Tariff Implementation Report

A REPORT PREPARED FOR ERGON ENERGY

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Introduction

This Tariff Implementation Report builds on Ergon Energy's Consultation Paper of July 2013 by articulating the next steps in the development of network tariffs for 2014/15 and beyond.

The Consultation Paper outlined indicative tariff structure pathways for different customer segments. These included:

- A move to a kVA basis for the Capacity (Authorised Demand) and Actual Demand components of ICC and CAC tariffs, as well as for the Actual Demand component of SAC large tariffs
- The introduction of a ToU charging basis for the demand elements of tariffs to ICCs and CACs and for the demand and energy components of SAC large tariffs
- Evaluation of the case for ToU energy (and subsequently demand) tariffs for SAC small customers
- Longer term, consideration of Critical Peak Pricing structures for all customer categories.

Consultation process feedback

Ergon Energy received 41 submissions on the Consultation Paper. In general, there was support for moving away from flat consumption-based tariffs and towards ToU structures on cost reflectivity and economic efficiency grounds. However, support for higher fixed charges was tempered by concerns from residential customers about the implications on fairness and affordability for small consumers. A retailer noted that a large fixed charge may de-motivate customers from reducing their energy use. The CEC contended that demand- or capacity-based charges were preferable to increasing fixed charges. Stakeholders suggested that changes should focus first on ICC and CAC customers before involving smaller customers and changes should be phased in over a number of years. Some local governments supported a shift of demand tariffs from kW to kVA-based, but this was opposed by some irrigation customers and SMEs. Both retailers and large businesses suggested that more consultation and analysis was necessary on the costs, benefits and customer impacts of such a move.

Efficient tariff framework refinements

As noted in the Consultation Paper, economic theory suggests that the most efficient price for a good or service is one that reflects the marginal cost of supplying it. However, the 'natural monopoly' characteristics of distribution network infrastructure can make the setting of optimal network prices a more complex exercise. For example, the definition of marginal cost can vary depending on the extent to which different inputs are regarded as fixed:

- Short-run marginal cost (SRMC) refers to marginal cost when most (or at least one) input(s) are fixed – such as capital expenditure
- Long-run marginal cost (LRMC) refers to marginal cost when all inputs, (ie including capital expenditure) can be changed.

Tariffs set to reflect SRMC would provide the most efficient signal to customers as to whether they should consume more or less grid-delivered electricity in a given half-hour. However, setting tariffs to reflect LRMC can provide more useful long-run signals to customers about the implications of their increased demand for the network.

Conceptually speaking, there are a number of ways to define and calculate LRMC. Any estimate of LRMC requires a large number of assumptions to be made, and many of these will necessarily be speculative. In response, decision-makers often develop or utilise measures that are designed to act as proxies for LRMC. At a practical level, for the purposes of the Network Tariff Strategy, Ergon Energy has decided to use the current Benchmark Cost of Supply (BCS) as a proxy for a broad-based network-wide LRMC.

Setting tariffs to reflect marginal cost – whether SRMC or LRMC – will typically not by itself allow a distribution network to recover all of its historical capital costs. In these circumstances, some other charge is necessary to recover the network's residual allowed revenue not recovered through LRMC-based charges. This additional charge is commonly described in economics as the second part of a 'two-part tariff' – with the first part reflecting marginal cost (as indicated by the BCS or otherwise) and the second part recovering the remaining allowed revenue to be recouped from customers. The conventional economic thinking around the recovery of sunk costs is that these costs should be recovered in a manner that has as little impact as possible on customers' decisions regarding use of the service. The best way to do this is to recover outstanding network costs from customers in proportion to their overall willingness to pay for the provision of the distribution network. This involves considering options for physical or economic bypass, subject to ethical and practical constraints.

In determining how to structure the first-part marginal cost tariff, it is important to base charges on those customer decisions that are most likely to require or bring forward the need for network augmentation. This will be strongly influenced by the methodology and processes used for distribution network planning. We note that in many cases, the cost of LV assets required to serve new connections is ultimately borne by the connecting customers. This means there is limited need for LV costs to be signalled to customers via distribution network charges. The bulk of Ergon Energy's network by line length is in the form of HV and sub-transmission lines and related assets. The main driver of augmentation of these types of assets is growth in peak demand. This suggests that the first-part marginal cost signalling tariff should, if practicable, seek to signal the cost of demand or consumption at peak summer times. Tariffs should also take account of the lagged way in which peak demand influences HV and sub-transmission investment.

There are a number of options for structuring the second-part cost recovery tariff – namely, connection capacity, peak demand/consumption, anytime consumption, customer category and other customer characteristics. Of these, customer category (and sub-category) may be the most appropriate. Tariff-setting should also take account of various constraints such as the retail transparency of network tariffs, limited geographic variation and metering technologies.

Assessment of Consultation Paper options

The potential tariff structure options described in the Consultation Paper remain broadly appropriate in light of the refined framework outlined above. However, some elements of the options are not warranted and will not be pursued at the present time.

- A move from kW-based demand tariffs to kVA-based tariffs remains desirable. This is because the delivery of apparent power (measured in kVA) is the best measure of network capacity and the clearest driver of augmentation cost.
- The introduction of ToU demand tariff structures (initially based on kW demand and later on kVA) to signal the cost of peak demand growth would be a worthwhile step for SAC large customers and possibly CACs.
- The introduction of (seasonal) ToU energy (kWh) tariffs would be a worthwhile step for SAC small customers, for whom imposing demand-based tariffs could be impracticable in the short term.
- The value of introducing CPP tariff structures is unlikely to exceed the costs for the foreseeable future, especially given the available alternatives.

Proposed path of tariff development

The implementation of the Network Tariff Strategy Review will commence in 2014/15, with further changes proposed for 2015/16 and beyond.

The changes proposed for 2014/15 involve progressing kVA tariffs for ICCs and commencing the process of rebalancing tariffs for SAC large customers from high variable/usage-related charges to more fixed/ less usage-dependent charges. This is in keeping with the underlying LRMC of increased demand for the network.

For SAC small customers, two key change options are proposed – these are:

- Offering an optional seasonal ToU energy tariffs

- Shifting all customers to an Inclining Block Tariff with a higher fixed charge and low rate for the first consumption band.

For 2015/16, the intention is to introduce kVA-based tariffs to CACs and to move to a seasonal ToU demand charge for SAC large customers. For SAC small customers, a default seasonal ToU tariff should apply to new and upgraded premises. An excess kVAR charge could be imposed on ICCs.

In the longer term, moves in these directions would be progressed, with gradual rebalancing of tariffs towards higher fixed components and greater use of kVA-based charging for demand tariff components.

1 Introduction

Frontier Economics has prepared this Tariff Implementation Report ("Report") for Ergon Energy Corporation Limited (Ergon Energy) to articulate the next steps in the development of network tariffs for 2014/15 and beyond. This Report follows from and builds on Ergon Energy's Network Tariff Strategy Review Consultation Paper of July 2013 ("Consultation Paper").

1.1 Network Tariff Strategy Review

The Network Tariff Strategy Review ("Review") is focused on the economics behind network tariffs and the future options for network tariff structures and associated implementation pathways that will influence Ergon Energy's network tariff strategy. As noted in the Consultation Paper, the drivers for the Review are:

- Rising electricity prices and affordability issues
- Increasing visibility of Ergon Energy's network tariffs in the regulated retail electricity price (or Notified Prices) and
- Changes in Ergon Energy's operating environment, including advances in technology such as metering, data management and communication.

The Consultation Paper outlined a range of tariff options intended to deliver benefits to customers and Ergon Energy. As discussed further below, these options included mechanisms such as time-of-use (ToU) prices, critical peak pricing (CPP) and reduced reliance on volumetric (energy) charges to better reflect the true cost of delivering electricity to consumers. This Report builds on the analysis in the Consultation Paper and seeks to refine both the economic framework used to derive the proposed options as well as the nature of the options themselves.

The planned implementation for the Review outcomes contemplates some changes to the tariffs for the forthcoming 2014/15 tariff year. However, the majority of tariff changes are expected to be implemented over the period 2015-2017.

1.2 Structure of this Report

This Report is structured as follows:

- Section 2 recounts the key tariff proposals tabled in the Consultation Paper and summarises stakeholder responses to the themes and questions raised in the Consultation Paper.

- Section 3 discusses and refines the Consultation Paper's framework for setting efficient network tariffs.
- Section 4 describes the proposed path of tariff development in light of the preceding discussion, including:
  - Evaluation of the tariff paths set out in the Consultation Paper
  - Proposed tariff structures for 2014/15 and for 2015/16.

2 Consultation Paper network tariff options

This section:

- Outlines network tariff options and pathways set out in the Consultation Paper and
- Summarises stakeholder responses to themes and questions raised in the Consultation Paper.

2.1 Indicative options and pathways

Section 5 of the Consultation Paper outlined indicative tariff structure pathways for different customer segments. Pathways were developed for each of the customer tariff classes:

- **Individually Calculated Customers (ICCs)** – number less than one hundred, but consume approximately 30% of energy delivered by Ergon Energy. ICCs currently pay tariffs with the following components:
  - Fixed Charge – approximately 30% of customer segment revenue
  - Capacity Charge (Authorised Demand in kW) – 25% of segment revenue
  - Actual Demand Charge (in kW) – 11% of segment revenue
  - Energy Charge (Volume kWh) – 34% of segment revenue.

  ICCs consume approximately 30% of the energy flowing through EECL's network, while paying approximately 4% of distribution use of system (DUoS) charges.
- **Connection Asset Customers (CACs)** – number less than two hundred. As compared to the SAC large category (see below), CACs typically require network access in excess of 1500 kVA and usually consume more than 4 GWh of electricity per annum. CACs currently pay tariffs with the following components:
  - Fixed Charge – approximately 15% of customer segment revenue
  - Capacity Charge (Authorised Demand in kW) – 54% of segment revenue
  - Actual Demand Charge (in kW) – 24% of segment revenue
  - Energy Charge (Volume kWh) – 7% of segment revenue.

  CACs consume approximately 10% of the energy flowing through EECL's network, while paying approximately 7% of DUoS charges.

- **Standard Asset Customers (SACs)** – describes all remaining customers and are further categorised as:
  - **SAC large customers** – consume over 100 MWh per annum and number approximately 8,400. SAC large customers currently pay tariffs with the following components:
    - Fixed Charge – approximately 5% of customer segment revenue
    - Actual Demand Charge (in kW) – 90% of segment revenue
    - Energy Charge (Volume kWh) – 5% of segment revenue.

    SAC large customers consume approximately 21% of the energy flowing through EECL's network, while paying approximately 23% of DUoS charges.
  - **SAC small customers** – consume less than 100 MWh per annum and number approximately 700,000. SAC small customers currently pay tariffs with the following components:
    - Fixed Charge – approximately 28% of customer segment revenue
    - Energy Charge (Volume kWh) – 72% of segment revenue.

    SAC small customers consume approximately 33% of the energy flowing through Energy Energy's network, while paying approximately 64% of DUoS charges.

    (NB: The outstanding DUoS not recovered from the above categories is recovered from controlled load and unmetered supply tariffs.)

Based on the framework developed in section 2 of the Consultation Paper, the main themes Ergon Energy sought to incorporate in its tariff development proposals were:

- An overall reduced reliance on energy consumption charges as the basis of revenue recovery
- Increased revenue recovery through demand-related charges
- Structuring demand charges to utilise fixed and variable components
- Denomination of demand charges as kVA rather than kW
- Incorporation of ToU variation within tariff structure parameters and
- Exploration of critical peak (dynamic) pricing.

The Consultation Paper suggested different indicative tariff development paths for the various customer classes. These are outlined in more detail below.

