Consumer
Challenge
Panel

Advice to the AER regarding the Draft Decision and Revised Regulatory Proposal 2025-30

Ergon Energy Network

AER Consumer Challenge Panel (CCP) Sub-Panel CCP30

Mark Henley

Mike Swanston

January 2025

Acknowledgement of Country

We acknowledge the Traditional Custodians of the various lands on which the AER operates, and where Energy Queensland own and operate their networks and facilities. We honour the customs and traditions and special relationship of those Traditional Custodians with the land. We respect the elders of these nations, past, present and emerging.

Confidentiality

To the best of our knowledge this report does not present any confidential information.

Authors' note – Commonality between the Energex and Ergon Energy advice to the AER

Energy Queensland, the parent company of Ergon and Ergon Energy, carried out much of the consumer engagement for the two distributors under a single programme and framework. In addition, there are many common elements across each of the two Revised Proposals.

CCP30 has chosen to present our Energy Queensland advice to the AER in two documents – one covering Ergon and the other Ergon Energy - reflecting the fact that they are two separate regulatory entities.

There will be many common elements between the two reports to the AER, especially in the area of consumer engagement and the discussion on the Tariff Structure Statement.

Contents

About CCP30

The Australian Energy Regulator (AER) engages informed customer advocates to their Consumer Challenge Panel (CCP).

CCP members are in turn appointed to sub-panels which will provide advice to the AER on specific network proposals, particularly to provide advice as to whether the proposals are in the long-term interests of consumers.

CCP30 is the subpanel assigned to the regulatory determination for the Energy Queensland (Energex and Ergon Energy Network) and South Australian Power Networks (SAPN) distribution businesses for 2025-30, to comment on the effectiveness of network businesses' engagement activities with their customers and how this is reflected in the development of the proposals.

The roles of the CCP support the delivery of its objective and include:

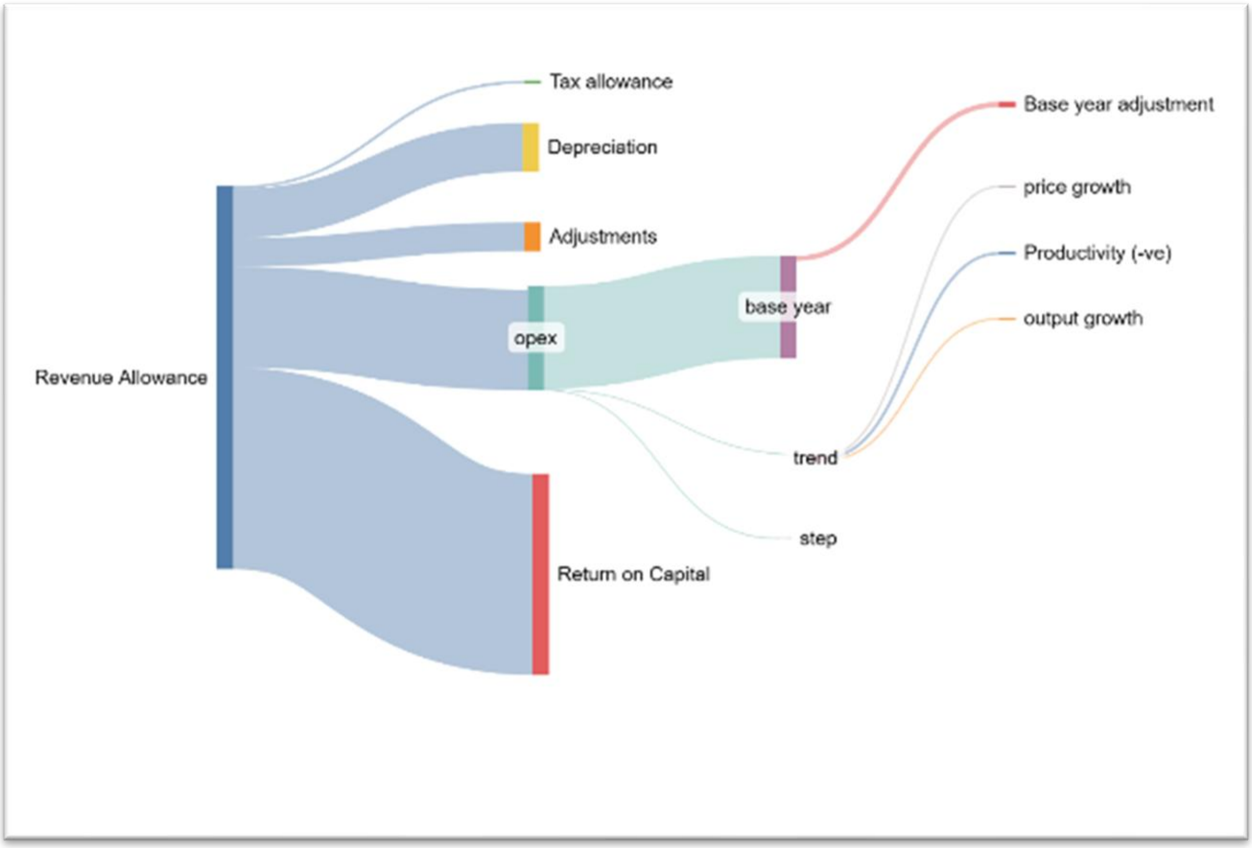
1. monitoring, assessing and where appropriate, informing how Network Service Providers are conducting their consumer engagement activities ('observe and inform')
2. assessing network proposals and provide assurance on the effectiveness of engagement and whether consumer views have been appropriately reflected ('assurance')
3. providing advice on consumer perspectives on issues related to network determinations and to challenge the AER to ensure that consumer views have been fully accounted for in decisions ('challenge')

Glossary

ACCC	Australian Competition and Consumer Commission
ACS	Alternative Control Services - activities by the utility that are 'fee for service'
AER	Australian Energy Regulator
AMI	Advanced metering infrastructure
Better Resets Handbook	A guide issued by the AER that outlines expectations for engagement
CAB	Consumer Advisory Board (SAPN)
CAPEX	Capital expenditure
CCP	Consumer Challenge Panel
CESS	Capital Efficiency Sharing Scheme
CSIS	Customer Service Incentive Scheme
Demand	Instantaneous power use
DNSPs	Distribution Network Service Providers (electricity distributors)
Draft Decision	The AER's response to the Regulatory Proposal in September 2024
EBSS	Efficiency Benefit Sharing Scheme
Ergon	The electricity distributor in South-east Queensland
EQL	Energy Queensland Limited, the holding company of Energex and Ergon Energy.
Ergon Energy Network	The electricity distributor for the areas of Queensland outside the SE corner ('Ergon')
Ergon Energy	The electricity retailer to the majority of electricity customers outside the SE corner
Ergon	For the purposes of this advice, is shorthand for Ergon Energy Network
ESP	Early Signals Pathway (See Handbook)
Final Decision	The AER's final decision on the allowable revenue and tariff structure
GSL	Guaranteed Service Level scheme
HV	High voltage
IAP2	International Association for Public Participation
ICT	Information and Communication Technology
LV	Low voltage, typically in reference to local distribution power lines
MTFP	Multilateral Total Factor Productivity
NEO	National Electricity Objective
OPEX	Operating expenditure
Proposal	The Regulatory Proposal submitted to the AER in January 2024
PTRM	Post Tax Revenue Model, which brings together the revenue building blocks

QEJP	Queensland Energy and Jobs Plan
Revised Proposal	The revised regulatory proposal submitted to the AER by Ergon in November 2024
RRG	Reset Reference Group - panel of consumer energy reset experts appointed by EQL
SAIDI	System Average Interruption Duration Index
SAPN	South Australia Power Networks, the electricity distributor in South Australia.
SCS	Standard Control Service (i.e. included in the allowable revenue cap)
STPIS	Service Target Incentive Scheme
ToU	Time-of-use (tariffs)

In this advice, the dollar amounts quoted are real, $2024-25, unless otherwise noted.



1. Introduction – The process so far

The Ergon Energy Network Regulatory Proposal

In its Regulatory Proposal for 2025-30 ("*the Proposal*") submitted to the AER in January 2024, Ergon Energy Network ("Ergon"), as was the case in many other recent proposals by other utilities, included substantial increases to forecast expenditure, citing the need to adapt to an evolving energy system as well as meeting the increasing energy demand requirements of a large, geographically and commercially diverse customer base in regional Queensland.

This follows a rollercoaster period of under-expenditure of network capital in the decade 2010-2020, followed by significant capital expenditure above that allowed by the AER for the 2020-25 regulatory period. This high level of capital investment is proposed to continue into the next (2025-30) period.

Overall, the proposal seeks a total revenue for the 2025-30 period of $7,819M, an increase of 15% in real terms relative to the expenditure forecast in the current regulatory control period.

Operating costs

Operating costs for the 2025-30 period are forecast at $2,379M [1] (including debt raising costs); which is in line with the forecast expenditure and 3.9% higher than the AER's allowance for the current period. Ergon is applying a full 1% productivity factor to their opex proposal, and consistent with customer feedback, pleasingly reduced the proposed amount significantly from that of the Draft Proposal some months earlier. Only one step change, to acquire metering data, is included.

Whilst the proposed total opex remained relatively stable and in line with longer term actuals and estimates, a steep trend of over-expenditure of the AER allowance occurred in the final three years of the current regulatory period. [2]

The opex forecast also included a base year benchmarked efficiency downward adjustment of 2.3%.

Capital investment

The proposal provides a useful insight into the past capital expenditure patterns. Ergon generally under-spent the AER allowances through 2010-2017; but there has been a significant 'ramping up' investment since 2017 (asset replacement) and 2022 (augmentation).

The proposal noted a capital investment requirement in 2025-30 of $5,805M – a 20% increase in over the estimated spend for the current regulatory control period, which, in turn, at $4362.9M exceeds the AER allowance of $3054.3M by 42.8%.

As an aside, Ergon's capital allowance in the 2005-10 regulatory period was over $8,000 M in today's money, with augmentation being largest are of expenditure.

The predominant areas of capital expenditure are network augmentation and asset replacement (mainly poles), but increases in other areas including property, are evident. Ergon reference a priority to replace ageing infrastructure and improve the reliability of the network in regional areas.

This over-expenditure excludes the above-allowance ICT project costs in the current period of approximately $113M, which Ergon has chosen to absorb and exclude from its regulatory asset base.

---

[1] Ergon Energy Network Regulatory proposal 2025-30, p17

[2] AER presentation, 2025-30 Distribution Revenue Forum, 11 April 2024, slide 12

Costs to customers

Residential network charges were estimated to rise by 6%, or $66, p.a., and 6.8% for small businesses. Large low voltage customers are expected to see an average annual increase in network charges of 7.1%

The AER Draft decision

The AER provided its Draft Decision in response to the Ergon proposal in September 2024.

In that Draft Decision, the AER noted the significant proposed increase in expenditure, along with a comment that investment

> *"… needs to be managed carefully, with the view of protecting the long-term interests of consumers"*

Revenue

The Draft Decision allows Ergon to recover $8,365.9M (nominal, smoothed) in revenue from its customers in the 2025-30 period, $154.6M less than that proposed, and $2,357M (13.2%) higher than the allowance for the current regulatory control period.

In real terms, the Draft Decision reduced Ergon's proposed revenue by $147.6M (1.9%) to $7,671.3M.

Just over half of the increase is noted as being due to the unavoidable impact of rising interest rates and hence allowable return on the asset base. The balance of the increase is due to higher expenditure on 'controllable factors.'

Operating costs (opex)

The Draft Decision accepted Ergon's total opex forecast of $2,379.1M. [3] This is only slightly higher than the forecast actual operating costs, and 4% ($90M) more that the approved opex for the current regulatory control period.

The AER noted that updated information for the 2023-24 base year will be considered in the Revised Proposal, saying:

> *" During our assessment process, Ergon Energy indicated that its actual opex for 2023–24 is likely to significantly exceed the estimate it provided in its initial proposal. For our final decision, we will need to consider actual opex for 2023–24."* [4]

The AER also proposed a 1.9 % downward efficiency adjustment to the base year. Ergon made no allowance for a glide path transition towards higher efficiency, however the AER included $18.3M in allowed costs for the transition.

The draft decision also included a negative revenue adjustment of $679.9, due mainly to the impact of the efficiency sharing schemes EBSS and CESS.

Capital

The AER's Draft Decision did not accept Ergon's capex forecast of $5,704.8 million and provided an alternative forecast of $4,188.1 million, 26.6 per cent lower than the proposal. As with the Energex

[3] All dollars in this advice are $2024-25 unless otherwise noted

[4] AER Draft Decision, Ergon Energy distribution determination 2025-30, Attachment 6 – Opex, section 6.1

Draft Decision, the AER left the door open on the decision should further information be made available and some parts of the proposal clarified.

