FINAL DECISION

Ergon Energy
Distribution Determination
2020 to 2025

Overview

June 2020

AUSTRALIAN ENERGY REGULATOR

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About our decision

The Australian Energy Regulator (AER) works to make all Australian energy consumers better off, now and in the future. We regulate energy networks in all jurisdictions except Western Australia. We set a maximum revenue that network businesses are allowed to recover from customers in providing network services.

The National Electricity Law and Rules (NEL and NER) provide the regulatory framework governing electricity transmission and distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[1]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

Ergon Energy is the electricity distribution network service provider in regional Queensland. On 31 January 2019, Ergon Energy submitted its regulatory proposal for the five year regulatory period commencing 1 July 2020. Following the release of our draft decision on 8 October 2019, Ergon Energy submitted its revised regulatory proposal on 10 December 2019.

This overview sets out our final decision for Ergon Energy's distribution determination. Each constituent component of our distribution determination is set out in appendix A and we have also published separate attachments.

A key component of our determination for Ergon Energy is the total revenue it can recover from customers for the use of its network over the next 5 years. These revenues are derived from our 'building block determination' and we discuss the cost components that make up the building blocks in section 2. Ergon Energy's Tariff Structure Statement explains the tariffs it will apply to customers to recover the total allowed revenue and we discuss this in section 3.

In making our draft and final decisions we have taken into consideration submissions from stakeholders and have referenced their views and comments throughout our decision attachments. Appendix B also lists the submissions received on our draft decision and Ergon Energy's revised regulatory proposal.

COVID-19 impacts

We understand the current challenges faced by all stakeholders due to the COVID-19 pandemic. As set out in our *Statement of Expectations of energy businesses: Protecting consumers and the energy market during COVID-19*, energy is an essential service and the energy market plays an important role in protecting and supporting

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[1] NEL, s. 7.

businesses and the community through the COVID-19 pandemic and our recovery.[2] We recognise that COVID-19 may add to the risks and uncertainties facing energy businesses, including network businesses like Ergon Energy.

Our decisions must be made in a manner that will or is likely to contribute to the achievement of the NEO.[3] The use of up-to-date available information is an important feature that contributes to achieving the NEO.

We undertake an 18 month process for making our decision. This process gives all stakeholders comprehensive opportunities to consider the positions of each other and respond accordingly. It recognises the complexity and depth of analysis required to forecast the costs of a major energy network over five years. The COVID-19 pandemic arose and only became a widely recognised factor as we were completing our final decision.

We have had regard to the impact of COVID-19 in making this distribution determination. At the time of making our decision, there are uncertainties around how COVID-19 will affect Ergon Energy's operations and costs in the next regulatory control period. However, we consider that information currently available allows us to make a decision that meets the requirements of the NEL and NER. We base our decision on current information and best forecasts that can reasonably be made in all the circumstances. We consider that the allowed revenue we have determined provides Ergon Energy a reasonable opportunity to recover at least its efficient costs.

Under our regulatory framework, once the forecasts of efficient costs for a network business are determined for a regulatory period, networks generally manage the risk on cost parameters, giving them an incentive to control these and continue to seek out efficiencies.

In another concurrent electricity distribution determination process, SA Power Networks has written to us and listed a range of factors that it states are causing its costs to increase due to COVID-19, such as movements in foreign exchange rates and the need for different ways of working. However, we consider other factors are likely to reduce network expenditures, including falling demand and the planned or unplanned deferral of works. Changes in costs may also have flow on effects to the operation of the various interrelated incentive schemes, which are a key element of the economic regulatory framework for network businesses. The various effects may act to reinforce each other, or be offsetting, and may manifest differently for different network businesses. Early information from the industry is mixed but appears to suggest that the overall impacts may not be material in terms of costs.

SA Power Networks proposed that we should delay our decision for an extended period so that the impacts of COVID-19 can be incorporated into our decision. Leaving

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2 AER, *Statement of Expectations of energy businesses: Protecting consumers and the energy market during COVID-19*, 27 March 2020.

3 NEL, s 16(1)(a)

the decision open for an extended time creates uncertainty for all. With an extended delay, Ergon Energy would not have clear parameters for guiding its decision making and consumers would not have certainty of prices, thereby impacting their operation and investment decisions. Whilst recognising the uncertainty caused by the COVID-19 pandemic, we consider that the revenue we have set based on the current information supports the ongoing operations of Ergon Energy and provides it with a reasonable opportunity to recover at least its efficient costs.

Therefore, delaying the determinations further to allow more time for the effects of COVID-19 to be assessed is not the appropriate response when balancing the importance of finalising the arrangements for the period commencing 1 July 2020, so that all stakeholders are aware of the position. In the light of these matters, we make this decision now.

Going forward, if it becomes clear that the impacts of COVID-19 are substantial, then a rule change would be required so that we can re-open existing revenue determinations. We are consulting with stakeholders to assess whether a rule change is warranted.

Note

This overview forms part of our final decision on the distribution determination that will apply to Ergon Energy for the 2020–25 regulatory control period. It should be read with all other parts of the final decision.

As a number of issues were settled at the draft decision stage or required only minor updates we have not prepared all attachments. The attachments have been numbered consistently with the equivalent attachments to our draft decision. In these circumstances our draft decision reasons form part of this final decision.

The final decision includes the following attachments:

Overview

Attachment 1 – Annual revenue requirement

Attachment 2 – Regulatory asset base

Attachment 3 – Rate of return

Attachment 4 – Regulatory depreciation

Attachment 5 – Capital expenditure

Attachment 6 – Operating expenditure

Attachment 7 – Corporate income tax

Attachment 8 – Efficiency benefit sharing scheme

Attachment 9 – Capital expenditure sharing scheme

Attachment 10 – Service target performance incentive scheme

Attachment 12 – Classification of services

Attachment 13 – Control mechanisms

Attachment 14 – Pass through events

Attachment 15 – Alternative control services

Attachment 17 – Connection policy

Attachment 18 – Tariff structure statement

Attachment A – Negotiating framework

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Executive summary

This final decision determines the amount of money Ergon Energy can recover from consumers in the 2020–25 regulatory control period.

Ergon Energy can recover $5925.9 million ($ nominal) from consumers in the 2020–25 regulatory control period.

We estimate that compared to current charges, the distribution network charges for a residential consumer will drop by $73 (4.6 per cent) in the first year of the 2020–25 period and then increase on average by $3 (0.2 per cent) for each of the next four years. For a small business consumer, the distribution network charges will drop by $82 (3.7 per cent) in the first year of the 2020–25 period and then increase on average by $3 (0.1 per cent) for each year of the next four years.

Distribution network charges make up about 35 per cent of a standard residential retail bill (28 per cent for small businesses).[4]

Our decision involves us assessing how much money Ergon Energy needs for the safe and reliable operation of this large network – they make a proposal of what they think they need and we decide if it is suitable and fair to consumers.

We are satisfied that the $5925.9 million ($ nominal) Ergon Energy can recover from consumers ensures households and businesses are paying no more than necessary for safe and reliable services.

We have accepted what Ergon Energy says it needs to run the operational side of its business (known as opex). But we haven't done the same with its capital expenditure (capex) proposals, which includes its plans for spending on replacing equipment or other material (repex).

Ergon Energy has a large area of responsibility. It covers regional Queensland with a network of poles and wires spanning over 151,976 kms servicing 752,909 consumers.

When we listened to the stakeholders in this area, they told us they were concerned about the amount of money Ergon Energy said it needed to address safety concerns, especially as this was a big increase on its previous spending.

These stakeholders put a high priority on safety, as we do, but also recognise that it is consumers who foot the bill for this spending. To justify the kind of spending Ergon Energy proposed, we need detailed supporting information which wasn't there.

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4 Our bill impact calculations for Ergon Energy adopt the network charges in our final decision for Energex as retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. Our comparison to the current level holds all other components of the bill constant and adopts the current estimate of future energy consumption as forecast by Energex.

Some submissions to this process questioned whether stakeholders were informed of the full costs, available alternative options and reasons why some assets have deteriorated given previous spending approvals.

The main points of difference between our final decision and Ergon Energy's revised proposal are:

- Our final decision on Ergon Energy's repex is $891.8 million, $397.8 million lower than what Ergon Energy forecast in its revised proposal.
- We support Ergon Energy’s efforts on tariff reform and its engagement with consumer representatives to inform these reforms, but have made some changes to reflect the distribution pricing principles. This includes transitional arrangements in the first year of the regulatory period for consumers and retailers to adjust to the new tariffs in light of COVID-19.

