CANEGROWERS-Sapere Electricity Report

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Australian energy regulator endorses inefficient electricity network prices for regional Queensland

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In a report commissioned by CANEGROWERS, with Dr James Swansson, we have found the Australian Energy Regulator is on a course to approve flawed Ergon Energy network tariffs that penalise customers using a lot of power over the summer. This is for the poles and wires, which is about half the retail bills seen by consumers.

In an October decision, the Regulator said Ergon had justified its summer seasonal network peak and inclining block tariffs. The final pricing decision by the Regulator is due early in 2017.

The new Tariff Statements by Ergon and other networks are part of national network pricing reform. The reform aim is to reduce network congestion. This is sensible and we strongly support congestion pricing where congestion is an actual thing.

Congestion drives additional investment to augment network capacity. By signalling the future cost of augmentation in current prices, consumers can be encouraged to reduce congestion. This should mean future network investment could be reduced or avoided, and future bills would be lower than otherwise.

System-wide, maximum demand is driven by extreme temperatures. Cane grower irrigation demand does not drive or correspond to peak network demand.

An efficient tariff design should yield lower current prices (or bills) for consumers that do not drive future network costs and higher current prices for consumers that do drive future network costs. Ergon's proposed tariffs fail this basic test. Our report is not defending free riding by a specific group of consumers.

Ergon's tariffs could mean unexpected large bills after the summer for some customers, regardless of whether they opt in to seasonal peak tariffs.

The default inclining block tariff is also flawed and can also mean large bills after the summer or following any billing period when a customer's demand is higher than its average demand. If there were cost savings from these tariffs, this would be OK. Without any cost savings, this is not OK.

Ergon's network tariffs may reduce peak demand during summer. But there would be no reduction in future network investment and no reduction in future network bills.

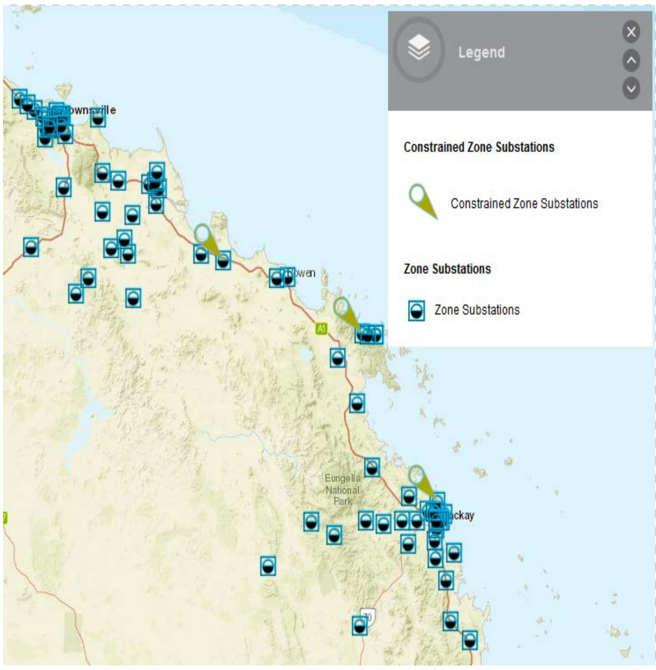
While the principles of Ergon's proposed cost-reflective tariff structures are reasonable, the analysis underpinning their implementation is flawed.

The fundamental source of the error is a failure on the part of both Ergon and the Energy Regulator to distinguish between marginal and infra-marginal network capacity, because existing spare capacity is ignored.

Marginal network capacity for price setting purposes may be defined as that part of capacity where even small increases in maximum demand can trigger a requirement for future capacity augmentation to maintain firm supply. Infra-marginal network capacity is everything up to the last unit of demand that is met by current capacity.

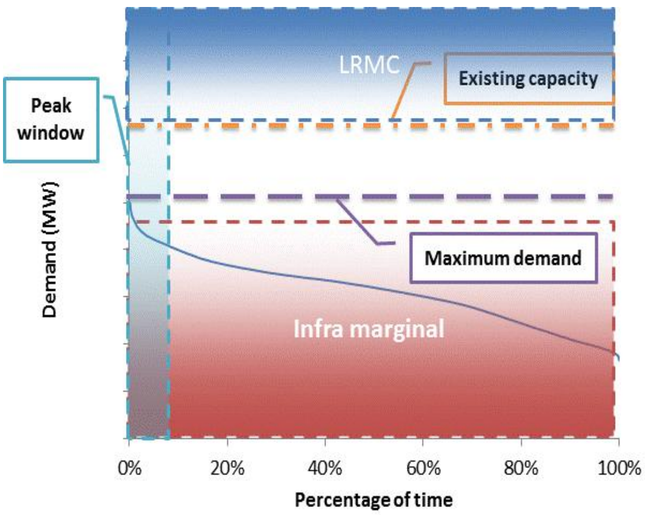
Ergon's Tariff Statement erroneously uses a definition of marginal network capacity, so far unchallenged by the Regulator, of 95 per cent of maximum annual demand at each of Ergon's zone substations (ZS).

While peak demand growth has slowed since the Global Financial Crisis, until recently Ergon and other networks kept investing in new network capacity, creating spare capacity.



Ergon's own 2016 Distribution Annual Planning Report shows that all but two per cent of the zone substations have enough spare firm capacity (allowing for one asset failure) to meet forecast peak demand growth for the foreseeable future.

Ergon's definition over-states marginal network capacity. This is because forecast peak demand growth would not in fact trigger augmentation, while any reduction in demand (driven by peak prices) would not avoid the cost of existing capacity.



This graph contrasts the peak charging window with maximum demand and existing firm capacity.

The Energy Regulator's draft decision ignores spare capacity and approves charging for non-existent future network investment. The Energy Regulator is signalling it will approve seasonal peak prices for the whole low voltage network and for periods where there is ample spare network capacity.

Distorted higher prices for infra-marginal demand have consequences. Some customers unfairly pay penalty prices far more than the cost of the network service they are getting – for example above average users of electricity such as larger families or more energy intensive businesses. Meanwhile other customers pay less than their share of network costs. Consumers can be expected to try and avoid higher prices by reducing actual demand or by-passing networks– where they have the resources.

This is not only unfair; it also makes the network pricing problem worse. Reducing infra-marginal demand means higher future tariff rates to cover fixed network costs. While wealthier consumers have the resources to bypass the network, consumers with fewer options will be picking up the bill. Overall, energy productivity will be reduced because network asset utilisation will be reduced.

Ergon's method for estimating congestion converts its spatial congestion error into a temporal congestion error – charging windows that do not target congestion. The two errors combined overstate the congestion problem by a factor of approximately 375. By our estimate, the economic distortion in network prices, the extra cost paid by some customers, is of the order of $1.8 billion over the current five year price control period.

There is necessarily a significant margin for error, and indeed some inaccuracies, in our estimates. If the difference between our estimate and the estimates (on which the AER's provisional approval of the Ergon Tariff Statement depends) were small, this could represent uncertainty and the application of different expert judgment and perspectives. However, a difference by a factor of 375 clearly indicates that one estimation method is fundamentally wrong.

While our estimate is necessarily inaccurate, our estimate is based on an analytical framework including an economically defensible distinction between marginal and infra-marginal network capacity combined with Ergon's published data on the actual and forecast level of congestion across Ergon's network.

Ergon's tariff statement breaks the national electricity rules. Unless reversed in the final decision, the Energy Regulator would also break the rules for price setting.

The Energy Regulator's decision on regional Queensland does not seem to be a one-off. The same flawed approaches have also been applied to Energex and in other parts of the National Electricity Market. Extrapolated to the NEM, the size of the pricing distortion could be of the order of $12-24 billion over the current five year price control period.

Our report concludes there are solid grounds for reviewing the Energy Regulator's entire network tariff statement review process.

CANEGROWERS

Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement

Simon Orme, Dr. James Swansson

22 November 2016

About Sapere Research Group Limited

Sapere Research Group is one of the largest expert consulting firms in Australasia and a leader in provision of independent economic, forensic accounting and public policy services. Sapere provides independent expert testimony, strategic advisory services, data analytics and other advice to Australasia's private sector corporate clients, major law firms, government agencies, and regulatory bodies.

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In an August 2016 Draft Decision[1] on Ergon Energy's Tariff Structure Statement (ETSS), the Australian Energy Regulator (AER), gave provisional approval to an electricity network tariff structure proposed by Ergon that is not cost reflective and inconsistent with Section 16.8 of the National Electricity Rules (NER), as amended by the Australian Energy Market Commission in 2014. The AER appears to be on course, in its Final Determination due in early 2017, to approve the ETSS, despite the ETSS not being cost reflective, and hence inconsistent with the NER network pricing objective and pricing principles.

In its Draft Decision, the AER reached a series of conclusions regarding Ergon's tariff proposals. Almost all of these conclusions contradicted by publicly available evidence provided in Ergon's 2016 Distribution Annual Planning Report (DAPR). Applying network congestion data available in the DAPR, it appears that network congestion in the Ergon network, upon which Ergon's tariff structure proposals depend, has been over-stated by two (2) orders of magnitude. It follows that the AER's overall finding that the ETSS contributes sufficiently to the achievement of compliance with the pricing rules (and exhibits movement along the cost reflectivity spectrum) is contradicted by reliable evidence from Ergon itself. Provisional approval of the ETSS should therefore be revoked in the AER's Final Decision.

In its assessment of other Tariff Statements, the AER appears to have applied approaches and methodologies similar to those applied in reviewing Ergon's Tariff statement. For example, reliance on misleading average daily profiles is evident in the AER's August 2016 Final Decision on Victorian Tariff Statements,[2] and also its August 2016 Draft Decision on NSW Tariff Statements. The evidence in this report demonstrates the shortcomings with these approaches and methodologies.

A further shortcoming is an apparent absence of seeking information necessary to enable cross checks of conclusions. These should include: reference to relevant load duration curve (LDC) data (not average daily profiles); an estimate of the implied value of congestion relative to total allowed revenue; and reference to broader indicators of the likely level of congestion, given recent growth in regulated asset base values alongside flat or even falling maximum demand across most parts of the National Electricity Market.

It is therefore possible that the AER's assessment of other Tariff Statements may also be in error. This suggests the AER should consider an internal assessment of the adequacy of the entire Tariff Statement review work stream, organisational capability and quality assurance.

[1] See *Draft Decision Tariff structure statement proposal Energex and Ergon Energy*, AER, August 2016 (henceforth AER DD).

[2] See extract from AER Final Decision in Section 3.7.1.

Introduction

This report has been prepared for CANEGROWERS on the AER's August 2016 Draft Decision to approve Ergon's Tariff Structure Statement (ETSS). In its Draft Decision, the AER found that:

> '*We consider Ergon Energy has sufficiently justified its cost reflective tariff peak charging windows. The charging windows target the broad network peaks for residential and business customers.*'[3]

Based on additional material provided by Ergon to CANEGROWERS and the AER on 2nd November, along with information from Ergon's 2016 DAPR, in this report we substantially revise and extend conclusions set out in our *Review of AER Draft Decision, Tariff Structure Statement proposals, Energex and Ergon, August 2016*, dated October 2016.[4]

In our October review, we expressed concern the AER's factual findings were not supported by evidence. We also noted there was insufficient transparency, in the ETSS evidence relied on by the AER, regarding the relationship between aggregate regulated revenues/prices, on the one hand, and the proposed tariff structure (rates and charging windows yielding the relative balance of long run marginal cost (LRMC) and residual tariff components), on the other.

Summary of updated assessment

In this updated assessment, we conclude that the basis for most of the AER's key findings on the ETSS, including the cost reflective tariff peak charging windows, is contradicted by reliable evidence from Ergon itself. Specifically, the AER's conclusion that the ETSS sufficiently justified cost reflective peak charging windows can now be demonstrated to be false. As a result, the ETSS is deficient relative to the requirements set out in Section 6.18 of the National Electricity Rules (the Rules). The AER should therefore reverse its provisional approval of the ETSS.

Table 1 below provides a summary of our assessment of the ETSS network congestion estimation on which proposed tariff structures, including the duration and definition of seasonal peak charging windows and tariff rates, are based. Our basic finding is that the Ergon TSS overstates the value of congestion to standard control services, and hence the corresponding required revenue, by approximately 375 times.

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[3] AER DD, p52.

[4] See Sapere report available at http://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20report%20-%20Review%20of%20AER%20draft%20decision%20Tariff%20Structure%20Statement%20proposals%2C%20Energex%20and%20Ergon%2C%20August%202016%20-%20October%202016.pdf

Table 1 Assessment of ETSS network congestion estimation

Issue	Ergon's Revised Tariff Statement	Our estimate	Difference
Extent of non-coincident local (spatial) congestion	252 Zone Substations (ZS)	5 ZS	63 times
Extent of temporal congestion (duration of peak charging windows)	650 hours or 7.4% of year	54.5 hours. or 0.62 per cent of the year	11.9 times
Additional capacity investment required	Not disclosed	N/A	N/A
Ratio of estimated value of congestion to total standard control revenue for tariff class	Circa 1 to 2 for residential, unknown for business	Circa 1 to 750	Circa 375 times
Indicative congestion revenue requirement relative to total smoothed revenue for 2015-16 to 2019-20*	$1,849.5 million*	$4.9 million	Circa 375 times

Source: Sapere analysis of Ergon, Energeia and Frontier data

*The values in the bottom line of the Table above are intended to illustrate the indicative dollar impact of the 375 times error, only, and do not purpose to be an accurate estimate of the value of congestion implied by the ETSS. The dollar values are based on the assumption low voltage business and commercial customer revenues represent half of total AER allowed smoothed revenues to mid-2020.

Basis for assessment

The fundamental source of the error is a failure on the part of both Ergon and the AER to distinguish correctly between marginal and infra-marginal network capacity. Marginal network capacity for price setting purposes may be defined as that part of network capacity where even small increases in future maximum demand can trigger a requirement for capacity augmentation to maintain firm supply. If this demand increase can be avoided, so can the requirement for augmentation and the long run marginal cost (LRMC) of augmentation.