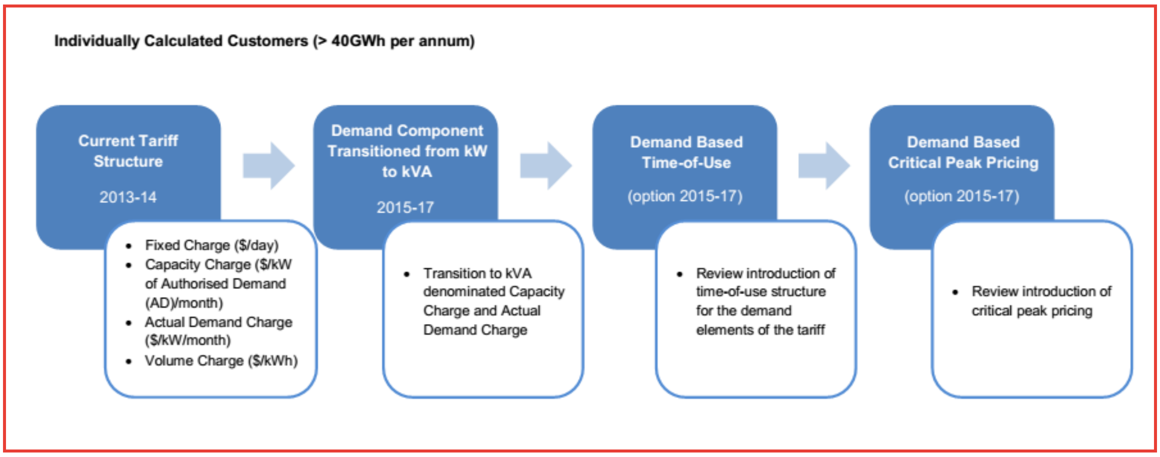
2.1.1 ICCs

The Consultation Paper noted that ICCs on average tend to have relatively flat load profiles, with a key factor compromising higher levels of network utilisation being the poor power factors of some customers.[1] The development of ICC tariffs would evaluate and consider:

- A move to a kVA basis for the Capacity (Authorised Demand) and Actual Demand components of ICC tariffs
- The introduction of a ToU charging basis for the demand elements of the tariff, both the Actual Demand and the Capacity (Authorised Demand) components
- Longer term, the introduction of CPP, particularly in relation to the demand component of ICC tariffs.[2]

See Figure 1 below.

Figure 1: ICC indicative tariff development path



Source: Consultation Paper, Attachment 2, p.51.

2.1.2 CACs

The Consultation Paper noted that CACs tend to have quite different load shapes to ICCs, more closely resembling the profiles of non-residential SACs.[3] This could mean that the benefits of CPP would be, at the margin, greater than for ICCs. The Consultation Paper also suggested that the development path of CACs would lead the path for non-residential SACs.[4]

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1 Consultation Paper, pp.35-36.

2 Consultation Paper, p.37.

3 Consultation Paper, p.39.

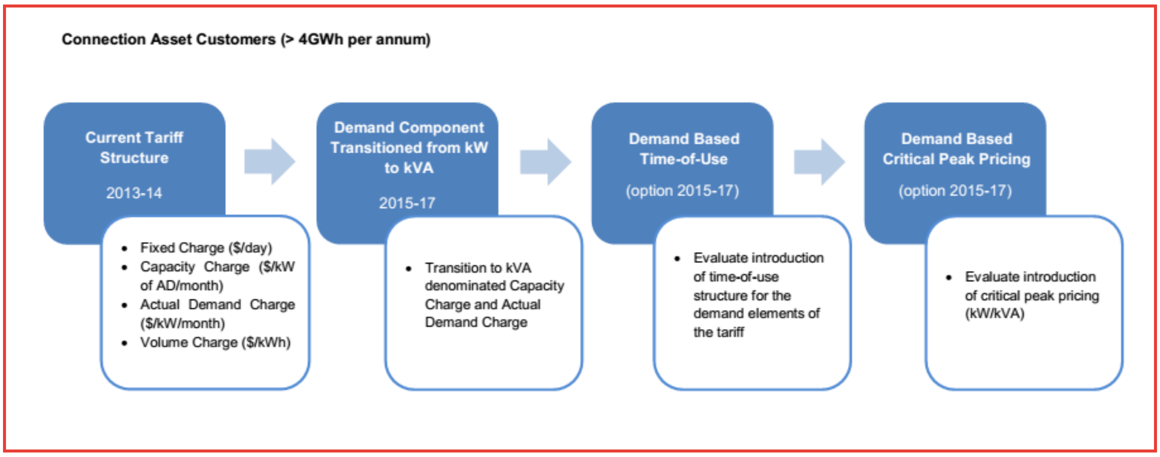
4 Consultation Paper, p.40.

The development of CAC tariffs would evaluate and consider:

- A move to a kVA basis for the Capacity (Authorised Demand) and Actual Demand components of CAC tariffs
- The introduction of a ToU charging basis for the demand elements of the tariff, both the Actual Demand and the Capacity (Authorised Demand) components
- The benefits of a ToU structure for volume (energy) charges
- Longer term, the introduction of CPP.[5]

See Figure 2 below.

Figure 2: CAC indicative tariff development path



Source: Consultation Paper, Attachment 2, p.52.

2.1.3 SAC large (>100 MWh pa)

Due to the similarities in load shapes, the Consultation Paper noted that the development of SAC large tariffs would follow a similar path as for CAC tariffs on a lagged basis.[6] That is, SAC large tariff development would involve evaluating and considering:

- A move to a kVA denominated Actual Demand Charge
- Introduction of a ToU structure for the Actual Demand and energy elements of the tariff
- Longer term, the introduction of CPP.

See Figure 3 below.

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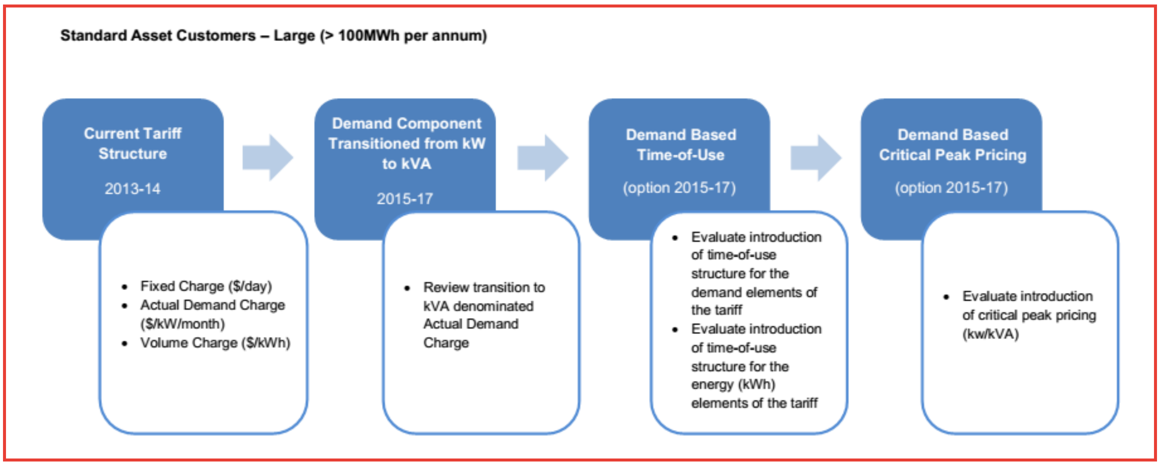
5 Consultation Paper, p.40.

6 Consultation Paper, p.42.

Figure 3: SAC large indicative tariff development path



Source: Consultation Paper, Attachment 2, p.53.

2.1.4 SAC small (<100 MWh pa)

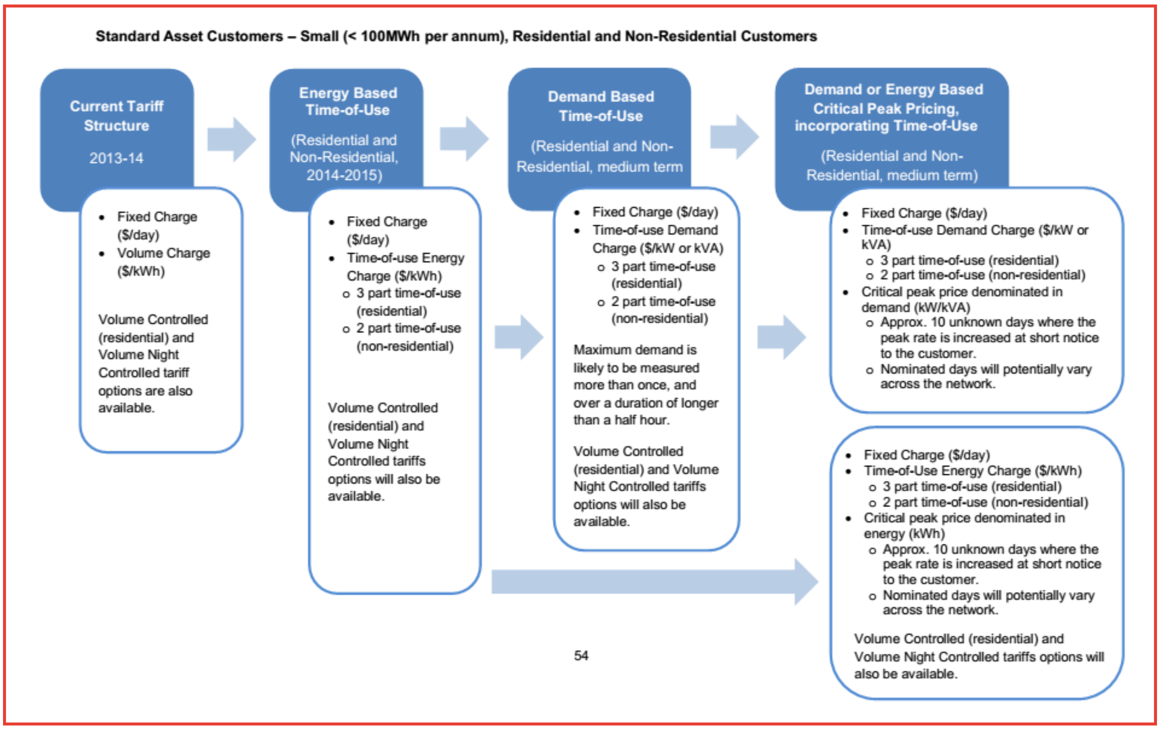
The development of SAC small tariffs would take a different path to tariff options for larger customers. It would:

- Initially involve evaluating and considering ToU energy (kWh) tariffs for small business and residential customers (volume controlled tariffs would still be available); the key difference would be a more refined structure of ToU tariffs for residential customers (3 ToU rates as compared to 2 ToU rates for small business customers)
- Subsequently involve evaluating and considering ToU demand (kW) tariffs
- Ultimately consider supplementing energy or demand-based ToU tariffs with energy or demand-based CPP tariffs.[7]

See Figure 4 below.

[7] Consultation Paper, pp.44-45.

Figure 4: SAC small indicative tariff development path



Source: Consultation Paper, Attachment 2, p.54.

2.1.5 Other tariffs

The Consultation Paper also discussed the state of existing volume controlled tariffs and embedded generator tariffs. The Consultation Paper raised the prospect of some minor changes to these tariffs consequential to the introduction of changes to the key customer class tariffs noted above. The Consultation Paper also raised the possibility of the future introduction of a single wire earth return (SWER) tariff.