Also, our final decision does not take into account the amount that may be passed on to consumers under the Queensland Government's Solar Bonus Scheme. The Solar Bonus Scheme is a jurisdictional scheme which is not considered as part of our building block approach to determine total revenue. The Solar Bonus Scheme costs are currently being funded by the Queensland Government and the subsidy is expected to end on 30 June 2020.

Ensuring consumers pay no more than they need for safe and reliable services

Ensuring consumers pay no more than necessary for safe and reliable electricity is a cornerstone of the regulatory determination process.

As part of this process we reviewed a range of materials including Ergon Energy's regulatory proposal and revised proposal, submissions from stakeholders and undertook our own analysis. Additionally we met with Ergon Energy representatives, our consumer challenge panel and other stakeholders to discuss the material put to us.

In its revised proposal, Ergon Energy requested $2804.3 million for its capital expenditure program. Of this, $1289.6 million was for replacement of existing network infrastructure. This estimate was $195.2 million higher than Ergon Energy's initial proposal.

Our final decision approves $891.8 million for Ergon Energy's replacement capital expenditure program, $397.8 million lower than what was proposed. The amount we have approved provides Ergon Energy with the funds to do the work it needs to maintain the network and meet its mandatory safety obligations.

In our draft decision we noted that Ergon Energy had not provided us with sufficient material to justify its proposed capex spending and we clearly set out the gaps Ergon Energy needed to address. Ergon Energy submitted some improved analysis, but it did not address the gaps we identified in its initial proposal.

To inform our final decision, consistent with previous decisions, we applied our standard assessment approach to better understand Ergon Energy’s forecast 43 per cent step up in repex. Amongst other things, we reviewed different trends, results of the repex model, Ergon Energy’s business cases and its supporting material, and stakeholder submissions. We also sought to better understand the material underspend of almost $300 million in total capex over the current regulatory period. In particular, we wanted to understand why Ergon Energy was not spending current funds to address the works it identified as high priority in its proposal. Ergon Energy did not address these issues satisfactorily.

We found that risks, especially safety risks associated with the network were overstated. This, in turn, meant that Ergon Energy's revised repex forecast to mitigate these risks was overstated. Publicly available network performance data also does not show that Ergon Energy’s network performance is deteriorating. The repex modelling results also indicate that, on average, Ergon Energy’s units costs, are higher than the industry average and it replaces its assets sooner than other businesses. For instance, for its clearance to ground and structure program, Ergon Energy did not provide sufficient evidence to support its forecast unit costs which were more than 80 per cent higher than it is currently incurring. Therefore, while we have accepted Ergon Energy’s proposed volume of compliance works for this program, we have not accepted the unit costs.

Our repex forecast is in line with Ergon Energy’s current spend. Given no material change in Ergon Energy’s network performance and insufficient evidence in support of a step up from its current spend, a repex forecast consistent with its historical recent spend will allow Ergon Energy to provide safe and reliable services. Further, Ergon Energy’s material underspend over the current period reveals that it does not require a large increase to its capital expenditure over the forecast period.

Even though we have approved a total forecast capex amount, this does not limit what Ergon Energy can invest in any one area of this expenditure and it is up to Ergon Energy to decide on the areas and timing of its capex in the long term interests of consumers.

Ergon Energy adopted our draft decision on opex in its revised proposal – this means that Ergon Energy's forecast operating expenditure will go down in the next regulatory period, with the savings being passed on to consumers.

Ergon Energy's engagement with its consumers

Ergon Energy demonstrated its commitment to consumers through its extensive engagement program, giving consumer groups the opportunity to influence its proposals. Consumers also appreciated the attendance of key executives, who answered questions and addressed concerns during Ergon Energy’s engagement events.

Some stakeholders were concerned about Ergon Energy's increased revised capex proposal, particularly the large step up from its current repex.

Ergon Energy's initial tariff structure statement was not up to standard and lacked consumer support. Ergon Energy improved its engagement closer to our draft decision and enhanced it further before submitting its revised proposal. Consumer groups appreciated Ergon Energy accepting our draft decision suggestions, but told us that the purpose of the proposed tariff changes and potential customer impacts have yet to be fully explained.

Ergon Energy focused on four key areas in its consumer feedback: safety, affordability, security and sustainability. We found that consumers were focused on affordability above other concerns.

The way we use and price electricity services is changing

The way Queenslanders engage with electricity is changing, and the rapid uptake in rooftop solar photo-voltaic (PV) generation is having an increasing impact on the low voltage (LV) network. Investment in new technologies as well as changes to pricing approaches are required to address the evolving system.

We recognise the need for distributors to deal with technologies like Distributed Energy Resources (DER) to address the evolving needs of consumers, but note that we must ensure that any spending is cost-efficient and in the long term interests of consumers.

Ergon Energy's original proposal on DER was not well supported as was reflected in our draft decision. In its revised proposal Ergon Energy provided better material to justify spending in this area.

Our final decision includes capital expenditure to build Ergon Energy's LV management platform that uses data and enhances operating capabilities so that consumers can maximise exports without increasing voltage problems in the LV network.

Other networks have integrated investment in DER alongside a clear rationale for network tariff reform and have proposed tariffs that clearly align with that rationale and encourage consumers to make the most of the technology. Pricing and these new technologies must, and will, evolve alongside each other.

This also gives consumers more control to manage their energy costs whilst helping alleviate voltage problems associated with increasing levels of PV installations.

1 Our final decision

Our final decision allows Ergon Energy to recover a total revenue of $5925.9 million ($ nominal) from its customers from 1 July 2020 to 30 June 2025.[5]

Ergon Energy is regulated using a revenue cap. Incentives are provided to it to reduce costs, improve service quality and undertake efficient investments.

We determine the total revenue Ergon Energy can recover from its consumers for the provision of common distribution services (standard control services (SCS)). This forms the basis of Ergon Energy's distribution tariffs for the 2020–25 regulatory control period. Ergon Energy's Tariff Structure Statement (TSS) sets out the tariff structure through which it will recover its regulated revenue for SCS from customers.

Ergon Energy also provides alternative control services (ACS), the costs of which are recovered only from users of those services, through a capped price on the individual service. These costs are considered separately to our building block determination.[6] Ergon Energy has not proposed to provide any services on a negotiated basis in the 2020–25 regulatory control period.[7]

1.1 What's driving revenue?

Revenue is driven by changes in real costs and inflation. We assess costs (such as capital and operating expenditure) in real terms (using 2019–20 as a common year) to reveal the underlying cost trends over a number of years or regulatory control periods. The numbers presented in this overview are in real 2019–20 dollars unless otherwise noted. Some impacts of our decision are presented in nominal terms, where required by the rules and to enable consumers to see the full impact of our determination inclusive of expected inflation.

The total revenue allowance in this 2020–25 final decision is 13.0 per cent lower than the allowed revenue in our 2015–20 final decision. Figure 1 shows that real revenues are decreasing from 2019–20 levels by 10.9 per cent in the first year of the next regulatory period. After that, Ergon Energy's revenue allowance is steady with a smaller 1.95 per cent decrease per year.

