LRMC and network tariffs
A REPORT PREPARED FOR ERGON ENERGY

June 2016
# LRMC and network tariffs

## Executive summary

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Executive summary

Frontier Economics has prepared this report for Ergon Energy in response to a report and presentation by Sapere Research Group (Sapere) for the Queensland Cane Growers Organisation and Australian Cane Growers Council (CANEGROWERS).

The National Electricity Rules (NER) incorporate a set of distribution pricing principles and impose a number of obligations on DNSPs as to how they set tariffs. These requirements include, but are not limited to, the need for tariffs to be based on long-run marginal cost (LRMC).

The Sapere report contends that Ergon’s approach of imposing a charge based on a customer’s own maximum demand is inappropriate because a customer’s own maximum demand has no connection with the efficient allocation of network costs. We accept that not all of Ergon’s legacy tariffs are as cost-reflective as they could be. However, the distribution pricing principles refer to considerations other than the need for tariffs to be based on LRMC. The maintenance of Ergon’s purely maximum demand-based tariffs is a reflection of its attempt to appropriately balance the pricing principles.

The Sapere report goes on to make a number of criticisms of Ergon’s approach to deriving and applying LRMC.

The first criticism is that Ergon’s approach fails to reflect both the network cost of supply curve and (the) customer demand curve(s). However, without some elaboration or explanation of Sapere’s understanding of these terms, it is unclear what they are intended to mean and how they are relevant to the tariff-setting obligations in the NER. In any case, we also do not consider that customer demand profiles are relevant to the estimation of LRMC. The estimation of the LRMC of direct control services provided by a DNSP is a substantially different exercise to the approach often followed for the setting of regulated retail tariffs. This is because the methodology often used for estimating the LRMC of wholesale energy involved an optimisation process to identify the elements of the most efficient stand-alone power system to specifically serve that customer class over a year. By contrast, the LRMC of DNSPs’ direct control services focuses on the forward-looking cost of providing an additional unit of the service at times of peak network utilisation. The shape of the load profile of the relevant customer class will have only a modest – if any – influence on these costs because the cost of augmenting the network is not strongly influenced by customer demand outside of times of peak network utilisation. The numerical examples raised in the Sapere report to support the case for taking demand into account to estimate LRMC do not provide any assistance.

Second, the Sapere report raises concerns regarding the implications of Ergon’s approach to estimating LRMC for the efficient adoption of non-network options, including the existence or otherwise of cross-subsidies towards solar PV. For
several reasons, we do not think it would be appropriate for the estimation of LRMC to reflect the potential costs faced by DNSPs in serving ‘total demand’ (as defined by Sapere) via investment in non-network options:

- First, DNSPs generally do not have good quality information about the costs of non-network options.
- Second, any analysis of how a non-network option influences LRMC would need to be performed on a case-by-case basis and would only affect the estimation of LRMC at the location where the option was to be implemented.
- Third, even assuming DNSPs could obtain reliable information about non-network option costs across their networks, the likely consequence of having regard to these options in estimating LRMC would be to lower the estimate and ‘crowd out’ unregulated private investment in these options. The result would be that the only non-network options that proceeded would be those that were undertaken by DNSPs.

Therefore, we submit that it would be preferable for DNSPs’ LRMC estimates to reflect the cost of network options only.

Third, the Sapere report criticises Ergon’s decision to retain an inclining block tariff (IBT) for its small customers. However, in light of the prominence given to the application of LRMC to flat tariffs and IBTs by the AEMC’s own consultants, and the lack of any substantive discussion of IBTs in the Commission’s own Final Rule Determination, DNSPs should be entitled to presume that IBTs would be regarded as capable of conforming to the NER pricing principles.

Fourth, the Sapere report makes a case for the estimation of a DNSP’s LRMC to be derived from the Post Tax Revenue Model (PTRM) used by the AER for capping the DNSP’s regulated revenues. The Sapere report suggests that the large ‘residual’ that results from subtracting tariffs based on DNSPs’ estimates of LRMC from the PTRM’s ‘implicit’ LRMCs implies that DNSPs’ LRMCs are substantially understated. However, this would only be correct if:

- Distribution networks did not exhibit increasing returns to scale (ie economies of scale) and
- Distribution network investment was not only available in ‘lumpy’ increments.

Neither of these propositions hold. Accordingly, we do not think that anything untoward about Ergon’s LRMC estimates or their use in tariff design should be inferred due to the current size of the ‘residual’ between its overall regulated revenues and the revenue it expects to earn through its LRMC tariff components.

