EQL RESET REFERENCE GROUP

Submission on the Australian Energy Regulator's Draft Decision and Ergon Energy Network's Revised Regulatory Proposal for 2025–30

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ENERGY QUEENSLAND
RESET REFERENCE GROUP

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1. Executive Summary

The Energy Queensland (EQL) Reset Reference Group (RRG) is an independent advisory panel comprising customer representatives and energy industry regulatory experts engaged to provide challenge and to work constructively with EQL on the development and implementation of the customer and stakeholder engagement plan, and the Ergon 2025-30 Regulatory Proposal.

This report from the RRG:

- reflects on the customer and stakeholder engagement program carried out by the business between lodgement of the Regulatory Proposal and Tariff Structure Statement (TSS) in January 2024 and lodgement of the Revised Regulatory Proposal and TSS in November 2024 (Phase 5 of the Engagement Program), and
- provides customer-focussed commentary on various elements of the AER's Draft Decision released in September 2024 and Ergon's Revised Regulatory Proposal and TSS submitted in November 2024.

Customer and Stakeholder Engagement

RRG has observed that, in the main, the EQL team have demonstrated continuous improvement in their engagement activities and have generally accepted constructive advice provided to them by their challenge partners. Overall, EQL preparation, planning and focus on maintaining and improving engagement in the phase 5 period was collaborative. The plan created for Phase 5 engagement was pragmatic and EQL did execute against most of the engagements in that plan. The effectiveness of these engagements, however, varied over time and across engagement groups.

Engagement with the community-based Voice of Customer Forum was patchy, with constructive, well-executed engagement early in the period undermined by the post-Draft Decision forum which failed to meet its objective of providing credible, independent customer support for Ergon's proposed capital expenditure program.

The Network Pricing Working Group (NPWG) was re-constituted during this phase of the regulatory reset process to include a broader representation of customers and other stakeholders. The RRG considers that the NPWG was the most empowered customer voice created during this engagement. EQL adopted a best practice approach to engaging with the NPWG. NPWG deliberations were well informed and balanced from all corners of the customer domain. On behalf of customers, and in majority, they sought the most cost reflective and equitable outcomes. NPWG members were disappointed not to see their expressed preferences reflected in the Draft Decision.

Ergon's approach to engagement with large customers on the regulatory reset process continued to be problematic. The RRG had been very vocal about engagement with large customers from the start of reset engagement in August 2022. Over 2024 EQL advised the RRG that they had undertaken a range of engagement activities with a focus on one-on-one meetings. Despite repeated requests throughout the period, the RRG felt they did not receive sufficient ongoing and detailed information on these engagements, and are not aware of what influence large customer engagement may have had on the regulatory proposals.

Engagement with Public Lighting customers continued to be exemplary.

The RRG continued to engage with the Regulatory Project Team and subject matter experts from the business, primarily through a series of deep dives on key topics. These included Innovation, CER Integration, Asset Management Strategy and ICT Governance.

While the deep dives enabled the RRG to better understand some of the issues and represent customer expectations in regard to some of these issues, they were at the 'inform' level and often lacked specific details eg how Ergon was going to improve its productivity to meet the 1% opex productivity promise given the large EBA increases it agreed to in early 2024.

RRG continued to meet with relevant business executives and the Board's Regulatory and Investment Committee on a regular basis. RRG members valued these opportunities to share perspectives on a range of matters related to the regulatory proposals.

Finally, affordability remains a key issue and RRG considers that more time could have been spent with customers exploring their thoughts on how affordability could have been further incorporated into the revised regulatory proposal.

Capital Expenditure

It remains to be seen whether Ergon has been able to provide the information the AER requires to support its revised capex proposal. Ergon faces considerable barriers in providing that information given the lack of a robust and comprehensive asset data base. The level of 'overservicing' with assets replaced well before the end of their technical life and too much inefficient opportunistic replacement bundling is not surprising. An asset management system is only as good as the data that is fed into it.

The RRG capex engagement was a high level 'inform' discussion. What is clear is that there remains considerable room for improvement in the economic evaluation and governance framework for capex. This is why it is difficult to accept that even the revised capex proposal is prudent and efficient, and Ergon's argument that the AER's capex reduction in the Draft Decision will adversely impact on reliability and safety.

Given the forecast over allowance spend in the last two years of the current period, the likelihood of a further ex post review for 2023-28 seems high, unless the new Queensland Government imposes some constraints on over allowance spending.

Operating Expenditure

The RRG expect that Ergon will be challenged to keep within its proposed opex allowance. While the RRG initially welcomed Ergon's proposed 1% annual productivity target, double the required 0.5%, to address affordability concerns, we have not been presented with any information that would give us confidence that Ergon is able to achieve this productivity target and hence its overall opex forecast. This view is supported by our engagement with Ergon on labour costs arising from the new four-year Enterprise Bargaining Agreement which took effect from July 2024.

A transition cost allowance was introduced in the Draft Decision, to cover the costs of moving from the current inefficient opex cost level to a 'not materially inefficient' opex cost level is also included in the Revised Regulatory Proposal. RRG are not convinced that the approach the AER has taken to transition costs in the past will be applicable to Ergon in 2025-30. We consider that more evidence of transition plans and costs is required in order to determine whether the proposed transition costs are prudent and efficient and that the allocation of transition costs must be linked to demonstrable outcomes.

Incentive Schemes

The decision to seek the suspension of EBSS given its acceptance in the Draft Decision is significant and the analysis of its impact on customers is complex. We have had little time to analyse what it means and the implications. If we correctly understand Ergon's proposal, Ergon will bear all costs above the AER allowance in 2020-25 and all costs above the AER allowance in 2025-30, however RRG do not have the capacity or tools to analyse these impacts in detail. We look to the AER's evaluation of the complex interactions presented by Ergon in its opex proposal to ensure it is consistent with the opex criteria and that customers are not bearing additional costs that are not prudent and efficient.

In the absence of a replacement reporting framework including governance arrangements, together with relevant performance metrics, the RRG supports the retention of the telephone answering metric in the current Service Target Performance Incentive Scheme.

Network Tariffs and Pricing

The RRG consider that the AER's Draft Decision is a retreat from their recent approach in DNSP resets of hastening the pace of moving to cost reflective tariffs. This seems to arise from a combination of two issues. The first is the AER's view that there is a risk of losing customer social licence for the transition and not realising the benefits of the accelerated rollout of smart meters, as a result of bill shock for consumers being put on complex TOU demand tariffs without the necessary consumer education and consultation. The AER considers that while reducing the pace of movement towards cost reflective pricing may be considered a backward step from its previous views, it is an appropriate response to minimise this risk in the longer term and better achieve the NEO.

While we can understand the AER's approach, we recommend that the Final Decision provide more discussion of what we consider is the central question:

> Why is slowing down the rate of movement towards cost reflective pricing in the Energex and Ergon TSS Proposals a prudent and efficient additional way of achieving the objective of continued consumer support for the transition given all the other measures in place to contribute to that objective?

The second issue is how the AER responds to the inclusion of an environmental objective in the NEO. This inclusion has been broadly welcomed by consumer advocates but consumers need to have an understandable narrative around the best approach to achieving this objective. Without further explanation, it appears to the RRG that the interests of commercial stakeholders such as retailers, advocates for the EV industry and battery proponents have taken priority over the expressed preferences of customers for equity and fairness in tariff design.

We would recommend that these changes in approach need a more comprehensive and transparent explanation of the AER's reasoning.

The AER's view on TOU demand tariffs seems to have unfortunately influenced Energex and Ergon's positions on two-way tariffs. Energex and Ergon's reasoning for delaying two-way tariffs until the next regulatory period is that the same complexity the AER sees in TOU demand tariffs applies to two-way tariffs. The limited benefits are outweighed by the implementation costs. Ergon consider that the delay will enable other pricing policy changes to be embedded around more cost reflective pricing as the smart meter rollout proceeds. The RRG urge Energex and Ergon to lay the foundations for two-way tariffs within the next 5-year period. At the very least this could be in the form of zero export and zero import charging to be catered for within its billing machine. This we believe would enable the networks to move quickly to implement import-export tariffs if desired in the future. Importantly it highlights to retailers and other market participants that import and export charging is an option that they must consider in developing both their billing machines and their retail product offerings.

Summary of Key Recommendations

The RRG recommend that Ergon:

1. Quickly progress the implementation of the new Customer and Stakeholder Engagement Framework. Ergon's customer and stakeholder engagement fell short of expectations for the 2020-25 reset, particularly engagement on tariffs, and again failed to meet the expectations set out in the Better Resets Handbook for the 2025-30 reset. This new framework will significantly expand business-as-usual engagement with customers and stakeholders and will incorporate input into the 2030-35 regulatory proposal. The RRG support this proposal and recommend that throughout the implementation of the new framework, EQL maintain a strong focus on applying robust processes to ensure that fully informed customer perspectives captured during business-as-usual engagements are transparently and explicitly carried forward into the 2030-35 regulatory proposal. (Section 3)
2. Make a renewed effort in its large customer business-as-usual engagement over the next few years to provide a sound basis for more effective engagement including reset engagement for 2030-35. (Section 3)
3. Dedicate time to work with customers to explore their thoughts on how affordability could be further incorporated into EQL's business operations and the next regulatory proposal. (Section 3)
4. Adapt future customer and stakeholder engagements to benefit from lessons learned during the current reset process. (Section 3)
5. Establish a standing agenda item for the Board's Regulatory and Investment Committee to explore the current status of customer engagement on issues of regulated revenue and revenue recovery and to oversee the maintenance of knowledge and experienced resources in this important area of customer engagement. (Section 3)
6. Put additional focus on the need to improve the capital evaluation and governance framework to give some confidence on the prudency and efficiency of capex spend (Section 5)
7. Provide further detail to customers and stakeholders on the proposed productivity program to give assurance that opex productivity targets for 2025-30 can be achieved. (Section 6)
8. Develop and implement a customer service reporting framework including governance arrangements, together with relevant performance metrics and targets in collaboration with customers. (Section 7)
9. Strive to include zero export and zero import charging in tariff structures during 2025-30 to lay the foundations for implementation of two-way pricing in the next regulatory period. (Section 8)

The RRG recommend that the AER:

1. Determine whether the proposed transition costs for Ergon are appropriate, prudent and efficient, and that they are linked to demonstrable outcomes. (Section 6)
2. Explain how customers can be assured that the requested suspension of EBSS will not have any adverse impact on the business's efficient choice between capex and opex. (Section 7)
3. Provide further explanation on why its approach to mitigating bill shock risk through tariff assignment to time-of-use energy tariffs for small customers is required in addition to existing approaches. (Section 8)
4. Provide further guidance to networks and consumers on how the 'contribution to emissions reduction' part of the NEO is assessed in tariff design. (Section 8)
5. Provide further guidance to networks and consumers on its TSS decision-making process for the Final Decision. (Section 8)
6. Provide further guidance to networks and consumers on the scope of future network TSS engagement. (Section 8)

2. Introduction

The Energy Queensland (EQL) Reset Reference Group (RRG) was established in November 2022 as an independent advisory panel comprising customer representatives and energy industry regulatory experts to provide challenge and to work constructively with EQL on the development and implementation of the customer and stakeholder engagement plan, and the Ergon Energy Network (Ergon) and Energex 2025-30 Regulatory Proposals.

The RRG was commissioned to provide independent reports as follows:

- reports in September 2023 on Ergon and Energex's Draft Proposals and Draft Tariff Structure Statements (TSS);
- reports in January 2024 on Ergon and Energex's Regulatory Proposals and Tariff Structure Statements (TSS);
- reports in December 2024 on Ergon and Energex's Revised Regulatory Proposals and TSS Proposals.

This report is the final report from the RRG covering the Ergon 2025-30 Regulatory Reset. It responds to both the AER's Draft Decision on Ergon's initial Regulatory Proposal and Tariff Structure Statement[1], and the Revised Regulatory Proposal and Tariff Structure Statement submitted by Energy Queensland on 26th November 2024[2].

Over the past two years, RRG members have worked closely with a range of EQL representatives including Board members, Executive managers, subject matter experts, the Regulatory team and the Customer Engagement team. We wish to acknowledge and thank them all for their support, their patience in responding to our numerous queries, their willingness to listen and their professionalism. We appreciate the time they have committed to assisting RRG members and we value the many friendships that have been forged during this process.

Finally, although we realise there are many challenges ahead, RRG members would like to wish Energy Queensland every success in achieving the objectives set for the 2025-30 regulatory period. It has been our privilege to play a small part in supporting Energy Queensland to serve the best interests of Queensland energy consumers.

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[1] https://www.aer.gov.au/industry/registers/determinations/ergon-energy-determination-2025-30/draft-decision

[2] https://www.aer.gov.au/industry/registers/determinations/ergon-energy-determination-2025-30/revised-proposal

3. Customer and Stakeholder Engagement

This section on engagement builds on the insights and evaluations presented in the March 2024 Reset Reference Group (RRG) Engagement Report[3], which assessed Ergon's customer and stakeholder engagement efforts leading up to the submission of their Regulatory Proposal for 2025–30 to the Australian Energy Regulator (AER). That March 2024 report provided a detailed review of engagement activities, highlighting both strengths and areas for improvement, and concluded with recommendations to enhance future engagement processes.

This report covers Ergon's engagement activities in what was referred to as Phase 5 of the Engagement Program. Planning for Phase 5 began in November 2023 and implementation was completed in November 2024.

Summary of Key Outputs from the March 2024 RRG Report

The March 2024 report identified the following key outputs:

1. Delayed Engagement Impact: The report noted that a delayed start significantly constrained the engagement timeline, affecting the breadth and depth of discussions, particularly on critical topics like capital expenditure programs and affordability impacts.
2. Targeted Engagement Success: Despite the delays, targeted and focused engagement on topics such as public lighting and tariff structures demonstrated the benefits of well-planned and early engagement efforts.
3. Resource Constraints: The dual engagement efforts for Energex and Ergon Energy stretched resources, limiting their ability to deliver broader engagement activities.
4. Customer-Centric Enhancements: The co-design approach to engagement was seen as a promising step toward more customer-focused processes, with notable improvements in accessibility and responsiveness during the engagement journey.
5. Key Recommendations: The RRG recommended continuing efforts to build capacity for more informed customer input, addressing the challenges of affordability and resilience, and embedding learnings from the current reset process into ongoing organizational practices.

This final review of engagement focuses on activities conducted since January 2024, assessing how Ergon's engagement practices evolved in response to earlier feedback and examining the overall outcomes of the engagement process leading up to submission of the revised regulatory proposal. Specifically, it evaluates:

- The response to recommendations from the March 2024 report.
- Further engagement outcomes on affordability, key components of the revenue building blocks and tariff reforms.
- Key stakeholder and customer interactions during the final phases of the regulatory reset process.

[3] https://www.aer.gov.au/documents/eql-reset-reference-group-engagement-report-2025-30-electricity-determination-ergon-energy-march-2024

Context

Engagement is a significant undertaking during the development of a regulatory proposal. It involves lots of different messages to lots of different stakeholders and the collection and interpretation of lots of different feedback. The stakeholders possess varying degrees of capability, and the messages delivered and heard possess varying degrees of clarity.

During the Ergon proposal development, some of those interactions have achieved what the Better Resets Handbook[4] would class as Best Practice whilst others did not meet those expectations.

What is clear is that, in the main, the EQL team have demonstrated continuous improvement in their engagement activities and have, in the main, accepted the constructive advice provided to them by their challenge partners.

That said, engagement after the release of the AER's draft decision is always challenging.

Previously the RRG noted the relatively small size of the engagement team delivering two regulatory proposals on behalf of EQL and the limited direct involvement of the subject matter specialists. Following the submission of the regulatory proposal, this team not only had to re-engage with existing stakeholder groups who had contributed to the proposal, they also had to contend with public forums and submission review, an intensive period of scrutiny by the regulator, review of a draft decision from the regulator and development of the revised regulatory proposal.

EQL has responded to feedback from the RRG, CCP30 and the AER and continued to improve. Indeed, amongst the many engagements that have been undertaken in the last twelve months there have been some excellent examples of engagement.

[4] https://www.aer.gov.au/industry/registers/resources/guidelines/better-resets-handbook-towards-consumer-centric-network-proposals

EQL's approach to the engagement

EQL commenced planning for the phase 5 engagement in November 2023, engaging Deloitte's to facilitate a collaboration with the RRG and CCP30[5] . The process captured engagement shortcomings to date and opportunities and detailed the topics, timeframes and targets of engagements. This formed the plan for phase 5 engagement[6] and was a demonstration of EQL's desire to improve engagement in the final phase of the determination process.

