installation)

Assumption:

- *Previous tariff* – A100/A180 (General Purpose with Off Peak Hot water)
- Current *retailer* – ABC
- Connection status – Existing *customer*
- Current *tariff* – Moved to A10X *tariff* on 1st August 2013
- Solar installation – 1st November 2013
- Tariff requested – A100/A180 with special instruction SAPPLY
- Request made via *B2B service order* Meter Reconfiguration paperwork with schedule date 15th December 2013.

Assessment:

a) The *customer* is with the ***same*** *retailer* being ABC.

b) The *customer* ***cannot*** revert to his *previous tariff* (A100/A180), as the A180 *tariff* is not available to *customers* that install embedded generation.

c) The *customer* can however, choose to revert to the closed *tariff* A10I to be effective from the schedule date, i.e. 15th December 2013.

8. NOTIFICATION

JEN has a regulatory obligation to notify the *customer* directly in writing of the *tariff* class to which the *customer* has been reassigned prior to the reassignment occurring[3].

Tariff Reassignment initiated by the *applicant*

In the event the *applicant* initiates the *tariff* reassignment, JEN will notify the *applicant* in writing of the success or otherwise of the application. Where the application is not successful, JEN will advise the *applicant* of the reason for not being successful.

Where the *applicant* is someone other than the *customer* or customer's *retailer*, the *applicant* will be required to obtain authorisation from the *customer* to deal with JEN on their behalf. The *applicant* will also take responsibility of communicating the outcome of the *tariff* reassignment to the *customer*.

Tariff Reassignment initiated by JEN

In the event JEN initiates the *tariff* reassignment, JEN will notify the *customer* directly in writing prior to the tariff reassignment occurring.

[3] Clause 6, Appendix G, the Final Decision – Appendices of the Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-15

9. OBJECTION

In addition to the notification obligation mentioned in Section 7, JEN is required to advise the *customer* that they may request further information from JEN and that they may object to the proposed *tariff* reassignment decision made by JEN. As part of this obligation, JEN will also make available to customers the internal procedures for reviewing the objections or the link to where such information is available on JEN's website. JEN encourages customers to request for further information or clarification of its *tariff* reassignment decision before an objection is lodged.

The objection provision allows the *customer* to formally request a review of the *tariff* reassignment decision. Customers who wish to lodge an objection must do so in writing by using the Tariff Reassignment Objection Form in Appendix D and providing any supporting evidence or documentation related to the decision being reviewed. The completed Tariff Reassignment Objection Form must be emailed to CustomerRelations@jemena.com.au.

JEN is committed to treating all customers equally and must comply with its regulatory obligations as mentioned in Appendix G, the Final Decision – Appendices of the Distribution Determination 2011-2015. JEN takes into account the *customer's load, connection* and *metering characteristics* in determining the *appropriate tariff* to be reassigned. Customers who wish to object to the *tariff* reassignment decision should make reference to their *load*, *connection* and *metering characteristics*. JEN relies on this information to be able to review the *customer's* objection application.

JEN encourages that *applicant* who initially lodged the Tariff Reassignment Request Form (Appendix C for Business Customers) or *B2B service order* for Residential Customers to also lodge the Objection Form (Appendix D), should Jemena reject their request for *tariff* reassignment. This will help to avoid delays and streamline the administration process.

If the completed objection form is lodged within 20 *business days* from the date the *customer* or *customer's representative* was advised of the *tariff* reassignment decision, JEN will apply the changes following a successful objection from the 1st billing period starting after the Notification. Where the completed objection form is received after 20 *business days* from the date the *customer* or *customer's representative* was advised of the *tariff* reassignment decision, JEN will apply the changes following a successful objection from the 1st billing period starting after receipt of the completed objection form.

In both situations, if JEN requests further information pertaining to the objection application and such information is not provided within 20 *business days* from the date requested, JEN will apply the changes following a successful objection from the 1st billing period starting after receipt of the requested information.