2.2 Stakeholder responses

Ergon Energy received 41 submissions on the Consultation Paper. The largest number of responses came from residential customers (13), followed by large businesses (9) and irrigators (6). Submissions were also provided by local governments, retailers, agricultural customers, small-medium sized businesses (SMEs), the CEC and Master Electricians Australia.

Comment was sought on six themes and ten specific questions. As there is considerable overlap between the themes and questions, this summary is arranged according to a rationalised list of the key issues. These are as follows:

- Reducing reliance on consumption-based charges and restructuring fixed and variable tariff components

- Increasing use of demand-related charges
- Utilising ToU variation
- CPP
- Charging based on kVA instead of kW.

The greatest interest from stakeholders was related to the prospect of reducing consumption-based tariffs and incorporating greater ToU-based tariff variation. The area of least relative interest was changing demand tariffs from a kW basis to a kVA basis. These results are likely to be a reflection of the large proportion of submissions that came from residential customers.

In general, stakeholders supported simplicity and the concept of cost reflectivity in setting network tariffs. However, this was subject to many submitters suggesting that they had little ability to respond to more sculpted ToU energy or demand tariffs. A retailer suggested that changes should focus first on ICC and CAC customers before involving smaller customers. Many submitters commented that a customer education process was required to clearly articulate and explain the nature of changes being put forward.

Reducing reliance on consumption-based charges and restructuring fixed and variable tariff components

There was support from many stakeholders for moving away from flat consumption-based tariffs on cost reflectivity and economic efficiency grounds (eg removing 'cross-subsidies'). For example, Origin Energy suggested that higher fixed charges better reflected the nature of network costs. However, support for higher fixed charges was tempered by concerns from residential customers about the implications on fairness and affordability for smaller-consuming customers. Some customers suggested that changes should be phased in over a number of years, while others proposed an inclining-block structure. Another retailer also noted that a large fixed charge may de-motivate customers from reducing their energy use. Agricultural customers said that seasonal variations would make higher fixed charges difficult to manage.

Increasing use of demand-related charges

The CEC contended that demand- or capacity-based charges were preferable to increasing fixed charges, as they would help address 'cross-subsidies' between customers with and without air-conditioning. However, irrigation customers said that demand-based charges could make the use of irrigation water totally unaffordable. More generally, many stakeholders – irrigators, agricultural customers, local governments, SMEs, SAC large customers and some residentials noted that they had little ability to alter their demand in response to price signals.

Agricultural customers, large businesses and SMEs all submitted that the current lack of information about customers' load profiles made it difficult to understand what the implications of changed tariff structures would be.

The Master Electricians suggested that controlled load off-peak tariffs provide by far the most effective tariff solution to managing peak demand and reducing electricity prices.

Utilising ToU variation

The local government submissions strongly supported the use of ToU tariff structures for energy. Retailers and residential customers also supported ToU usage charges, but some residential customers supported starting with a simple two-rate (peak/off-peak) tariff structure for both residential and non-residential customers. This contrasts with the Consultation Paper proposal to implement a 2-rate tariff for businesses and a 3-rate tariff for households. The Master Electricians noted that ToU tariffs would mainly benefit customers who already consumed at off-peak times (such as shift workers) and harm customers with little ability to alter their usage patterns.

Large business customers noted that consumption-based charges for both CAC and SAC large customers contributed a small share of overall network revenue, such that the impact of ToU energy tariffs on customer behaviour was likely to be limited.

CPP

There was patchy support across submitters for CPP. Many stakeholders, including irrigators, local governments and large businesses reiterated that they had little scope to respond to sharp pricing signals and residential customers opined that CPP was unlikely to be beneficial to them.

Retailers were broadly supportive of exploring the benefits of CPP, but some questioned whether it would offer significant benefits over other measures. Origin Energy supported further CPP trials in cooperation with retailers and retailers generally considered that CPP should not be introduced without further trialling.

Charging based on kVA instead of kW

Some local governments supported a shift of demand tariffs from kW to kVA-based. However, many irrigation customers and SMEs opposed the shift. Both retailers and large businesses suggested that more consultation and analysis was necessary on the costs, benefits and customer impacts of such a move, with the added cost and complexity potentially not justified by marginal improvements in cost-reflectivity. Large businesses went further, suggesting that even where the benefits of kVA charge outweighed the costs in general, kVA charges should only be applied in areas where the network was facing capacity constraints. Large businesses also noted that if kVA charges were to be implemented, customers would need to be provided with information about their power factors and kVA demand with a suitable transition period to take action to mitigate the impact on their bills.

3 Refinements to the framework for efficient tariffs

The Consultation Paper outlined a framework for efficient network pricing, which helped to guide the development of the tariff options raised in that paper. This section of the Report further develops and refines the Consultation Paper framework in order to provide further insight into the rationale for the more specific tariff proposals and implementation paths discussed in the next section.

In particular, this section:

- Explains the economics of network pricing in more detail than in the Consultation Paper (section 3.1)
- Considers the approach Ergon Energy employs in relation to network planning and investment and its implications for the setting of network tariffs (section 3.2)
- Discusses the appropriate basis for setting marginal cost-based 'signalling' tariffs (section 3.3)
- Discusses the appropriate basis for setting residual 'cost recovery' tariffs (section 3.4)
- Acknowledges the limitations to the development of certain tariff options due to the capabilities of existing metering infrastructure and implementation costs more generally (section 3.5).

The application of this refined framework to the evaluation of the tariff options in the Consultation Paper and the development of the proposed path of tariff development in section 4 will also have regard to comments made during the consultation process (see section 2.2 above).

3.1 Economics of network pricing

As noted in the Consultation Paper, economic theory suggests that the most efficient price for a good or service is one that reflects the marginal cost of supplying it. 'Marginal cost' refers to the incremental or avoidable cost of providing an additional unit of the relevant good or service. Put differently, it is the change in the total costs of providing a good or service when satisfying an additional unit of demand.

In many contexts, the application of marginal cost pricing is fairly straightforward and provides a comprehensive solution to how prices should be set to promote efficiency. However, the 'natural monopoly' characteristics of distribution network infrastructure can make the setting of optimal network prices a more complex exercise. These characteristics include:

- **Economies of scale** in the provision of distribution networks – such that it is typically cheaper (on a per customer or per kVA capacity basis) for a network to:
  - supply more customers than fewer customers and to
  - expand capacity by a larger amount than by a smaller amount
- **'Lumpiness'** of network infrastructure – network assets tend to be available at particular capacities or voltages and cannot be scaled up in small increments
- **'Sunk' costs** – investment in network assets cannot be reversed if the assets are made redundant or otherwise no longer required, meaning that there is very low opportunity cost in utilising the existing network. The form of regulation applying to distribution networks in the NEM also means that sunk costs must be recouped from customers.

These characteristics give rise to two key dilemmas for network businesses in setting efficient network tariffs:

- How should marginal cost be determined?
- How should regulated network revenue not recovered through marginal cost tariffs be recouped?

3.1.1 Marginal cost

SRMC and LRMC

The definition of marginal cost can vary depending on the extent to which different inputs are regarded as fixed when assessing how total cost changes in response to an increase in demand. Although there is no necessary relationship between the proportion of a firm's inputs that are fixed and particular lengths of time:

- Short-run marginal cost (SRMC) refers to marginal cost when most (or at least one) input(s) are fixed – this corresponds to a timeframe of minutes, hours, days, weeks or months, depending on the industry in question. Due to economies of scale and the 'lumpiness' of network investment, and as the costs of the existing network are largely sunk, the SRMC of network service will typically be limited to incremental distribution losses and other variable operating costs.
- Long-run marginal cost (LRMC) refers to marginal cost when all inputs can be changed – this often corresponds to a timeframe of months or years (sometimes decades), again depending on the industry. The LRMC of network service will typically be much higher than the SRMC because LRMC incorporates the longer run investment cost implications of higher demand.

The choice between using SRMC or LRMC to set network tariffs involves making a trade-off between promoting economic efficiency in the short run versus in the long run.

To encourage maximum utilisation of existing distribution network assets in the very short term, network tariffs should reflect the SRMC of providing network services; that is, the additional costs incurred to serve an increment of demand holding fixed the capital invested in the existing network. Tariffs set to reflect SRMC would provide the most efficient signal to customers as to whether they should consume more or less grid-delivered electricity in a given half-hour. SRMC-based pricing is effectively the principle behind the operation of the NEM wholesale spot market.

However, setting tariffs to reflect SRMC has a number of drawbacks. First, it would require locational marginal pricing (ie nodal pricing) at the distribution level so that the effect of network losses and congestion could be signalled in real-time. Given that congestion on the distribution network is virtually non-existent (outside outages), SRMC-based tariffs would recover very little of the total cost of providing distribution network services. Further, SRMC-based tariffs provide very little information about the future cost consequences of increased demand for network services.

Setting tariffs to reflect LRMC can provide more useful long-run signals to customers about the implications of their increased demand for the network. For example, customers and prospective customers will make decisions to invest in particular types of facilities and locate in particular geographic areas based in part on the level and structure of network tariffs they face. To provide an efficient longer term signal to customers that growth in demand can bring forward the need for additional network investment in the future, it would be necessary to set tariffs on the basis of LRMC. For these reasons, most networks and policy-makers express a preference for pricing based on LRMC and LRMC pricing has also been used to set regulated prices in other utility sectors such as water and telecommunications networks.

Conceptually speaking, there are a number of ways to define and calculate LRMC. The two key broad approaches are as follows:

- Turvey 'perturbation' or marginal incremental cost approach – this approach, developed by the late Professor Ralph Turvey, incorporates the present value cost of additional capacity required to serve a permanent increase in forecast demand at a particular location. This approach takes the existing network and technologies as given and considers how the present value of future costs expected to be incurred would change if forecast demand increased incrementally and permanently.
- Average incremental cost (AIC) approach – this approach takes the present value of incremental costs expected to be incurred over a future period of

time and divides this by the discounted value of the additional capacity or output provided over the same period.

The Turvey approach is often viewed as providing a more theoretically 'pure' estimate of LRMC than the AIC approach, but it is usually more difficult to calculate. Any estimate of LRMC requires a large number of assumptions to be made, and many of these will necessarily be speculative. This is because calculating LRMC involves considering what costs are likely to be incurred in future as a result of higher demand today.

In response, decision-makers often develop or utilise measures that are designed to act as proxies for LRMC. For example, the British transmission network operator, National Grid, applies the Investment Cost Related Pricing (ICRP) methodology. In the NEM context, TNSPs apply the Cost-Reflective Network Pricing (CRNP) methodology or variants based on CRNP. Both ICRP and CRNP use load-flow modelling to estimate a deemed long-run cost of serving customers at different locations.

Role of the BCS

At a practical level, for the purposes of the Network Tariff Strategy, Ergon Energy has decided to use the Benchmark Cost of Supply (BCS) as a proxy for a broad-based network-wide LRMC. The BCS was originally developed to assess the appropriateness of undertaking non-network alternative initiatives, but it can also be used as a rough estimate of LRMC across the network as a whole.

The BCS is a measure of the network-average cost (in $/kVA/year) of providing additional network capacity to meet additional peak demand at the zone substation level of the network. The BCS is derived using data from across the network and is not based on augmentation costs at any individual location or customer tariff class. The most recent estimate of Ergon Energy's BCS is $162/kW/year, which represents a network average value based on the Capital Works Program at the time of compilation.

The BCS captures the network augmentation costs arising between (but not including):

- the sub-transmission bus at bulk supply points (BSPs) and
- low voltage distribution substations.

This means it includes the cost of sub-transmission lines, zone substations, high voltage buses and high voltage lines/feeders are included in the BCS but <u>not</u> the cost of bulk supply point busses on the upstream side or distribution substations and the low voltage network on the downstream side.