In additional information provided to support the definition of charging windows in its Tariff Statement, it emerged the ETSS is based on defining marginal network capacity as equal to or greater than 95 per cent of maximum annual demand at each of Ergon's zone substations (ZS).[5] The AER has so far not challenged this definition. For any ZS where there is substantial excess firm capacity, after allowing for the loss of one transformer (N-1), this definition would over-state marginal network capacity. This is because any forecast growth in maximum demand would not trigger a requirement for augmentation. Similarly, any reduction or even a fall in maximum demand would not avoid any existing capacity cost.

According to Ergon's September 2016 DAPR, only five (less than two per cent) of the 252 ZS are subject to congestion within firm capacity (N-1). Ergon's own assessment is that the top 5 per cent of annual maximum demand, and any forecast increases in maximum demand over the duration of the DAPR to mid-2021, would not exceed the summer firm capacity of the other 98 per cent of ZS.[6]

The revised ETSS does not correspond to the significantly reduced congestion forecast in Ergon's 2016 DAPR. The ETSS estimate of ZS (spatial) congestion is 63 times higher than implied by the 2016 DAPR.

The use of peak demand rather than firm capacity to define congestion directly results in a substantial exaggeration of the duration of congestion. The proposed charging windows are equivalent to 650 hours (7.5 per cent of the year) for business and 587 hours (6.7 per cent of the year) for residential. This overstates the duration of congestion in the information supporting the 2016 DAPR by nearly 12 times.

The combined effect of these errors is a very large over-statement of the required level of future network capacity augmentation. While an estimation of unit low voltage network LRMC is provided in the ETSS and supporting documents, no estimate of the network capacity volume used to convert unit LRMC to forward network costs (aggregate LRMC) is provided by Ergon.

The only available benchmark for assessing the possible scale of the combined error is provided in a Frontier "STOUD Explainer", dated 31 October 2016. The STOUD Explainer suggests that, for typical residential customers, Ergon is defining its peak seasonal peak charging windows and setting seasonal peak rates so they represent 50 per cent of the total network annual unit price ("bill"). It also suggests the peak to non-peak revenue ratio could be above or below 1:2, depending on whether individual demand during the peak charging windows is more or less than that for typical residential customers. No information is provided by Ergon, Energeia or Frontier as to what the peak to non-peak revenue ratio is for typical small business customers.

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5 See especially the statement on slide 14 of Energeia' slide pack 'Peak Period Optimisation, 1 November 2016. This states that *'Peak is defined as >=95% of annual actual peak'.* It notes that: *Technical optimum peak period maximizes volume weighted accuracy of price signalling*'; '*Different future peak thresholds will change the optimisation result*'; *'95% used here based on previous work'.* We do not have access to the technical report from which the slide pack is drawn arising in some necessary ambiguity over interpretation.

6 See more detailed discussion in Section 3 below.

The Frontier ratio can reasonably be applied to Ergon's total allowed revenue for standard control services for small customers over the current five year price control period. If the estimated congestion overstatement of 375 times is applied to an estimate of allowed revenue, then the ETSS implied value of congestion over the period is perhaps $1,850 million. A more accurate value is less than 5 million.[7]

In the limited areas where congestion does exist, according to the DAPR, it appears to be driven by growth in customer numbers, rather than growth in demand from existing customers. Economic efficiency and the pricing principles (avoidance where feasible of cross subsidies) suggests that network costs arising from new demand should properly be recovered from capital contributions or connection charges (alternate control).[8]

The Revised ETSS does not demonstrate that the cost of augmentation, to address the small amount of real congestion, should be recovered from standards control network tariffs instead of from network connection charges or capital contributions. In the alternative, if congestion costs were recovered from standard control tariffs, it would seem more efficient to apply local congestion pricing instead of distorting prices across the network.

There is necessarily a significant margin for error, and indeed some inaccuracies, in our estimates in Table 1 above, and in particular the conversion of the combined error into dollar values. This is principally due to the absence of key information and data provided in the ETSS and supporting documents, and previous sought in submissions to the AER earlier in the process.

If the difference between our estimate and the estimates (on which the AER's provisional approval of the ETSS depends) were small, this could represent uncertainty and the application of different expert judgment and perspectives. A difference between our estimate and the AER estimate that is two (2) orders of magnitude clearly indicates that one estimation method is fundamentally wrong. While our estimate is necessarily inaccurate, the basis for our estimate of the scale of the error in the AER's Draft Decision is sound, based on an analytical framework that takes into account the current network pricing rules, and an economically defensible distinction between marginal and infra-marginal network capacity, taking into account the overall difference between maximum demand and maximum firm capacity. It is also based on public evidence provided in Ergon's 2016 DAPR regarding the actual and forecast level of congestion across Ergon's network.

Direct implications for AER provisional approval of ETSS

In broad terms, for a typical small customer, it appears that 50 per cent of their annual network bill would be used to signal non-existent future network costs (LRMC). The

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7 See more detailed discussion in Section 3 below.

8 See for example page 7 of 'A new methodology for establishing a water entity's revenue allowance', Kieran Murray and Richard Tooth, 9th July 2015 available at: http://www.esc.vic.gov.au/wp-content/uploads/esc/46/46408491-8a59-4773-b956-ce1b27cc254a.pdf. The RAB-capital contributions boundary is fixed for the current regulatory period but can be addressed in the process for determining prices for the following regulatory period.

proposed Ergon network tariffs clearly do not reflect Ergon's efficient cost of providing standard control services to the retail customer. There is certainly no basis for applying different windows and rates for business and residential customers.

As the AER notes in a different context:

> *'Regulatory decisions are complex, technical and are based on forecast data and subject to contested estimation theories. Our role is to consider all relevant information and correctly exercise our discretion to determine an answer out of range of possible answers that best meets either the national electricity or gas objectives.'*[9]

In its Draft Decision on the ETSS, it appears the AER has reached an answer that, based on a flawed estimation theory, lies outside the range of possible answers that meet the national electricity objective.

Depending on take up, the proposed 'cost reflective' tariffs would inefficiently suppress demand and encourage higher rates of by-pass of the network. This is both allocatively and dynamically inefficient. There is no basis for concluding in Ergon's case that *'Reducing peak demand means less network capacity will be required, meaning lower customer bills over the longer term'*[10]

The ETSS, if approved by the AER in its final decision, would result in unit network prices for Queensland canegrowers (and eventual retail tariffs) that substantially exceed efficient cost. To the extent canegrowers are exposed to the new tariffs as obsolete irrigator retail tariffs cease to apply, canegrowers would be worse off (even if remaining on default inclining block network tariffs). This would have adverse effects for the efficiency and productivity of this sector of the Queensland economy and the localities within which it operates.

Broader implications

We recognise the difficulties in applying the new network pricing principles, for both networks and the AER. These arise from the limited guidance in the Rules on converting LRMC to tariff structures, alongside the fact there was no opportunity for the AER to develop a Guideline for the preparation of Tariff Statements. Such a process could have reduced the risk of distorted tariffs being developed and provisionally approved.

Final approval of a Tariff Statement that overstates network congestion by two orders of magnitude would represent a regulatory error. The COAG Energy Council is currently reviewing the Limited Merits Review (LMR) regime. LMR allows parties affected by an AER decision to have the decisions reviewed by the Australian Competition Tribunal where it can be established there are grounds for this to occur; for example, regulatory errors and that addressing them would result in a materially preferable decision.

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9 See AER letter to Mr. Rob Heferen, COAG Energy Council Senior Committee of Officials, dated 4 October 2016

10 See p9 of the AER's Draft Determination.

Distorted network tariff structures, and tariffs, are inimical to the electricity network aspects of the COAG Energy Council's National Energy Productivity Plan.[11] This is because they suppress efficient utilisation of electricity distribution networks and could encourage inefficient network by-pass.

Distorted tariffs could also undermine public confidence in the integrity of both network pricing reform and network pricing regulation. This brings to mind the extended delays to the adoption of network pricing reform in Victoria due to controversy over the mandated introduction of smart meters under a jurisdictional derogation granting network monopolies over smart metering services. While there may be little benefit from introducing peak network pricing in Ergon, this is not the case over the entire NEM. A highly distorted tariff structure, if approved for Ergon, could have adverse implications for the credibility and acceptance of network pricing reform elsewhere in the NEM.

11 See *'National energy productivity plan 2015–2030; Boosting competitiveness, managing costs and reducing emissions'* Australian Government, December 2015.

1. Background

This report has been prepared for CANEGROWERS' on the Australian Energy Regulator (AER) August 2016 Draft Decision to approve Ergon's Tariff Structure Statement (ETSS).[12] Based on additional material provided by Ergon to CANEGROWERS and the AER on 2nd November, along with information from Ergon's 2016 Distribution Annual Planning Report (DAPR), in this report we substantially revise and extend conclusions set out in our *Review of AER Draft Decision, Tariff Structure Statement proposals, Energex and Ergon, August 2016*, dated October 2016.[13]

1.1 AER Draft Decision

In our October review of the AER Draft Decision to approve the ETSS, we expressed concern the AER's factual findings were not supported by evidence. We also noted there was insufficient transparency, in the ETSS evidence relied on by the AER, regarding the relationship between aggregate regulated revenues/prices, on the one hand, and the proposed tariff structure (rates and charging windows yielding the relative balance of LRMC and residual tariff components), on the other.

In its Queensland Draft Decision, the AER makes the following key findings regarding the ETSS:

- '*…[Ergon] sufficiently justifies its cost reflective tariff peak charging windows.*'[14]
- '*We consider Ergon Energy has sufficiently justified its cost reflective tariff peak charging windows. The charging windows target the broad network peaks for residential and business customers.*'[15]
- '*…exhibits movement along the cost reflectivity spectrum, incorporating time of use and demand tariff options for small customers*'[16];
- '*…includes tariffs with varying charges targeting network peak demand*'[17]
- '*…demonstrates Ergon Energy has accounted for customer impacts by:*
  - *making: making small customer time of use and demand tariffs opt-in'*
  - *gradually increasing the demand charge component of small customer demand tariffs to equal long run marginal cost (LRMC)*[18]'

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[12] See *Draft Decision Tariff structure statement proposal Energex and Ergon Energy*, AER, August 2016 (henceforth AER DD).

[13] See Sapere report available at http://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20report%20-%20Review%20of%20AER%20draft%20decision%20Tariff%20Structure%20Statement%20proposals%2C%20Energex%20and%20Ergon%2C%20August%202016%20-%20October%202016.pdf

[14] AER DD p52

[15] AER DD, p52.

[16] AER DD, p8.

[17] AER DD, p8

- *'…links LRMC and residual costs to specific tariff components, reflecting efficiency goals and consideration of customer impacts.'*[19]
- *'It may not be practicable… to establish charging windows to suit more narrowly defined customer classes such as particular types of irrigators. We accept that … Ergon Energy may not have information to further disaggregate a customer group into a separate tariff class.*[20]

In our October review of the AER Draft Decision, and in two related discussions with the AER, we expressed concern the AER's statements above were not evidence-based. We also noted there was insufficient transparency, in the ETSS evidence relied on by the AER, regarding the relationship between aggregate regulated revenues/prices, on the one hand, and the proposed tariff structure (rates and charging windows yielding the relative balance of LRMC and residual tariff components), on the other.

1.2 Ergon Tariff Statement proposals

Ergon's proposed indicative seasonal peak windows and rates for Seasonal time of use Energy (STOUE) and Seasonal time of use Demand (STOUD), for the final year of the Tariff Statement period are provided in Table 2 below.[21]

Table 2 Ergon's proposed seasonal peak tariffs

"Indicative" 2019-20	Seasonal peak window (of time)	Seasonal peak window (of energy)	STOUE	STOUD
Residential	6.7%	9%	0.47537	96.873
Business	7.5%	10.2%	0.43259	120.387
Residential as % of business	89.3%	88.2%	**109.9%**	**80.5%**

Source: Ergon Energy

Four points on Table 2 are noteworthy.

- The seasonal peak windows vary significantly between Residential and business. The residential seasonal peak window is a little more than 10 per cent "narrower" than the business window, but includes weekends as well as weekdays.

18 AER DD, p8

19 AER DD, p8

20 AER DD, p54

21 We focus on the final year of the ETSS period, because this best expresses the intent of the proposed tariff structure, since there is less emphasis on transitioning from existing tariff structures.

- For STOUE, the residential rate is at an around 10 per cent premium to the business rate. This may offset the narrower window to result in a similar proportion of expected annual revenue for the typical customer in each class.
- However, for STOUD, the residential rate is at an around 20 per cent discount to the business rate. The STOUD residential discount appears anomalous compared with the STOUE residential premium (the charging windows for STOUD and STOUE are identical.) It is possibly an error. Ergon has so far provided no explanation or evidence as to why the relativity between the STOUD and STOUE should be reversed.
- The indicative STOUD and STOUE rates in the 2016 Revised ETSS in Table 2 above barely changed compared with the 2015 ETSS. This indicates there may have been no substantial revision in the estimation of future network congestion in the 2016 Revised ETSS.

Table 3 below summarises Ergon's proposed indicative default tariff structure (IBT), for the final year of the Tariff Statement.

Table 3 Ergon proposed default tariff (inclining block)

Block	Variable rate	Premium from Block 1	Change from 2015 ETSS
		Residential 2019-20	
Block 1	0.0227	%	5.2%
Block 2	0.07318	222%	8.9%
Block 3	0.10559	**365%**	9.0%
		Business 2019-20	
Block 1	0.02713	%	20.6%
Block 2	0.0931	243%	1.1%
Block 3	0.12135	**358%**	-0.8%

Source: Ergon Tariff Statement

Three points on Table 3 are noteworthy.

- The right hand column shows there have been substantial revisions in the rates between the Revised 2016 ETSS and the 2015 ETSS. This is in contrast to the virtually unchanged rates for STOUD and STOUE shown in Table 2 above.

- The overall increase in rates may reflect an updated demand (volume) forecast, possibly with lower volumes, consistent with the 2016 DAPR and the Australian Energy Market Operator's National Energy Forecast Report (NEFR).
- The previous difference in the third block premia between residential and business has largely been removed, it seems via a combination of an overall increase in residential rates and a substantial increase in the rate for the first business block.