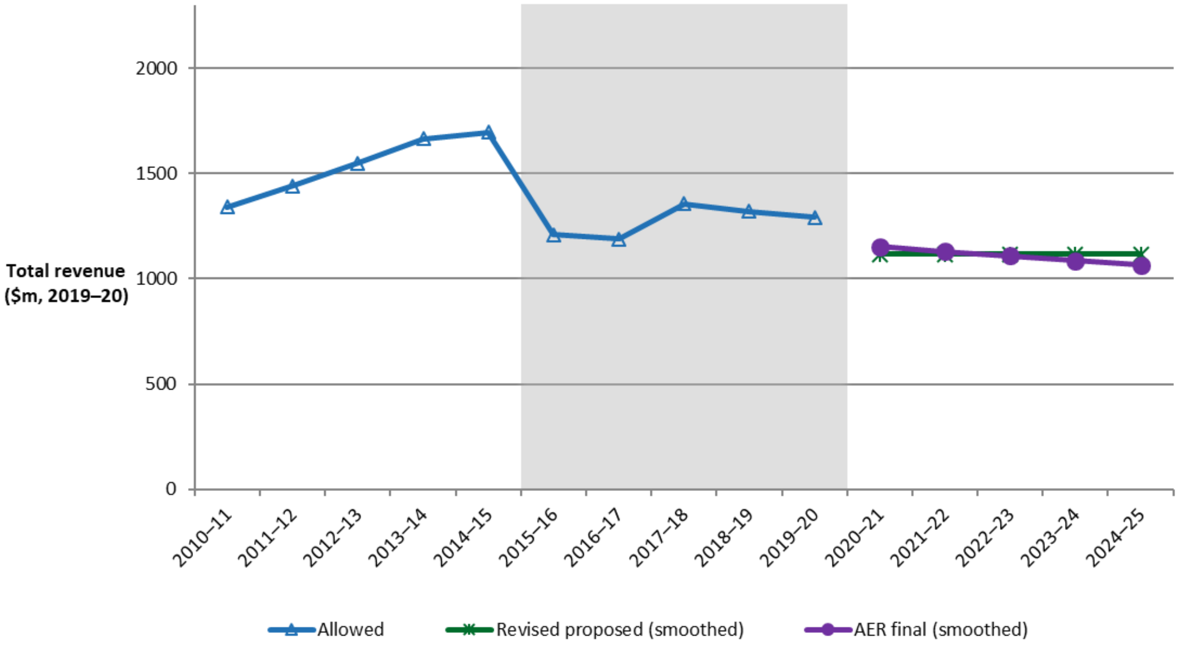
Figure 1 shows our final decision for Ergon Energy's smoothed revenue for the 2020–25 regulatory control period, and its allowed revenues over the 2010–20 regulatory control periods.

5 This is the total smoothed revenue and Table 2 below sets out both smoothed and unsmoothed revenue.

6 We discuss alternative control services in Attachment 15 to this final decision.

7 Our distribution determination for Ergon Energy includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because Ergon Energy has not included any negotiated services in its proposal, these elements of our determination will be inactive for the 2020–25 regulatory control period.

Figure 1 Revenue over time ($ million, 2019–20)



Source: AER analysis, smoothed revenue.

Note: The relatively lower allowed revenues in 2015–16 and 2016–17 is largely explained by costs associated with solar feed-in tariffs that were passed through separately in annual pricing for those years. By anticipating these pass through costs during its final decision in 2015, the AER helped smooth the overall revenues customers ultimately faced over the entire 2015–20 regulatory control period.

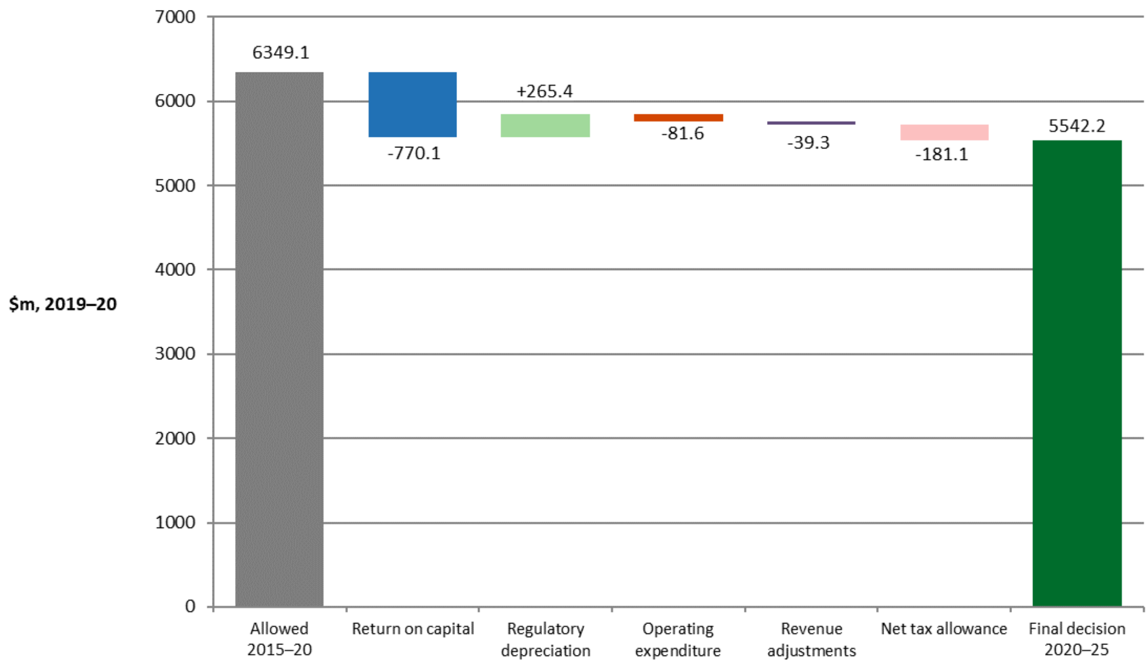
Figure 2 highlights the key drivers of the change in Ergon Energy's allowed revenue from the 2015–20 regulatory control period compared to the 2020–25 regulatory control period. It illustrates that the largest driver of change is the return on capital building block. The rate of return has decreased from around 6.0 per cent in the 2015–20 regulatory control period to about 4.7 per cent for the 2020–25 regulatory control period. This is because interest rates have decreased markedly since we made our last decision and Ergon Energy can obtain the capital it needs to run its business more cheaply. As a result, the total cost of capital has reduced by $770.1 million.[8] In 2019, we reviewed how we calculate the tax allowance and made changes to our approach to align with the latest rulings of the Australian Tax Office. This means we expect the tax allowance for Ergon Energy will be lower than it was in the past. As a result, Figure 2 also shows a decrease in the net tax allowance building block of $181.1 million.[9] Other changes include:

[8] The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has decreased by a similar amount. Please see section 2.2 for further details.

[9] Please see section 2.6 for further details.

- increase to forecast regulatory depreciation of 34.8 per cent. Each year, Ergon Energy builds new equipment to keep its network running. The cost of this new equipment is added to a cumulative total called the regulatory asset base or RAB. Over time, the cost of this equipment is paid back to Ergon Energy through our depreciation allowance. Because Ergon Energy added new equipment to its network over the last five years and is proposing to add more in the next five years, its RAB is increasing and so is its depreciation.[10]
- reduction to forecast operating expenditure of 4.3 per cent. Each year, Ergon Energy undertakes maintenance on its network to keep it operating well.[11]

Figure 2 Change in revenue from 2015–20 to 2020–25 ($ million, 2019–20)



Source: AER analysis, building block revenue.

Note: Revenue adjustments include increments or decrements accrued under incentives schemes such as the CESS, EBSS and DMIAM.

Figure 3 compares our final decision forecast RAB to Ergon Energy's revised proposed and actual RAB. Ergon Energy proposed to substantially increase its capital expenditure going forward which would have led to an increase in its RAB. We reviewed this proposal carefully and did not think it was warranted. We asked Ergon Energy for more information to justify its proposed increase in capex but it did not provide satisfactory reasons. We therefore decided to provide a capex forecast that is more in line with Ergon Energy's current spending. Ergon Energy’s RAB is forecast to