Upon receipt of the *customer's* completed Tariff Reassignment Objection Form:

a) JEN will acknowledge receipt of the objection application within 5 *business days*

b) The objection will be escalated to the Manager Commercial Strategy & Performance for the review.

c) In reviewing the objection, the Manager Commercial Strategy & Performance will assess if the original decision complied with this policy, JEN's regulatory obligations and will take into consideration any supporting evidence and documentation provided.

d) The *applicant* will be notified in writing of the outcome of the internal review and reasons for accepting or rejecting the *applicant*'s objection within 20 *business days* from the date JEN receives the objection application.

e) JEN may contact the *applicant* to request further information.

f) If JEN believes the objection review process will take longer than 20 *business days*, the *applicant* will be advised accordingly.

Should the *customer* not be satisfied with the response received from JEN, the *customer* may escalate the matter to the Energy and Water Ombudsman (Victoria) or other relevant external dispute resolution body, provided the resolution of such dispute are within their jurisdictions.

If the *customer* is still not satisfied with the external party's assessment, the *customer* can seek a decision from the *AER* using the dispute resolution process available under Part 10 of the NEL.

10. General Conditions and Administration Procedures

- JEN reserves the right to amend this policy at any time without notice.
- All requests for *tariff* assignment or reassignment of Business Customers must be made in writing by the *customer* or the *customer's representative* using the appropriate form.
- All requests for *tariff* assignment or reassignment of Residential Customers must be made by the *customer's retailer* using the appropriate *B2B Service Order* paperwork.
- If a *customer* on the General Purpose and Off Peak Heating *tariffs* (A100/A180) installs solar they will be eligible to be assigned to the A10I tariff. Where *retailer* specifies another eligible open *tariff* to be assigned via the B2B paperwork, this requested *tariff* will be assigned.
- The *applicant* is wholly responsible for conveying the correct information to JEN and communicating any further requests and decisions made by JEN to the *customer*.
- JEN may request the *applicant* to re-submit the application form if the initial form is not correctly completed.
- JEN will advise the *applicant* in writing of the decision to a *tariff* assignment or reassignment within 10 *business days* of receipt of the request.
- The number of *tariff* reassignment applications a *Customer* may make in any 12-month period is limited to one per *supply point* except in the case of a request for Residential Customers.
- Where there is a reference in this policy to JEN exercising a right or discretion or that JEN "may" consider or perform an action, it is in JEN's sole discretion whether or not JEN chooses to exercise that right or power and how JEN exercises that discretion, right or power.

APPENDIX A – TARIFF CRITERIA

A tariff code starting with the letter "F" and "T" indicates that the *tariff* attracts the feed in *tariff* rebate.

Tariff Class	Tariff Code	Tariff Name	Criteria
Residential	**A100 / F100[a] / T100[b]**	General Purpose	Customers with a single rate accumulation meter.
	A10X / F10X[a] / T10X[b]	Flexible	Customers with a remotely read AMI meter.
	A10I / F10I[a] / T10I[b]	Time of Use Interval Meter	Customers with an interval meter. This tariff is closed to new entrants.
	A140	Time of Use	This tariff is closed to new entrants.
	A180	Off Peak Heating Only	Customer with off-peak dedicated load.
Small Business	**A200 / F200[a]/ T200[b]**	General Purpose	Customers with a single rate accumulation meter.
	A210 / F210[a]/ T210[b]	Time of Use Weekdays	Customers consuming < 160 MWh pa and having a maximum demand < 60 kW OR to customers with a two rate accumulation meter.
	A230 / F230[a]/ T230[b]	Time of Use Weekdays - Demand	Customers with a meter capable of measuring demand.
	A250 / F250[a]/ T250[b]	Time of Use Extended	Customers consuming < 160 MWh pa and having a maximum demand < 60 kW OR to customers with a two rate accumulation meter. This tariff is closed to new entrants.
	A270 / F270[a]/ T270[b]	Time of Use Extended - Demand	Customers with a meter capable of measuring demand. This tariff is closed to new entrants.
Large Business-Low Voltage	**A300 / F300[a]/ T300[b]**	LV 0.4 - 0.8 GWh	Customers consuming ≤ 0.8 GWh pa
	A30E	LVEN Annual Consumption ≤ 0.8 GWh	Customers with an Embedded Network consuming ≤ 0.8 GWh pa
	A320	LV 0.8+ - 2.2 GWh	Customers consuming > 0.8 GWh pa BUT ≤ 2.2 GWh pa
	A32E	LVEN 0.8+ - 2.2 GWh	Customers with an Embedded Network consuming > 0.8 GWh pa BUT ≤ 2.2 GWh pa
	A340	LV 2.2+ - 6.0 GWh	Customers consuming > 2.2 GWh pa BUT ≤ 6.0 GWh pa
	A34E	LVEN 2.2+ GWh	Customers with an Embedded Network consuming > 2.2 GWh pa