1.3 Actual vs. proposed Ergon tariffs

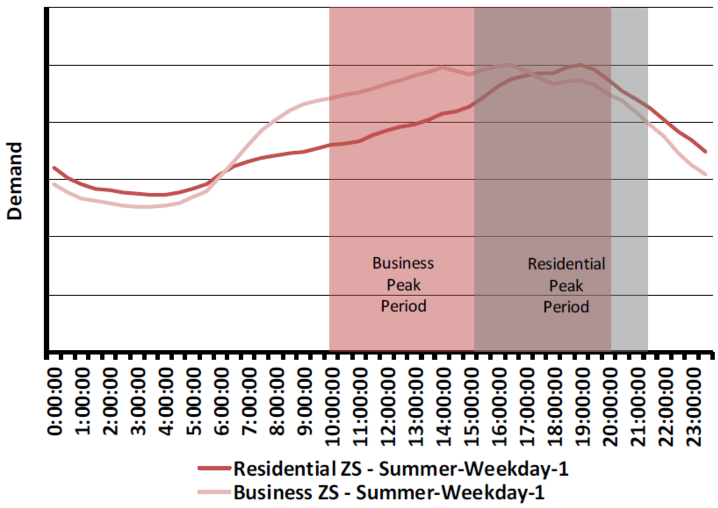
The present Rules were finalised at the end of 2014 and in Ergon's case will be implemented beginning from the 1 July 2017, following the AER's Final Decision. We understand Ergon's existing tariff structures are similar to those proposed in Ergon's present Tariff Statement, and that existing tariff structures have been approved by the AER under the former network pricing rules.

The purpose of Ergon's present Tariff Statement is to propose tariff structures for assessment by the AER as to whether they contribute to the achievement of the current distribution pricing principles and in particular the NPO. This means it is possible that the existing tariff structure could be found to be inconsistent with the current network pricing rules, following the AEMC's 2014 Final Determination and rule change.

1.4 Ergon's peak period optimisation

A key product of Ergon's peak period optimisation analysis is the daily profiles and peak period charging windows depicted in Figure 1 below.[22]

Figure 1 Ergon Energy peak windows compared to daily profiles



Source: Energia presentation pack, Slide 10

[22] These are similar to the summer daily profiles cited in Figure 5-4 and 5-5 on pages 51 and 52 of the AER DD.

As noted in Figure 2 below, the top five per cent of non-coincident maximum demand at each ZS is used by Ergon as the basis for the definition of the peak pricing windows).
Figure 2 Economic Optimisation of Hours – The Matrix[23]

		Zone Sub is:	
		Peak	**Offpeak**
Pricing is:	**Peak**	Correct Peak	Overcharge
	Off Peak	Undercharge	Correct Offpeak

* = Peak is defined as >= 95% of annual actual peak

Note: Colour indicating preference for getting peak correct at expense of getting offpeak correct

Source: Energia presentation pack, Slide 15

While there is necessarily some ambiguity in a brief presentation summarising a much more detailed and nuanced analysis, the Energeia presentation finally enabled us to identify the fundamental errors in Ergon's proposed charging windows that lead it to price infra-marginal capacity at marginal cost. Our understanding is the matrix is testing the alignment of peak and offpeak pricing windows with peak and off peak demand across Ergon's fleet of ZS. The green squares indicate a correct alignment. The "optimal" pricing window definition represents a 'best fit' relative to the peak and offpeak periods across a set of ZS. Because the 'best fit' is purposed to vary between clusters of ZS deemed to be residential or business, the optimisation results in different charging windows for residential and business customers.

Since March 2016, we have been highlighting the need for the AER to have data for and understand the balance between future network (LRMC) and current ("residual") cost components of tariff structures, as this is a notable gap in the ETSS documents. In its "STOUD Explainer", Frontier states that: [24]

> *'A residential customer could save up to 50% of their network bill and 25% of their retail bill by adopting a STOUD-based retail tariff such as T14. However, those customers with high levels of usage during daily peak demand windows during summer could see increased network charges…*

[23] See page 15 of Energeia slide pack which also notes that 95% used here is based on previous work.

[24] See page 18 of the Frontier STOUD Explainer.

> *'…Given that the summer peak demand charge recovers approximately 25% of the annual T14 bill, but is based on electricity consumption over only 6-7% of the year, a customer who can minimise their usage during this time could potentially save even more of their annual retail bill.'*

The STOUD Explainer suggests that, for typical residential customers, Ergon is defining its peak seasonal peak charging windows and setting seasonal peak rates so they represent 50 per cent of the total network annual unit price ("bill"). It also suggests the peak to non-peak revenue ratio could be above or below a 1 to 2 ratio depending on whether individual demand during the peak charging windows is more or less than that for typical residential customers. No information is provided by Ergon, Energeia or Frontier as to what the peak to non-peak revenue ratio is for typical small business customers.

1.5 Process since March 2016

Appendix 1 summarises points made to the AER in a series of interactions since March 2016. The authors first queried the AER's proposed approach to its assessment of the ETSS in a March 2016 memo to CANEGROWERS submitted as part of a CANEGROWERS submission to the *AER Issues Paper, Tariff Structure Statement Proposals, Queensland electricity distribution network service providers, February 2016,*[25] alongside a report to CANEGROWERS from the Alternative Technology Association. Among other things, our memo noted:

> *'The ETSS has provided insufficient evidence and analysis to support its proposed definition of charging windows. The ATA report for CANEGROWERS suggests these are far too broad compared with the shape of the demand profile (if it were made transparent). There is no basis under the NPO and principles for the pricing windows proposed in the ETSS.*

It also observed that the ETSS and supporting documents did not provide sufficient transparency to enable cross checks of Tariff Structure proposals and reconciliation with the AER's approved Post Tax Revenue Model.

On 2nd November, Simon Orme, and James Swansson from Sapere accompanied CANEGROWERS, represented by Head – Economics Warren Males and the Chair of Economics Committee Rajinder Singh, attended a meeting with the AER and Ergon Energy, accompanied by Ergon consultants, Frontier Economics and Energeia. Around an hour before the meeting commenced, the AER distributed additional materials from Ergon via email including:

- a letter from Energeia to Ergon commenting on our slide pack distributed earlier in the week;
- a presentation pack from Energeia regarding 'Peak Period Optimisation', and
- an 'Explainer' on Ergon Energy's SAC-Small STOUD tariff by Frontier Economics.

The AER provided hardcopies of these documents on our arrival at the meeting but we were unable to review and respond to the new information during the course of the meeting.

[25] Available at http://www.aer.gov.au/system/files/AER%20-%20Issues%20paper%20-%20Queensland%20electricty%20distributors%20-%20Tariff%20structure%20statement%20proposals%20-%2011%20March%202016_0.pdf

Late on the afternoon of Friday 4th November we set out our initial analysis of whether the new material provided at the meeting of 2 November changed the conclusion in our October review of the AER Draft Decision. This was forwarded via email by CANEGROWERS to the AER and Ergon. The key conclusions were that the additional information confirmed our earlier identification of evidence gaps was justified and that further it was not sufficient to support the AER's Draft Decision. Further information regarding the network peak optimisation method (such as the report from which the slide pack was drawn) is required to address the gap in the evidence base for the Tariff Statement proposals.

On Monday 7th November, in response to the Friday email, the AER stated that *'We will be in contact if we have further questions or require a discussion.'* This could be interpreted as suggesting the AER sees no need to make any further enquiries regarding the matters raised in the 4th November initial analysis and did not propose to refer to these matters in its Final Decision. This interpretation is also suggested by AER staff suggesting in both meetings that canegrowers should be able to modify their demand profiles to minimise or avoid exposure to Ergon's seasonal peak tariffs.

In other words, the response suggests the AER was not of a mind to change the main conclusions in its Draft Decision. In response, later that day, CANEGROWERS informed the AER it would submit a formal response to the new material presented by Ergon.

2. Basics of efficient tariff design

2.1 Regulatory framework

The network pricing objective (NPO) in the National Electricity Rules (6.18.5(a)) is as follows:

> *"the tariffs that a Distribution Network Service Provider charges in respect of its provision of direct control services to a retail customer should reflect the Distribution Network Service Provider's efficient costs of providing those services to the retail customer."*

The AEMC in its Final Decision on the new network pricing rules states that:

> *Cost reflectivity in relation to network tariffs has three key components:*
>
> *(i) Sending efficient signals about future network costs.*
>
> *(ii) Allowing a DNSP to recover its regulated revenue so that it can recover its efficient costs of building and maintaining the existing network.*
>
> *(iii) Each consumer should pay for the costs caused by its use of the network.*
>
> *Taken together, these three components of cost reflectivity should result in an outcome where the network prices that each consumer faces reflect the costs that particular consumer causes through its use of the network.*

Under 6.18.5 (f) Each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

> (1) the costs and benefits associated with calculating, implementing and applying that method as proposed;
>
> (2) the additional costs likely to be associated with meeting demand from *retail customers* that are assigned to that tariff at times of greatest utilisation of the relevant part of the *distribution network*; and
>
> (3) the location of *retail customers* that are assigned to that tariff and the extent to which costs vary between different locations in the *distribution network*.

2.2 Tariff design and individual customer prices ("bills")

A key premise in our various analyses of network pricing is the proposition that an efficient tariff design should yield lower current prices for consumers that do not drive future network costs and higher current prices for consumers that do drive future network costs. This is implied by the third limb of the AEMC's three components of cost reflective pricing discussed in the previous section.

At the 2nd November discussion and in the Energeia letter, this proposition has been misconstrued and interpreted as suggesting that peak network charges (for recovery of future network cost (LRMC)) should not apply to irrigators. It has also been suggested we are not using the term "price" accurately.

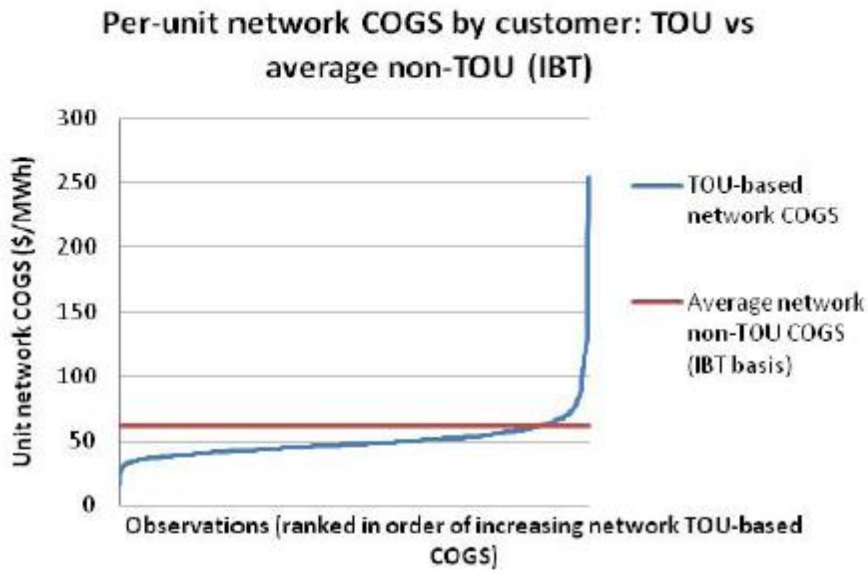
The implication is that our analysis is tantamount to proposing Canegrowers should free ride on other network users. There is no basis for this implication, which is based on a misunderstanding of efficient pricing theory and evidence.

The demand behaviour of consumers is not homogenous. This heterogeneity has been obvious since data from large numbers of interval and smart meters at small customer level have revealed the dynamics of individual consumption behaviour in contrast to average collective behaviour otherwise obscured by use of net system load profiles (NSLP). One of the present authors participated in some of the very first publicly available analyses of significant samples of small customer interval data in Australia.

Using interval and half hourly network capacity cost data for a representative sample of a cross section of customers, it is possible to estimate volume normalised total network unit costs per customer and then to rank customers from lowest to highest cost. This can be compared with the unitised outcome[26] under a net system load profile, which removes variation in customer behaviour. This is illustrated in Figure 3 below.

[26] As there is no systematic relationship between demand profile and annual consumption volume, unitisation does not represent a distortion.

Figure 3 EnergyAustralia (now Ausgrid) interval meter sample for 2006/07: Network COGS – comparison of per unit network costs on TOU vs. non-TOU network tariff[27]



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These studies have consistently demonstrated that demand profiles and hence costs for a small proportion of the population (at far right) substantially deviate from the averaged profile (represented by the red line). This indicates that, where there is network congestion, there may be significant cross subsidies from the large bulk of consumers on the left, who pay more than their costs, to consumers on the far right, who pay much less than their costs as determined by their individual profiles. It is therefore entirely accurate to state there is a sub-segment of a tariff class that "drives" additional network costs (where there is congestion, as discussed further below).

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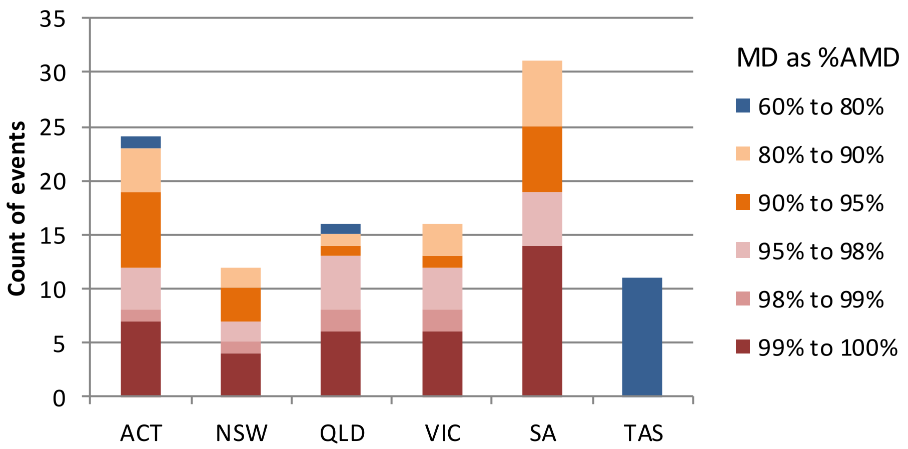
[27] See page 49 of *'Smart meter consumer impact: initial analysis, Sell, Orme and Prins*, dated February 2009 still available at https://link.aemo.com.au/sites/wcl/smartmetering/Document%20library/Smart%20meter%20background%20info/Background%20-%20MCE%20-%20Smart%20meter%20consumer%20impact%20-%20initial%20analysis%20-%2027%20Feb%202009.pdf?Mobile=1&Source=%2Fsites%2Fwcl%2Fsmartmetering%2F_layouts%2Fmobile%2Fdispform.aspx%3FList%3D4f269b27-0e1c-46e0-a867-e43fc357690c%26View%3D059f5bf2-cbf1-4bba-9467-765056f79500%26RootFolder%3D%252Fsites%252Fwcl%252Fsmartmetering%252FDocument%2520library%252FSmart%2520meter%2520background%2520info%26ID%3D138%26CurrentPage%3D1 The basic idea was applied to the total cost of goods sold (COGS) in Figure 16 of AGL Working Paper No. 41 – Inequity of tariffs, July 2014. We are not aware of any more recent public examples that refer to the network-only component of COGS. At the relevant time, there was substantial demand growth and relatively little excess capacity. Hence the simplifying assumption of network congestion corresponding with peak demand was under those conditions broadly valid.

