Consumer
Challenge
Panel

CCP14

Advice to the AER on the Energex and Ergon Energy 2020-25 Revised Regulatory Proposals

Revised report, March 2020

AER Consumer Challenge Panel - Sub-Panel CCP14

Mike Swanston

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Contents

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CCP14 wishes to express our appreciation and thanks to the members of stakeholder groups associated with the Queensland Electricity Distribution Regulatory Reset, who have generously provided information and insights to assist the sub-panel in its review of the businesses' consumer engagement programs.

Finally, thanks go to Louise Benjamin for her contribution and wise counsel as a member of CCP14 until September 2019 and to Mark Grenning who held the important role of chair of CCP14 until mid-February 2020.

Confidentiality

To the best of our knowledge this advice neither presents any confidential information nor relies on confidential information for our comments.

The Consumer Challenge Panel sub-panel CCP14

The AER established the Consumer Challenge Panel (CCP) in July 2013 as part of its Better Regulation reforms. These reforms aimed to deliver an improved regulatory framework focused on the long-term interests of consumers.

The CCP assists the AER to make better regulatory determinations by providing input on issues of importance to consumers. The expert members of the CCP bring consumer perspectives to the AER to better balance the range of views considered as part of the AER's decisions.

The author of this submission is CCP14, a sub-panel of the AER's Consumer Challenge Panel that the AER has established to focus specifically on the AER's regulatory determination of SA Power Networks, Energex and Ergon Energy for 2020-2025. CCP14 has provided various advice related to these determinations throughout 2018 – 20, which can be found on the AER website.

CCP14 members are Mark Grenning (until February 2020), Louse Benjamin (to September 2019) and Mike Swanston.

Revision

This is a revised version of the CCP14 advice to the AER regarding the Energy Queensland (Energex and Ergon Energy) regulatory proposals. The review of the advice was carried out following the request by the AER by email of 10 March 2020.

Mike Swanston
CCP14
11 March 2020

1. Executive Summary

The 2020-25 regulatory determination process for Energex and Ergon Energy has to date been a curious experience for consumers, the AER and the utilities alike.

Throughout the regulatory reset process, it has been clear that Energy Queensland Limited (EQL) is reflecting the public commitment made by their state-government shareholder to deliver significant reductions in distribution network charges to Queensland electricity customers. Commendably, there has been a clear intent by the two distributors to deliver a reduction in their required revenue, including returning to electricity customers the operating cost efficiencies arising from their amalgamation in 2016.

Against this commitment however, EQL has highlighted to customers their concerns regarding a number of safety-related non-compliances and asset condition risks, particularly in the Ergon Energy service territory of regional and rural Queensland. These risks, whilst having manifested over a period of time, are seen by EQL as a priority to address, resulting in an increasing requirement for asset replacement capital.

A notable feature of this determination process so far has been the almost singular focus by community stakeholder groups on tariffs and prices. We believe this has come about by the revenue reduction offered by EQL being seen as 'a given', with the conversation then centering on how those price reductions will feed through to the residential, commercial, primary production and industrial consumers in the state.

Another peculiarity has been the fact that Ergon Energy is recognised as the electricity retailer for almost all customers in regional Queensland. This creates difficulty for many consumer representatives to consider the matters related to Ergon's network business revenue determination (and that of Energex as well, given the common engagement processes) at arms-length from the retail, wholesale, metering and transitional tariff issues that also exist in relation to their electricity supply. We observed a number of consumer engagement events where the subject of discussion drifted to retail or government tariff policy matters. Similarly, EQL's customer consultation committee seems to cover both retail and network matters, with Ergon Energy retail issues predominating in the session we attended.

CCP14, along with almost all consumer groups, are supportive of the AER's draft decisions. We note that the reduction in the Rate of Return has been responsible for a large proportion of the reduction in the revenue requirement of both companies and therefore is the major, but not sole, contributor to average price reductions.

Energy Queensland Limited ran a commendable consumer engagement programme in the face of the challenges of a large service area, the blurring between network and retail issues and a range of strong voices amongst the many customer cohorts. We observed some activities approaching the 'involve' range under the IAP2 engagement spectrum for public participation. The majority of the engagement was, in our opinion, largely 'inform', particularly late in the reset process.

We acknowledge that EQL has accepted much of the AER's draft determinations regarding operating expenditure, despite the calculation of the final opex position being somewhat confusing to customers with the application then removal of efficiency scheme benefits. We commend EQL for these decisions however, including the acceptance of the substituted ICT capital forecast.

This advice, which incorporates an assessment of both the Energex and Ergon Energy revised proposals, highlights the following issues:

1. The EQL engagement model was effective and reasonably reflects informed consumer support. We believe that EQL may have 'glossed over' a lot of detail in the opex build-up and capital requirement changes in the latter stages of their engagement, choosing instead to devote a lot of time to the Tariff Structure Statement and pricing impact analysis. Given the limited resources and the strong stakeholder interest in TSS matters, we believe that was a reasonable response.

2. Whilst the falls in revenue and likely prices are welcomed, there is still a level of concern around the sustainability of these savings into future regulatory periods given that a major proportion of the change is due to one-off factors around merger benefits, falling WACC and a change in the tax allowance calculation methodology. Ergon customers (including to a lesser extent, those covered by tariff equalisation) are particularly exposed given the proposed large rise in RAB per customer in 2020-25.
3. We note and respond to EQL's continuing somewhat unique approach to operating expenses and productivity, particularly for Ergon. We find it difficult to agree that a network that has consistently been in the bottom quartile of the 14 DNSPs in the AER's opex productivity analysis can be seen as not materially inefficient on the basis that their bushfire risk is greater than Victorian DNSPs.
4. EQL, and in particular Ergon Energy, in stating their capital requirements have made a strong and emotive case regarding the poor condition of some network assets and many non-compliance safety-related risks that have been 'discovered' in recent years. Whilst we, along with other consumer groups, recognise the case EQL is making and believe a response is necessary, there is concern just how such a situation could have arisen. Stakeholders are questioning the impact of previous capital expenditure, especially repex, and the effectiveness of Ergon Energy's past asset inspection and maintenance practices.
5. CCP14 does not support all of the capital expenditure proposed by EQL. We continue to have concerns about the approach being taken to address the many non-compliance risks in the Clearance to Ground and Structure business cases. There is a disconnect between the business cases, which tend to discuss corporate compliance risk, and public case made to consumers that was much more focussed on customer and community safety. We believe a more balanced and measured response should be feasible.
6. The EQL Tariff Structure Statement (TSS), which has had a rocky path, largely reflects the guidance provided by the AER in the draft decision. Therefore, the broader tariff proposals are supported. We continue to see some shortcomings in the TSS, however. For instance, the tariff structure could be far more explicit in the integration, function and application of off-peak controlled load (OPCL) in addressing falling network utilisation and the continued uptake of new customer technologies. The TSS is not strong on making the link between the challenges faced by the EQL networks in meeting the high growth of customer-owned distributed energy resources and how new tariffs are intended to address this energy future.
7. Finally, consistent with the engagement related to other recent determinations, customers continue to highlight concerns regarding how effectively and transparently network tariff initiatives and savings will translate through to retail bills.

2. Introduction

2.1 Our role as a Consumer Challenge Panel

Customer Challenge Panel 14 (CCP14) was established by the AER to provide advice to them regarding the Ergon Energy and Energex electricity distribution regulatory determinations for 2020-25.

In our advice to the AER, CCP14 is guided by the National Energy Objective (NEO), which is:

> *"to promote efficient investment in, and efficient operation and use of, energy services for the long-term interests of consumers of energy with respect to price, quality, safety, reliability and security of supply of energy."*

Some of the factors in the regulatory determinations are set by the regulatory framework and the National Electricity Rules, and therefore are out of scope for the CCP's consideration. The in-scope items account for approximately 35 to 40% of the proposed revenue.

In scope	Out of scope
✓ Proposed capex in period	✗ Rate of return – AER binding guideline in December 2018
✓ Proposed opex in period	✗ Opex productivity – AER decision March 2019 for 0.5%/yr
✓ Application of incentive schemes	✗ Taxation allowance – AER decision in December 2018
✓ Tariff Structure Statement	✗ Regulatory depreciation
✓ Consumer engagement	

Table 1: CCP14 scope of advice

The CCP considers how well the Ergon Energy and Energex Proposals reflect a fair and balanced interaction with their community and customers, how valid consumer needs have informed the proposals and where aspects of the proposals have received informed support from their customers and stakeholders.

We also consider, from the point of view of an informed consumer, matters such as:

- How prudent and efficient is proposed capex and opex expenditure in meeting customer needs ?
- How will the incentive schemes be implemented and affected?
- How will costs be allocated to different consumers through the TSS?
- How does the Proposal reflect the changing electricity market and long-term issues?

2.2 CCP advice in the Energex and Ergon Energy regulatory resets

Energex and Ergon Energy submitted their Regulatory Proposals (RPs) in January 2019. Following publication of AER Draft Decisions (DDs) in October 2019, the companies then filed their individual Revised Regulatory Proposals (RRPs) on 10 December 2019. In this advice, we focus on the engagement and factors related to Energy Queensland regulatory proposal since the publishing of the AER Draft Decision, while also making some general observations on the overall reset process.

Whilst we recognise that each distributor is undergoing its own reset process, Energy Queensland Limited (EQL) has chosen to carry out its customer and stakeholder engagement for both companies as one integrated exercise. Many of the issues and documents are common to both distributors. Therefore, consistent with our earlier advice regarding this determination, this advice covers the Revised Regulatory Proposals for both Energex and Ergon Energy. While most of the issues raised are specific to these networks, some of the matters discussed have wider application across all electricity networks.

3. The draft decisions and the Revised Regulatory Proposals

3.1 Key features of the EQL Revised Regulatory Proposals (RRPs)

The Acting EQL CEO of Energy Queensland Limited (EQL), Peter Scott, highlights in his opening message to the Revised Regulatory Proposal (RRP):

> *"Our revised proposals deliver balanced outcomes for our communities and customers - while safety remains our top priority, we are outperforming our affordability commitment."*

We welcome the fact that the AER and EQL have agreed on many aspects of the draft decision, including the TSS, opex (Energex), ICT investment and a number of other capex programmes.

3.1.1 Revenue

The total revenue proposal in the RRP is 10% below that of the RP for Energex, and 8% lower for Ergon, shown below in Table 2.

$M nominal	Regulatory Proposal (RP)	AER Draft Decision (DD)			Revised Regulatory Proposal (RRP)		
	Forecast	Forecast	Difference from RP	Difference from RP (%)	Forecast	Difference from RP	Difference from RP (%)
Energex	6,541.17	5,839.97	- 701.19	- 11%	5,900.32	- 640.84	- 10%
Ergon Energy	6,515.77	5,787.89	- 727.87	- 11%	5,997.40	-518.36	- 8%

Table 2: Revenue proposals, Energex and Ergon Energy (data from EQL RRP - Overview, p14 & p15)

The revenue building blocks and change in revenue drivers for Energex are shown in Table 3 and Figure 1 .

For Energex, the revenue reduction beyond that of the initial Regulatory Proposal (RP) has largely been driven by a combination of lower WACC (driving a major fall in return on capital) and the elimination of the tax allowance following the change in calculation resulting from the 2018 review.

The reduction is offset in part by the reversal of the decision taken by EQL in the RP to return the EBSS and CESS benefits from the current period to customers, as well as higher proposed capex driving depreciation.

Energex $M nominal	Regulatory Proposal (RP)	AER Draft Decision (DD)			Revised Regulatory Proposal (RRP)		
	Forecast	Forecast	Difference from RP	Difference from RP (%)	Forecast	Difference from RP	Difference from RP (%)
Return on Capital	3,643	3,110	- 533	- 15%	2,956	- 687	- 19%
Operating expenditure	1,941	1,942	2	0%	1,937	-2.9	0%
Depreciation	804	756	- 48	- 6%	822	18	+ 2%
Taxation	153	22	- 131	- 86%	-	- 153	- 100%
Revenue Adjustment	6	5.5	- 0.49	- 8%	184	178	+ 2962%

Table 3: Revenue Building Blocks, Energex (data from EQL RRP - Overview, p14)

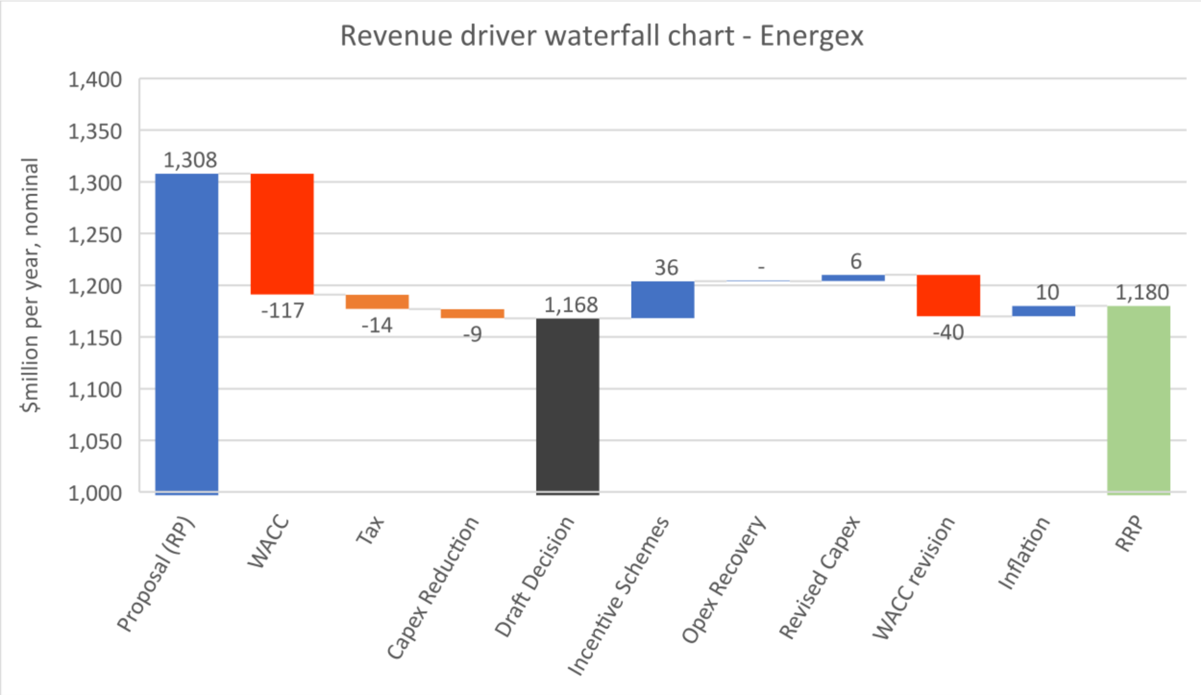


Figure 1: Revenue Driver Waterfall from RP to RRP - Energex (data from Energex RRP - Overview, p14)

The revenue building blocks and change in revenue drivers for Ergon Energy are shown below in Table 4 and Figure 2 below.