The BCS is calculated using a Forward Looking Incremental Cost (FLIC) approach. In applying the FLIC approach, Ergon Energy first calculates the Average Capital Cost of Capacity (ACCC).

This is:

- The sum of forecast capital expenditure associated with the installation of additional network capacity for the next five years

  divided by

- The amount of additional capacity expected to be installed over that time.

The annualised BCS is then derived as follows:

ACCC * (WACC (%) + Annual depreciation (%) + Annual Opex (%))

As between the two broad approaches for estimating LRMC outlined above, the FLIC methodology for calculating the BCS more closely resembles an average incremental cost approach than a Turvey-style marginal incremental cost approach.

Basis for marginal cost tariff component

Having established that network tariffs ought to seek to reflect LRMC rather than SRMC and having decided to use the BCS as a rough proxy for LRMC, the next step is to select the appropriate basis for imposing marginal cost-based charges. The key options are:

- Meter type/connection capacity
- Peak demand
- Peak consumption and
- Anytime consumption.

Each of these has its own advantages and disadvantages, as discussed in section 3.3 below. The key determinant of which variable should be selected is the directness of the relationship between the variable and the need for network investment. This is a function of the approach adopted to network planning, which is discussed in section 3.2.

3.1.2 Recovery of remaining network costs

Need for 'two-part' tariffs

Setting tariffs to reflect marginal cost – whether SRMC or LRMC – will typically not by itself allow a distribution network to recover all of its historical capital costs. This follows from the economies of scale inherent in network provision and the lumpiness of network investment. Together, these characteristics can cause *marginal cost* to fall below the *average cost* of providing the network. Put differently, it means that pricing at marginal cost may not enable a distribution network to recover its allowed regulated revenue, which is set to enable the business to recover its total (efficient) costs.

A demonstration of the economic theory in the present context is provided by comparing the BCS – as a proxy for LRMC – to current peak demand tariffs for SAC large customers. Even in the cheaper-to-serve East Zone, SAC large customer demand tariffs are currently set at between $20-31/kW/month of the customer's actual (or profiled) monthly peak demand. This represents approximately $240-370/kW/year. Assuming an average power factor of 0.9, this suggests that SAC large customers are currently paying a peak demand charge of approximately $217-332/kVA/year. This is about one-third to 100% more than what the $/kW cost would be if the BCS ($162/kVA/year) were used to set the actual peak demand tariff. In the absence of any other changes, setting peak demand charges for SAC large customers on the basis of BCS would clearly lead to less recovery of regulated revenue than under the existing tariff structure. A further point to note is that even the current SAC large demand tariff does not recover all of Ergon Energy's allowable revenue allocated to this customer tariff class; as noted in the Consultation Paper, the actual demand charge recovers just over 90% of the allocation.

In these circumstances, some other charge is necessary to recover the network's residual allowed revenue not recovered through LRMC-based charges. This additional charge is commonly described in economics as the second part of a 'two-part tariff' – with the first part reflecting marginal cost (as indicated by the BCS or otherwise) and the second part recovering the remaining allowed revenue to be recouped from customers. A common example of two-part tariffs is the structure of fees imposed by gyms and many sporting clubs, which combine an annual membership or joining fee with a separate usage fee. The usage fee represents the first-part marginal cost-based tariff and the annual fee represents the second-part cost recovery tariff. The question is then how this second-part residual cost recovery charge should be structured.

Role of customer willingness to pay and the scope for bypass

The conventional economic thinking around the recovery of sunk costs is that these costs should be recovered in a manner that has as little impact as possible on customers' decisions regarding use of the service. That is, the second-part tariff should play no signalling role at all. The rationale for recovering outstanding costs in this way is that the first-part tariff (reflecting marginal cost) does all the signalling work required of prices; hence, the second-part tariff should be set in a way that avoids upsetting or distorting the usage signals flowing from the marginal cost charge. This means that the second-part tariff should, at the very least, not be based on electricity consumption. The best way to do this is to recover outstanding network costs from customers in proportion to their overall willingness to pay for the provision of the distribution network.

Recovering outstanding sunk costs on the basis of willingness to pay means that it is necessary to examine what alternatives customers have to paying for (and receiving) network access. This involves considering options for physical or economic *bypass*. Bypass broadly refers to avoiding use of the network:

- ***Physical bypass*** – refers to building a private network to one or a group of generators to avoid using and paying for the regulated network in question.
- ***Economic bypass*** – refers to avoiding use of the network in question, either by not investing/locating in the service provider's network or disconnecting from its network. This may involve developing some form of distributed generation, possibly accompanied by energy storage facilities.

Most distribution network customers cannot credibly engage in physical bypass of the network. The scope for complete economic bypass is also limited at present, as residential and most commercial customers are heavily dependent on some form of external access to reliable supply of electricity. However, many customers are presently engaging in a form of partial economic bypass through the installation of solar PV units. These units enable customers to consume less grid-supplied power, reducing the extent to which they pay volumetric network charges. As the bulk of network charges to SAC large and small customers are recovered directly or indirectly on the basis of electricity consumption,[8] the result has been that customers with solar PV are contributing far less to the recovery of sunk network costs than customers without PV units, even though PV customers would likely place a similar value on network access as non-PV customers. This has provided an artificial (and inefficient) incentive for customers to install solar PV units, because in doing so they can avoid paying the same amount for network access as other customers.

Economic efficiency is likely to be enhanced if much of residual costs of the network not recovered through marginal cost-based tariffs are recovered from tariffs that reflect the value customers place on network access rather than the amount of electricity customers consume.

Ethical and practical issues

While clear in theory, charging based on willingness to pay raises ethical and practical issues.

First, because willingness to pay will vary across customers, setting tariffs based on willingness to pay involves price discrimination. This may be regarded as unfair. Concerns about fairness can be at least partly addressed by limiting the extent of price discrimination – such as by requiring tariff structures for particular groups of customers to be uniform within the group. For example, second-part cost recovery tariffs for all SAC small volume-small customers could

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8 In the case of SAC large customers, charges are notionally largely based on customers' Actual Demand. But due to metering limitations, demand for non-market customers is inferred from a deemed profile applied to accumulated consumption.

be the same, but different from second-part tariffs for SAC small volume-large or SAC large and CAC customers.

The second issue – which is the principal practical barrier to charging based on willingness to pay – is that customers' willingness to pay is difficult to observe directly and is likely to differ substantially between customers. Instead, it is necessary to consider some proxy for willingness to pay. In the case of electricity distribution services, willingness to pay could be inferred in a variety of ways from more readily observable variables, such as:

- Meter type/connection capacity
- Peak actual or historical demand
- Electricity consumption
- Customer class or category.

Each of these measures has advantages and disadvantages, as discussed in section 3.4 below.

3.2 Approach to network planning

In determining how to structure the first-part marginal cost tariff, it is important to base charges on those customer decisions – such as:

- whether to connect
- how large a connection capacity to seek
- how many appliances to install and
- how much electricity to consume and when to consume it,

that are most likely to require or bring forward the need for network augmentation.

Appropriate choices for basing the first-part tariff in particular will be strongly influenced by the methodology and processes used for distribution network planning. This is because the approach used for network planning will determine the extent to which different types of increases in network usage – eg connection numbers, connection capacities, peak demand, consumption, etc – will lead to higher network costs in the future.

This sub-section discusses Ergon Energy's approach to network planning adopted at both the Low Voltage (LV) and the High Voltage (HV)-Zone Substation-Sub-transmission levels, as it relates to different customer classes. The role of this information in tariff-setting is taken up in section 3.3 below.

By way of introduction, Ergon Energy normally refers to:

- LV as voltages of 1,000 volts or less (up to 1 kV)

- HV as voltages between 1 kV and 33 kV and
- Sub-transmission as voltages between 33 kV and 66 kV.

LV assets

Most residential and small business customers (SAC small) are connected to the LV distribution network through lines coming off a LV bus. Larger commercial and rural customers (SAC large) are typically connected at a LV bus or at a distribution substation, although some are connected to the HV network. Larger customers (CACs and ICCs) are also connected at higher voltages (see below).

The minimum residential connection consists of a single-phase 240 volt supply, capable of a maximum 80 amps – that is, about 19 kVA. However, the Developers Handbook obliges developers to make provision for an After Diversity Maximum Demand (ADMD) allowance per lot in a new development of 4 to 5 kVA for urban subdivisions (depending on whether the development is north or south of Mackay). The 4 or 5 kVA ADMD allowance takes into account the expected demand diversity between different customers within a development.[9]

The primary source of new SAC small customer connections in Ergon Energy' network is new housing developments. The Ergon Energy Developers Handbook notes that developers are responsible for providing or funding all distribution reticulation infrastructure within their developments, as well as any required upstream and 'headworks' investment.[10] To the extent developers provide this infrastructure themselves, the assets are often subsequently gifted to Ergon Energy, who then becomes responsible for their ongoing maintenance and ultimate replacement. The contribution required for upstream works may be reduced if the works provide a shared benefit to other customers connecting simultaneously or if the works involved are part of any planned network alterations and upgrades that Ergon Energy has within its 5-year planning horizon. In these cases, the connecting party will only pay the costs of bringing forward the project.[11]

Where new SAC customers seeking connection are not associated with a new development, those customers are often not required to contribute directly to LV costs. Rather, network costs attributed to such connections are often smeared across all customers connected to the LV network. However, we understand that Ergon Energy's expenditure on LV augmentation not provided by or recouped

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9 Developers Handbook, p.7.

10 Ergon Energy, *Underground Distribution Construction Developers Handbook, Developer Design and Construct*, (Developers Handbook) pp.4-5.

11 Developers Handbook, p.5.

from customers is a relatively small share of its overall capital expenditure budget.

The key point to note is that in many (but not all) cases, the cost of LV assets required to serve new connections is ultimately borne by the connecting customers. This means there is limited need for LV costs to be signalled to customers via distribution network charges.

HV and Sub-transmission assets

The bulk of Ergon Energy's network by line length is in the form of HV and sub-transmission lines and related assets. Zone substations represent the boundary between HV and sub-transmission lines. CACs tend to connect at HV levels (including at zone substations), while ICCs mainly connect at the sub-transmission level.

Based on Ergon Energy's planning documents, network planning at the HV and sub-transmission levels considers both short (5-year) and long (20-30 year) time horizons. The results of both processes are used to produce five-year development plans for augmentation projects, as well as a further five-year projection of probable works. Augmentation projects are presently identified and scoped so as to meet energy planning security criteria approved as part of the Electricity Network Capital Program (ENCAP). The approved security levels used as planning targets employ deterministic standards based on maintaining supply or limiting the loss of supply under credible contingency conditions. The assessment of whether the network is likely to meet these standards is primarily based on demand forecasts with a 50% probability of exceedance (PoE), based on normal expected growth rates and temperature-corrected starting loads. A 50% PoE means that the forecast represents a median expectation that would be exceeded in one year out of two.

The rising level of network costs in recent years has prompted a range of government reviews. In June, the Queensland Government gave its response to the Interdepartmental Committee on Electricity Sector Reform.[12] The Government accepted in principle the Independent Review Panel's recommendation to replace prescriptive security and reliability standards with more economically-derived outcomes-based planning approaches.[13] Adoption of outcomes-based standards may reduce or defer network augmentation. However,

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12 See *Queensland Government response to the Interdepartmental Committee on Electricity Sector Reform*, 2013, available at: http://www.dews.qld.gov.au/__data/assets/pdf_file/0007/78568/queensland-government-response-to-idc-report.pdf (accessed 8 October 2013).