The Tariff Structure Statement (TSS) was not accepted. Tariffs was a topic that Ergon engaged heavily in with its RRG and consumers and had gained some support for its position. At the time of writing this advice, discussions on the proposed tariff structures continue, in particular the issue of default assignment of customers to time-of-use tariffs, and the application of demand tariffs to 'peaky' loads.

In its draft decision, the AER reduced the allowable revenue by 2.2%, as shown in Table 1 below.

Category $M, $2024-25	Draft Decision	Change from proposal
Revenue	$7,671.3	$147.6 (1.9%) reduction
Operating expenditure ($M)	$2,379.1	accepted
Capital forecast ($M, $2025)	$4,188.1	$1,513.4M (26%) reduction
Asset Replacement (incl clearance)	$1,844.3	$874.4M (32.2%) reduction
Augmentation	$429.2	$84M (16.4%) reduction
ICT	$208.7	$50.1 (19.4%) reduction

Table 1: AER Draft Decision- change from proposal (summary) - Ergon (source: AER DD)

The ex-post review of capital expenditure 2018-23

The AER determined that Ergon has overspent its forecast capex in the ex-post period 2018-23. In addition, it considered the exclusion of capex incurred during the ex-post period that does not reasonably reflect the capex criteria from the regulatory asset base.

The draft decision is to reduce the total capex to go into the asset base for that period by precisely 50%, or $598.8M. The vast majority of the overspend by Ergon is in the area of asset replacement. Expenditure on network capacity augmentation was again underspent, this time by $171M (42%).

The Ergon Revised Proposal

In response, Ergon lodged its Revised Proposal ("*the revised proposal*") in November 2024, which included additional information to support the required revenue to provide quality network services for the 2025-30 period.

Revenue

The Revised Proposal notes an increase in the proposed revenue to $7,952.1M, 3.7% above the Draft Decision. This amount is 15% above the current period's allowed revenue. The main drivers of this change are:

- The use of higher actual costs for the 2023-24 base year, replacing the estimated forecast,
- the impact of the proposed exit from the Efficiency Benefit Sharing Scheme, and
- the impact of the revised (higher) capital forecast on the value of the regulated asset base.

Operating cost

The AER in the Draft Decision accepted Ergon's opex proposal. In the Revised Proposal, Ergon has replaced the forecast expenditure in the base year with an actual cost. The use of a higher actual base year costs was flagged in the proposal and the draft decision.

The actual cost, replacing the placeholder forecast, had the effect of increasing the forecast opex for the next regulatory period by $183M, from $2379.1 to $2,562.9M (including debt raising costs), a 7.7% increase on the Regulatory Proposal forecast and the AER's Draft Decision.[5]

Notably, both Ergon and Energex now propose to suspend the Efficiency Benefit Sharing Scheme, arguing that they risk being 'double penalised' for over-expenditure through both the EBSS and benchmarking adjustments.

Capital

Regarding capex, Ergon's response to the AER's Draft Decision is a revised forecast of $5,011.4 million (including asset disposals). Ergon has proposed modified forecasts for asset replacement, augmentation, fleet and capitalised overheads and will accept the substitute forecasts for all other remaining capex categories.

Category $m, $2024-25	Draft Decision	Revised Proposal
Revenue	$7,671.3	$7,952.1 (up 3.4%)
Operating expenditure	$2,379.1	$2,562.9 (up 7.7%)
Nominal bill increase (residential)	avg 3.5% p.a.	avg 5.0% p.a.
Capital forecast	$4,188.1	$5,011.4 (up 19.7%)
Asset Replacement, incl Clearance	$1,844.3	$2,449.8 (up 32.8%)
Augmentation	$429.2	$489.2
Capitalised overheads	$874.4	1009.7 (up 15.5%)

Table 2: Ergon Revised Proposal – change from AER Draft Decision (source: Ergon Revised proposal, Table 11)

Tariff Structure Statement

As AER's Draft Decision accepted many elements but not all of the Ergon / Energex TSS, changes were required, notably the shift of the default assignment for residential and small business customers with smart meters from time of use (TOU) demand tariffs to TOU energy tariffs.

In the draft decision, the AER maintained their position to shift the default assignment for residential and small business customers with smart meters from TOU demand tariffs to TOU energy tariffs,. Ergon has largely accepted the AER's draft decision to support energy-based time of use tariffs in their proposal, and we acknowledge and support the continuing to work with its RRG and the AER regarding the merits and detail of the AER's decision.

[5] Ergon Energy Network Revised Proposal, section 6.2

2. Key Observations

1. *Customer and Community Engagement focussed on tariffs, CSIS and the AER's capex decision.*

Energy Queensland have faithfully delivered the remaining stage ('Phase 5') of their consumer engagement plan, presenting the AER's draft decision to consumer forums and their RRG prior to lodgement of the revised proposal in November. Throughout the revenue reset process, both Energex and Ergon remained very active in their engagement with consumers across a number of forums, including their RRG.

The stated purpose of the engagement was to inform Ergon regarding their Revised Proposal. Time was limited so the scope of the engagement remained narrow. In respect to the discussion on capex, the engagement leant towards 'what was wrong with the AER Draft Decision' as a means of reinforcing the revised capital investment plans.

This phase of engagement continued the theme of diving deep into the tariff structure plans, and to some extent continue to outwork the Customer Service Incentive Scheme. Otherwise, the engagement remained very much as IAP2 level 'inform'. The wider community-based engagement remained at a high level, such as considering the need for understandable tariffs and the future of renewables.

We acknowledge that Energy Queensland is very good at this type of 'big picture' energy-in-the-community engagement, but it is of limited value in generating true consultation on details of the price reset.

The engagement is discussed in detail in Chapter 3- Customer Engagement.

2. *We support the AER in taking a strong view of affordability, shared risk and keeping costs as low as reasonable.*

Cost of living impacts have continued to be a major context for SAPN's regulatory proposal, right through to the final decision. Even a 'modest' increase in electricity costs, particularly for people in the bottom half of the income distribution, bites hard on household budgets.

We provide qualified support overall for the draft decision; yet highlight the fact that we believe the AER must continue to consider the impact of the decision on electricity prices and affordability. CCP30 supports the areas where the AER agrees with Ergon analysis, however for other categories such as capex, the door was left open for Ergon to respond with further information; thereby providing a significant opportunity to reinstate the proposal's significant cost increases.

With the imperative of affordability not clearly threaded through the Ergon proposal, there is an opportunity for the AER to encourage Ergon to review its network risk settings and the efficient delivery of services through setting challenging commercial targets.

3. *There are significant changes in the Revised Proposal that were not consulted on.*

The revised proposal contains a number of significant departures from the Draft Decision. These changes in the proposal - being the rejection of the Efficiency Benefit Sharing Scheme (EBSS), the increase in capital, the increase in operating expenses– have not been adequately and transparently discussed to the point where it can be said that there is strong consumer support for these positions.

Granted, time was limited, but these major issues were not made clear to the RRG or the community until the final briefing for the Revised Proposal in early November, at which time these decisions were more or less 'locked in.'

4. Perceived bias in Ergon presentations

The customer engagement following the Draft Decision included a number of presentations regarding the changes to capital expenditure in the AER Draft Decision. These presentations by Ergon tended to be very supportive of the EQL position and critical of the Draft Decision, without any fair and reasonable discussion about the alternatives or clarity of the reasons behind the AER decisions.

For example, in the Customer Panel Workshops in October, following the draft decision, we were concerned that the Ergon (and Energex) presentations were tilted in the direction of supporting the Ergon position, with an undercurrent that any reductions in funding by the AER would most likely result in reduced service quality to customers and heightened safety risks.

Important and useful context such as the capital and operating over expenditure and penalties, the decision to step back from the efficiency schemes, were not presented nor discussed.

Understandably, the feedback from the Customer Panel and Focus Group workshops heavily favoured the Ergon position.

We discuss this possible bias in Chapter 3- Customer Engagement, later in this advice.

5. The need for balance in tariff reform

In the customer forum of 5 November, the RRG and the EQL Network Pricing Group – customer representatives, the operation of which we observe to be highly informed and effective - highlighted that they do not support key elements of the AER's Draft Decision on the Tariff Structure Statement.

We respect the position of the RRG and its role with Ergon , and acknowledge the position taken regarding the importance of reducing cross subsidies, signalling customer energy use behaviour and establishing true cost-reflective pricing. However, from a consumer point of view we continued to have serious reservations about the effectiveness of demand-based tariffs to meaningfully influence customer energy use and put customers at the centre of the energy market.

> *"Every tariff design is the product of subjective judgements about the preferred distribution, or redistribution, of risks, costs and benefits."* [6]

In its early engagement, Ergon highlighted, quite validly, that consumers want simpler bills, where it is easier to interpret the cost components and drivers, and, importantly, respond to those drivers in order to deliver lower energy costs.

Whilst demand pricing is promoted by networks as a much more appropriate reflection of the assets and investment needed to provide the service, it remains a mystery to almost all consumers other than perhaps a small number of informed large users of energy. We have concerns that demand pricing will remain invisible to consumers, especially should retailers choose to modify the pricing signal and build in demand risk. The risk of higher prices exists, especially to those least empowered to influence their energy demand.

As the ACCC reported recently:

> *"We also see increasing numbers of customers on offers with multiple layers of complex pricing, for example, time of use offers where tariff components vary by season or time of use offers that also have a demand charge. We observe that many customers struggle*

[6] Dr Ron Ben-David, *'What if the consumer energy market were based on reality rather than assumptions?',* 2024

with the increasing complexity in their tariffs, including moving to time of use or demand tariff structures." [7]

We ask that the AER in their final decision to support a progression to cost reflective pricing, but to balance this with consideration of the needs of everyday consumers for pricing that is understandable, measurable and empowers customers to take reasonable actions to manage their energy costs.

We recognise that the AER has invested significant attention to these matters with retailers over recent years, including but not limited to Better Bills Guideline and Energy Made Easy. There remains a challenge to assist customers to better understand their electricity billing.

In conclusion

Overall, we are supportive of the AER's Draft Decision.

We also note the need for Ergon to continue higher levels of investment in asset replacement and network capacity.

However, there must be pressure placed on Ergon to be passionate about costs, prudent investment and efficient investment that balances the risks between the utility and customers.

Being the highest total cost per customer in the national grid, Ergon must turn their affordability rhetoric into reality.

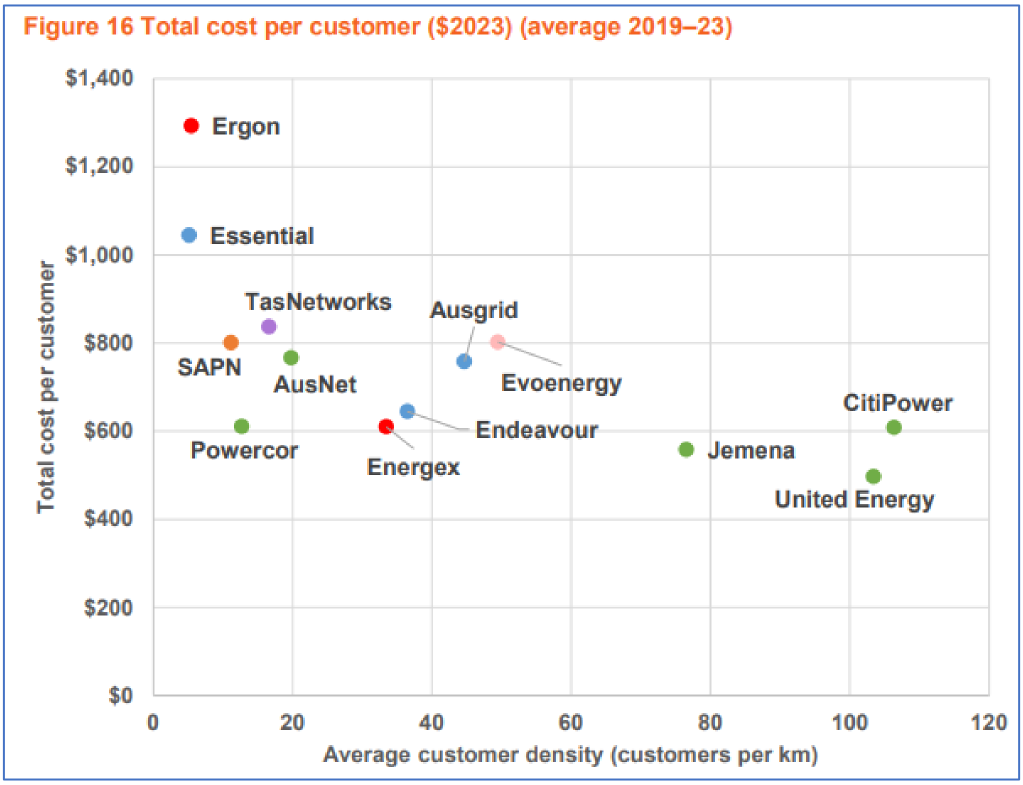


Figure 1 - Total cost per Customer benchmarking (AER BEnchmarking report 2024, Figure 16)

We trust that the consideration of the revised proposal from Ergon by the AER reflects a commitment by the AER to place more pressure on utilities to innovate, manage increasing risks skilfully without passing the risks onto consumers through increased prices. Knowing the capability and commitment of utilities such as Ergon, this is not an unrealistic ask.

