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31 January 2020

Mr Charles Millsteed
Chief Executive Officer
Queensland Competition Authority
GPO Box 2257
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Via email: charles.millsteed@qca.org.au

Dear Mr Millsteed

Regulated retail electricity prices for 2020–21

Thank you for the opportunity for CANEGROWERS to respond to the Interim Consultation Paper issued for the regulated retail electricity price determination 2020–21.

Representing around 75 per cent of Australia's sugarcane growers, CANEGROWERS is the peak body for the sugarcane industry in Australia. The Queensland sugar industry relies heavily on irrigation. The cost of the electricity used in that task is threatening the international competitiveness of farmers in our industry and in other agricultural industries across the state. CANEGROWERS is also an active member of Queensland Farmers' Federation (QFF) and endorses the concerns raised by QFF in its response to the Queensland Competition Authority's (QCA) Interim Consultation Paper.

Like QFF and many others, CANEGROWERS is deeply concerned about ever escalating electricity prices.

For the 2020-21 retail price determination, CANEGROWERS recommends QCA:

- ***Consult** users closely over the N and R components of retails prices before the final regulated retail prices for the Ergon network for 2020-21 are determined.*
- ***Not** adopt an indexation approach to smooth retail prices for use in its 2020-21 retail price determination.*
- ***Develops** a new benchmark or uses the AER's methodology in setting the DMO in setting the DMO when determining retailer costs for the Ergon network.*
- ***Provides** the analysis required to compare the additional standing offer services that support the application of any standing offer adjustment.*

As acknowledged in the Interim Consultation Paper, QCA's price review for 2020-21 is occurring before the AER has delivered its final decision on the Regulatory Proposal and Tariff Structure Statement 2020-25 Energy Queensland's has lodged for its Energex and Ergon networks. We agree, the two processes are inextricably linked. Taken together, the setting of regulated network prices by the AER and the setting of other retailer costs by QCA should determine the final retail prices paid by small business and residential customers in regional Queensland from 1 July 2020. We share QCA's concern that the AER may not have issued a final determination on regulated network prices by the time QCA makes a final determination on retail prices, inclusive of regulated network prices. Our recommendations reflect this concern.

As an acknowledgement of the intwined nature of the impending AER decision on network prices for both the Energex and Ergon networks and the QCA's determination of retail prices for regional Queensland for 2020-21, CANEGROWERS with the support if funding from Energy Consumers Australia (ECA) CANEGROWERS engaged the Sapere Research Group (Sapere) to assist and provide expert advice informing the preparation of this submission and our response to the AER. Sapere's report in relation to these matters is **attached**.

In relation to the QCA retail price determination Sapere's report contains several very important findings:

- **Consultation Question 3**: there is a high level of uncertainty over the outcome of the AER review of EQ's revised tariff structure proposals. Under these conditions, it is preferable for QCA to apply a flexible N+R approach where there is an opportunity to consult over retail price structures before retail tariff decisions are made.
- **Consultation Question 5**: because it would exceed any reasonable estimate of the actual costs of making, producing or supplying the goods and services, using an indexation approach to smooth the N component of retail prices between the period 2019-20 and 2020-21 would be inconsistent with the *Electricity Act 1994*.
- **Consultation Question 7**: the fact that the federally determined Default Market Offer (DMO) price exists, confirms that QCA's existing retailer cost index should not be applied. Instead, it is important that QCA develops a new benchmark or uses the AER's methodology in setting the DMO when determining retailer costs for the Ergon network.
- **Consultation Question 8**: QCA has not demonstrated that its standing offer adjustment, a 5 per cent mark up on benchmark retailer costs "reflects the more favourable terms and conditions in standard contracts" than market offers including the DMO. Neither has QCA demonstrated what the economic value of those more favourable terms and conditions may be. Hence it is not possible to assess whether this premium reflects the actual costs of those premium services consistent with Section 90 (5). Therefore, it is important that the QCA's draft determination provides the analysis required to compare the additional standing offer services that support the application of any standing offer adjustment.

These findings underpin CANEGROWERS recommendation to QCA.

Conclusion

CANEGROWERS acknowledges the steps taken by Energy Queensland to improve the Regulatory Proposals and Revised Tariff Structure Statements 2020-25 for its Ergon and Energex networks. However, reflecting its concerns the Energy Queensland's revised regulatory proposal and Tariff Structure statement are not consistent with the rules and not in the long-term interests of consumers, CANEGROWERS has recommended further AER intervention ahead of its final network price decision for both the Energex and Ergon networks.

Given the uncertainties and to support economic growth and development across regional Queensland, CANEGROWERS urges QCA to closely consult energy users across regional Queensland before it determines a final retail tariff structure for 2020-21.

Yours faithfully

Dan Galligan
Chief Executive

CANEGROWERS

Regional Queensland distribution and retail price determinations - Ergon Energy revised proposal 2020-2025 and QCA issues paper 2020-21

Simon Orme, Dr. James Swansson

January 2020

sapere research group

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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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1. Introduction

1.1 Report objectives and scope

The authors have been retained by CANEGROWERS to provide expert advice to assist CANEGROWERS prepare:[1]

- A submission to the Australian Energy Regulator (AER) on Energy Queensland's (EQ) *Ergon Energy revised regulatory proposal 2020-25* and *Revised Tariff Structure Statement [TSS], 2020-25*, both dated December 2020. These revised proposals are in response to the AER's *Draft Decision: Energy electricity distribution determination; Energex and Ergon Energy, 2025-25*, dated October 2019.
- The Queensland Competition Authority (QCA) *Interim consultation paper regulated retail electricity prices [for regional Queensland] for 2020-21*, dated 11 December 2019.

Together, the setting of regulated network and other retailer costs will determine the network and retail prices to be paid by small business and residential customers in regional Queensland starting from 1 July 2020. Regulated network charges are the largest single component in consumer bills, representing between 40 and 43 per cent of total bills. In addition, the QCA has indicated its decisions on retail tariff structures for regional Queensland will be influenced by the final outcome of the AER's consideration of EQ's network tariff structure proposals for Energex.