2.3 Irrigation does not drive growth in maximum demand

The uptake of domestic air-conditioning is widely recognised as a leading factor in peak demand growth. A report for the AEMC Power of Choice review identified climate as a driver of peak demand growth, whereas population growth, household size and household income are not.[28] Similarly, the Productivity Commission (PC) inquiry into electricity networks highlighted the doubling of household air conditioning stock over ten years to 75 percent of households in 2008.[29]

Figure 4 below reproduces the authors' analysis of heatwave driven network demand peaks for the 2014 National Energy Security Assessment (NESA), illustrating that heatwaves are a driver of maximum demand in all mainland states, and particularly demand drivers in South Australia, Victoria and Queensland, where a significant majority of demand peaks during heatwaves are in the top 5 per cent of annual maximum demand.[30]

Figure 4 Heatwaves and demand peaks (relative to annual maximum demand) – January 1999- April 0214



These high level conclusions also seem to apply to Ergon. Ergon's 2016 Distribution Annual Planning Report 2016-17 to 2020-21 (DAPR) states that:

[28] Ernst & Young, Rationale and drivers for DSP in the electricity market – demand and supply of electricity, AEMC Power of Choice, 20 December 2011.

[29] See Figure 9.7, page 350, Electricity Network Regulatory Frameworks, Productivity Commission Inquiry Report, Volume 2, No. 62,9 April 2013

[30] Simon Orme, James Swansson, Implications of extreme weather for the Australian National Electricity Market: historical analysis and 2019 extreme heatwave scenario, Australian Department of Industry National Energy Security Assessment, August 2014 http://www.industry.gov.au/Energy/EnergySecurityOffice/Documents/ExtremeweatherandNEMscenarioreport2014.docx

Air conditioning is one of the major drivers in peak demand load on the network. There has been constant and linear growth in peak demand load from air conditioners.[31]

In unpublished research for a State government, we have further refined our analysis of the individual supply cost curve from interval data, network cost data and consumer air-conditioner ownership and use data. This enabled segmentation of consumers on the individual supply cost curve by air-conditioner ownership and actual use during periods of greatest utilisation of the relevant network. In this sample, air-conditioner owners are higher on the cost curve than non-owners, and in particular those without air-conditioning were contributing a cross-subsidy to those who use their air-conditioning during network peaks.

In its first submission in the present process, in May 2016, CANEGROWERS attached a report from the Alternative Technology Association, including an Appendix prepared by Dr. Martin Gill analysing canegrower interval data provided by Ergon. This indicates that, over a year, demand by canegrowers is highest over summer. The data does not indicate that demand at half hourly resolution is at all influenced by heatwaves when periods of greatest utilisation of the network are most likely. In other words, irrigators are not in the customer segment depicted at the far right hand side of Figure 3 above.

Under efficient tariffs, Canegrowers would certainly face peak network prices. But their exposure would be limited because their demand (MW) does not expand when total network demand approaches the secure capacity of the relevant part of the network. In this sense they can reasonably be described as using infra-marginal network capacity, rather than using marginal network capacity.

[31] See page 53 of the 2016 DAPR.

3. Errors in Ergon analysis

3.1 Overview

Table 4 below provides a summary of our assessment of the ETSS network congestion estimation on which proposed tariff structures, including the duration and definition of seasonal peak charging windows and tariff rates, are based. Our basic finding is that the Ergon TSS overstates the value of congestion to standard control services, and hence the corresponding required revenue, by approximately 375 times.

Table 4 Assessment of ETSS network congestion estimation

Issue	Ergon's Revised Tariff Statement	Our estimate	Difference
Extent of non-coincident local (spatial) congestion	252 Zone Substations (ZS)	5 ZS	63 times
Extent of temporal congestion (duration of peak charging windows)	650 hours or 7.4% of year	54.5 hours. or 0.62 per cent of the year	11.9 times
Additional capacity investment required	Not disclosed	N/A	N/A
Ratio of estimated value of congestion to total standard control revenue for tariff class	Circa 1 to 2 for residential, unknown for business	Circa 1 to 750	Circa 375 times
Indicative congestion revenue requirement relative to total smoothed revenue for 2015-16 to 2019-20*	$1,849.5 million*	$4.9 million	Circa 375 times

Source: Sapere analysis of Ergon, Energeia and Frontier data.

*The values in the bottom line of the Table above are intended to illustrate the indicative dollar impact of the 375 times error, only, and do not purpose to be an accurate estimate of the value of congestion implied by the ETSS. The dollar values are based on the assumption low voltage business and commercial customer revenues represent half of total AER allowed smoothed revenues to mid-2020.

There is necessarily a significant margin for error, and indeed some inaccuracies, in our estimates in Table 4 above, and in particular the conversion of the combined error into dollar values. This is principally due to the absence of key information and data provided in the ETSS and supporting documents, and previous sought in submissions to the AER earlier in the process.

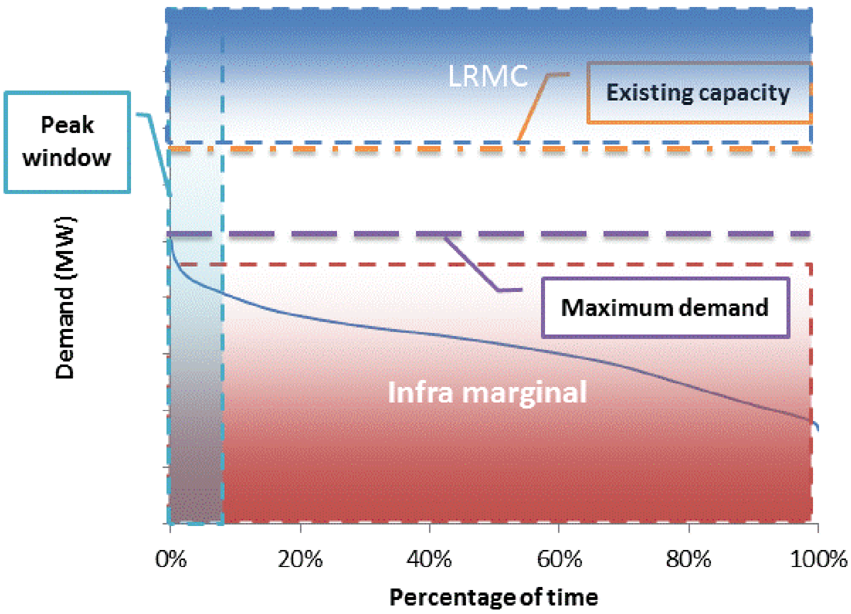
If the difference between our estimate and the estimates (on which the AER's provisional approval of the ETSS depends) were small, this could represent uncertainty and the application of different expert judgment and perspectives. A difference between our estimate and the AER estimate that is two (2) orders of magnitude clearly indicates that one estimation method is fundamentally wrong. While our estimate is necessarily inaccurate, the basis for our estimate of the scale of the error in the AER's Draft Decision is a sound, based on an analytical framework that takes into account the current network pricing rules, and an economically defensible distinction between marginal and infra-marginal network capacity, taking into account the overall difference between maximum demand and maximum firm capacity. It is also based on public evidence provided in Ergon's 2016 DAPR regarding the actual and forecast level of congestion across Ergon's network.

3.2 Distinguishing marginal and infra-marginal network capacity

The fundamental source of the error in both the ETSS and AER Draft Determination is a failure to distinguish correctly between marginal and infra-marginal network capacity. Marginal network capacity for price setting purposes may be defined as that part of network capacity where even small increases in future maximum demand can trigger a requirement for capacity augmentation to maintain firm supply. If this demand increase can be avoided, so can the requirement for augmentation.

Figure 5 below provides an illustration of the distinction between marginal and infra-marginal network capacity at the network wide or system level.

Figure 5 Defining marginal and infra-marginal network capacity



Source: Sapere

The blue curved line represents Ergon's load duration curve (LDC) for its actual NSLP – the sum of small residential and business maximum demand (MW) for each interval over the year ranked from highest to lowest.[32] The red area represents the minimum infra-marginal network capacity. This forms the minimum part of the "residual," or the cost of the existing network.

The horizontal purple line represents maximum demand across the entire network. The area between the top of the red box and the purple line represents the top part of the LDC – similar to the >=95 per cent value used by Ergon as discussed earlier.[33] The orange line represents existing firm capacity, including a reliability margin (N-1).

The vertical turquoise area represents Ergon's proposed business peak charging window (7.5 per cent of the horizontal axis). The issue that we have been attempting to understand since March is the efficiency basis for setting the right hand side of this boundary at around 80 per cent of maximum demand (where the LDC and the right hand side of the turquoise area cross).

As shown below, the area between maximum demand (purple line) and existing capacity (orange line) in Figure 5 above has been more or less ignored in the derivation of the proposed peak charging windows. Unless maximum demand is compared with existing capacity, and incorporates an assessment of spare firm capacity, there is a basic flaw in the analysis on which the ETSS seasonal peak pricing tariff design is based.

3.3 Error 1 – overstating non-coincident peak congestion

The ostensible justification for a broad charging window is non-coincident peak congestion across the fleet of Zone Substations (ZS). This concept is illustrated in Figure 6 below. The red line represents the load duration curve for the combined ZS that are recognised as congested. For brief periods during the year these assets approach and breach existing firm capacity, potentially triggering a requirement for augmentation. The blue LDC represents the remaining ZS that operate continuously within firm capacity.

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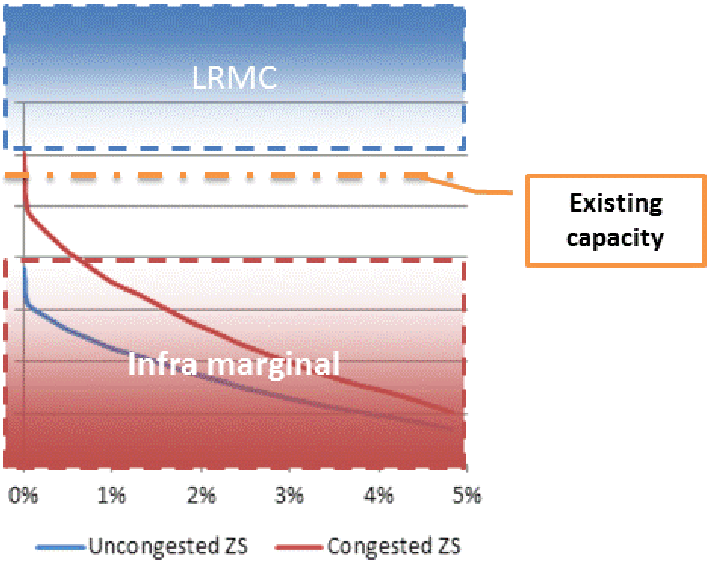
32 Where interval meter data is available, this may be excluded from the NSLP. The AEMO now generates a "synthetic" NSLP from interval meter data.

33 We do not contest use of a <=95% capacity threshold, although note other values could reasonably be applied, depending for example on the existence and rate of any trend growth in maximum demand.

Figure 6 Distinguishing between congested and uncongested ZS



Source: Sapere

In determining the duration and definition of its seasonal peak charging windows, Ergon has defined marginal network capacity as equal to or greater than 95 per cent of maximum annual demand at each of its zone substations (ZS).[34] However, for any ZS where there is substantial excess firm capacity, after allowing for the loss of one transformer (N-1) this definition would over-state marginal capacity. This is because any forecast growth in maximum demand would not trigger a requirement for augmentation. Similarly, any reduction or even a fall in maximum demand would not avoid any existing capacity cost.

For the vast bulk of ZS, according to the ZS data base supporting Ergon's DAPR, the lower blue line in Figure 6 is accurate. However, the inaccurate red line has been applied in the Revised Ergon ETSS. For all but a handful of the network assets used to drive Ergon's analysis, the top of the infra-marginal box should be aligned to 95 per cent of existing capacity, not 95 per cent of maximum demand.

According to Ergon's September 2016 DAPR, only five zone substations out of 252 ZS (less than two per cent) are subject to congestion and correspond to the LDC in figure 6 above. As illustrated in Figure 7 below , for all but five (5) zone substations, Ergon's own assessment is that forecast increases in maximum demand over to mid-2021 would not exceed summer firm capacity.