13 Independent Review Panel on Network Costs, *Electricity Network Costs Review – Final Report*, available at: http://www.dews.qld.gov.au/__data/assets/pdf_file/0010/78544/irp-final-report.pdf (accessed 22 October 2013).

it would not sever the link between peak and average demand and network expenditures.

3.3 Basis for setting the 'first-part' marginal cost tariff

Having settled on the use of the BCS as a proxy for LRMC to set the first-part marginal cost-based signalling tariff, the next question is determining the unit basis upon which the tariff should be imposed. As noted above, the key options for the unit basis include:

- Meter type/connection capacity
- Peak demand and consumption and
- Anytime consumption.

The appropriateness of each of these options is discussed below.

3.3.1 Meter type/connection capacity

As discussed in section 3.2, the number of small customer connections is a significant driver of distribution network investment at the LV level. If LV investment were the only form of investment in the distribution network, it would seem logical to impose marginal cost-based tariffs largely on the basis of meter type (eg single-phase, three-phase) or connection capacity (which are often linked in any case). As most residential customers have the same sized connection (ie single-phase 240 volt), and as upstream assets are built to accommodate a standard 4-5 kVA capacity allowance per connection, a fixed $/connection amortised charge would appropriately attribute and signal the costs of network investment to the central driver of that investment.

However, as a large proportion of LV investment is funded by developers (and indirectly by property purchasers), there is less need to signal LV costs through network tariffs. Rather, it would make more sense to focus on the drivers of HV and sub-transmission investment in deciding how to structure tariffs.

3.3.2 Peak demand and consumption

The planning criteria for HV and sub-transmission investment presently emphasise the need to maintain security of supply under specified contingency and peak demand conditions. This may change over time to place more emphasis on reliability outcomes. Nevertheless, the use of peak demand forecasts to assess the adequacy of network capacity at the HV and sub-transmission levels combined with the lack of weight placed on customer connection numbers suggests that the key driver of recoverable shared network investment costs is growth in peak demand. In other words, peak demand – or consumption at peak times – is the variable most directly linked to the need for increased (or brought forward) HV and sub-transmission network investment.

In most cases, peak zone substation demand occurs during summer afternoons and evenings in Ergon Energy's network, although the definition of 'summer' can span from October to March. This suggests that the first-part marginal cost signalling tariff should, if practicable, seek to deter demand or consumption at peak summer times. The proposed tariff structures in section 4.2 below explore the option of seasonal ToU tariffs further.

In determining how to set marginal cost-based tariffs, it is also important to take account of the lagged way in which peak demand influences HV and sub-transmission investment. Network planning is undertaken based on peak demand forecasts, which are themselves heavily influenced by historical growth in peak demand. This means that the peak demands achieved in a given month can exert a persistent influence on planning and investment decisions for many months or years afterwards. For example, despite the recent moderation of peak demand across most of the NEM, AEMO as well as many network planners are forecasting a resumption of growth in future years. This is in part a result of forecasting processes, which, in the absence of strong evidence of a permanent reduction in peak demand, rely heavily on longer-term past trends to justify the expectation that peak demand will resume its growth.

The implication is that in providing signals to network users, it is important to set tariffs in a way that appropriately flags the cost consequences of high peak demand for some time after that peak occurs. Just because a customer's demand peak reached in one summer month is not matched in the next summer month does not imply that the customer should enjoy lower charges in that second month; the network planning process would already have been encouraged to approve irreversible investments on the basis of the peak reached in that earlier higher-demand month. A practical means of implementing this approach to setting network tariffs is discussed in section 4.2.2 below.

3.3.3 Anytime energy consumption

For the reasons given above, anytime consumption is not an appropriate basis for the first-part signalling component of network tariffs. Imposing charges on anytime consumption taxes consumption at all times equally, even at those times when higher consumption does nothing to increase or bring forward network investment.

3.4 Basis for setting the ‘second-part’ residual cost tariff

As explained in section 3.1.2, the purpose of the second-part tariff in the pricing of natural monopoly services is to recover outstanding costs in a manner that exerts as little effect as possible on customers’ infrastructure usage decisions. There are a number of candidates for the basis of this charge:

- Meter type/connection capacity
- Peak demand and consumption
- Anytime energy consumption
- Customer category
- Customer characteristics.

The appropriateness of each of these options is discussed below.

3.4.1 Meter type/connection capacity

Setting cost recovery tariffs on a fixed basis based on meter type or connection capacity has the advantage that these are not variables that customers can easily affect through their future behaviour. Hence, a fixed charge based on meter type or connection capacity will not directly distort customers’ network usage decisions. On the other hand, meter type or connection capacity may be uniform across customers with such a wide range of willingness-to-pay that it fails to provide a useful proxy for any given customer’s willingness-to-pay. For example, as noted above, Ergon Energy’s smallest customer connections (single-phase 240 volt) are sized to accommodate approximately 19 kVA of peak demand (80 amps). However, the ADMD allowance per lot is 4 to 5 kVA for urban subdivisions. For the ADMD to be so much lower than the potential capacity of LV infrastructure suggests – notwithstanding the presence of demand diversity – that relatively few residential customers have the appliances that cause them to use as much power as their connection potentially allows. This suggests that meter type/connection capacity may not be the best proxy for a customer’s willingness to pay for access to and use of the distribution network. For example, a customer with even a basic 19 kVA connection that demands an average 3 kW across the year – well below the potential of the connection – would consume over 26 MWh per annum. This is well above the consumption of a typical residential household customer and enough to place the customer in the volume-large sub-category of SAC small customers.

Another disadvantage with using connection capacity is that it may not match customer category (see below) and/or it may not be known to or easily ascertainable by the network, leading to confusion about the level of charge for different premises.

3.4.2 Peak demand and consumption

Setting cost recovery tariffs based on peak actual or historical demand (eg cents/kW or kVA) could provide a better reflection of a customer's willingness to pay for the distribution network. However, it would have one major drawback: charges imposed on this basis would penalise usage of the network at peak utilisation times. This would reinforce marginal cost pricing signals from the first-part tariff, potentially leading to 'over-signalling' the cost of network use. Another issue, though not insurmountable, is that most of Ergon Energy's customers (SAC small and –large) do not currently have metering installations that record peak demand. While a reasonable proportion of the SAC large customers do have such meters, these data are presently often not collected (the actual demand charge for SAC large is based on a deemed load profile).

3.4.3 Anytime energy consumption

Setting cost recovery tariffs based on volumetric energy usage (ie cents/kWh) has its own advantages and disadvantages. The key advantage lies in the ability of even the simplest meters to record accumulated consumption, which facilitates such charges. Another advantage is that energy consumption would bear some relationship to the benefits that customers receive from access to the network. Customers with large solar PV units may have less need for – and hence value from – the distribution network than customers without such units. On the other hand, customers with large PV units may obtain value from being able to export back into the network and earn generous feed-in tariffs.

However, charges based on usage do have the substantial disadvantage that they alter customers' incentives to use the existing network. Second-part tariff parameters based on consumption tax network usage and thereby distort the peak signals provided by the marginal cost-based charge by overlaying an additional cost on both peak and off-peak consumption.

3.4.4 Customer category

Setting cost recovery tariffs on the basis of customer category involves customers within a certain category (eg SAC small, volume-small) paying the same fixed dollar charge for their second-part tariff. This avoids many of the difficulties associated with setting tariffs on the basis of connection capacity: customer category is known and is likely to provide a reasonable proxy for customers' willingness to pay for network access, so long as all available sub-categories are used (eg SAC small, volume-small and volume-large, SAC large demand-small, demand-medium and demand-large). It may even be appropriate to create additional sub-categories to further refine the relationship between likely willingness to pay and the magnitude of the second-part tariff. This would also help address concerns about fairness and equity for smaller-consuming customers that were raised in stakeholder submissions (see section 2.2 above).

The key disadvantage with using customer categories to set the second-part tariff – which is heightened as more sub-categories are used –arises to the extent that customers can self-select their tariff category. If this is possible, tariffs will need to be structured in a manner that takes account of customers' ability to self-select their categories in a way that minimises their overall bills. This means that customer categories and tariffs should be set so as to avoid creating strong incentives for customers to curb network usage. For example, overall network charges should not increase dramatically as a customer increases its consumption – and hence tariff category – from, say, SAC small volume-small to SAC small volume-large.

3.4.5 Customer characteristics

The best indicator of customer willingness to pay for network access may be characteristics external to electricity consumption or demand. For example, council valuations of residential properties may provide an indication of customer willingness to pay: customers living in more expensive properties are likely to have a higher willingness to pay than customers living in cheaper properties. Another characteristic for residential customers may be household income or the number of adult residents living in the dwelling. A relatively simple and verifiable characteristic for residential customers could be whether the account-holder is eligible for hardship or similar concessions. All customers eligible for concessions could face a discounted second-part tariff compared to all other customers.

As becomes clear, the use of any measure relating to customer characteristics is likely to give rise to legitimate concerns about privacy and intrusiveness. Even if these issues can be managed, the use of such measures can create the need for additional monitoring and enforcement mechanisms to ensure customers cannot misrepresent their status or otherwise 'game' the measure to reduce their charges.

3.5 Other considerations

In addition to the pursuit of economically efficient network tariff structures, the Consultation Paper discussed the relevance of a number of other considerations to the development of network tariffs. Briefly, these other considerations are as follows:

- ***Retail transparency of network tariffs:*** Most Ergon Energy retail customers do not currently face Ergon Energy's network tariffs. In 2012/13, QCA adopted a new approach to setting Notified Prices, whereby retail tariffs are based on a network (N) plus retail (R) ("N+R") cost build-up approach. This means that all customers on Notified Prices consuming over 100 MWh per annum pay retail prices that incorporate Ergon Energy's network tariffs. However, many such customers remain on transitional retail tariffs and all non-market SAC small (consuming up to 100 MWh per annum) pay notified prices based on Energex's network tariffs. Nevertheless, as explained in the Consultation Paper, Ergon Energy considers that it should pursue a tariff development path based on robust economic efficiency principles irrespective of the extent to which they are currently seen by end-use customers.[14]

- ***Geographic variation***: As noted in the Consultation Paper, Ergon Energy is not planning to implement greater geographic tariff granularity than is currently in place. The existing set of distribution tariff structures are based around three geographic zones: East Zone, West Zone and Mt Isa Zone. The Consultation Paper stated that changing the number of zones would have little, if any, impact on tariff structures but would result in additional tariff level variation between zones for each tariff structure. The current zones have been developed based on achieving a balance between reflecting zonal cost differentials and a manageable overall suite of tariffs. In addition, there are three Powerlink transmission pricing regions (T1, T2 and T3), which do not correspond to Ergon Energy's pricing zones. This means there are seven network tariff codes applicable to each customer category: East T1, East T2, East T3, West T1, West T2, West T3 and Mt Isa.[15]
- ***Metering limitations***: At least in the short term, proposed tariff structures need to reflect the limitations of metering installations and metering data services. Premises with consumption in excess of 750 MWh per annum (mainly ICCs and CACs) have remotely-read interval meters whether they are customers of EEQ or other retailers. Only second tier customers consuming greater than 100 MWh per annum need to have remotely-read interval meters. This accounts for just over two thousand customers out of over eight thousand in this category (about one-quarter). Further, not all interval meters installed at these premises would presently be capable of measuring kVA demand. Fewer than 10% of SAC small customer premises would have electronic meters. These metering limitations mean that it would be difficult to impose kVA or 'true' peak demand tariffs on SAC large customers, except on an optional basis where the customer agreed to request installation on an appropriate meter. Similarly, SAC small customers could only access ToU tariffs on an optional basis.
- ***Role of demand management***: Efficient network pricing is a means to an end rather than an end in itself. The ultimate goal of efficient pricing is to help ensure that network capacity is developed to provide electricity to consumers up to the point where customers are willing to pay a price just

14 Consultation Paper, pp.17-18.

15 See Ergon Energy, *2013-2014 Pricing Proposal, Ergon Energy Corporation Limited*, 7 June 2013, Version 1.1 – AER approved, Appendix 1, pp.72-75.

equal to the marginal or incremental cost of delivering that power. As consumer valuations of power and the costs of delivering that power can vary greatly across customers, times and locations, even carefully-developed network tariffs are unlikely to be locationally- or temporally-refined enough to maximise economic welfare under all conditions. Demand management strategies can help to address the inevitable shortcomings in network tariff-setting by promoting improved investment-usage outcomes in relation to particular locations and times. For example, there may be a specific area where the costs of augmentation are extremely high – much higher than the average LRMC across the overall network or the pricing zone. Demand management activities could reveal that although customers at that location were willing to pay a price based on the average LRMC of network expansion, they were not willing to pay the actual forward-looking cost of augmentation at that location. This would allow a bargain to be struck whereby customers were paid a price somewhere between the network-average LRMC and the actual cost of augmentation to forgo the benefits of network expansion. Ergon Energy currently has an ongoing program of demand management, with a budget of approximately $15 million for 2013/14 to secure an annual demand reduction target of 24 MVA.[16] This follows 107 MVA of demand management delivered up to 30 May 2013.