[7] ACCC, *Inquiry into the National Electricity Market*, December 2024

3. Customer Engagement

The Energy Queensland Regulatory Reference Group (RRG)

The EQL RRG and the Pricing Working Group remained very active, well informed and continued to engage extensively with both Energy Queensland and the AER. Energex and the RRG initiated a number of meetings to clarify or explore issues related to the Draft Decision. There was limited time, and therefore limited discussion, regarding the content of the Revised Proposal.

Our observation is that Ergon welcomed the RRG and NPWG approaches for meetings or further information.

In our observation of the RRG in action, there is no evidence of ‘capture’ by Energy Queensland. The RRG remain independent in their diverse views, and frequently challenged Ergon in workshops and meetings. Our only issue is that Ergon, consistent with their overall theme in all the engagement, tended to ‘inform’ the RRG, rather than meaningfully ‘involve’ or ‘collaborate’[8] in a way we have seen recently in other utilities. We did not see a lot of evidence where the RRG were able to sway Ergon in any material way regarding the components of the Revised Proposal.

No better example of this exists than the decision by Energex and Ergon to step back from the EBSS. The RRG only found out in a presentation late in the process after the decision had been ‘locked in’ and were not able to engage Ergon in any meaningful way regarding the impact the decision may have had on customers. This is from what CCP30 was able to observe.

The RRG continues to display a high level of understanding of regulatory reset processes and issues; and continues to meaningfully represent the sentiments of consumers. We are particularly impressed with the range of skills, dedication and perspectives across the RRG members.

CCP30 believes that the AER can place weight on any submission by the RRG, particularly regarding matters of tariff structure and service incentives.

Observations of the ‘Phase 5’ engagement

Energex and Ergon Energy continued their engagement with their customer focus groups and their RRG into ‘Phase 5’ of their Customer and Stakeholder Engagement Plan. This stage was intended to assist in the development of the Energex and Ergon Energy revised regulatory proposals.

Despite the limited time available for wider consultation, Ergon did reconvene its Voice of Customer panel and its Customer and Community Council (CCC) to review a number of issues raised in the Draft Decision. The RRG was also quite active in the period leading up to the Revised Proposal.

Energy Queensland continued to welcome the CCP and the RRG (and the AER) to all engagement sessions, including the occasional briefing to the EQL Board Regulatory committee meetings. As with all the regulatory workshops, the engagement sessions were professionally run by the regulatory and customer advocacy teams, often with the assistance of recognised professional support, with extensive supporting documents. Sometimes, it could be said that maybe there was a little too much engagement and papers to read. There is always a blurring between quality and quantity in this area.

Ergon convened its wider CCC in November to update members on how Ergon had framed its Revised Proposal. This was a useful session; however again it focussed on ‘inform’, and the volume of

[8] The use of the words “inform’, “involve’ and ‘collaborate’ reflects the meanings applied in the IAP2 spectrum of public participation.

information and time allotted meant that detailed discussion on any issues within the Revised Proposal was not possible. It was also too late to meaningfully influence any content.

Commendably, at that CCC meeting, Ergon outlined its plans for a continued engagement framework beyond the current determination, based on learning from the existing reset process. We look forward to the new arrangements.

As with all the engagement, both Energex and Ergon Energy proposals were considered in parallel.

Our observations of the Phase 5 engagement are:

1. The workshops continued to develop the service quality monitoring framework proposed by Energy Queensland as a proxy for the CSIS. This work was encouraging, however to our knowledge EQL has not yet presented any detail on this initiative. We hope that EQL don't 'drop the ball' on this initiative after the regulatory reset is done.
2. The engagement focussed heavily on the issue of tariff structures and the discrepancy between the draft decision (which rejected the Ergon TSS) and the position reached by Ergon. There were many hours devoted to EQL's thinking and their plans with their customers. This work approached the 'collaborate' level with the RRG.
3. After the Draft Decision, the VoC and The CCC were taken through the capital decisions. Our impression is that this work presented Energex and Ergon's positions in a very positive light, and positioned the AER as not being supportive of the reliability and safety objectives of the distributors.

   At no time did Ergon willingly withhold information or provide misleading data to consumers, but at times we felt that the information presented was 'filtered' and the audience was being steered towards favouring the Ergon case, particularly regarding the AER Draft Decision. Context setting and counterfactuals, such as the AER 'capital wall' diagram, were not included in presentations, yet they would have been of great benefit to assist consumers evaluate the broader implications of the revised proposal and make a more balanced assessment.

   We are firmly of the opinion that this bias is not an intentional strategy of Ergon or Energex; rather an oversight, due to the commitment, expertise and enthusiasm by the staff for the content of proposals themselves. They had spent years preparing it, with experts developing the content, and hours spent with consumers expressing their support for a reliable, safe and modern network. It had to be right, yes?

   It was as if the AER also needed airtime in front of these community workshops to 'state the alternative case'.

We maintain our position that when it comes to the building blocks of the required revenue, Ergon (and Energex, in that case) were not willing to engage in detail or consider consumer feedback that would 'move the needle' on the expenditure categories, preferring to focus on justifying their current position and relying on broad (and somewhat guided) discussions on service / cost balance.

Interestingly, we see parallels between the engagement and the AER's view of capex:

> *"We found a lack of supporting material to demonstrate prudency and efficiency in most of the capex categories, including information gaps, and limited evidence to support key inputs."* [9]

[9] AER Draft Decision- Ergon – Attachment 5- Capex, p14

Engagement sessions

The engagement process under Phase 5 included :

a) August 24 – A Voice of Customer panel, mainly to discuss the proposed service quality measures.

b) October 12 - A Voice of Customer Panel to present the findings of the AER draft decision and outline the likely implications of the decision.

c) November 5 - An Energy Queensland Customer and Community Council forum largely to explore the ongoing EQL customer engagement strategy. The session did spend some time informing the council about the revised regulatory proposals.

d) Network Pricing Working Group meetings - October 14 and 3 December.

e) A number of RRG meetings, in particular on 28 October with an open discussion with the EQL executive. Again, this session was valuable in answering questions, but there was no impression that the executive took on feedback that in any way influenced the revised proposal.

   This session concluded with an update to the RRG on the revised proposal. This was the first time that the RRG and the CCP were informed in any detail of the revised proposal.

Case Study: The Customer Panel and Recall Day – 12 October 2024

The Customer Panel and Recall Day, designed to allow a broader segment of 23 energy customers understand and discuss the implications of the Draft Decision, was held on 12 October 2024.

The workshop was professionally managed (Mosaic Labs) and well-supported by Energy Queensland senior staff, including the Chair. The scope of the day was to review how the AER's Draft Decision aligned with issues raised previously by the Voice of Customer panel and customer focus groups, with the areas of focus being tariffs and tariff structures and a high-level view of capital expenditure (managing growth).

Discussion on the Customer Service Incentive Scheme rounded out the day.

In their presentation to the participants, Ergon was quite clear that their Revised Proposal required significantly increased expenditure for capital and overall revenue when compared to the current period, and that without the uniform tariff policy, the price for residential customers could increase by $66 per year, every year.[10]

On the active issue of asset replacement, Ergon presented the subject as:

> *"Across regional Queensland, some of our assets are ageing and are at risk of failure. Replacement or reinforcement of older poles, wires and crossarms is critical to ensuring we meet the safety and reliability expectations of our customers and communities."*

That is a perfectly reasonable statement. Ergon then went on to present the difference between the proposed amount on asset replacement and the draft decision amount as being worth "$2.90 per customer per year" [11]

[10] Ergon Energy Network VoC Panel, Saturday 12 October 2024, slide 11

[11] Ergon Energy Network VoC Panel, Saturday 12 October 2024, slide 56

This was followed by slides that were clearly intended to reinforce the Ergon position, including discounting the AER's work to benchmark Ergon against Essential Energy, and suggesting that reliability and safety were at risk should the Ergon capex proposal not be accepted. (Figure 2 below)

We acknowledge that safety and reliability are critical issues to customers, but we do not view these presentations as being balanced or transparent in terms of meeting reliability targets or pole failure rate limits. In our opinion, the AER role and decisions were in some ways misrepresented.

It is worthwhile asking whether the AER should ask for equal time to state their case in some of these presentations. It would also have been useful to discuss matters such as 'the capital wall' and the chronic underinvestment in capacity and asset replacement in the 2010-2020 period.

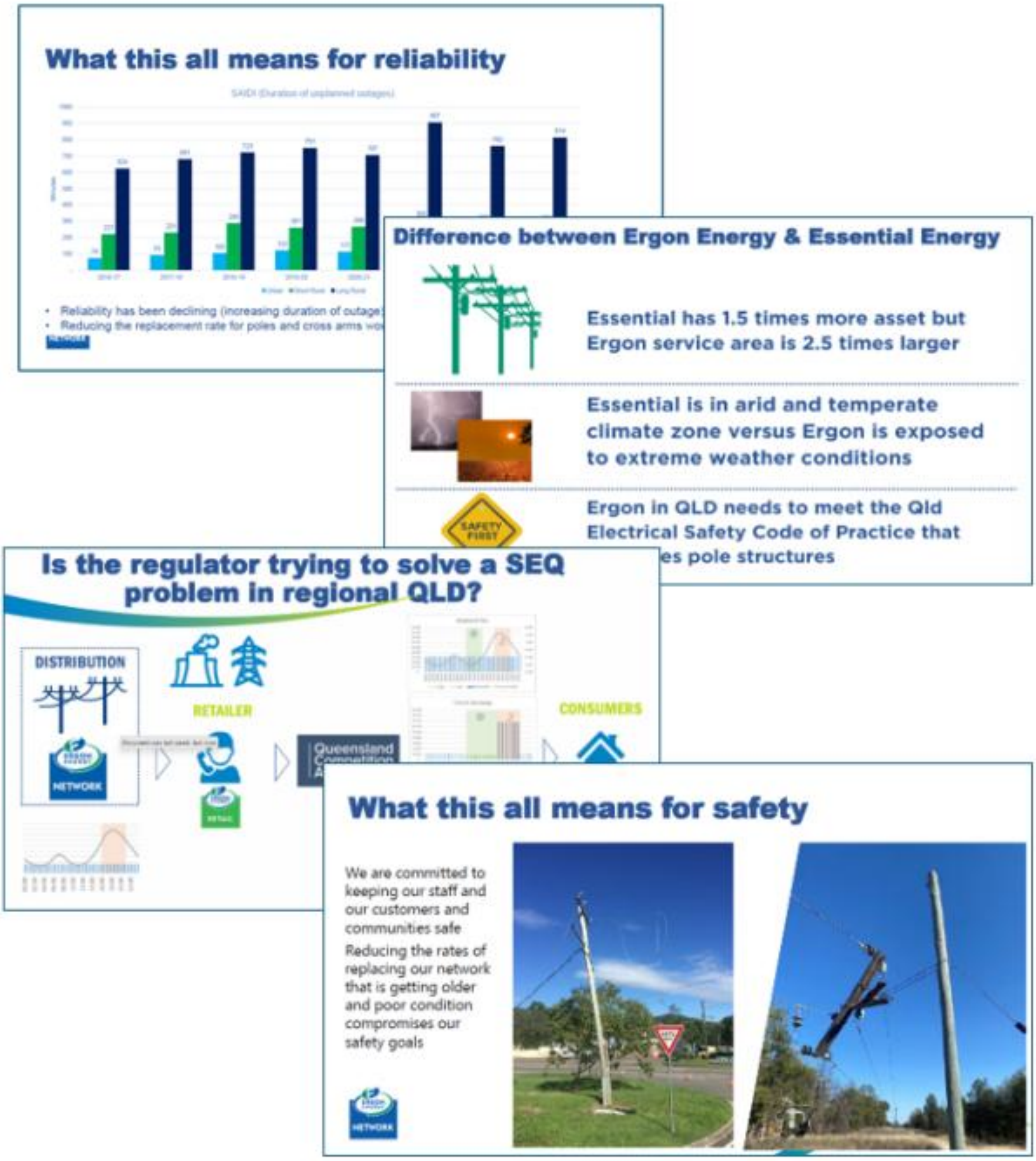


Figure 2- Slides from the Ergon Energy Network VoC Panel, Saturday 12 October 2024, slide 58, 59

Despite this bias (which was much stronger in the Energex presentations, in our opinion), our assessment is that the Voice of Customer session resulted in some quite valid results. Whilst customers were unsupportive of the benchmarking with Essential Energy (an area we believe the information was not balanced), some useful observations arose that suggested customers did not have sufficient information to take an informed position, such as:

> *How can we make comment if we do not know the failure rates of the current system, how many fail per year? What is the maintenance schedule? Minutes down does not indicate the reason for downtime just that there is downtime How is data gathered to complete the comparison?* [12]

and

> *"In the AER report the safety risk is imbedded in the investment calculation/ rating and would like to see the safety risks (high impact or common) spelt out as well."* [13]

It was nice to see one particular piece of feedback:

> *"We wish that EQ would be a little more proactive before this was a pressing issue …"*[14]

Regarding the extensive tariff discussion, customers understood that there was merit in the more complex and demand-based tariffs and the need for choice, but the wariness of being able to understand and respond to complex tariffs was evident.