Finally, the Sapere report contends that the Ergon TSS exhibits “a fundamental failure to meet the [Network Pricing Objective]” in the NER. For the reasons provided in this report, we completely reject this proposition.
1 Introduction

1.1 Background

Frontier Economics has prepared this report for Ergon Energy in response to a report and presentation by Sapere Research Group (Sapere) for the Queensland Cane Growers Organisation and Australian Cane Growers Council (CANEGROWERS).

The Sapere material we have reviewed is:

- A report entitled, “Comments in response to Appendix 5, Questions for Stakeholder: AER Issues Paper Tariff Structure Statement Proposals, Queensland electricity distribution network service providers, March 2016” by Simon Orme and James Swansson and

- A presentation entitled, “Ergon 2015 tariff structure statement, Notes for CANEGROWERS’ meeting with AER, June 2016”.

The Sapere material was submitted by CANEGROWERS to the Australian Energy Regulator (AER) in response to the AER’s Issues Paper on Ergon’s Tariff Structure Statement (TSS).

1.2 Sapere’s key points

The key points made in the Sapere report are that the Ergon TSS:

1. Inappropriately bases network tariffs on an individual customer’s peak demand.

2. Does not apply the concept of long run marginal cost (LRMC) properly, including:
   a) By failing to incorporate customer demand curves, thereby misapplying the concept of LRMC
   b) By failing to take account of different customer load profiles on the calculation of LRMC, in accordance with industry practice and legal precedent
   c) By estimating LRMC differently to how it is determined in the context of retail tariff regulation in Queensland
   d) By substantially understating the incremental LRMC of network capacity, thereby deterring the adoption of more efficient non-network substitutes
   e) By omitting data on demand profiles to enable testing of the efficiency of proposed tariff structures – for example, inclining block tariffs (IBTs) cannot be reconciled with the LRMC principle
f) By not drawing a distinction between total electricity demand (which may be provided from both network and non-network sources) and operational demand (provided via the network)

g) By claiming that solar PV installation – rather than air conditioning use during heatwaves – was the major source of cross-subsidisation between customer tariff classes.

h) By producing tariffs that result in the need to recover a large residual of the regulated revenue generated through the AER’s Post-Tax Revenue Model (PTRM).

i) Accordingly, Sapere contends that the Ergon TSS does not satisfy the Network Pricing Objective (NPO) in the National Electricity Rules (NER).

3. Does not provide sufficient evidence to support:
   a) Ergon’s choice of charging windows
   b) Ergon’s decision to replace minimum chargeable demands with increased fixed charges
   c) Ergon’s choice of seasonal variations within tariff structures.

4. Does not provide sufficient information to assess customer impacts of proposed tariff structures, especially given the benign load profile of CANEGROWERS.

The Sapere report also comments on the AER’s Issues Paper on the Ergon TSS.

Our report focuses on the first two major points above (1) and (2): the role of individual customer demands and Ergon’s approach to determining and applying LRMC.

1.3 Structure of this report

This report seeks to respond to and address the issues raised by Sapere in relation to individual customer demands and Ergon’s determination and application of LRMC. To aid exposition, our responses are structured in the following manner:

- Section 2 explains why it is appropriate for Ergon’s network tariffs to be based to individual customer demands (Responding to Sapere’s point (1)).
- Section 3 explains why Ergon’s approach to estimating LRMC is not a misapplication but is appropriate and why Sapere’s suggested approach is inappropriate (Responding to Sapere’s points (2(a) and (b))).
- Section 4 discusses the implications of Ergon’s approach to estimating LRMC for non-network alternatives and inefficient cross-subsidies (Responding to Sapere’s points (2 (c), (d), (f) and (g)).
Section 5 outlines how IBTs can be reconciled with an LRMC pricing principle (Responding to Sapere’s point (2)(e)).

Section 6 responds to the suggestion that properly-determined LRMC tariff elements should not leave a significant ‘residual’ of Ergon’s regulated revenues to be recovered through other components of customer tariffs (Responding to Sapere’s point (2)(h)).

Section 7 responds to Sapere’s view that Ergon’s TSS reflects an overall failure to meet the Network Pricing Objective (Responding to Sapere’s point (2)(i)).
2 Role of individual customer demands

The Sapere report refers to the description of Ergon’s Standard Asset Customer (SAC) Large demand tariffs in its TSS and highlights the fact that these tariffs impose a charge based on a customer’s own maximum demand. Sapere contends that such a charging basis is inappropriate because a customer’s own maximum demand has no connection with the efficient allocation of network costs. The report goes as far as stating that:

1 In our opinion there is no basis under the rules for the adoption of a ‘demand tariff’ defined in terms of a customer’s own maximum demand.

We accept that not all of Ergon’s legacy tariffs are as cost-reflective as they could be, as compared to how they might be designed if commencing from a ‘blank slate’. However, the distribution pricing principles in the NER refer to considerations other than the need for tariffs to be based on LRMC, including the impact on retail customers due to tariff changes. The maintenance of Ergon’s purely maximum demand-based SAC tariffs is a reflection of its attempt to appropriately balance the pricing principles.