As for Energex, Ergon's revenue reduction beyond that of the initial Regulatory Proposal (RP) has been predominantly a result of a combination of lower WACC and the elimination of the tax allowance, offset in part by the reversal of the EBSS and CESS benefits as well as higher proposed capex driving an increase in depreciation.

We acknowledge and accept EQL's changed approach regarding the two incentive schemes, noting that the AER also reflects that position in the Draft Decisions.

Ergon Energy $M nominal	Regulatory Proposal (RP)	AER Draft Decision (DD)			Revised Regulatory Proposal (RRP)		
	Forecast	Forecast	Difference from RP	Difference from RP (%)	Forecast	Difference from RP	Difference from RP (%)
Return on Capital	3,346	2,807	- 539	- 16%	2,710	- 636	- 19%
Operating expenditure	1,972	1,973	1	0%	1,968	-4	0%
Depreciation	1,052	997	- 55	- 5%	1,052	-1	0%
Taxation	144	0.6	- 143	- 100%	-	- 144	- 100%
Revenue Adjustment	6	5	- 1	- 9%	260	254	+ 4251%

Table 4: Revenue Building Blocks, Ergon Energy (data from Ergon Energy RRP - Overview, p14)

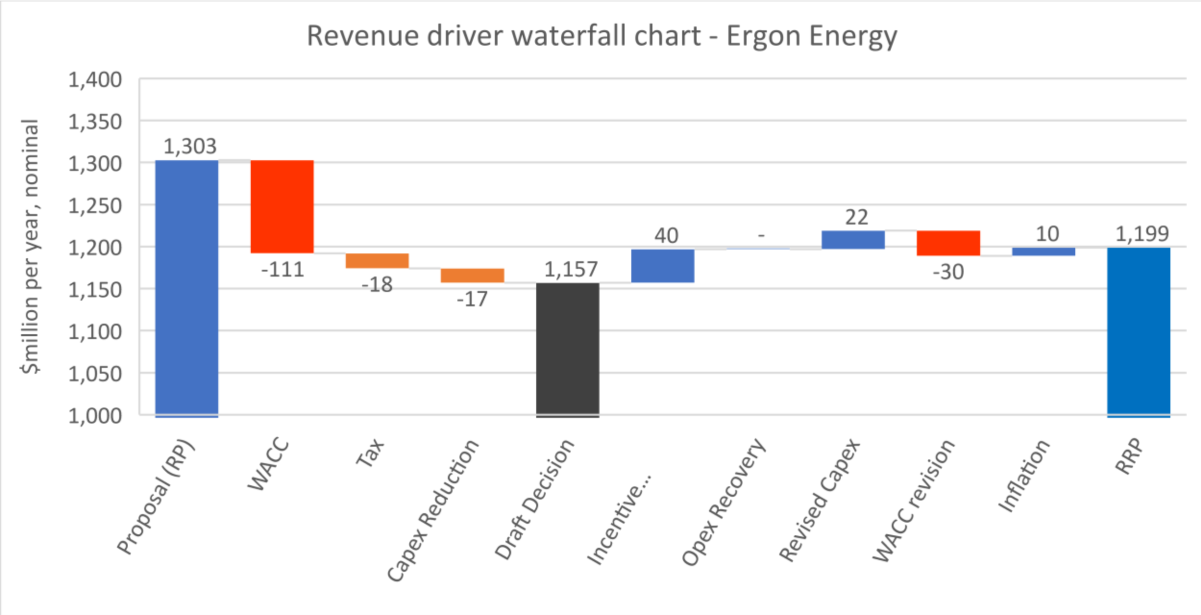
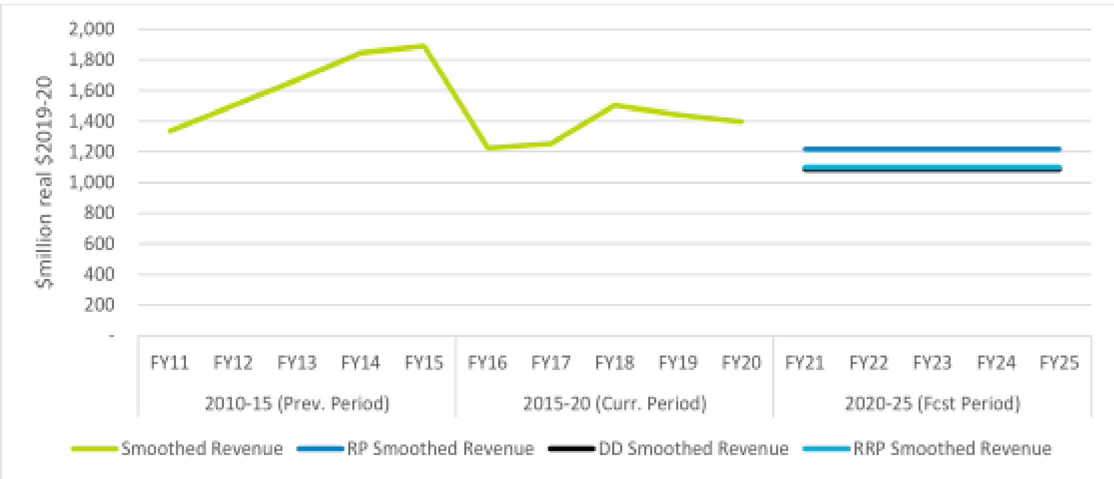


Figure 2: Revenue Driver Waterfall from RP to RRP - Ergon Energy (Source: data from Ergon RRP - p14)

We also note that the proposed regulated revenue is lower than at any other time that Energex and Ergon Energy have been regulated by the AER shown in Figure 3 below.



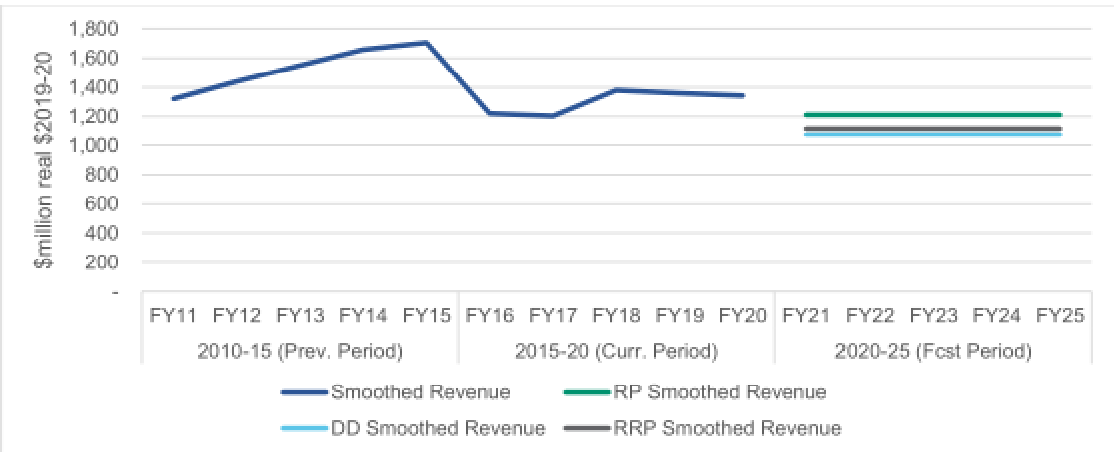


Figure 3: Revenue trends, Energex (top panel) and Ergon Energy (lower panel) (Source: RRP - p14)

3.1.2 Regulatory Asset Base

The changes in the Regulated Asset Bases (RAB) for Energex and Ergon Energy are shown below in Table 5.

RAB $M, nominal	2015-16 Opening	2019-20 Closing	Change	2020-21 Opening	2024-25 Closing	Change
Energex	11,172	12,736	14.0 %	12,861	14,216	10.54 %
Ergon Energy	9,873	11,513	16.6 %	11,513	13,515	17.4 %

Table 5: Energex and Ergon Energy Regulatory Asset Base (RAB) (data from EGX and EE RRPs, Table 4, p15)

For Energex, the increase of the real level of the RAB is still slightly lower than the 14% in the current period it is still a very high very high at 10.5% in 2020-25. Customers are expecting this reduction in growth of the RAB, based on factors such as:

a) a lower rate of peak demand growth and the continued adoption of customer-owned distributed energy resources;

b) sensitivity by utilities to the risk of rising prices from a growing RAB should financial conditions change; and

c) the use of more innovative and advanced solutions to meet customers' energy needs.

Given forecast customer numbers, the RAB per customer for Energex continues to fall, as shown in Figure 4 below.

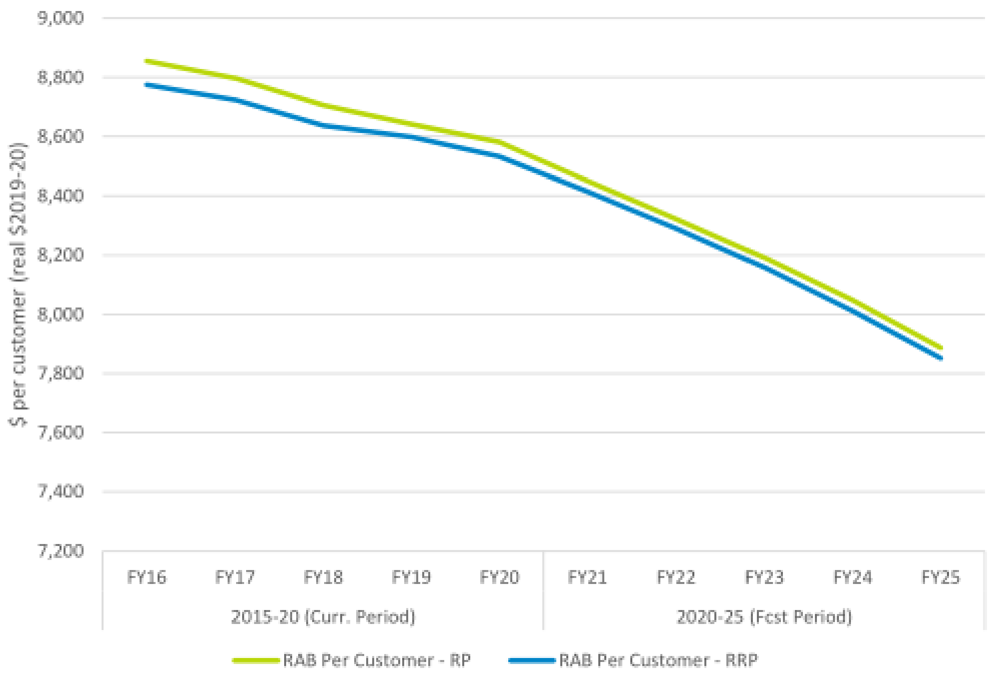


Figure 4: Real RAB per Customer, Energex (Source: Energex RRP - p16)

For Ergon Energy however, the real level of the RAB continues to increase at the very high rate of 17% in 2020-25 compared with 16% in the current period. As shown in Figure 5, the RAB per customer consequently increases significantly, reflecting a combination of the significant increase in capex in the RRP and a slowing rate of growth in customer numbers.

Whilst acknowledging the many factors that influence historical value of RAB per customer, we also note that Ergon Energy has the highest RAB / customer in the NEM.

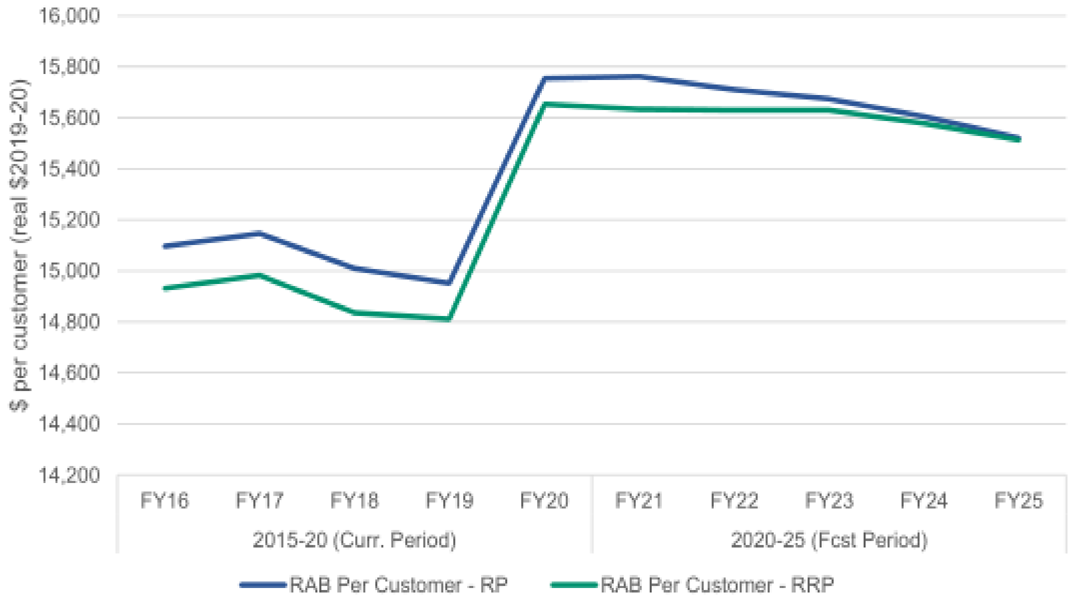


Figure 5: Real RAB per Customer, Ergon Energy (Source: Ergon Energy RRP - p16)

3.1.3 Prices

The reductions in revenue results in the average network pricing outcomes shown in Table 6.