Exploring Affordability in the Revised Proposal

This revenue reset comes at a time when affordability, the cost of living and the cost of doing business remain serious challenges in the community. Throughout the engagement, all feedback continued to include comments regarding the high cost of energy in the context of living expenses. Energex and Ergon are well aware (as is the AER) of the issue in so much of their engagement; for example:

> *"…they have also told us that affordability of electricity is their primary concern, both from a cost-of-living and cost-of-business perspective."* [15]

It would have been more useful for Ergon to present to their consumer forums more detail and the thinking behind the key changes between the proposal, the draft decision and the revised proposal, in order to garner greater support and confidently say that their consumers has been provided with all the information needed to give balanced and informed support for the actions.

However, this is not the case, with reliance on broad statements such as:

> *"In response to customer feedback, we have sought to strike the right balance between investing in the network to provide clean, reliable, and smart electricity into the future and efficiently delivering electricity services in an affordable way that provides value to our customers and communities across South-east Queensland "*[16]

[12] *Ergon Energy Network Recall Day – What was said report*, Mosaic Labs, October 2024 – page 9
[13] *Ergon Energy Network Recall Day – What was said report*, Mosaic Labs, August 2024 – page 13
[14] ibid
[15] Ergon Revised Regulatory Proposal, p25
[16] ibid.

This is no doubt the case, but engagement and trust would have benefitted greatly from Ergon showing consumers how just that balance was struck, how options were considered and how the Draft Decision may be prudently and efficiently applied without asking for increased revenue.

We reflect these sentiments to the AER and ask that the final decision clearly indicates how the issue of affordability has been incorporated.

Exploring Productivity

At the RRG / Energex executive discussion on 28 October, the RRG put forward a number of questions related to Energex's productivity and how the 1% productivity dividend may be delivered. This reflects a valid concern as to how the productivity imperative will be reflected across the competing pressures of dividend (noting the past relationship between Energex dividend and the Queensland Government uniform tariff policy), increased labour costs and the pressure to keep prices low.

CCP30 notes the 2024 Energy Queensland Union Collective Agreement includes guaranteed compounding annual salary increases of 4.5%, 4.5%, 3.5% and 3% from 2024, and confirmation that forced redundancies are 'off the table.'

Our observation was that the RRG did not receive a clear answer on the productivity measures that are incorporated into the EBA that offsets the cost of labour increases over the last three years and next four years. Energex outlined that better management of assets; more efficient crew planning and better work packaging would form the backbone of the productivity initiatives; and gave no commitment to provide more detail in the Revised Proposal.

Attachment 6.05 – Productivity insights – of the Revised Proposal refers to embedding digital systems, improving business processes and harmonising workforce planning. Unfortunately, any further detail is redacted and not publicly available.

We remain unconvinced that these productivity initiatives will be effective and able to be delivered transparently. Given the upward pressures on costs, including internal labour, we assume that the productivity will be delivered by 'doing more with the same resources.'

The RRG questions on productivity progressed to issues such as the delivery of the promised efficiencies through the establishment of Energy Queensland itself in 2016, and the delivery of benefits (return on investment) through the significant ICT refresh programme. Again, little detail was forthcoming from Energy Queensland.

We appreciate that discussions on productivity can be very sensitive, and respect that much of the detail must remain confidential.

We seek the insight and information available to the AER to consider the strategy and plans on the productivity offsets as a result of the last 3 years and recently started 4-year EBAs, and trust that some confidence can be relayed in the Final Decision. We join the RRG in asking:

> *"What confidence should consumers have in EQL's ability to meet its promises of 1% productivity in opex and capex overheads, and that benefit being passed onto customers in lower prices?"*

4. Capital Investment

Ergon's capital investment expenditure patterns are a vexed issue, and the subject of much discussion between Ergon, the regulator(s) and their RRG. Customer engagement regarding Ergon's capital plans and the long-term impact on prices remained very high-level, and informs general statements like:

> *"Customer views around maintaining our current levels of reliability and safety of the network have informed the development of our capital investments."*[17]

Ergon's proposal includes increases in every capital category compared to the forecast expenditure in this regulatory period, other that ICT, which has been absorbed by Ergon.

The AER, in the Draft Decision, made a substitute capital forecast of $4,188.1M, 26.6% below Ergon's forecast in the proposal (including asset disposals and modelling adjustments). The AER also noted:

> *"At this stage, we see our draft decision as a placeholder. There may be other information not currently available to us which could mean a more optimal estimate can be achieved. In this regard, we encourage Ergon Energy to engage with us prior to its submission of its revised proposal to discuss what further information is available to support its proposal."*[18]

The breakdown of Ergon's Revised Proposal capital investment plan is shown below in Figure 3 below.

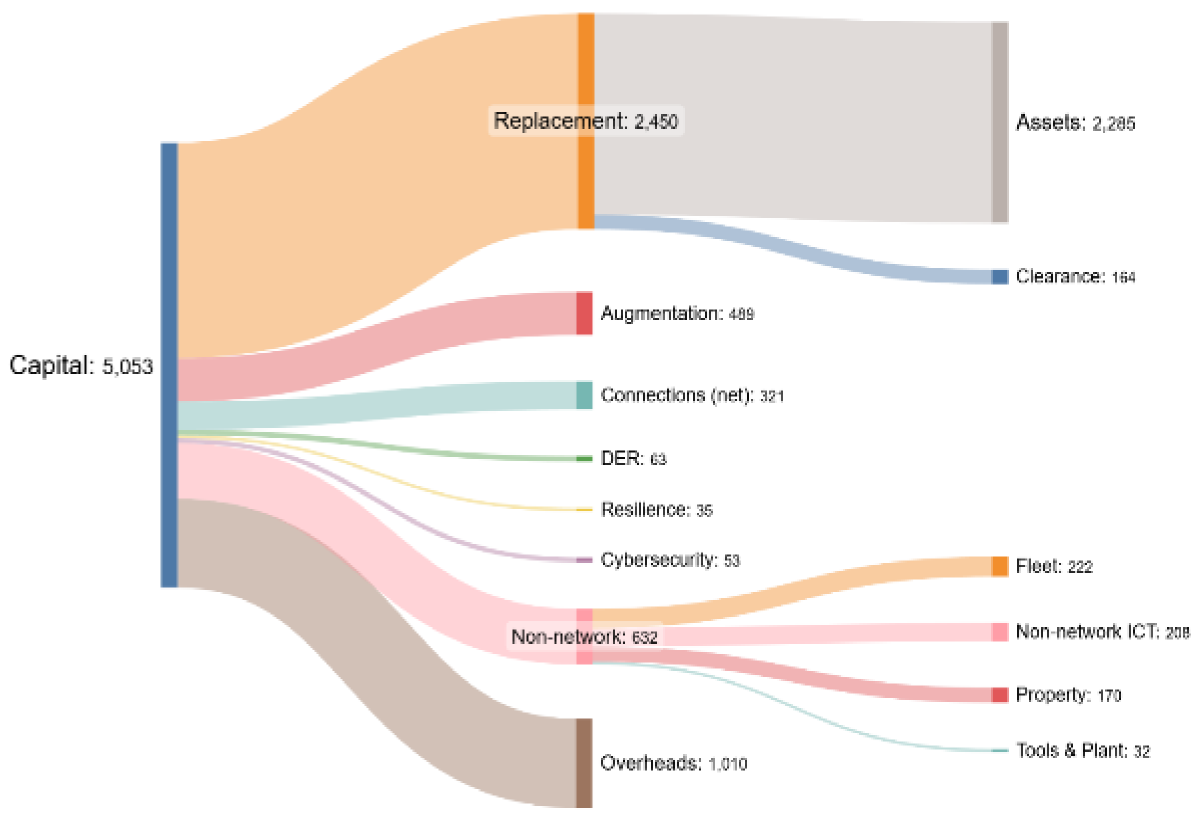


Figure 3 - Ergon Capital breakdown (Revised Proposal) (Source: Ergon FP, CCP30 analysis)

---

[17] Ergon Energy Regulatory Proposal, ch 5, p78

[18] AER Draft Decision – Ergon Energy distribution determination 2025-30, Attachment 5 (Capital), p4

Ability to deliver

It is useful to compare the forecast expenditure in the current regulatory period with that in the Revised proposal. This analysis gives us an insight into what Ergon is 'passionate about' over the decade, and just how it is likely to deploy its resources in the next period.

In addition, it gives a view on what Ergon is currently undertaking, and where the risks lie in being able to source the appropriate resources in the competitive market that exists nationally and globally.

ICT has been removed from the totals, as the decision by Ergon to absorb a large part of the current period overspend distorts the picture.

Capex Category **$M, $2024-25**	**2020-25 actual / forecast**	**2025-30 Proposal**	**Revised proposal**	change: Revised proposal to 2020-25 forecast
Augmentation	358.0	513.2	489.2	37%
Connections (net)	321.0	321.2	321.3	0%
Asset Replacement	2432.4	2718.8	2449.8	1%
Property	141.9	174.7	170.2	20%
Fleet	170.6	243.0	222.3	30%
Resilence	0.0	53.1	34.6	
Cybersecurity	0.0	53.4	53.3	
CER integration	0.0	63.0	63.0	
Other	27.2	31.7	31.6	16%
Capitalised Overheads	986.3	1316.1	1009.7	2%
TOTAL CAPEX	**4437.4**	**5488.2**	**4845.0**	9%

Figure 4 – Change from 2020-25 forecast expenditure to the Revised Proposal (Ergon RP Table 11, CCP30 analysis)

From this analysis, it can be seen that, compared to the current period, Ergon intends to:

a) significantly ramp up spending on network augmentation and reliability. This requires specialist internal and contractor resources that are already under pressure to deliver increased works programmes around Australia. It is unclear whether conductor, electrical equipment, protection relays and specialist skilled resources will be available.

b) Maintain the extraordinarily high investment in asset replacement; continuing the catch-up of under expenditure of asset replacement from a decade ago. Ergon has demonstrated that it has access to adequate internal and contract resources for this work, however the continued reliable supply of poles (hardwood and softwood) should be confirmed.

c) Continue to increase expenditure on property in buildings, which may just reflect increasing input prices, noting the AER has approved this expenditure in the Draft Decision. The majority of resources for this area would come from outside Ergon, largely the building industry.

d) Significantly increase expenditure on fleet (noting the AER has also approved this expenditure in the Draft Decision). Ok, that is mainly all about buying cars and trucks and trailers.

e) Largely preserve the status quo on connections and tools & plant, and

f) Increase the amount for capitalised overheads, noting that this is where 1% productivity dividend has been promised.

Essentially, Ergon proposes to do around 5-6% 'more work' in the next period, after making a simple allowance for input cost increases.

This tends to pass the 'pub test' in considering capability to actually deliver what is being proposed; certainly more achievable that the level of work proposed in the draft proposal of early 2024 and the initial Proposal.

Long term trends

Figure 5 below shows the trend of capital expenditure in Ergon since 2015-16. As we discuss below, there is a consistent trend of under-investment of capital going back before 2010. Since 2019, there has been a history of annual expenditure over the AER final decision at a trajectory a lot like that of 'an F111 dump-and-burn' - refer Figure 9 at the end of this advice for further clarification.