That said, we note that Ergon’s Seasonal Time of Use Demand (STOUD) tariff available to both SAC Large and SAC Small tariffs – which are intended to provide stronger LRMC signals than its standard anytime demand and energy tariffs – also charge to some extent on the basis of individual customers’ demands. For example, the SAC Small STOUD tariffs impose a peak demand charge on an individual customer’s four highest average demand days in a summer month, where average demand is measured across a peak daytime period.

The rationale for the STOUD tariffs stems from the fact that the timing of a DNSP’s actual annual network utilisation peak is unknown in advance. If Ergon could perfectly predict its annual peak network utilisation, it could in theory set its tariffs equal to LRMC for that period and keep them low across all other periods. In reality, such precise forecasting is not possible. However, although the precise hour or hours of Ergon’s annual peak utilisation within an entire summer season cannot be predicted at the time its tariffs are set, it is known that the peak is likely to occur within a comparatively narrow specified demand window which will have seasonal, time of day and day of week dimensions. Our understanding is that

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1 Sapere report, p.2.
2 NER clause 6.78.5(h).
3 See Ergon TSS, pp.22-23 and 26-27.
4 Assuming that customers did not respond to the LRMC price in the peak period by reducing or shifting their demand to the extent that the timing of the annual network peak changed.
5 For example, summer working weekday afternoons.
within that ‘peak window’, an individual customer’s maximum demand can convey useful real-time information about the occurrence of the annual peak within the broader peak period. This is because, on average, individual customer maximum demands are likely to be higher on days when Ergon’s network is operating at levels closer to its annual maximum utilisation.

Therefore, there is a reasoned logic to imposing LRMC-based tariff elements on individual customers’ maximum average demands to some extent, because this could be more effective in signalling the long run cost implications of utilising the network at peak times than relying solely on pre-determined windows to impose a highly-averaged LRMC signal.
Interpretation and application of LRMC

3.1 NER pricing principles

Clause 6.18.5(f) of the NER sets out the requirements relating to LRMC applicable network tariffs. Clause 6.18.5(f) is reproduced in Box 1 below.

Box 1: Clause 6.18.5(f) NER

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

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

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

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

Long run marginal cost is defined in chapter 10 of the NER as:

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

It is worth unpacking each of these provisions.

The definition of LRMC in chapter 10 of the NER focusses on how the total cost of supplying direct control services changes, in the long run, when demand for those services changes. If, for example, total cost increases by $100 when demand increases by one kVA, then LRMC is $100/kVA. The ‘long run’ in economics refers to a timeframe in which, as stipulated in the definition, all inputs required to provide the commodity can be varied.

Additionally, clause 6.18.5(f)(2) makes clear that the methodology for estimating LRMC must focus on the additional cost of serving the relevant class of retail customers at times of greatest utilisation on the relevant part of the network serving those customers. This wording appears to be in recognition of the fact that due to

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6 Assuming both changes in costs and demand are stated in present value terms.
the high fixed and sunk costs incurred to provide direct control services, and the discontinuous or ‘lumpy’ nature of such costs, the additional costs of providing direct control services is extremely low when network utilisation is below its maximum.

Other elements of clause 6.18.5(f) refer to:

- Whether it is worthwhile to adopt a more or less refined approach to basing tariffs on LRMC (part (1)) and
- The appropriate extent of locational differentiation of tariffs to reflect locational differences in LRMC (part (3)).

Apart from the obligation for tariffs to be ‘based on’ LRMC, network tariffs must also satisfy the other distribution pricing principles in clause 6.18.5, including the need to consider impacts on retail customers and for tariffs to be reasonably capable of being understood by retail customers.\(^7\)

### 3.2 Ergon’s approach to estimating LRMC

Ergon’s approach to estimating LRMC is consistent with the NER. It focuses on signalling the cost of meeting demand for network services at times of greatest utilisation of the network.

This involves answering the question:

> If demand for direct control services from customers connected at a given voltage level were to increase by one unit (e.g. 1 kVA) at the time of peak utilisation on the network serving those customers, what would be the impact on Ergon’s total costs?