A key issue identified in the QCA paper is the possibility the AER may not have issued a final determination on regulated network prices by the time the QCA makes a final determination on retail prices, inclusive of regulated network prices. Accordingly, there are strong linkages between the two regulatory processes, as discussed in this report.

With regard to the submission to the AER, this report builds on a series of reports and submissions we have prepared for CANEGROWERS pointing out that the tariff structures Energy Queensland has proposed for its Ergon and Energex networks are not based on Long Run Marginal Cost (LRMC) and therefore not consistent with the relevant national electricity rules and specifically the distribution pricing principles. The most recent report in this series is *QLD electricity distribution determinations - Energex and Ergon Energy 2020-2025: Submission to Australian Energy Regulator's Issues Paper on distribution*, dated June 2019.[2] That report also contains references to earlier reports.

1.2 Key points

With respect to network tariffs, the main finding of this report is that:

- The LRMC component of Ergon's total revenue requirement appears to have decreased in the revised proposal, at four per cent, relative to six per cent in the original proposal.

[1] CANEGROWERS received funding from Energy Consumers Australia to support the network analysis

[2] Available from AER https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ergon-energy-determination-2020-25/proposal#step-63380

This appears to reflect reductions in proposed capital expenditure (CAPEX) that exceed reductions in the other key revenue building blocks. If reasonable, the proportional increase in LRMC supports a higher proportion of tariff LRMC than would have been the case under the original revenue proposal.

- The historical and forecast RAB trend is decreasing, especially in real terms. This aligns broadly to the forecast flat demand. This broad alignment is a significant improvement from Ergon's proposals for the 2015-2020 revenue control period, which incorporated what have turned out to be inaccurate forecasts of maximum demand growth.
- There remains the possibility that the downward trend in the RAB (in real terms) may not be sufficient against a background where there is substantial excess capacity. We are, however, unable to comment further on this matter without undertaking a full review of CAPEX.
- EQ has made substantial progress toward ensuring that Ergon and Energex Energy's tariff structures are in fact cost reflective and conform with the relevant National Electricity Rules.
- Ergon's two new optional tariffs do not yet appear to be cost reflective, even after allowing a high allocation of total LRMC to residential and small business customers.
- In the context of Queensand's uniform tariff policy, it may be of concern that Energex's two new optional tariffs appear less cost reflective than those for Ergon.

With regard to the submission to the QCA, our most recent report is: *Comments on Queensland Competition Authority Draft Determination for Queensland regional electricity prices, dated April 2019*. That report focused on two issues:

- The estimation of retailer costs, and in particular whether the QCA methodology includes non-existent retailer costs.
- Whether the QCA referred to any empirical evidence in forming a view that legacy irrigator tariffs that are being phased out are cross-subsidised by other consumers.

With respect to retail tariffs in regional Queesland the main finding of the report is:

- There is a high level of uncertainty over the outcome of the AER review of EQ's revised tariff structure proposals. Therefore, it is important that QCA apply a flexible N+R approach. Especially where there is an opportunity to consult over retail price structures before final retail tariff decisions are made.
- An indexation approach to calculating the N component is likely to exceed any reasonable estimate of the actual costs of making, producing or supplying the underlying goods and services. Therefore smoothing the N component of revenues for 2019-20 and 2020-21 would be inconsistent with the Electricity Act 1994.
- The very existence of the AER's Default Market Offer (DMO) implies that the QCA's existing retailer cost index should not be applied.
- It is far from clear there is any basis, under the statutory framework governing this review, for including a standing contract adjustment and market headroom adjustments being proposed. The AER's methodology for setting the DMO already incorporates ample market headroom. It is unclear whether the standing contract mark up represents an estimate of additional value or instead merely an indication of the consumer inertia or lazy tax that gave rise to the need for a DMO.

1.3 Report structure

The structure of the remainder of this report is as follows.

Section 2 analyses Ergon and Energex's populated PTRM models to derive an estimate of the proportion of the total revenue requirement that is LRMC, that is in effect LRMC 'network costs' to be recovered from consumers.

Section 3 establishes the proportion of revenue for cost reflective tariffs that Energy Queensland proposes to be LRMC based, focused on the 'cost reflective' tariffs – default transitional demand and optional demand and time of use tariffs for small residential and small business customers. These can then be compared with the percentage LRMC cost can then be compared with LRMC percentage required revenue from section 2.

Section 4 addresses the network component of the QCA's Interim Consultation Paper on regulated retail electricity prices for 2020.

Section 5 addresses the retail component of the QCA's Interim Consultation Paper on regulated retail electricity prices for 2020.

2. Revised revenue proposal (network)

2.1 Key points

- The LRMC component of Ergon's total revenue requirement appears to have decreased in the revised proposal, at four per cent, relative to six per cent in the original proposal. This appears to reflect reductions in proposed capital expenditure (CAPEX) that exceed reductions in the other key revenue building blocks. If reasonable, the proportional increase in LRMC supports a higher proportion of tariff LRMC than would have been the case under the original revenue proposal.
- The historical and forecast RAB trend is decreasing, especially in real terms. This aligns broadly to the forecast flat demand. This broad alignment is a significant improvement from Ergon's proposals for the 2015-2020 revenue control period, which incorporated what have turned out to be inaccurate forecasts of maximum demand growth.
- There remains the possibility that the downward trend in the RAB (in real terms) may not be sufficient against a background where there is substantial excess capacity. We are, however, unable to comment further on this matter without undertaking a full review of CAPEX.