During that process, the RRG reiterated concerns for greater engagement on the building blocks of the determination with a focus on capex. Ergon's late start to engagement resulted in the RRG and Ergon agreeing to have only very limited engagement on capex in the lead-up to the January 2024 Proposal to a level substantially less than expected under the Better Resets Handbook or what RRG members have seen on other recent electricity distribution resets. This set the scope for any post Proposal engagement to be similarly very narrow.

The RRG also recognised that the time had passed for customers to influence the proposal, yet time spent exploring these costs would assist customers in understanding both the Draft Decision and Revised Proposal that followed. The lack of early engagement meant it was difficult to engage at any more than the 'inform' level on the IAP2 spectrum, however it was agreed that continued engagement at this stage would set the foundation for ongoing business-as-usual engagement on the components of regulated revenue.

On the IAP2 spectrum, much of the conversation in phase 5 was expected to take the form of "inform" only. In the end however, some of these conversations, particularly with the NPWG, would ultimately help to inform and influence the Revised Proposal.

There were five distinct regular engagement activities undertaken by Ergon during this period that were of particular interest to the RRG.

a) Voice of Customer (VoC)
This group consisted of representatives of residential and small business customers. This group had previously received information and education on a small range of issues relevant to the regulatory proposal. General engagement was undertaken with this group on some key components of the proposal. Their motivation was high, however the engagements occurred for whole days on a weekend or parts of evenings midweek, making attendance, and attention to any detail presented, challenging at times.
b) Network Pricing Working Group (NPWG)
The refreshed NPWG was created in early 2024 and engaged representative from a range of stakeholders including residential customers, large customers, small business, agriculture, energy retailers, rural, vulnerable and older customers. All members of the RRG also joined the NPWG. They received more detailed education on tariff structures, regulations and operation. Detailed engagement was undertaken with this group on the proposed tariff structure changes. Their motivation was high, and all engagement was undertaken during business hours.
c) Large customers

[5] The CCP are engaged by the AER to make better regulatory determinations by providing input on issues of importance to consumers. you can read more at https://www.aer.gov.au/consumer-challenge-panel
[6] See https://www.talkingenergy.com.au/82264/widgets/390999/documents/299414

Large customers are defined as representatives of customers connected to the network at 11kV or higher. This was direct engagement with specific large customers who responded to invitations to engage individually (and occasionally in forums). The representatives of these customers are generally expected to be well informed about their organisation's interaction with the Ergon network and the components of their network prices, suggesting a high level of motivation to engage driven by their desire to understand impacts of the proposal on their business. Engagement occurred at a time suitable to them.

d) Public Lighting Networks
This was also direct engagement with Councils who responded to invitations to join regular forums. The representatives were generally well informed, holding roles in their organisations where they were responsible for the operations of these lighting networks. Their motivation to engage was high, driven by their desire to understand impacts of the proposal on their business. Engagement occurred during business hours.

e) The Reset Reference Group
This was direct engagement with our team who were responsible for providing advice, insight and challenge relating to engagement on the regulatory proposal. Our motivation to engage was high, driven by our purpose.

In addition to these key groups, EQL continued to provide regular updates for their Customer and Community Council (CCC). EQL also had intermittent engagements with other groups such as their Agricultural Forum and the RDP2025 Stakeholder Forum.

Approach to engaging the Voice of Customer group

There was seven months between the publication of the regulatory proposal and that of the Draft Decision. The RRG had been hopeful that two VoC forums could be conducted in that time, with a follow up forum in October to discuss the Draft Decision. In the end, only one VoC forum was conducted in early August with the follow up in October. EQL's resources were stretched responding to AER Information Requests.

EQL's approach to the first VoC in August was very well planned and executed.

They provided pre-reading together with a pre-briefing meeting that ensured the forum attendees were reconnected to the process and focussed prior to the one-day online workshop. The meeting was expertly facilitated and utilised the GroupMap engagement tool that allowed individual input to be collected. They also utilised breakout rooms very effectively to create small group conversations that promoted participation by all parties. There was meeting follow up. The framework used was another demonstration of EQLs desire to continually improve.

The second VoC forum in October was less well planned, reflecting resource constraints. There was no pre-reading or pre-briefing and final slides being developed right up to event with the RRG having no opportunity to provide meaningful input in the slides.

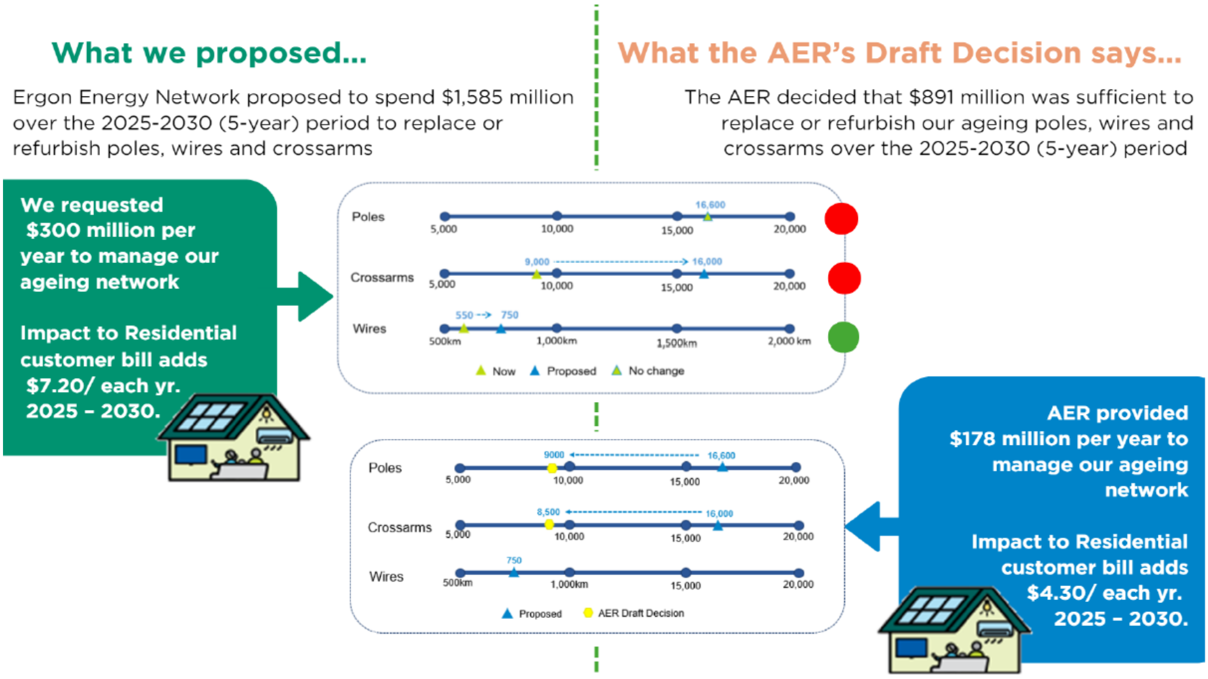
When considering the effectiveness of the content presented to the VoC forums, the RRG observed a mixed bag in regard to the content provided to customers.

As requested by the RRG, during both VoC forum engagements, EQL sought to help participants understand some of the capex expenditure that represented a key contributor to regulated revenue.

It is a difficult subject that was explored through explanation and comparison to participants but the RRG felt that EQL did misrepresent themselves at some key moments in the engagements.

We provide two examples from the October forum during discussion on the reduction in replacement capex in the Draft Decision where Ergon sought to argue that the decision did not make sense from either a cost saving or reduction in reliability perspective.

In the first example, the following message appeared on a slide that identified the drivers of major investments. The slide suggests that the $300 million in capital would impact customer bills by $7.20 each year between 2025 and 2030. In truth, this spending is likely to impact customer bills well past 2060.
The RRG felt this type of message could be easily misunderstood amongst the VoC participants and identified that there were no clear discussions during this period of the inter-generational costs of investing in capex.



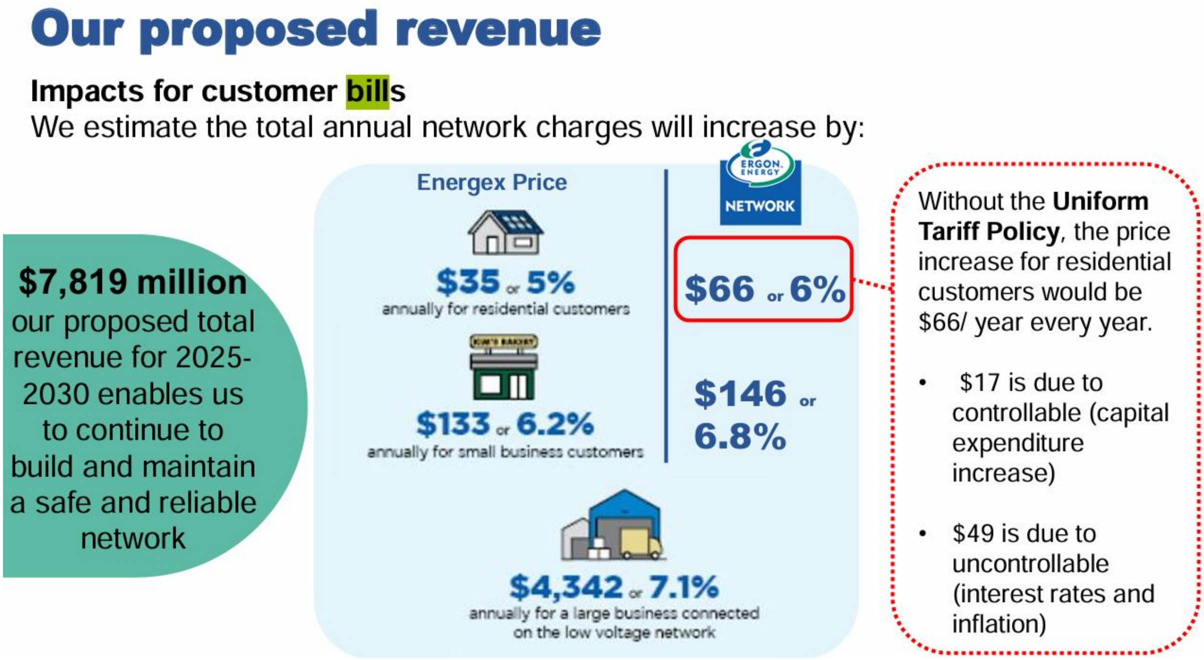
This discussion is a vital part of understanding the long-term affordability issue and needs to be incorporated more transparently into comparisons.

With better transparency comes better questioning and better understanding.

The second example was the use of this image below to discuss network reliability in the face of AER reductions in the capex allowance. The RRG recognise that lower spending on replacement capital can result in poorer security and reliability performance. However, it is appropriate that if those impacts are to be highlighted as they were in the VoC forums (see slide below), then effort should also be made to quantify the size of those reliability impacts to enable participants to assess the impacts rather than be alarmed by images.

We discuss our views on both these examples in more detail in the Capex section.

An area where the RRG remain concerned is discussion in forums such as the VoC Forum regarding bill impacts for small Ergon customers, related to the Revenue Proposal. Whilst discussion on capital spending is important to customers in the Ergon network service area, this spending has no direct effect on bills due to the Uniform Tariff Policy. It is hard to effectively explain the mechanism at play in these conversations. EQL did do well documenting the issue as it arose but the RRG felt the message was lost on many simply because of the amount of information being passed on. More thought needs to be focussed on this explanation.



The corollary of this issue is the examination of how bill impacts were discussed with large Standard Asset Customers. Many of these larger SMEs were missing from the discussion and there were some known challenges motivating this cohort to engage. As a result, their influence was missing from the proposal. The RRG would like to see this issue receive greater focus in coming proposals.

On the positive side, explanations of the engineering decisions driving the replacement expenditure were detailed and easy to follow.

More broadly, the RRG would have liked the VoC to receive more engagement on augex, connex and opex, however time did not allow for these discussions.

Finally, in the case of the TSS engagement, the October VoC express disappointment that the Draft Decision did not accept some of their views that Ergon had reflected in the January 2024 Proposal. Examples include:

- Stronger demand tariffs for better cost reflectivity
- Two-way tariffs for better equity (subject to a delayed introduction and spending on education to assist understanding prior to taking affect).

It should be noted that participants at the VoC Forums individually voiced some annoyance at giving up their weekends to help in weekend forums only to find their preferences appeared to be ignored while retailers had their concerns addressed. This remains a challenge for delivering better resets as conceived in the AER Better Resets Handbook.

If the proposed new Standing VoC group, identified in the Revised Proposal, were to include any members of this VoC Forum, they will have benefited from Phase 5 engagement.

Approach to engagement with Network Pricing Working Group

The group was provided with detailed exposure to the process of developing the TSS and members of the group committed to spending appropriate amounts of time to consider, discuss and comment on the tariffs. Given the role the group was to play, EQL adopted a best practice approach to engaging with the NPWG. That included:

- the provision of pre-reading material for every meeting to assist in preparing attendees
- The provision of short pre-briefing meetings to align objectives prior to the meeting
- separate training on the technology platforms to be used in the engagements
- establishment of digital whiteboards for collecting notes prior to and during meetings
- development of methods for establishing consensus (or not) amongst the team
- development of a clear agenda that was developed and explored over successive meetings, and
- channels for sharing permanent records of meeting outcomes.

The purpose of this planning and effort was to ensure conversations with the NPWG could advance at pace throughout the year on key issues.

The RRG felt that the approach to engagement by EQL worked very well, with a wide group of perspectives able to consider in detail during the meetings. The group proved to be an excellent representation of stakeholders and the success of the capacity building meant:

- there was some healthy friction in the discussions as all points of view were heard,
- the conversations were much more productive that with other customer groups that did not receive the same level of capacity building.

Importantly, EQL's work in enabling this group meant that meetings with the NPWG after the Draft Decision were able to effectively consider the AER Draft Decision and provide feedback into the EQL Revised Proposal.

Overall, the RRG felt that the NPWG was an effective and knowledgeable group who were able to provide an educated and balanced representation of customer preferences. On behalf of customers, and in majority, they sought the most cost reflective and equitable outcomes and were surprised with some of the directions in the Draft Decision

The Draft Decision signalled a change in the approach to cost reflective pricing, and this was confusing to members of the NPWG who spent so much of their time and effort understanding and considering the tariffs. The NPWG found parts of the Draft Decision surprising.

The RRG considers that the NPWG was the most empowered customer voice created during the engagement. Their deliberations were well informed and balanced from all corners of the customer domain. We note that despite the many hours spent by this group considering and evaluating tariff positions on behalf of Queensland customers, the AER did not reference the views or preferences of that group in the Draft decision and indeed they appear to have played little role in shaping the next five-year proposal.

The RRG is pleased that the NPWG will remain as a standing group for EQL moving forward and hope that into the future, their considerations might be given more attention.

Approach to engagement with large customers

The RRG had been very vocal about engagement with large customers from the start of reset engagement in August 2022. We discussed this in our earlier Engagement Report[7]. Ergon's focus was on one-on-one meetings. As was the case with the VoC, the absence of engagement on building blocks leading up to the January 2024 meant it was difficult to do much more than simply 'inform' large customers in the post Proposal period. So, the RRG's focus was to recommend to Ergon that these one-on-one meetings focus on the likely price path over 2025-30 were the Proposal to be accepted. Over 2024 EQL advised the RRG that they had undertaken a range of these meetings. The RRG was not involved.

EQL provided a briefing on large customer engagement during the deep dive activities held in March 2024. This noted the challenges in providing five-year glide paths for CAC and ICC pricing due to the annual changes in calculations that drive their prices. We understood the complexities but they have not stopped other networks providing indicative data to their large customers. Despite repeated requests throughout the period, the RRG felt they did not receive sufficient ongoing and detailed information on these engagements.

Some members of the RRG who have observed large customer engagement with other networks recognise there are some issues with engaging this group. However, that has not stopped other networks from undertaking that engagement and providing their RRG equivalents with confidence that quality engagement has occurred. The RRG supports Ergon making renewed effort in its large

[7] https://www.aer.gov.au/documents/eql-reset-reference-group-engagement-report-2025-30-electricity-determination-energex-march-2024

customer business-as-usual engagement over the next few years to provide a sound basis for more effective reset engagement for 2030-35.

Approach to engagement with Public lighting operators

Engagement with this group of customers was exemplary prior to 2024. There was a high degree of consensus amongst participants in this group already and the AER accepted the regulatory proposal in this area.

Much of the engagement planned for 2024 (three meetings) was to progress and clarify the details of the agreed five-year strategy rather than to further explore the Revised Proposal. In this regard, the EQL team commenced engagement almost immediately after the regulatory proposal and maintained momentum throughout phase 5.