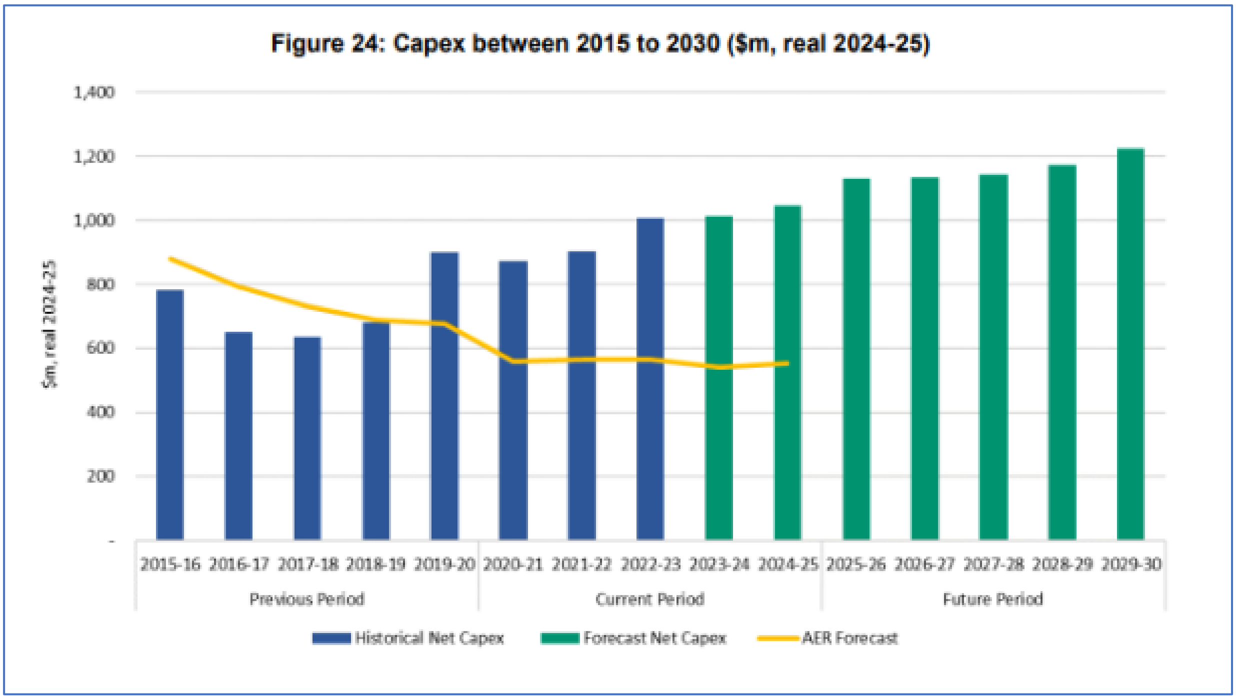


Figure 5 - Ergon Network Capex between 2015 and 2030 (source: Ergon Proposal p79)

In our research, CCP30 has gone back through the regulatory files over the past 20 years, to 2005, and identified a number of 'phases' of Ergon capital expenditure. We do this to help with two questions:

a) At a macro level, does it look like Ergon is justified to claim the need for a continued high level of regional asset maintenance, and a significant ramp-up in network augmentation investment?

b) Is there a risk that customers have already paid for this work in their tariffs, yet the investment was deferred or cancelled and now needs to be 're-justified?'

There are a number of milestones in Ergon's capex history.

The Somerville Report

In 2004, network capacity and reliability was on the Courier Mail's front page. After widespread power outages due to storms and hot weather, an independent review into the electricity distribution system in Queensland was commissioned (the '*Somerville Report'*)[19]. A key outcome was that new and highly conservative network security standards were put in place, and capital investment in network capacity was stepped up considerably to meet the challenge of the rapid uptake of air conditioning.

In their 2010-15 revenue proposal, Ergon proposed a capital investment for the 2010-15 period of over $6,270M (over $8,000M in $2025), the majority of which was system augmentation. Overall maximum demand for energy in Queensland was expected to grow at around twice the rate of growth of customer numbers over the period 2010–2015.[20] Revenues increased in nominal terms by 32.9% in 2010-11 compared to the previous year.[21]

Essentially, Ergon had a lot of money to spend to invest in the network. Driven by very optimistic demand forecasts, and despite some moderation by the AER, Queensland saw the age of 'gold plating' arrive. Despite the funding, both Energex and Ergon had difficulty actually spending their capital obligations due to resource and major plant supply limitations. There was no CESS arrangements in place at the time to provide incentive for efficient investment.

In its review of Ergon Energy's revised regulatory proposal for 2010-15, Parsons Brinckerhoff, as consultants to the AER, noted as far back as May 2010:

> *"PB notes that Huegin argues further, that Ergon Energy has **historically under spent replacement capex** and that this was recognised by the QCA in its last determination.*
>
> *Huegin also notes that replacement capex has been under spent in the current regulatory period as shown by benchmarking and RIN analysis and concludes that a business-as-usual level of spending is inappropriate in terms of prudence and efficiency as a continuing under spend on replacement capital is evident."* [22]

2015-20 Regulatory Decision

In its Final Decision for 2015-20 regulatory period in October 2015 the AER also noted a significant under-expenditure of Ergon's capital allowance in the 2010-15 regulatory period, as shown below in Figure 6. In that decision the AER brought the allowed capital expenditure more 'back into line' with actual expenditure.

In its proposal for the 2015-20 period, the AER said:

> *"Ergon Energy did not support our preliminary decision to apply the CESS as set out in the Capex Incentive Guideline.*
>
> *Ergon Energy also submitted that if the EBSS did not to apply in the 2015–20 regulatory control period then it would not be appropriate to apply the CESS."*

From 2010, the Queensland DNSPs saw the excess and put the spending brakes on hard. Capital investment slowed right down, faster that the AER revenue resets adapted. A decade of capital austerity commenced. The financial 'books' were being tightened up in case a change of government

---

[19] Electricity Distribution and Service Delivery for the 21st Century, Queensland Government, 2003
[20] Final decision Queensland distribution determination 2010–11 to 2014–15, AER, page vi.
[21] Ibid, page v
[22] *Review of Ergon Energy's revised regulatory proposal July 2010 to June 2015*, PB Australia, 2010, p35

decided to pursue the sale of the Energex energy retail business with a sale of networks, similar to what was happening in other NEM jurisdictions.

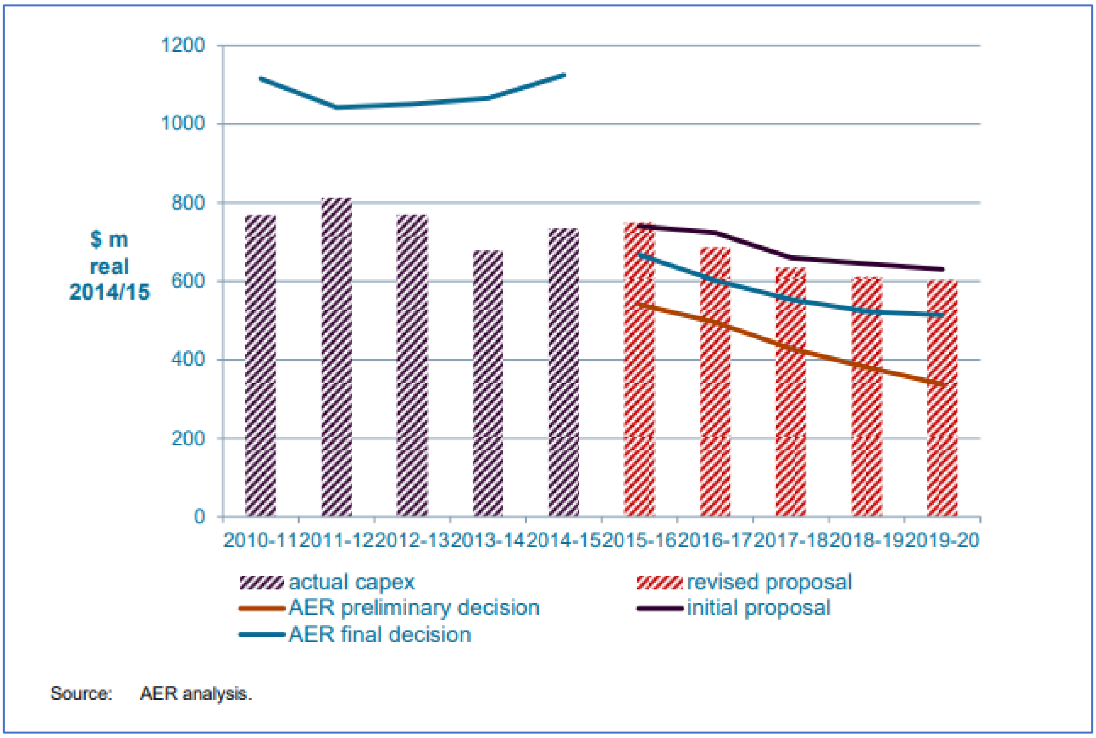


Figure 6 - Ergon Energy's total actual capex and forecast capex 2010-2020 (source: AER FD 2015-20, Attach 6, Fig 6.1)

Energex / Ergon merger to form Energy Queensland

Energex and Ergon Energy merged in 2016 to form Energy Queensland, a state-owned electricity company in Queensland, Australia. The merger was intended to improve efficiency, reduce costs, and create new jobs.

Around the same time, Ergon was refining the use of LIDAR (aircraft mounted mapping equipment) to more efficiently and accurately assess the condition of their overhead network, including line safety clearances from ground and structures.

The data from this technology, along with changes to the engineering management structure as part of the establishment of Energy Queensland, including a trend towards safety standards more aligned with urban requirements, saw a growing awareness within EQL of the consequences of under-spending in asset replacement, including the driving down of prices for asset inspection. A few years later, the imperative to invest significant money onto asset replacement re-emerged.

Summary

It appears clear that Ergon capex generally has been underspent for some time until a reversal of position in 2019. It certainly appears that the impacts of that underspend are in many ways driving the significant increase in current asset replacement needs.

There was substantial investment in new plant and capacity in the early 2000s, more so in Energex that Ergon. Capital money was plentiful, and the DNSPs were unable to spend it all. Most capex was funnelled to new capacity – transformers and substations.

Essentially, expenditure on asset replacement was lower than necessary for at least a decade, and the significant uptick in expenditure since 2020 is probably justified in response to this. In addition, there is some credence to the EQL claim that there was significant investment in network augmentation over the 2004- 08 period, but spending really slowed down since then – hence the need to ramp up ***some*** augmentation now .

Importantly, there is no evidence in the big scheme of things, that Queensland energy customers have already paid for work that was not undertaken. For example we cannot see any evidence that Ergon has received efficiency dividends for capex underspend, which would have meant that customers had effectively paid for work not undertaken. The question still remains: how long until spending stabilises and the substantial additional spending, period on period reverts to similar carried forward capex spending?

EMCA issues

We note the significant space in the Revised Proposal allocated to refuting the AER and (consultant) EMCa's position in the Draft Decision. Issues such as contractual and conservative planning are noted, and we respect that there has been considerable discussion about these issues behind closed doors.

As there was very little discussion in the consumer arena regarding the detail of these matters, CCP30 will not weigh into that area of discussion, other than to highlight that the final decision documents will need to clearly explain the factors that have contributed to final decision making.

Engagement

Ergon brought the issue of capex, and the AER's Draft Decision regarding capex, to their Voice of Customer Panel. The session spent most time on tariffs and took the opportunity to raise the issue with their customer forums.

As noted throughout this advice, Ergon chose not to engage with customers in any detail of the capital proposal, rather presenting it broadly as: [23]

> *"Overall, customers and stakeholders have told us that they value the services we provide and how we go about keeping the lights on. However, they have also told us that affordability of electricity is a primary concern, both from a cost of living and cost of doing business perspective."*

and

> *"To address customers' affordability concerns, all capex investments were subjected to rigorous analysis and scrutiny to ensure that our proposal reflects the best value for customers."*

Ergon was clear to customers that they were happy to absorb the ICT overspend as part of the ex-post review, as a symbol of the commitment to affordability.

This issue is discussed in more detail in Section 3 – Engagement.

[23] Ergon

Ex-post decision

In the Draft Decision, the AER were not satisfied that Ergon Energy's capex overspend in the ex-post period (2018-23 period) of $1,195.0 million ($2024–25) reasonably reflects prudent and efficient costs to meet the capex objectives.