2.2 Analysis of LRMC relative to demand and RAB trends

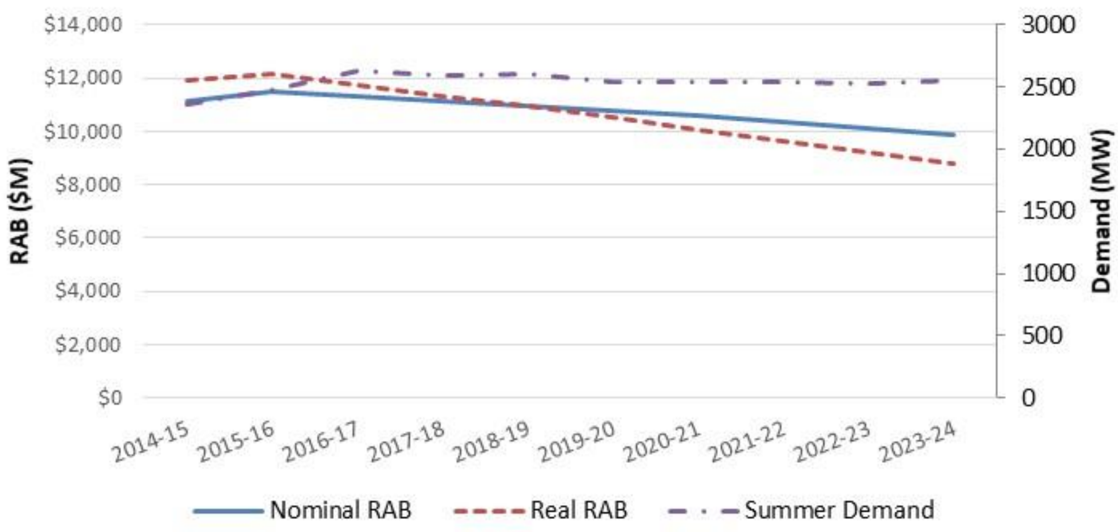
The LRMC component of Ergon's total revenue requirement appears to have decreased in the revised proposal, at four per cent, relative to six per cent in the original proposal. This appears to reflect reductions in proposed capital expenditure (CAPEX) that exceed reductions in the other key revenue building blocks.

For present purposes, the significant point is that, if reasonable, the proportional increase in LRMC supports a higher proportion of tariff LRMC than would have been the case under the original revenue proposal.

A comprehensive review of the reasonableness of proposed LRMC (CAPEX) relative to total regulated cost building blocks is beyond the scope of this paper. As set out in our June 2019 report, there is ample spare capacity in most of Ergon's network for future demand growth.

We have nevertheless reviewed trends and forecasts in the RAB from 2014-15 through to 2024-25. We have then compared these with historical maximum and forecast maximum demand (at POE50 for the forecast). The outcome of this analysis is summarised in Figure 1 below.

Figure 1 Forecast change in maximum demand relative to forecast change in the Regulated Asset Base



Source: Sapere analysis of revised PTRM, RBA deflater, 2019.

Figure 1 shows that change in maximum demand (which occurs in summer) has been and is expected to be somewhat flat over the entire period. Indeed, maximum demand has not materially increased since 2006/07.[3] As discussed in our June 2019 report, the major source of increase maximum demand over the period appears to be associated with liquified natural gas production rather than changes in demand from residential and small business customers.

The historical and forecast RAB trend is decreasing, especially in real terms. This aligns broadly to the forecast flat demand. This broad alignment is a significant improvement from Ergon's proposals for the 2015-2020 revenue control period, which incorporated what have turned out to be inaccurate forecasts of maximum demand growth.

There remains the possibility that the downward trend in the RAB (in real terms) may not be sufficient against a background where there is substantial excess capacity. We are, however, unable to comment further on this matter without undertaking a full review of CAPEX.

2.3 LRMC portion of network costs – data and methods

2.3.1 Reference to ACCC findings

The extent of prudent incremental LRMC depends on both future demand trends, as discussed in the section above, and the extent of any existing excess capacity. Other things

[3] See for example Figure 18: Trend in System-wide Peak Demand, from the 2019 DAPR.

being equal, any requirement for future augmentation is lower to the extent there is excess network capacity.

ACCC recommended in its July 2018 final report *Restoring electricity affordability & Australia's competitive advantage* that Energy Queensland assets should be written down as this would 'enhance economic efficiency by reducing current distorting price signals.'

> **Recommendation 11**
>
> The governments of Queensland, NSW and Tasmania should take immediate steps to remedy the past over-investment of their network businesses in order to improve affordability of the network. With appropriate assistance from the Australian Government, this can be done:
>
> - in Queensland, Tasmania and for Essential Energy in NSW, through a voluntary government write-down of the regulatory asset base
> - in NSW, where the assets have since been fully or partially privatised, through the use of rebates on network charges (paid to the distribution company to be passed on to consumers) that offset the impact of over-investment in those states.
>
> Such write-downs would enhance economic efficiency by reducing current distorting price signals. The amount of the write-downs and rebates should be made by reference to the estimates of over-investment by the Grattan Institute, and should result in at least $100 a year in savings for average residential customers in those states.

This reflected its finding that there had been over-investment in capacity in the past. The ACCC's July report referred to evidence from the Grattan Institute suggesting that nearly half of Ergon's RAB growth may have been in excess of the capacity required to meet maximum firm demand under a once in a decade demand event.

Table 1 Queensland's network RAB growth

Network	Excess growth	As percentage of RAB growth
Energex	$1673–3935m	26% to 61%
Ergon Energy	$2442m	48%
Powerlink	$885m	24%

2.3.2 Approach to estimating the LRMC portion of total network costs

Consistent with our June 2019 report in response to the AER's Draft Determination, we have calculated LRMC using the forward-looking component of total revenues as set out in the Post Tax Revenue Model (PTRM) for Ergon. The PTRM is among other things a model for converting incremental LRMC for a given period into an increment to the annual revenue requirement for each year within that same period. The PTRM typically draws on the revenue requirement for the last year of the current revenue control period (in this case 2019-20) and forecasts this for two future revenue control periods for a decade (in this case to 2030).