	A34M[c]	LVMS 2.2+ - 6.0 GWh	Customers taking supply from multiple supply points on a single site other than an embedded network customer with aggregated annual consumption of > 2.2 GWh BUT ≤ 6.0 GWh. This tariff is closed to new entrants.
	A370	LV 6.0+ GWh	Customers consuming > 6.0 GWh pa
	A37M[c]	LVMS 6.0+ GWh	Customers taking supply from multiple supply points on a single site other than an embedded network customer AND with aggregated annual consumption of > 6.0 GWh. This tariff is closed to new entrants.
Large Business-High Voltage	**A400**	HV	Customers consuming < 55 GWh pa
	A40E	HVEN	Customers with an Embedded Network
	A40R	HVRF	This tariff is closed to new entrants
	A480	HV - Annual Consumption ≥ 55 GWh	Customers consuming ≥ 55 GWh pa
Large Business - Subtransmission	**A500**	Subtransmission	Nominal voltage of 22,000 volts or greater
	A50A	Subtransmission MA	Nominal voltage of 22,000 volts or greater
	A50E	Subtransmission EG	Customers with embedded Generators connected to TTS-SSS-ST-EPG-TTS Loop.

[a] A tariff code starting with the letter "F" indicates that the tariff attracts the Premium Feed-In-Tariff rebate. Tariff reassignment requests to a tariff starting with the letter "F" can only be made by the customer's retailer.

[b] A tariff code starting with the letter "T" indicates that the tariff attracts the Transitional Feed-In-Tariff rebate. Tariff reassignment requests to a tariff starting with the letter "T" can only be made by the customer's retailer.

[c] A tariff code ending with the letter "M" is applicable to customers taking supply from multiple supply points on a single site other than an embedded network customer. The terms and conditions applicable for the assignment to this tariff can be obtained from the Jemena website via the link below,
http://jemena.com.au/what-we-do/assets/jemena-electricity-network/tariff-reassignment.aspx

APPENDIX B – JEN - TARIFF ASSIGNMENT REQUEST FORM – BUSINESS CUSTOMER

Jemena Electricity Networks (VIC) Ltd

Network Tariff Assignment Request Form for Business Customer

[Please use one form per Supply Point and e-mail the form to JENTariffs@jemena.com.au]

This **Request Form** must be used to request a network tariff assignment with respect to a *Change of Occupancy* situation where the customer or the customer's representative believes the network tariff and/or contract demand that applied to the previous tenant are no longer appropriate to continue to apply.

Generally, a change of business name or business ownership ***does not*** constitute a *Change of Occupancy* for network tariff assignment purposes (i.e. current network tariff and contract demand applies). However, where the customer can demonstrate that the business' operation will change (or has changed) as a result of the change in business name or business ownership, then this form can also be used to request a tariff assignment ***provided*** supporting documentation is submitted with the Request Form.

Supporting documentation may include a statement from the customer (a person holding a General Manager position or higher) explaining what changes will be (or have been) implemented that would cause the site's current load characteristics to change, why in the customer's views these changes will cause the site's current load characteristics to change, the date(s) these changes will be (or have been) implemented and the impact of these changes to the site's current load characteristics.