Like all the DNSPs in the NEM, Ergon has estimated its initial LRMCs using the Average Incremental Cost (AIC) methodology.\(^8\) The AIC methodology was discussed by the AEMC in its Final Rule Determination on the distribution network pricing arrangements. It was described as follows:\(^9\)

\[
\text{[AIC]} \text{ estimates LRMC by identifying the stream of capital, operations and maintenance expenditure needed to satisfy projected demand growth, typically over 10 years, and then dividing this by projected demand growth. It then calculates the present value of the expenditure required and divides this by the present value of incremental demand growth to estimate the LRMC.}
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\(^7\) NER clauses 6.18.5(h) and (i), respectively.  
\(^9\) Final Rule Determination, pp.122.
More succinctly:¹⁰

…the AIC methodology calculates the average of expected capacity related expenditure over a defined period to meet load growth and uses that average to calculate network prices for consumers.²¹⁷

[Footnote] 217. In practice, DNSPs assess their future investment requirements based on average maximum demand over those periods of the year when the network is reaching its capacity limits.

The Commission considered that AIC was one of several acceptable methodologies for estimating LRMC and there was merit in providing flexibility to DNSPs as to the choice of methodology.¹¹

Details of how Ergon implemented the AIC methodology are set out in the report prepared by Dr Harry Colebourn entitled, *Estimating the Average Incremental Cost of Ergon Energy's Distribution Network*, dated March 2015 (the Colebourn report). This document demonstrates that while a number of judgements need to be made in implementing AIC – as with any pricing methodology – Ergon has sought to be as transparent as possible in estimating AIC LRMC values in accordance with the description provided in the AEMC’s Final Rule Determination.

### 3.3 Sapere’s proposed approach to LRMC

#### 3.3.1 Relevance of customer demand

The Sapere report contends that the definition of LRMC in the NER implies that both:

- the network cost of supply curve for all of the network’s demand and
- the demand curve for the particular tariff class or retail customer in question, are relevant to the setting of tariff structures.

This is because:¹²

…both elements are necessary to determine the point at which the supply and demand curves intersect, with respect to the particular retail customer in question.

Further:¹³

…at the point where the two curves intersect, demand related LRMC relates to the average LRMC under the supply curve at this point. Because of the slope of the supply

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¹⁰ Final Rule Determination, pp.126.
¹¹ Final Rule Determination, pp.118, 129.
¹² Sapere report, p.2.
¹³ Sapere report, p.2.
curve, average LRMC under this area will be influenced by, but less than, the incremental LRMC at the point where the two curves intersect.

And: \(^{14}\)

…the [Ergon TSS] confuses the incremental supply LRMC with the average LRMC of demand. Against a single supply LRMC, there should be multiple average LRMC values, depending on differences in demand profiles between tariff classes, as explained below.

Although LRMC estimation methodologies and labels vary, we are not aware of any specifically ‘demand-side’ or ‘supply-side’ approaches to estimating LRMC. We are also unfamiliar with Sapere’s concepts of ‘incremental supply LRMC’ and ‘average LRMC of demand’. \(^{15}\) In fact, the Sapere report appears to contradict itself in the way it applies these terms to Ergon’s TSS. On the one hand, the ‘Summary’ of the Sapere report says that the Ergon TSS: \(^{16}\)

Does not apply the concept of Long Run Marginal Cost (LRMC) as set out in the pricing principles, which relate to the LRMC of an incremental change in demand for direct control services. **It appears instead to define LRMC only at the point where the supply and demand curves are assumed to intersect.** [Emphasis added]

Later, on page 6, the Sapere report comments that:

In addition, the ETSS LRMC estimate refers to the network capacity cost as if it were near the bottom of the supply curve ($471/kVA), **rather than at or around the point where the supply curve intersects with the demand curve** (perhaps $23,550/kVA). [Emphasis added]

It is unclear whether Sapere believes that the LRMC in Ergon’s TSS is (wrongly) defined at the point where the demand and supply curves intersect or at some other point. Without some elaboration or explanation of Sapere’s understanding of these terms, it is unclear what they are intended to mean and how they are relevant to the tariff-setting obligations in clause 6.18.5 of the NER.

We also do not consider that customer demand profiles are relevant to the estimation of LRMC for direct control services. In this respect, the estimation of the LRMC of direct control services provided by a DNSP is a substantially different exercise to the approach often followed for the setting of regulated retail tariffs (see below).

Finally, we note that Ergon’s estimates of LRMC are presently the highest of all DNSPs in the NEM (see Table 1 below). This suggests that the Sapere report is effectively saying that all DNSPs in the NEM have a flawed interpretation of LRMC under the NER.

\(^{14}\) Sapere report, p.2.

\(^{15}\) See Sapere report, p.3.