The PTRM uses inputs for current capacity, the demand forecast and CAPEX, regarding both the unit rates for different types of new network capacity (e.g. transformers and feeders), as well as inputs on the volume of new assets and the capitalised labour required for installing new capacity. From these two kinds of inputs, the PTRM calculates the change in the total revenue requirement associated with incremental capacity.

The change in the revenue requirement associated with increasing capacity by a certain increment, for example in response to rising peak demand or change in reliability regulations, represents a measure of the incremental LRMC. To be very clear, the resulting incremental increase in the revenue requirement represents incremental LRMC not incremental Short Run Marginal Cost (SRMC).

Expenditure on expanding total network capacity is set out in the PTRM input sheets, and specifically inputs regarding forecast capital expenditure (CAPEX) and forecast customer contributions expenditure. The latter expenditure is not recovered from regulated network tariffs, but instead via customer contributions and hence is not relevant for tariff design purposes. CAPEX may be further sub-divided into expenditure to augment the regulated network (AUGEX) and other CAPEX, for example replacement capital expenditure (REPEX), and other CAPEX categories.

The PTRM typically adjusts the major cost building blocks in response to changes in total regulated CAPEX. This occurs automatically in relation to the largest cost building block: Return on capital, and also relation to the return of capital (depreciation) cost building block. The PTRM may also adjust operating and maintenance expenditure (OPEX), but this may not always be the case.

Where incremental LRMC varies from year to year within a regulatory period, this variance is dealt with by the smoothing mechanism or X factor. It is possible and indeed likely that the total incremental LRMC for one five-year period differs from the total incremental LRMC for the preceding or following five-year period. But this does not justify increasing the LRMC revenue requirement in one five-year period in case the LRMC revenue requirement in a succeeding five-year period (for a set of assets that are not yet approved or under construction) could turn out to be higher. That approach would be equivalent to pre-empting the following price or revenue reset determination by the AER. It may also breach the Australian Consumer Law (charging for a non-existent service).

The LRMC component of the total revenue requirement has been calculated in both cases by calculating the incremental impact on total revenue of removing all regulated CAPEX from the PTRM's for Ergon and Energex. The resulting reduction across the cost building blocks reflects the incremental impact of the forward looking component total costs. No change was made to PTRM inputs, other than removal of CAPEX.

The difference in the total revenue before and after the removal of CAPEX is the impact of the CAPEX on network costs. It therefore indicates, for the network as a whole, the LRMC or forward-looking portion of its total costs.

Note that for present purposes, there was no attempt was to split the network capacity augmentation CAPEX (AUGEX) from total CAPEX.[4] The resulting LRMC component of the total revenue requirement is therefore conservatively generous. This may be a reasonable indication of the LRMC for small residential and business customers (standard asset class SAC)). This is because of the possibility that SAC demand profiles are relatively "peaky" and hence represent a higher proportion of total AUGEX than for the entire Ergon customer base.

4 This is a simpler approach than that adopted in our June 2019 report where we identified and quantified three possible options for identifying the LRMC component of total capital operating expenditure.

Our LRMC estimates make no reference to the unit LRMC cost model set out in EQ's revised proposal. The unit LRMC cost model is for a notional augmentation.

On its own, the unit LRMC model is not relevant to tariff structure. This is because it does not reflect existing ample spare capacity on all but a few sections of the Ergon network over the period to 2025, or the forecast increase in maximum demand, as outlined for example in the Distribution Annual Planning Report (DAPR) for Ergon released in December 2019. Put simply, the unit LRMC model on its own does not provide a basis for estimating the LRMC portion of total network costs and hence the portion of tariff revenue that should be 'based on' LRMC.

The LRMC component of network costs discussed in this section is discussed further below, in the context of assessing EQ's revised tariff structure proposals under the National Electricity Rules.

3. Revised tariff structure proposals

3.1 Key points

- The forward looking LRMC components of EQ's proposed 'cost reflective' tariffs have been substantially reduced compared with its earlier revised proposals from May 2019. Accordingly, in response to the AER's Draft decision finding that Ergon proposed "high" estimates for LRMC, EQ has made substantial progress toward ensuring that Ergon and Energex Energy's tariff structures are in fact cost reflective and conform with the relevant National Electricity Rules.
- For example, the most important of Ergon's new tariffs is the transitional demand tariff, which is the default for all customers with digital meters. The LRMC component of the tariff, or the premium for consumption during peak demand periods ('tariff LRMC') is broadly consistent with our high-level estimate of LRMC (for Ergon as a whole). Similarly, the tariff LRMC component of Energex's default transitional tariff also appears broadly consistent with LRMC.
- There are significant differences in the allocation of tariff LRMC between residential and small customer classes. This seems to be cost reflective, to the extent business demand profiles correspond more closely with periods of high output from distributed energy resources (rooftop solar) than residential demand profiles, where demand may be higher after dusk.
- Ergon's two new optional tariffs do not yet appear to be cost reflective, even after allowing a high allocation of total LRMC to residential and small business customers. Nevertheless, these are optional tariffs, and the mismatch between tariff LRMC and LRMC is much reduced from the May 2019 proposals.
- Energex's two new optional tariffs appear less cost reflective than those for Ergon. For both residential and business customers, and both the demand and ToU tariff, tariff LRMC is well in excess of the LRMC component of Energex's total network costs, as set out in its December 2019 revised revenue proposal. Our understanding is that EQ's revised proposal takes into account network augmentation requirements arising from recent and future demand growth in SE Queensland.