Note: All fields are mandatory except for those denoted with *

1 – NEW CUSTOMER DETAILS

Business name: ____

Business ABN or ACN: ____

Supply point address: ____

NMI: **VDDD**______________ or **6001**______________

Date the change of occupancy (name or business ownership) occurred: ___ **/** ___ **/** ___

Briefly describe the nature of the business and hours of operation *:

____

____

2 – PREVIOUS CUSTOMER DETAILS

Business name: ____

Business ABN or ACN: ____

Date the previous customer moved out: ___ **/** ___ **/** ___

3 – TARIFF ASSIGNMENT DETAILS

Type of network tariff assignment request (choose a number from the list below): _____

1. *Change of occupancy, i.e. previous tenant moved out and new tenant moved in.*
2. *Change of business name (supporting documentation is required for this type of request)*
3. *Change of business ownership (supporting documentation is required for this type of request)*
4. *Other (specify)* ____

Site's load characteristics resulting from the change:

1. *Estimated annual consumption in kWh:* ____________*kWh*
2. *Estimated maximum demand in kW *:* ____________*kW*

Metering type currently installed (please tick):

1. *Interval/Smart meter manually or remotely read* ☐
2. *Two rate accumulation meter WITHOUT demand meter* ☐
3. *Two rate accumulation meter WITH demand meter.* ☐
4. *Single rate accumulation meter* ☐

4 – PROPOSED NETWORK TARIFF DETAILS

Nominated network tariff name *: ____

Nominated network tariff code: **A** _____ or **T**_____ or **F**_____

5 – CONDITIONS APPLYING TO THE REQUEST

- The applicant must sign and e-mail the completed request form to JENTariffs@jemena.com.au
- Requests to assign a Customer to a network tariff code starting with the letter "**T**" must be made by the customer's retailer.
- Where the applicant is not the Customer, the applicant is wholly responsible for conveying the correct information to Jemena Electricity Networks (Vic) Ltd (JEN) and communicating any further requests and decisions made by JEN to the Customer and the Customer's Retailer.
- JEN may request the applicant to re-submit the Request Form if the initial request form is not correctly completed or if the form is modified in any manner.
- The applicant acknowledges that if the completed Request Form is received by JEN within 20 business days from the date the change of occupancy (business name or business ownership) occurred, the new tariff assignment (if approved) will take effect from the date the change of occupancy (business name or business ownership) has occurred. Otherwise, the tariff change (if approved) will take effect from the first billing period after the date JEN receives the Request Form by e-mail at the address specified above.
- Any network tariff assignment request will not take effect until JEN advises the applicant in writing of the approval and the effective date of the new tariff assignment.

6 - APPLICANT DETAILS

Name *(person lodging the request form)*: ____

Business Name: ____

Position Title *(if applicable)* *: ____

Telephone Number: (   ) ________________ **E-mail:** _________________________________

Applicant's Signature: ______________________________ **Date:** ______/______/_____

Note: If the applicant is the Customer's Retailer, the applicant warrants that it has been authorised to act on the Customer's behalf.

The section below is required to be completed by the customer, if the Applicant is someone other than the Customer or Customer's Retailer.

I ___________________________________ **at the supply point address referred to in this Request Form, consent to the above applicant acting on my behalf. My contact details are as follows:**

Position Title: ____

Telephone Number: (   ) ________________ **E-mail:** _________________________________

Customer's Signature: ______________________________ **Date:** ______/______/_____

APPENDIX C – JEN - TARIFF REASSIGNMENT REQUEST FORM – BUSINESS CUSTOMER

Jemena Electricity Networks (VIC) Ltd
Network Tariff Reassignment Request Form for Business Customer

[Please use one form per Supply Point and e-mail the form to JENTariffs@jemena.com.au]

This **Request Form** must be used to request a network tariff reassignment for an existing business customer.