Average customer saving	TSS of June 2019	Revised TSS, December 2019	
		Energex	Ergon Energy
Residential	10.3 %	16.1 % 19.8 % (interval meter)	15.4 % 17.6 % (interval meter)
Small Business	11.4 %	14.7 % 15.7% (interval meter)	15.4 % 20 % (interval meter)

Table 6: EQL average network pricing outcomes (Source: EQL stakeholder presentation 17 Dec 19, slide 34)

In summary, the reduction in proposed revenue and the increased price falls from 1 July 2020 (compared with June 2019) are driven by factors outside of EQ's control – lower WACC and taxation allowance.

Despite the revenue adjustments and capital investment position of the RRP, our observation is that consumers have largely welcomed the revenue reduction and the price outcomes of the EQL RRP.

3.2 EQL's response to the Draft Decisions

We welcome the fact that the AER and EQ have largely agreed on many aspects of the draft decision, including the TSS, Energex opex, ICT and a number of other capex programmes.

The significant departure of the RRP from the AER Draft Decision is in the area of capital expenditure.

From Table 7, EQL has proposed reinstating almost all of the investment previously proposed. We acknowledge that the capital funding approval is a 'decision as a whole', and that the companies can prioritise their capex spending across all areas of need. We do note with some concern that, once the impact of EQL's decision to accept the AER's substituted amount of a significantly reduced allowance for ICT investment is removed (as highlighted in Table 10, page 27), the restated or even increased proposed expenditure on items such as repex, augmentation and property is stark.

	Proposal (RP)	Draft Decision	Draft Decision - change from RP		Revised RP	Revised RP - change from RP	
$m, 2020	$M	$M	$M	%	$M	$M	%
Energex	2,327	2,076	- 251	- 10.8 %	2,292	- 35	- 1.5 %
Ergon Energy	2,905	2,339	- 566	- 19.5 %	3,007	- 102	+ 3.5 %

Table 7: EQL Revised Regulatory Proposal - Capex

Source: derived from EQL RRP Overview p18. CAPEX excludes disposals and capital contributions.

We take a more detailed view on EQL's capex response in section 7 below.

4. Some overall comments on the RRPs

This reset process has been a very complex one for all parties – particularly for consumer advocates and the CCP. While this is somewhat inevitable given the scope of EQ's operations across Queensland – and the nature of the Queensland climate, population density and state of the asset base – it was also influenced by other factors:

i) The *late start* of the process – both consumer engagement and detailed internal analysis of opex and capex needs - was delayed by the restructuring flowing from the formation of Energy Queensland. This has brought a high level of activity, revisions of some positions and recasting of TSS decisions late in the reset process. The result is that some consumer and stakeholder groups have not been able to fully and extensively respond to the RRP.

ii) The approach taken in the initial Regulatory Proposal of *setting strong stretch targets* for reductions in opex and capex and the decision to 'hand back' expected EBSS and CESS benefits in the current period - all to deliver a desired P_0 outcome. These detailed adjustments were not well communicated to consumer groups.

iii) While the proposed price reductions in the RP were welcome, we *did not consider the RP 'capable of acceptance'*. The main reasons for this position were:

- We questioned the prudency and efficiency of the proposed increase in replacement capital requirements (Repex), particularly by Ergon Energy, in the light of previous replacement expenditure and maintenance practices;
- the lack of wider consideration of options to address the matter of neutral conductor failure risk;
- the justification of the proposed significant investment in ICT, especially considering the ICT efficiency and systems harmonisation to be delivered in previous regulatory proposals through the establishment of a wholly owned common ICT service provider (Sparq Services);
- addressing the question of Ergon Energy's operating expenditure as being 'not materially inefficient'; and
- the unclear context, lack of clarity and number of significant revisions of the Tariff Structure Statements.

We were pleased to see these issues addressed in the AER DDs which were generally welcomed with strong acceptance by consumer groups.

iv) We continue to question the *sustainability of the revenue reductions* proposed by EQL, given the number of 'one-off' reductions through merger savings, the return of efficiency benefits, the change in tax allowance and lower WACC. The one-off factors outside of EQL's control driving the price falls in 2020-25 suggests that consumers may be exposed to a high risk of a reversal of these price decreases in the next 2025-2030 period. Any reversal of the downward direction in the Government risk free rate may result in significant price increases in the next reset period. This is particularly the case for Ergon customers (including to a lesser extent, those covered by tariff equalisation) given the large rise in real RAB per customer in 2020-25.

v) The EQL approach to developing capex business cases and, in particular, *their approach to risk analysis,* was quite different from the approach the AER requires networks to take. This resulted in a protracted and somewhat frustratingly unproductive level of engagement between EQL, the AER and stakeholders, which ultimately led to a significant reduction in capex allowance in the Draft Decision. EQL continued to engage with the AER and provide a large amount of additional information after the DD.

vi) Further analysis since the RP has shown that the *initial stretch targets were unsustainable*. A fuller understanding of their current asset condition has led to a Revised Proposal that:

- For capex – EQL proposes a significant increase in the capex level even above that proposed in RP and that was significantly reduced in the Draft Decision;
- For opex – while EQL and the AER agree on the position taken in the Draft Decision, the RRP details a significant increase in what EQL now thinks opex should be (but has not claimed); and
- To help it fund some recovery of foregone revenue, EQL has withdrawn its decision from the RP to give back the EBSS and CESS for the current period.

vii) EQL is fortunate that the *reduction in WACC and revised tax allowance methodology* has allowed it to propose similar network cost reductions to the RP despite:

- much higher capex proposed; and
- withdrawal of the somewhat ambitious productivity factors of 1.72% and 2.58% per year for Energex and Ergon Energy [1] in the RP, replaced by the AER's standard 0.5% productivity factor;

We note that any further reduction in the risk-free rate prior to the setting of the WACC in April 2020 will increase that price reduction.

viii) A number of *jurisdictional issues* that are outside of this reset process remain 'in play', and frequently featured in customer's comments and feedback in tariff workshops:

- Transitional tariffs established for regional farming and manufacturing businesses were due to expire at the end of the current regulatory period on 30th June 2020 but have now been delayed by the State Government until 1 July 2021[2]. Without a further delay these businesses may incur a significant increase in prices from 1 July 2021.
- The current arrangements for the State Government's funding of the solar bonus are only in place until 30th June 2020. To put this cost back on EQL consumers would likely offset a significant proportion of the proposed network cost reduction.

[1] See Section 5.3 Productivity in "*Revised Regulatory Proposal for the 2020-25 Regulatory Period Internal Operating Expenditure Forecasts December 2019*"

[2] See http://statements.qld.gov.au/Statement/2019/6/21/regional-businesses-win-oneyear-extension-to-switch-power-tariffs

Even though these jurisdictional issues were outside the scope of the reset process, they were very much to the fore in consumer advocates concerns. This led to the significant focus consumer advocates brought to TSS discussion and only a cursory focus on building block issues that they were happy to leave to the CCP to review.

5. Consumer and Stakeholder engagement

In the experience of this CCP, this has been a curious regulatory reset.

Energy Queensland presented their Revised Regulatory Proposal to consumer groups at their consumer workshop of 17 December 2019, soon after its submission to the AER. A number of tariff-centric workshops were held with specific industry sectors around the same time.

Energy Queensland (EQL) has continued to approach the consumer and stakeholder engagement related to the Revised Proposals in the same positive manner that was a highlight of the earlier engagement; responsive, inclusive, with enthusiasm, transparency and commitment. However, the later stages of the engagement process are notable from a number of aspects, not least the sharp focus by consumer groups on the tariff structures and the strong public-safety focussed narrative by EQL. These and other features of the engagement are discussed in section 5.1 below.

EQL has provided its *Customer Engagement Report* as part of the supporting documentation for the RRP. Due to the geographic diversity in Queensland and the sheer number of specific local engagement workshops that were held, CCP14 was unable to observe many of the engagement activities. We are confident, however, that the Engagement Report fairly represents the intent and extent of EQL's work in considering the wider environment of the regulatory reset eg the integration of DER, network reliability and tariff imperatives.

We saw no information that contradicted the wider consumer sentiments that the CCP has observed across the NEM, including:

a) Affordability remains a major concern to most customers;

b) Many customers are willing to reduce peak energy usage and participate in Demand Response (DR) provided the right tools and incentives exist;

c) The majority of customers are satisfied with the overall reliability of their electricity supply; and

d) There is a general expectation that networks will continue to invest to ensure electricity supply infrastructure supports changing customer energy needs and technologies.

We did note some reliance on consumer feedback that, in our opinion, can be obtained without a full and balanced understanding of the true costs and alternatives available to meet changing energy needs. For example, EQL highlights the high level of support in the capability and investment to automatically detect fallen power lines and reduce potential power safety issues [3]. We would be most surprised if customers and communities did *not* reflect a strong preference for powerline safety. The question is whether EQL is undertaking this responsibility in a prudent and efficient way, consistent with their obligations and considering all reasonable alternatives. This more informed, in-depth consideration of a number of EQL's expenditure proposals was not evident to CCP14, certainly not to the same depth as similar matters have been discussed in other jurisdictions.

Also, whilst EQL's engagement has not occurred in a robust customer-centric and challenging framework such as that employed by SA Power Network's Customer Consultation Panel, Essential Energy's

[3] *2020 and Beyond Community and Customer Engagement Report*, December 2019, EQL, p22

Deliberative Forums or Ausgrid's (post determination) Network Investment Advisory Committee; it has covered a wide range of issues with many diverse stakeholders all the same. We recommend that EQL adopt a more co-ordinated and structured form for their ongoing engagement, similar to good practice observed elsewhere. Similarly, we see opportunity for the engagement on matters such as network management, risk prioritisation, investment priorities and operational efficiency to move further along the IAP2 spectrum towards *consult* and *involve*, similar to EQL's approach to tariff design.

We are pleased to note the continued involvement of senior management and, in many cases, Directors of Energy Queensland in the consumer engagement workshops.

5.1 Features of the consumer and stakeholder engagement

Throughout the workshops on the RRP, we noted a number of features of the engagement.

A. The majority of consumer interest remains with the Tariff Structure Statement

In the latter half of this reset, consumer groups have almost exclusively focussed on the Tariff Structure Statement (TSS) and its implications to the final electricity bill. We believe the publicly-owned Energy Queensland Limited's commitment to low network costs – reflecting a clear shareholder commitment – has largely met the community expectations of falling network charges. As an anecdotal comment at a recent EQL workshop noted, "*We will take the 19 percent reduction. It's how that will flow through to all sectors of the community fairly that matters now. Whether there are even more savings to be had; we will leave that to the AER and the CCP*"

This approach is amplified by the unique relationship between Ergon Energy Networks and its retailer of the same name. We found that consumers in regional Queensland in essence did not identify network prices per se, preferring to take the wider view of retail prices as the outcome of the reset, recognising that the process was a complex one involving the retailer, the Queensland Government's energy policy and the influence of the Queensland Competition Authority.

Consequently, much of the engagement relevant to Ergon Energy's customers in regional Queensland, and by association that for Energex and south-east Queensland, has been blurred with matters such as retail pass-through intentions, pricing pressures for primary producers, government policy on legacy retail tariffs and the possible re-introduction of the solar bonus scheme costs to electricity consumers.

B. EQL's public position on capex remains firmly focussed on consumer safety and compliance

Energex continues to present a very safety-focussed narrative in their discussion with consumer groups regarding their proposed capital expenditure, particularly replacement capital expenditure (REPEX). This has led to lack of detailed engagement on capital expenditure generally, as consumer groups were unwilling to engage in a discussion that openly considers safety – cost trade-offs. The opportunity to discuss the prudency and efficiency of capex expenditure, and to some extent the revenue building blocks, in any detail in the latter stages of the determination process was not offered by EQL, nor was it actively pursued by consumer groups.

One reason for this is that EQL in their engagement positioned capex as having only a minimal impact on revenue and therefore prices, so any detailed consideration was lost as consumers focussed on the headline influences on tariff structure and price. The long-term impacts of growth in the RAB were not considered in any detail, nor was any detailed investigation into the prudency and efficiency of past asset investment based on allowances and actual spend in previous periods.

In addition, EQL and consumer groups largely accepted the DDs as a whole, with most engagement focussing on how the revenue reduction would impact customers through prices.

C. The sheer volume of new information provided after the Draft Decision made reasonable assessment by consumers difficult

The AER 'kept the door open' for EQL to provide further information in the period after the Draft Decision to clarify their position on a number of matters. We understand why the AER took this approach, as we were well aware of the difficulty the AER and EQL were experiencing in reaching agreement on the content and nature of particular expenditure proposals. Our consideration of the business cases at the time, particularly those other than network augmentation projects, supported the AER's view that many investment justifications lacked depth, a practice description of the intended action, a clear consideration of alternatives and an adequate consideration of risk according to AER requirements and impacts to consumers and the wider community.

We wish to express our disappointment that such a situation was necessary however, especially considering the time available, investment in consultants and extent of the information requests that were undertaken in the period between the initial proposal and the draft determinations. Whilst the frustration with the situation was evident from both sides, we are complementary of the way AER staff approached EQL both formally and in less formal circumstances to work towards a mutually acceptable position regarding information quality and the form of justification.