16 *Ergon Energy Demand Management Plan 2013/14*, 30 April 2013.

4 Proposed tariff structures

This section defines and explains Ergon Energy's proposed tariff structures for the tariff years 2014/15 and 2015/16, and provides indications of further likely tariff developments in subsequent years.

Prior to discussing the proposed structures, this section begins by referring to the options put forward in the Consultation Paper and discussing the extent to which those options will or will not be pursued.

4.1 Appropriateness of Consultation Paper options

The potential tariff structure options described in the Consultation Paper (and reiterated in section 2 above) remain broadly appropriate in light of the refined economic efficiency framework outlined in section 3. However, some elements of the options are not warranted and will not be pursued at the present time.

4.1.1 kVA-based tariffs

A move from kW-based Actual Demand and Capacity (Authorised Demand) tariffs to kVA-based tariffs remains desirable. This is because the best measure of network capacity and the clearest driver of augmentation cost is the delivery of apparent power (measured in kilowatt-amperes or kVA). The transportation service provided by electricity networks is fundamentally concerned with the conveyance of apparent power. A given increase in real power demand (measured in kilowatts or kW) can utilise and call forth more kVA network capacity and augmentation cost if the relevant customer has a 'poor' (ie low) power factor than if the customer has a high power factor. Additionally, the importance of kVA means it may be appropriate to implement an excess kVAR charge in the long term, as discussed in the next section.

Therefore, modifying the current kW-based demand tariffs applicable to ICCs and (subsequently) CACs to kVA-based tariffs would provide better signals to customers regarding how their behaviour can influence the timing and extent to which future costs will be incurred.

4.1.2 ToU demand

ToU demand tariffs seek to signal the high LRMC of increased demand during peak times. The advantage of ToU demand tariffs over ToU energy tariffs (see below) is that ToU demand tariffs can help deter short-term increases in consumption that may not lead to a great deal of additional consumption, but which might still contribute to bringing forward network investment. ToU energy tariffs are likely to exert a much weaker effect in this regard.

The introduction of ToU demand tariff structures (initially based on kW demand and later on kVA) would be a worthwhile step for SAC large customers and possibly CACs, who share a similar load shape to non-residential SACs (see section 2.1.2 above). This is because:

- SAC large customers and CACs tend to have relatively 'peaky' load shapes, whereas most ICCs have relatively flat load profiles
- SAC large customers connect to the network at relatively low voltages (generally at or below a HV bus), as do CACs (generally at or below a zone substation) – whereas ICCs mainly connect at the subtransmission level. This means that SAC large customers and CACs utilise shared network assets to a much greater extent than ICCs.

As a result, most network planning at HV and zone substation levels is based around serving a non-flat load shape driven by SAC (large and small) and CAC load profiles. The implication is that it is primarily SAC and CAC demand at peak times that will influence the need for new network investment at these levels of the network.

SAC small customers could be charged on the basis of ToU demand in the medium to longer term, but a number of current barriers would need to be overcome. Apart from potentially requiring more sophisticated metering, it would involve introducing customers to the concept of demand as distinct from energy consumption. For customers who are only familiar with simple Fixed and Energy tariffs, this is likely to require significant time and resources. ToU demand tariffs may also give rise to customer resistance if not structured to avoid unpredictable outcomes from very short term or accidental excursions in a customer's peak demand. A feasible transitional option for this customer class would be the introduction of seasonal ToU energy tariffs, as discussed below.

On the other hand, introducing ToU demand structures for ICCs is unlikely to be worthwhile. This is because ICCs have relatively flat loads and connect at higher voltages where their behaviour has much less influence on the need to augment the shared network. The connection assets that ICCs primarily utilise and fund are usually built to accommodate their full requirements and so consuming more at certain times than others will do little to bring forward shared network augmentation costs.

4.1.3 ToU energy

ToU energy tariffs seek to signal the high LRMC of increased demand at peak times indirectly, by setting higher prices for peak consumption than for off-peak consumption. As noted above, the disadvantage of ToU energy tariffs is that they may not provide a great (strong financial/ cost reflective) disincentive to short-term increases in demand during peak periods, because little energy may be consumed during these periods. Yet even short term excursions of demand may contribute to bringing forward costly network investment.

The introduction of seasonal ToU energy (kWh) tariffs would be a worthwhile step for SAC small customers. Like SAC large customers, SAC small customers have peaky profiles – particularly during extreme summer days – and connect to the network at low voltages. This means that their peak demand often contributes to the need for investment in HV and zone substation assets. However, imposing peak demand-based tariffs on SAC small customers, at least in the short term, is likely to be impracticable for the reasons outlined above. ToU energy tariffs are currently offered to residential customers at the retail level, but these are based on Energex's ToU network tariff for which Ergon Energy currently has no equivalent.

4.1.4 CPP

Critical Peak Pricing (CPP) refers to the setting of an extreme peak tariff – often multiples of regular 'peak' tariffs – for a limited duration on a number of 'critical peak days' nominated shortly in advance. Typically, a service provider may have the ability to call five to fifteen critical peak days a year and is obliged to inform end-use customers of its decision to call a critical peak day by at least the afternoon of the previous day. CPP has been trialled internationally, especially in California and other US markets. The motivation behind CPP is to send a particularly strong price signal for customers to moderate their demand on unusually hot summer days or when planned network outages are scheduled.

As noted above, there was only patchy support across submitters for CPP. Many stakeholders commented that they had little scope to respond to sharp pricing signals and some retailers questioned whether it would offer significant benefits over other measures.

In the context of managing Ergon Energy's dispersed and non-coincident distribution system peaks, the value of introducing CPP tariff structures is unlikely to exceed the costs for the foreseeable future, especially given the available alternatives. For SAC large, CAC and ICC customers, demand-based tariffs (including the proposed seasonal ToU rolling 12 month demand tariff outlined below) are likely to be more effective in deterring extreme peak demand excursions than CPP tariffs. For SAC small customers, the implementation of CPP would not only require meters capable of recording half-hourly ('interval') consumption, but also a robust mechanism or process for network (or retail) businesses to inform customers in advance of a nominated critical peak day. Further, in Ergon Energy's network, it is extremely difficult to accurately and consistently predict critical peak days and times in particular constrained locations sufficiently in advance to reliably moderate annual peaks. Finally, the uncertainty of customer behavioural responses under CPP combined with the difficulty of accurately predicting critical peak days in advance can lead to new business risk and a high degree of revenue and demand volatility for Ergon Energy. The introduction of ToU peak demand or seasonal ToU energy tariffs is likely to achieve many of the same benefits as CPP but with fewer costs and risks.

The best application of CPP is likely to be as a tool available for targeted demand management activities in areas of the network where other demand-side options are being considered to address localised shortages of network capacity. For example, a demand management product offer based on CPP could be considered alongside other augmentation and distributed generation options as part of a regulatory investment test for distribution (RIT-D) assessment process. The use of CPP in such a tailored manner would make it easier to overcome metering and IT requirements and provide appropriate customer education.

4.2 Proposed path of tariff development

The implementation of the Network Tariff Strategy Review will commence in 2014/15 with alternations to some existing tariffs and the addition of certain optional or prospective tariffs. Further changes and additions have been proposed for 2015/16. For the tariff years beyond 2015/16, this Report outlines key areas of tariff development. The key changes are outlined below.

Appendix A provides a full diagrammatic summary of the proposed changes.

4.2.1 Proposed tariffs for 2014/15

In broad terms, the changes proposed for 2014/15 involve starting the introduction of kVA tariffs for ICCs and commencing the process of rebalancing tariffs for other customers from high variable/usage-related charges to more fixed/ less usage-dependent charges. This rebalancing is driven by the empirical finding that the true LRMC of Ergon Energy's network appears to be well below the notional LRMC implied in current tariff structures.

The key tariff changes for 2014/15 are as follows:

- ***ICC:*** Transfer all customers onto a revised tariff structure incorporating:
  - Capacity (Authorised Demand) and Actual Demand tariffs based on kVA rather than kW
  - Similar Fixed and Energy tariffs
- ***CAC:*** No changes planned
- ***SAC large:*** Commence rebalancing existing tariff structure by using the BCS measure as a proxy for LRMC to adjust the Actual Demand charge – this is likely to lead to a reduction in the Actual Demand tariff and an increase in the Fixed charge

- ***SAC small:*** two broad options are available:
  - Package SS1: Make available an optional seasonal ToU energy charge based with peak (and possibly shoulder) rates based on the BCS measure. This will likely involve a higher fixed charge to recover the remainder of regulated revenue allocated to SAC small customers
  - Package SS2: As above, but transfer all customers onto an Inclining Block Tariff (IBT) incorporating a fixed charge and rising energy tariffs corresponding to ascending consumption bands.

ICC tariff changes

The key proposed change for ICC tariffs in 2014/15 is a move from a kW basis for the two demand-related tariffs (Capacity and Authorised Demand) to a kVA basis for the reasons described in the previous section. This change will be effected by altering the way that Ergon Energy's 'DCOS' cost allocation model allocates Ergon Energy's annual allowable revenue between ICCs. Due to interdependencies in the model, this may lead to small changes in the total network charges of customers in other tariff categories.

SAC large tariff changes

The key proposed change for SAC large tariffs in 2014/15 is to commence the process of 'rebalancing' the tariff components to increase their cost reflectivity. This involves recalibrating the Actual Demand tariff so that it moves toward the BCS. This would help ensure that the Actual Demand tariff better reflects the LRMC of network use than it does presently. To the extent this causes Actual Demand tariffs to fall, the Fixed tariff component will need to rise to recover the residual revenue allocated to the SAC large customer category.

SAC small tariff changes

Optional seasonal ToU energy

Under package SS1, the only change proposed for SAC small customer tariffs in 2014/15 is to offer customers an optional seasonal ToU energy tariff structure.

The advantage of a seasonal ToU tariff over a standard non-seasonal ToU structure lies in the ability of a seasonal ToU tariff to more accurately signal the high costs of consumption at times when zone substation is likely to be highest – such as summer weekday afternoons and early evenings. As noted above, it is incremental demand or consumption at these times that most strongly drives the need for investment in the shared network. Incremental consumption outside of these times is likely to have much less impact on the need for or timing of network investment.