A substitute forecast is $598.8 million, which is 50.0% below Ergon Energy's actual capex overspend, was applied.

Capex Category $M, $2024-25	AER Forecast 2018-23	Ergon actual expenditure 2018-23	Assessed overspend	proposed overspend to include in the RAB	% included in the RAB	over / underspend by (%)
Augmentation	400.2	228.4	-171.8	-171.8	100%	-43%
Connections (net)	270.7	314.9	44.2	44.2	100%	16%
Asset Replacement	989.6	2221.5	1231.9	674	55%	124%
ICT	132.7	246.3	0	0	0%	86%
Property	99.8	151.5	51.7	51.7	100%	52%
Fleet	185.6	129.1	-56.5	-56.5	100%	-30%
Plant & Equipment	33.6	34.7	1.1	1.1	100%	3%
Capitalised Overheads	942.1	1036.5	94.4	56.1	59%	10%
TOTAL CAPEX	**3054.3**	**4362.9**	**1195**	**598.8**	**50%**	**143%**

Table 3: Ex-post capital adjustments (source: AER Draft Decision. CCP30 analysis)

From the summary in Table 3 above, it is clear that by far the major area of overspend is asset replacement, with expenditure over double the AER allowance. This is consistent with Ergon's information that following extensive LIDAR surveys, pole condition and conductor presented major safety concerns.

We note Ergon's acceptance of the Draft Decision regarding ex-post capex, as well as the ongoing discussion with the AER regarding the volume of replaced poles that will be included in the RAB.

Overall, we have no comment about the 50% acceptance of the overspend into the Regulated Asset Base, as we are aware of many conversations between Energy Queensland, the AER and the Queensland Government on this issue.

There has been no customer or community engagement on this matter.

Issues in the ex-post that may influence the 2025-30 proposal

1. **Ongoing high repex spend**

Regarding the expenditure on pole and conductor repair and replacement, on a number of occasions CCP30 asked Ergon whether this was a temporary corrective measure that would revert back to normal levels of expenditure, or was it a 'new normal?' We did not receive clear advice or evidence to support any position – so we are still pretty much in the dark as to what future repex spend will look like. The AER noted in the Draft Decision that:

"We also note Ergon Energy's own admission that in the AER's 2015–20 review it submitted a forecast of poles repex that was incorrect and too low." [24]

We continue to highlight our position from earlier reports that it would be an exercise in good faith for Ergon to present a strategic and longer-term view of how they intend stabilising the pole replacement rates over time, and at what cost to customers.

2. Continued underspend in augmentation

We note from Table 3 that network capacity augmentation expenditure was well under the allowance for the period 2018-23.

The proposal notes strong population growth is driving increased demand, with a forecast 1% rise annually in peak demand, and growth in new customer connections of 1.6%.

With augmentation clearly underspent, CCP30 asks which projects have not been undertaken, and have these deferred projects been re-proposed in 2025-30?

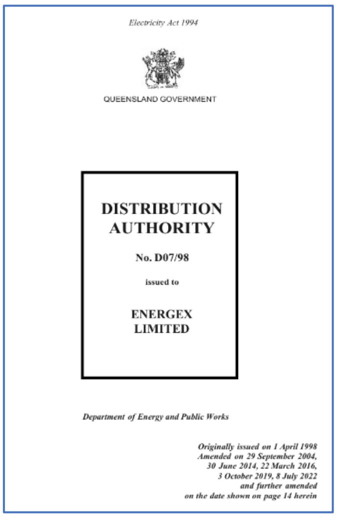
3. Property

Ergon overspent its property capital investment allowance in the ex-post period of $99.8M by $51M or 52%. The AER found this over expenditure prudent, including above-forecast costs for the redevelopment of Maryborough and Cairns sites, and allowed this spending to be added to the asset base.

In the proposal, Ergon also expect to overspend its allowance by approximately $30M in 2023-24 and 2024-25. This equates to an over expenditure in the current regulatory period of $63M over the allowance of $78.5M (all $2025 and noting that the ex-post period and the current regulatory period overlap).

The issue is that Ergon has a strong record of overspending its property capital since about 2019. Whilst property capital is not a large line item in the Proposal's capex plan, we believe that the AER should take a close look at Ergon's track record of over expenditure on property and ask if there is a case to reduce the allowed amount on the basis that work has been already brought forward? Or is there a case for a larger allowance because the underlying cost drivers of property development are rising and difficult to accurately forecast?

The Distribution Licence 'Safety Net'


Electricity Act 1994

QUEENSLAND GOVERNMENT

DISTRIBUTION AUTHORITY

No. D07/98

issued to

ENERGEX LIMITED

Department of Energy and Public Works

Originally issued on 1 April 1998
Amended on 29 September 2004,
30 June 2014, 22 March 2016,
3 October 2019, 8 July 2022
and further amended
on the date shown on page 14 herein

Section 10 of the Ergon Energy Network Distribution Authority, originally issued by the state Department of Energy and Public Works in 1998, includes obligations for Energex in the area of distribution network planning.

The purpose of the service safety net, applicable from 1 July 2014 onwards, is to seek to effectively mitigate the risk of low probability - high consequence network outages to avoid unexpected customer hardship and/or significant community or economic disruption.

These obligations are:

a) define minimum service standards (clause 9),

b) reliability safety net provisions (clause 10) and

[24] Ergon Energy, Att. 5.3.02 Ex-post review of Ergon Energy 2018–23 Capital Expenditure, January 2024, p. 11

c) set responsibility to address poor performing areas ('worst performing feeders') in the network (clause 11).

These reliability and security measures have a large bearing on the capital investment by Ergon.

We are aware of the conversations between Ergon and the AER that underpin the interpretation of the Safety Net and the capital projects that follow on from its requirements.

QCA Review of safety net targets

In June 2019, the Queensland Competition Authority (QCA) reviewed the Reliability standards for Energex and Ergon Energy for the 2020–25 period. In that review, the QCA noted:

> *"Considerable scope remains for further reform of the safety net provisions; we recommend these matters be revisited in advance of the 2025–30 regulatory period."* [25]

In their submission to the AER as part of the review, EQL stated:

> *". The Safety Net security criterion underpins network augmentation investment and hence we are very cautious to ensure that the criteria do not result in unintended consequences or investment and hence increased prices to customers."* [26]

Ultimately, the AER concluded:

> *"… the QCA considers that it ought to be demonstrated that adopting the revised safety net provisions will deliver benefits to customers and/or the network businesses that outweigh any associated costs."* [27]

We see this comment as supporting the need for Energex and Ergon to consider the balance of costs and benefits of applying the safety net in any planning decision. We also look forward to the QCA, Energex and Ergon undertaking the review of the provisions. To our knowledge this review has not started yet, so we look forward to that valuable work in the near future.

CCP30 view

From a consumer point of view, we agree with the Ergon interpretation of the Safety Net requirements, supported by the letter from the Queensland Regulator.

However, we believe that Ergon tends to take too literal an interpretation of the requirements as a 'hard limit'; based on three considerations.

1. Key in the wording of the safety net target is: [28]

> *"The distribution entity will design, plan and operate its supply network to ensure**, to the extent reasonably practicable**, that it achieves its safety net targets as specified."*

The term ' reasonably practical' brings a level of interpretation and value assessment into the obligation beyond the factors noted by Ergon in section 5.4.3 of the Final Proposal; and can include considerations of the cost to customers to comply and the risks associated with the planning.

---

[25] *Reliability standards for Energex and Ergon Energy for the 2020–25 period*, Queensland Competition Authority, June 2019, section 4, p27

[26] Energex and Ergon Energy Submission to the AER Safety Net review 2019, p13

[27] Ibid, s 4.3, P31

[28] *Distribution Authority, Energex Limited* – Queensland Government s10.2(a)

2. Other than the probability assigned to the P_{50} demand forecast, Ergon does not consider other probabilities, such as the fault occurring outside the time of peak demand, or the fact that the load curve suggests that the period of peak demand could be shorter than the restoration time limit.
3. It is unclear how Ergon applies option analysis to meet the safety net requirements and the need for new capacity, given that they are interrelated.

Summary

Ergon has gone to great lengths to respond to the many issues raised in the AER's Draft Decision. These issues have not been reasonably aired in the consumer arena, as we contend that the capital investment discussion with the VoC in October was somewhat biassed towards Ergon's case and did not allow the consumer group to respond in an informed way.

Asset replacement

Ergon plan to continue their high level of asset replacement. We are reasonably sympathetic to the cause, noting the significant, previous under-expenditure in capex generally, but asset inspection and replacement in particular, prior to around 2016. We have not been able to validate this position with data such as pole age profiles, but from a cursory look at the previous lack of investment, it appears reasonable to conclude that there is still a lot of work to do out there.

We agree with the AER / EMCa comments rejecting the adoption of common pole standards across the whole of Queensland. Similarly, we support the AER position regarding the opportunistic replacement of assets during site work.

The question remains; 'how much work, and for how long' will this high level of investment in asset replacement be required until a 'new normal' level is established. Given the impact on long-term costs, safety and reliability, it is important that Ergon 'come clean' on the pole replacement situation over time.

Whilst much is written regarding asset replacement in the Draft Decision and the Proposal, one thing that seems to stand out is the application of newer standards to assessing pole safety and hence replacement need. We contend that, without unequivocal evidence that the existing pole fleet must be subject to the new standards, only new installations should be subject to new standards. This is consistent with general practice for implementing updated standards elsewhere.

Augmentation

Ergon is running the same argument as Energex regarding network augmentation - that the level of investment in network capacity will trend upward as the 'spare capacity' installed in the years of very conservative network security standards of 15 years ago 'runs out.' That does not absolve Ergon however from developing detailed, well considered and cost-aware investment proposals.

We support Ergon's interpretation of the Safety Net requirements and note that the augmentation expenditure forecast in the Revised Proposal maintains their interpretation of the Safety Net Targets as set out in the Distribution Authority.

However, with the imperative to respond to their customers' strong message regarding long term affordability, we believe that Ergon's application of the Safety Net requirements is too deterministic and simplistic. It does not consider cost, probability, load at risk, cost-benefits and options – all of which can reasonably fall into the consideration of '*to the extent reasonably practical'*.

We contend that the term 'practical' refers to not just a physical practicality, it is also a commercial consideration for consumers.

Therefore, CCP30 supports the approach taken by the AER in challenging the associated capital proposals, and trust that much of the increased capital claim in the Revised Proposal is not passed through.

Challenge

We see significant value for customers and the AER challenging the quality and content of the Energex investment proposals. Our preference is that the AER does not approve the full amount of capital in the Revised Proposal, on the basis that Energex does not seem to be providing robust, well considered investment cases that align with customers' expectations of considering all options in the name of long-term affordability and value.

A lower capital allowance will encourage prudent and efficient investment, innovative solutions and reduce the transfer of planning risk onto customers.

5. Operating costs

In the Draft Decision, the AER accepted Ergon's forecast opex of $2,379M (including debt raising costs) for the 2025-30 regulatory period. This decision is in line with the forecast expenditure, and slightly above the opex allowance, for the current period.

The AER's modelling of opex included:

a) An efficiency adjustment for the base year (2023-24) of -$45.2M

b) Introduced an efficiency transition glide path cost allowance of $18.3M

c) A productivity growth reduction of -$34.6M (0.5%, as opposed to Ergon's 1% factor)

The Draft Decision included the standard 0.5% productivity growth factor, whilst Energex will maintain their offered 1%.

Actual base year costs

Ergon had indicated that its actual opex for 2023–24 is likely to significantly exceed the estimate it provided in its initial proposal. The AER's final decision will consider the actual opex for 2023–24 and will undertake further benchmarking analysis to test the efficiency of its updated base year opex.