As stated, the Public Lighting team had a program of work related to enhanced connection services for public lighting in place and followed it exactly meeting all expectations. The resourcing for that team and limited workload related to the rest of the proposal meant they were able to commence engagement almost immediately after the release of the regulatory proposal.

This was followed up by a further two forums for the stakeholders where these issues were addressed and updates were provided

Approach to engagement with the RRG

As mentioned, the RRG had expressed concern at the engagement shortcomings during planning for phase 5 and felt there was much that still needed to be considered.

In response, EQL included increased engagement on some key topics, and arranged for key staff, including senior management to provide the RRG with deep dives on a range of topics that concerned them including:

- The ex-post review
- Innovation and engagement
- CER Integration
- Asset management strategy
- Customer engagement activities
- ICT Governance
- Affordability

While the deep dives enabled the RRG to better understand some of the issues and represent customer expectations in regard to some of these issues, they were at the 'inform' level and often lacked specific details eg how Ergon was going to improve its productivity to meet the 1% opex productivity promise given the large EBA increases it agreed to in early 2024.

Separate to the deep dives the RRG undertook regular engagements with the Regulatory project team, progressing issues and assisting with the engagement planning during phase 5. The project team ensured that Senior Management attended each of these meetings when requested by the RRG. This provided the RRG with a channel for accelerating some of the concerns that are flagged elsewhere in this report.

Finally, the Regulatory and Investment Committee of the EQL Board ensured a standing agenda item for all of their meetings during Phase 5 to ensure the RRG could discuss the progress and share feedback. This again, was another demonstration of commitment to engagement by EQL.

Overall, EQL preparation, planning and focus on maintaining and improving engagement in the phase 5 period was collaborative. The plan created for engagement was pragmatic and EQL did execute against most of the engagements in that plan. The effectiveness of these engagements, however, varied over time and across engagement groups.

The RRG felt that members of the VoC and NPWG were not provided with satisfactory explanations as to why their preferences which were partially or fully reflected in each network's proposal had been set aside by the AER in its Draft Decision, often because of a greater weight assigned to views of other stakeholders. The Better Resets Handbook promotes the importance of customers influencing proposals and where their preferences are not prioritised, it is important that there are clear explanations of the reasons why.

Finally, affordability remains a key issue and for all the talk around affordability, more time could have been spent with customers exploring their thoughts on how affordability could have been further incorporated into the proposal.

Recommendations for engagement in future regulatory periods

EQL have acknowledged that the engagement undertaken was not as good as it could have been with this regulatory reset. The reset experience led EQL to commission Deloitte to undertake an independent assessment of the customer and stakeholder engagement approach undertaken by EQL for the 2025-30 reset as well as the current BAU engagement structures. This was presented to the CCC in November 2024 for discussion. EQL is now in the process of refining and implementing the recommendations.

The RRG is very encouraged by the direction EQL is taking in this new framework. There will be a reconstituted CCC with an independent Chair and the establishment of specialised sub-committees coving issues like Grid of the Future, Tariffs and Affordability, Asset Management and Safety and Customer Service and Digital. The NPWG will continue to advise on the implementation of the tariff structure statements and other developments that occur within the 2025-2030 regulatory period. There will be a standing Voice of Customer Forum for residential and business customers.

There are a number of lessons that have been learned during this regulatory proposal process and the RRG are hopeful that EQL will look to adapt future engagements to benefit from these hard learned lessons. They include:

- Planning for engagements needs to commence very early and physical engagement should be started early as well.
- When planning business-as-usual engagement, it is important to identify how and when that engagement will capture fully informed customer perspectives that can be transparently and explicitly carried forward into a regulatory proposal. Broad engagement focussed at the 'inform' level of the IAP2 spectrum is likely to fall short of the expectations for genuine engagement set out in the Better Resets Handbook.
- Prioritised topics for engagement should include elements of the building blocks that have the greatest impact on revenue.
- Customers need to be able to understand and be able to respond to the impact of various investment choices on longer term bills, with models available to support different scenarios and iterations.

- Use the examples of the successful parts of the 2025-30 engagement on public lighting and the TSS to replicate across other topics
- Ensure there are sufficient resources to undertake two network resets simultaneously
- Strive for transparency in engagement through better comparisons, trade-offs and options analysis.
- Institutionalise those engagement practices that delivered the best outcomes including, collaborative engagement planning, provision of pre-reading materials and pre-briefings, adoption of online collaboration tools and consensus building processes.
- Prioritise work on bill impacts associated with different choices early and ensure customers are able to understand how these impacts change as the process moves through its stages.
- Seek ways to engage more effectively with large customers.

EQL have progressed their engagement capability substantially during this regulatory proposal and yet at times the RRG questioned why mistakes of past resets appear to be reoccurring in this reset. The RRG would therefore encourage the Regulatory and Investment Committee to establish a standing agenda item that explores the current status of customer engagement on issues of regulated revenue and revenue recovery and oversee the maintenance of knowledge and experienced resources in this important area of customer engagement. Reporting to the Board on this issue offers an opportunity to mitigate future risk in this area.

Other issues that the RRG would like to see incorporated into future engagements include

- Discussion and transparency in explaining the inter-generational cost that flow through from capital expenditure decisions made during a regulatory reset process.
- Discussion and transparency in explaining and quantifying network utilisation.
- Discussion and collaboration in understanding customers perspectives on affordability.
- Development of stronger relationships with large customer associations and organisations and leveraging these contacts to reach customers.

The RRG while welcoming the enhanced engagement does acknowledge that the proof of the success of these foundations will be only realised at the release of the 2030- 2035 regulatory proposal. As such there will be a need for a strong body that holds EQL to their commitments with regards to ongoing and deep consultation and engagement.

Finally, the RRG will be preparing a letter to the future RRG tasked with reviewing and challenging EQL for 2030-35.

4. Demand, Energy Delivered and Customer Forecasts

Ergon have provided revised forecasts for demand, energy delivered and customers using the same methodology as the Regulatory Proposal, updated with actuals from the 2023-24 financial year. The changes in forecasts are summarised in Table 7:

Table 7: Comparison of forecasts from the Regulatory Proposal and Revised Regulatory Proposal

Forecast	Regulatory Proposal	Revised Regulatory Proposal
System peak demand	1.0%	0.8%
Forecast change in minimum demand	-116 MW	-142 MW
Energy delivered	-0.2%	-0.4%
Customer numbers	0.8%	0.8%
Electric vehicle volumes	41,000 to 118,00 units	66,625 to 144,474 units
Solar PV	8.0%	9.5%
Battery energy storage systems	27.7%	25.5%

System Peak Demand

In its Regulatory Proposal, Ergon forecasted system peak demand for 2023-24 to be 2,970 MW (10 PoE) and 2,647 MW (50 PoE). Actual peak demand was recorded at 2,874 MW, which is 3.2% less than the 10 PoE forecast.

In its Revised Proposal, Ergon forecasts system demand to increase by an average of 0.8% annually (50 PoE) between 2025 and 2030, reduced from the 1.0% annual growth rate projected in the Regulatory Proposal. These forecasts have been derived from the updated actual peak demands.

Forecast Change in Minimum Demand

The RRG noted that the trend in falling minimum demand was tempered in 2023-24 compared to prior years. In the most recent year minimum demand increased by 15MW (from 799 MW to 784 MW), with the prior 5 years recording an average decrease of 57 MW per annum. See Table 8 below:

Table 8: Historical data

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22	2022-23	2023-24
Recorded peak demand (MW)	2,481	2,651	2,716	2,689	2,677	2,688	2,702	2,637	2,874
Recorded minimum demand (MW)	1,117	1,128	1,165	1,070	1,128	961	969	799	784
Customer numbers[1]	739,353	745,505	752,141	757,726	762,303	767,583	776,533	786,523	792,127
Energy delivered (GWh)	13,747	13,332	13,243	13,504	13,567	13,477	13,780	13,868	13,927

In the revised proposal, minimum demand is forecast to continue its downward trajectory, with an average annual reduction of 141MW per annum. The RRG inquired with Ergon regarding the current trend, considering that solar capacity uptake continues to remain strong. Ergon provided the following response:

"While the forecast has many different forecast inputs like solar pv generation capacity, load growth (increasing native demand), electric vehicle uptake and installation of battery storage systems – it is also dependent on other factors like estimated rates of solar generation at the time of minimum demand – i.e. a kWh forecast.

While the forecast of the amount of rooftop solar pv capacity increased between 2023 and 2024, there was also a refinement (reduction) to the estimation of solar pv generation at the time of minimum demand. The change in the forecast estimate of generation at the time of minimum demand overshadowed the increase in solar pv capacity forecast, as the generation assumption acts on the entire population of solar pv systems.

The net result of the change year to year was that the load offsetting impact of solar pv generation has reduced, with the minimum demand forecast being less negative at the end of the forecast horizon."

Distributed Energy Resources

The projection in distributed energy resources (electric vehicles, solar PV systems and battery energy storage systems) has been updated using the most recent actual data and inputs.

Ergon's 2024 Distribution Annual Planning Report (DAPR)[8] reveals that 50PoE and 10PoE values are calibrated to account for demand management initiatives, solar PV, battery storage and the expected impact of electric vehicles via a post-model adjustment.

It is noteworthy that:

- The electric vehicle unit forecasts, encompassing both Medium and Fast scenarios, have been increased by 62.5% and 22.4% respectively. Ergon's 2024 DAPR indicates there is no evidence that EV charging is currently overloading any local networks.
- Battery energy storage systems are forecast to increase by 25.5%, or 36.2 MWh per annum under the Medium Scenario. Ergon's DAPR clarifies that this forecast encompasses systems installed in residential and business customer premises, as well as Ergon's 4/8MWh batteries installed alongside zone substations and <100kW/200kWH neighbourhood and community batteries on the low voltage network.

[8] https://www.ergon.com.au/__data/assets/pdf_file/0011/1492391/Ergon_Energy_Distribution_Annual_Planning_Report_2024.pdf

5. Capital Expenditure

AER's Draft Decision

The AER did not accept the overspend in the ex-post review for 2018-2023 nor the proposed expenditure for 2025-30:

- For the ex-post review, Ergon sought $1,195m to be added to the opening RAB for 2025-26. The AER approved $598.8m, a 50% reduction
- For 2025-30 capex, Ergon proposed net capex of $5,704.8 and the AER approved $4,188.1m, a 26% reduction.

The AER said[9]:

> "The key issue in setting Ergon Energy's required revenue for the next 5 years is related to its replacement expenditure (repex) overspend over 2018–23 and determining how much is rolled into the regulatory asset base (RAB). Our draft decision recognises that Ergon Energy had a genuine need to make capital investments beyond the AER's forecast over the current period in response to an emerging issue with pole defects in its network. However, based on the information before us, we consider the magnitude of overspend was not in line with prudent and efficient decision making."
>
> …
>
> We found that most of Ergon Energy's repex forecast was based on a continuation of its historical capex, which our ex-post review found not be prudent and efficient. Ergon Energy's proposed augex programs, particularly for grid communications, protection and control and the distribution feeder augmentation project require further evidence to show that these investments reflect prudent and efficient business practices."

The AER's ex post decision was a 'placeholder' given the AER found[10]:

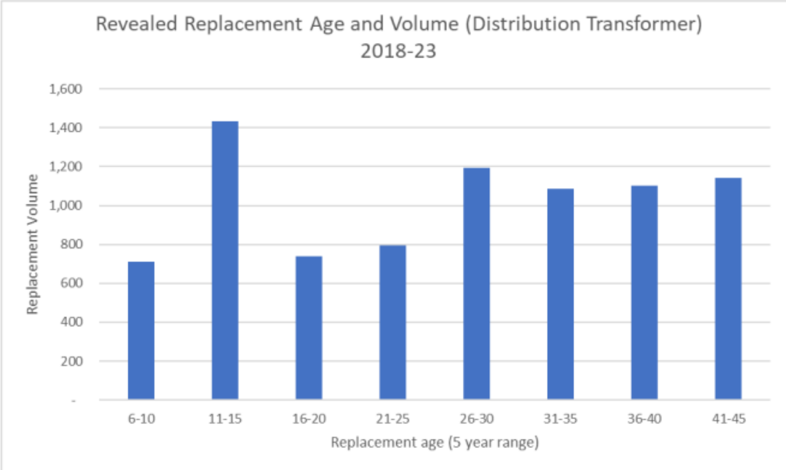
> "… that Ergon Energy's supporting documentation contained significant information and data gaps, data discrepancies and reconciliation issues, and lack of detail and sufficient reasoning to substantiate the prudency and efficiency of its proposal. EMCa came to the same conclusion."

Replacement capex dominated the overspend and the two key components were poles ($341.3m or 27.7% of the total repex overspend) and 'opportunistic' replacement ie where other assets are replaced at the same time as targeted assets ($544m or 44.2% of the total repex overspend). An

[9] See pp. vi-vii https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf
[10] See p. 8 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

example of the latter was replacement of distribution transformers much earlier than their design life of 45 to 55 years[11].

Figure 5.2 Revealed Age of Replacement of Distribution Transformers



Source: AER analysis

The AER had numerous information gaps even after 60+ information requests and face to face meetings to discuss information gaps and data errors. This led to the AER selecting Essential Energy as the benchmark for assessing repex. The AER looked forward to further discussions with Ergon and the provision of the additional information to better asses the ex-post capex.

The analysis of the ex-post period flowed into the 2025-30 proposed capex. While the AER accepted some parts of Ergon's proposal eg DER, connections, cyber and tools and equipment, major categories – replacement and augmentation - have significant reductions. Again, this decision was a placeholder awaiting further information from Ergon.

In an issue highlighted by the RRG in its submission on the Regulatory Proposal engagement[12], the AER agreed with us on the lack of engagement on capex, noting[13]:

> "… that Ergon Energy did not satisfy any of the capex expectations in the Handbook. In particular, its forecast capex for the 2025-30 period is a 18.5% step up from the ex-post period, where it is proposing a step up in all capex categories except for ICT. Submissions in response to the Issues paper also noted the lack of genuine consumer engagement on its capex proposal. There was little evidence of how Ergon Energy had regard to consumer feedback in developing its capex proposal especially on the key priority issue of affordability."

<u>What is Ergon proposing?</u>

Ergon's revised proposal:

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[11] See p. 11 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[12] https://www.aer.gov.au/documents/eql-reset-reference-group-engagement-report-2025-30-electricity-determination-energex-march-2024

[13] See p. 21 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

- while arguing that the expensed volume of major parts of the ex-post review overspend were justified (pole, pole top structure and consequent conductors), accepted the Draft Decision's $598.8m to be added to the opening RAB rather than the proposed $1,195.0m; this was presented to the RRG as an 'affordability' measure
- nevertheless, argues that the volumes of two major parts of the overspend – poles and opportunistic replacement - were required and that their historical replacement rate is an acceptable basis for assessing 2025-30 capex
- accepts the AER's Draft Decision on many capex categories – DER, connections, cyber, property, tools and equipment – which make up ~20% of the Draft Decision
- proposes 'modified' (ie higher) expenditure in repex and augex than the Draft Decision, but lower than their original proposal

$2024-25m	Regulatory Proposal	Draft Decision	Revised Regulatory Proposal		
				Change from Regulatory Proposal	Change from Draft Decision
Repex	2,537.6	1,738.6	2,285.0	- 252.8	+546.4
Augex	513.2	429.2	489.2	-24.0	+70.0

Ergon say[14]:

> "… we accept that there is room for improvement in some aspects of our CBA and in the way we document some of our business cases and supporting materials. Updated materials that address the relevant feedback have been included with this Revised Regulatory Proposal…"

and then go on to say that they do not accept three economic modelling matters in the EMCa report that the AER drew on it their Draft Decision – incorrectly specified counterfactual, assessment period of benefits does not align with costs and the adoption of Energy Queensland standards that result in a higher pole replacement for Ergon. Ergon provide a range of consultant reports to support their position[15].

Ergon sets out a range of reasons that limit the relevance of benchmarking against Essential Energy.

<u>RRG comments</u>

Following the Draft Decision, the RRG had had only limited engagement with Ergon on capex. We did participate in a debrief meeting with the AER capex team and Energy Queensland at the end of the capex team's visit to Brisbane in October. The purpose of that visit was to explain the additional information the AER required to not use Essential Energy as the benchmark (its preferred position) and understand what additional information EQL was able to provide.