\(^{16}\) Sapere report, p.1.
### Table 1: NEM DNSPs’ LRMC Low Voltage (LV) estimates

<table>
<thead>
<tr>
<th>DNSP</th>
<th>LRMC range</th>
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<tr>
<td>Energex</td>
<td>$130/kW per annum</td>
</tr>
<tr>
<td>AusGrid</td>
<td>$164/kW per annum</td>
</tr>
<tr>
<td>Essential Energy</td>
<td>$150/kVA per annum</td>
</tr>
<tr>
<td>Endeavour Energy</td>
<td>$133/kVA per annum</td>
</tr>
<tr>
<td>AusNet Services</td>
<td>$89/kVA per annum</td>
</tr>
<tr>
<td>CitiPower</td>
<td>$94-110/kVA per annum</td>
</tr>
<tr>
<td>Jemena Electricity Networks</td>
<td>$94-120/kW per annum</td>
</tr>
<tr>
<td>Powercor</td>
<td>$97-113/kVA per annum</td>
</tr>
<tr>
<td>United Energy</td>
<td>$124/kVA per annum</td>
</tr>
<tr>
<td>SA Power Networks</td>
<td>$119-124/kVA per annum</td>
</tr>
<tr>
<td>TasNetworks</td>
<td>$90-165/kW per annum</td>
</tr>
</tbody>
</table>

Source: DNSP TSSs, various.

### 3.3.2 Relevance of approach to retail tariff-setting

In support of its position on the relevance of customer demand profiles to DNSPs’ LRMC estimates, the Sapere report refers to the process for setting regulated retail tariffs in Queensland. This process yields different estimates of the wholesale energy purchase cost of supplying electricity to different retail customer classes, based on the average load profile of customers in those classes. Sapere comments:

> Faced with identical wholesale prices for every trading interval, the retail methodology yields substantial variations in LRMC depending on the demand profile of the tariff class in question.

> The approach applied to retail pricing is equally applicable in the context of efficient network pricing and indeed is mandated by the pricing principles read in combination with the definition of LRMC.

However, we note that the current Queensland Competition Authority (QCA) approach to setting regulated retail tariffs is based entirely on the wholesale energy purchase costs of serving regulated customers and has *nothing to do with estimating the LRMC* of the energy used to supply those customers. Further, the approach that was formerly used (under the BRIC methodology) to estimate the LRMC of

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17 Sapere report, pp.3-4.
wholesale energy for Queensland retail tariffs considered the load profile of all Queensland customers, rather than the profile of regulated customers.

Prior to the uncapping of retail prices in New South Wales, regulator IPART had consistently utilised an LRMC approach to estimating the wholesale cost of energy component. The methodology it used for estimating the LRMC of wholesale energy involved an optimisation process to identify the elements of the most efficient stand-alone power system to specifically serve that customer class over a year. The need for such an optimisation arises because different plant types embody different combinations of fixed and variable costs. ‘Baseload’ plant, such as super-critical black coal generators, tend to have high fixed costs but low variable costs. This makes them the most efficient type of plant to operate for large proportions of the time. ‘Mid-merit’ plant, such as combined-cycle gas turbines, have lower fixed costs, but higher variable costs, which make them the most efficient plant type to run for moderate proportions of the time. ‘Peaking plant’, such as open-cycle gas turbines, have low fixed cost and high variable costs, which make them the most efficient plant to run for short proportions of the time.

These cost characteristics mean that efficient plant mixes for serving different customer load profiles will vary. For example, a power system optimally designed to supply industrial customers with flat loads would be largely comprised of baseload coal-fired plant, which would operate on a continuous basis. Conversely, a power system designed to supply residential customers engaged in intensive use of air conditioners on hot summer days and electrical heaters on winter evenings would require a mix of baseload, mid-merit and peaking generators. The baseload coal generators would operate most of the time; the mid-merit CCGTs would not run overnight but would run on most days/evenings; and the peaking OCGT plant would only run on hot summer days and the coldest winter nights. Accordingly, the long-run costs of efficient power systems comprising such different mixes of plant to suit different load profiles would vary significantly.

By contrast, the LRMC of DNSPs’ direct control services focuses on the forward-looking cost of providing an additional unit of the service at times of peak network utilisation. The shape of the load profile of the relevant customer class will have only a modest – if any – influence on these costs because the cost of augmenting the network is not strongly influenced by customer demand outside of times of peak network utilisation. For example, if network utilisation peaks on summer weekday afternoons, LRMC should be determined by reference to the cost of serving an increment of demand at those times. Whether customer demand at other times – such as weekends or autumn and spring days – is 80% of summer weekday afternoon demand or 20% has little bearing on the need for and level of network costs required to serve the increment to summer weekday afternoon demand. This is because unlike the case with the optimisation of wholesale energy provision for retail tariff-setting, there is no comparable baseload/mid-merit/peaking plant type of trade-off with network augmentation costs. For
example, the development of a distribution line of a given voltage and length designed to convey a given amount of power (in MW) will impose a certain cost, and this cost will not be significantly higher or lower if the line is utilised 1% of the time or 99% of the time.

Furthermore, the numerical examples raised in the Sapere report to support the case for taking demand into account to estimate LRMC do not provide any assistance.