Such action was not without a significant downside, however. Many consumer groups treat the Draft Decision as a 'peg in the sand' to respond to, but the permission (or was it a requirement?) to submit a large number of new business cases and additional information after the Draft Decision was made, meant that to prepare a meaningful response to the RRP, a large amount of additional data needed to be absorbed. Much of this new data was not provided as part of the post-draft decision engagement (as it focused on TSS matters) and was not generally available until after the information was published on the AER website on the 13 December.

This placed unrealistic expectations on consumer advocates to meaningfully assess and respond to the new information, especially considering the impact of the Christmas / New Year holiday period.

D. Towards the end of the engagement, consumer resources became stretched, and is likely to impact the number and completeness of some responses

Whilst we are complementary about the commitment by EQL in their engagement process and recognise the cost of such engagement , such interaction has also been a large investment by many stakeholders. As the complex analysis and response process nears completion, a number of consumer groups have expressed an inability to meaningfully respond to the RRP, particularly in the area of the TSS.

This is largely a result of the fact that EQL have changed their approach to the TSS a number of times in the reset process, leading to an exhaustion of available resources and funding for those consumer groups reliant on limited funding to meaningfully respond to the final position. Some have suggested to CCP14 that '*given the AER in its DD provided significant guidance for EQL to get to an acceptable TSS and EQL has said that is will follow the AER's advice, then we will accept the RRP TSS on this basis*'.

Also, with the volume of new information regarding spending proposals that was provided after the 10th December, in conjunction with the intervening Christmas and New Year period, some organisations have indicated an inability to meaningfully respond to the revised proposal.

5.2 Matters arising from the later stages of consumer engagement

The engagement quite rightly tended to focus on the few key issues that were raised by consumer groups and stakeholders. We note that most of these matters have been raised by consumers prior to the RRP was made public in mid-December 2019, so some of these matters have been addressed in the revised proposal.

These key issues are:

1. The headline price reductions from the proposal and the Draft Decisions are welcomed by consumers, as is the decision by EQL to accept the AER Draft Decisions on operating expenditure and other building block components.
2. Consumers are uncomfortable with the intention by EQL to 'reinstate' almost all the proposed capital spending (other than ICT) from the initial RP. Consumers are disappointed that EQL approached the draft decision almost exclusively as an opportunity to provide further justification of existing investment plans and did not seek to embrace opportunities for reductions in expenditure beyond those for ICT.
3. The timing, extent and complexity of these new justifications has created difficulties for some stakeholders to do anything more than provide only limited feedback on the proposal, with most choosing to focus their limited resources onto the TSS.
4. There is not sufficient clarity in the reasons behind the increase in Energex's peak demand forecast. This data is seen as important in assessing the recovery of augmentation capital proposed from the draft decision, and the influence that demand forecasts have on pricing guidance.
5. EQL's acceptance of the AER's draft decision on ICT expenditure is supported and welcomed.
6. The increase in proposed replacement capital (Repex) spend based on 'more network problems that have been found since the proposal was submitted' presents a real dent in EQL's credibility that it has its long-term asset management under control. The overall issue of past maintenance practices and the safety of assets, particularly in the Ergon region, continues to be of major concern to consumers and communities alike.
7. The discovery of more assets requiring replacement has 'taken most of the oxygen' and overshadowed any opportunity for consumers to consider in any detail efficient work practices, appropriate risk management and the prudency of past maintenance expenditure. Customers have asked for a longer term and more comprehensive explanation of how things 'got this bad' from EQL outside the regulatory reset process.
8. Further guidance beyond the one-off nature of the revenue reductions, and the likely revenue requirement (and hence price) trends beyond the current reset is of great interest to consumers.
9. Whilst generally well-received, the Tariff Structure Statement remains a somewhat incomplete document, with questions around the justifications that underpin the tariff designs, and the validity of the datasets that were applied to the sensitivity modelling.
10. Customers generally, not just in this engagement, are becoming more concerned about how new tariff structures and network price reductions will be passed through by retailers to consumers, and how consumers will be able to choose the best tariff options.
11. Some specific stakeholder groups, in particular councils, are asking for longer-term views on tariffs for street-lighting, particularly regarding innovation and the adoption of new technologies.

6. Operating forecasts

6.1 Productivity and other adjustments

EQL's approach to opex is unique in this CCP's experience:

- propose a number in the RP that excludes the EBSS from the current period
- find that the AER accepts that number in its DD because the AER's alternative estimate is higher (noting their caveats around Ergon Energy)

- discuss at length in the RRP a higher level of opex being required (a $ number that is still around (Ergon) or below (Energex) the AER's alternative estimate)
- accept the DD numbers but include the EBSS from the current period

The opex forecasts for Energex and Ergon Energy are set out in Table 8.

$2020m including Debt Raising Costs	EQL Regulatory Proposal / Draft Decision accepted by EQL	AER draft decision alternative estimate	EQL internal forecast of opex requirement	Accepted Opex plus recalculated EBSS
Energex	$1,806	$1,947	$1,909	$1,874
Ergon	$1,835	$1,964	$1,968	$2,029

Table 8: EQL operating costs forecasts

(source: EQL RRP – Operating Expenditure Forecasts attachment 7.001, p2, and CCP14 analysis)

As the RP comments, this higher revised proposal estimate:

> *"…largely reflect(s) reductions to the proposed management stretch targets that were previously included."* [4]

Energex and Ergon are now proposing to adopt the AERs industry-wide productivity factor of 0.5% per year replacing the somewhat ambitious productivity factors of 1.72% (Energex) and 2.58% (Ergon) in the Initial Proposal. CCP14, along with consumer advocates, questioned EQ's ability to achieve these higher targets given the lack of detail provided. Nevertheless it is disappointing to see the approach being 'let's give up trying to achieve the stretch targets' rather than 'let's see how we might provide more detail on how they might be achieved' and then take on the risk of achieving these rather than leaving the cost difference between 0.5% and 1.72/2.58% to be borne by consumers.

The actual base year numbers for 2018/19 indicate:

- For Energex - actual expenditure was lower than estimated in the Regulatory Proposal
- For Ergon – actual expenditure was higher than that estimated on the Regulatory Proposal

While it is pleasing to see that both Energex and Ergon Energy have not sought to recover their revised estimate by taking advantage of the AER Draft Decision's higher Alternative Estimate[5], they have effectively achieved a similar outcome (slightly lower for Energex and slightly higher for Ergon) by withdrawing the previous refund of the EBSS for the current period.

6.2 Ergon Energy, and the interpretation of 'not materially inefficient'

While Ergon Energy has indicated that it accepts the Draft Decision, the AER's decision was dependent on a review of actual base year expenditure. The AER commented that[6]:

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[4] RRP Attachment 7.001 "Revised Regulatory Proposal for the 2020-25 Regulatory Period Internal Operating Expenditure Forecasts December 2019" p.1

[5] We are assuming that for Energex using the actual (lower) 2018/19 Base Year costs will still lead to a higher Alternative Estimate than $1,806m

[6] AER *Ergon Energy Draft Decision, Attachment 6 - Operating expenditure*, October 2019 p. 6-8

"Historically, Ergon Energy has performed poorly against our benchmarking metrics. It has had high operating costs compared to other networks, even after accounting for its status as a rural, low density network. Limited reductions in operating expenditure over the first three years of the current regulatory control period (relative to the previous period) have improved Ergon Energy's benchmarking performance only marginally."

When considering the forecast cost reduction in Ergon Energy's base year opex and its unique OEFs, Ergon Energy's benchmarking performance improves to the point where we do not consider its estimated base year opex to be materially inefficient.

However, we note that this is a finely balanced assessment. We will review this position after updating our benchmarking analysis, considering the actual base year opex included in Ergon Energy's revised proposal and the results of our 2019 Annual Benchmarking Report, which will be published in late November 2019."

The AER's conclusion on Ergon Energy opex performance was reinforced by the most recent AER benchmarking analysis for 2017-18 that was released after the Draft Decision. It shows that, after rising in the previous year, Ergon's opex productivity fell in 2017-18 so that it is now among a group of four DNSPs with the lowest productivity. Over the period since 2006, apart from 2013 and 2014, it has consistently been in the bottom quartile of relative opex productivity.

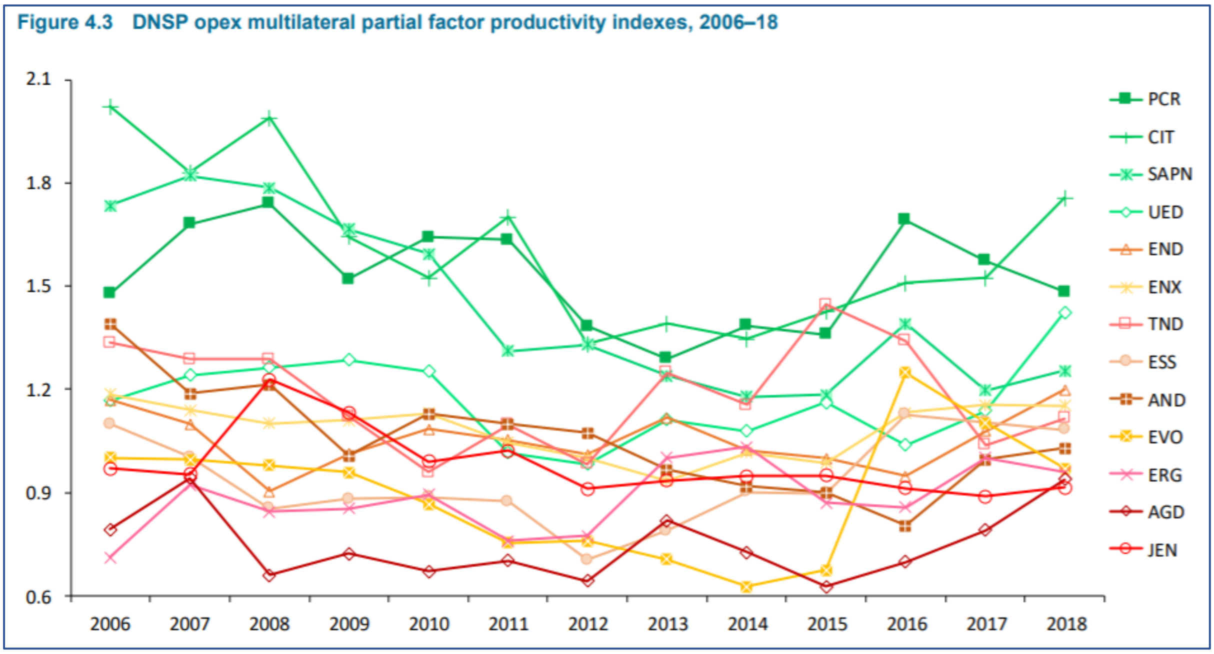

Figure 6: Operating cost productivity indices

(source: Annual Benchmarking Report, AER, November 2019, table 4.3)

Given that revealed opex for 2018-19 is above the forecast opex used by the AER in its Draft Decision, there is the potential for the AER to conclude that Ergon Energy is materially inefficient.

Ergon Energy argues that after 'recasting' and 'normalisation' of the revealed opex, the resulting base opex is not materially inefficient, drawing on a Frontier analysis of the appropriate OEFs. We comment on two aspects – bushfire risk and emergency response costs.

In the former, Frontier argues that the AER has incorrectly adjusted the OEF bushfire factor compared with Victorian DNSPs, because the bushfire risk for Egon is greater than for the Victorian DNSPs. Frontier presents an analysis of bushfire data from 2011 to 2016 to support its view. We look forward to the AER's analysis of the data provided. Given the ongoing bushfire damage in Victoria over the 2019/20 summer we find it very difficult to believe Ergon has greater risk.

For the latter, Ergon argues that the emergency response costs in 2018-19 of $66.21M were abnormally high, driven by the Townsville floods (which occurred after submission of their RP). It proposes adjusting ('normalising') the base year costs down by $12.16m to reflect the average emergency response expenditure over the period 2008-9 to 2018-19 of $54.2m.

This impact is shown in Figure 7, as reproduced from the Ergon Energy RRP.

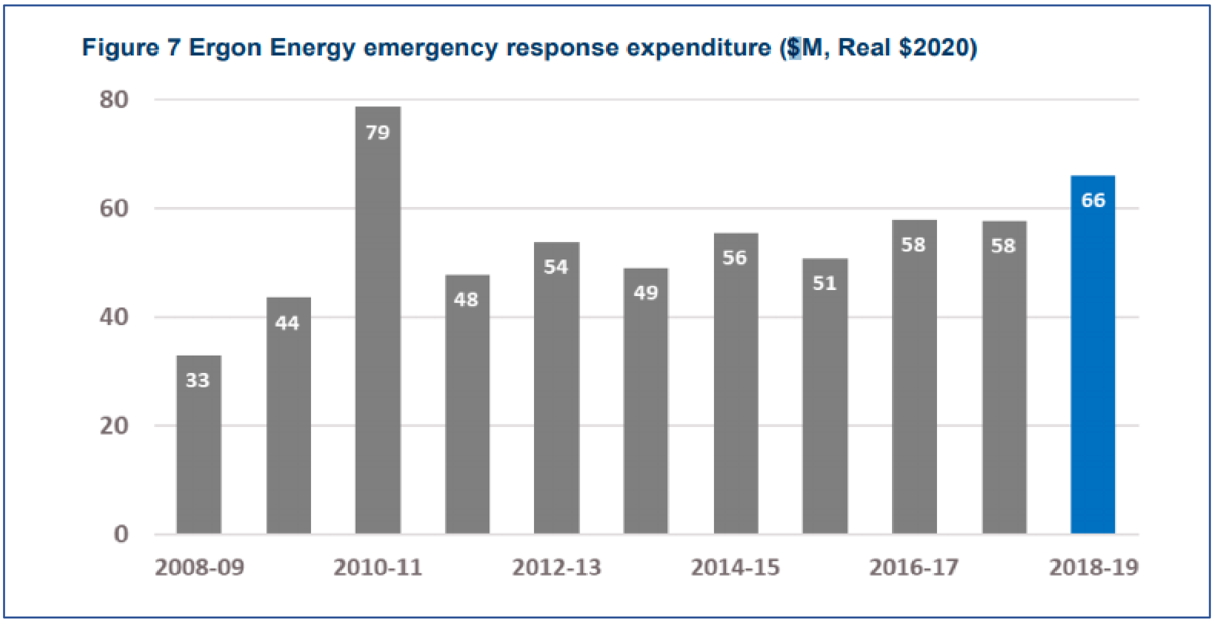

Figure 7: Ergon Energy emergency response expenditure (source: Ergon Energy RRP, attachment 7.001, p13)

We can understand Ergon Energy's approach here and look forward to the AER's perspective.