At that meeting Ergon acknowledged they have a lack of data required to undertake the analysis that the AER expects. The RRG believes that this lack of data can contribute to culture in the field of

[14] See p. 55 https://www.aer.gov.au/system/files/2024-12/Ergon%20-%202025-30%20Revised%20Regulatory%20Proposal%20-%202%20December%202024%20-%20public.pdf
[15] See Attachments: https://www.aer.gov.au/system/files/2024-12/Ergon%20-%205.3.01%20-%20Aurecon%20-%20Independent%20response%20to%20EMCa%E2%80%99s%20Report%20-%20November%202024%20-%20public.pdf; https://www.aer.gov.au/system/files/2024-12/Ergon%20-%205.3.02%20-%20TSA%20Riley%20-%20Review%20of%20Ergon%20Replacement%20Expenditure%20-%20October%202024%20-%20public.pdf; and https://www.aer.gov.au/system/files/2024-12/Ergon%20-%205.3.03%20-%20Frontier%20Economics%20-%20Counterfactual%20for%20repex%20business%20cases%20-%20November%202024%20-%20public.pdf

'overservicing' or 'conservatism' ie replacing too many assets too early compared to what an asset management system underpinned by a robust and comprehensive data base would recommend. This 'overservicing' outcome is not unexpected if there is the workforce has been historically sized to enable this level of asset replacement. An asset management system's recommendations are only as good as the data that is fed into it.

As Ergon improve their data quality and do less inefficient opportunistic replacement bundling this will further increase unit costs as there are more fixed costs (labour and overheads) to spread over fewer assets being replaced. Given the EBA prevents retrenchments, EQL has argued that these workers will be moved to unregulated business eg installing community batteries or being available to sub-contract to Powerlink. It remains to be seen how successful this is and how much it mitigates the risk of Ergon exceeding its capex allowance and consumers picking up 70% of these costs. We comment on this further below.

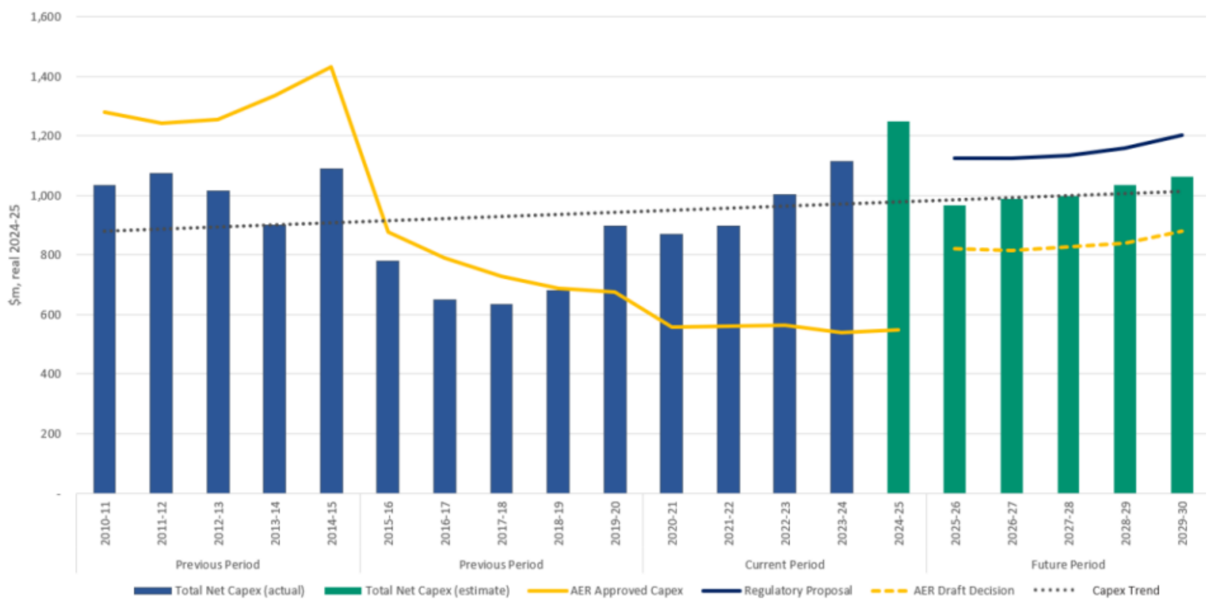
We await the AER's decision on whether the level of information provided in both the revised proposal and in subsequent information requests meets the AER's requirements.

A long term 'Historical trend' is not a useful guide to the prudency and efficiency of proposed expenditure

Ergon argue that[16]:

> "As illustrated in Figure 6, our expected spend is in line with our long-term historical trend"

Figure 6: Capex between 2010 to 2030 ($m, real 2024-25)



While it is useful to look at trends, it is not clear why past expenditure, which has been significantly above the AER approved capex, is a useful guide to the prudency and efficiency of forecast capex.

EMCa methodology

We were unaware of Ergon's engagement with a range of consultants seeking to critique the EMCa report. We do not seek to opine on a 'competing consultants' debate – who is the more technically

[16] See p. 55 https://www.aer.gov.au/system/files/2024-12/Ergon%20-%202025-30%20Revised%20Regulatory%20Proposal%20-%202%20December%202024%20-%20public.pdf

correct or who best follows AER practice notes or Guidelines. We do, however seek to understand the relevance of the Ergon submission on the AER's final decision.

The first point we would note is that EMCa's role is that of an advisor to the AER. It is the AER that determines its alternative estimate and in doing so it draws on a range of information of which EMCa reports are one, albeit important, part. In our long and extensive experience with these resets, the AER has not always followed everything that EMCa may recommend or agreed with every EMCa conclusion.

The second point is that it is not clear how material are Ergon's concerns. In the case of the 'incorrectly specified counterfactual' Ergon provides an example[17] to show[18]:

> "… an "incorrect" choice of counterfactual does not render our CBA unusable, nor does it unduly bias any option over the other…"

RRG's understanding of Ergon's position is that had EMCa applied Ergon's methodology in this and the other two matters they do not accept in EMCA's report, then the approved capital allowance would have been higher. However, no analysis is provided to support that proposition. Changes in methodology cannot address fundamental problems in data availability. Further we are unable to form an opinion on whether Ergon's approach would result in a better outcome for consumers.

ICT capex

We commented on this at length in our earlier submission with particular focus on the poor project implementation of the DEBBs portfolio that led to the 2020–25 period overspend of $203.4 million and Ergon's decision to exclude it from the RAB[19]. In discussions earlier this year, EQL sought to assure the RRG that lessons had been learnt and business case development was now much more sophisticated.

Ergon's forecast for the 2025–30 period is still $91.6 million higher than the AER's final decision for 2020–25 with a fall in its non-recurrent capex and an increase in recurrent capex. The reallocation is due to its new approach called 'Evergreening' which has a focus on more frequent recurrent upgrades to applications and technologies rather than the DEBBS major transformation approach.

Table B.8 Ergon energy's ICT capex forecast compared with the AER allowance and actual/estimated capex for the 2020–25 period ($ million, $2024–25)

AER forecast 2020–25	Actual/estimate 2020–25	Overspend	2025–30 forecast
197.6	400.1	203.4	288.3

Source: Ergon Energy's proposal

Despite the experience with DEBBs and the PIRs Ergon commissioned, the AER was very critical of the poor business case analysis put forward for 2025-30 leading to a reduced allowance of $208m. The RRG had no engagement with Ergon on ICT business case development following our submission

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17 See Attachment 5.03.04 https://www.aer.gov.au/system/files/2024-12/Ergon%20-%205.3.04A%20-%20Response%20to%20EMCa%20Cost%20Benefit%20Analysis%20Concerns%20-%20November%202024%20-%20public.pdf

18 Ibid p.57

19 See p. 76 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

on the Regulatory Proposal. So, we are unable to form an opinion on whether Ergon's new approach will ensure prudent and efficient ICT investment in the future.

Economic evaluation and governance continue to be a 'work in progress'

In our submission on the Regulatory Proposal, we commented on the AER's assessment of the poor level of capex justification in Ergon over many years. We noted the increased effort in recent years to improve the quality of the analysis and commented that[20]:

> "From our experience with other networks[21], Ergon is still on the 'maturity journey' to put in place best practice asset management and project evaluation. This is particularly seen in the partial implementation of Copperleaf which has been delayed by problems implementing a major ICT systems upgrade discussed below. Ergon hope to complete implementation over the coming year. Another example will be how safety is considered in the asset management framework. Good asset management is not about ignoring safety, it is about better understanding of the safety risk to make better informed expenditure decisions."

We agree with the AER's comments in the Draft Decision on the poor quality of their capital governance framework and that 'little weight can be placed on Ergon Energy's PIRs'[22]. We discussed the PIR on DEBBS portfolio in our submission on the Initial Proposal[23].

We had no engagement with Ergon subsequent to the RRG making this submission and leave it to the AER to assess whether Ergon's improvements in project evaluation and governance have assisted in them meeting the capex criteria.

The results of the consumer engagement on 'managing the ageing network' should not be relied on by the AER

<u>What Ergon presented</u>

In our submission on the Regulatory Proposal[24] we noted the very narrow scope of consumer engagement on capex spend leading up to submission of the Regulatory Proposal in January 2024. We estimated that this engagement covered only ~$20-25m or <1% of proposed capex. The overall Draft Plan capex trends were presented generally in an 'inform' context - what was proposed by component and total and why it was increasing. There was no sense that consumers had any ability to influence that expenditure. We noted there was more extensive engagement with the RRG

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[20] See p. 39 https://www.aer.gov.au/documents/eql-reset-reference-group-submission-2025-30-electricity-determination-energex-ergon-may-2024

[21] See the description of the Endeavour framework provided to the AER as part of its 2024-29 revenue proposal https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/endeavour-energy-determination-2024%E2%80%9329/proposal

[22] See p. 31 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[23] See pp. 22-25 https://www.aer.gov.au/system/files/2024-06/EQL%20Reset%20Reference%20Group%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex%20%26%20Ergon%20-%20May%202024.pdf

[24] https://www.aer.gov.au/system/files/2024-06/EQL%20Reset%20Reference%20Group%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex%20%26%20Ergon%20-%20May%202024.pdf

subsequent to January but again this was more on the 'inform' level with the RRG having no influence on the level of expenditure.

In early October, Ergon held a day long online engagement session for the combined Voice of the Customer panel members and the Townsville Focus Group members. Facilitated by Mosaic Lab, the focussing question was[25]:

> "How should Ergon Energy Network plan for the new energy future, while providing affordable services that meet changing customer and community needs?"

The purposes of the day were to update the Panel on the main issues engaged upon, provide an update on the AER Draft Decisions and Ergon's reaction to it and to get the Panel's sentiment on the Draft Decision. This resulted in discussion of three topics – affordability and pricing (network tariffs); capital expenditure (managing an ageing network) and CSIS. These insights would assist Ergon in landing a position on those issues for the Revised Regulatory Proposal. Our focus here is on the second topic – managing an ageing network.

In the Revised Proposal Ergon noted[26]:

> "Following the Draft Decision, we engaged with our VOC Panel on the challenges of our ageing network and replacement capex proposal for poles, pole top structures (cross-arms) and overhead conductors. We sought our customers' views on the AER's Draft Decision to significantly reduce our proposed expenditure for poles and pole top structures, noting that the AER approved our overhead conductor capex forecast.
>
> Overall, customers were uncomfortable with the AER's Draft Decision to reduce our replacement capex on pole and pole top structures. Participants expect Ergon Energy Network to consider prudent investment in managing our ageing assets, balancing the costs of investment in the 2025-30 regulatory control period against future costs if asset replacement programs (in particular those relating to poles and pole top structures) were delayed into the future.
>
> A key take-away from this customer consultation was that customers were not only concerned about the safety and reliability impacts of significantly reduced replacement expenditure, but also disagreed with the benchmarking comparisons between Ergon Energy Network and Essential Energy, primarily due to the operating environment in regional Queensland. There was a general view that the regional nature of the network means that it takes longer for power to be restored and that it is therefore better to invest now rather than wait until poles fail. Customers made it clear that they expect safety and network reliability performance to be maintained."

The capex discussion referred to the Ergon proposal of a 20% increase on the current period which is higher again on the previous period. This is due to a combination of the large/ageing network, population and housing growth, the importance of repex as a major portion, and safety and

[25] https://www.aer.gov.au/system/files/2024-12/Ergon%20-%202.02%20-%20MosaicLab%20Customer%20Panel%20and%20Focus%20Groups%20Report%20-%20October%202024%20-%20public.pdf

[26] See pp. 66-7 https://www.aer.gov.au/system/files/2024-12/Ergon%20-%202025-30%20Revised%20Regulatory%20Proposal%20-%202%20December%202024%20-%20public.pdf

compliance driven by a ground clearance rectification program. The discussion then turned to the Draft Decision and where it differed from the proposal.

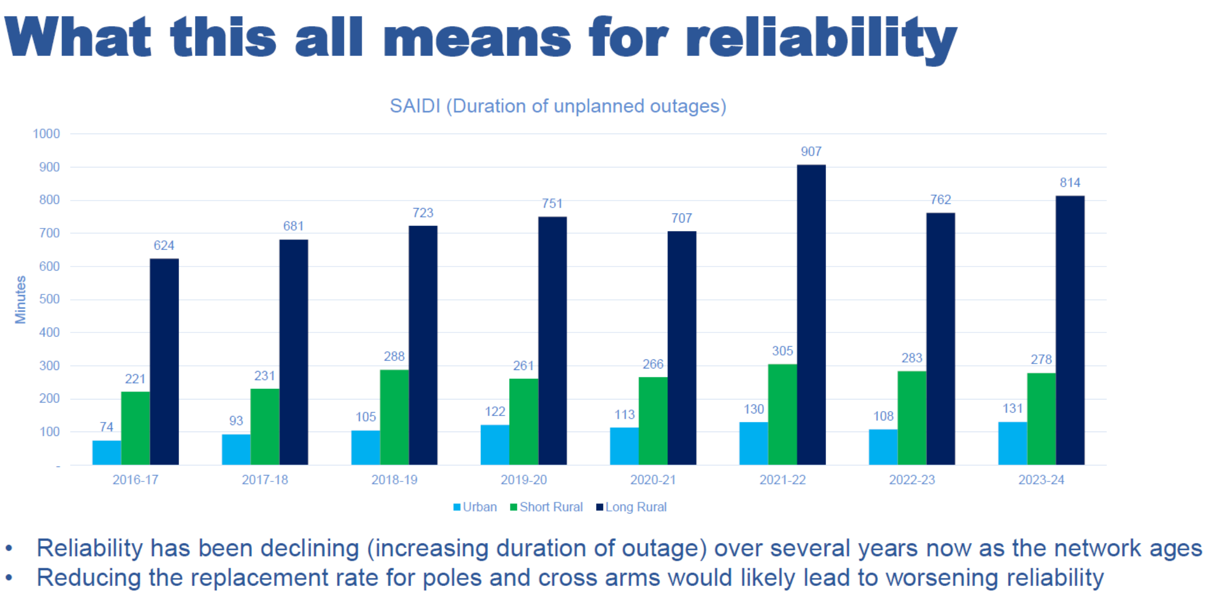
As we noted in the engagement section above, the 'managing an ageing network' discussion began with a picture of a very old car. This analogy served to provide context for the presentation of the large reduction in capex in the Draft Decision and the subsequent VoC response.

> "We requested $300 million per year to manage our ageing network. Impact to residential customer bills of $7.20 each year 2025-30"
>
> "AER provided $178 million each year to manage our ageing network. Impact to residential customer bills adds $4.30 each year 2025-30"

The implication is that consumers will not have a reliable network for the sake of saving only $2.90/year. There was no reference to the cost for decades post 2030.

There was only passing reference in the presentation to the AER's major reason for the reduction in capex – the lack of supporting data and analysis and that that it was a 'placeholder' decision awaiting the provision of that information. There was no language in the slides referring to this.

Ergon sought to differentiate itself from Essential – Essential has more assets but substantially smaller service area; Essential's climate is quite different eg not exposed to extreme weather conditions, and Ergon has to meet the Queensland Electrical Safety Code of Practice. Then Ergon provided data on SAIDI to argue that reliability has been decreasing over time as the network ages.



We note that the presentation did not provide an indication of performance against targets, as included in the Ergon Distribution Annual Planning Report[27]. The most recent (2023-24) reliability performance against Minimum Service Standards (MSS) indicates Ergon reliability of supply was favourable to MSS limits for the SAIFI performance measures for all three Urban, Short Rural, and

27 https://www.ergon.com.au/__data/assets/pdf_file/0011/1492391/Ergon_Energy_Distribution_Annual_Planning_Report_2024.pdf

Long Rural networks, however SAIDI for the three feeder categories were unfavourable to the MSS. Ergon states this was due to the increased safety driven Program of Works since 2018.

Table 19: Annual normalised reliability performance compared to MSS limits

	Feeder Category	2022-23 Actual	2023-24 Actual	2021-25* MSS Limits
SAIDI (mins)	Urban	231.92	262.07	149
	Short Rural	481.51	498.09	424
	Long Rural	1,141.30	1,340.28	964
SAIFI	Urban	1.635	1.757	1.98
	Short Rural	3.033	3.057	3.95
	Long Rural	5.853	6.120	7.40

* A single MSS limit is set for each feeder category for each regulatory control period.