Note: All fields are mandatory except for those denoted with *.
Fields denoted with # only apply to customers currently assigned to a demand network tariff.

1 – CUSTOMER DETAILS

Business name: ____

Supply point address: ____

NMI: **VDDD**_______________ or **6001**_______________

Reasons for change in load and/or connection characteristics *:

____

____

____

2 – TARIFF REASSIGNMENT DETAILS

The network tariff code currently assigned to the customer: ____________________

The contract demand currently applicable to the customer #: ______ kW

The maximum demand recorded over the past 12 months #: ______ kW

Actual consumption (complete section A or B as applicable):

A. Where the customer has been connected for a period of at least 12 months

- *The actual annual consumption over the past 12 months: _______________ kWh*

B. Where the customer has been connected for a period less than 12 months

- *The customer's actual consumption: _______________ kWh*
- *Recorded over the period: From: __ / __ / __ To: __ / __ / __*

Metering type currently installed (please tick):

1. *Interval/Smart meter manually or remotely read* ☐
2. *Two rate accumulation meter WITHOUT demand meter* ☐
3. *Two rate accumulation meter WITH demand meter.* ☐
4. *Single rate accumulation meter* ☐

3 – PROPOSED NETWORK TARIFF DETAILS

Nominated network tariff name *: ____

Nominated network tariff code: **A** _____ or **T**_____ or **F**_____

4 – CONDITIONS APPLYING TO THE REQUEST

- The applicant must sign and e-mail the completed Request Form to jentariffs@jemena.com.au.
- Requests to reassign a Customer to a network tariff code starting with the letter "**T**" must be made by the customer's retailer.
- Where the applicant is not the Customer, it is the applicant's responsibility to ensure the Customer is aware of and agrees to this tariff reassignment request. The applicant is wholly responsible for conveying the correct information to JEN and also communicating the decision made by JEN to the Customer.
- JEN may request the applicant to re-submit the request if the initial Request Form is not correctly completed or if the form is modified in any manner.
- The applicant acknowledges that in the event the request is approved the contract demand applicable to the new tariff will be set in accordance with the JEN Policy for Resetting Contract Demand.
- Any network tariff reassignment request will not take effect until JEN advises the applicant in writing of the approval and the effective date of the new tariff assignment.
- Network tariff reassignment requests are limited to one application over any 12 months period.

5 - APPLICANT DETAILS

Name *(person lodging the request form)*: ____

Business Name: ____

Position Title *(if applicable)* *: ____

Telephone Number: (   ) ______________ E-mail: _____________________________________

Applicant's Signature: __________________________ **Date:** _____/_____/_____

Note: If the applicant is the Customer's Retailer, the applicant warrants that it has been authorised to act on the Customer's behalf.

The section below is required to be completed by the customer, if the Applicant is someone other than the Customer or Customer's Retailer.

I ______________________________ at the supply point address referred to in this Request Form, consent to the above applicant acting on my behalf. My contact details are as follows:

Position Title: ____

Telephone Number: (   ) ______________ E-mail: _____________________________________

Customer's Signature: __________________________ **Date:** _____/_____/_____

APPENDIX D – JEN - TARIFF REASSIGNMENT OBJECTION FORM – BUSINESS AND RESIDENTIAL CUSTOMER

Jemena Electricity Networks (VIC) Ltd

Network Tariff Reassignment Objection Form - Business and Residential

[Please use one form per Supply Point and e-mail the form to CustomerRelations@jemena.com.au]

This **Objection Form** must be used to lodge a tariff reassignment objection to a decision JEN has made with regards to a network tariff reassignment either initiated by the customer or by JEN.

Note: All fields are mandatory except for those indicated with a *.