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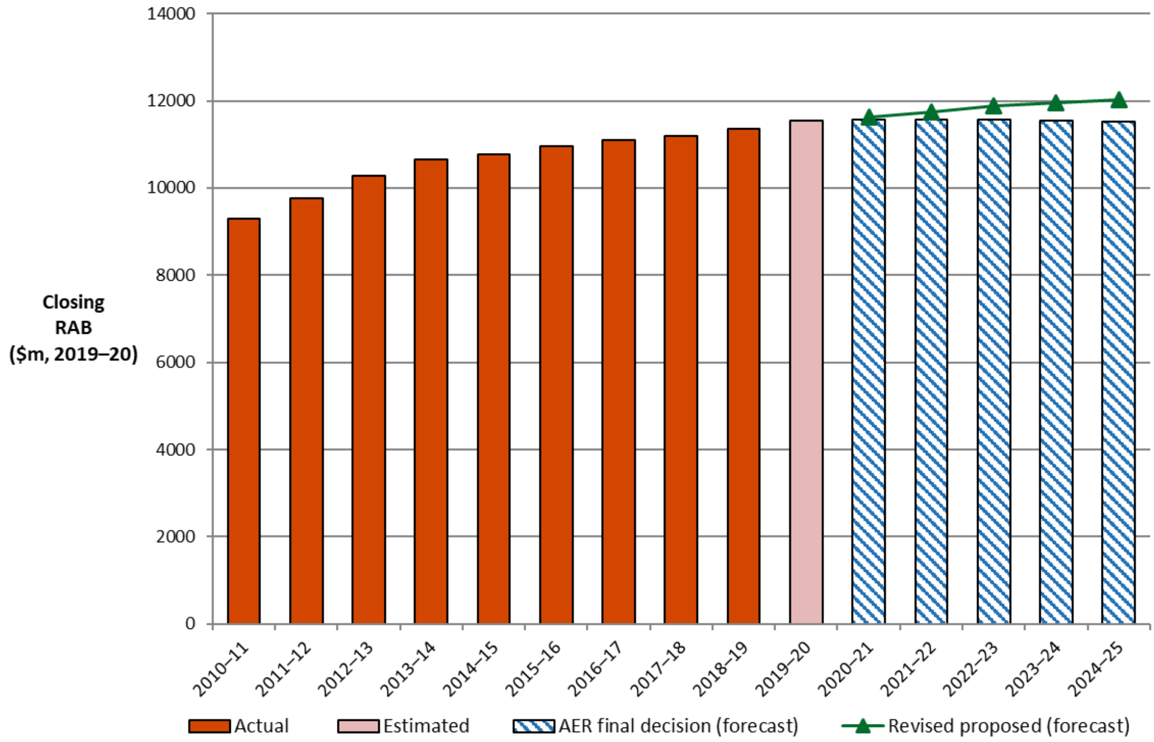
10 Please see section 2.3 for further details.

11 Please see section 2.5 for further details.

remain fairly steady in real terms over the 2020–25 regulatory control period. In the previous period, its RAB increased by 7.2 per cent.[12]

Figure 3 Value of Ergon Energy's RAB over time ($ million, 2019–20)



Source: AER analysis.

1.2 Key differences between our final decision and Ergon Energy's revised proposal

The total revenue we are allowing in our final decision is $5925.9 million ($ nominal) for the 2020–25 regulatory period. This is $71.5 million or 1.2 per cent lower than Ergon Energy's revised proposal of $5997.4 million.

Our rate of return of 4.73 per cent is higher than Ergon Energy's revised proposed rate of 4.67 per cent because we have used updated estimates of the risk free rate and return on debt.

Ergon Energy's revised proposal includes a level of forecast capex that we consider goes beyond what is efficient and prudent for the maintenance and operation of its network. Our total capex forecast of $2276.2 million is 19 per cent or $528.1 million below Ergon Energy's revised capex proposal of $2804.3 million.

[12] Please see section 2.1 for further details.

Our final decision total revenue is an increase of $138.1 million ($ nominal) on our draft decision revenue of $5787.9 million. The lower rate of return compared to our draft decision reduced our final decision revenue by $106.4 million. The higher regulatory depreciation compared to our draft decision increased our final decision revenue by $105.7 million. Ergon Energy's election in its revised proposal to claim the incentive scheme benefits resulted in an additional $155.2 million compared to our draft decision.[13]

1.3 Expected impact of our final decision on electricity bills

Our bill impact calculations for Ergon Energy are based on our final decision for Energex. This is because retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. The policy sets retail electricity prices in Ergon Energy's distribution area in line with those in Energex's area.[14]

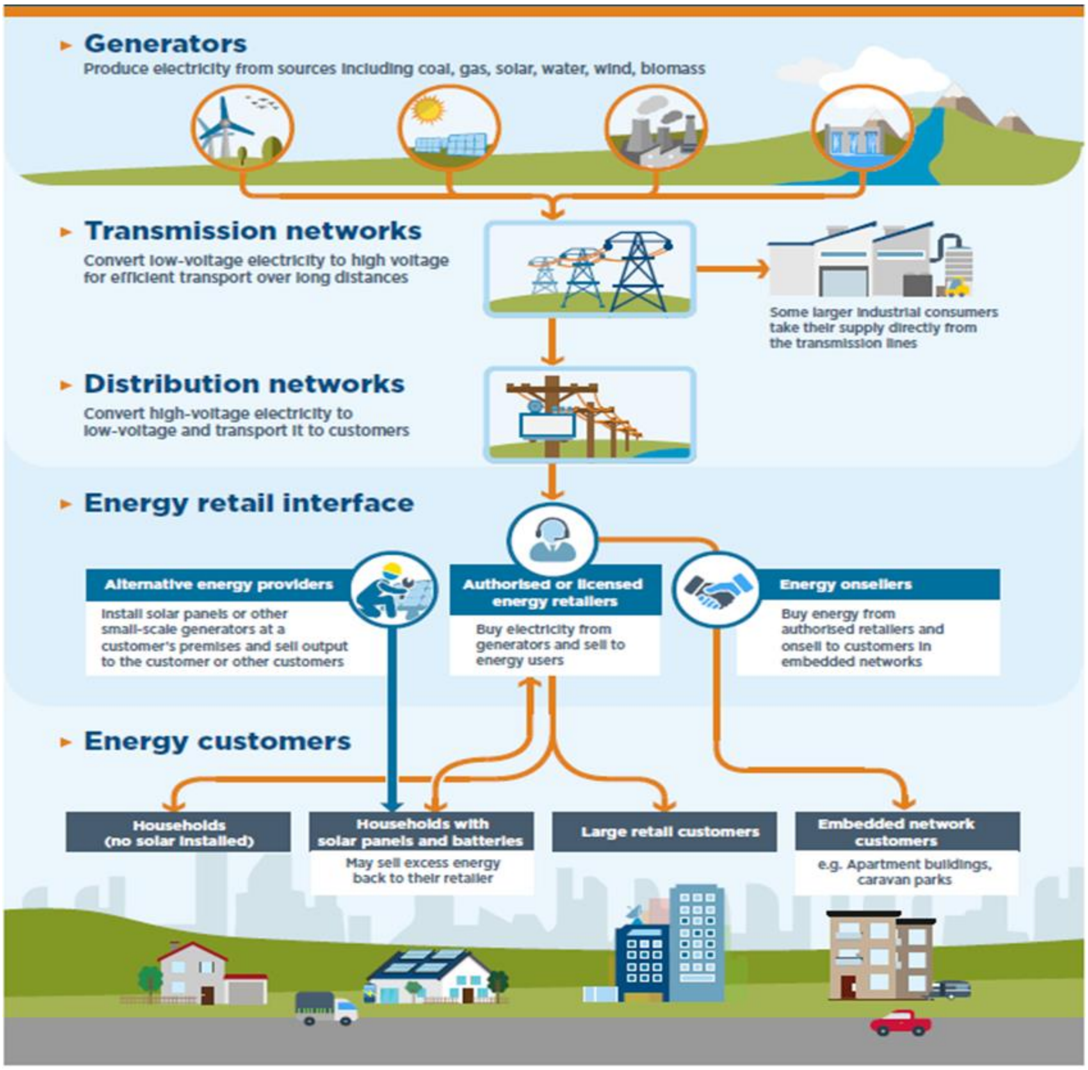
Distribution network charges make up around 35 per cent of the total residential bills and 28 per cent of the total small business retail electricity bills.[15] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 1 illustrates the different components of the electricity supply chain. Each of these costs contributes to the retail prices charged to consumers by their chosen electricity retailer.

13 The differences between the draft and final decisions set out in this paragraph are in $, nominal.

14 Queensland Competition Authority, *Final Determination–Regulated retail electricity prices for* 2019–20, May 2019, p. iii.

15 AEMC, *Residential electricity price trends 2019 data – trends in QLD supply chain components*, December 2019; AER, *Final decision – Determination of default market offer prices* 2020-21, April 2020.

Figure 4 Electricity supply chain



Source: AER, *State of the Energy Market*, December 2018, p. 28.

For this final decision, we have estimated some indicative average distribution price impacts flowing from our allowed revenue determination. These prices are indicative and might change with changes in demand.