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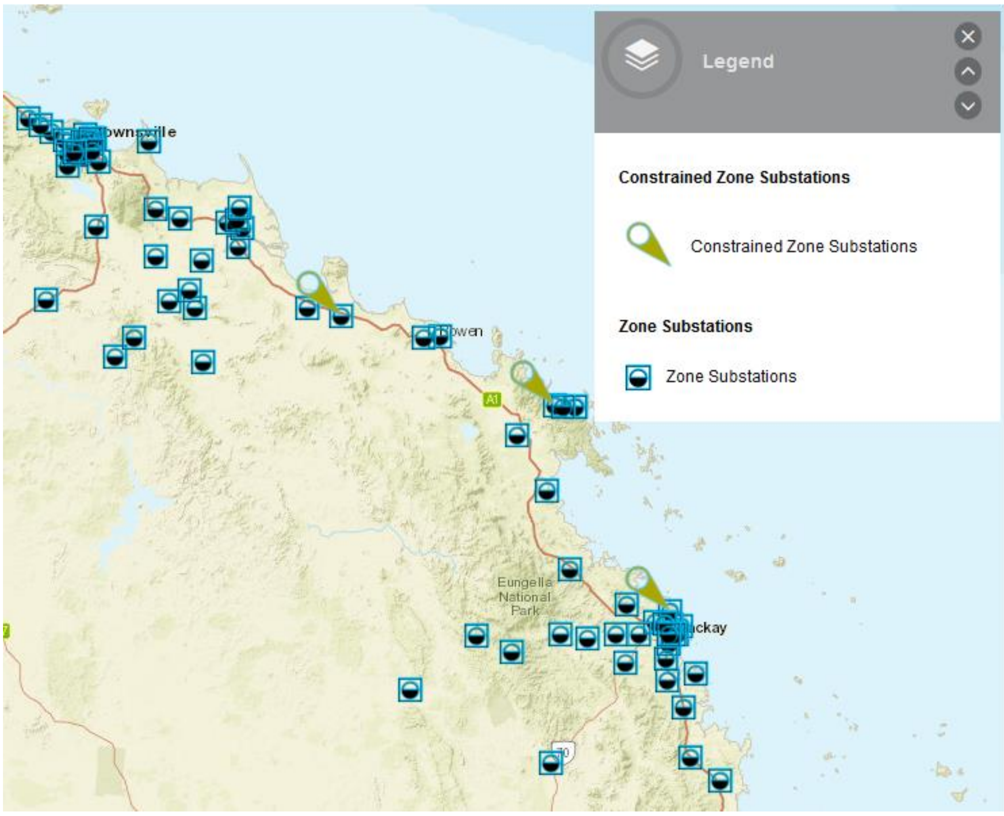
34 See especially the statement on slide 14 of Energeia' slide pack 'Peak Period Optimisation, 1 November 2016. This states that *'Peak is defined as >=95% of annual actual peak'*. It notes that: *Technical optimum peak period maximizes volume weighted accuracy of price signalling*'; '*Different future peak thresholds will change the optimisation result*'; '*95% used here based on previous work*'. We do not have access to the technical report from which the slide pack is drawn arising in some necessary ambiguity over interpretation.

Figure 7 Map of total vs. constrained Ergon ZS[35]



Source: Ergon Energy

The ETSS estimate of spatial congestion is 63 times higher than implied by the 2016 DAPR. The revised ETSS does not correspond to the significantly reduced congestion forecast in Ergon's 2016 DAPR. The two documents were published within weeks of each other.

[35] See https://www.ergon.com.au/network/network-management/future-investment/distribution-annual-planning-report/dapr-map. Two of the congested ZS are outside this shot (Malchi and Emerald).

This is illustrated in the Table 5 below from Substations Forecast (Ergon Energy Distribution Annual Planning Report 2016 -17 to 2020 -21) for BLRI – Black River (66/11kV).

Table 5 Ergon DAPR 2016 for BLRI

PEAK LOAD FORECAST AND CAPACITY	SUMMER				
	2016/17	2017/18	2018/19	2019/20	2020/21
NCC Rating (MVA)	56.0	56.0	56.0	56.0	56.0
Contracted non-network (MVA)	0.0	0.0	0.0	0.0	0.0
10 PoE Load (MVA)	21.4	22.0	22.7	22.9	23.9
LARn (MVA)					
LARn (MW)					
Power Factor at Peak Load	0.95	0.95	0.95	0.95	0.95
ECC Rating (MVA)	29.9	29.9	29.9	29.9	29.9
50 PoE Load (MVA)	18.8	19.2	20.0	20.4	21.1
50 PoE Load > 95% (MVA)	0.9	1	1	1	1.1
Substation Category	Regional Centre	Regional Centre	Regional Centre	Regional Centre	Regional Centre
Meets Security Standard	Yes	Yes	Yes	Yes	Yes
Implied firm spare capacity at 10% PoE (MVA)[36]	8.5	7.9	7.2	7.0	6.0
Implied firm capacity as % of peak demand at 10% PoE	39.7%	36%	32%	30%	25.1%

This example suggests that Energeia's Peak Period Optimisation method "optimises" the top five per cent of maximum demand. This suggests it is drawing on data similar to the line '50PoE Load > 95% (MVA)'. It may apply the 95 per cent threshold to 10 PoE, as this is the metric that relates to network reliability standards.

Comparing the line 'EEC Rating (MVA)' with the line '10 PoE Load (MVA)' implies there is 25.1 per cent forecast capacity headroom in the final year of the forecast. This is after taking into account the Power Factor at Peak Load.

Correcting for the error of using maximum demand instead of maximum firm capacity, there would in fact be no avoided future network cost (LRMC), if forecast maximum demand growth were moderated by peak network prices (or if demand growth were significantly higher than forecast). Any demand response from applying peak prices would represent

[36] Calculation by the authors.

suppressed demand (a cost) with virtually no offsetting benefit.[37] There would be no future reduction in customer bills.

A related matter that should be taken into account is the sources of congestion. That is, the extent it arises from additional customer demand or additional customers, as discussed below in Section3.7.2.

3.4 Error 2 – overstating temporal congestion

The preceding sections identify and discuss the error of selecting the top 5 per cent of maximum demand, instead of firm capacity, for defining peak charging windows. This results in a substantial over-statement of local congestion. The assumption that all ZS are subject to congestion also results in a substantial exaggeration of the duration of congestion, and hence the definition of efficient charging windows.

Ergon's peak network optimisation yields charging windows equivalent to 650 hours (7.5 per cent of the year) for business and 587 hours (6.7 per cent of the year) for residential. This is a substantial overstatement of the duration of congestion in the small set of ZS where congestion actually occurs. The times of peak demand and duration of possible congestion is set out below in Table 6 below.

Table 6 ZS congestion according to 2016 DAPR

ZS	Latest peak compensated load	Hours PA > 95% Peak Load
Cannonvale	14.4 MVA on 05/01/2016 at 19:30	16
Emerald	37.1 MVA on 27/11/2015 at 16:30	23.5
Guthalungra	0.5 MVA on 01/01/2016 at 19:00	0
Malchi	17.4 MVA on 03/02/2016 at 18:30	6.5
Planella	16.9 MVA on 31/01/2016 at 19:00	8.5

Source: Ergon Energy 2016 DAPR supporting data

The sum of the hours where congestion is a risk is 54.5.[38] This represents just 0.62 per cent of the year or 8.3 per cent of the business seasonal peak window.

[37] Any benefit would mostly consist of reduced network energy losses from any reduction in demand. In 98 per cent of the fleet, there would be no network benefit, since these losses are already taken into account in the peak forecasts. There could be a very modest wholesale energy cost benefit but this is unlikely to be sufficient to offset the cost of suppressed demand.

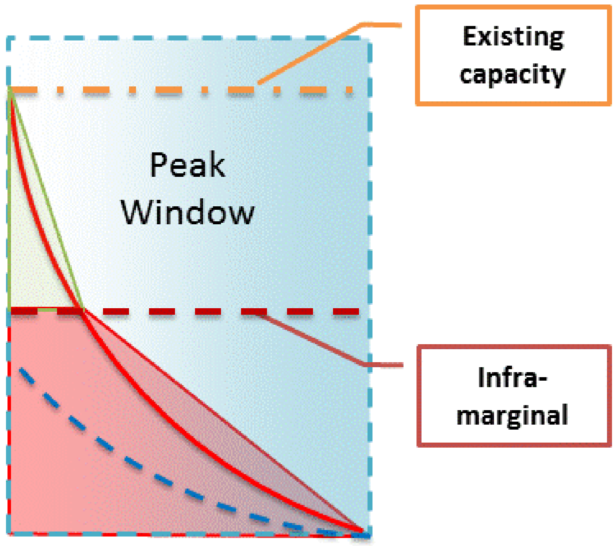
[38] We recognise that a proper analysis of local congestion would draw on data from multiple years, ideally a decade or more. It would also require greater granularity as to the distribution of the number of hours. For

This may be too high because it assumes no overlap between any of the peak hours.[39] The demand peaks are between 16.30 and 19.00. Without load duration curve data for each zone substation, which is technically feasible, it is not possible to determine the times of day to which (especially in the case of Emerald) the hours apply. An LDC can be applied to any level of a network or any end user, provided there is available interval data.

3.5 Implications for economic efficiency

Figure 8 below illustrates the economic costs and benefits of peak pricing relative to Ergon's proposed peak window. This is not to scale and represents a call out of the top left hand corner from Figure 6 above, where the solid red curve represents the LDC for the 5 congested ZS and the lower dashed blue curve the LDC for the remaining 247 uncongested zone substations.

Figure 8 Illustrating costs and benefits of peak pricing



Source: Sapere

The area of the green triangle (the area to the left of the solid red LDC and within about 5 per cent of firm existing capacity) represents the 'sweet spot'. This is where efficient network pricing, if it reduced demand, could potentially avoid triggering a requirement for new investment in future. This is basis for the proposition that network pricing reform, *'means lower customer bills over the longer term'*.

The lower red triangle (the red area to the left of the solid red LDC, and below the top of the infra-marginal box) represents the 'sour spot'. This is where application of congestion

Cannonvale, for example, this would include how many days and the times of day the over which the 16 hours per year occurs.

[39] There are other variables, as highlighted by one of the 5 Ergon ZS that may require augmentation, Guthalungra.

pricing may inefficiently suppress demand, increasing network by-pass. There would, however, be no avoided network capacity requirement and no avoided costs. Under these conditions, network pricing reform does not mean lower customer bills over the longer term.

Under the Energeia analysis, the area of the sweet spot appears substantially to exceed the area of the sour spot. The assertion is the balance between the two areas has been optimised to ensure seasonal peak windows hit the target sweet spot and avoid the sour spot.

The DAPR data shows that in fact the sweet spot only applies to less than two (2) per cent of the ZS fleet where the red LDC is broadly accurate. For 98 per cent of the ZS fleet, the dashed blue LDC is broadly accurate. The red box is far too large, both in area and in "depth", representing the number of ZS where the blue LDC is broadly accurate.

Under current regulatory arrangements, network revenue risk from network by-pass is transferred to customers. Reduced demand in the 'sour spot' may therefore mean higher customer bills over the longer term.

Once it is understood that the red area is very much larger than the green area, it is clear it does not make sense to apply network level tariff structures to address very limited local network congestion. Locational price signals would be more efficient, as discussed in the following section.

Referring to the AEMC's three components of cost reflectivity; the ETSS proposals do not:

- Send efficient signals about future network costs; or
- Result in an outcome where the network prices that each consumer faces reflect the costs that particular consumer causes through its use of the network.

3.6 No evidence for inclining block tariff structure

In the case of the Inclining Block Tariff (IBT), it remains the case that, while the conclusion is not evidence based, it is not demonstrably false. If part of the rationale for an IBT is to minimise inefficient by pass from more demand elastic customers, the revised ETSS has provided no evidence of any relationship between risk of by-pass and consumption volume.

We note the AER's Draft Decision for NSW challenged NSW networks to produce evidence around demand elasticity to justify proposed Declining Block Tariff structures. In response, in their Revised Tariff Statements, all three NSW networks reverted to two part "flat" tariffs. This suggests there may be no sound available evidence linking variations in demand elasticity with annual consumption volume.

What can be determined is that, for high volume customers, including canegrowers, the IBT does not represent a safe harbour alternative to distorted peak seasonal tariffs. The ETSS, if approved by the AER in its final decision, would result in unit network prices for Queensland canegrowers (and eventual retail tariffs) that substantially exceed efficient cost. To the extent canegrowers are exposed to the new tariffs as obsolete irrigator retail tariffs cease to apply, canegrowers would be worse off (even if remaining on default IBT network tariffs). This would have adverse effects for the efficiency and productivity of this sector of the Queensland economy and the localities within which it operates.

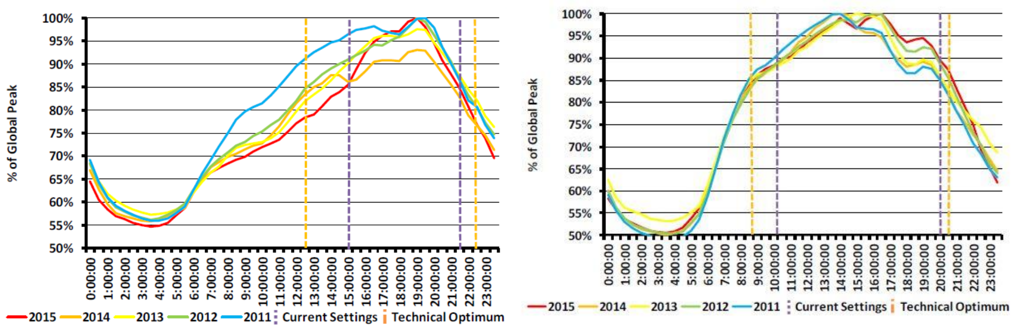
3.7 Contributing errors

3.7.1 Reliance on daily profiles

In the Ergon's TSS, Energia's presentation pack and Frontier Economics 'explainer' on Ergon Energy's SAC-Small STOUD tariff, we are presented with daily profiles of energy use such as Figure 1 above or Figure 9 below. However, daily profiles are fundamentally misleading in understanding the temporal characteristics of the network at periods of greatest utilisation.

Daily profiles like these are attractive to the layperson, being easier to understand through the illustration of the diurnal pattern of sleeping, waking, breakfasting, working or learning, dining and relaxing, before sleeping once again as reflected in our use of power for these activities. Daily profiles may then be subject to confirmation bias, that is we accept such analysis as evidence confirming our experience, even as the method itself alters data about the periods about which we are concerned.

Figure 9 Energeia presentation pack, slides 20 & 24, Summer Weekday Max HH for residential and business



Networks typically define asset congestion in terms of the percentage of time in a year that an asset load exceeds its firm rating.[40] It follows that, in identifying the timing of greatest utilisation of the network, analysis must proceed from fine grained (typically ½ hour) data for a period of at least one year, and ideally longer to assess inter-annual variability and Probability of Exceedance estimates.