The Frontier analysis argues that the base year opex is not materially inefficient by:

- Including normalisation is not materially inefficient using 'unadjusted' benchmarks over both a 'short' (2012-17) or 'long' (2006-2017) benchmark period
- Including or excluding normalisation is not material inefficient using 'adjusted' benchmarks as Frontier argues the AER's application of the benchmarking analysis results in the AER attributing a false sense of preciseness to the results when a correct application would bring wider confidence intervals and hence a wider $ range of the "not material inefficient" level of opex.

This is shown below in Figure 8.

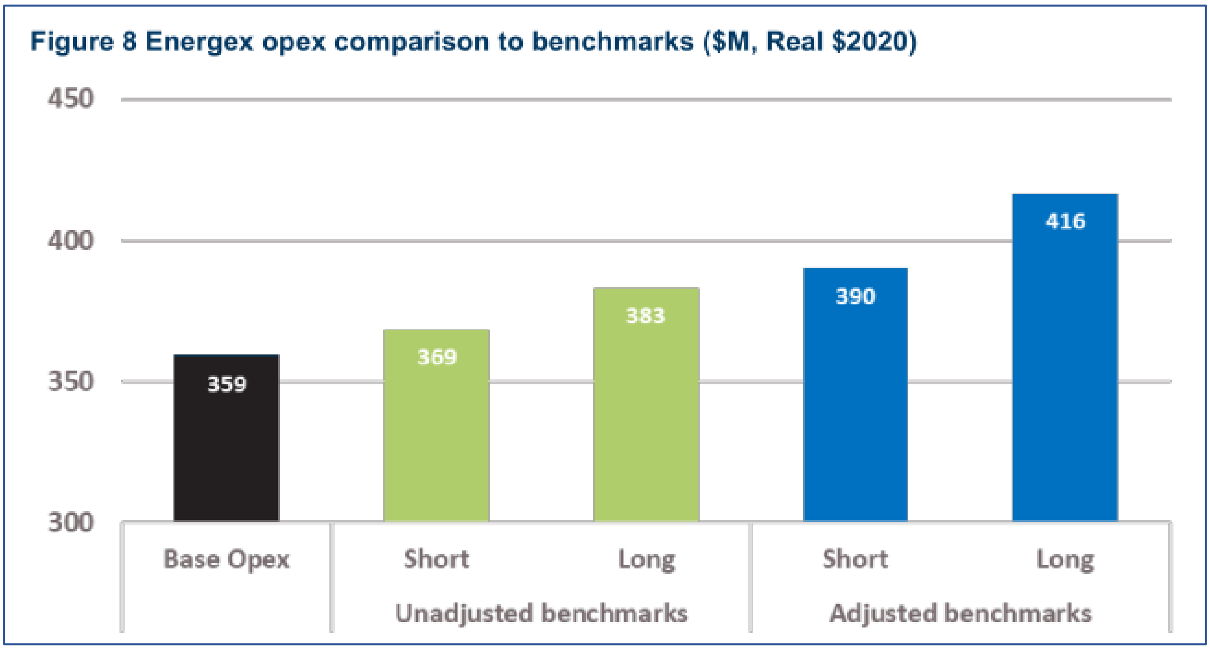

Figure 8: Energex efficiency benchmarks (source: Ergon Energy RRP attachment 7.001 p14)

The Frontier analysis claims to have found a number of flaws in the AER's benchmarking methodology e.g. around the use of overseas data, relative weighting of the short vs long periods, rural vs urban DNSPs and OEFs.

Again, we look forward to the AER analysis of the Frontier report. We are concerned that if it is accepted that it could effectively render the whole benchmarking exercise of limited use. Consumers advocated for many years for the AER to undertake benchmarking and have strongly supported it since its introduction. We believe it now serves as a crucial role in allowing consumers to advocate on the need for networks to constantly improve their efficiency replicating what happens in a workably competitive market.

One reason for the Frontier analysis being able to draw its conclusion is the AER benchmark comparison score used to determine whether a DNSP is not materially inefficient. This score means that a network that is consistently in the bottom quartile and that the AER, commenting on Figure 6.7 that include AER forecasts of Ergon's 2018-19 MPFP score notes [7]:

> *"…while Ergon Energy's opex MPFP score has improved somewhat since 2015–16, the first year of the current regulatory control period, Ergon Energy's MPFP scores based on its 2017–18 actual opex and its estimated 2018–19 base year opex continue to place it as a relatively poor performer amongst distributors in the NEM.*
>
> *In terms of comparative performance, Figure 6.7 shows that Ergon Energy has improved marginally from 12th place out of 13 distributors in terms of average MPFP score over the 2006–2019 time period, to 11th place in 2017–18 and an estimated 10th place in 2018–19.*
>
> *We note that this marginal relative improvement in opex productivity has occurred during a time of significant increases in opex MPFP scores of some of the other distributors in the NEM."*

can be considered "not materially inefficient".

[7] Draft Decision Opex pp. 6-37-38

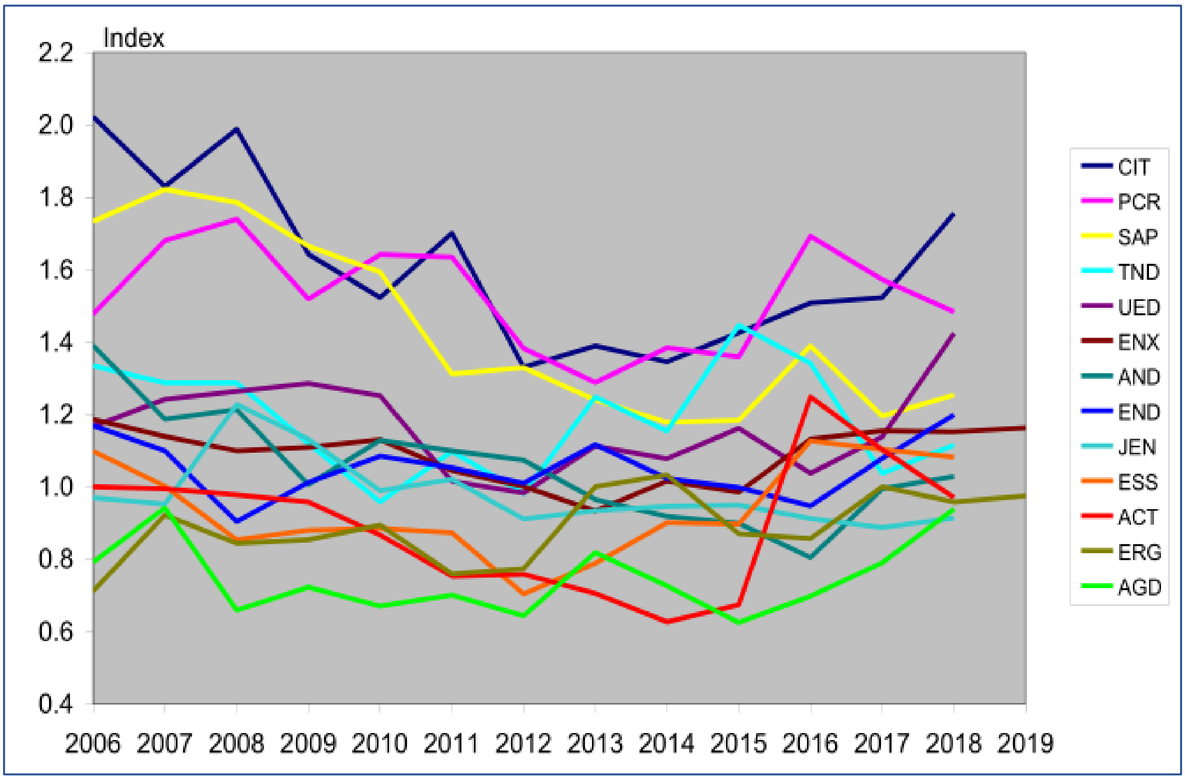

Figure 9: Opex MPFP with Energex and Ergon Energy forecasts to 2019
(Source: AER Draft Decision Attachment 6 – Operating Expenditure p. 6-38, Figure 6.7)

The AER describes its methodology:

> *"We then draw on our benchmarking scores from our econometric benchmarking models to assess whether to make an efficiency adjustment to the distributor's (Ergon Energy's) period-average opex for each of the two periods.*
>
> *For each of the models, the size of the efficiency adjustment is calculated by comparing the distributor's (Ergon Energy's) efficiency scores over 2006–17 and 2012–17 against a benchmark comparison score of 0.75 (after adjustment for OEFs as discussed below). The benchmark comparison score reflects the upper quartile of possible efficiency scores by distribution businesses and reflects our conservative approach to setting a benchmark comparison point.*
>
> *This is consistent with the comparison point we adopted in our April 2015 decision for Ergon Energy and subsequent decisions in November 2018 for NSW distributors."*

This is important as opex is around a third of total network price paid by consumers and is passed straight through in prices.

The CCP's submission in December 2018 to the AER's opex productivity review discussed this 0.75 score and why it may be no longer relevant, and we refer the AER to the more extensive discussion there.[8] Here we note the AER's comment in its original 2015 Ausgrid decision that led to the 0.75 score [9]:

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[8] See Section 2.3 pp 10-14 of the CCP submission at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-our-approach-to-forecasting-opex-productivity-growth-for-electricity-distributors/initiation

[9] AER Final Decision Ausgrid Determination Section 7 Operating Expenditure Section 7, A7 The benchmark comparison point and adjustment to base opex April 2015 pp 270 https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/ausgrid-determination-2014-19/final-decision

"However, given this is our first application of economic benchmarking, our view is this application is appropriate for this determination. That is, we have allowed a wide margin between the frontier firm (0.95) and the benchmark comparison point (0.77). Service providers should be aware, however, that as we refine our approach and receive more data, we may reduce the size of that margin when adjusting base opex to develop alternative opex forecasts."

The following figure from the recently released 2019 Benchmarking report compares the range of productivity measures used by the AER[10] and shows the 0.75 benchmark.

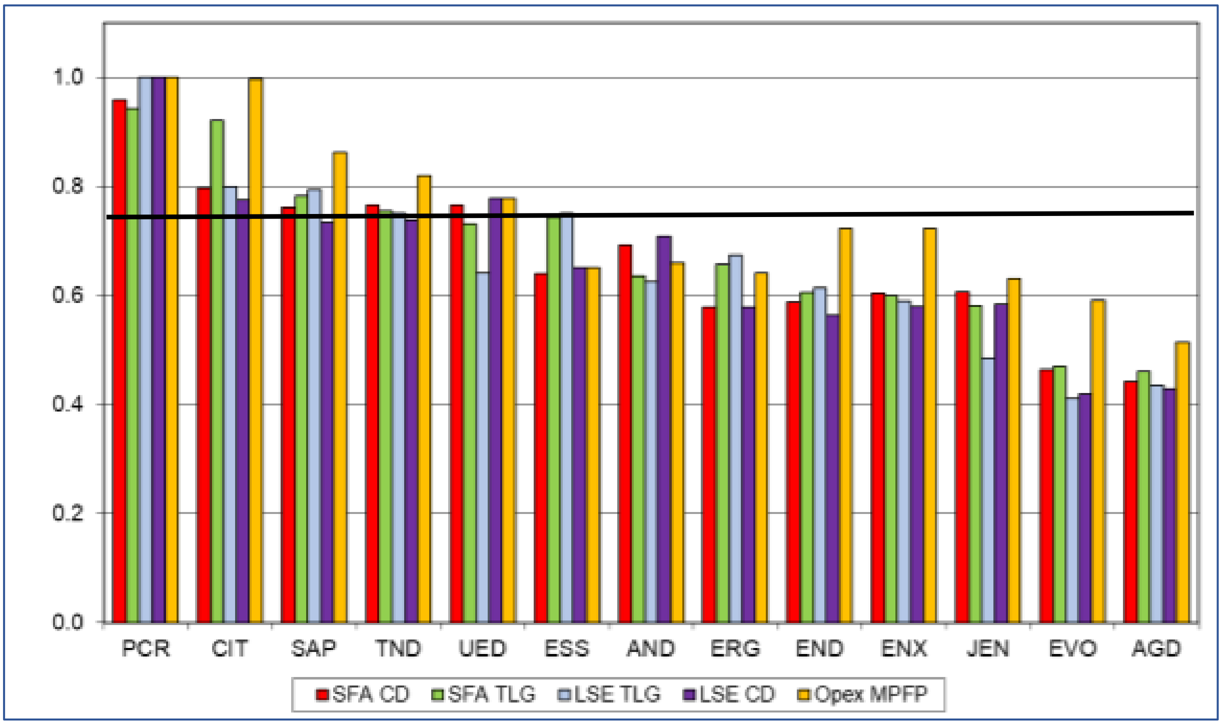

Figure 10: AER Econometric modelling and opex MPFP (2012-18 average
(from: AER Annual Benchmarking Report , November 2019, p30, figure 5.2)

It shows that applying the > 0.75 decision rule would mean that networks that are 20-25% less efficient that the frontier performer – Powercor – would still be regarded as "not materially inefficient". Consumers do not accept this conclusion as meeting the NEO. While we understand the reticence of the AER in its 2015 decision, we think that it is reasonable, given the much greater data available and the refinements undertaken to the productivity measures[11], for the AER to review the "not materially inefficient" decision.