Table 1 shows the estimated average annual impact of our final decision for the 2020–25 regulatory control period on electricity bills for residential and small business consumers.[16]

We estimate the expected impact on bills by varying the distribution charges in line with our 2020–25 final decision, while holding all other components constant. This

[16] Our bill impact calculations for Ergon Energy adopt the network charges in our final decision for Energex as retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy.

approach isolates the effect of our final decision on distribution network tariffs from other parts of the bill. However, this does not mean that other components will remain unchanged across the regulatory control period.[17]

Under the final decision we estimate that compared to current charges, the distribution network charges ($ nominal) in Ergon Energy's area:

- for an average residential consumer would:
    - reduce by $73 (4.6 per cent) in the first year of the 2020–25 regulatory control period
    - increase on average by $3 (0.2 per cent) for each of the remaining four years of the 2020–25 regulatory control period.
- for an average small business consumer would:
    - reduce by $82 (3.7 per cent) in the first year of the 2020–25 regulatory control period
    - increase on average by $3 (0.1 per cent) for each of the remaining four years of the 2020–25 regulatory control period.

This bill impact calculation does not take into account the Queensland Government's electricity asset ownership dividend which offsets the residential bill amount by $50 for each year in the 2020–23 period,[18] or the household relief package for COVID-19 impacts announced by the Queensland Government, which reduces the residential bill amount by a further $50.[19] It also does not take into account the impact of the Solar Bonus Scheme (SBS) costs currently being funded by the Queensland Government.[20] This subsidy is due to end on 30 June 2020.[21] The end of the subsidy will have an upward impact on the network component of electricity bills. This is because the SBS costs will be recovered from consumers as jurisdictional scheme amounts through network charges. Energy Queensland has advised that the SBS costs to be recovered in 2020–21 are estimated to be around $148 million for Energex and $90 million for Ergon Energy.

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17 It also assumes that actual energy consumption will equal the forecast adopted in our final decision. Since Ergon Energy operates under a revenue cap, changes in energy consumption will also affect annual electricity bills across the 2020–25 regulatory control period

18 Queensland Government, *QLD power assets continue to pay dividends*, 15 March 2020.

19 Queensland Government, *Palaszczuk Government unveils $4 billion package to support health, jobs, households and Queensland businesses*, 24 March 2020; Queensland Government*, Electricity Relief for Households and Businesses Q&A*, 24 March 2020.

20 Queensland Competition Authority, *Draft Determination–Regulated retail electricity prices for 2020–21*, pp. 13–16.

21 Queensland Competition Authority, *Draft Determination–Regulated retail electricity prices for 2020–21*, pp. 13–16

Table 1 Estimated contribution to annual electricity bills for the 2020–25 regulatory control period ($ nominal)

	2019–20	2020–21	2021–22	2022–23	2023–24	2024–25
AER final decision						
Residential annual bill	1570[b]	1497	1499	1503	1506	1507
Annual change[d]		–73 (–4.6%)	2 (0.1%)	4 (0.3%)	3 (0.2%)	2 (0.1%)
Small business annual bill	2222[c]	2140	2142	2146	2149	2151
Annual change[d]		–82 (–3.7%)	2 (0.1%)	5 (0.2%)	3 (0.1%)	2 (0.1%)
Ergon Energy revised proposal[a]						
Residential annual bill	1570[b]	1473	1482	1494	1505	1515
Annual change[d]		–97 (–6.2%)	9 (0.6%)	12 (0.8%)	11 (0.7%)	10 (0.7%)
Small business annual bill	2222[c]	2112	2122	2136	2148	2159
Annual change[d]		–110 (–5%)	11 (0.5%)	13 (0.6%)	12 (0.6%)	11 (0.5%)

Note: Our bill impact calculations for Ergon Energy adopt the network charges in our final decision for Energex as retail electricity prices in Ergon Energy's distribution area are determined under the Queensland Government's uniform tariff policy. Therefore Energex's bill impacts are used in this table.

Source: AER analysis; AER, *Final determination, Default Market Offer Prices 2019–20*, April 2019, p. 8; Queensland Competition Authority, *Draft Determination–Regulated retail electricity prices for 2020–21*, p. 5.

(a) Energex's revised proposal bill impacts are used in this table.

(b) Annual bill for 2019–20 is sourced from our final determination on Default Market Offer Prices for 2019–20 and reflects the average consumption of 4600 kWh for residential consumers in Queensland.

(c) Annual bill for 2019–20 is sourced from Queensland Competition Authority's Draft Determination on regulated retail electricity prices for 2020–21, and reflects the average consumption of 6831 kWh for small business consumers in Queensland.

(d) Annual change amounts and percentages are indicative. They are derived by varying the distribution component of the 2019–20 bill amounts in proportion to yearly expected revenue divided by forecast energy as provided by Energex. Actual bill impacts will vary depending on electricity consumption and tariff class.

1.4 Ergon Energy's consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions. It is important that Ergon Energy has engaged with its consumers to determine how best to provide services that align with their long-term interests. Consumer engagement in this context is about Ergon Energy working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence Ergon Energy's decisions. Apart from two exceptions, we accept that Ergon Energy has undertaken a positive consumer engagement process. It has been well informed of consumers' interests and concerns in framing its revenue proposals with key executives in attendance at most of its community engagement events.[22]

While both Energex and Ergon Energy have submitted individual regulatory proposals to the AER, a joint engagement approach was undertaken by Energy Queensland. As a result, except where indicated otherwise, references to Energy Queensland's engagement process includes that undertaken for both entities.

We tasked CCP14 specifically with advising us on the effectiveness of Ergon Energy's engagement activities with consumers and how this was reflected in the development of its proposal.

CCP14 noted that engagement right throughout the process, from development of the draft plan through to the revised proposal stage has been conducted in a positive manner, which was “responsive, inclusive, with enthusiasm, transparency and commitment”.[23] The Energy Queensland proposals have focussed on the four key themes identified in its initial consumer engagement of: safety; affordability; security; and sustainability.[24]

Of these, we note that consumers were mainly focussed on the key concern of affordability. In response to this CCP14 noted the Energy Queensland’s clear intent to deliver cost savings to consumers through a reduction in its required revenue.[25]

The two areas where Ergon Energy's consumer engagement was less effective were its capex proposal and the structure of its tariffs.

First, CCP14 observed that Energy Queensland had not informed its consumers of the full costs of its proposed safety expenditure and the available alternatives. It stated:

> We would be most surprised if customers and communities did not reflect a strong preference for powerline safety. The question is whether EQL is undertaking this responsibility in a prudent and efficient way, consistent with their obligations and considering all reasonable alternatives. This more informed, in-depth consideration of a number of EQL’s expenditure proposals was not evident to CCP14, certainly not to the same depth as similar matters have been discussed in other jurisdictions.[26]

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[22] QCOSS*, Submission on Ergon Energy's Regulatory Proposal 2020–25*, 31 May 2019; CCP14, *Submission on Ergon Energy's Regulatory Proposal 2020-25*, 31 May 2019, p.15.

[23] CCP14, *Submission on Ergon Energy's draft decision and revised proposal 2020–25 - revised*, March 2020, p.14.

[24] Energy Queensland, 2.001 *Customer Engagement Strategy* - Regulatory Proposal 2020–25, January 2019, p. 22.

[25] CCP14, *Submission on Ergon Energy’s draft decision and revised proposal 2020–25 - Revised*, March 2020, p.4.

[26] CCP14, *Submission on Ergon Energy’s draft decision and revised proposal 2020–25 - Revised*, March 2020, p.14.

In the context of Ergon Energy's revised capex proposal, consumers raised concerns around the state of Ergon Energy's assets and also how past capex, asset maintenance and inspection had been undertaken.[27]

Second, Energy Queensland acknowledged that it should have done more work consulting on the structure of its tariffs before it submitted its proposal.[28] Accordingly, Energy Queensland held an extensive round of consultations with its Tariff Structure Statement Working Group, who met several times during the development of the revised proposal.[29] CCP14 confirmed that in the later part of the reset, "*consumer groups have almost exclusively focussed on the Tariff Structure Statement (TSS) and its implications to the final electricity bill*".[30]

Despite this increased engagement, CCP14 noted that consumers continue to highlight concerns about the lack of clarity on how tariff changes and revenue reductions will translate through to their bills.[31]

The QCOSS observed that Energy Queensland has not set out a clear rationale for the proposed tariffs or tariff reform more broadly.[32] QCOSS further recommended that Energy Queensland, in conjunction with the Queensland Government, establish a transition working group to provide oversight and advice in preparation for the 2025–2030 regulatory period.[33]

Taking into account these observations, we acknowledge that Energy Queensland has otherwise conducted an inclusive engagement process, involving the views of stakeholders in the design of its proposals.