It was unclear to the RRG if the intent of this slide was to demonstrate the Ergon environment is subject to worsening reliability due to increased asset replacement works, whether the environment is subject to increasingly longer duration outages due to the nature of failures, or whether asset reliability is contributing to more frequent outages.

The presentation ended with pictures of damaged power poles with lines hanging down and the text:

> "We are committed to keeping our staff and our customers and communities safe
>
> "Reducing the rates of replacing our network that is getting older and poor condition compromises our safety goals"

Participants were then divided into seven small groups of 3-4 people to discuss in more detail. On the Mosaic Lab 'L scale' of 'Love it/Like it/ Live with it/Lament it/Loath it, one group could not agree, four loathed it, one lamented and one could live with it. Participant comments included[28]:

> "Main takeaway: Proactive replacement instead of reactive work
>
> "Concern of safety standards if AER doesn't consider the extra expenditure of poles and wires"
>
> "Being in rural QLD, there is a safety concern for poles and wires as we are far from major cities Especially in North QLD in rural areas where cyclones are common, being without electricity for days and possibly weeks is a concern Happy to pay the extra costs associated with extra safety regulations"
>
> "Comparison of Ergon and Essential Energy NSW not comparable"
>
> "This is not the place to cut costs Safety and reliability are most important, and we are happy to invest that small amount of increase to our annual bill, for these very important high-risk areas the investment is addressing Having to spend more money, on something that though authorities may be not sure is a needed spend, is worth this risk for the small amount that we will be paying, vs the impact risks if we didn't"

[28] See pp 9-10 https://www.aer.gov.au/system/files/2024-12/Ergon%20-%202.02%20-%20MosaicLab%20Customer%20Panel%20and%20Focus%20Groups%20Report%20-%20October%202024%20-%20public.pdf

Given the information provided and the language used by Ergon, it was not surprising there was strong support for Ergon's position on required capex spend to keep the network safe and reliable.

RRG comments

Based on our observation of this engagement in early October, we do not agree with the conclusions Ergon has drawn. Ergon's presentation was 'inform' on the IAP2 spectrum.

Almost by definition a network is likely to be aging. Yet AER data on the regulatory service life in 2023[29] show major parts of the Ergon network are quite 'young' and well below the average of distribution networks. The AER's description of the data says:

> "Regulatory service life is an indicator of the regulatory age of assets in service across the DNSPs. In general terms an increasing regulatory service life implies increased maintenance expenditure may be required, or the asset may be reaching the end of its useful life and may need to be replaced. Regulatory service life has been calculated as the difference between the expected life of a new asset and the residual life of the existing assets in service."

Average asset age (years)	Ergon	Essential	DNSP Average
Overhead lines <33kV (wires and poles)	13	47	25
Distribution substations and transformers	15	26	22
Zone substations and transformers	19	24	25

The AER data says the network is getting and staying younger – no doubt reflecting the very large investment that is the subject of the ex-post review. The AER graph shown at Figure 5.2 on p. 23 "Revealed Age of Replacement of Distribution Transformers" shows a significant number have been replaced at less than 25 years of age when the expected asset life is 45-55 years. Over the period since 2017, Ergon has consistently had the third youngest asset base of the 14 DNSPs in the NEM. The table shows average asset age in years for the three asset categories of Ergon and Essential.

	Average Asset Age (years)						
Ergon/Essential	2017	2018	2019	2020	2021	2022	2023
Overhead lines <33kV (wires and poles)	22/43	21/44	20/44	20/45	14/46	13/46	13/47
Distribution substations and transformers	15/24	15/24	15/24	16/24	15/25	15/25	15/26
Zone substations and transformers	12/25	12/25	10/26	14/26	18/23	19/24	19/24

None of this context or data was presented to the VoC group. Nor was the AER statement that the Draft Decision was a placeholder and that Essential Energy was used as a benchmark because of the lack of information provided by Ergon. The presentation was more akin to push polling than an accurate presentation of the situation and the reasons for the AER Draft Decision. The information provided to the VoC meant that they received only limited information to be able to express an informed view of the Draft Decision. We think the outcome was inevitable given the biased way the topic was presented.

[29] https://www.aer.gov.au/documents/aer-operational-performance-data-2024-electricity-distribution-networks

The likelihood of a further ex post review for 2023-28 seems high

In our submission on the Regulatory Proposal we commented on the way the incentive regulatory framework does not seem to work for Ergon in contrast to privately owned networks. We suggested that the drive to meet the AER capex allowance is perhaps weaker in Ergon because the CESS does not act as the same efficiency incentive as it does in privately owned networks. The impact of overspend is substantially mitigated for residential and small business customers because of the Uniform Tariff Policy. However large users bear the impact.

Figure 6 reproduced above shows the forecast capex for the last two years of the current period is significantly above the AER allowance. If the Final Decision does not result in a capex allowance close to the Ergon Revised Proposal, we would not be surprised to see expenditure in the first three years of the 2025-30 reset period being above allowance resulting in another ex-post review for 2023-28, unless, of course, the new Queensland Government imposes some constraints on over allowance spending.

Ergon will have to deliver a significant turnaround in both project delivery performance and volume of works were the Final Decision to still be substantially lower than the Revised Proposal. The experience with the digital transformation process in 2020-25 – where the shareholder decided to bear the $121.3m cost overrun – is an important example of this. This project was supposed to make a major contribution to improved productivity and cost reduction. We have seen no evidence that it has made any positive contribution to productivity.

While Ergon has accepted the Draft Decision of $208.7m non-network ICT (a reduction of $50.1m on its Regulatory Proposal), past experience, discussed in our earlier submission, suggests there is a lot of improvement to be achieved to meet the allowance. We made a number of suggestions in our earlier submission on how to improve ICT governance.

Ergon has built an internal and contractor workforce to deliver a volume of works that is substantially above what the AER regards as prudent and efficient. Even if volumes are lower in 2025-30, given labour costs are largely fixed (the new EBA only allows adjustment in field employees by natural attrition) unit costs could well increase as these fixed costs are spread over fewer assets being replaced and the allowance exceeded. It remains to be seen whether the Government's suspension of the Best Practice Industrial Conditions has an impact on lowering unit rates[30].

Recommend that the AER provide greater clarity on the role of capex benchmarking in their decisions.

The capital expenditure factors for DNSPs set out in clause 6.5.7 (e) of the rules requires the AER to have regard to the following[31]…

> "(4) the most recent annual benchmarking report that has been published under rule 6.27 and the benchmark capital expenditure that would be incurred by an efficient Distribution Network Service Provider over the relevant control period"

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[30] https://www.housing.qld.gov.au/news-publications/strategies-plans/buy-qld/queensland-procurement-strategy-2023/suspending-bpics
[31] https://www.aemc.gov.au/sites/default/files/content/NER-v94-Chapter-06.PDF

As we noted in our submission on the Regulatory Proposal, Ergon's productivity has been in continual decline since 2013[32]. While it is clear how benchmarking impacts on opex where econometric opex efficiency scores can be directly applied to base year opex, it is less clear how it impacts on capex.

The difficulty in applying the AER's capex productivity results is that the AER measures the productivity of capital stock (transformers, power lines) not capex expenditure. This means the benchmarking results cannot be used deterministically in capex assessments in regulatory determinations. The long-lived nature of a network's capital stock, as well as the AER's use of capital volume (transformer MVA, circuit MVAkm), as opposed to a capex dollar value rolled into the Regulatory Asset Base, limits using the capital productivity results in capex assessments beyond providing context for movements in network or industry productivity. Finally, given the asset lives, capital stays in the RAB a long time and it is difficult to turn around poor capex productivity in the short term.

Nevertheless, that only emphasises the need for close scrutiny of proposed capex to ensure it does not contribute to a continuation of the long-term capex productivity decline.

The AER does use the capex productivity as one of many information sources when is assess forecast capex. We recommend that how it is used be more explicitly explained in the final decision.

[32] https://www.aer.gov.au/system/files/2023-11/AER%20%E2%80%93%20Fact%20Sheet%20for%20the%202023%20Annual%20Benchmarking%20Report%20%E2%80%93%20Electricity%20distribution%20network%20service%20providers%20%E2%80%93%20November%202023_1.pdf

6. Operating Expenditure

AER's Draft Decision

The AER accepted the Regulatory Proposal expenditure of $2,379.1m on the basis that the AER alternative estimate was higher. Both Ergon and the AER numbers included a base year efficiency adjustment to reflect the opex benchmarking results showing Ergon to be materially inefficient in its opex expenditure. The approved expenditure is an increase relative to the 2020-25 forecast mainly driven by the trend forecast and the network visibility step change. It is also slightly higher than Ergon Energy's actual and forecast opex over the current regulatory control period.

The AER assessment was based on forecast costs in the 2023-24 base year and will be updated in the Final Decision based on actual costs in the base year. The AER noted that during discussions on the initial proposal Ergon had indicated actual costs in 2023-34 were likely to significantly exceed the estimate it provided in its initial proposal.

What is Ergon proposing?

Based on actual costs in the 2023-24 base year, the revised opex forecast is $2,562.9m for 2025-30 – an increase of 7.7% over the initial proposal and draft decision. The major changes are:

- a significant increase in base year opex – $263.8m or 10.6%
- a larger efficiency adjustment ie the higher actual costs indicated even greater level of inefficiency with the adjustment (after considering extreme weather events and provisions) to be 7.9% reduction vs 2.3% in the initial proposal
- larger transition costs given that larger efficiency adjustment – the transition cost recognise that it is not possible to immediately move to a lower cost base

$2024-25m	Regulatory Proposal	AER Alternative estimate	Revised Regulatory Proposal
Base opex	2,481.0	2,476.3	2,744.8
Efficiency adjustments	-55.3	-45.2	-206.5
Transition costs	$0	18.3	83.1
Total	2,379.1	2,401.8	2,562.9

RRG Comments

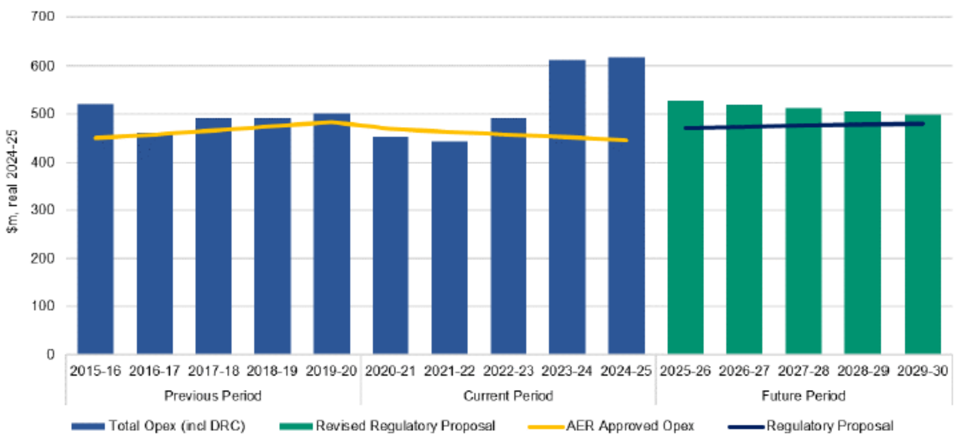
There are many complex interrelated issues with Ergon opex driven by its poor performance in recent years against the AER's 'not materially inefficient' benchmark. Some we have sought to pursue in engagement eg the labour cost rises in the recently negotiated EBA and productivity offsets. Some were new to us eg proposed non-application of EBSS and the issue of the prudent and efficient level of transition costs. Ergon informed the RRG of its intentions in relation to the EBSS and transition costs prior to submitting its Revised Proposal, but did not engage the RRG in any detail on these matters. Given the short period to prepare this submission we have only had time to explore these matters at a relatively high level.

In its Initial Proposal, Ergon claimed that its proposal met the opex objectives, criteria and factor in the NER[33] and the AER agreed given the proposal was accepted. We look forward to seeing whether the revised proposal continues to meet that standard.

We expect that Ergon will be challenged to keep within its proposed opex allowance

The forecast over allowance expenditure in the current period in the initial proposal led the RRG to be very concerned about the affordability impacts. The Revised Proposal shows this overspend has increased significantly[34].

Figure 9: Opex between 2015 to 2030 ($m, real 2024-25)



While the RRG initially welcomed Ergon's proposed 1% annual productivity target, double the required 0.5%, to address affordability concerns, we have not been presented with any information that would give us confidence that Ergon is able to achieve this productivity target and hence its overall opex forecast.

This view is supported by our engagement with Ergon on labour costs.

The RRG had extensive interactions with Ergon over many months seeking information on the impact on labour costs and productivity of the previous three-year EBA that ended in July 2024 and the new four-year EBA that replaced it that applies from 9th July 2024 to 29th February 2028[35]. The ETU's view of the new EBA is[36]:

> "This campaign has delivered industry standard wages, with increases of up to 40% over four years, but just as importantly, it delivered industry leading conditions such as income protection, 14.75% superannuation, 10 days mental health leave,10 days reproductive leave, improved parental leave, ability to accrue unused reproductive leave, apprentice wages set at 60% for 1st year, 70% 2nd year, 80% 3rd year of the trade rate, overtime at double time, and the list goes on."

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[33] https://www.aer.gov.au/system/files/2024-02/Energex%20-%206.01%20-%20Addressing%20opex%20objectives%2C%20criteria%20and%20factors%20-%20January%202024.pdf
[34] See https://www.aer.gov.au/documents/ergon-2025-30-revised-regulatory-proposal-november-2024, p. 84
[35] https://www.energyq.com.au/__data/assets/pdf_file/0018/1092501/Energy-Queensland-Union-Collective-Agreement-2024.pdf
[36] https://www.etunational.asn.au/2024/04/30/prior-planning-strategic-engagement-and-steely-resolve-provides-premium-outcomes-at-energy-queensland-and-powerlink/

We asked Ergon the following questions on the dates indicated and received the following answers on the dates indicated:

Question	Response
Previous three-year EBA (19th July 2024) What was the effective average (across all job classifications) % nominal increase in annual wage/salary for each year of the current EBA. This would include pay increases, allowances and the costs of changes in work practices New four-year EBA (19th July 2024) What is the effective average (across all job classifications) % nominal increase in annual wage/salary for each year of the new EBA. This would include pay increases, allowances and the costs of changes in work practices eg increase in employer superannuation, 10 days mental health leave, higher apprentice wages etc etc Combined EBAs (27th August 2024) Is it correct to interpret information provided on the increases under each EBA to mean the average nominal increase over the 7 years from the start of the previous EBA (February 2022) to the end of the new EBA (28/2/2028) is 50%?	New four-year EBA (8th August 2024) The cumulative increase inclusive of all conditions from the new EQL EBA against the baseline assumed for the EBA costings is approximately 25% across the four-year EBA term. The nominal % increase for each year of the new EBA is: Year 1 – 14%; year 2 – 18%; year 3 – 22%; year 4 – 25%. Combined EBAs (10th September 2024) The compounded increase across the previous three-year EBA and the new for year EBA is approximately 50%.
Previous three-year EBA (19th July 2024) What productivity commitments, measured in impact on EQL costs, were made by the unions in that EBA? What productivity improvements have been achieved (measured by cost impact on EQ) and how have these improvements been measured? How have those productivity improvements been reflected in the proposed opex and capex for 2025-30 proposal? New four-year EBA (19th July 2024) What productivity commitments have been made by the unions in the EBA?	Previous three-year EBA (7th August 2024) EQL is still working through quantifying the productivity and excellence program to quantify this as part of our business planning process Both EBAs The business is not in a position to answer the remaining the questions regarding the EBA. (26th September 2024)

What is the % reduction in EQL costs that will result from the successful achievement of these productivity improvements? What % of the 1% annual opex productivity for 2025-30 will rely on productivity improvements under the new EBA? Productivity commitments in 2025-30 proposal (27th August 2024) Given EQ is yet to measure the productivity benefits from the new EBA, what confidence should consumers have that EQL has a pathway to actually achieve what EQL represents as a key part of its affordability claims – higher opex and capitalised overheads productivity?	