The actual cost of $599.9M replaced the placeholder forecast of $489.2 – an increase of $110.7M (22.6%). This is substantial! We also note that Ergon have updated the forecast for the final year as well.[29]

---

[29] Ergon Revised Regulatory Proposal, EBSS Model 7.03, November 2024

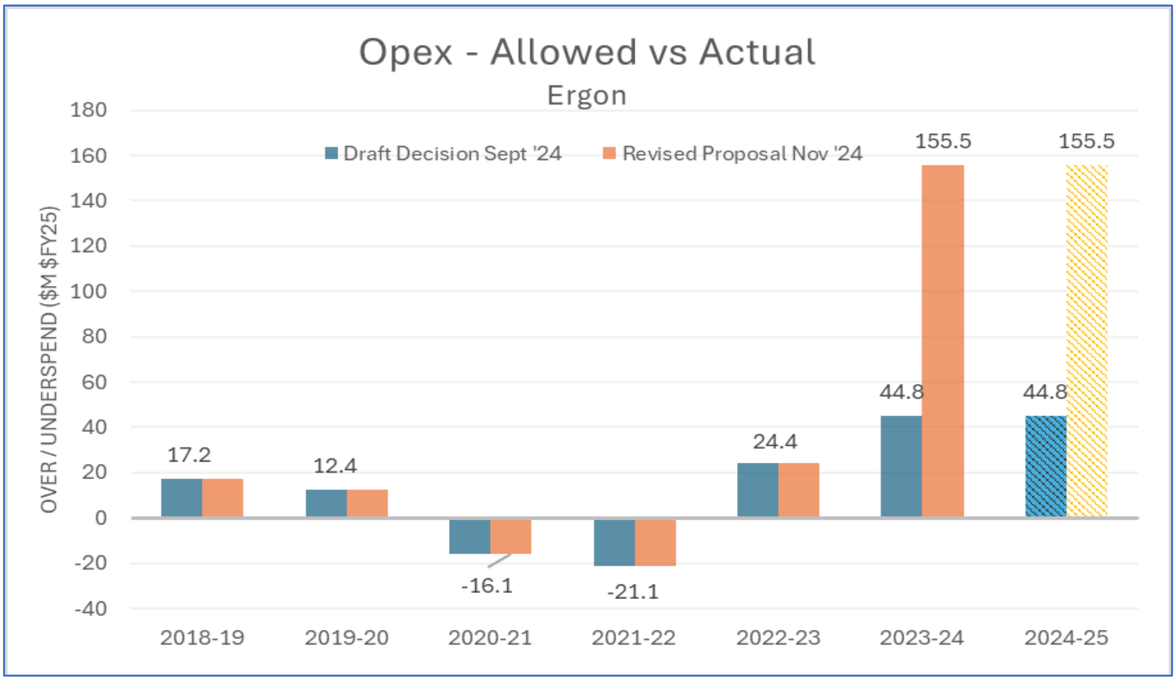


Figure 7 - Allowed Actual operating expenditure variance, Ergon (source: EBSS models)

This had the effect of increasing the forecast opex for the next regulatory period by $184M, from $2379.1 to $2,562.9M (including debt raising costs), a 7.7% increase on the Regulatory Proposal forecast and the AER's Draft Decision.[30]

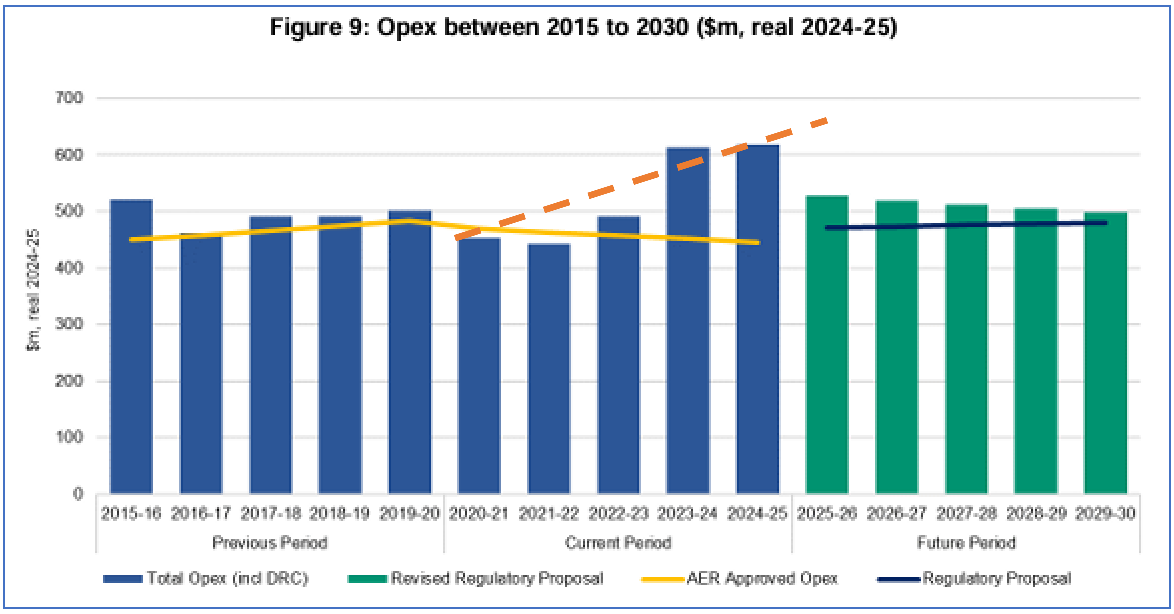


Figure 8: Opex trend, Ergon (Source: Ergon Revised Proposal, figure 9) (trend line: CCP30)

Transition Costs

The Proposal was silent regarding costs to transition to an efficient utility. In the Draft Decision, however, the AER allowed $50.1M for this, and Energex has subsequently incorporated transition costs into the Revised Proposal. From a consumer point of view, we do not believe transition costs are

[30] Ergon Energy Network Revised Proposal, section 6.2

warranted unless Energex has a clear and well-articulated plan to transition to a more efficient utility in the next regulatory period.

Observations

In the past 3 years, Ergon's operating costs have been on a steep upward trend, consistently overspending the AER allowance. This is concerning, and the engagement did not indicate to customers that this happening, or why.

The AER notes in the Draft Decision regarding a 'heads up' from Ergon on the higher base year opex:

> *"Ergon noted that the higher actual opex is due to ongoing cost increases it faces from a variety of internal and external drivers, including rising labour, materials and overhead costs, and significant weather events.*

Ergon stated that it expects some of these drivers (i.e. increasing labour and overhead costs) to be recurrent, increasing its opex over the next regulatory control period, while some of the drivers (i.e. above average emergency response costs related to severe storms) are one–off costs in 2023–24."[31]

Also unclear is how Ergon will reverse this trend quickly to meet the opex in the Revised Proposal.

6. Incentive Schemes

Efficiency Benefit Sharing Scheme (EBSS)

The EBSS is a fundamental aspect of the Australian (and, in many cases, international) regulatory framework. Reviewed in April 2023[32], it aims to provide a continuous incentive for electricity distributors to pursue efficiency improvements in opex and to share efficiency gains with their customers. In that review, the AER noted concerns with the scheme but determined in aggregate that the scheme provided favourable outcomes for consumers.

The Draft Decision

The Ergon Regulatory Proposal supported the application of the EBSS. Subsequently, the AER Draft Decision is to include EBSS carryover of $196.8M.[33] Ergon was clear, as was the AER, that this assessment was a placeholder, and that higher actual costs for the base year, once available, would be substituted into the EBSS calculation in the Revised Proposal.

> *"During consultations with us, Ergon indicated that its actual opex for 2023–24 is likely to significantly exceed the estimate it provided in its initial proposal. This is likely to result in an increase in the size of the EBSS penalty applied in our final decision."* [34]

The Revised Proposal

In the Revised Proposal, Ergon reviewed their analysis using the actual opex result for 2023-24 (the base year) has changed their support of the EBSS scheme, now asking:

a) the penalties from the application of the EBSS in the current 2020-25 regulatory control period should not be applied in the 2025-30 regulatory control period, and

[31] AER Draft Decision – Attachment 6 – Operating Expenditure Section 6.4.1, p13
[32] *Review of incentive schemes for networks, Final Decision*, AER, April 2023
[33] AER Draft Determination, EBSS model, September 2024 - Public
[34] AER Draft Decision, Ergon – attachment 8 – EBSS, s8.1

b) the EBSS should be suspended for the 2025-30 regulatory control period.

Ergon stated:

> *"We consider that the magnitude of the efficiency adjustment means we are no longer relying on our revealed costs to forecast our opex. Instead, we are primarily relying on benchmarking.[35]"*

Note that this proposal has not been presented to the consumer forums in any way, particularly through any analysis of the pros or cons of the intention to opt out of the scheme. We are aware that the RRG has, as has the AER, spent significant time considering its position on this proposal.

Our comparison of the EBSS models in the Draft Decision and the Revised Proposal in below suggests why Ergon has changed their position on the application of the EBSS. The over expenditure will also trigger a significant benchmark efficiency adjustment for the base year being materially inefficient.

Should the EBSS remain, Ergon could see a downward carryover amount of the order of $630M (assuming the data is right). See Table 4 below.

2023-24 base year opex **($M, real, June 2025)**	**Opex allowance (EBSS target)**	**Opex for EBSS purposes**	**EBSS carryover to the PTRM**
Assumed opex in the Draft Decision model	$444.4	$489.2	($196.8)
Revealed cost in the Revised Proposal model	$444.4	$599.9	($639.6)

Table 4: EBSS calculations - Draft Decision and Final Proposal. Ergon (Source: EBSS models, AER website)

A customer perspective

This proposal raises many questions and does not lend itself to simple analysis. We commend the AER opex teams for their dedication and skill in assessing this situation.

Our first impression is that Ergon has significantly overspent its allowance, especially in the base year, and they should bear the full penalties of the regulatory process designed to encourage efficient delivery of distribution services. Ergon would have been well aware of the efficiency penalty framework at the time the expenditure was approved. We also doubt that they would be taking the same philosophical position if they were to receive a benefit.

This position is exacerbated by the fact that Ergon has not gone to any length to explain to its customers why this additional expenditure was justified, efficient and resulted in better outcomes for those who are expected to pay for them (noting our position that 'everybody always pays' in a state-owned utility).

In the earlier discussions regarding the CSIS, customers were very clear of their expectation that Ergon should strive to be a very efficient organisation, and that they should not be rewarded for that. We would surmise that the reverse is also true – that customers should not be expected to pay for inefficiencies. Of course, we are assuming this overspend is a bad thing – there could be some terrific

[35] Ergon Revised Proposal, s7.4, p80

reasons why it was necessary to spend that much; its just a pity that Ergon did not make the reasons clear to those who are expected to pay.

At the very least, Ergon should have had this important conversation about efficiency and value of the over-expenditure with their customers. Granted, there was little time, which again asks the question "what made Ergon change their mind in this late stage of the process, only when the actual costs, being much more than forecast, were revealed?"

Put plainly (and intentionally provocatively), customers could be excused for thinking:

> *"Ergon spent well over what the regulator considered efficient for their operation in the past five years. They have not told us why, nor what we got for that money. Now they wish to pass that additional expenditure to us through our electricity bills.*
>
> *We were promised lower bills by the state government when Energy Queensland was formed, yet our electricity bills are only going one way.*
>
> *Ergon also now want to step out of line with their peers and opt out of the predominant scheme that is intended to encourage them to be an efficient electricity distributor. The benchmarking process only encourages them to be in the top 25%, not the best they can be.*
>
> *Can you please explain why this is a good outcome for customers, and how can we have confidence that Energex will spend our money wisely in the future?"*

Related comments from the Draft Decision and subsequent engagement

The RRG supported the continued application of the EBSS in the 2025–30 regulatory control period for Ergon , while noting that the network will likely overspend against its opex forecast in the next period.

The RRG also questioned whether the EBSS provides the same incentive for Ergon to move to efficient levels of expenditures as it does for privately owned distribution businesses. The RRG noted that '70% of any opex overrun is paid for by consumers, irrespective of whether it is efficient and prudent' and Government electricity rebates cushion the affordability impacts on households.

CCP30 also highlighted a trend of over expenditure by Ergon in its operating costs, noting there is a clear risk that this over expenditure will impact consumers. CCP30 further stated that this over expenditure in opex indicates that Ergon does not respond strongly to the AER incentive schemes, including the EBSS.

It highlighted that the penalties flowing from the incentive schemes in the current period, including the EBSS, form part of 'lower costs for consumers in the next regulatory control period.

The case for opt-out of the EBSS

We acknowledge that Energex and Ergon, and Energy Queensland generally, with its state government ownership are not 'normal' utilities in the context of the national market in Australia. They are required to meet the requirements of a political shareholder that has a wide view of the role of its energy companies in terms of meeting community responsibilities. Many of these are evident in the *Queensland Energy and Jobs Plan*, a major input into EQL strategy.

Having a shareholder with significant financial resources also tends to suggest that it is not as reliant on the regulatory determination in considering its investment and operating priorities.

In addition, with state ownership comes the issue that regardless of the cost overruns, irrespective of whether they are efficient or otherwise, customers will pay - it just depends through which mechanism.

This questions a statement by the AER at the introduction of the EBSS in 2013:

> *"If a utility has operated under an effective incentive framework, **and sought to maximise its profits**, the actual opex incurred in a base year should be a good indicator of the efficient opex required."* [36]

It could be argued that Energex operates under a shareholder regime that does not view the maximising of profits in a way similar to that of a privately-owned utility.