A lot of this debate is around how productivity improvements should be shared between networks and consumers. The benefits of the 0.5% productivity adjustment will go 100% to consumers. The current AER approach means that once the network gets over the "not materially inefficient" hurdle, EBSS allows the network to retain 30% of all the efficiency improvements it makes beyond that point. We would argue that the more extensive benchmarking data now available provides an opportunity for the AER to review the 0.75 "not materially inefficient" decision rule. Any increase in this level would result in consumers getting 100% of these additional productivity improvements.

[10] AER "Annual Benchmarking Report - Electricity network distribution service providers" November 2019 p. 30

[11] See Chapter 6 in the 2019 Benchmarking Report for a discussion of the range of improvements made in recent years.

6.3 Labour real price growth

In the past the AER has used an average of the forecasts from the networks' forecaster (usually BIS Oxford) and the AER's forecaster (Deloitte) to assess real cost escalation. In our May 2019 submission on the SAPN Regulatory Proposal we commented that: [12]

> *"It is perhaps no coincidence that across networks, the networks' forecasts are consistently showing higher real wage increases than the AER's forecasts."*

The higher the forecast the higher the revenue outcome. The data for Energex/Ergon shows a considerable difference between the two forecasts with the cumulative impact of continuing the part average approach being an additional 1.44% [13]:

	2020-21	2021-22	2022-23	2023-24	2024-25	Cumulative
DAE	0.47%	0.63%	0.52%	0.58%	0.50%	**2.73%**
BIS Oxford	0.90%	1.10%	1.30%	1.30%	0.90%	**5.62%**
Average	**0.68%**	**0.86%**	**0.91%**	**0.94%**	**0.70%**	**4.17%**

Note: The DAE forecasts are taken from the AER's Draft Decisions. The BIS Oxford forecasts are sourced from an updated independent expert report, contained at Attachment *EGX ERG 7.004*.

Table 9: Labour cost changes - comparison of DAE and BISOE analysis

(source: Ergon Energy RRP, attachment 7.001, p21, table 9)

Following a review of the relative accuracy of the two forecasts as part of its Draft Decisions for EQL and SAPN, the AER concluded[14]:

> *"Based on this analysis, we now consider that Deloitte's utilities industry real WPI growth forecast, rather than BIS Oxford Economics', or an average of the two, better reflects actual Australian utilities real WPI growth."*

EQL (and SAPN) commissioned BIS Oxford to undertake a critique of the AER's decision. This critique argued for retention of the existing averaging approach. While we will leave the response to the BIS Oxford paper to the AER and Deloitte, what us clear to us from Figure 11 below is that the result of using the averaging approach over the current 2015-20 period has resulted in an allowance for wage growth that is much higher than the actual level of wages growth. Consumers have paid more than they should have had the wage forecasts, made at the time of the current period reset, been more accurate. Consumers want to avoid that occurring in the future.

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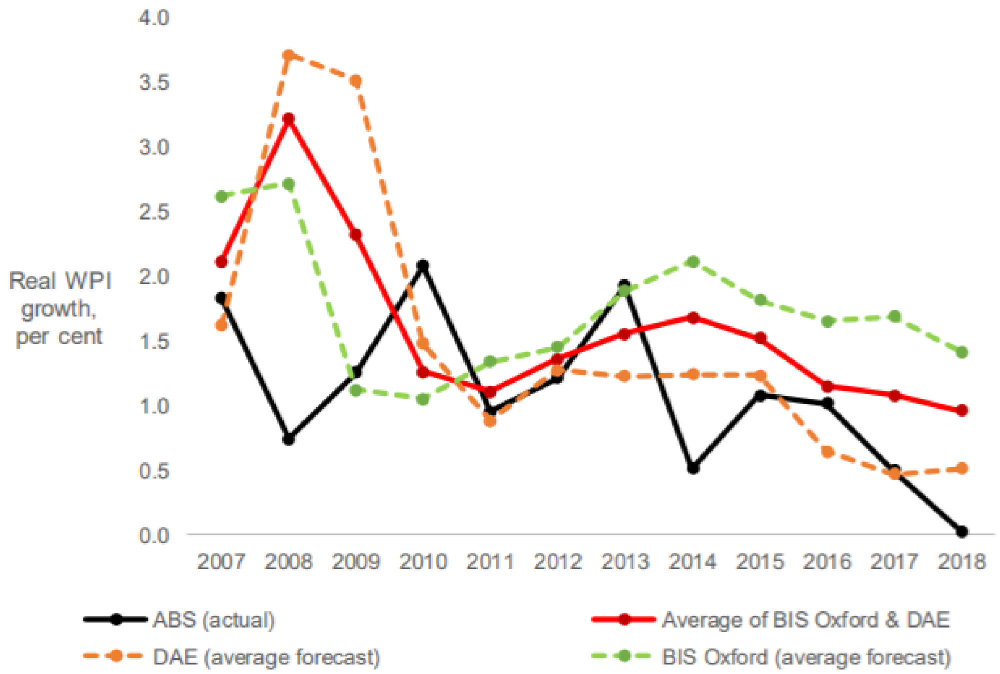
[12] See p. 33 https://www.aer.gov.au/system/files/CCP14%20-%20Submission%20on%20SA%20Power%20Networks%20Regulatory%20Proposal%202020-25%20-%2016%20May%202019_0.pdf

[13] See p. 21 Revised Regulatory Proposal for the 2020-25 Regulatory Period Internal Operating Expenditure Forecasts December 2019

[14] See p. 6.-32 https://www.aer.gov.au/system/files/AER%20-%20SA%20Power%20Networks%202020-25%20-%20Draft%20decision%20-%20Attachment%206%20-%20Operating%20expenditure%20-%20October%202019_0.pdf

Figure 6.5 Real WPI growth—Australian utilities sector



Source: AER analysis.

Figure 11: Wage Price Growth (AER SAPN Draft Decision Attachment 6 p. 6-31)

We make some brief comments on the respective forecasting approaches:

- Both start with forecasting the all industries WPI and then seek to forecast the margin between the all industries and the EGWWS sector
- Both over forecast the all industries WPI – Deloitte less so than BISOE in early years, the opposite in later years
- Deloitte under forecasts the EGWWS margin, BISOE over forecasts the margin; so the greater Deloitte accuracy seems to be because it's 'under and over' forecasts combine to make a more accurate overall forecast
- We understand the comments around the future greater accuracy of Deloitte depends on this historical forecast bias continuing

EQL advances five challenges to the AER's analysis – here is our response:

- *First* – the fact that the AER has not tested whether its new proposed approach (Deloitte only) is better that the old approach (average) is not needed given if it is clear that Deloitte is more accurate
- *Second* – it seems to set up a straw man argument to suggest that because the ABS actual outcome is the result of a survey "…of 5,000 or so" businesses it is only ever "indicative" of what is actually happening to labour costs; extending that argument would mean that whatever historical measure the ABS publishes on the basis of a sample approach is only ever "indicative" of what has actually happened e.g. CPI is only ever "indicative"; however all stakeholders have long accepted the ABS measures (whether based on "actual" or a robust statistical sample) as the best impartial measure of what is actually happening and hence the basis for this regulatory function; so the aim is to get

the best forecast of what the ABS sample results will be – and the AER analysis suggests the Deloitte measure is the best

- *Third* – we do not understand the "relatively small sample period" comment; the AER analysis covers forecasts made from 2007-2018 - which covers periods of both high and low actual real wage growth; EQL provides no arguments in favour of a different sample period
- *Fourth* – yes, past performance provides no indication of future outcomes – but what the current approach has meant is that consumers have paid a lot more than they would have paid had the proposed approach of using just the more accurate Deloitte forecast been used; we see no reason why this shifting of risk to consumers should continue
- *Fifth* – we presume that BIS Oxford has continually evaluated its forecasting methodology over the 2007-18 period; if so then there would have been considerable change from when the 2014 actual data was published given the large overestimate since then in the BIS Oxford forecasts shown in this Figure from the AER's Draft Decision on SAPN[15].

If there were changes in the forecasting methodology from 2015 (and so the AER is not "(t)esting *old* forecasting approaches") then these changes apparently did not result in any change in the trend of the BIS Oxford forecast being consistently higher than the Deloitte forecasts. The BIS Oxford technical paper does not seem to provide a reason for this. We may be more supportive of the averaging approach were this the case.

So, in summary, we have difficulty in agreeing with EQ's arguments and support the AER's approach. We consider the AER's approach "good regulatory practice" – it recognises when methodology needs to change to ensure the allowed expenditure is prudent and efficient. We are not convinced that the "two forecasts are better than one" approach is in the long-term interests of consumers.

7. Capital Expenditure

Overall, EQL in their Revised Proposal appear to have responded to the consumer requirements expressed in the response to the initial proposal; by providing better investment justification to the AER, accepting the substituted ICT investment levels and reviewing property needs.

The response by EQL to the Draft Decision continues to focus on the 'Safety First' headline [16], highlighting the additional safety issues related to pole failure rates and conductor clearance defects that have come to light since the submission of the RP; also raising a significant compliance risk with legislated standards.

The draft decisions challenged EQL's capital proposals, leading to an 11% ($251M) reduction in gross capex allowance for Energex, and a 19% ($565M) reduction in that for Ergon Energy. Consumers' responses tended to support the draft decisions.

We recognise that the AER 'left the door open' for EQL to provide further justification of the capital expenditure; particularly network augmentation and non-system capital such as vehicle fleet and property. EQL have highlighted to consumers that they have put considerable resources into this new information for the AER, but the extent and nature of most of the new information has only become evident to stakeholders after the revised proposals were published. Therefore, consumers and the CCP have not

[15] See p.6-31 in https://www.aer.gov.au/system/files/AER%20-%20SA%20Power%20Networks%202020-25%20-%20Draft%20decision%20-%20Attachment%206%20-%20Operating%20expenditure%20-%20October%202019_0.pdf
[16] 'Our Revised Regulatory Proposal – an Overview', EQL, December 2019, p10

rigorously assessed this revised information, and we will take interest in the AER consideration of the revised justifications.

A brief sample of the revised business cases, in particular those not related to network augmentation proposals, tend to poorly describe the background as to why certain options were considered, and are light on practical descriptions of what is actually proposed, and how the work will be implemented. This does not engender a high level of confidence by customers in the robustness of the cases themselves.

We do note that EQL and the AER agree on capital proposals for ICT and connections, with only minor additions. EQL have stated that they do not consider that the draft decisions allow sufficient capital to meet their plans and obligations.

Interestingly, EQL does not take a strong stand on the social equity or intergenerational cost transfer matters raised by SAPN in its RRP. These matters did not arise in the engagement process to any extent.

7.1 Overview of the revised capital requirements

We are somewhat surprised that EQL has taken the opportunity to reinstate almost all of the capital investment challenged by the AER in the draft decision. In fact, both utilities are proposing *increases* in gross capital expenditure compared to the initial proposals when the impact of the generally agreed ICT expenditure reductions are excluded, as demonstrated in Table 2.

In fact, net of ICT, both utilities are seeking *increases* in the capital allowances relative to the RP.

Energex	Proposal (RP)	Draft Decision	RRP	change from RP	
	$M	$M	$M	$M	%
Gross Capex	2327	2076	2292	- 35	- 1.5 %
ICT	193	145	148	- 45	- 23.5 %
Capex net of ICT	2134	1931	2145	+ 11	+ 0.5 %

Ergon Energy	Proposal (RP)	Draft Decision	RRP	change from RP	
	$M	$M	$M	$M	%
Gross Capex	2905	2339	3007	+ 102	+ 3.5 %
ICT	210	158	164	- 46	- 21.8 %
Capex net of ICT	2695	2181	2842	+ 148	+ 5.5 %

Table 10: Capital Investment, excluding ICT

Source: Energex Revised Proposal – An Overview, p18. Amounts are $M, real $2019-20. Some rounding.

This situation can result in a level of distrust in the significant work undertaken in reconsidering the project business cases, for two reasons.

Firstly, customers expect utilities to be explicit and active in addressing the long-term impacts of RAB growth. There is an expectation that utilities recognise and accept the intent of the opportunities raised by the regulator in setting substituted estimates to reduce capital expenditure and not widely seek to counter the AER's comments with further information that restores the bulk of the proposed investment back to the initial (pre-draft decision) levels.

Secondly, we would hope that during the revision of the business cases by the utilities after the draft determinations, new and innovative solutions may arise as a result of the more rigorous cost-benefit analysis, improved sensitivity analysis or from new information. Some investments may be deferred or changed. When the result of extensive revision and the re-justification of the investment proposals result in an unchanged value of investment required, customers must be forgiven for thinking that the utilities are demonstrating a commitment to the earlier plans.

We are not suggesting this is the case here, only highlighting that the risk of a lack of trust by consumers may exist. We acknowledge that the reviews have resulted in some decreases to the cost of the LV safety programme (Energex) and a number of Ergon Energy augmentation plans, however the revised headline capital requirements are still approximately the same or higher than the initial proposal.

Table 11 summarises our observations regarding the capital expenditure in the revised proposal, where:

- Increase - Seeks to increase the level of investment (>5%) from that stated in the initial proposal through further justification
- Maintain - Seeks to maintain (± 5%) the level of investment stated in the initial proposal through further justification
- AER acceptance - The AER has accepted the initial proposal (± 5%)
- EQL acceptance - EQL has accepted the AER's substituted amount (± 5%)

We appreciate that the regulatory determination is a decision as a whole, and the utilities can reprioritise capital expenditure depending on need. Based on the matters noted in Table 11, we wish to highlight a number of specific matters from the revised proposals.