3.2 LRMC component of tariff structures: data and methods

In EQ's December 2019 revised tariff structure proposal, the current optional capacity tariff would be discontinued. It is now proposing three new cost reflective tariffs for small customers:

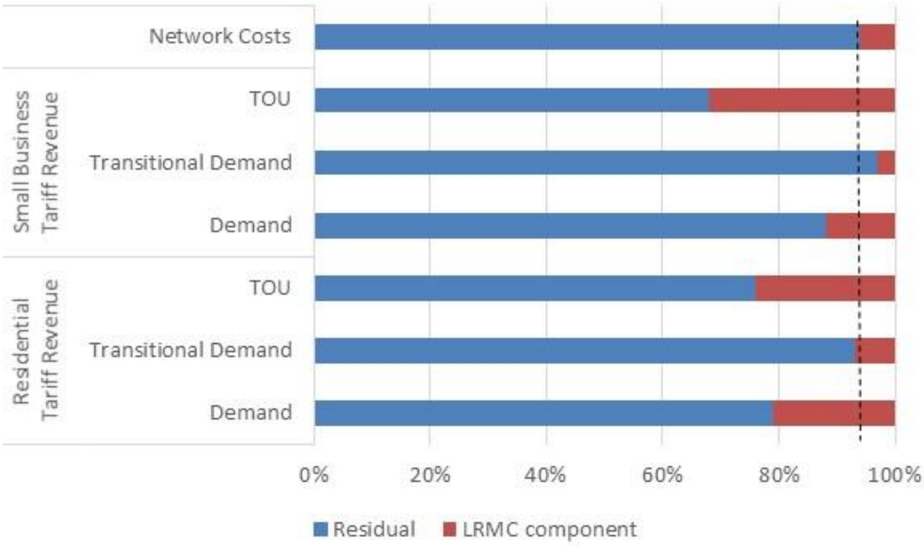
- a transitional demand tariff which will be the default tariff for customers with a digital meter
- an optional 'standard' demand tariff, and
- an optional time-of-use (ToU) energy tariff.

Our analysis focuses on the allocation within tariff structures between forecast revenue from LRMC based revenue, authorised under 6.18.15(f) of the rules, and non-LRMC revenue authorised under 6.18.15(g) of the rules. For convenience we use the term 'tariff LRMC revenue' to refer to the former revenue.

Tariff LRMC can be compared with LRMC, as defined and quantified in the previous section. As explained below, the rules require that revenue from tariff LRMC should be 'based on' LRMC. This implies that Tariff LRMC relative to total tariff revenue and LRMC relative to total revenue should be proportionately similar.

Figure 2 below summarises the LRMC component of EQ's revised total revenue proposal ('network costs') compared with the tariff LRMC for the revised tariff structures, (see tariff data provided in Appendix 1). The dotted line is aligned with LRMC component of network costs for comparison with tariff revenue.

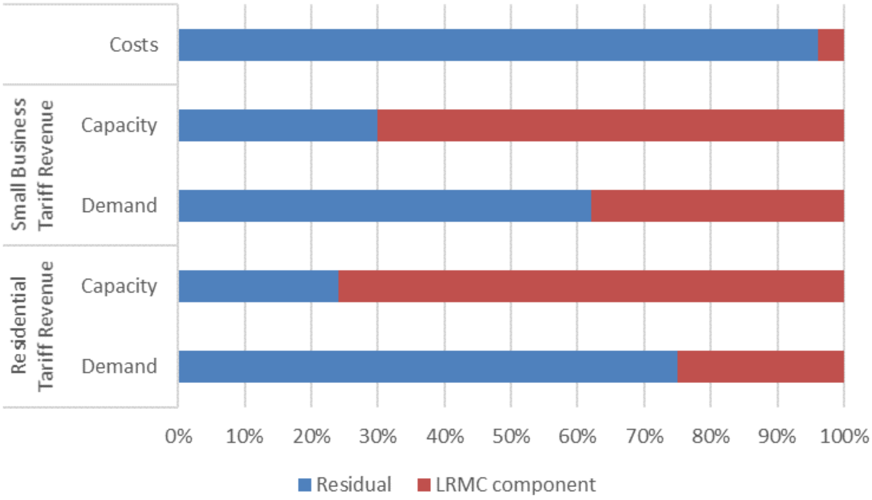
Figure 2 Summary of revised (December 2019) Ergon tariff proposals relative to LRMC component of network costs



Source: Sapere analysis of EQ data

Figure 3 below summarises, under EQ's May 2019 proposal, the LRMC component of proposed network costs compared with tariff LRMC.

Figure 3 Summary of Ergon (May 2019) tariff proposals relative to (May 2019) LRMC component of network costs

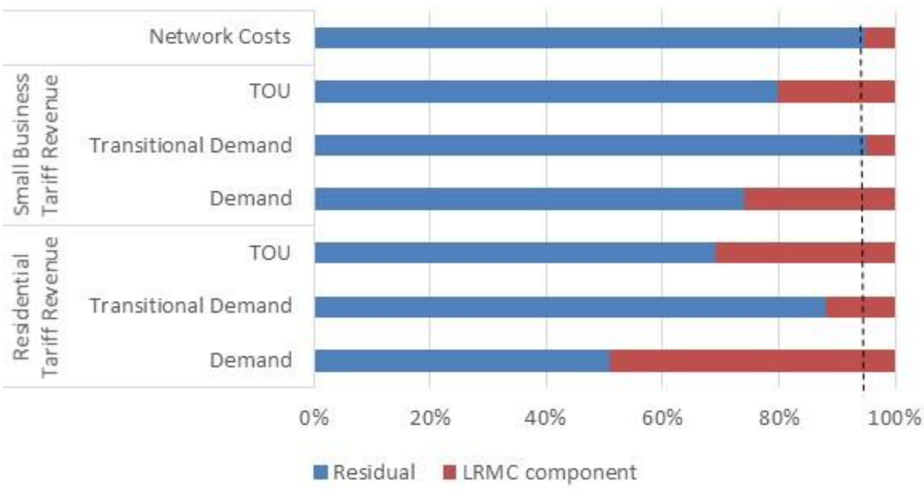


Source: Sapere analysis of EQ data

The LRMC component of tariffs is substantially reduced in Figure 2 compared with Figure 3. For example, the Ergon optional small business demand tariff, tariff LRMC has been reduced from 38 per cent of forecast total revenue, as proposed in May 2019, to 12 per cent of total revenue. Similarly, for the optional residential demand tariff, the LRMC component has reduced from 25 per cent to 21 per cent. The reduction is greatest for the transitional demand tariff, which we understand is the default tariff for customers with digital meters.