The production of daily profiles is a deeply reductive approach, deriving just 48 ½ hourly or 24 hourly data points from at least 17,520 ½ hourly periods per annum. This means demand data for the small set of periods (say 47 for Emerald, see Table 6) when network capacity is most highly utilised may be completely removed by representing multiple days (say every week day over summer) as a single daily profile. The impression of network demand variability they provide, and with that an understanding of the extreme of peak network capacity utilisation, is completely wrong. Consequently the system conditions inferred from them, such as peak windows, are mistaken.

[40] See, for example, Endeavour Energy TSS Explanatory Statement, October 2016. There are other variables, as highlighted by one of the 5 Ergon ZS that may require augmentation, Guthalungra.

Necessarily the peak values for multiple days, as presented here, would be significantly lower than for the much small number of days when the maximum occurred. This suggests adjustments have been made to push the curves for most periods up to the maximum.

We consider this when interpreting the charts in Figure 9, and it is questionable whether they are even internally consistent.[41] These daily profiles represent a substantial reduction of data over summer weekdays and zone substations, normalised to the 'global' peak[42]. We know that the daily profiles average or condense data over both zone substations and summer weekdays. The options for temporal and locational manipulation include;

- The average or maximum over substations of the individual day of each for their peak annual demand.
- The average or maximum over substations of the individual ½ hour each substation reaches maximum demand in the summer/weekday window.

On any of these methods it is mathematically impossible for a (weighted) majority of substations to exceed the threshold of 95% of demand used in the analysis where the profile is below an indicated 95% of global peak. Therefore these profiles of themselves cannot justify either the current peak window or 'technical optimum' window suggested.

In a technical context, annual load data is succinctly visualised as an annual load duration curve (LDC), ranking the in excess of 17,520 points of data from highest to lowest, permitting focus on the period of peak utilisation that is of concern. We note that this is a non-specific method of analysis of asset utilisation, and is not specific to any asset level.

As an example we consider Endeavour Energy's approach in its TSS. Noting that its tariffs are applied at a network level, Endeavour Energy employs the network LDC in Figure 10 to identify the level of network demand for consideration in the determination of its tariff peak windows[43]. It proceeds to perform a statistical analysis of what hour of the day the identified ½ our periods each year occur in order to identify a peak window within which it is probable the network peak will occur.[44]

Figure 11 below compares Ergon's actual net system load profile (NSLP) with the LDC implied by the daily profile presented in the Ergon/Energeia/Frontier Economics documents – giving the dramatic implication that the top 20 percent of demand is utilised for some 50 percent of the year, instead of 8-9 percent of the year. Figure 11 also illustrates the assumption implicit in daily profiles that the peak of network utilisation is approached gradually. This underpins assumptions, for example, that the probability of network peaks is relatively similar for each ½ hour period across a peak window.

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41 We are cautious interpreting these charts from Energia's presentation pack, in the absence of any explanatory narrative regarding assumptions and methods, but we highlight some inconsistencies.

42 We note that for the residential profiles the 'global peak' does not fall in the summer weekday window in 2013 or 2014, so that these years do not peak at 100%

43 Endeavour Energy TSS Explanatory Statement, October 2016, Figure 7.2

44 See Figure 7.3, Endeavour Energy TSS Explanatory Statement, October 2016

Figure 10 Endeavour Energy chart of network load duration curve

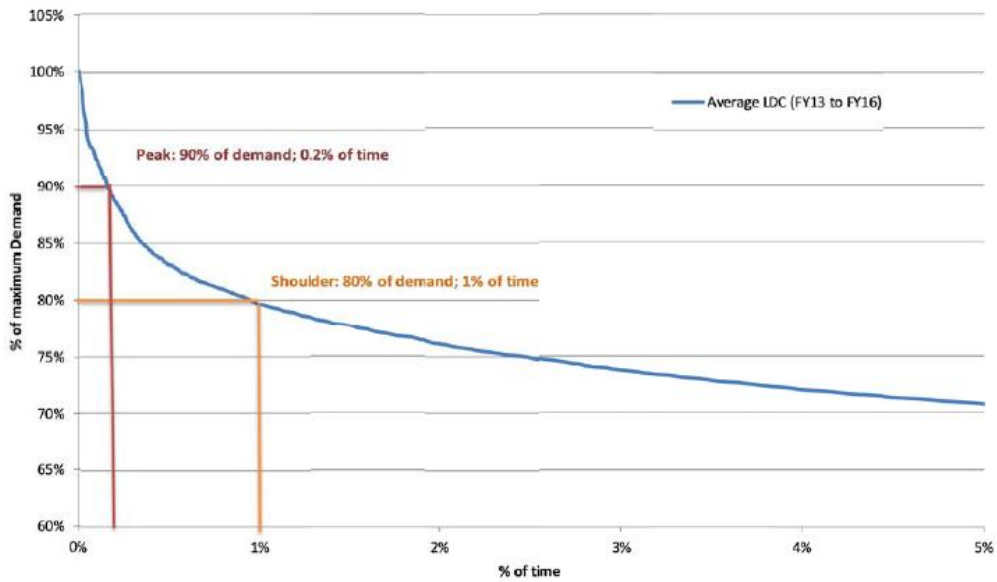
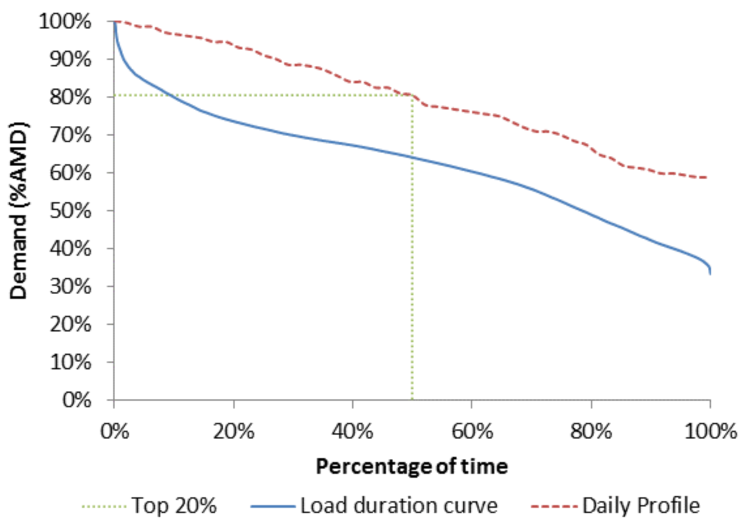


Figure 11 Ergon Energy NSLP load duration curve and LDC implied by TSS daily profile



However, further to the LDC focusing on just 175 ½ hour periods or one percent in the year, unlike wholesale price peaks that may be volatile on such a time scale, network peaks are characterised by longer duration of ascension and descension in demand, which means that the periods adjacent to the maximum on a peak day also approach annual maximum demand. Hence even these few periods of maximum demand fall on an even smaller number days in the year.

The statistical consequence of this pattern is that the distribution of probabilities of reaching maximum demand in any period is an approximately normal distribution with “broadened” shoulders. Figure 12 below provides an estimate of the probability distribution by time of day of a top decile demand event in Endeavour's network.[45] This distribution is clearly not uniform. It suggests an approximate 75 percent chance that these annual network peaks will occur between 3:30pm and 7pm and 25 percent chance of occurring in the shoulder periods between 1-3pm and 7-9pm.

Figure 12 Approximate probability distribution of network peaks by time of day

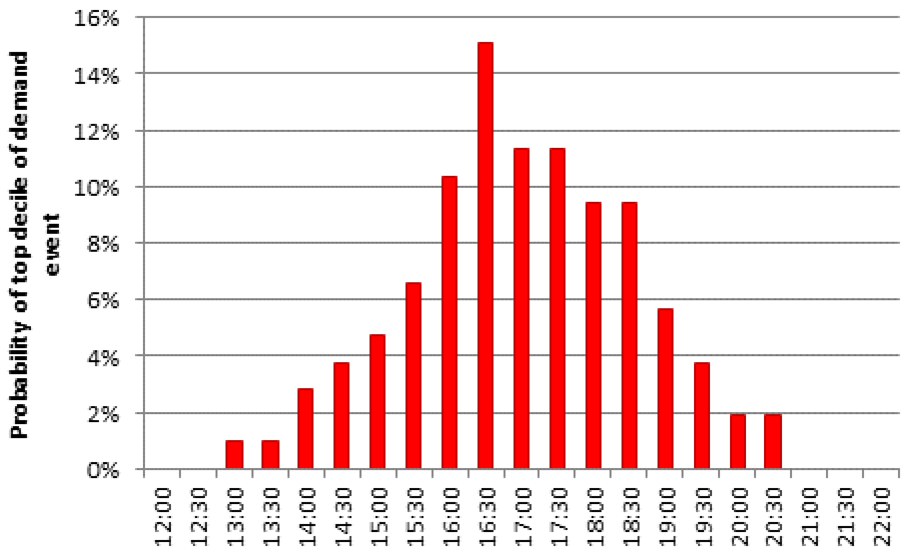


Figure 12 is entirely generalizable, that is a similar shape would derive from the analysis of the cumulative probability of a fleet of like assets.[46]

Frontier Economics' 'explainer' states that "the ex ante probability of the network peak demand occurring is similar across the daily peak demand window" (p 13). This assumption appears to be drawn from an interpretation of daily profiles that is unsustainable. It follows that the arguments dependent on this assumption, such as price signalling periods adjacent to a narrower peak window derived from annual peaks, would fail.

The ex ante probability of a network peak occurring in an adjacent period to a peak window derived from statistical analysis of historical peaks, while not zero, is significantly lower than the probability within the window. Conversely the probability that period is not a peak event is very high. It is a restatement of the argument above to say that applying the risk of such an event occurring on consumers through a wider peak window is imposing a cost on their more likely behaviour with a very low probability of an offsetting benefit.

[45] Derived from Figure 7.3, Endeavour Energy TSS Explanatory Statement, October 2016

[46] We use 'like assets' as this may include a clustering approach analogous to such as Ergon/Energia's approach dividing the zone substation asset level into a small number of categories.

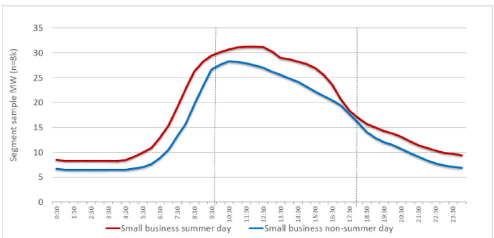
We note that the AER has apparently relied on daily profiles presented by network businesses in approving morning to evening peak charging windows for small business, with extracts below of some examples with regard to the Victorian Tariff Structure Statements.[47]

5.2.2 Small business customer charging windows

Figure 5-7 presents United Energy's small business demand profile for summer and non-summer months. The summer peak demand time period is roughly the same as the non-summer demand period but it is higher in terms of consumption, which we consider gives support for seasonal variation in demand charges. United Energy has determined that a demand charge window of 10am to 6pm workdays is most appropriate in meeting the desire for cost reflectivity balanced against other requirements, including minimising the customer impacts of the transition. We are satisfied that United Energy's proposed charging window reflects the higher cost of meeting customer demand during times of greatest network utilisation.

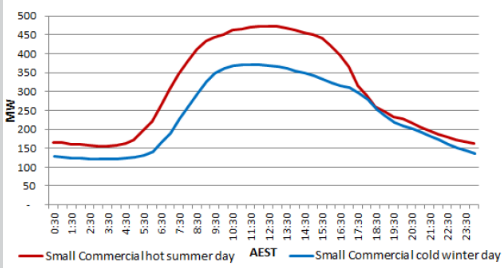
CitiPower and Powercor have proposed to measure demand between 10am and 6pm for small and medium business customers. This period reflects the timing of maximum demand on each of their networks, as shown in Figure 4-8 and Figure 5-9. CitiPower and Powercor have proposed to set higher demand charges for summer months than non-summer months as the networks experience more demand pressure during this period, shown by the red line in Figure 5-8 and Figure 5-9. We are satisfied that CitiPower and Powercor's proposed charging windows reflect the higher cost of meeting customer demand during times of greatest network utilisation.

Figure 5-7: United Energy - sample small business customer demand profile, MW



Source: United Energy, Revised Tariff Structure Statement, 29 April 2016, p.10.

Figure 5-8: CitiPower – sample small business customer summer/winter demand profile, MW



3.7.2 Congestion costs and standard control services

The DAPR aptly distinguishes between organic growth (increased demand from existing customers) and increases in connections or new block loads (customer expansion). The DAPR forecasts a significant increase in future customer numbers. Increases in new connections appear to be driving forecast congestion in at least some of the identified five (5) ZS, for example, Emerald.

[47] Final Decision, Tariff Structure Statement proposals, Victorian electricity distribution network service providers— CitiPower, Powercor, AusNet Services, Jemena Electricity Networks and United Energy, Australian Energy Regulator, August 2016.

Economic efficiency and the pricing principles (avoidance where feasible of cross subsidies) suggests that network costs arising from new demand should properly be recovered from capital contributions.[48] If new network infrastructure to meet expansion of the customer base is funded by other customers, this could result in networks inefficiently substituting for non-grid connected micro-grids.[49]

The 2016 DAPR indicates that not all congested ZS have been or are currently subject to a RIT-D process. It is possible that future developments could lead to further reductions in forecast increases in maximum demand. Demand forecast growth has been consistently overestimated for more than half a decade, as indicated by the changes to the AEMO's NEFR over this period. This raises the issue of whether it is reasonable for present day tariff structures to reflect possible future network augmentation that has yet to be subject to a RIT-D and about which there is considerable forecast uncertainty.

The boundary between standard control and new connection (alternate control)/capital contributions for the current ETSS period was settled in the context of the AER's current revenue determination to mid-2020. The 2016 DAPR forecast goes to mid-2021. Whether the boundary in the current revenue determination should apply from the final year of the DAPR forecast and beyond this is a matter that could and should be addressed in the Framework and Approach stage for the next regulatory price reset.

The Revised ETSS does not demonstrate that the cost of augmentation, to address the small amount of real congestion, should be recovered from network tariffs instead of from network connection charges or capital contributions which are outside the revenue cap for standard control services. If congestion costs were recovered from standard control tariffs, it would seem more efficient to apply local congestion pricing rather than distorting prices across the network.