The labour costs used to determine the opex proposal are significantly below the actual costs under the EBA[37]:

Table 24: Forecast real price growth 2025-30

Per cent	2025-26	2026-27	2027-28	2028-29	2029-30
Real labour forecast – Oxford Economics	0.64%	1.05%	1.05%	1.28%	1.38%
Real labour forecast – Deloitte Access Economics	0.61%	0.79%	0.77%	0.88%	1.09%
Average of real labour forecasts	0.63%	0.92%	0.91%	1.08%	1.23%
Superannuation guarantee	0.50%	0.00%	0.00%	0.00%	0.00%
Average plus superannuation guarantee	1.13%	0.92%	0.91%	1.08%	1.23%

Ergon provides a document in its Revised Proposal[38] saying that it intends to achieve the target with a productivity program with three core elements - people, processes and systems/data. Details are '…in development and work is ongoing'. Some details are provided but have been redacted in the public document and the RRG has not had access to the full document. The RRG had a very general and high-level presentation from Ergon on possible initiatives prior to submission of the Revised Proposal and was looking forward to seeing more detail. The RRG do not consider that the information available provides adequate detail of the proposed productivity program to give any assurance that the opex productivity targets can be achieved.

Transition costs

Ergon is proposing $83.1m in 'transition costs' in 2025-30 to cover the costs of it moving from its current 'materially inefficient' opex to a 'not materially inefficient' opex level.

[37] See https://www.aer.gov.au/documents/ergon-2025-30-revised-regulatory-proposal-november-2024, p.90
[38] Attachment 6.05 - Productivity initiatives https://www.aer.gov.au/system/files/2024-12/Ergon%20-%206.05%20-%20Productivity%20initiatives%20-%202%20December%202024%20-%20Public.pdf

The concept of transition costs came from the Australian Competition Tribunal's decision on the Ausgrid's merits review appeal to the AER's decision on its 2014-19 revenue reset[39]. The AER had reduced the DNSPS opex allowance to reflect what the annual opex benchmarking had indicated was the efficient level. The DNSPs successfully challenged the AER's decision in the Tribunal and the AER was unsuccessful in this matter on appeal to the Federal Court.

In its Final Decision in January 2019 on the Ausgrid 2014-29 determination, the AER remade the opex forecast to consist of two components[40]:

- an estimate of a prudent and efficient level of recurrent (or underlying) opex that Ausgrid would need for the safe and reliable provision of electricity services, and
- an estimate of any non-recurrent costs (including transition costs) above this level of underlying opex that can be considered efficient and prudent costs consistent with the opex criteria"

The AER used the term 'transition costs'[41]:

> "… to describe restructuring costs incurred in transitioning from a higher level of opex to a lower level of opex."

The intention was that a network would be required to 'spend money in the short term to save money sustainably in the long term' to reach the benchmark 'not materially inefficient' opex level and then maintain that in the long term.

The issue of how to calculate transitions costs was the subject of detailed debate in the ACT and Federal Count actions. There were specific circumstances applying to the then recently privatised Ausgrid eg the sale legislation prevented them from changing the existing EBA which prohibited forced redundancies before 21st June 2020, which would influence their ability to reduce costs quickly. Following these decisions the AER had to assess transition costs[42]:

> "The approach we have applied in considering transition costs and in remaking this final decision has been influenced by the circumstances that we face now. Ultimately, whether we include transition costs remains a matter for us to determine against the opex criteria, taking into account the RPP and in a way that forms part of an overall decision that we are satisfied will, or is likely to, contribute to the achievement of the NEO to the greatest degree."

So the AER had to assess what costs were legitimately 'transition' and then whether the level of those costs proposed by Ausgrid was 'prudent and efficient'. The advantage the AER had was that the legal appeal process meant that it was making the 2014-19 decision in January 2019. Ausgrid's forecast opex in 2018-19 was consistent with the opex allowance made in the AER's 2015 final decision. The AER decided that:

> "…we consider Ausgrid's transition costs are of a kind, in the circumstances, that can be characterised as costs required by a prudent operator to achieve the opex objectives; or alternatively, as cost inputs that would be reasonably expected to achieve the opex objectives."

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[39] Merits review appeals were abolished in 2017.
[40] See p. 20 https://www.aer.gov.au/system/files/AER%20-%20Final%20decision%20Ausgrid%202014-19%20distribution%20determination%20-%20January%202019.pdf
[41] Ibid p.23 footnote 61
[42] Ibid p. 24

We understand that the AER assumes a linear glidepath over the 5-year regulatory control period for a network to reach the not materially inefficient level of opex in the final year ie 20% improvement in year 1; 40% improvement in year 2 and so on. This is irrespective of the size of the efficiency adjustment.

The AER approach assumes that the network has a strong incentive and ability to reach and continue to strive to exceed the not materially inefficient opex 0.75 benchmark level. We are not convinced this is the case for Ergon especially when EBA labour costs are going to be significantly higher than the assumptions the opex allowance is built on. In our submission on the initial proposal[43] we argued that comparative opex spend data across a range of networks suggested Ergon is less incentivised that privately owned networks to reduce opex below the AER allowance. Residential and small business customers do not see the impact of an opex overrun because of the Uniform Tariff Policy, but larger customers do.

In summary, we are not convinced that the approach the AER has taken to transition costs in the past will be applicable to Ergon in 2025-30. The RRG are concerned that the circumstances facing Ergon during the next regulatory period will mitigate against their ability to achieve the necessary productivity improvements. We consider that more evidence of transition plans and costs is required in order to determine whether the proposed transition costs are appropriate, prudent and efficient, and that the allocation of transition costs must be linked to demonstrable outcomes.

Are 2023-34 revealed costs underestimating the base for 2025-30?

In the Revised Proposal, Ergon argues (p.87):

> "For the 2025-30 regulatory control period, we have selected a base year of 2023-24. We chose 2023-24 as the base year because it continues the well-accepted regulatory practice of using the most recent year for which audited data is available by the time of the final distribution determination.
>
> We are unable to use 2022-23 as a base year as it does not provide a realistic expectation of ongoing costs. The 2022-23 year does not include the full increase in external contractor costs, general inflationary increases and internal labour costs which we have experienced recently. We anticipate our on-going annual opex to provide SCS services over the 2025-30 regulatory control period to be higher than this level."

As we saw above in Table 9 from the Ergon Revised Proposal, actual 2023-24 and forecast 2024-25 expenditures are significantly above costs for the previous 8 years.

The 2023-24 costs were higher from cyclone costs that are the subject of a recent cost pass through application[44] and these are removed in determining the base year expenditure. As a result of using actual expenditure in 2023-24 rather than forecast, as was used in the initial proposal and Draft Decision, the revised opex forecast is 7.7% higher.

Our comment is around the forecast 2024-25 costs which are only slightly higher than the 2023-24 costs that include non-recurrent eg cyclone costs. Excluding these non-recurrent costs in 2023-24

[43] pp. 62-3 https://www.aer.gov.au/system/files/2024-06/EQL%20Reset%20Reference%20Group%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex%20%26%20Ergon%20-%20May%202024.pdf

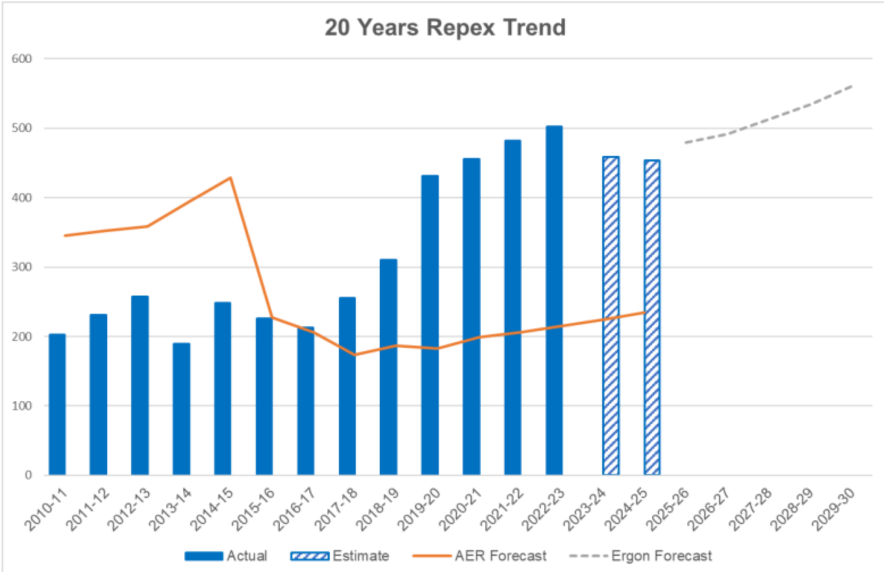
[44] https://www.aer.gov.au/news/articles/communications/have-your-say-energy-queenslands-cost-pass-through-applications

would mean a more significant increase in 2024-25, perhaps driven by it being year 1 of the new EBA. The AER uses revealed actual costs in its assessment so cannot use forecast 2024-25. While the revised proposal has a much higher base year based on actual 2023-24 costs, we wonder how representative it is of costs in 2025-30 that will include the step change in labour costs under the new EBA.

The impact of the large overspend in repex since 2017-18 on forecast opex needs more explanation

The Figure shows the large repex overspend since 2017-18 with Ergon's initial proposal forecast spend showing the continuing large increase[45].

Figure A.2 Ergon Energy historical repex trend ($ million, $2024–25)



While the revised repex proposal ($2,449.8m) is lower than the initial proposal ($2,718.8m) the trend is similar. Yet Ergon gives no explanation on why this capex spend does not have any impact on lowering opex in 2025-30. While Ergon's regulatory obligation to inspect poles (and by extension overhead assets) every 5 years means a lower asset age may not impact much on opex, it would have been helpful to have a fuller explanation of the impact of very high capex in other categories on future opex.

[45] See p. 23 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%205%20-%20Capital%20expenditure%20-%20Ergon%20Energy%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

7. Incentive Schemes

Efficiency Benefit Sharing Scheme (EBSS)

AER's Draft Decision

In the Draft Decision, the AER accepted application of the EBSS for 2025-30, and recalculated EBSS negative carryovers to $196.8 million.

What is Ergon proposing?

A significant change in the Revised Proposal is that Ergon is proposing suspension of the EBSS – it had previously accepted its application. It now proposes[46]:

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

This is driven by the significant increase in actual 2023-24 opex base year compared with the forecast 2023-24 opex used in the initial proposal and the Draft Decision. Given the AER is relying on adjusted costs to account for the benchmark efficiency adjustment rather than actual revealed costs to set the base year, Ergon argues that this results in a distortion of how the EBSS works with the business potentially being penalised for more than 100% of the efficiency losses.

RRG comments

Some general comments on incentive schemes and Ergon expenditure

The AER's recent review of incentive schemes said[47]:

> "Incentive schemes form an important part of our approach to regulating national monopoly electricity and gas networks in Australia. We seek to incentivise network service providers to run an efficient business so that customers pay no more than necessary for services that they value the most. The framework is designed to mimic the outcomes from effectively competitive markets."

The review went on to note that the review would cover both CESS and EBSS[48]:

> "The EBSS has been in operation since 2008 and was previously reviewed in 2013, when the CESS was created. We consider that the EBSS is broadly fit-for-purpose and plays an important role in ensuring that actual operating expenditure can be used in setting forecasts in subsequent regulatory periods. Nevertheless, given that capital expenditure and operating expenditure are to some extent substitutable, it is appropriate to also review the incentives for efficient operating expenditure and the role of the EBSS."

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[46] See https://www.aer.gov.au/documents/ergon-2025-30-revised-regulatory-proposal-november-2024, p. 96
[47] See p. 7 https://www.aer.gov.au/system/files/AER%20-%20Review%20of%20expenditure%20incentive%20schemes%20-%20discussion%20paper%20-%20%20December%202021.pdf
[48] Ibid p.9

Given the substitutability of opex and capex, it is surprising that Ergon provides no explanation as to why they believe that the suspension of EBSS will not have any adverse impact on the efficient choice between capex and opex.

The proposed approach to EBSS needs more explanation

The decision to seek the suspension of EBSS is significant. The RRG was informed of this change prior to submission of the Revised Proposal but in the time available were not able to develop a full understanding of the potential impact on customers.

If we correctly understand Ergon's proposal, Ergon will bear all costs above the AER allowance in 2020-25 and all costs above the AER allowance in 2025-30. But then why is Ergon asking for transition costs? Where is the incentive to improve more than just being on the 0.75 opex benchmark?

We look forward to the AER evaluating the complex interactions presented by Ergon in its opex proposal to ensure it is consistent with the opex criteria and that customers are not bearing additional costs that are not prudent and efficient.

Service Target Performance Incentive Scheme (STPIS) – telephone answering component

AER's Draft Decision

In the absence of a Customer Service Incentive Scheme (CSIS), the Draft Decision did not accept the removal of the customer service (telephone answering) component of the STPIS[49]. The AER highlighted the importance of phone communications in emergency events, but acknowledged the strong customer support for not adopting incentive schemes for customer service. The AER indicated that this decision was 'finely balanced'.

What is Ergon proposing?

Ergon consulted with its VOC Panel on the Draft Decision, and VOC members indicated that they could 'live with' this outcome. Ergon has therefore accepted the Draft Decision to retain the telephone answering component of STPIS.

RRG Comments

In our Technical Report[50] on Ergon's initial proposal, we wrote:

> "RRG considers that in the absence of both customer service incentive schemes it is essential that a replacement reporting framework including governance arrangements, together with relevant performance metrics and targets is developed and implemented in collaboration with customers. Engagement on this framework needs to be broader than the residential customer cohort that were engaged through the VoC process. Energex and Ergon state that they: "commit to work with our customers and stakeholders to develop agreed customer

[49] See https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2010%20-%20Service%20target%20performance%20incentive%20scheme%20-%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[50] https://www.aer.gov.au/documents/eql-reset-reference-group-submission-2025-30-electricity-determination-energex-ergon-may-2024

> service performance reporting throughout the period". The RRG believes that this framework must be developed in time for it to be included as part of the Revised Regulatory Proposal to give customers and the AER confidence that a strong focus on good customer service will be maintained in the future."

Despite this commitment being given by Energex and Ergon prior to submission of the initial proposal in January 2024, the RRG are extremely disappointed that the proposed reporting framework and governance arrangements have not yet been developed and agreed with customers and stakeholders. Preliminary discussions on possible customer service metrics have taken place, however to date this has not included specific performance measures, targets or governance arrangements. Given the amount of work and consultation yet to be undertaken, it seems highly unlikely that the target date for implementation of 1 July 2025 will be met. This is indeed a missed opportunity for the business to demonstrate that it is listening and responding to customer voices.

Future Customer Service Incentive Scheme (CSIS)

Energex and Ergon have suggested that they intend to start their consultation in 2025 for the 2030-35 regulatory proposal. The RRG recommend that Energex and Ergon should dedicate resources and attention to devising future focused and meaningful customer service metrics, potentially with a view to including a CSIS in the next regulatory proposal. This the RRG believes will be critical given the rapid change in consumer energy resources and a commitment to long and deep engagement prior to the 2030 proposal. The RRG believes there is a real opportunity for Energy Queensland to develop forward-facing consumer-centric customer service metrics that meet a future network dominated by consumer energy resources.

8. Network Tariffs and Pricing

This is a combined Energex and Ergon response given there is a combined Energex and Ergon Draft Decision on the TSS – Attachment 19[51].

AER's Draft Decision

The AER accepted parts of the initial 2025-30 TSS:

- tariff structures for residential and small business customers, not including two-way tariffs or the proposed new optional flexible load control tariffs
- tariff structures for large low voltage and high voltage business customers, not including two-way tariffs
- tariff assignment for high voltage business customers
- continuation of existing primary and secondary load control tariffs
- tariff streamlining and withdrawal of obsolete or closed tariffs, and
- Energex and Ergon's approach to setting and assigning customers to ICC tariffs.

and did not approve other parts:

- tariff assignment for residential and small business customers
- proposed two-way tariffs
- tariff assignment for large low voltage business customers
- proposed flexible load control tariffs, and
- grid-scale storage tariffs.

The AER noted that[52]:

> "While our draft decision does not accept Energex's tariff proposal, we consider Energex is making progress on network tariff reform, responding to feedback and supporting the energy transition. This includes introducing solar soak windows and streamlining its suite of tariffs. Two key elements of our draft decision are to require the default tariff assignments for small customers to have a time-of-use structure rather than demand-based structure, and to offer a time-of-use tariff for business customers with peaky demand but low consumption. We consider these changes better comply with the NER pricing principles (for the default tariffs) and better contribute to the achievement of the NEO (for the time-of-use business tariff), particularly the achievement of jurisdictional targets for emissions reduction."

The AER's approach to reviewing the TSS is[53]:

[51] https://www.aer.gov.au/documents/aer-draft-decision-attachment-19-tariff-structure-statement-ergon-energy-and-energex-2025-30-distribution-revenue-proposal-september-2024
[52] See p. vii https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf
[53] Ibid p.21

> "Principally, we are making a determination on whether the proposed tariff structure statement complies with the pricing principles of the NER, and any other applicable rules. After that, our decision takes the NEO into account and considers whether the tariff structure statement will or is likely to contribute to achievement of the NEO. For tariff structure statements, we consider the NEO elements of price and achievement of jurisdictional emissions reduction targets to be most relevant."