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27 For example see: QEUN, *Submission on Ergon Energy's draft decision and revised proposal 2020–25,* February 2020, p. *2.;* QFF, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.3.; Canegrowers, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.2.

28 Ergon Energy, *Revised regulatory proposal – Overview* – December 2019, p. 9.

29 https://www.talkingenergy.com.au/regulatory-tss-working-group

30 CCP14, *Submission on Ergon Energy's draft decision and revised proposal 2020–25 - Revised*, March 2020, p.15.

31 CCP14, *Submission on Ergon Energy's draft decision and revised proposal 2020–25 - Revised*, March 2020, p.15. See also; QCOSS, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.1.; ECA, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.3; QFF, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p. 2.

32 QCOSS, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.1.

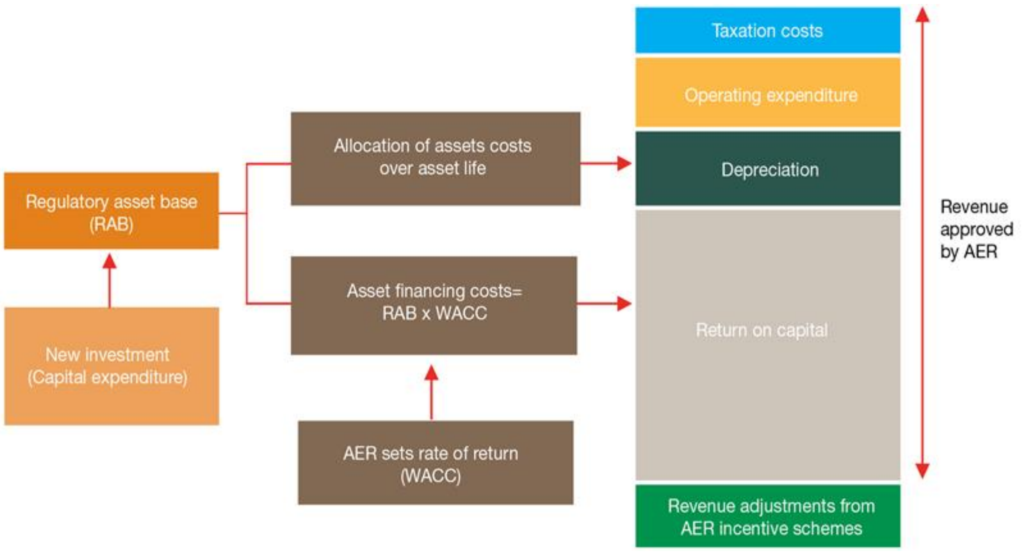
33 QCOSS, *Submission on Ergon Energy's draft decision and revised proposal 2020–25*, January 2020, p.3.

2 Key components of our final decision on revenue

The total revenue Ergon Energy proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period. Ergon Energy's proposal, and our assessment of it under the NEL and NER, are based on a 'building block' approach to determine a total revenue allowance (see Figure 5) which looks at six cost components:

- a return on the RAB (or return on capital, to compensate investors for the opportunity cost of funds invested in this business) (section 2.2)
- depreciation of the RAB (or return of capital, to return the initial investment to investors over time) (section 2.3)
- capex — the capital expenditure incurred in the provision of network services — mostly relates to assets with long lives, the cost of which are recovered over several regulatory control periods. The forecast capex approved in our decisions directly affects the projected size of the RAB and therefore the revenue generated from the return on capital and depreciation building blocks (section 2.4)
- forecast opex—the operating, maintenance and other non-capital expenses incurred in the provision of network services (section 2.5)
- the estimated cost of corporate income tax (section 2.6)
- revenue adjustments, including revenue increments or decrements resulting from the application of various incentive schemes (section 2.7).

Figure 5 The building block model to forecast network revenue



Source: AER, *State of the Energy Market*, December 2018, p.138.

We use an incentive approach where, once regulated revenues are set for a five year period, networks that keep actual costs below the regulatory forecast of costs retain part of the benefit. This incentive framework is a foundation of the regulatory framework, which aims to promote the NEO. Network businesses have an incentive to become more efficient over time, as they retain part of the financial benefit from improved efficiency. Consumers also benefit when efficient costs are revealed and a lower cost benchmark is set in subsequent regulatory periods.

Our final decision on Ergon Energy's distribution revenues for the 2020–25 regulatory control period is set out in Table 2.

Table 2 AER's final decision on Ergon Energy's revenues for the 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Return on capital	545.4	543.7	541.1	537.7	532.6	2700.5
Regulatory depreciation[a]	188.3	207.1	222.2	233.0	252.4	1103.1
Operating expenditure[b]	385.4	388.7	392.6	396.1	399.7	1962.5
Revenue adjustments[c]	48.0	32.0	52.8	15.9	12.0	160.6
Net tax allowance	0.8	0.0	0.0	0.0	0.0	0.8
Annual revenue requirement (unsmoothed)	1167.9	1171.5	1208.8	1182.7	1196.7	5927.6
Annual expected revenue (smoothed)	**1178.6**	**1181.9**	**1185.2**	**1188.5**	**1191.8**	**5925.9**
X factors[d]	n/a[e]	1.95%	1.95%	1.95%	1.95%	n/a

Source: AER analysis.

(a) Regulatory depreciation is straight-line depreciation net of the inflation indexation on the opening regulatory asset base (RAB).

(b) Includes debt raising costs.

(c) Includes revenue adjustments from demand management innovation allowance mechanism (DMIAM).

(d) The X factors will be revised to reflect the annual return on debt update. Under the CPI–X framework, the X factor measures the real rate of change in annual expected revenue from one year to the next. A negative X factor represents a real increase in revenue. Conversely, a positive X factor represents a real decrease in revenue.

(e) Ergon Energy is not required to apply an X factor for 2020–21 because we set the 2020–21 expected revenue in this decision. The expected revenue for 2020–21 is around 10.9 per cent lower than the approved total annual revenue for 2019–20 in real terms, or 8.9 per cent lower in nominal terms.

2.1 Regulatory asset base

The RAB is the value of assets used by Ergon Energy to provide regulated distribution services. The value of the RAB substantially impacts Ergon Energy's revenue requirement, and the price consumers ultimately pay. Other things being equal, a higher RAB would increase both the return on capital and depreciation (return of capital) components of the revenue determination.

As part of our decision on Ergon Energy's revenue for 2020–25, we make a decision on Ergon Energy's opening RAB as at 1 July 2020. We use the RAB at the start of each regulatory year to determine the return of capital (regulatory depreciation) and return on capital building block allowances.

Our final decision is to determine an opening RAB value of $11533.8 million ($ nominal) as at 1 July 2020 for Ergon Energy. This amount is $20.6 million (or 0.2 per cent) higher than Ergon Energy's revised proposed opening RAB of $11513.2 million ($ nominal) as at 1 July 2020.[34] While we largely accept the proposed methodology for calculating the opening RAB, we made the following amendments to Ergon Energy's proposed inputs to the roll forward model (RFM):

- Amended the actual capex for 2015–16 to 2018–19 to a correct for an error in the allocation of under and over recoveries of corporate overheads between capital and operating expenditures.
- The 2019–20 inflation input in the RFM with actual CPI for this year, which became available after Ergon Energy submitted its revised proposal.
- The value of legacy ICT assets to be rolled into the RAB as at 1 July 2020. This amount has been affected by updates to the capex spent on these assets in the final two years of the 2015–20 regulatory control period discussed further below).

Table 3 sets out the roll forward of the RAB to the end of the 2015–20 regulatory control period.

Table 3 AER's final decision on Ergon Energy's RAB for 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20 [a]
Opening RAB	9873.0	10226.0	10501.0	10806.7	11141.8
Capital expenditure[b]	620.4	511.8	498.9	552.1	550.4
Inflation indexation on opening RAB	166.7	150.9	200.5	192.8	205.1
Less: straight-line depreciation[c]	434.1	387.7	393.6	409.8	423.7
Interim closing RAB	10226.0	10501.0	10806.7	11141.8	11473.7
Difference between estimated and actual capex in 2014–15					–54.2
Return on difference for 2014–15 capex					–15.8
Roll-in of legacy ICT assets					130.2
Closing RAB as at 30 June 2020					**11533.8**

Source: AER analysis.