In Figure 4 below, for Energex, we compare the tariff LRMC components of EQ's revised tariff proposals for relative to the LRMC component of network costs.

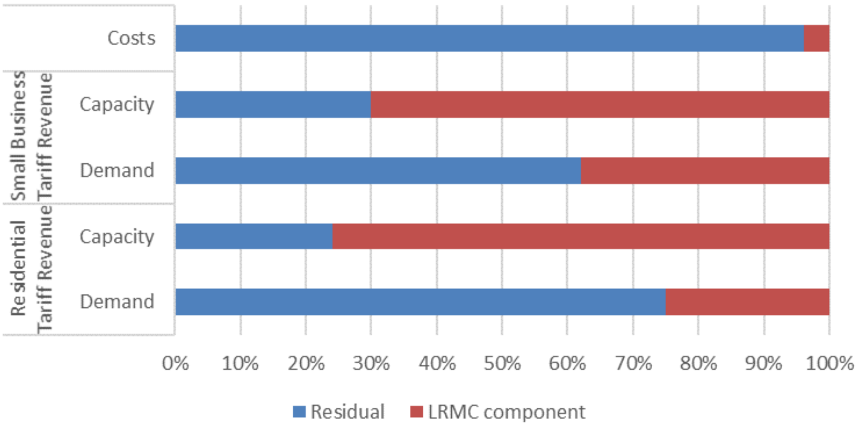
Figure 4 Summary of revised (December 2019) Energex tariff proposals relative to LRMC component of network costs (per December 2019)



Source: Sapere analysis of EQ data

Figure 5 below provides a similar analysis for Energex under its May 2019 revenue and pricing proposals.

Figure 5 Summary of Energex (May 2019) tariff proposals relative to (May 2019) LRMC component of network costs



Source: EQ and PTRM

3.3 Methodology and data sources

Our methodology divides forecast tariff revenue for each customer class into LRMC and other revenue. This reflects the national electricity rules.
Under 6.18.5 (f) of the distribution network pricing principles under the National Electricity Rules (NER): 'each tariff must be based on the *long run marginal cost* of providing the service to which it relates to the *retail customers* assigned to that tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:

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

The balance of the regulated revenue requirement (total network costs) is authorised under Section 6.18.5(g) of the NER. As detailed in Appendix 1, on request, EQ provided the data in the tables below breaking down forecast revenue between different tariff components or "baskets". For clarity, we have shown these two baskets in two columns of Table 2 below for Ergon and Energex tariffs, referencing the relevant pricing principles in the NER.

Table 2 EnergyQueensland tariff revenue relative to rules

Zone	Tariff	LRMC based revenue (6.18.5(f))	Residual revenue (6.18.5 (g))
Ergon East Residential	Demand	21%	79%
	Transitional Demand	7%	93%
	TOU	24%	76%
Ergon East Small Business	Demand	12%	88%
	Transitional Demand	3%	97%
	TOU	32%	68%
Energex Residential	Demand	49%	51%
	Transitional Demand	12%	88%
	TOU	31%	69%
Energex Small Business	Demand	26%	74%
	Transitional Demand	5%	95%
	TOU	20%	80%

4. QCA Interim Consultation Paper – Regulated retail electricity prices for 2020-21 – network component

4.1 Key points

A key issue identified in the QCA ICP is the possibility the AER may not have issued a final determination on regulated network prices by the time the QCA makes a final determination on retail prices, inclusive of regulated network prices. The ICP identifies and sought views on three broad options (Consultation Questions 2 and 5):[5]

- Apply a standard N+R approach, passing through the N component once available. This results in retail tariff structures that reflect the underlying network tariff structures approved by the AER. However, it may not provide certainty to stakeholders or may not allow adequate time for consultation.
- Maintain the existing suite of retail tariffs by setting the N component using the price indexation approach (i.e. adjusting existing network costs with a suitable index).
- Apply a flexible N+R approach where there is an opportunity to consult over retail price structures before final retail tariff decisions are made.

Regarding consultation Question 3, we suggest there is a high level of uncertainty over the outcome of the AER review of EQ's revised tariff structure proposals. Under these conditions, it appears preferable for QCA to apply a flexible N+R approach where there is an opportunity to consult over retail price structures before retail tariff decisions are made.

Regarding consultation Question 5, we do not consider an indexation approach, where the N component of revenues is smoothed between the period 2019-20 and 2020-21, is consistent with the Electricity Act 1994. This is because the N component would exceed any reasonable estimate of the actual costs of making, producing or supplying the goods and services.