The AER's Draft Decision on the TSS noted[54]:

> "We observe that Ergon Energy and Energex have generally engaged well with stakeholders in developing their 2025–30 tariff structure statements."

Two significant influences on the AER's decision to reject key components were:

(i) How the decision will or is likely to contribute to the achievement of the NEO

TSS decisions need to consider two elements - emissions reduction and efficient pricing. While TOU demand tariffs meet the pricing element, the AER decided that Energex and Ergon should offer additional time-of-use only tariffs to contribute to the achievement of the emissions part of the NEO. In particular, a consistent NEM-wide structure for network tariff charges for EV charge point operators would further contribute to achievement of Queensland's emissions reduction targets. This consistency has already been achieved in Victoria, NSW, Tasmania and the ACT where EV charge point operators can access time-of-use tariffs while consumption is less than 160 MWh. Only South Australia and Queensland do not have these tariffs.

The AER's argument is that consistent pricing across the NEM[55]:

> "…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. Together, these outcomes could contribute to outcomes sought under the Australian Government's National Electric Vehicle Strategy, specifically, to "make it easy to charge EVs across Australia" and "reduce road transport emissions" and Queensland's Zero Emission Vehicle Strategy which is one of its emissions targets under the NEO."

While this means the tariff is available to all customers irrespective of them contributing to emissions reduction, the AER[56]:

> "… consider it preferable to retain tariffs that are technology and industry neutral."

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[54] See p. 3 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[55] See p. 40 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[56] ibid

(ii) Maintaining customer support for the transition

The AER is very aware of the recent publicity around bill shock for residential and small business customers who get a smart meter and then, without their knowledge, or with insufficient education on the impact, end up with a TOU demand tariff. This results in a large and unexpected increase in their bill compared to their previous flat tariff. The AER notes[57]:

> "The fundamental change we require of Energex and Ergon is to shift default assignment for residential and small business customers with smart meters from time-of-use demand tariffs to time-of-use tariffs. While demand tariffs remain a viable cost reflective tariff preferred by some customers and retailers, we consider the potential impact on small customers of default demand tariffs could be unacceptably high for the 2025–30 period, as it would be the first exposure of many to cost reflective tariffs and customers typically find demand tariffs more difficult to understand and therefore to respond to, relative to time-of-use tariffs. We considered this in the context of widespread cost of living pressures occurring at the same time as the anticipated accelerated smart meter rollout which would see more customers having smart meters installed (and being assigned to cost reflective network tariffs)."

The AER's view is that there is a risk of customer social licence for the transition and realising the benefits of the accelerated rollout of smart meters, being reduced by bill shock from consumers being put on TOU demand tariffs. The AER considers that while reducing the pace of movement towards cost reflective pricing may be considered a backward step from its previous views (as recently as May 2024 in the final Ausgrid TSS decision), it is an appropriate response to minimise this risk in the longer term and better achieve the NEO.

<u>Energex and Ergon's response</u>

Energex and Ergon's revised TSS accepts many of the AER Draft Decision comments. Exceptions relate to where the Draft Decision was not consistent with customer feedback or operational implementation capacity. These are:

Issue in Draft Decision	Change requested by the AER	Energex and Ergon response
Tariff assignment for residential and small business	Reassign existing customers from current default transitional demand tariffs to TOU energy tariffs	New and upgraded customers will be assigned TOU energy tariffs. TOU demand and energy tariffs will remain as optional tariffs. TOU energy tariffs will not be assigned retrospectively to customers on the current default tariff; they will have the option to access TOU energy tariffs
Two-way tariffs	Include an explicit export tariff transition strategy and convert export charges and basic export	Delay the introduction of two-way tariffs until 2030-35 regulatory control period

[57] See pp 21-2 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

	level from kW to kWh; include network bill analysis for small businesses and large customers to face two-way tariffs	
Grid-scale storage tariffs	Provide further details on these tariffs, including more detail on the critical peak pricing mechanism	The initial TSS provided for two tariffs – dynamic price and dynamic flex; Two dynamic price tariffs will be offered in a trial from 1 July 2025 – one incorporating critical peak period import and export charge components and a complementary one with critical peak period import and export reward components The dynamic flex tariff will be optional from 1 July 2025

We also note the late TSS amendment[58] where Energex and Ergon have modified their revised TSS to accept the Draft Decision where all residential and small business customers assigned to the TOU Demand and Energy tariffs as at 1 July 2025 would transition to the new default TOU Energy tariffs over a period of 6 months from 1 July 2025. Customers assigned to the optional demand tariffs as at 30 June 2025 would also be reassigned to the TOU Energy tariffs on 1 July 2025.

RRG comments

We begin by making some comments on the consumer engagement post submission of the initial proposal in January 2024 and then discuss the way the AER has sought to explain its Draft Decision. Our overall recommendation is that the AER provide more information in the Final Decision on these TSS decisions and specific guidance for networks on what the AER expects from TSS engagement in the future.

Consumer engagement was broad and deep to some customer cohorts but not to others

The RRG continued its deep engagement with Energex and Ergon leading up to the submission of the revised proposal. This was both on a standalone RRG basis as well as the RRG being members of the reformed and expanded Network Pricing Working Group established as a standing Working Group under the Terms of Reference of the Energy Queensland Customer & Community Council. While this engagement was a considerable improvement on that undertaken as part of the 2020-25 reset, the 2023 focus on residential and small business continued. Large customers were invited to meet with Energex and Ergon 1:1 to discuss their indicative bills. The RRG were not involved in these discussions. We understand that Energex and Ergon were unable to provide much information on likely tariffs beyond the last year of the current period (2024-25) and the first year of the next period (2025-26).

There seems to be a tension between the AER's aim of increased cost reflectivity and network utilisation and addressing the public debate on the impact of TOU demand tariffs

[58] https://www.aer.gov.au/system/files/2024-12/TSS%20Amendment%20-%20Ergon%20and%20Energex and Ergon%20-%2020%20Dec%202024.pdf

The AER's Draft Decision is a retreat from their approach – seen as recently in the final decision on the Ausgrid TSS in April 2024 – of hastening the pace of moving to cost reflective tariffs. Indeed, a key reason the AEMC has supported a faster rollout of smart meters in its recent Final Determination on the accelerated smart meter rollout[59] has been to improve the efficiency of the transition through more cost reflective pricing and this is referred to by the AER[60].

As the Draft Decision notes[61]:

"A tariff structure statement informs customer choices by:

- providing clear price signals—network tariffs which reflect what it costs to use electricity at different times can allow customers (or their retailer) to make informed decisions to better manage their bills
- transitioning tariffs to greater cost reflectivity—with the requirement that distributors explicitly consider the impacts on retail customers, by engaging with customers, customer representatives and retailers in developing network tariff proposals
- managing future expectations—providing guidance for retailers, customers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for a set period of time."

In the engagement process for the current 2020-25 regulatory period, Energex and Ergon were criticised by many stakeholders and the AER for its past slow transition to cost reflective tariffs. It resulted in the networks proposing and the AER accepting transitional demand tariffs as the default tariffs for small customers from 1 July 2021. In its final decision on the 2020-25 reset, the AER said[62]:

> "We note that some stakeholders oppose demand tariffs on the grounds that this particular tariff structure is too difficult for customers to understand and respond to. These stakeholders also raise serious concerns about the economic efficiency properties of demand charges given that they are based on the individual customer's maximum demand, which may not necessarily coincide with the timing of localised critical network congestion.
>
> As stated in our draft decision, we consider that demand tariffs can be designed to be as cost reflective as time of use tariffs. This is not to suggest that these tariff structures are perfectly cost reflective. Nevertheless, they represent a reasonable step towards cost reflectivity for many distributors, particularly where time of use energy tariffs are also offered on an opt-in basis.

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59 https://www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment

60 See p. 2 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

61 See p. 20 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

62 See p. 20 https://www.aer.gov.au/system/files/Final%20decision%20-%20Energex and Ergon%20distribution%20determination%202020-25%20-%20Attachment%2018%20-%20Tariff%20structure%20statement%20-%20June%202020_0.pdf

> We also pointed out that in the early stages of tariff reform distributors need to be cognisant when designing their cost reflective tariffs that many of their customers have made significant investment in energy appliances in response to the incentives under existing consumption tariffs. We are satisfied that the transitional demand tariff is appropriate for the Queensland distributors given that the customer impact concerns have been addressed by transitioning the demand charge to LRMC over a reasonable timeframe. It should also be noted that the introduction of opt-in time of use energy tariffs for residential and small business customers on 1 July 2020 is likely to ensure that customers that find demand charges too complex to understand and respond to will be given a choice of cost reflective tariffs. The Queensland distributor's commitment to tariff education under their Tariff Education and Dynamic Incentive (TEDI) proposal will also support customers making informed tariff choices".

So, Energex and Ergon moved to implement TOU demand tariffs in the current period and the RRG was very pleased to see the Energex and Ergon commitment to hurry the pace of the move to more cost reflective tariffs for 2025-30.

Then we had the AER Chair's speech to the ENA Regulation Seminar in Brisbane on 31st July. The AER published a Q&A with the Chair where she said[63]:

> "I also showed data on the significant proposed capital expenditure increases for many distribution networks which are on top of the billions to be spent on projects that are critical to unlocking new sources of renewable energy to replace our aging and increasingly unreliable coal plants.
>
> I described this as a "wall of capex" coming at consumers that could more than offset the lower costs of wholesale energy as we make the switch to renewables unless we find ways to be more efficient.
>
> These network capex costs will be baked in not just for today but for many years to come. So it is vital that before we build more network, we use more network.
>
> To support this, I wanted to make it clear that the AER is open-minded as to how the regulatory framework can be utilised to help deliver this in the long-term interests of consumers."

We would have expected that this meant a focus on supporting a faster pace of implementing cost reflective pricing to support more efficient network utilisation before the AER would approve new capex. However, since that speech there has been considerable press coverage of bill shock from TOU demand tariffs and it has become a popular topic for the press to assign blame – whether to retailers or networks or the governments. The Energex and Ergon TSS Explanatory Statement refers to this political debate[64]:

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[63] https://www.aer.gov.au/news/articles/news-releases/qa-aer

[64] See p. 15 https://www.aer.gov.au/system/files/2024-12/Energex and Ergon%20-%20Tariff%20Structure%20Statement%20-%20Explanatory%20Statement%20-%20November%202024%20-%20public.pdf

- “lack of transparency and heightened confusion for households regarding transfer to tariffs which have different structures to what customers are used to, often without warning or communication, and
- claims that customers face higher bills due to their inability to shift energy consumption to cheaper off-peak periods.”

Energex and Ergon note that these national debates ignore the situation in Queensland eg consumers are not automatically placed on a demand TOU tariff when they receive a smart meter. There is no automatic assignment of customers to network tariff structures when a smart meter is installed. It is the retailer’s decision on whether to apply a particular network tariff. Around 36% of Energex and Ergon customers have a smart meter but only around 35% of those are on a TOU or flex tariff ie <15% of Energex and Ergon customers are on a cost reflective tariff.

At a practical level we find it difficult to understand why the AER wants Ergon Network to transition hundreds of thousands of their customers back to default TOU energy charges when Ergon Retail has an effective monopoly of retail customers in the Ergon network and 98% of Ergon Retail’s customers with a smart meter are on a flat retail tariff. It would have been helpful if the AER provided a cost benefit and bill impact analysis of their decision.

The AER seems to be saying that while the Draft Decision might be at odds with their long-term approach to use pricing to get more efficient asset utilisation, we need to take a few temporary (?) backward steps away from TOU demand pricing to ensure we retain customer social licence to enable achievement of the longer-term efficiency and emissions objectives.

We recommend that the AER provides further explanation on why its approach to mitigating bill shock risk is required in addition to existing approaches

We agree with the AER that applying demand tariffs without any consultation with consumers can result in falling support for the transition. Our question is – what should be the role of the various supply chain players and regulators in addressing this risk? If the AER considers that it should use an Ergon and Energex’s TSS to mitigate that risk then it would be very helpful to provide further explanation in the Final Decision on why that approach is an efficient and equitable addition to other existing approaches designed to contribute to the same objective.

The AEMC has just released its final determination on the accelerating smart meter deployment rule change[65]. The decision focussed on the need to have strong customer safeguards to ensure the deployment will be a success and realised its benefits. Safeguards include a two-year explicit informed consent period where retailers must obtain the explicit consent from a customer to change their retail tariff structure after a smart meter is installed. After that two-year period the retailer must still provide 30 days’ notice and a historical bill estimate to the customer. This safeguard is a transitional rule and will apply from 1 December 2025 until 31 May 2031. Further, retailers must also provide smart meter customers with a flat tariff option in those jurisdictions that have adopted the measure through local instruments.

Governments make decisions to address customer concerns on electricity prices. The Queensland Government has done that in two ways – a $1,000 rebate in 2024-25 (in addition to the Australian Government’s $300 rebate) and, in September, by adopting the AEMC decision directing retailers to

[65] https://www.aemc.gov.au/rule-changes/accelerating-smart-meter-deployment

offer a flat tariff[66]. The AER has just published[67] its direction to retailers in Queensland on how they are expected to comply with the Queensland Government's derogation.

Traditionally the role of the AER has been to ensure the network tariff structures and assignment arrangements comply with the rules so the network presents retailers with the appropriate cost reflective tariffs. It is then the retailer's role to present a range of retail tariffs to customers where the retailer is managing the risk along the electricity supply chain eg spot market risk and network tariff risk. The retailer presents a range of tariffs that may or may not reflect the cost reflective network tariffs it is being charged by the network eg it may have a flat tariff option, either because they think it is economic to do so or because of a Government directive, when the network does not provide a flat tariff.

The Australian Energy Council, which represent retailers, has been advocating against demand tariffs, preferring flat tariffs[68]:

> "Frankly, would a simple fixed distribution cost for all residential customers be a fairer and more transparent way to recover the costs related to distribution, which in themselves are largely fixed? As retailers will tell you, most customers in our experience are actually looking for a very simple and predictable energy tariff."

This was clear in the Red and Lumo Energy submission to the Energex and Ergon TSS Proposals[69]:

> "To this point, some networks have not engaged effectively with consumers or had sufficient regard to how retailers incorporate network tariffs into retail prices. Complex structures and frequent changes to those structures and to assignment policies present significant challenges. In contrast, retailers are better able to construct pricing offers that consumers understand and can respond to if networks present them with stable and simple price signals. This necessarily involves some trade-offs and means network pricing will retain an element of cross subsidy. On the other hand, tariff reform will not achieve its desired outcome if it does not adequately account for the consumer perspective. This is a consistent theme throughout this submission."

Flat tariffs certainly make the life of a retailer easy – no need to develop sophisticated bill engines that cost money to set up and operate. No need to bear the risk of cost reflective tariffs for networks as they develop their suite of retail tariffs. But flat tariffs are bad news for achieving what the AER wants to achieve in efficient network utilisation and the lowest customer bills. It is also bad news for the objectives the AEMC wants to achieve with its smart meter rollout. Consumers are left with the large costs of smart meters while waiting longer for the benefits.

While we can understand the AER's approach, we recommend that the Final Decision provide more discussion of what we consider is the central question:

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[66] https://statements.qld.gov.au/statements/101123

[67] https://www.aer.gov.au/system/files/2024-12/AER%20letter%20to%20retailers%20-%20Queensland%20Derogation%20-%2019%20December%202024.pdf

[68] Eg https://www.energycouncil.com.au/analysis/cost-reflective-tariffs-the-disconnect-between-theory-and-reality/

[69] See p. 1 https://www.aer.gov.au/system/files/2024-05/Red%20Energy%20and%20Lumo%20Energy%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex and Ergon%20%26%20SA%20Power%20Networks%20-%20May%202024_1.pdf

> Why is slowing down the rate of movement towards cost reflective pricing in the Energex and Ergon TSS Proposals a prudent and efficient additional way of achieving the objective of continued consumer support for the transition given all the other measures in place to contribute to that objective?

The discussion of the range of stakeholder feedback is limited in some parts of the Draft Decision

The Draft Decision discusses the AER's expectations as set out in the Better Resets Handbook which include[70]:

> "… significant stakeholder engagement and broad stakeholder support for their proposed tariff structures"

The AER provides a short summary of submissions [71]:

> "Stakeholder submissions supported many aspects of Energex and Ergon's tariff strategies. For example, they generally supported two-way tariffs. However, many stakeholders did not support default demand tariffs for small customers.

but this gives a very limited view of the breadth. While there was the occasional reference to the RRG's views in the Draft Decision and a passing reference to 'network pricing groups'[72] , we could not find any specific reference to the NPWG's views.