34 Ergon Energy - distribution roll forward model, *ERG 4.003 RFM - SCS DEC19 PUBLIC*, December 2019. This RAB value is based on as-incurred capex.

(a) Based on estimated capex provided by Ergon Energy for that year. We will true-up the RAB for actual capex at the next reset.

(b) Net of disposals and capital contributions, and adjusted for actual CPI and half-year WACC.

(c) Adjusted for actual CPI. Based on forecast capex.

For this final decision, we determine a forecast closing RAB value at 30 June 2025 of $12892.3 million ($ nominal) for Ergon Energy. This is $622.6 million (or 4.6 per cent) lower than Ergon Energy's revised proposal of $13514.9 million ($ nominal). Our final decision on the forecast closing RAB reflects the amended opening RAB as at 1 July 2020, and our final decisions on the expected inflation rate (section 2.2 of the Overview), forecast depreciation (attachment 4) and forecast capex (attachment 5).[35] Table 4 sets out our final decision on the forecast RAB values for Ergon Energy over the 2020–25 regulatory control period.

Table 4 AER's final decision on Ergon Energy's RAB for 2020–25 regulatory control period ($ million, nominal)

	2020–21	2021–22	2022–23	2023–24	2024–25
Opening RAB	11533.8	11818.9	12100.1	12378.1	12634.4
Capital expenditure[a]	473.4	488.3	500.2	489.3	510.3
Inflation indexation on opening RAB	262.3	268.8	275.2	281.5	287.3
Less: straight-line depreciation	450.6	475.9	497.4	514.5	539.7
Closing RAB	**11818.9**	**12100.1**	**12378.1**	**12634.4**	**12892.3**

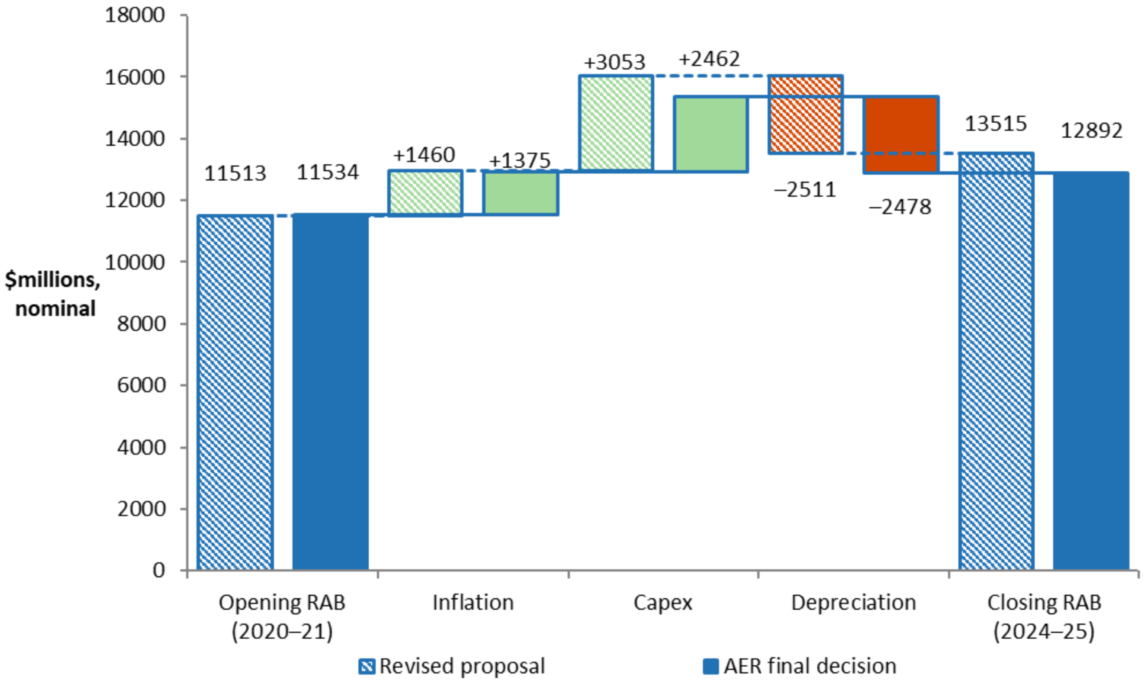
Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the post-tax revenue model (PTRM), the capex includes a half-year WACC allowance to compensate for the six-month period before capex is added to the RAB for revenue modelling.

Figure 6 shows the key drivers of the change in Ergon Energy's RAB over the 2020–25 regulatory control period for this final decision. Overall, the closing RAB at the end of the 2020–25 regulatory control period is forecast to be 11.8 per cent higher than the opening RAB at the start of that period, in nominal terms. The approved forecast net capex increases the RAB by 21.3 per cent, while expected inflation increases it by 11.9 per cent. Forecast depreciation, on the other hand, reduces the RAB by 21.5 per cent.

[35] Capex enters the RAB net of forecast disposals. It includes equity raising costs (where relevant) and the half-year WACC to account for the timing assumptions in the PTRM. Therefore, our final decision on the forecast RAB also reflects our amendments to the rate of return for the 2020–25 regulatory control period (section 2.2 of the Overview).

Figure 6 Ergon Energy's revised proposal and AER final decision RAB ($ million, nominal)



Source: AER analysis.

Note: Capex is net of forecast disposals and capital contributions. It is inclusive of the half-year WACC to account for the timing assumptions in the PTRM.

Further detail on our final decision regarding the RAB is set out in attachment 2.

2.2 Rate of return, expected inflation and imputation credits

The return each network business is to receive on its RAB (the ‘return on capital’) is a key driver of proposed revenues. We calculate the regulated return on capital by applying a rate of return to the value of the RAB.

This means we combine the return from the two sources of funds for investment: equity and debt. This allowed rate of return provides the network business with a return on capital to service the interest on its loans and give a return on equity to investors.

The rate of return is necessary to promote efficient prices in the long-term interests of consumers. If the rate of return is set too low, the network business may not be able to attract sufficient funds to be able to make the required investments in the network and reliability may decline. Conversely, if the rate of return is set too high, the network business may seek to spend too much and consumers will pay inefficiently high tariffs.

As required under the NEL, we apply the 2018 rate of return instrument (2018 Instrument) to estimate the rate of return for Ergon Energy.[36]

This leads to a rate of return of 4.73 per cent (nominal vanilla) for this final decision. This is 0.14 percentage points lower than our draft decision placeholder estimate of 4.87 per cent (nominal vanilla).[37]

This rate of return, in Table 5, will apply to the first year of the 2020–25 regulatory control period. A different rate of return will apply for the remaining regulatory years of the period. This is because we will update the return on debt component of the rate of return each year in accordance with the 2018 instrument, which uses a 10-year trailing average portfolio return on debt that is rolled-forward each year. Hence, only 10 per cent of the return on debt is calculated from the most recent averaging period with 90 per cent from prior periods.[38]

We also note that Ergon Energy's proposed risk free rate[39] and debt averaging periods have been (and will be) used to estimate its rate of return because they complied with conditions set out in the 2018 instrument.[40]

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[36] AER, *Rate of return instrument*, December 2018. See https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rate-of-return-guideline-2018/final-decision.

[37] AER, *Draft Decision, Ergon Energy Distribution Determination 2020-25,* October 2019, Overview, p. 28.

[38] This is the reason why in Ergon Energy's revised proposal and this final decision, the return on equity is below the return on debt. Our most recent estimate of the return on debt is below the contemporaneous return on equity (as expected, given debtholders face less risk than equity investors). However, the return on debt in past years was substantially higher than current estimates, and the trailing average reflects the interest costs facing a network that spreads its debt issuance across time.

[39] This is also known as the return on equity averaging period.

[40] AER, *Rate of return instrument*, December 2018, clauses 7–8, 23–25, 36.

Table 5 Final decision on Ergon Energy's rate of return (% nominal)

	AER draft decision (2020–25)	Ergon Energy's revised proposal (2020–25)	AER final decision (2020–25)	Allowed return over regulatory control period
Nominal risk free rate	1.32% [a]	0.90%	1.03% [b]	
Market risk premium	6.1%	6.1%	6.1%	
Equity beta	0.6	0.6	0.6	
Return on equity (nominal post–tax)	4.98%	4.56%	4.69%	Constant (%)
Return on debt (nominal pre–tax)	4.79%	4.75%	4.76% [c]	Updated annually
Gearing	60%	60%	60%	Constant (60%)
Nominal vanilla WACC	4.87%	4.67%	4.73%	Updated annually for return on debt
Expected inflation	2.45%	2.37%	2.27%	Constant (%)

Source: AER analysis; Ergon Energy, *Revised Regulatory Proposal 2020–25*, December 2019 p. 41.