The proposed seasonal ToU structure would differ as between residential and non-residential customers as follows:

- Residential SAC small customers – 3 ToU periods: peak, shoulder and off-peak, with these periods varying across months of the year to reflect seasonal patterns of peak demand
- Non-residential SAC small customers – 2 ToU periods: peak and off-peak, with these periods varying across months of the year to reflect seasonal patterns of peak demand

In both cases, the levels of the peak and shoulder tariffs will be based on the likelihood of incremental consumption leading to higher network costs being incurred, as indicated by the BCS. This will help ensure that customers on these tariffs pay a price for peak period consumption that appropriately reflects the influence of their peak consumption on the need for network augmentation. As with SAC large tariffs, the level of the fixed charge under this optional tariff would likely need to rise compared to its level under the current Fixed and Energy structure.

IBT

Under package SS2, existing Fixed and Energy tariffs will be replaced by Inclining Block Tariffs (IBTs). As noted in section 2.2, the introduction of IBTs received some support from residential customers in the consultation process.

An IBT is a tariff structure that incorporates:

- A fixed charge
- Two or more consumption tariff rates, with rising rates corresponding to ascending bands of consumption

By way of illustration, SA Power has a low voltage residential customer IBT comprising the following DUoS charges:

- A fixed charge of $0.363 per day plus
- A tariff of $0.092/kWh for the first 333.3 kWh per month plus
- A tariff of $0.12/kWh for the next 500 kWh per month plus
- A tariff of $0.143/kWh for any additional consumption per month.[17]

Ergon Energy's intention is to introduce an IBT for SAC small customers with a fixed monthly charge similar to the current monthly network bill paid by relatively low-consuming residential households. This would ideally (to facilitate comparisons) be similar to the fixed charge derived for the optional seasonal

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[17] SA Power Networks Network Tariffs, Applies to usage from 1 July 2003, available at: http://www.sapowernetworks.com.au/centric/industry/our_network/network_tariffs.jsp

ToU energy tariff (see above). The rate for the first consumption band would then be set at a low level, minimising bill changes for the smallest customers.

Given the structure of IBTs, it is likely that SAC small customers with relatively high levels of consumption will find that the seasonal ToU tariff will result in bill savings. As higher-consumption customers are more likely to own air-conditioners and other energy-intensive appliances, they are also likely to have peakier – and hence more costly-to-serve – load profiles. In this way, the introduction of IBTs can provide a desirable incentive for customers that are likely to be comparatively costly to serve to take up more cost-reflective ToU tariffs. This would promote economic efficiency without resorting to compulsion to put SAC small customers onto ToU rates.

4.2.2 Proposed tariffs for 2015/16

The key tariff changes for 2015/16 are as follows:

- ***ICC:*** The key change is to introduce an excess kVAR charge to promote power factor compliance.
- ***CAC:*** tariffs for these customers will in part reflect the implementation of the ICC tariff changes from 2014/15 with a one-year lag. This means transferring all customers onto a revised tariff structure incorporating:
  - Capacity (Authorised Demand) and Actual Demand tariffs based on kVA rather than kW
  - (Unlike for ICCs) possible implementation of a seasonal ToU actual demand kVA tariff to reflect the SAC large-like load shape of CACs
  - (Unlike for ICCs) it may be necessary to commence rebalancing the tariff components to increase their cost reflectivity.
- ***SAC large:*** Two sets of changes are proposed:
  - For existing premises: Continued rebalancing and convert the rebalanced Actual Demand tariff component for 2014/15 into a seasonal ToU demand tariff
  - For new and upgraded premises: Apply a default seasonal ToU rolling 12 month demand tariff (in kW or kVA).
- ***SAC small:*** Two key sets of changes are proposed:
  - For existing premises: Continue with default Fixed and Energy tariff or IBT, depending on the choice between SS1 and SS2 made for 2014/15
  - For all new and upgraded premises: Apply a default seasonal ToU energy tariff with the same (higher) level of fixed tariff as for the optional seasonal ToU energy tariff made available in 2014/15

- For all customers: Introduce an optional revised structure incorporating a seasonal ToU rolling 12 month demand tariff (kW).

ICC tariff changes

The key follow-up change to ICC tariffs for 2015/16 is to introduce an excess kVAR tariff to provide customers with an incentive to improve their power factors where they are non-compliant. Other things being equal, this should help to reduce the need to augment the network for a given increase in real power (kW) demand.

CAC tariff changes

The proposed changes to CAC tariffs will in part follow the changes made to ICC tariff structures in 2014/15. However, given the similarity in load shape between CACs and non-residential SAC large customers, it may be appropriate to introduce a seasonal ToU actual demand tariff component and to commence rebalancing the structure of charges using the BCS so that they better reflect the LRMC of increased demand.

SAC large tariff changes

For existing premises, the Actual Demand tariff structure applied in 2014/15 will be further rebalanced and converted into a seasonal ToU demand tariff. The peak and shoulder rates will be based on the BCS to ensure that the tariff appropriately signals the LRMC of increased demand.

New and upgraded premises will become subject to a seasonal ToU rolling 12 month demand tariff (in kW or kVA). Under this tariff, customers will face different demand tariff rates that will apply to the maximum demand they reach during nominated peak and shoulder periods over the previous 12 month period. The precise times will be determined based on a thorough analysis of historical load data. A customer will then be charged the peak tariff rate on its maximum level of demand reached during 'peak' periods over the preceding 12 months. Likewise, the customer will be charged the shoulder tariff rate on its maximum level of demand reached during 'shoulder' periods over the preceding 12 months.

The purpose of this tariff structure is to reflect the fact, as discussed in section 3.3, that increases in demand have cost consequences for some time after a peak occurs. Even if a certain level of demand is only achieved once, it will tend to influence network planning and investment decisions for some time (often years) afterwards. This means that even a 'once-off' excursion of demand should be charged a rate that reflects the long-run costs that may be incurred as a result.

SAC small tariff changes

The key change proposed for 2015/16 is the application of a default seasonal ToU energy tariff for new and upgraded premises (based on the optional seasonal ToU tariff for 2014/15. Also under consideration is an optional seasonal ToU rolling 12 month demand tariff for all customers.

The imposition of the default seasonal ToU charge for new and upgraded premises is intended to take advantage of the relatively low incremental costs of installing ToU-compatible meters at these premises. A seasonal ToU structure will provide better signals to customers as to the cost implications of consuming more energy at different times than a simple fixed and energy or a non-seasonal ToU structure.

An optional seasonal ToU rolling 12 month demand tariff would operate in a similar manner as the tariff to apply to new and upgraded SAC large premises. It will give smaller customers the opportunity to benefit from a highly focused tariff structure that rewards customers for avoiding short-term demand excursions that have high long term cost consequences for network planning and augmentation.

Appendix A – Summary of proposed tariff structures

2014/15

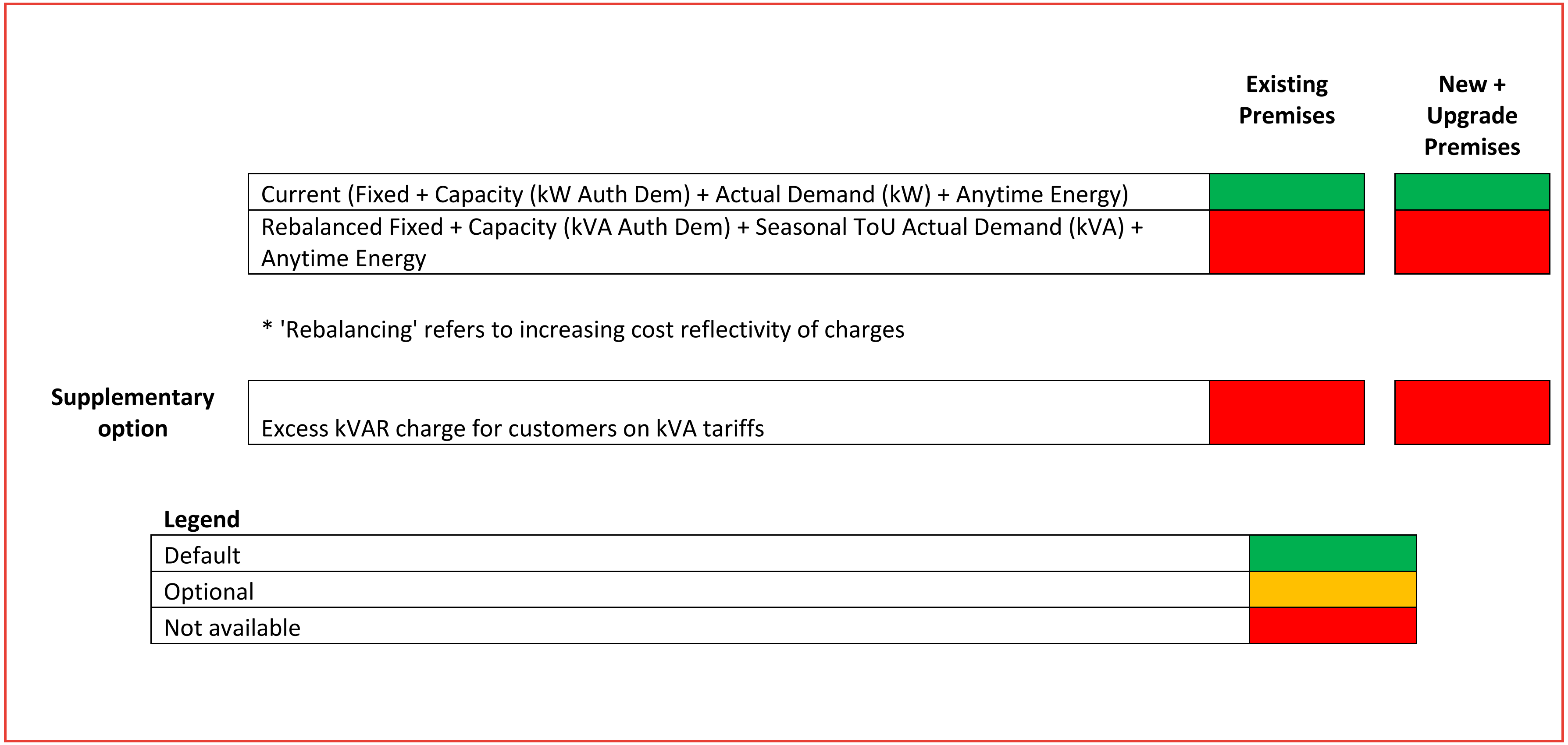
Figure 5: ICC 2014/15

		Existing Premises	New + Upgrade Premises
	Current (Fixed + Capacity (kW Auth Dem) + Actual Demand (kW) + Anytime Energy)		
	Fixed + Capacity (kVA Auth Dem) + Actual Demand (kVA) + Anytime Energy		
Supplementary option	Excess kVAR charge for customers on kVA tariffs		

Legend

Default	
Optional	
Not available	

Figure 6: CAC 2014/15



Appendix A – Summary of proposed tariff structures

Figure 7: SAC large 2014/15

	Existing Premises	New + Upgrade Premises
Rebalance existing structure to reduce 'Actual' Demand (kW) and increased Fixed		
Higher Fixed + Seasonal ToU Demand (kW) + Anytime Energy		
Higher Fixed + Seasonal ToU Rolling 12m Demand (kW or kVA) + Anytime Energy		