Capex Component	Energex	Ergon Energy
Repex	Maintain	Increase
Augex	Maintain	Maintain
Connections (Gross)	AER acceptance	AER acceptance
ICT	EQL acceptance	EQL acceptance
Property	Partially reinstate	Partially reinstate
Fleet	Maintain	Maintain
Other non-network	AER acceptance	EQL acceptance
Overheads	Increase	Maintain

Table 11: Overview of the RRP capex intentions Source: CCP analysis of the RRPs – Table 12, p27

7.2 The impact of changes to key inputs

The revised proposals include changes to a number of key inputs to capital investment drivers were made relative to the initial proposals and those accepted by the AER in the draft decisions. They are:

Energex:

- Average growth in peak demand more than doubled, from 0.29% to 0.7%
- Net new customer growth was scaled down by 10% to 105,000.

Ergon Energy:

- Average growth in peak demand more than halved, from 0.38% to 0.15%
- Net new customer growth was scaled down by 40% to 36,000

In its Consumer Engagement Report, EQL notes approximately 31,000 new connections in Energex in 2018-19, and 7,720 new connections for Ergon Energy [17].
These changes, in the greater scheme of overall capital investment, are to some extent immaterial. However, Table 12 below suggests that Energex and Ergon Energy assign little or no sensitivity to the changes in the key drivers. Despite an increase in forecast peak demand for Energex and a decrease for Ergon, the plans for network capacity augmentation appear, on the information presented to consumers at least, to have not changed. Similarly, the decrease in number of expected new connections appears to have had no influence on the costs for customer connections.

We recognise that there are a number of factors in play in these proposed amounts, including individual project justifications and the impact of customer connection cost recovery policy. We do suggest, however, that some investigation and commentary on the impact of the change in the key augmentation drivers is required.

$M	Initial Proposal	Revised Proposal	Note
Augex, Energex	301	297	Peak demand revised up from 0.29% to 0.7%
Augex, Ergon Energy	249	240	Peak demand revised down from 0.38% to 0.15%
Gross connections, Energex	475	474	Estimated connections revised down by 10%
Gross connections, Ergon Energy	376	377	Estimated connections revised down by 40%

Table 12: Capital Investment related to customer numbers and demand growth

Source: excerpt from EQL RRP – An Overview, p18. Amounts are $M, real $2019-20

7.3 Revised replacement capex (Repex)

A. An increase in asset replacement Investment in regional Queensland (Ergon Energy)

Ergon Energy has proposed a significant increase ($455M, 55%) in the level of replacement capital beyond that of the AER's substituted amount in the draft decision, and even a larger ($200M, 18%) increase in the amount required in the RP. The changes include an increase in pole replacement from $315M to $376M, an increase in the cost of the major project to replace a Childers to Gayndah 66KV line, and notably an increase in the powerline clearance programme from $14M to $150M.

Ergon justifies this increase through two factors. Firstly, the submission of a number of revised repex business cases is intended to address the AER's concerns regarding the prudency and efficiency of the proposal [18]. Secondly, Ergon advise that the increased amount includes provisions for newly identified safety issues in the Ergon Energy distribution area. This is the second time Ergon Energy has flagged an

[17] 2020 and Beyond Community and Consumer Engagement Report, EQL, December 2019, p 39
[18] The Ergon response is noted in the 'Revised Regulatory Proposal Repex Summary', Ergon Energy, Dec 2019

increase in repex requirements, as an extra $208M (23%) was proposed over the investment in the 2018 Draft Plan to address concerns related to asset safety and replacement in regional Queensland.

The subject of Ergon Energy's increased allowance for asset replacement (Repex) in regional Queensland is difficult for customers to assess. In its consumer engagement Ergon Energy has made a powerful case for increased repex based on the condition assessment and failure risks of major plant items across their region, along with an emotive case for power system integrity and public safety. The few statistics that were shared some time ago on pole failure rates, conductor condition and substation plant failure risk support the increased focus on public safety and suggest an increase in repex- regardless of how it is funded - is warranted.

The major business case related to this proposal – *6.019 Business Case CTG CTS – December 2019* – however is fundamentally based on an obligation to observe the requirements of the *Queensland Safety Regulation 2013* [19], and the risk that non-compliance could place on EQL and its officers. The business case itself makes limited attempt to quantify the public safety risk that the non-compliance has presented over the many years the conductors have potentially been outside regulated limits. There is a disconnect between the emotive public safety concerns enunciated in the EQL public consultation and the rather black-and-white compliance argument that is at the centre of the project business case and options analysis.

Similarly, CCP14 does not believe that Ergon Energy has made a strong case that this increased replacement capital expenditure should be fully funded by customers in the next regulated reset. Our questions centre largely on how such a situation was able to arise, and who carries the responsibility to fund both the proposed actions to rectify the current non-compliances and to establish a more robust risk-based future maintenance regime. We acknowledge the increase in Repex expenditure by Ergon Energy in the current period, signifying the genuine concern within the organisation to meet their safety and performance obligations.

Consumers have the perception that there is a risk of 'paying twice' – originally previous periods and then again in 2020-25 to fix past problems. Given the regulatory framework is designed to reflect what happens in a workably competitive market, this cost should be borne by the shareholders, not consumers.

We understand that the proposed replacement capital, in particular for Ergon Energy, is a current matter for detailed engagement with the AER and Energex and Ergon Energy. We ask however:

- Should customers carry responsibility for what appears to be sub-optimal construction, inspection and preventative maintenance practices of the past ?
- Given that many of the instances of non-compliant conductor clearance have been in existence for many years, can the problem be addressed in a long-term, prioritised approach. What action has EQL taken with safety regulators and, if necessary, their government stakeholders to aggressively seek a more considered rectification programme for what has been a long-term risk ?
- Why has it taken an automated LiDAR process to detect these risks, when assets have been physically inspected on a regular cycle of approximately 5 years ?
- Can the rectification and accelerated capex programme generally be reasonably and efficiently resourced ?

B. The M028 Childers – Gaydah line

EQL arranged for some customer representatives to inspect this line. Some interesting issues became evident:

[19] Business Case 6.019 – CTS and CTG – Ergon Energy, p1, section 1.3

The line in many locations comprises tall poles on private property well off-road reserve and presents significant challenges for inspection and repair. These challenges may give insight into the high failure rates of the conductor and structures, and the time needed and high costs to inspect and repair the line.

The copper conductor appears aged, and despite little evidence of overloading and annealing, is in poor condition and clearly approaching the end of its service life. Ergon Energy advises of frequent conductor breakages, and the field staff confirm the difficulty and safety risks of repairing the aged conductor. This raises an interesting challenge regarding aged overhead lines. Replacing considerable distances of conductor can be impractical due to the inability and inefficiency of replacing like- with-like. However, using a different conductor over long spans introduces the need for line redesign for clearance and rating; requiring new structures that will need to be on a new easement in order to maintain the existing line in service.

This leads to the action of basically building a new line.

We recommend that the AER consider the practicalities of replacing sub-transmission lines that have long lengths of aged, outdated conductor in their repex analysis.

On the evidence presented on the field tour, the general proposal to construct a new line is supported., despite the revised increased cost. This does not remove the obligation from Ergon Energy to revise their inspection and maintenance practices for such lines, as in our opinion the effectiveness of past management of this line is questionable.

With the replacement of the Childers- Gayndah line, it is unclear what allowances are made to reflect the fact that many of the poles along the line have been replaced over time, are still serviceable and could become stranded assets should a new line be constructed. As one Ergon field staff member on site suggested: "*we would happily pull the good ones out and use them somewhere else*. *They're good poles*."

C. Addressing public LV safety risks, in particular failed neutral connections

Energex and Ergon Energy have responded to the CCP and AER's concerns regarding the LV safety project by providing additional risk quantification and assessments, further analysis of options and the adoption of a non-technology specific approach.

As detailed in their submission document '*6.001 Business Case – LV network Safety*', capital expenditure (unmodelled repex) of over $80.9M (reduced from $100M originally proposed) is planned to build the capability across both networks to detect faults in low voltage networks, particularly at the connection to customers' premises. In conjunction, Ergon Energy is proposing $55.2M to implement a more condition-based programme of replacing LV service wires, as discussed in '*6.028 Business Case – LV Service Lines'.*

We support initiatives intended to address public safety risk, especially where there is clear evidence of a degrading situation and increasing risk, and where new technologies can reasonably be employed. EQL has provided evidence that the number of service-related shocks is increasing, particularly in the Ergon Energy region. Again, we find the business cases lack detail on the narrative of why certain options were selected and then discounted, and what was actually proposed to be undertaken as the preferred option.

Therefore, we remain sceptical that the extent and nature of the risk is adequately expressed in practical terms, and that the solution proposed - installing new-technology network monitoring devices at a customer's premises – is an efficient and effective way to address the risk . The business case does not represent a full and fair assessment of the options available. For example:

- every risk scenario in the analysis highlights a risk due to degradation or corrosion of a neutral connection – impacts that occur over a long period of time. This places into question the need for the proposed near-instantaneous alert of failure, when low-cost routine inspection (perhaps 5 years in high risk areas) would also be likely to effectively address the risk.

- The proposed unit cost of each unit of less than $400 installed seems remarkably low when considering the likely costs of supplying and installing such equipment in a customer switchboard and implementing the necessary communications and back-end equipment. The business case is silent on these aspects.
- The value of AMI as a data source is mentioned in the business case, but the wider benefits of AMI rollout – an activity that could be negotiated or encouraged with the related retailer even within current market arrangements – are not meaningfully explored.
- Finally, the business case does not seem to consider the relationship between the business cases 6.001 and 6.028, where at-risk services will be replaced on a condition assessment basis anyway.

We are unable to support this proposal.

7.4 Capitalised Overheads

Energex has adopted the AER methodology in calculating the allowance for capitalised overheads. This method has allowed Energex to increase its proposal for capitalised overheads by $35M, from $524M to $558M. This change has negated the reductions in capital requirements in other areas such as property.

We acknowledge that the calculation of capitalised overheads reflects a base and trend methodology as well as adjustments valued through an agreed ratio of fixed and variable overhead costs. We also note that some calculation errors were evident in the original proposal.

That being said, Energex has not, in our opinion, adequately articulated the reasons for the increased level of overheads, particularly in light of opportunities in contracting, work standardisation and packaging and ICT harmonisation that has been proposed. We encourage the AER to consider the proposal for increased capitalised overheads closely.

8. Other comments

8.1 Measure of Expected Inflation

In 2017, the AER undertook an extensive review of their methodology to calculate the expected inflation rate. It sought to answer two questions:

(i) Does the current AER approach (which uses a 10-year average of the RBA forecast for the first two years then the mid-point of the RBA inflation band for the next 8 years) result in the best measure of expected inflation?

(ii) Is inflation appropriately compensated for in the post-tax revenue (PTRM), roll forward (RFM) and pricing models?

The network's focus was on (i) arguing for the bond break-even approach which was the methodology until 2012 when the networks successfully convinced the AER to change to the current approach. The networks preferred methodology would have given a lower expected inflation rate.

The networks initially sought to avoid (ii) by presenting simplistic one period (5 year) models that suggested that the current approach resulted in under compensation for the networks. At a workshop in August 2017 to discuss the modelling results, the networks finally acknowledged that it was appropriate to look at the multi-period PTRM model and agreed with the CCP that, with a few minor exceptions (first year depreciation), networks do receive the real rate of return.

Now this led to a discussion on whether the current AER approach of networks earning a real WACC on a real RAB (and where consumers bear the inflation risk) should be changed to something else e.g. AER targets nominal debt (which could be a cost pass through base on some benchmark with sharing of the 'overs and unders' with consumers similar to other costs) and real equity. However, these matters are best dealt with in a much wider context e.g. the next Rate of Return review, than in a narrowly focussed expected inflation rate review.

The AER concluded in its December 2017 Final Position Paper that[20]:

> *"Our final position, after carefully considering the submissions and the further material submitted to us is to not depart from our preliminary position.*
>
> *That is, we will continue our current approach to the regulatory treatment of inflation in our determination of revenues and prices for electricity and gas network services. Based on the material before us at this time, we therefore do not propose any amendments to the PTRM or RFM."*

Which the CCP supported in its earlier submission on the on 6th November 2017[21]:

> "*We agree with the ACCC/AER's arguments in their Position Paper favouring continuation of the existing method of calculating expected inflation. Each approach has its strengths and weaknesses and selection is a matter of judgement, bearing in mind the AER's principles of congruence, robustness, transparency, replicability and simplicity. We support both the AER's principles and their judgement."*

The networks preferred bond break-even approach has its problems as well which were highlighted over the course of the review.

The Tribunal in its October 2017 ActewAGL decision specifically endorsed the AER approach when ActewAGL was arguing for the bond break-even approach.

In its 2017 decision the AER committed to on-going monitoring of the situation. At the networks' instigation, the AER has convened a Working Group of AER, networks, consumer advocates and the CCP which met twice in the second half of 2019 to consider ENA evidence on actual and forecast inflation. In September 2019, SAPN formally applied to the AER to undertake a new formal review of expected inflation. In its 7th November response, the AER Chair declined to initiate a new review and concluded that the existing Working Group should continue its process.

Subsequent to the AER letter, the networks presented additional information to a Working Group meeting in late November[22] and this material is drawn on in the SAPN RP. Given that any change to the estimation methodology away from the RBA approach would require a change to the PRTM model which has an established timetable in the Rules, it is unlikely that any change would be applied in the AER's final decision on SAPN or EQ. Any change in the rate of return objective would introduce a new level of complexity and time required to make any change.

[20] See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/review-of-expected-inflation-2017/aer-position

[21] ibid

[22] See https://www.aer.gov.au/system/files/QTC%20%E2%80%93%20Issues%20raised%20by%20QTC%20at%20the%20AER%20inflation%20working%20group%20meeting%20%E2%80%93%209%20December%202019.pdf

9. Tariff Structure Statement (TSS)

9.1 Linkage between tariff reform and network requirements

We have highlighted in previous advice the rocky path that the EQL Tariff Structure Statement (TSS) has travelled. We acknowledge however that throughout the TSS journey EQL has been transparent, co-operative and engaging. The challenge has been that EQL attempted to navigate a path through technical need, diverse customer requirements and regulatory obligations without, in our opinion, a clear objective of 'what the problem was'.