The first issue with the examples is lack of clarity around what the cost figures are meant to represent. The report highlights a case where an “average cost of each unit of network capacity is $1m”. However, it is not clear if that is an annualised cost or a simple one-off cost and whether it is a cost per MW or per kW. The Sapere report later refers to a figure of $471/kVA per annum from the Colebourn report. This is derived from a value of approximately $451,000 per MW per annum. This reference to the Colebourn report suggests that the example used by Sapere is intended to refer to an annualised cost per MW – even though the value of $1 million per annum is more than double the Colebourn figure. However, at the same time, the conversion of this figure into a “unit cost per annum” of $114.16 by dividing $1 million by 8760 hours would seem to indicate that the figures are meant to refer to a cost per kW.

The second issue with the examples is that they do not allow any useful inferences to be drawn. Assuming that the Sapere example refers to an annualised cost per MW, this equates to an approximate cost of $1,000/kW per annum. If this is indeed the annualised cost of serving a one kW increment of demand at times of greatest network utilisation, then it is a cost that ought to be signalled to, and recovered from, customers in respect of their kW load at peak times. Assuming a LV customer has an average demand of 2 kW at network peak times, its LRMC-based charge would be $2,000 for that year. This would, under Ergon’s STOUD tariff, be recovered over the summer months. However, this would be the case regardless of whether the network capacity used to serve that customer’s demand was utilised for 40% of the year, 2% of the year or 0.1% of the year.

It may be that with a demand-based charge, the average effective charge per kWh consumed during those peak times would be higher to customers with a relatively ‘peaky’ load profile compared to those with a relatively ‘flat’ load profile. But this is not relevant to either the estimation of a DNSP’s LRMC or its network charge on a per kW or kVA basis. Therefore, the notion put forward in the Sapere report that Ergon’s estimated LV LRMC of $471/kVA per annum could translate into an

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18 Sapere report, p.5.
19 Sapere report, p.6.
21 Page 6.
LRMC of $23,550/kVA per annum or $470,000/kVA per annum depending on the load profile of Ergon’s customers is simply incorrect.
4 Implications for non-network alternatives and cross-subsidies

Subsequent passages in the Sapere report raise concerns regarding the implications of Ergon’s approach to estimating LRMC for the efficient adoption of non-network options, including the existence or otherwise of cross-subsidies towards solar PV.

4.1 Non-network alternatives and ‘operational demand’

As a result of the claimed deficiencies in Ergon’s approach to estimating LRMC, page six of the Sapere report contends that Ergon has substantially understated the ‘incremental LRMC’ of network capacity. Sapere suggests that not only is this inconsistent with the distribution pricing principles in the NER, but that it would have adverse efficiency implications. This is because an understated LRMC would result in artificially low utilisation-related tariffs that would undercut and deter the efficient adoption of lower-cost non-network alternatives:

The ETSS gives rise to the false and misleading notion that incremental network capacity may be far lower cost compared with substitutes than it would be if the incremental LRMC were calculated with reference to demand (utilisation factor). If the current ETSS proposals were implemented, lower cost non-network supply options are likely to be substituted by higher cost network supply options.

Subsequently, Sapere makes the point slightly differently, by criticising the Ergon TSS for not differentiating between ‘operational demand’, which is demand served by Ergon’s network, and the ‘total demand’ for energy (including energy that is self-supplied via customers’ own sources – such as solar PV). By not taking account of the ability of DNSPs to now meet total demand through investments behind customers’ meters where this is efficient, Sapere contends that Ergon’s approach to applying LRMC to tariff-setting was flawed, because “non-network solutions may be more efficient than network solutions”. We note that these two points work in opposite directions. Sapere’s first point is that Ergon’s approach to estimating LRMC substantially understates the true LRMC of providing direct control services by failing to somehow account for customer demand profiles. The second point is that Ergon’s approach to estimating LRMC overstates true LRMC by failing to reflect the scope for non-network options to efficiently substitute for augmentation.

22 Sapere report, p.6.
23 Sapere report, pp.7-8.
Section 3.3.2 above explained why we do not think that Sapere’s comments on the relevance of customer load profiles to the estimation of LRMC are valid.

On the second point, there are several reasons why we do not think it would be appropriate for the estimation of LRMC to reflect the potential costs faced by DNSPs in serving ‘total demand’ (as defined by Sapere) via investment in non-network options. These are:

- First, DNSPs generally do not have good quality information about the costs of non-network options. Even DNSPs’ estimates of future network augmentation costs reflect a degree of uncertainty; DNSPs would be in a much weaker position to assess the integrity of potential non-network costs.