* All ToU and kVA demand options subject to suitable metering infrastructure

** kVA option subject to compliant power factor

Legend

Default	
Optional	
Not available	

Figure 8: SAC small 2014/15

Appendix A – Summary of proposed tariff structures

2015/16

Figure 9: ICC 2015/16

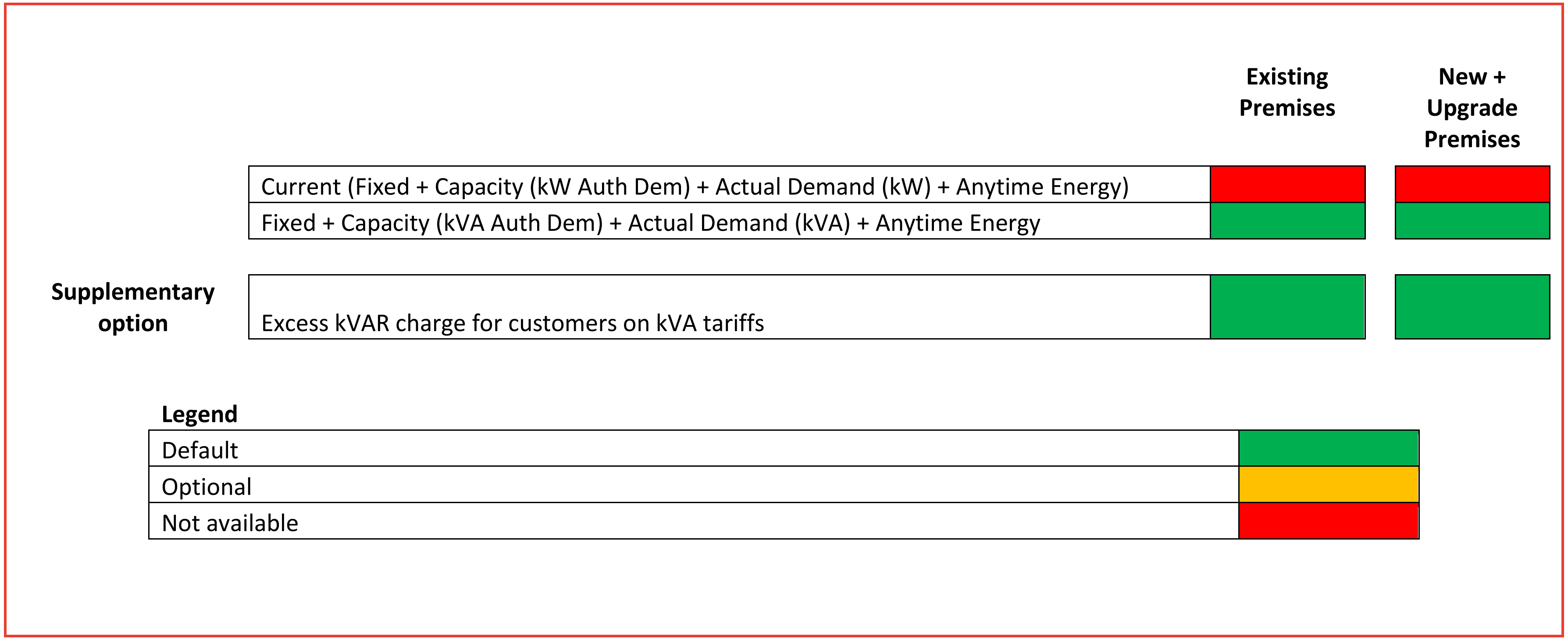
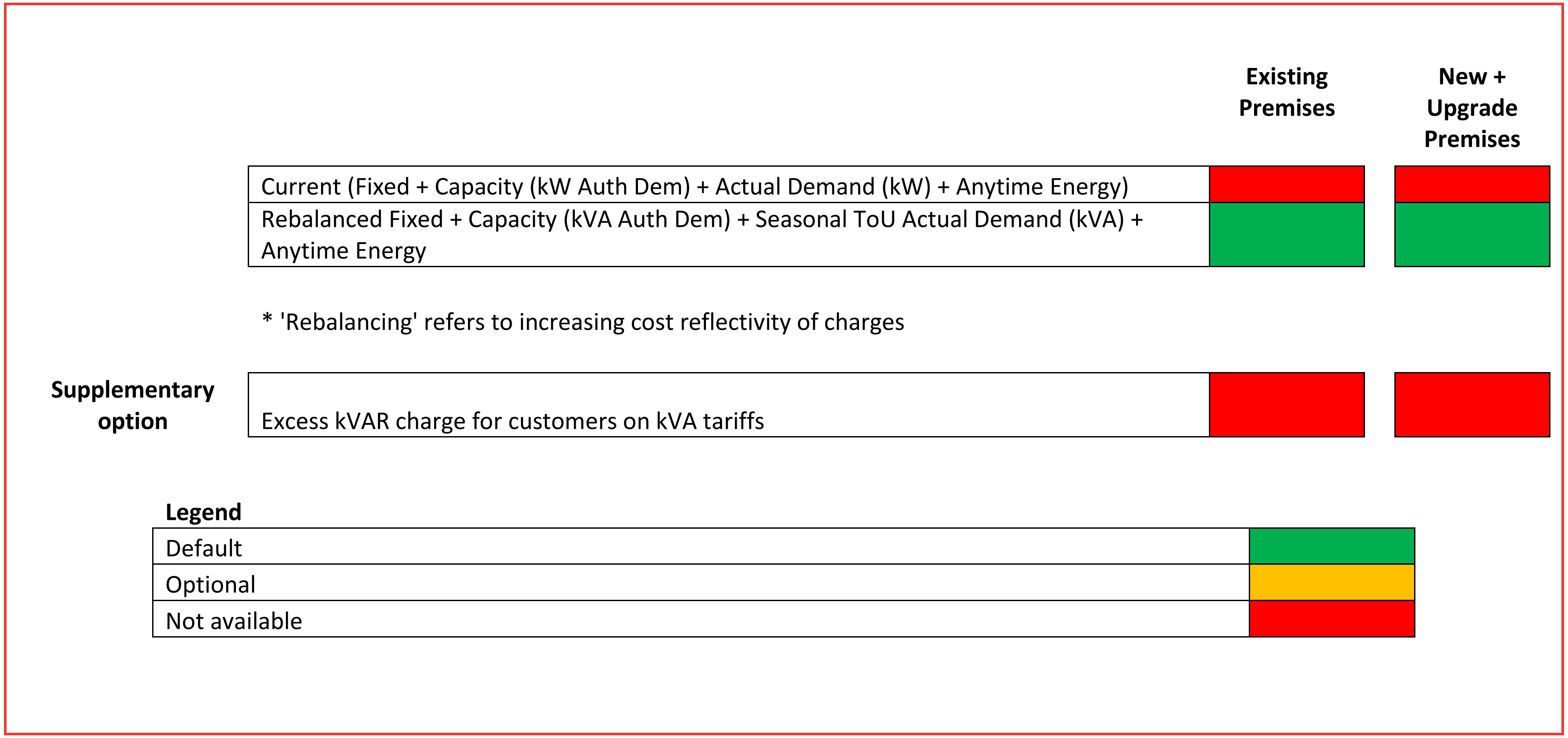


Figure 10: CAC 2015/16



Appendix A – Summary of proposed tariff structures

Figure 11: SAC large 2015/16

	Existing Premises	New + Upgrade Premises
Rebalance existing structure to reduce 'Actual' Demand (kW) and increased Fixed		
Higher Fixed + Seasonal ToU Demand (kW) + Anytime Energy		
Higher Fixed + Seasonal ToU Rolling 12m Demand (kW or kVA) + Anytime Energy		

* All ToU and kVA demand options subject to suitable metering infrastructure

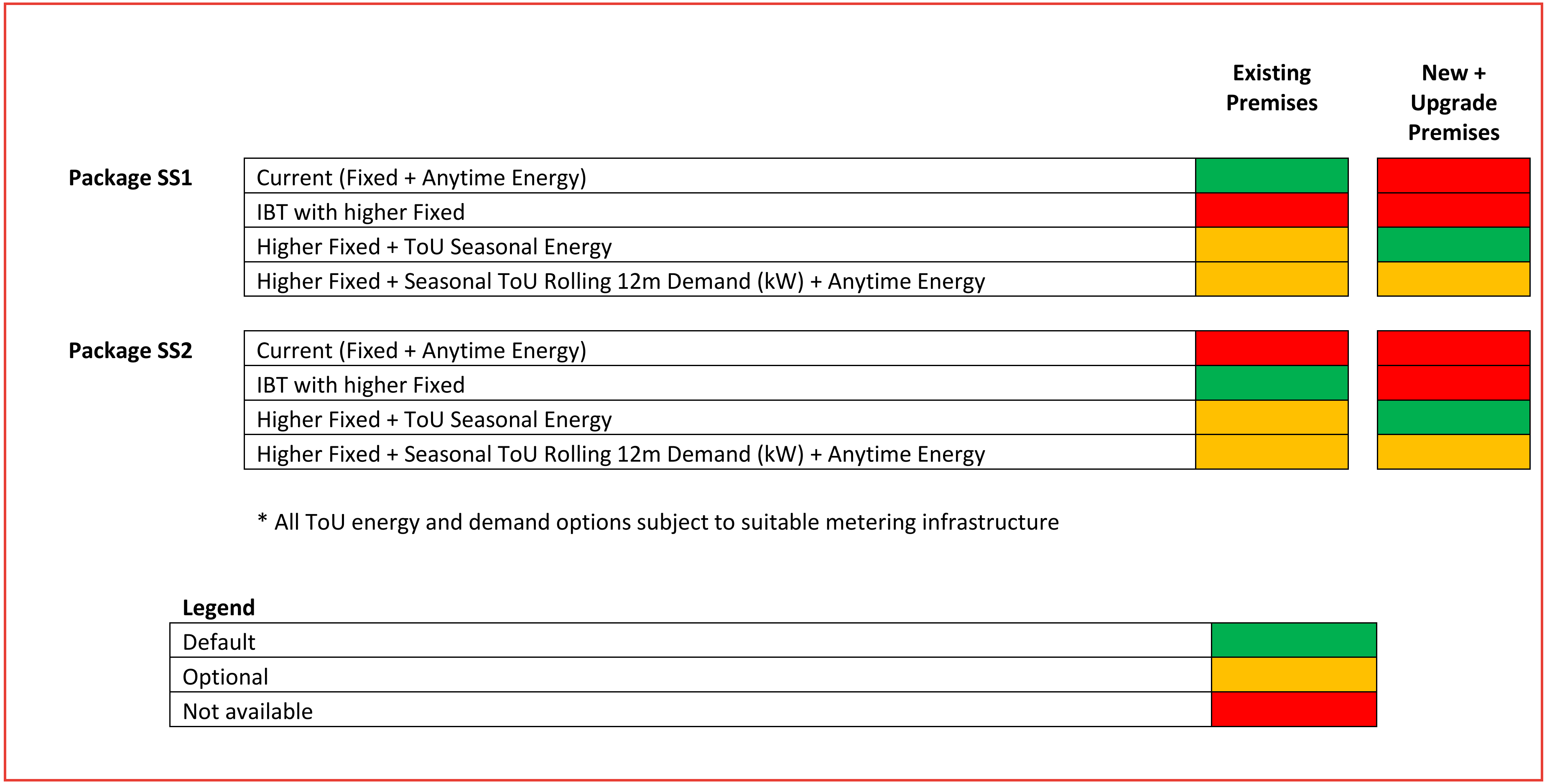
** kVA option subject to compliant power factor

Legend

Default	
Optional	
Not available	

Appendix A – Summary of proposed tariff structures

Figure 12: SAC small 2015/16



Appendix A – Summary of proposed tariff structures

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FRONTIER ECONOMICS | MELBOURNE | SYDNEY
Frontier Economics Pty Ltd 395 Collins Street Melbourne Victoria 3000
Tel: +61 (0)3 9620 4488 Fax: +61 (0)3 9620 4499 www.frontier-economics.com
ACN: 087 553 124 ABN: 13 087 553 124