3.7.3 Reference to contextual cross checks

Our analysis demonstrates shortcomings in the approaches and methodologies applied by the AER. These include reliance on misleading daily profiles and absence of cross checks to test the reasonableness of Tariff Statement proposals.

An example is reference to contextual information on the likely level of network congestion under conditions where maximum demand growth since 2010 has been low, while the regulated asset base has increased by more than 50 per cent. A similar cross check would be to compare the implied value of congestion with total allowed revenue.

[48] See for example page 7 of 'A new methodology for establishing a water entity's revenue allowance', Kieran Murray and Richard Tooth, 9th July 2015 available at: http://www.esc.vic.gov.au/wp-content/uploads/esc/46/46408491-8a59-4773-b956-ce1b27cc254a.pdf. The RAB-capital contributions boundary is fixed for the current regulatory period but can be addressed in the process for determining prices for the following regulatory period.

[49] A notable example is the micro-grid for the Huntlee development in NSW. See http://reneweconomy.com.au/us-giant-enters-australia-market-to-take-suburbs-off-the-grid-30744/

3.8 Broader implications

We recognise the difficulties in applying the new network pricing principles, for both networks and the AER. These arise from the limited guidance in the Rules on converting LRMC to tariff structures, alongside the fact there was no opportunity for the AER to develop a Guideline for the preparation of Tariff Statements. Such a process could have reduced the risk of distorted tariffs being developed and provisionally approved.

Final approval of a Tariff Statement that overstates network congestion by two (2) orders of magnitude would represent a regulatory error. The COAG Energy Council is currently reviewing the Limited Merits Review (LMR) regime. LMR allows parties affected by an AER decision to have the decisions reviewed by the Australian Competition Tribunal where it can be established there are grounds for this to occur; for example, regulatory errors and that addressing them would result in a materially preferable decision.

In its assessment of other Tariff Statements, the AER appears to have applied approaches and methodologies similar to those applied in reviewing Ergon's Tariff statement. For example, reliance on daily profiles is evident in the AER's August 2016 Final Decision on Victorian Tariff Statements,[50] and also its August 2016 Draft Decision on NSW Tariff Statements.

The evidence in this report demonstrates the shortcoming with these approaches and methodologies. A further shortcoming is apparent absence of cross checks. These should include reference to the implied value of congestion relative to total allowed revenue, load duration curve data and broader indicators of the likely level of congestion, given recent growth in regulated asset base values alongside flat or even falling maximum demand.

It is therefore possible that the AER's assessment of other Tariff Statements, including in its August 2016 Final Decision on Victorian Tariff Statements, may also be in error. This suggests the AER should consider an internal assessment of the adequacy of the entire Tariff Statement review work stream, organisational capability and quality assurance.

Substantially distorted and inefficient network tariff structures are not in the commercial interests of Ergon. They may encourage higher rates of network by-pass. It does not appear that Ergon obtained an independent assessment as to whether the ETSS conformed to the Rules.

Distorted tariffs could undermine public confidence in the integrity of both network pricing reform and network pricing regulation. This brings to mind the extended delays to the adoption of network pricing reform in Victoria due to controversy over the mandated introduction of smart meters under a jurisdictional derogation granting network monopolies over smart metering services. While there may be little benefit from introducing peak network pricing in Ergon, this is not the case over the entire NEM. A highly distorted tariff structure, if approved for Ergon, could have adverse implications for the credibility and acceptance of network pricing reform elsewhere in the NEM.

[50] See extract from AER Final Decision in Section 3.7.1 above.

Appendix 1 Summary of previous interactions with AER on ETSS

The authors first queried the AER's proposed approach to its assessment of the ETSS in a March 2016 memo to CANEGROWERS submitted as part of a CANEGROWERS submission to the *AER Issues Paper, Tariff Structure Statement Proposals, Queensland electricity distribution network service providers, February 2016,*[51] alongside a report to CANEGROWERS from the Alternative Technology Association. Among other things, our memo noted:

> *'The ETSS has provided insufficient evidence and analysis to support its proposed definition of charging windows. The ATA report for CANEGROWERS suggests these are far too broad compared with the shape of the demand profile (if it were made transparent). There is no basis under the NPO and principles for the pricing windows proposed in the ETSS.*

It also observed that the ETSS and supporting documents did not provide sufficient transparency to enable cross checks of Tariff Structure proposals and reconciliation with the AER's approved Post Tax Revenue Model.

These matters were presented to the AER in a meeting on 14th June 2016. The points raised in the March 2016 memo and subsequent meeting were dismissed in the AER's August Draft Decision.[52]

The key conclusions of our October review the AER's Draft Decision were:[53]

- 'The evidence and analysis provided in this review suggests that the key propositions on which the AER's Queensland DD to accept Ergon's Draft Tariff Statement are not evidence based.'
- 'The proposed tariff structures do not appear consistent with the network pricing objective. They allow the DSNSP to recover its regulated revenue. They do not send efficient signals about future network costs. Nor do they yield tariffs under which each customer pays for the costs caused by their use of the network.'
- 'In its Final Determination, the AER needs to make further enquiries of Ergon in order to assess whether gaps in the evidence base supporting the AER DD can be addressed. If these gaps cannot be addressed, the AER needs to consider revising key findings in the AER DD. This reassessment may require reconsideration as to whether the ETSS contributes to compliance with the pricing principles. The AER

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51 Available at http://www.aer.gov.au/system/files/AER%20-%20Issues%20paper%20-%20Queensland%20electricty%20distributors%20-%20Tariff%20structure%20statement%20proposals%20-%2011%20March%202016_0.pdf

52 See Appendix A to our October review of the AER DD.

53 See pages v-vii from Sapere report available at http://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20report%20-%20Review%20of%20AER%20draft%20decision%20Tariff%20Structure%20Statement%20proposals%2C%20Energex%20and%20Ergon%2C%20August%202016%20-%20October%202016.pdf

has the power either to require Ergon to undertake detailed analysis and justification of the proposed tariffs, or to amend the ETSS directly (Cl. 6.18.8(b) refers).'

In support of these conclusions, we noted the following points:

- The proposed seasonal peak charging windows are too broad and as a result the major effect may be to charge marginal prices for utilisation of infra-marginal capacity. The AER's finding on the definition of peak charging windows appears to rely on considerations of local congestion not provided in the ETSS or in the AER DD and hence is currently not evidence based. To the extent that local congestion is an issue, under the pricing rules, consideration would need to be given to placing locational boundaries on peak charges, alongside ensuring the charging windows reflect periods of greatest utilisation on the relevant local network elements.
- We queried the implication in the ETSS and acceptance by the AER, of the proposition that there is a substantial Ergon network congestion problem. We noted that Ergon's current Regulatory Information Notice indicates that substantial new augmentation capital expenditure resulted in the nominal Regulated Asset Base for standard control services increasing by 53 per cent or $3.5 billion over the five year period to mid-2015.[54]
- We noted the AER DD finds that the ETSS gradually increase the demand charge component of small customer demand tariffs to equal long run marginal cost. Given that the most recent outlook for demand growth is substantially lower than the outlook that informed the ETSS, alongside the likelihood of substantial spare capacity, it is currently highly uncertain whether any significant future marginal network costs would be triggered over the period of the ETSS. Accordingly, the AER conclusion on this point does not appear to be evidence based.
- We noted the ETSS states that incremental network demand forecasts are 'taken from the information provided to the AER as part of the October 2014 Regulatory Proposal.'[55] Maximum demand for standard control services changed less than two (2) per cent between 2010 (2,319MW) and 2015 (2,354MW).[56] In its 2014 proposal Ergon notes that over the course of the regulatory price control period, in response to lower than forecast demand growth, actual capital expenditure was less than approved capital expenditure. The change in the reliability margin following changes to jurisdictionally set reliability settings also enabled significant capital expenditure to be avoided during this period.[57] The most recent data suggest business forward demand (MW) in Queensland as a whole is not expected to grow rapidly over the next two decades. Separate forecasts for the Ergon network area and small business (versus residential) demand for the next two decades are not publicly available.
- There appears to be a lack of clarity and transparency in both the ETSS and the AER DD over the impact of avoided marginal network costs, attributable to cost reflective

54 See Table 3.3.1 of relevant Ergon RIN returns.

55 ETSS, p25.

56 See Ergon's Regulatory Information Notice, line DOPSD0106.

57 See Queensland Government (2011), *Electricity Network Capital Program Review 2011: Detailed report of the independent panel,* p73

tariffs, on allowed standard control network revenue. The AER's finding on this point does not, so far, appear to be evidence based.

- The AER DD finds that Ergon has accounted for customer impacts by making small customer time of use and demand tariffs opt in. Because of the very substantial penalty component in the third volume block, once the IBT is fully deployed, the IBT does not appear to provide a 'safe harbour', consistent with retaining customer choice and managing customer impacts. Under these considerations, the IBT may force customers to opt-out of the IBT, rather than opt-in to time of use and demand tariffs. The AER's finding on the IBT does not appear to be evidence based.
- The AER did not query the balance of revenue to be raised by LRMC based tariffs relative to "residual" based tariffs. While some aspects of the process of converting forward LRMC to LRMC based tariffs are discussed at length in the Tariff Statements, the overall method is not clearly articulated. The Draft Determination does not provide further clarification of this conversion. An understanding of the conversion would be assisted by improved transparency by way of a reconciliation between TSS proposals and regulated revenue. The basic question is, within total allowed revenue, what is the balance between forward LRMC and residual, and why? This suggested that the ETSS should be more transparent over the proposed total revenue split between tariff elements that recover LRMC vs. the residual for each proposed tariff class. Ergon states that it allocates its revenue cap to user groups. It provides a flow chart but not actual data on the revenue split.[58]

Shortly before finalising its review, we were invited to attend a meeting between CANEGROWERS and the AER at which our review was discussed.[59] It was agreed at that meeting that the AER would convene a further meeting in the second half of October to discuss the matters raised with Ergon itself. On 4th October, Ergon's Revised TSS was published by the AER.[60] Later that week, CANEGROWERS sent our review of the AER's Draft Decision to the AER, as part of its response to the Draft Decision.

Toward the end of October, the AER informed CANEGROWERS and Sapere that the scheduled three way meeting would take place on 2nd November. In preparation for that meeting, late on 30th November CANEGROWERS provided the AER and Ergon with a slightly expanded and modified version of our presentation pack from the September meeting with the AER. The main developments were in response to some changes arising from Ergon's Revised TSS. Some additional material was drawn from new data provided in revised NSW TSS. The new slide pack concluded that, after review of revisions to the ETSS, the key conclusions in Sapere's October Review continued to be valid.

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58 See ETSS Appendices, p80.

59 The Sapere presentation for this meeting is available at: http://www.aer.gov.au/system/files/CANEGROWERS%20-%20Sapere%20-%20AER%20draft%20decision%20on%20Ergon%20Tariff%20Structure%20Statement%20Review%20and%20comments%20for%20CANEGROWERS%20-%20September%202016.pdf

60 This is available at http://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/pricing-proposals-tariffs/ergon-energy-tariff-structure-statement-2015/revised-proposal

On 2nd November, Simon Orme, and James Swansson from Sapere accompanied CANEGROWERS, represented by Head – Economics Warren Males and the Chair of Economics Committee Rajinder Singh, attended a meeting with the AER and Ergon Energy, accompanied by Ergon consultants, Frontier Economics and Energeia. Around an hour before the meeting commenced, the AER distributed additional materials from Ergon via email including:

- a letter from Energeia to Ergon commenting on our slide pack distributed earlier in the week;
- a presentation pack from Energeia regarding 'Peak Period Optimisation', and
- an 'Explainer' on Ergon Energy's SAC-Small STOUD tariff by Frontier Economics.

The AER provided hardcopies of these documents on our arrival at the meeting but we were unable to review and respond to the new information during the course of the meeting.

Late on the afternoon of Friday 4th November we set out our initial analysis of whether the new material provided at the meeting of 2 November changed the conclusion in our October review of the AER Draft Decision. This was forwarded via email by CANEGROWERS to the AER and Ergon. The key conclusions were that the additional information confirmed our earlier identification of evidence gaps was justified and that further it was not sufficient to support the AER's Draft Decision. Further information regarding the network peak optimisation method (such as the report from which the slide pack was drawn) is required to address the gap in the evidence base for the Tariff Statement proposals.

On Monday 7th November, in response to the Friday email, the AER stated that *'We will be in contact if we have further questions or require a discussion.'* This could be interpreted as suggesting the AER sees no need to make any further enquiries regarding the matters raised in the 4th November initial analysis and did not propose to refer to these matters in its Final Decision. This interpretation is also suggested by AER staff suggesting in both meetings that canegrowers should be able to modify their demand profiles to minimise or avoid exposure to Ergon's seasonal peak tariffs.

In other words, the response suggests the AER was not of a mind to change the main conclusions in its Draft Decision. In response, later that day, CANEGROWERS informed the AER it would submit a formal response to the new material presented by Ergon.

Memorandum

13 January 2017

To: Craig Madden, Dale Johansen, Kristi Falconer, Qldtss2016
From: Simon Orme, Dr. James Swansson
CC Warren Males, CANEGROWERS
Re: Ergon Energy's response to Canegrowers – Sapere further submission

Dear Craig,

Thank you for your email of 21 December 2016 attaching Ergon Energy's 12 December response to our report *Errors in Australian Energy Regulator's Draft Decision on Ergon Energy's 2016 Tariff Structure Statement*, dated 22 November 2016, and including attached new material from Frontier and Energeia.

This memo provides a brief response to Ergon's letter and attachments. We think it important to convey to the AER our view that Ergon's response does not invalidate the finding in our November report that the conclusions in the AER's October Draft report are contradicted by the available public information, most notably Ergon's 2016 Distribution Annual Planning Report (DAPR).

We emphasise that our analysis is consistent with a Long Run Marginal Cost (LRMC) approach, as required under the Rules. Our key point is that, properly applied, an LRMC approach needs to take into account existing spare capacity for all but 2 per cent of Ergon's Zone Substations (ZS), rather than merely assuming that the top 5 per cent of demand always utilises marginal capacity. Once this is recognised, Ergon's conclusion (implicitly accepted by the AER in its Draft Decision) that LRMC represents 50 per cent of a typical residential bill is a substantial over-estimation of network congestion.