1 - CUSTOMER DETAILS

Business name (if business customer): ___________________________

Customer name (if residential customer): ___________________________

Supply point address: ___________________________

NMI: **VDDD**_______________ or **6001**_______________

2 – TARIFF REASSIGNMENT DETAILS

This objection is in relation to JEN's decision regarding (please tick one):

- Network Tariff Reassignment Application ☐
- JEN initiated Network Tariff Reassignment ☐

Date on letter or email communication (Notification) received from JEN: __ /__ /__

3 – OBJECTION DETAILS

The applicant should provide reason for their objection. The applicant is encouraged to attach as a separate document:

1. The reasons for the objection to JEN's decision regarding the Tariff Reassignment
2. Provide any supporting evidence or documentation.

4 – CONDITIONS APPLYING TO THE REQUEST

- Applicant to sign and e-mail the completed form to CustomerRelations@jemena.com.au.
- The applicant acknowledges that he has read the Policy for Tariff Assignment and Reassignment and that the information provided in this form is true, accurate and complete.
- Where the applicant is not the Customer, the applicant is wholly responsible for conveying the correct information to JEN and also communicating the decision made by JEN to the Customer.
- The applicant acknowledges that if the completed Objection Form is received within 20 business days from the date of JEN's Notification to the Customer or Customer's representative, JEN will apply the changes following the successful objection from the 1st billing period starting after the Notification.
- The applicant acknowledges that if the completed Objection Form is received after 20 business days from the date of JEN's Notification to the Customer or Customer's representative, JEN will apply the changes following the successful objection from the 1st billing period starting after receipt of the completed Objection Form.
- JEN may request the applicant to re-submit the Tariff Reassignment Objection Form if the initial form is not correctly completed or if the form is modified in any manner.

5 - APPLICANT DETAILS

Name *(person lodging the objection form)*: ____

Business name: ____

Position title *(if applicable)* *: ____

Telephone number: (   ) _______________ E-mail: _______________________________________

Applicant's signature: ____________________________   Date: ______/______/_____

Note: If the applicant is the Customer's Retailer, the applicant warrants that it has been authorised to act on the Customer's behalf.

The section below is required to be completed by the customer, if the Applicant is someone other than the Customer or Customer's Retailer.

I _________________________________ at the supply point address referred to in this Objection Form, consent to the above applicant acting on my behalf. My contact details are as follows:

Position Title: ____

Telephone Number: (   ) _______________ E-mail: _______________________________________

Customer's Signature: ____________________________   Date: ______/______/_____

Appendix H
User-requested services indicative prices

H1. USER-REQUESTED SERVICES PRICE CHANGES

Table H1-1: User-requested services schedule of fee-based services—normal hours ($nominal, excluding GST)

Service	2016	2017	2018	2019	2020
Connection - single phase service connection to new premises - (JEN responsible)	744.88	775.32	804.40	826.37	853.93
Connection - three phase service connection to new premises (less than 100amps) - (JEN responsible)	953.75	995.93	1,033.55	1,051.72	1,081.81
Connection - single phase service connection to new premises - (JEN not responsible)	744.88	775.32	804.40	826.37	853.93
Connection - three phase service connection to new premises (less than 100amps) - (JEN not responsible)	953.75	995.93	1,033.55	1,051.72	1,081.81
Manual energisation of new premises	35.54	37.02	38.53	40.16	41.95
Manual re-energisation existing premises	35.54	37.02	38.53	40.16	41.95
Manual de-energisation existing premises	54.90	57.19	59.52	62.03	64.81
Temporary single-phase connection	729.52	759.02	787.45	809.92	837.40
Reconnection after temporary disconnection for non-payment	67.24	70.05	72.90	75.97	79.37
Manual special meter reads	31.77	33.09	34.44	35.90	37.51
Service vehicle visit	460.42	477.52	495.23	513.83	533.39
Wasted service truck visit - not JEN's fault	428.56	444.49	460.99	478.33	496.58
Fault response - not JEN's fault	460.42	477.52	495.23	513.83	533.39
Re-test types 5, 6 and AMI smart metering installations	372.49	388.10	403.83	420.70	439.58
Reserve feeder charge	15.12	16.09	16.73	16.10	16.11
PV installation	N/A	N/A	N/A	N/A	N/A
Remote meter re-configuration	49.98	52.07	54.18	56.45	58.98
Remote de-energisation	9.56	9.96	10.37	10.80	11.29
Remote re-energisation	9.56	9.96	10.37	10.80	11.29
Type 7 metering (meter data service)	0.58	0.61	0.63	0.66	0.69
Temporary three-phase connection	771.38	790.85	810.81	831.28	852.26