In their its *TSS Explanatory Notes 2020-2025, December 2019,* EQL discusses the many challenges facing the distributors including the growth of rooftop solar PV, the onset of electric vehicles and the decline in the adoption of off-peak controlled load (OPCL) by customers with solar PV. We believe EQL fails to make a clear link between these challenges and the intent of the tariffs to meet the new energy landscape.

We contrast the EQL TSS with that of SA Power Networks. In the SAPN document, the underlying network objectives from which the tariffs were designed are clearly articulated. Similarly, the tariffs are to some extent targeted at retailers and aggregators, with an element of flexibility and an eye to the future development of demand response capability. We did not get a similar impression from the EQL TSS, and suggest a similar approach to SAPN would be useful in assisting EQL effectively deploy their new tariffs.

9.2 Off Peak controlled load (OPCL)

We believe an oversight in the EQL TSS is the lack a clear integrated strategy for the future of off-peak controlled load with that of the new Time-of-Use and demand tariffs.

Over 60% of customers in South-east Queensland, and many in regional cities, make use of electric water heating, pool filtration and air conditioners that are connected to retail tariffs 31 and 33. Hundreds of megawatts of customer load is under control, with more customer demand targeted with the expansion of the primary load control tariff. In addition, the commendable *peaksmart* initiative has been an effective engagement tool for customers to adopt greater levels of load control.

Yet the TSS tends is largely silent on the role and future of off-peak controlled load as an integral strategy for future network and grid management to meet changing customer needs. Despite being a very powerful and prominent tool with a significant amount of infrastructure supporting its functionality (Audio-frequency load control), OPCL does not feature as part of neither the SAC Small Residential tariff implementation strategy nor that for small business [23].

It is unclear where the OPCL capability integrates with the new residential and small business demand and transitional demand tariffs, both strategically and technically. The TSS notes that controlled load rates will maintain the existing relativities to basic meter tariffs [24], yet the workshop on the TSS of 17 December noted 'options to access more attractive load control tariffs will be available from 2020' [25]

The presentation to consumers of 17 December also makes no reference to OPCL as being part of the SAC Small – residential customers landscape (slide 39), and the availability of OPCL for business customers is noted as being available as an 'opt in' for customers with digital (Type 4) meters.

We trust the situation will become clearer when the pricing documents are ultimately prepared.

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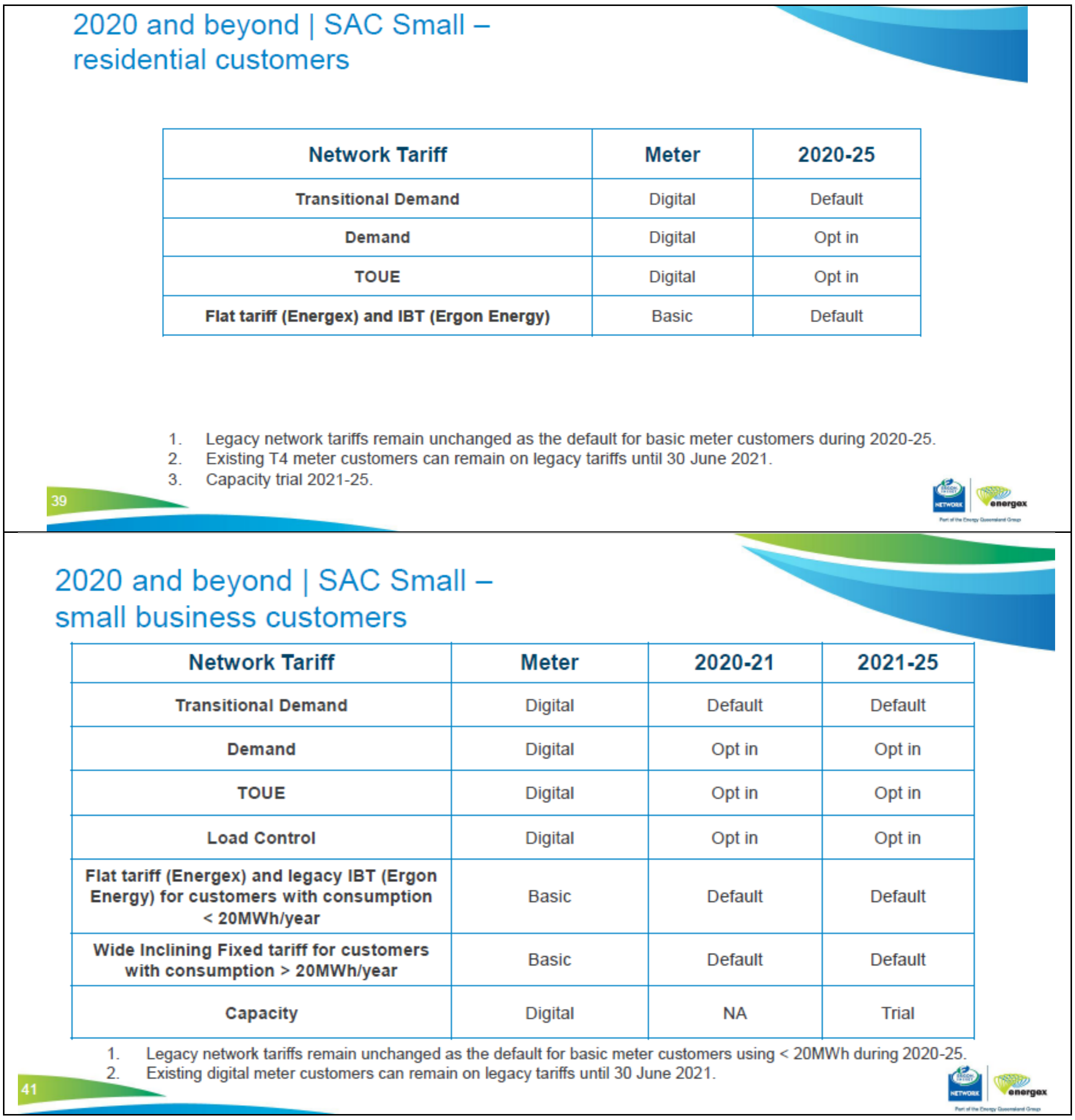
[23] *TSS Explanatory Notes 2020-2025, December 2019, p32 & 33*
[24] Energex TSS, p13
[25] EQL Working Group Forum 17 Dec 2019, handouts 36



2020 and beyond | SAC Small – residential customers

Network Tariff	Meter	2020-25
Transitional Demand	Digital	Default
Demand	Digital	Opt in
TOUE	Digital	Opt in
Flat tariff (Energex) and IBT (Ergon Energy)	Basic	Default

1. Legacy network tariffs remain unchanged as the default for basic meter customers during 2020-25.
2. Existing T4 meter customers can remain on legacy tariffs until 30 June 2021.
3. Capacity trial 2021-25.

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2020 and beyond | SAC Small – small business customers

Network Tariff	Meter	2020-21	2021-25
Transitional Demand	Digital	Default	Default
Demand	Digital	Opt in	Opt in
TOUE	Digital	Opt in	Opt in
Load Control	Digital	Opt in	Opt in
Flat tariff (Energex) and legacy IBT (Ergon Energy) for customers with consumption < 20MWh/year	Basic	Default	Default
Wide Inclining Fixed tariff for customers with consumption > 20MWh/year	Basic	Default	Default
Capacity	Digital	NA	Trial

1. Legacy network tariffs remain unchanged as the default for basic meter customers using < 20MWh during 2020-25.
2. Existing digital meter customers can remain on legacy tariffs until 30 June 2021.

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Figure 12: Extract from the EQL TSS Working Group presentation, 17 December 2019 (p 39 & 41)

9.3 Consumer Support for the TSS

On a positive note, EQL has almost completely accepted the welcome and informed advice provided by the AER in the draft determinations. This action has led to consumers and CCP14 being largely supportive of the Energex and Ergon Revised Tariff Structure Statements (December 2019). EQL has gone to some lengths to ensure the revised TSS has been socialised with a wide range of customer cohorts, and their impact modelling, despite come customers having reservations about the representative nature of the data used, is extensive.

EQL presented their TSS to consumer groups, including through a number of workshops targeted at specific customer cohorts, in November and December 2019.

We note the complexity of meeting some requirements of the food and fibre industry, in particularly irrigation. EQL has spent considerable time with the customer group, seeking to establish reasonable arrangements to meet the irrigator's needs within the tariff requirements. Our understanding is that this industry cohort is pleased with the proposal, particularly with the availability of off-peak controlled load for irrigation. It is clear, however, that the gazetted tariff rules will need to be targeted to ensure a 'best-fit' to the irrigators' requirements.

9.4 Other issues regarding the TSS

Whilst being generally supportive of the EQL TSS, a few questions and suggestions remain.

1. The terminology in the TSS is unclear. For instance, 'digital meter' could include the EM1000 electronic type 6 meter that has been the standard accumulation for many years and is a 'basic' meter. Similarly, EQL refer to 'transitional' tariffs I a number of contexts. Our understanding is that 'transitional' means 'an interim step towards a different final outcome'. Many consumers find the terminology 'transitional demand tariff' confusing.

   We note EQL has in some ways addressed the use of variable terminology in the latest TSS, however we suggest the document be reviewed for clarity and 'plain language' before it is made more widely available to customers as part of the implementation of tariff policy.

2. A peculiarity regarding OPCL in Queensland is that the legislation allows the switching times to be at the distributor's discretion. This was fine when the main load was storage water heating (essentially a battery) and customers were ambivalent about the switching times. But as more loads – residential and commercial – see OPCL as an option, especially in these days of demand response requirements – it becomes important that the switching times 'firm up' to give customers some surety about when they could expect power.

   Whilst it is unlikely that legislative change is required, EQL needs to be more prescriptive regarding its approach to OPCL and its future in Queensland, including its relation to Time of Use rates and strategy and the relationship between OPCL and any demand tariffs.

3. CCP14 is complementary to SA Power Networks in their approach to offer OPCL tariffs (slightly different to ToU rates and window) to retailers or aggregators who wish to use technologies other than AFLC, opening the door to VPPs and battery charging, as well as many new energy management options beyond AFLC. We would encourage EQL to provide similar vision.

4. The modelling broadly considered 'solar' and non-solar. In Qld, many thousands of customers remain on the solar bonus scheme, where energy use profiles are very different. We have not seen evidence of modelling of both cohorts of customers with DER.

9.5 Retailer response to the TSS and changing tariffs

A point of vigorous discussion in the EQL consumer tariff workshops has been the role of the retailer in passing through the new tariffs. This issue is particularly poignant in Queensland where the reduction in network prices is likely to be considerable for some customers. Consumer groups, most notably those representing vulnerable customers, raised concern about the ability for consumers to identify the 'best' tariff for them, and highlighted the risk that some retailers may not assist the customer in identifying the most beneficial tariff.

The likely benefit for customers with interval meters has been a feature of the EQL tariff modelling. Consumer groups noted the role of retailers in determining the costs associated with the transition to advanced metering.

This issue is complicated in regional Queensland through the role of the Queensland Competition Authority and the relationship between Ergon Energy and Ergon Retail, who is the energy retailer for the vast majority of residential and small business customers in regional Queensland.

10. Ongoing engagement

EQL has made no indication of their intention to maintain or enhance their engagement capability after this regulatory determination. As we have noted earlier in this advice, we believe the EQL engagement framework related to this recent reset, whilst being wide-ranging and inclusive, has been, almost by requirement, relatively fragmented and somewhat 'ad-hoc'.

EQL reconstituted its consumer engagement committee as a wide representative group in early 2018. From our brief observation, we noted that this group considered matters well beyond those of the regulatory reset, including retail issues, prices, metering and billing. Of course, the unique situation regarding the close relationship Ergon Energy network and retail businesses means that a novel and specific consumer engagement model may be appropriate.

We do trust, however, that this model does not lose focus of the important 'ring-fenced' issues specific to a network regulatory reset such as the revenue building blocks and prudent capital expenditure. We also believe that the matters arising from the combined network / retail landscape that exists in regional Queensland could overshadow the importance of the market-centric south-east corner.

We recognise that the choice of engagement model is up to EQL. We do encourage EQL however to investigate the successful consumer engagement models that operate in some other distribution businesses, including the consumer forum of Jemena Gas and Electricity, the collaborative role of the Ausgrid CCC and the Consumer Consultative Panel framework employed by SA Power Networks.

Similarly, the proposed SAPN customer and retailer coordination for connections and tariff implementation has the potential of being an effective way of delivering tariff reform.

We would trust that by refining their effective engagement arrangements, EQL can deliver the significant undertakings relevant to this regulatory reset and undertake a more effective and efficient engagement through to the next reset period.

11. Glossary

AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
Augex	Network Augmentation capital expenditure
CCP	Consumer Challenge Panel
CESS	Capital Efficiency Sharing Scheme
DER	Distributed Energy Resource (small scale energy generation or storage devices that are grid connected)
DM	Demand Management
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ECA	Energy Consumers Australia
EQL	Energy Queensland
EUAA	Energy Users Association of Australia
ICT	Information and Communications Technology
LV	Low voltage
MPFP	Multilateral partial factor productivity (an index)
NEL	National Electricity Law
NEM	National Electricity Market
OPCL	Off-peak controlled load
Opex	Operating expenditure
Peaksmart	An EQL demand management initiative
PTRM	Post-tax revenue model
QCOSS	Queensland Council of Social Services
RAB	Regulated Asset Base
Repex	Network Asset Replacement capital expenditure
RIN	Regulatory Information Notice
SAPN	SA Power Networks
TOU	Time of Use (a form of tariff)
TSS	Tariff Structure Statement
VPP	Virtual Power Station (Customer DER with storage)