Therefore, we agree that the AER is justified in at least considering Ergon and Energex's proposal to exit the EBSS.

The case for maintaining the EBSS

Exiting the EBSS means that benchmarking is the remaining regulatory mechanism to encourage efficiency. The AER's benchmarking of efficiency is certainly maturing, and the proposed 'dashboard' will assist in transparency to stakeholders. However, questions exist about whether the adjustment of the base year calculated from the position on the benchmarking scale alone is a powerful and effective incentive for a utility to be as efficient as possible.

We wish to raise a number of observations that would need to be considered and explained by the AER as part of the decision.

a) We view the EBSS and CESS as interrelated; as the ability to shift costs, particularly overheads, exists within the organisation. This provides the opportunity to distort the true cost of an efficient utility.

b) The EBSS provides a consistent incentive to reduce opex across a regulatory control period. We believe that Energex has been unable to respond to this incentive, and that without such incentives there may be even less pressure to improve productivity to the detriment of customers.

c) Benchmarking, and the adjustment of the base year expenditure to the 75% percent efficiency horizon, is not a powerful efficiency incentive. It also includes normalisations that are themselves a source of debate and can detract from clarity of any efficiency discussion.

d) Ergon has in the past raised concerns about the validity of the benchmarking, questioning their commitment to the mechanism.[37]

> *"While we consider that an efficiency adjustment is not required in light of the material concerns that we have with the AER's benchmarking model, we have incorporated the efficiency adjustment to further address affordability concerns"*

e) Benchmarking does not provide an incentive for a utility to outperform the (relatively imprecise) 75% threshold.

f) The EBSS requires distributors to be transparent and reveal their true opex costs, much more so than benchmarking. Tracking expenditure – allowed versus actual – is a powerful

[36] *Better Regulation – Explanatory Statement – EBSS,* AER, November 2013
[37] Refer Ergon Regulatory Proposal, s 6.5

information source to consumers and consumer representatives to consider the operation efficiency of a utility.

g) Efficiency incentive schemes are more effective when consistently applied overtime. They should not be an option for a regulated business to opt in or out of, when it suits them.

h) Finally, we have concerns about the cost to consumers in the following regulatory period. It is certainly possible that Energex may revert to the EBSS again. I this case, a glide-path (transition) cost would most likely apply back to efficient levels, at further cost to consumers.

We question:

"Is there sufficient evidence that Energex and Ergon Energy could revert to an efficient utility in the following regulatory period, and also can consumers have confidence that efficiency would be reached?

Who pays for the costs inherent with the gradual transition to efficiency ?"

We look forward to the AER's deliberations on this issue. Our leaning is to support the continuation of the EBSS – an outcome that best drives a longer-term culture of operating efficiency and transparency of costs.

7. Tariffs and pricing

Note: this section is identical to that in the advice to the AER regarding ENERGEX

Engagement

Electricity tariffs and pricing is certainly a hot topic in the community, fuelled by mistrust and misinformation. Developing and promulgating new energy tariffs is a challenge.

Energy Queensland Limited (EQL), for the common tariff Structure Statement for Energex and Ergon Energy, carried out a remarkable amount of engagement with their customer forums regarding tariff structures and their proposal to redesign and restructure many common tariffs. This included a number of review sessions with customer forums after the Draft Decision. We commend Energy Queensland on their intent to streamline tariffs, provide choice to customers, and encourage efficient use of the network.

A lot of the engagement highlighted customers' concerns and wariness about changing from the well understood flat tariffs. Customers appreciated the story being told by Energy Queensland about the logic behind tariff changes and they understood the possibility of lower bills exist should a new tariff be adopted. Discussions about the relationship with the rollout of smart meters and the intent to reduce cross-subsidies within the tariffs frequently arose, along with many questions regarding the role of the energy retailer.

There were times when we felt that the presentations to the customers were heavily to the benefits of adopting time varying or demand tariff structures, with little explanation of the alternatives or risks. In addition, there is always the underlying issue that "in a revenue capped environment, for every winner, there is a loser."

Despite our concerns about some of the engagement, there is no doubt that it was comprehensive, well-explained, well researched and did highlight the advantages for those who could change to adopt the benefits of changed energy usage patterns.

Therefore, customer feedback regarding tariff structures should be considered by the AER as being based on clear and informed engagement. We also note that engagement continues between EQL, their RRG and the AER on tariff structure issues.

We expect that the AEMC current consultation "*The pricing review: Electricity pricing for a consumer-driven future"* will also have impact on the tariff decisions.

Draft Decision

Many elements of the TSS were accepted by the AER in the Draft Decision. We note the main exceptions and requirements for changes in the TSS, being to:

a) make default assignment for residential and small business customers with smart meters from the proposed time-of-use demand tariffs to the proposed time-of-use tariffs.

b) include an explicit export tariff transition strategy, convert proposed export charges and basic export levels from kW to kWh and include network bill impact analysis for small businesses and large customers proposed to face two-way pricing.

c) provide further detail on proposed grid-scale storage tariffs, including more detail on the proposed critical peak pricing mechanism.

d) offer time-of-use tariffs for LV large customers with demand greater than 120 kVA and with consumption less than 160 MWh per annum .

e) include further description of control arrangements that are contained in the Queensland Electricity Connections Manual, including the relationship between the Manual and tariff structure statements, and the extent to which control arrangements influence tariff options, including the proposed new flexible load control tariff.

Balancing cost reflectivity with bill simplicity and customer response capability

In its early engagement, EQL highlighted, quite validly, that consumers want simpler bills, where it is easier to interpret the cost components and drivers, and, importantly, respond to those drivers in order to deliver lower energy costs.

Whilst demand pricing is promoted by networks as a much more appropriate reflection of the assets and investment needed to provide the service, it remains a mystery to all consumers other than a number of informed large users of energy. We have concerns that demand pricing will remain invisible to consumers, especially should retailers choose to modify the pricing signal and build in demand risk. The risk of higher prices exists, especially to those least empowered to influence their energy demand.

As the ACCC reported recently:

> *"We also see increasing numbers of customers on offers with multiple layers of complex pricing, for example, time of use offers where tariff components vary by season or time of use offers that also have a demand charge. We observe that many customers struggle with the increasing complexity in their tariffs, including moving to time of use or demand tariff structures."* [38]

We appreciate the AER's comments in requiring Energex to set a default tariff assignment as time-of-use is a reasonable compromise, noting:

[38] *Inquiry into the National Electricity Market*, ACCC, December 2024

"Customers not involved in Ergon Energy and Energex's stakeholder engagement do not have the understanding or have had the capacity building to understand and respond to default demand-based tariffs, and as a result could experience stress and higher bills when faced with a cost reflective demand tariff.

RACE for 2030 … also commented that demand tariffs add further complexity, and make it harder for customers to understand their bills" [39]

We ask that the AER in their final decision to continue to support a progression to cost reflective pricing, but to balance this with consideration of the needs of everyday consumers for pricing that is understandable, measurable and empowers customers to take reasonable actions to manage their energy costs.

Analysis

1. **Default assignment to time of use, not demand**

Whilst demand pricing is promoted by networks as a much more appropriate reflection of the assets and investment needed to provide the service, it remains it well outside the reasonable understanding of customers to measure and take reasonable actions to respond to the pricing.

We have concerns that demand pricing will remain invisible to consumers, especially should retailers choose to modify the pricing signal and build in demand risk. The risk of higher prices exists, especially to those least empowered to influence their energy demand.

CCP30 supports this requirement to make the default assignment as time-of-use of energy, and notes that Energex has accepted that recommendation of the Draft Decision.

Ironically, Ergon Energy, the retailer to almost all residential and other small customers in regional Queensland, has chosen to absorb the default assignment of customers with smart meters to demand pricing, and customers by default remain on the flat 'Tariff 11'.

2. **Deferral of two-way tariffs**

Despite the reasons for two-way tariffs being made clear in the consumer workshops, support was varied. We understand EQL's decision to defer consideration of two-way tariffs until after the 2025-30 regulatory period. Customers were of the view that the transition to two-way pricing should not occur until other reforms have been embedded first and is supported by increased education for customers.

Our assessment of the situation is, put colloquially, that Energex has "kicked the can down the road."

Given the inconsistent support for two-way pricing from customers, and a strong likelihood that the new shareholder will not be keen to introduce a 'sun tax', Energex's action is understandable.

3. **Flexible load control tariffs**

Energy Queensland remains active in the area of controlled (scheduled) tariffs. We support this direction and also are highly supportive of a revision of the QECM to be far clearer on the application of flexible load tariffs.

4. **Time of use tariffs for LV large customers with small (< 160 MWh) energy use**

The Draft Decisions requires Energex to implement a cost-reflective time-of-use tariff for large customers consuming less that 160MWh of energy but with a demand of over 120 kVA. We note the

[39] *AER Draft Decision, Attachment 19 – Tariff Structure Statement* – AER, section 19.4.2.2

keen interest by the Electric Vehicle Council and how such a tariff would support the EV charging industry.

CCP30 has seen a number of initiatives by distributors to better integrate with the needs of the community, including EV charging. Changing access arrangements to infrastructure, chargers on poles and attractive connection arrangements have been observed. Distributors are now keen to install pole-mounted EV charging themselves (that's another long conversation.)

However, the AER's application of the emissions reduction requirement of the NEO being reflected in tariff structure statement decisions is an interesting one that deserves discussion. In their consideration, the AER notes: [40]

> *"If EV charge point operators were to face a similar network tariff structure NEM-wide, we consider it could increase the confidence of charge point operators (and potential investors) to extend their charging networks.*
>
> *Similar network tariff structures would also assist charge point operators to roll out more consistent charging structures for their customers.*
>
> *We anticipate this would increase the confidence of consumers in the charges they would face to charge their EVs and would further support uptake and utilisation of EVs."*

From a customer point of view, we are not uncomfortable with this foray into sustainability and carbon policy by the AER under the banner of the revised NEO. We agree that standardisation across states and alignment of determinations is consistent with a broader view of "long term interest of consumers … with respect to reducing Australia's greenhouse gas emissions" is valuable and meaningful to the wider community.

However, there will be valid challenges regarding cross subsidies, especially regarding supporting the EV market which is often seen as supporting those with the means to purchase new cars. The AER will need to be very clear just how the objective to reduce economic cross subsidies and at the same time provide lower prices for sectors of the community is achieved, especially without clear guidelines on the economic cost of carbon.

More broadly, we ask "where could this approach extend?" Could capital investment targeted at carbon reduction be favoured, even though pricing of carbon is not clear enough to be included definitively in cost-benefit investment decisions?

More to come, no doubt.

8. Other issues

Metering

We note that Ergon has accepted the AER's Draft Decision on the classification of metering services, including the treatment of legacy metering services, including the shift from Alternative to Standard Control Services.

CCP30 supports this position, and it is consistent with Ergon's consumer engagement outcomes following transparent and clear discussion.

[40] *AER Draft Decision, Attachment 19 – Tariff Structure Statement* – AER, section 19.4.4.3

Alternative Control Services - Supply abolishment as an SCS

Ergon challenges the AER's Draft Decision regarding the reclassification of supply abolishment services.

It happens that the author of this report has witnessed exactly the behaviour Ergon is concerned about – that is, the customer behaviour to 'walk away' from a vacant premises, and the high risk of electrical accidents in the demolition phase, with power still connected.

Ergon is not completely out of the picture here, as one of the prime complaints from contractors was the high price and, at times, long delays until a supply abolishment could be done. As a consequence, developers sometimes proceeded with the work regardless, often with the service wire still connected or an illegal removal of the service fuse at the pole.

Overall, the proposal is supported, and agree with Ergon's position that:

> *"… this activity is consistent with other activities concerned with providing a safe and reliable electricity supply to customers and that the benefits of mitigating public safety risks outweighs a "user-pays" approach."* [41]

The decision is consistent with the application as an SCS in other states, as Ergon notes.

Public Lighting

Ergon undertook extensive and useful engagement with councils regarding its intentions for public lighting. We note that Ergon is very progressive in the area to upgrade lighting to new technologies, and ion general is highly regarded by its customers (mainly local councils).

The Revised Proposal notes changes to labour rate escalators and updates actual costs for 2022-23. We support this detailed analysis by the AER.

In their consideration of the proposed changes, we wish to highlight that Ergon tends to have good support from its customers, however we did not have the opportunity to observe any engagement that addressed these matters included in the Revised Proposal.

[41] Ergon Revised proposal, ch 12, p113

Figure 9 - F111 ‘Dump and Burn', Brisbane, July 2010 (source: ABC news)