Of the three submissions not supporting default TOU demand tariffs, two were from retailers – Origin and Red and Lumo Energy who have long opposed these tariffs. There was no mention of the support for these tariffs from Energy Australia (expressed in an EQL engagement forum), and both of EQLs' engagement forums – the RRG and Network Pricing Working Group (NPWG).

In the discussion of some areas where the AER did not accept the Energex and Ergon TSS, there was reference to submissions that supported the AER's decision but no reference to submissions supporting Energex and Ergon's position. For example:

- in the discussion on the threshold for large customer access to TOU energy tariffs[73] there was reference to the submissions from the EV Council and Evie Networks supporting the AER's position, but no reference to the RRG's submission and NPWG which supported Energex and Ergon's position on equity and efficiency grounds

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[70] See p. 9 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[71] See p. 12 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[72] See p. 11 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[73] Section 19.4.4.3 pp 38-41 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

- in the discussion on grid-scale storage tariffs[74] there was reference to the number of submissions from stakeholders associated with the Noosa battery project that supported the AER's position, but no reference to the RRG's submission which supported Energex and Ergon's position on equity and efficiency grounds; in our submission[75] the RRG argued that it is the role of Governments to support new technology that is not yet commercial – not other Energex and Ergon consumers who do not have access or cannot afford rooftop solar paying cross subsidises; further we are not sure how the preference for a technology and industry neutral tariff supported the EV tariff decision is consistent with what appears to be a technology specific tariff for community batteries.

Energex and Ergon engaged in comprehensive consultation with the NPWG after the regulatory proposal was submitted and following the Draft Decision. Appendix I of the Energex and Ergon Explanatory Statement[76] summarises the NPWG's views on the areas where the AER did not accept the initial TSS and Energex and Ergon's response. The NPWG:

- supports load control tariffs - TOU demand tariffs provide a better price signal to customers than TOU energy-based tariffs,
- does not support a further delay in introducing two-way tariffs and how this will mean the lack of a pricing signal to underpin new market offerings such as dynamic connection agreements,
- does not support storage tariffs that are not cost reflective and hence introduce inequities for other customers who are paying the cross subsidy inherent in those storage tariffs; it is not the AER's role to use the TSS to impose tariffs to support a particular technology – we maintain that is the role of Governments,
- supports Energex and Ergon proposed tariffs for customers consuming between 100-160MWh with a 'peaky' load; supports greater transparency from the AER regarding how it assesses efficiency and equity trade-offs (including the value of emissions reductions),
- supports Energex and Ergon's proposal to not reassign any existing customers on TOU demand tariff (current default tariff) to TOU energy tariff (new default).

The AER's view on TOU demand tariffs seems to have unfortunately influenced Energex and Ergon's views on two-way tariffs

Energex and Ergon's reasoning for delaying two-way tariffs until the next regulatory period is that the limited benefits are outweighed by the implementation costs. The level of export charges is unlikely to change consumer behaviour. The delay will enable other pricing policy changes to be embedded around more cost reflective pricing as the smart meter rollout proceeds.

We also consider there is a subsidiary reason that is important.

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[74] See Section 19.4.6 pp 42-44 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[75] See p 66 https://www.aer.gov.au/system/files/2024-06/EQL%20Reset%20Reference%20Group%20-%20Submission%20-%202025-30%20Electricity%20Determination%20-%20Energex and Ergon%20%26%20Ergon%20-%20May%202024_0.pdf

[76] See Appendix I pp. 99-103 https://www.aer.gov.au/system/files/2024-12/Energex and Ergon%20-%20Tariff%20Structure%20Statement%20-%20Explanatory%20Statement%20-%20November%202024%20-%20public.pdf

The AER did not support TOU demand tariffs because of their complexity and difficulty to explain to consumers. At the same time the AER supported a transition to two-way tariffs, despite their complexity and difficulty to explain to consumers. As Energex and Ergon note[77]:

> "The AER's Draft Decision regarding demand tariffs creates a high hurdle for demand tariffs that needs to be carefully considered in the context of any Revised TSS. When assessing two-way tariffs with the same criteria, we have suggested a more cautious approach to our transition strategy."

The RRG has been a consistent supporter of the two-way tariffs in Energex and Ergon's initial TSS. We are disappointed that Energex and Ergon have decided on this course but understand given the AER's approach to tariff complexity. Even though the likely level of tariffs is very low and the impact on customer behaviour marginal, we see it as important to have the tariffs 'in the system' to give Energex and Ergon the opportunity to introduce them in 2025-30 if the other related policy reforms are progressed to the stage which would allow their introduction without having to wait for the 2030-25 regulatory period.

At the very least this inclusion could be in the form of zero export and zero import charging be catered for within it is billing machine. This we believe lays the foundations for network to move quickly in changes and import-export tariffs if desired. Importantly it highlights to retailers and other market participants that import and export charging is an option that they must consider in developing both their billing machines and their retail product offerings.

We recommend that the AER provides further guidance to networks and consumers on how it assesses the 'contribution to emissions reduction' part of the NEO in assessing tariffs

The AER justifies its decision to reject the Energex and Ergon tariffs for consumers between 100 and 160MWh with 'peaky' loads – public EV chargers are an example – based on a desire to have consistency across networks[78]:

> "While we consider that Ergon Energy and Energex and Ergon's time-of-use demand tariffs meet the economic pricing principles set out in clauses 6.18.5(e) – (g), and contribute to the price element of the NEO, we consider Ergon Energy and Energex and Ergon should offer additional time-of-use only tariffs for their tariff structure statement to further contribute to the achievement of the NEO. In particular, a consistent NEM-wide structure for network tariff charges for EV charge point operators would further contribute to achievement of Queensland's emissions reduction targets (i.e. its net zero 2050 target and its Zero Emission Vehicle Strategy (ZEV Strategy) 2022–2032).
>
> This consistency has already been achieved in most NEM jurisdictions. Across Victoria, NSW, Tasmania and the ACT, EV charge point operators can access time-of-use tariffs while consumption is less than 160 MWh. South Australia and Queensland are now the only NEM regions that do not align with this approach."

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[77] See p. 34 https://www.aer.gov.au/system/files/2024-12/Energex and Ergon%20-%20Tariff%20Structure%20Statement%20-%20Explanatory%20Statement%20-%20November%202024%20-%20public.pdf

[78] See p. 40 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

While there is an argument to be made that subsidising EV owners to be able to charge at peak times may lead to a reduction in emissions, we think that the AER should mount a stronger justification than a simple qualitative judgement that reflects EV advocate submissions. It seems the AER is holding itself to a lower level of analysis than what it expects from networks under the Better Resets Handbook. At least we would have expected this decision to be supported by a marginal cost of abatement analysis. When asked, the AER responded that it had not developed a marginal cost of abatement curve. At least we might have expected some analysis based on the AER's Draft Guidance Note on valuing emission reduction[79]. But that did not occur either.

Is this cross subsidy, embedded in the TOU energy tariff, from low-income earners who cannot afford an EV to high income earners who can, the most efficient way of achieving emissions reductions? What is the bill impact of it?

In commenting on the cost reflectivity of the Energex and Ergon TSS, the AER noted[80]:

> "…in consideration of NER cl. 6.18.5(h), we consider Ergon Energy and Energex and Ergon could provide further information in revised proposals on customer impact analysis. For example, the percentage of customers better/worse off from moving tariffs (analysis currently only shows the percentage of customers better/worse off from remaining on a default tariff), or how bill impacts may be mitigated through controlled load."

It would have been good to the AER provide some bill impact data showing the impact of the cross subsidies the Draft Decision creates, expands or redresses.

What should be the relationship between the QECM and the TSS?

The purpose of the Queensland Electricity Connections Manual (QECM) is to set out the technical requirements for connection to and interfacing with the Energex and Ergon network[81]:

> "It has been developed to ensure the safe and stable operation of electrical installations connected to the distribution system without causing material degradation in the quality of supply to distribution system users. The document is primarily used by electrical contractors, engineers, consultants, builders, developers, architects, metering providers, and others directly concerned with electrical installations that are connected, or are to be connected, to the distribution system."

Energex and Ergon have used connection arrangements to allow active and mandatory device management for decades eg off peak hot water systems to manage system demand. The most recent QECM update in February 2024 expanded the active device management options available eg for EVs. The AER, which has no remit over the QECM, supports optional, not mandatory load control.

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[79] https://www.aer.gov.au/system/files/2024-03/AER%20-%20Valuing%20emissions%20reduction%20draft%20guidance%20-%20March%202024.pdf

[80] See p. 16 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex and Ergon%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

[81] See Appendix 2 p. 80 https://www.aer.gov.au/system/files/2024-12/Energex%20-%20Tariff%20Structure%20Statement%20-%20Explanatory%20Statement%20-%20November%202024%20-%20public.pdf

Given this the AER, in discussing the QECM impact on connection options for home EV charging noted that:

> "…these options are not made clear in the tariff structure statements and were only made clear to us through the distributors' responses to information requests. Further, the tariff structure statements do not make it clear that the proposed optional flexible load control rebate tariff is only available to those EV customers who opt into a dynamic connection under the Queensland Electricity Connections Manual."

and required Ergon in its revised TSS to[82]:

- include further description of control arrangements that are contained in the Queensland Electricity Connections Manual, further explanation of 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.

The AER's approach seems to be one of ensuring the relevant information is transparently available to the market to enable EV owners to assess retail offers.

In its deliberations, the NPWG considered the AER's Draft Decision and came to the following clear majority decision:

- that the right approach to moving forward with load control tariffs is to continue with the position EQL has adopted post Draft Decision
- this included support by the NPWG for EQL providing further explanation where available and include references to other information and documentation including the QECM
- the redesign of the customer rebate (from one off to over time) on this issue by EQL is appropriate, due to concerns a one-off rebate may not reach consumers
- there were some concerns that there could be conflict between QECM and historical connection agreements that should be investigated

Ergon explain in their revised proposal that the QECM does not mandate customer assignment of tariffs and does not specify which network tariff a customer must choose eg a flexible load tariff is enabled by several device management options in the QCEM[83].

> "In our conversations with customers, they have informed us that optionality is important. By providing multiple active device management options, and eligibility for different tariffs depending on the choice of active device management, the QECM supports this goal."

The AER noted that there were two submissions on this matter – from Tesla and the Electric Vehicle Council – both of which opposed mandatory controls. The EV Council[84]:

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[82] See p. 22 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20-%20Overview%20-%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf
[83] See Appendix 2 p. 80 https://www.aer.gov.au/system/files/2024-12/Energex%20-%20Tariff%20Structure%20Statement%20-%20Explanatory%20Statement%20-%20November%202024%20-%20public.pdf
[84] See pp 24-5 https://www.aer.gov.au/system/files/2024-09/AER%20-%20Draft%20Decision%20Attachment%2019%20-%20Tariff%20structure%20statement%20-%20Ergon%20Energy%20and%20Energex%20-%202025-30%20Distribution%20revenue%20proposal%20-%20September%202024.pdf

> "…submitted that control without consent falls short of industry and consumer expectations, and it prefers cost reflective tariffs and optional control tariffs."

This seems strange given their support for technology specific tariffs for public EV charging stations. We would understand the AER's position for optional load control based on customer evaluation of retail offers were those offers based on cost reflective pricing rather than technology specific non cost reflective pricing the AER supports.

We recommend that the AER provide further guidance to networks and consumers on its decision-making process for the Final Decision

We understand that recent events meant the AER has to consider the wider political landscape in its decisions. The move to cost reflective pricing without the necessary consumer education and consultation has been a poor outcome for consumers. The inclusion of the environment in the NEO has been broadly welcomed by consumer advocates but consumers need to have an understandable narrative around the best approach to achieving the energy transition objectives.

We would recommend that these changes in approach need a much more comprehensive and transparent explanation of the AER's reasoning eg:

- what is the additional transition social licence benefit of the retreat from cost reflective tariffs above all the other measures taken by Energex and Ergon, the AEMC and the Queensland and Australian Governments?
- what is the impact of the unintended consequences of the Draft Decision on two-way tariffs where Energex and Ergon are now not proposing to introduce two-way tariffs until the next period post 2030 after initially proposing to introduce them from 1st July 2026 for new customers and 1st July 2028 for existing customers, a move the RRG strongly supported and the AER supported the timetable in the Draft Decision?
- what are the comparative costs and benefits of active Energex/Ergon load control based on cost reflective EV charging tariffs vs optional load control based on non-cost reflective EV charging tariffs?
- what is the bill impact of the decisions on storage tariffs?
- what are the costs and benefits of requiring Energex and Ergon to transitioning ~900,000, as of 1st July 2025, residential and small business customers with TOU demand and energy tariffs to TOU energy even though <1% actually face the TOU demand tariff from Ergon Retail?

We recommend that the AER provides further guidance to networks and consumers on the scope of future network TSS engagement

Until this Draft Decision, the scope for TSS engagement has been clear. The Better Resets Handbook guides networks on the AER's expectations with DNSPs expected to demonstrate[85]:

1. progression of tariff reform consistent with the network pricing objective and pricing principles set out in the Electricity Rules
2. incorporation of its tariff strategy in its overall business plan
3. demonstration of significant stakeholder engagement and broad stakeholder support
4. insight into and management of any adverse customer impacts

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[85] See p. 33 https://www.aer.gov.au/system/files/2024-07/AER%20-%20Better%20Resets%20Handbook%20-%20July%202024.pdf

The Draft Decision suggests that the scope of future DNSP tariff engagement now must also include:

- what is the scope of the DNSP engagement and its relationship to other consumer and stakeholder inputs eg AEMC, AER customer Council, retailers and the role of precedent in previous AER reset decisions?
- how to give consumers and network reset engagement forums confidence that the AER is taking their views into account?
- how potential political reaction to tariffs that meet the pricing elements of the rules might be included in tariff design?
- how the objective of uniformity across jurisdictions should apply – when will a political decision in one jurisdiction lead to the AER applying that policy to other jurisdictions to ensure uniformity?
- the approach to technology specific tariffs that provide a subsidy to support new technology that has an emissions reduction benefit, and
- how the network balances the pricing and emissions elements without guidance on the value of those emission reductions or how tariff equity is supposed to feature in the analysis.

We look forward to the AER providing detailed guidance on what it is looking for in a network's engagement on these matters.

9. Alternative Control Services

Public Lighting

AER's Draft Decision

The AER's draft decision did not accept Ergon's public lighting proposal, although considering it largely reasonable. The AER updated Ergon's proposal to apply a draft decision on labour escalators, weighted average cost of capital (WACC) and consumer price index (CPI). These substitute inputs resulted in minor downward adjustments to Ergon's public lighting prices.

What is Ergon proposing?

Ergon proposes three key changes in its Revised Proposal:

- The incorporation of 2022-23 actual capex has resulted in a significant increase compared to budget due the accelerated conversion of mercury vapour lights to LEDs. This has increased the projected opening Public Lighting Asset Base figure.
- Labour escalators have been revised to be consistent with those used in the calculation of SCS opex.
- The same values for WACC (as used to derive SCS revenue) and inflation (as defined in the Draft Decision) have been applied to public lighting charges.

The first change has resulted in upward pressure on public lighting charges, while the other changes have caused downward pressure. The net result is an initial estimated increase of 21% for the 2025-26 year followed by flat pricing over the remaining four years.

RRG Comments

Ergon held an engagement session with customers on the 9th of October 2024[86] to provide an update on information on the AER Draft Decision on the Ergon 2025-30 Regulatory Proposal - Public Lighting. Ergon provided an overview of the AER's draft decision and an updated table of tariffs indicating the anticipated reduction in charges based on acceptance of all feedback in the draft decision.

The RRG is disappointed that the increased prices now proposed were not communicated to customers at the October engagement session. However, the increased replacement rate of mercury vapour lights to LEDs in 2022-23 would suggest that customers are in agreement with the proposed strategy and are accelerating the migration to LED technology to achieve the related benefits. As such, the RRG supports the application of the proposed changes given the outcome of an increased asset base value.

Service reclassification for supply abolishment services

AER's Draft Decision

The AER did not accept Ergon's proposal to change its supply abolishment service from alternative control services to standard control services. This decision was justified on the basis that a clear single customer is creating the service and that other distributors offer supply abolishment services as an alternative control service.

[86] https://www.talkingenergy.com.au/35806/widgets/200811/documents/296987

What is Ergon proposing?

Ergon remains of the view that there is a case to change the supply classification for simple supply abolishments to SCS for public safety reasons and to align with similar reclassification decisions applying to distributors in Victoria and Tasmania.

RRG comments

The RRG was not involved in the engagement on these matters and so we have no comments.