This memo incorporates slight revisions to an earlier version dated 22 December 2016. For your convenience, these are highlighted in track change.

A) Our conclusions remain valid

The new information in Ergon's letter and attachments does not contradict the factual and rules-interpretation matters on which our 22 November conclusions are based, most notably the following points.

a) For 98 per cent of Ergon's ZS, the top five percent of Ergon's currently forecast annual maximum demand (in its 2016 DAPR) does not exceed firm capacity and therefore is unlikely to trigger a requirement for network augmentation for the entire Tariff Statement period (to 30 June 2020), and the following year (to mid-2021).

b) That is to say, none of the information in Ergon's 12 December letter and attachments demonstrates the top five (5) per cent of maximum demand for 98 per cent of ZS would be likely to trigger *'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.'* (Section 6.18.(5)(f)(2). This means that, for 98 per cent of ZS, the top five (5) percent of demand is likely to represent use of infra-marginal not marginal capacity for the duration of the relevant Tariff Statement period.

c) With respect to the remaining two (2) per cent of ZS, the new information does not challenge or contradict our conclusion that there appears to be no basis under the pricing principles for recovery of network augmentation costs from standard control rather than alternate control (or negotiated) services, to reflect the fact the requirement for augmentation appears to arise from new connections rather than existing connections (connections growth, not demand growth from existing connections). This means the proposed tariff structure fails the third test in the AEMC's definition of cost reflective network tariffs – '*Each consumer should pay for the costs caused by its use of the network.*'

d) Frontier confirms that, for a typical residential customer, the LRMC component of the tariff represents 50 per cent of their annual bill (that is to say Ergon is proposing that aggregate congestion costs for low voltage customers represents around $1.8 billion over the five year period to 30 June 2020). However, there continues to be no evidentiary basis for a conclusion this quantum reflects Ergon's efficient costs of providing those services to the defined retail customers for that period.

e) The new information does not change our conclusion there is no cost or demand response-related evidence base in the public domain to support retention of an Inclining Block Tariff structure under the new pricing principles.

f) The new information does not change our conclusion that average daily profiles are not sufficient to support conclusions on the definition of seasonal peak charging windows, due to the necessarily reductive nature of daily profiles.

g) The costs of applying congestion prices, in the absence of evidence there is a high probability of actual congestion costs arising over the duration of the Tariff Statement (suppressed demand and network by-pass), are likely to exceed the benefits (avoided network augmentation costs and lower future network prices than otherwise). That is to say, the proposed tariff structures do not conform to the NEL objective.

B) Elaboration on post 30 June 2021 LRMC

There is one issue raised in the two responses prepared for Ergon that does require elaboration. This relates to the suggestion our analysis is at odds with the requirement in the Rules for network tariffs to reflect Long Run Marginal Cost (LRMC). This is not the case. Our analysis is consistent with the Rules.

We acknowledge that possible higher than currently forecast future growth in maximum demand, even where it is limited to infra-marginal capacity, may bring forward (or increase the likelihood of) the point at which the top five (5) per cent of maximum demand triggers a marginal capacity threshold, potentially requiring additional future network augmentation expenditure. We also acknowledge that this threshold could possibly be crossed before or beyond 30 June 2021. Our responses on this point are set out below.

1. Structural changes in future demand can be addressed by modifying Tariff Statements

We recognise there may be future structural changes in future and future forecast maximum demand. A good example of such a development could be a faster and more widespread electrification of light transport than expected under current forecasts. It is certainly possible that maximum demand growth to 30 June 2021 could exceed the central forecast in Ergon's 2016 DAPR (and included in the per ZS maximum demand forecasts at 10 per cent POE).

As the AER is aware, there are already provisions in the Rules to enable networks to seek to modify their Tariff Statements before the expiry of the current approved Tariff Statement (out of cycle). In addition, new information around demand trends can be incorporated into the next scheduled Tariff Statement review (within cycle) for the subsequent Tariff Statement period (starting 1 July 2020). The possibility of future congestion costs arising that are not forecast at the time a Tariff Statement is assessed by the AER does not in itself justify a decision to apply congestion pricing to current and future infra-marginal demand over the period to 30 June 2020.

2. Need to quantify spare capacity for purpose of aggregate LRMC calculation

In reaching its findings in its October Draft Decision, the AER does not refer to any evidence on the public record that Ergon adjusted the estimate of aggregate LRMC (on which the LRMC component of its tariff structures is based) to take into account existing and forecast spare capacity to mid-2021 and beyond. This should, however, be an explicit element in the calculation converting unit LRMC to aggregate LRMC (rates and charging windows). This key point is explained on page 114 of: *Our plan for the future: Sydney Water's prices for 2016-20; Appendices – Public version*.[1]

> *'By definition, the LRMC of water resources is a forward-looking concept. It estimates the change in costs of the water supply system for a given change in output. LRMC ignores the cost of past investments for the purposes of calculating LRMC. But it includes any unused capacity from those investments (technically, the benefit of that unused capacity in terms of water demand met and the costs of using it). For simplicity, we refer to this as 'spare' capacity. Starting from current levels of demand and supply capacity, the LRMC calculation estimates how long it will be before current 'spare' capacity is used up and hence when investment in new capacity is likely to be needed. The greater the spare capacity, the longer it will be before new investment is needed, and the lower the LRMC figure will be, because of the 'time value of money'.*[2]

That is to say, there is no evidence adduced in the AER's Draft Decision that Ergon has taken existing spare network capacity into account in determining the LRMC component of its various tariff structures. To the extent the AER's conclusions in its Draft Determination take into account existing and forecast spare network capacity, this is not supported in the public body of evidence provided by Ergon, cited in the AER's Draft Determination.

For example, if a 50 year investment horizon is applied, and it is assumed that forward LRMC is on average $2m per year ($100m in aggregate), then the LRMC estimate would need to be adjusted for existing spare capacity. If spare capacity were equivalent to the first 20 years of demand growth ($40m), then LRMC would need to be adjusted to $60m.[3] In addition, to the time value of money point, it may also be prudent to incorporate a further discount for assumed efficiency gains over the first 20 years. In other words, in present value terms, LRMC would be significantly lower than $60m.

3. Uncertainty over future demand forecasts

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[1] Available at https://www.ipart.nsw.gov.au/files/sharedassets/website/trimholdingbay/sydney_water_s_proposal_to_ipart_on_prices_to_apply_from_1_july_2016_%E2%80%93_appendices_%E2%80%93_public_version.pdf

[2] This statement is not strictly correct. The principal reason the aggregate LRMC will be lower is because the volume of LRMC will be reduced to the extent future increases in maximum demand utilise existing spare capacity rather than requiring augmentation (or replacement) capital expenditure.

[3] This is obviously a simplification; in reality some spare capacity will used up earlier or later than given in this example.

The only publicly available forecast of Ergon maximum demand we have been able to locate is that contained in the 2016 DAPR, up to 30th June 2021. To the extent the AER's conclusions rely on forecasts of maximum demand growth extending beyond 30 June 2021, they must be based on information that is not in the body of publicly available evidence incorporated in Ergon's Tariff Statement and supporting documents.

As the AER is aware, there is a great deal of uncertainty over maximum demand growth over the period beyond mid- 2021. This is reflected in the difference between the 2016 and previous AEMO National Energy Forecast Report (NEFR) for the whole of Queensland, referenced in our October report. As noted in our November report:[4]

- *The indicative STOUD and STOUE rates in the 2016 Revised ETSS in Table 2 above barely changed compared with the 2015 ETSS. This indicates there may have been no substantial revision in the estimation of future network congestion in the 2016 Revised ETSS.*
- *The right hand column shows there have been substantial revisions in the [IBT] rates between the Revised 2016 ETSS and the 2015 ETSS. This is in contrast to the virtually unchanged rates for STOUD and STOUE shown in Table 2 above.*
- *The overall increase in [IBT] rates may reflect an updated demand (volume) forecast, possibly with lower volumes, consistent with the 2016 DAPR and the Australian Energy Market Operator's National Energy Forecast Report (NEFR).*

This indicates Ergon's revised 2016 Tariff Statement does not adjust STOUD and STOUE rates (which with the charging windows corresponds to the LRMC component of those tariffs) to reflect the reduction in forecast maximum demand growth between the 2016 DAPR from the 2015 DAPR.

First, this highlights the uncertainty and challenges in setting the LRMC component of current tariffs against changing and uncertain future maximum demand. Second, it suggests that Ergon is not in fact adjusting its tariff structures to reflect the increase in spare capacity (reduction in LRMC) represented by the downward revisions to the demand forecast contained in the 2016 DAPR.

4. Conclusions on LRMC component of proposed tariff structures

Drawing the above three points together, with reference to congestion costs beyond 30 June 2021, the LRMC calculation should incorporate the value of avoided LRMC equivalent to existing spare network capacity in 98 per cent of the Ergon low voltage network (represented by ZS). The revised Ergon Tariff Statement and supporting documents do not appear to provide sufficient evidence to conclude it is reasonable for future LRMC to represent 50 per cent of a typical annual residential bill for the period from 1 July 2017 to 30 June 2020.

C) Other comments

We are not seeking in this memo to rebut all of the points raised in the attachments to Ergon's letter. Our overall comment is that most of the responses either do not address the key propositions in our November report (see section A), or misrepresent statements made in our report (and are often a mixture of the two).

a) **We are not seeking to propose alternative tariff structures.** Ergon's letter and attachment imply that our November report seeks to propose an alternative tariff structure. This is not the case. While over the course of the engagement with the

[4] See pages 3-4.

AER since March we have made some observations on tariff design, our focus has always been on whether the proposed tariff design is consistent with the network pricing rules. We have not attempted to propose an alternative tariff design that would be consistent with the rules. Criticisms on this point do not invalidate our conclusions.

b) **Misrepresentation of our report by Frontier.** On page 21 of the Frontier attachment, a statement is made that: *'… it is false for Sapere to claim that '…for typical residential customers, Ergon is defining its peak seasonal charging windows and setting seasonal peak rates* ***so they represent*** *50 per cent of the total network annual [unit][5] price…[Emphasis added]'* However, the preceding statement by Frontier confirms the our statement above is accurate (excluding the incorrect inclusion of the word "unit" which is not the basis for the Frontier claim). As Frontier states: '*This is because approximately one quarter of the typical customer's bill (half the network bill) would be attributable to the summer peak demand charge. Ergon Energy did not determine its STOUD tariff to reflect this 'one to two' relationship – it is merely a description of how the tariff is expected to affect a typical residential customer.'* In other words, the content of the propositions on this point in our discussion and the Frontier discussion are identical. Further, our discussion is entirely consistent with Frontier's subsequent observation that '*Different… customers will find the summer peak demand charge represents different proportions of their network and retail bills.'* Indeed, we make the very same observation: *'It also suggests the peak to non-peak revenue ratio could be above or below a 1 to 2 ratio depending on whether individual demand during the peak charging windows is more or less than that for typical residential customers.'* Contrary to Frontier's assertions, there is no conflict between Frontier's and our propositions regarding the intended impact of the LRMC component of proposed tariffs for typical and non-typical customers. There is, however, a clear contradiction between Frontier's propositions and its assertion that our statement on this matter is false.

c) **Misrepresentation of our report by Energeia.** Page 13 of Energeia's letter implies that our analysis relies on system demand data (and hence that our conclusions on the spatial aspect of network congestion are incorrect): *"A key difference between distribution network costs and generation costs is that the latter [sic] are driven by spatial demand, not system demand. There can be, and often there is, growth at the spatial level that is masked by the averaging inherent in the calculation of system demand. It is therefore industry best practice to use substation load interval data rather than less accurate system load interval data. Although zone substation interval data is readily available, Sapere's analysis relies on Net System Load Profile (NSLP) interval data.'* Our analysis explicitly relies on Ergon's ZS data, which includes both the time and the duration of the top five per cent of maximum demand. While we did not refer to ZS interval data, reference to this data is not necessary to reach the conclusion that the duration of historical congestion, according to one of the excel spreadsheets accompanying the DAPR, is 54.5 hours or 0.62 per cent of the year, not 650 hours and 7.5 per cent of the year (as far as can be assessed from the Energeia peak optimisation slide pack, its optimisation method is also based on historical data).

d) **Other problems with Energeia's peak optimisation methodology.** Energeia's response suggests that its conclusions regarding the appropriateness of the peak demand windows in the STOUE and STOUD tariff structures are based on a method that is undocumented beyond the presentation pack produced shortly before

[5] The term "unit" is in our November report but this is an error on our part. The intended reference is to the annual price ("bill") for the consumption volume and demand profile of the typical customer as defined by Ergon itself.

our last meeting in November. This method is openly dependent on a reductive approach using daily data profiles that employs information about some hours on some days in some months and applies it to all hours of all days with equal probability, when the probability is in fact unequal. Energeia's method may well be 'innovative', but without a full description there is no opportunity to assess the method, either against similarly reductive methods of obtaining daily profiles, or against approaches that are not reductive at all, but retain all information about all periods. In addition, as noted in Section A) above, the Energeia peak optimisation method fails to make the distinction between infra-marginal and marginal demand necessary to derive LRMC.

Concluding comments

Thank you for confirming that Ergon's 12 December letter and attachments, alongside this memo, will be published on the AER website and hence form part of the evidence base for the AER's Final Decision.

We trust the comments above are clear and self-explanatory. We are anxious to minimise any risk that the AER misconstrues the analysis in our November report and in this memo.

Once again, we wish to emphasise that our analysis is consistent with an LRMC approach required under the Rules. Our key point is that, properly applied, an LRMC approach needs to take into account existing spare capacity, rather than merely assuming that the top 5 per cent of demand always utilises marginal capacity. Once this is recognised, Ergon's conclusion (implicitly accepted by the AER in its Draft Decision) that LRMC represents 50 per cent of a typical residential bill is a substantial over-estimation of network congestion.

We are of course available and would welcome any opportunity to respond to any queries you may have.

Yours sincerely

Simon Orme