- Second, any analysis of how a non-network option influences LRMC would need to be performed on a case-by-case basis and would only affect the estimation of LRMC at the location where the option was to be implemented. Ergon, like other DNSPs in the NEM, has derived its initial AIC estimates of LRMC across broad areas of its network, using the data it has available from its regulatory proposals.

- Third, even assuming DNSPs could obtain reliable information about non-network option costs across their networks, the likely consequence of having regard to these options in estimating LRMC would be to lower the estimate and ‘crowd out’ unregulated private investment in these options. After all, if network tariffs reflect the ability of DNSPs to invest in non-network options, on what basis could non-DNSP proponents compete for investment? The result would be that the only non-network options that proceeded would be those that were undertaken by DNSPs.

We submit that it would be preferable for DNSPs’ LRMC estimates to reflect the cost of network options only. If non-network proponents did not subsequently come forward, that could reflect the fact that the costs of non-network options were more expensive than network options. To make sure efficient non-network options are not overlooked, DNSPs have been obliged since 2013 to undertake a cost-benefit analysis (via the Regulatory Investment Test for Distribution, RIT-D) prior to committing to a significant network augmentation (with a value greater than $5 million). Where a RIT-D assessment shows that a non-network option is preferable to network augmentation, the DNSP is not permitted to proceed with the network option. We submit that this provides a more sensible framework for efficient investment in both network and non-network options than including non-network costs in DNSPs’ LRMC estimates.

4.2 Cross-subsidies to solar PV

The Sapere report goes on to criticise Ergon’s statements in its TSS that its proposed tariff reforms are seeking in part to address distortionary cross-subsidies between different network users inherent in legacy tariffs. In particular, the Sapere
Implications for non-network alternatives and cross-subsidies

The Sapere report criticises the reference to solar PV in the context of cross-subsidies. The most prominent reference to solar PV and cross-subsidies in the TSS is as follows:

"The other important consideration in our approach has been the need to create value in the network for those seeking to adopt new and emerging energy-related technologies. Our reforms allow these innovations to be accommodated where it makes sense, and deliver real value to those investing in their own solutions, like solar and battery storage combinations, without being cross subsidised by other network users. Our approach also supports technologies, like electric vehicles, that could significantly boost the utilisation of the network, which helps reduce the unit cost of supplying electricity for all."

The Sapere report opines that:

"The Productivity Commission in its 2012 analysis makes it clear that air conditioning usage patterns were at that stage the major driver of cross subsidies and inefficient pricing of around $350 per year per customer across the NEM. Similarly, a report prepared for the 2015 National Energy Security Assessment found that air conditioner use during extreme heatwaves was a major driver of changing electricity costs. No evidence presented in the ETSS leads to the conclusion that the recent high uptake of solar PV has fundamentally changed the major source of cross subsidisation within tariff classes, and inefficiency of existing network tariff structures. There is therefore no basis for the conclusion that the ETSS tariff design proposals would reduce inefficient cross subsidies."

We note that any tariff reforms that improve cost-reflectivity should reduce cross-subsidies, irrespective of which customer class or technology presently benefits from those cross-subsidies. Economically efficient tariff reform is agnostic towards impacts on customer classes and technologies. For the reasons provided above, we consider that implementation of network tariffs based on Ergon’s LRMCs should help drive more efficient decisions regarding both air-conditioning and solar PV, as well as battery storage, electric vehicles and other new technologies.

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24 Ergon TSS, p.11.
IBTs and LRMC

As part of its critique of Ergon’s lack of regard to demand profiles in estimating LRMC, the Sapere report criticised Ergon’s decision to retain an inclining block tariff (IBT) for its SAC Small customers. The report said:

..numerous independent studies of interval data in Australia have shown there is no connection between individual customer load profiles and annual consumption volume. Ergon’s proposed IBTs cannot be reconciled with the LRMC principle.

As noted above, not all of Ergon’s network tariffs are as cost-reflective as they could be due to the need to balance the full range of the pricing principles. That said, the AEMC’s consultants, NERA, devoted considerable attention to the methodology for applying an AIC estimate of LRMC to customers:

...where metering technology means that the only tariffs available for the tariff class are flat, inclining or declining block usage tariffs ($/kWh) and fixed charges ($/customer/annum)

The NERA report went so far as to provide examples of how LRMC should be used to set the minimum tariff for flat tariffs and IBTs – see Figure 1.

Figure 1: NERA’s application of LRMC to setting minimum flat tariffs and IBTs

5.6. **Step 5: Develop network tariffs that promote efficient future network investment**

The next step involves converting the information on costs caused by consumers within the tariff class to network tariffs. In practice, because of the need to recover the total costs of existing network infrastructure, the tariffs developed at this step should be considered as a minimum. Additional charges can be added to these minimums so as to allow the total cost of existing infrastructure to be recouped.