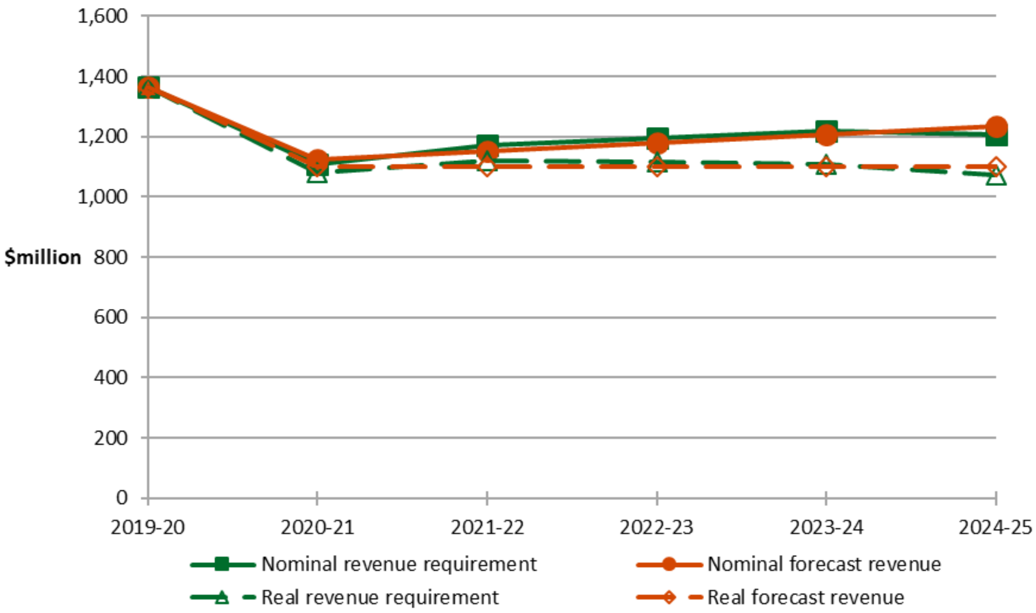
4.2 Analysis and discussion

Figure 6 below is an extract from EQ's revised revenue proposal. It shows the trend in the proposed N component of total retail prices (for Energex as a whole) as between 2019-20 and 2020-21 and beyond, in both nominal and inflation adjusted terms.

The key development is a step change in the nominal revenue requirement between the two years, which reduces by 18.8 per cent. Among other things, this step change reflects the implementation of a new mandatory AER guideline for the setting of the rate of return or profit on regulated assets.

5 See page 10 of the ICP.

Figure 6 EQ December 2019 revised revenue proposal chart



Source: Chart 1 (Revenue cap) EQ revised PTRM from December 2019

It is possible that in its final decision the AER may not accept some aspects of EQ's proposals as prudent and efficient. It may also adopt a different forecast of sales volume (depending on the form of regulation, this can be significant). In this case, the step change reduction above is around 19 per cent.

EQ's proposed network tariff structures represent a substantial change from its earlier (already revised proposals from May 2019. This reflects EQ's response to the AER's draft decision of October 2019 where it concluded

Our draft decision is to not approve EQ's proposed tariff structure statement, as we are not satisfied that it complies with the distribution pricing principles in the Rules.[6]

The AER concluded that Energex proposed high estimates of LRMC. However, given the level of excess capacity on its network and the prospect of minimal growth in peak demand in the foreseeable future, the AER considered low LRMC estimates to be more appropriate.

As noted in section 3 above, Energex has modified its tariff structures to reduce the LRMC component of tariffs. The previous substantial discrepancy as shown in Figure 5 between LRMC as a proportion of network costs, on the one hand, and the LRMC proportion of forecast revenue from components of tariff structures 'based on' LRMC, on the other, has been reduced. Importantly, for the default demand tariff for small business the default transitional demand tariff, tariff LRMC as a proportion of total forecast revenue is the same as the LRMC proportion of total forecast network cost.

However, as shown in Figure 4 for Energex, substantial discrepancies remain under the revised December 2019 proposals for some tariff proposals. For example, while the LRMC

6 See Attachment 18-13 of the AER draft decision for Energex.

component of total network costs is 5 per cent, the LRMC portion of forecast revenue under the Business optional demand tariff is 31 per cent. As a result, it remains open to question whether the proposed optional demand tariff will be found by the AER to conform to the relevant pricing rules. In addition, there are other aspects of EQ's proposals, not discussed in section 3 above, where the AER may not accept EQ's revised pricing proposals.

Against this background, it is not possible in advance to assess what the implications of a simple N+R approach (the first option identified in the ICP) would imply for the structure of new retail tariffs. We therefore suggest that it may be in the best interests of CANEGROWERS members for the QCA to adopt the third option identified – under which the implications of final Network tariff structures for retail tariff structures is consulted before the QCA adopts any particular retail tariff structure.

5. QCA Interim Consultation Paper – Regulated retail electricity prices for 2020-21 – retail component

5.1 Key points

With respect to retail costs, the ICP notes that in previous decisions it set the allowance for retail operating costs using an established benchmark set as part of the 2016-17 price determination process, adjusted for inflation. This year, the QCA is considering whether (Consultation Question 7):

- To establish new retail cost allowances, based on more recent market data, noting market changes (such as the AER's DMO and the network tariff reforms) may impact retailer pricing strategies and costs observed in the market; or
- Maintain the current approach and apply the established benchmark, adjusted for inflation, noting this would provide stakeholders with increased certainty over the level of costs to expect.

We do not support maintenance of the current retail cost benchmark. The very existence of the DMO confirms that the QCA's existing retailer cost index should not be applied. Instead the QCA needs to develop a new benchmark or draw on the methodology applied by the AER in setting the DMO for the Ergon network area.

The ICP suggests that QCA apply a standing offer adjustment, in line with the delegation (Question 8). This is currently set as five per cent mark up on benchmark retailer costs. QCA is proposing to retain this mark up, although it notes that the value should be discounted so that the resulting bill does not exceed the Default Market Offer set by the AER.

While the ICP states that the standing offer adjustment "reflects the more favourable terms and conditions in standard contracts", it has so far not been demonstrated that standard contracts do, in fact, offer more favourable terms than market offers including the DMO, nor what the economic value of those terms may be. Hence it is not possible to assess whether this premium reflects the actual costs of those premium services consistent with Section 90 (5). Therefore, it is recommended that the QCA's next discussion paper provides the analysis required to compare the additional standing offer services that support the application of any standing offer adjustment.

5.2 Analysis and discussion

As set out in our report for CANEGROWERS dated April 2019, the current benchmark includes non-existent costs. This appeared to be inconsistent with the statutory criteria under which the QCA is required to set prices. These criteria are set out under Section 90 (5) of the Electricity Act 1994 (Queensland). These include, among other things, reference to the *'**actual** cost of making, producing or supplying the goods and services'* (emphasis added).