Table H1-2: User-requested services schedule of fee-based services—after hours ($nominal, excluding GST)

Service	2016	2017	2018	2019	2020
Connection - single phase service connection to new premises - (JEN responsible)	744.88	775.32	804.40	826.37	853.93
Connection - three phase service connection to new premises (less than 100amps) - (JEN responsible)	953.75	995.93	1,033.55	1,051.72	1,081.81
Connection - single phase service connection to new premises - (JEN not responsible)	744.88	775.32	804.40	826.37	853.93
Connection - three phase service connection to new premises (less than 100amps) - (JEN not responsible)	953.75	995.93	1,033.55	1,051.72	1,081.81
Manual energisation of new premises	56.35	58.70	61.09	63.67	66.52
Manual re-energisation existing premises	56.35	58.70	61.09	63.67	66.52
Manual de-energisation existing premises	71.96	74.96	78.02	81.31	84.95
Temporary single-phase connection	729.52	759.02	787.45	809.92	837.40
Reconnection after temporary disconnection for non-payment	75.04	78.17	81.35	84.78	88.58
Manual special meter reads	N/A	N/A	N/A	N/A	N/A
Service vehicle visit	598.45	620.68	643.69	667.87	693.30
Wasted service truck visit - not JEN's fault	598.45	620.70	643.74	667.95	693.43
Fault response - not JEN's fault	598.45	620.68	643.69	667.87	693.30
Re-test types 5, 6 and AMI smart metering installations	612.64	638.31	664.19	691.94	722.98
Reserve feeder charge	N/A	N/A	N/A	N/A	N/A
PV installation	N/A	N/A	N/A	N/A	N/A
Remote meter re-configuration	N/A	N/A	N/A	N/A	N/A
Remote de-energisation	N/A	N/A	N/A	N/A	N/A
Remote re-energisation	N/A	N/A	N/A	N/A	N/A
Type 7 metering (meter data service)	N/A	N/A	N/A	N/A	N/A
Temporary three-phase connection	771.38	790.85	810.81	831.28	852.26

Table H1-3: Proposed indicative public lighting OMR charges ($nominal, excluding GST)

Light Type	OMR charge $ per year				
	2016	2017	2018	2019	2020
Mercury Vapour 80 watt	58.46	60.60	62.57	63.49	64.94
Mercury Vapour 125 watt	85.94	89.08	91.98	93.33	95.46
Mercury Vapour 250 watt	186.80	194.60	202.11	207.40	214.29
Mercury Vapour 400 watt	210.15	218.92	227.38	233.33	241.08
Sodium High Pressure 50 watt	241.07	251.14	260.85	267.67	276.57
Sodium High Pressure 100 watt	264.21	275.25	285.89	293.37	303.12
Sodium High Pressure 150 watt	192.85	200.91	208.68	214.14	221.25
Sodium High Pressure 250 watt	194.59	202.70	210.53	216.05	223.22
Sodium High Pressure 400 watt	258.80	269.60	280.01	287.34	296.88
Metal Halide 70 watt	150.24	155.73	160.81	163.17	166.89
Metal Halide 150 watt	428.13	446.02	463.26	475.38	491.18
Metal Halide 250 watt	418.36	435.82	452.65	464.50	479.92
T5 (2 x 14W)	55.33	58.17	60.82	62.22	64.25
T5 (2 x 24W)	62.32	65.52	68.50	70.08	72.37
Compact Fluoro 32W	47.73	50.18	52.46	53.67	55.42
Compact Fluoro 42W	53.82	56.59	59.16	60.53	62.50
LED 18W	21.52	22.62	23.65	24.20	24.99