The approach to estimating the minimum tariffs differs for usage tariffs depending on whether the tariff is a flat, inclining or declining block tariff, peak tariff, critical peak tariff or capacity based tariff.

For flat, inclining or declining block tariff, the minimum tariff (for the flat and for each block of the inclining or declining block tariff) can be calculated as follows:

\[
\text{Minimum Flat, Block Tariff ($/kWh)} = \text{Max}\left[ \frac{LRMC_{of} \cdot kVA}{8,760 \times \text{Average Power Factor} }, \frac{\text{Avoided Cost if No Usage}}{\text{Total Electricity Use}} \right]
\]

Source: NERA report, p.25.

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26 Sapere report, p.7.

In light of the prominence given to the application of LRMC to flat tariffs and IBTs by the AEMC’s own consultants, and the lack of any substantive discussion of IBTs in the Commission’s own Final Rule Determination, DNSPs should be entitled to presume that IBTs would be regarded as capable of conforming to the NER pricing principles. The notion that IBTs are *ipso facto* incapable of sufficiently reflecting the pricing principles to remain NER-compliant for at least a transitional period has no basis in the AEMC’s published documents.
6 Residual regulated revenues

The Sapere report makes a case for the estimation of a DNSP’s LRMC to be derived from “the aggregate LRMC implicit in the Post Tax Revenue Model (PTRM)” used by the AER for capping the DNSP’s regulated revenues.

The Sapere report suggests that differences between the PTRM’s ‘implicit’ LRMC and tariffs based on a DNSP’s ‘efficient’ LRMC may arise as there is now no scope under the PTRM regulatory process for network-wide optimisations or ex post write-downs in response to reductions in mandated reliability standards. Sapere then comments that:

> However, the residual should represent a very small part of the network cost, because the bulk of this cost is covered by LRMC, as properly estimated consistent with the rules.

By contrast, the ETSS and supporting material suggest that the residual is a substantial portion of the efficient cost determined under the PTRM – essentially corresponding to existing or sunk network cost below the point where the supply and demand curves intersect. This is a further indicator that the concept of LRMC has been misunderstood and misapplied.

If we understand Sapere correctly, they are suggesting that in equilibrium, tariffs based on the true LRMC of a DNSP should recover the bulk of that DNSP’s regulated revenues as generated under the PTRM. By implication, Sapere thinks that Ergon’s (and other DNSPs’) LRMCs are significantly understated. However, this would only be correct if:

- Distribution networks did not exhibit increasing returns to scale (ie economies of scale) and
- Distribution network investment was not only available in ‘lumpy’ increments.

Neither of these propositions hold. The first proposition – that distribution networks do not exhibit strong economies of scale – contradicts an important stylised and empirically-verified fact about electricity networks. Regarding the second position, most commentators accept that in light of the recent consistent declines in peak demand forecasts, most DNSPs’ networks on average have relatively high levels of spare capacity.

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28 Sapere report, p.8.
29 Sapere report, p.9.
The AEMC commented on this latter point in its Final Rule Determination:30

Magnitude of residual costs

Step six of Figure A3.1 highlights that the magnitude of residual costs is dependent on total efficient network costs, the LRMC of providing network services and forecasts of all tariff components. In particular, differences in LRMC result in large fluctuations in the magnitude of residual cost because LRMC varies significantly depending on demand conditions. For example, when peak demand is generally rising, the LRMC of providing network services is likely to be high, and as a result residual costs will be low. However, when peak demand is flat or falling, as it is in many networks currently, the LRMC of providing network services will likely be low, resulting in residual costs making up the majority of total efficient cost recovery.

Accordingly, we do not think that anything untoward about Ergon’s LRMC estimates or their use in tariff design should be inferred due to the current size of the ‘residual’ between its overall regulated revenues and the revenue it expects to earn through its LRMC tariff components.

30 AEMC Final Rule Determination, p.148.
7 Overall conformance to the NPO

The Sapere report contends that the Ergon TSS exhibits “a fundamental failure to meet the NPO”.

The report states:

"Given the fundamental issues identified with the ETSS above, in our view the ETSS proposals do not conform to the NPO and the pricing principles. Under these conditions, if the AER agrees, we understand the AER has the ability to reject the ETSS proposals and request that the ETSS is resubmitted."

For the reasons provided in this report, we completely reject this proposition. As discussed throughout, Ergon’s TSS and proposed tariff structures need to reflect the full range of the pricing principles in clause 6.18.5 of the NER. A number of the principles moderate the need for tariffs to be based on LRMC. In any case, we consider that Sapere’s conception of LRMC as it appears in its report is confusing and offers no useful guidance for Ergon, other DNSPs in the NEM or the AER as to how network tariffs should be reformed going forward.

31 Sapere report, p.9.
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