The current QCA benchmark is based on the assumption that, over the period used to derive the benchmark, competition was effective to constraining retailer costs to no more than efficient costs. The best available data and analysis conducted, both by us in 2016 and more recently by the ACCC, clearly show that the retail cost methodology the QCA proposes for its estimates of retail costs for regional Queensland is unsound.

The concerns set out in our 2016 report regarding the effectiveness of retail competition to constrain retail prices have been accepted in Part 3 of the ACCC's Retail Electricity Pricing Inquiry (REPI). Among other things, the REPI states that:

> *… there is a contrasting view, that price dispersion only reflects information asymmetry and search costs. The NEM does not display other characteristics of a well-functioning market, such as low levels of concentration, low margins and price, and a large degree of price moderation.*

The REPI makes a series of recommendations to address retail prices that incorporate non-existent costs. These include among other things: the establishment of a default offer (Recommendation 30); the application of the consumer data right (Recommendation 31), better disclosure around discounting (recommendation 32), improvements to retail price monitoring (Recommendation 40).

Subsequently, on 22 October 2018, the Commonwealth Treasurer and Minister for Energy requested that:

> *7 …the AER commence work immediately on developing a mechanism for determining the price of the default market offer, consistent with the ACCC's recommendations. As part of this, we ask that the AER also develop a mechanism for determining a reference bill for each network distribution region, from which headline discounts can be calculated, in accordance with ACCC Recommendations 32 and 50.*

On 30th April, the AER issued its final determination on the setting of the default market offer (DMO), including for SEQ. It decided to set the DMO at the mid-point of the range between the median market offer and the median standing offer in each network distribution zone.

For Energex, according to the AER, the DMO results in a reduction in annual retail bills for a typical business customer of $457 and $118 for a typical small residential customer.[7] This is in circumstances where the DMO is higher than 82 per cent of market offers for the small business flat rate.[8] That is the DMO already provide sufficient headroom in Queensland that the typical business customer can obtain larger potential savings by switching to existing competitive market offers than by switching to the DMO.

7 See https://www.aer.gov.au/news-release/aer-issues-default-market-offer-decision

8 See Table 6, page 35 of the AER final determination – Default market offer prices, April 2019.

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Appendix 1 EnergyQ Correspondence

Energy Queensland data supplied 24 January 2020

From: Michael MacNamara (EnergyQ)
Date: 24 January 2020
To: Warren Males (CANEGROWERS)
Cc: regulatoryproposal (EnergyQ), Kenny Mizzi(EnergyQ) Grahame Foulger (Smart Grid Partners)
Subject: FW: Ergon East Residential and Small Business Customers - data requested

Good Morning Warren,

Thank you for your email below, and my apologies for the delay in pulling together the data to support our response. With Grahame and Kenny out of today, please allow me to provide the below tables.

We have expanded upon the previous tables to break up revenue in the ToU tariffs while also providing DUOS Rates for ease of reference.

	Ergon East Residential - DUOS (2020-21)				Ergon East Small Business - DUOS (2020-21)				
	Inclining Block	Demand	Transitional Demand	Time of Use (ToU) Energy	Inclining Block	Demand	Transitional Demand	Time of Use (ToU) Energy	Wide IFT
Fixed Revenue	65%	54%	63%	55%	57%	8%	31%	33%	7%
Demand Revenue	0%	21%	7%	0%	0%	12%	3%	0%	0%
Volume Revenue	35%	25%	30%		43%	80%	66%	0%	93%
Volume Evening Revenue				24%				32%	
Volume Overnight Revenue				12%				21%	
Volume Day Revenue				9%				14%	
Volume Rates $/kWh									
Volume Revenue	IBT	$0.02190	$0.04379		IBT	$0.05297	$0.06621		$0.09100

	Ergon East Residential - DUOS (2020-21)				Ergon East Small Business - DUOS (2020-21)				
	Inclining Block	Demand	Transitional Demand	Time of Use (ToU) Energy	Inclining Block	Demand	Transitional Demand	Time of Use (ToU) Energy	Wide IFT
Volume Evening Revenue				$0.12042				$0.24193	
Volume Overnight Revenue				$0.02520				$0.04600	
Volume Day Revenue				$0.01800				$0.01800	
Demand rates $/kW		$4.18500	$0.83700			$4.01760	$0.33480		

	Energex Residential - DUOS (2020-21)				Energex Small Business - DUOS (2020-21)				
	Volume Flat	Demand	Transitional Demand	Time of Use (ToU) Energy	Volume Flat	Demand	Transitional Demand	Time of Use (ToU) Energy	Wide IFT
Fixed Revenue	37%	18%	38%	55%	15%	10%	18%	23%	19%
Demand Revenue	0%	49%	12%	0%	0%	26%	5%	0%	0%
Volume Revenue	63%	32%	50%	0%	85%	65%	78%	0%	81%
Volume Evening Revenue				31%				20%	
Volume Overnight Revenue				9%				26%	
Volume Day Revenue				5%				30%	
<u>Volume Rates $/kWh</u>									
Volume Revenue	$0.05672	$0.01928	$0.04353		$0.06548	$0.03956	$0.05922		$0.06548

	Energex Residential - DUOS (2020-21)				Energex Small Business - DUOS (2020-21)				
	Volume Flat	Demand	Transitional Demand	Time of Use (ToU) Energy	Volume Flat	Demand	Transitional Demand	Time of Use (ToU) Energy	Wide IFT
Volume Evening Revenue				$0.11150				$0.12253	
Volume Overnight Revenue				$0.02485				$0.05676	
Volume Day Revenue				$0.01800				$0.03945	
Demand rates $/kW		$5.28904	$0.99170			$6.48167	$0.64817		

Please don’t hesitate to make contact should if you require anything further information.

Regards

Michael

Michael MacNamara
Network Tariff Strategy Specialist
Energy Queensland