[a] Calculated using a placeholder averaging period of 20 business day ending 31 July 2019.

[b] Calculated using an averaging period of 20 business day ending 20 February 2020.

[c] We use the proposed debt averaging period. The return on debt has been updated for this averaging period.

Expected inflation

Our estimate of expected inflation is 2.27 per cent. It is an estimate of the average annual rate of inflation expected over a 10 year period. We estimate expected inflation over this 10 year term to align with the term of the rate of return. Our estimate of expected inflation is estimated in accordance with the method set out in the post-tax revenue model (PTRM). The NER sets out how we are to apply the PTRM and the expected inflation estimation method in the model in our electricity determinations.[41]

Ergon Energy adopted our inflation approach in its revised proposal but proposed that we conduct a review into the method for estimating expected inflation and then apply the result of that review to its final decision.

For this final decision, we estimate expected inflation in a manner that is consistent with the method specified in the PTRM. In applying this method we have made two adjustments to our usual practice:

41 NER, r. 6.4.2(a) and (b)(1).

- We use inflation forecasts from the most recent Reserve Bank of Australia's (RBA) Statement on Monetary Policy (SMP) released on 8 May 2020. The RBA's SMP is released quarterly. Our usual approach is to use the RBA's February SMP in the PTRM in April final decisions for network businesses with regulatory years starting 1 July (that is, the regulatory period is based on financial years).[42] However, we delayed our decision to allow us to use the RBA's May SMP as we expected they would be a more accurate reflection of the economic circumstances expected for the next regulatory control period.
- We use the RBA's trimmed mean inflation (TMI) forecasts for the first two regulatory years (year-to-June 2021, and year-to-June 2022).[43] Our usual implementation is to use the (headline) consumer price index (CPI) forecasts for these periods.[44] In the current circumstances of COVID-19, we consider that the TMI series better reflects expectations of core inflation as set out in the RBA's May SMP. Further, the TMI smooths the transient volatility in the CPI forecasts in the RBA's May SMP.

We ran a short consultation process on the proposal to delay our final decision and use the RBA's May forecasts. Energy Queensland supported the delay and the use of forecasts from the RBA's May SMP, though it restated its position that the AER's overall inflation method was inadequate and unreliable.[45]

We have considered Ergon Energy's submissions on these matters in this final decision, attachment 3 Rate of Return.

Debt and equity raising costs

In addition to compensating for the required rate of return on debt and equity, we provide an allowance for the transaction costs associated with raising debt and equity. We include debt raising costs in the operating expenditure (opex) forecast because these are regular and ongoing costs. We include equity raising costs in the capital expenditure (capex) forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Ergon's revised proposal adopted the total opex forecast in our draft decision including our approach to estimate debt raising costs.[46] Our final decision is to accept Ergon Energy's revised (total) opex proposal including debt raising costs.

Ergon Energy's revised proposal calculated equity raising costs using our benchmark approach in the PTRM. Using this approach Ergon Energy forecasts zero equity raising

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42 The PTRM method specifies that we will use the *latest available* RBA SMP.

43 We have consistently used the TMI inflation forecasts from the RBA's May SMP in other related areas of our decision, in particular our opex assessment (see attachment 6).

44 The PTRM method specifies that we will use RBA SMP inflation forecasts for the first two years, but does not specify the series used.

45 Energy Queensland, *Letter re: Delay final decisions for Energex and Ergon Energy*, 24 April 2020.

46 See section 2.5 for our final decision on opex (which encompasses debt raising costs)

costs.[47] Therefore, we have updated our estimate for this distribution determination based on the benchmark approach, using updated inputs. This results in zero equity raising costs.

Imputation credits

Our final decision applies a value of imputation credits (gamma) of 0.585 as set out in the binding 2018 Instrument.[48] This was the result of extensive analysis and consultation conducted as part of the 2018 rate of return review.[49] Ergon's revised proposal has adopted the value of gamma set out in the 2018 Instrument.[50]

Further detail on our final decision in regards to Ergon Energy's allowed rate of return, expected inflation, debt and equity raising costs and imputation credits is set out in attachment 3.

2.3 Regulatory depreciation (return of capital)

Regulatory depreciation is the allowance provided so capital investors recover their investment over the economic life of the asset (return of capital). Ergon Energy invests capital in assets to provide electricity network services to its customers. The costs of these assets are recovered over the asset's useful life, which in many cases can be 50 or more years. This means only a small part of the cost of such assets are recovered from customers upfront or in any year. The greater proportion is recovered over time through the depreciation allowance. The regulatory depreciation allowance is the net total of the straight-line depreciation less the inflation indexation adjustment of the RAB.

Our final decision on Ergon Energy's revenue for 2020–25 includes a regulatory depreciation allowance of $1103.1 million ($ nominal). This is $51.6 million or (4.9 per cent) higher than Ergon Energy's revised proposal.

We adopt the same approach to regulatory depreciation as Ergon Energy, including its revised proposed standard asset lives which determine how quickly an asset class is removed from the RAB. We have accepted Ergon Energy's revised proposal to reallocate some of its property capex to the 'Office furniture & equipment' asset class, which has a shorter standard life than the 'Buildings' asset class where the capex was initially allocated.

We accept Ergon Energy's revised proposal to apply the year-by-year tracking approach, subject to minor updates to its depreciation tracking model. We have also made determinations on other components of Ergon Energy's revised proposal, which affect the RAB and in turn impacts the forecast regulatory depreciation allowance. The

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47 Ergon Energy, *2020–2025 Revised Regulatory Proposal*, December 2019, p. 46; Ergon Energy, *Revised Proposal 4.002-PTRM*, December 2019

48 AER, *Rate of return instrument*, December 2018, clause 27.

49 AER, *Rate of return instrument explanatory statement*, December 2018, pp. 307–382.

50 Ergon Energy, *2020–25 Revised Regulatory Proposal,* December 2019, p. 41.

increase to the regulatory depreciation allowance from the revised proposal primarily reflects our final decision expected inflation rate for the 2020–25 regulatory control period. Our final decision for Ergon Energy’s straight-line depreciation component of regulatory depreciation is lower than the revised proposal by $33.4 million due to our determination of the opening RABs (attachment 2) and the forecast capex (attachment 5). However, this reduction is offset by our final decision on the indexation of the RAB, which is $85.0 million lower than the revised proposal. This is largely due to applying a lower expected inflation rate of 2.27 per cent per annum in this final decision (attachment 3) compared to Ergon Energy’s revised proposal of 2.37 per cent per annum. Subsequently, the net effect is an increase in the regulatory depreciation allowance of $51.6 million.

Further detail on our final decision regarding depreciation is set out in attachment 4.

2.4 Capital expenditure

Capital expenditure (capex) refers to the investment in assets to provide network services. This investment mostly relates to assets with long lives and these costs are recovered over several regulatory periods. Capex is added to Ergon Energy's RAB, which is used to determine the return on capital and return of capital (regulatory depreciation) building block allowances. All else being equal, higher forecast capex will lead to a higher projected RAB value and higher return on capital and regulatory depreciation allowances.

Ergon Energy’s revised total net capex forecast is $2804.3 million ($2019–20). Its revised capex forecast is 3 per cent higher than its initial proposal and 30 per cent higher than our draft decision. Ergon Energy’s revised proposal accepted our draft decision on ICT capex and aspects of property capex, but it increased its repex forecast by 18 per cent in its revised proposal.

Our final decision on Ergon Energy's revenue includes a total net capex forecast of $2276.2 million ($2019–20) for the 2020–25 regulatory control period. This is 19 per cent lower than Ergon Energy's revised proposal. We came to the view that Ergon Energy had proposed more capex than an efficient and prudent operator needs for the safe and reliable operation of its system. Our final decision is $125.3 million (6 per cent) higher than our draft decision. Higher repex and augex forecasts than our draft decision primarily drive this difference. Table 6 shows our final decision compared with Ergon Energy's revised total net capex forecast.

Table 6 AER’s final decision on total net capex ($ million, 2019–20)

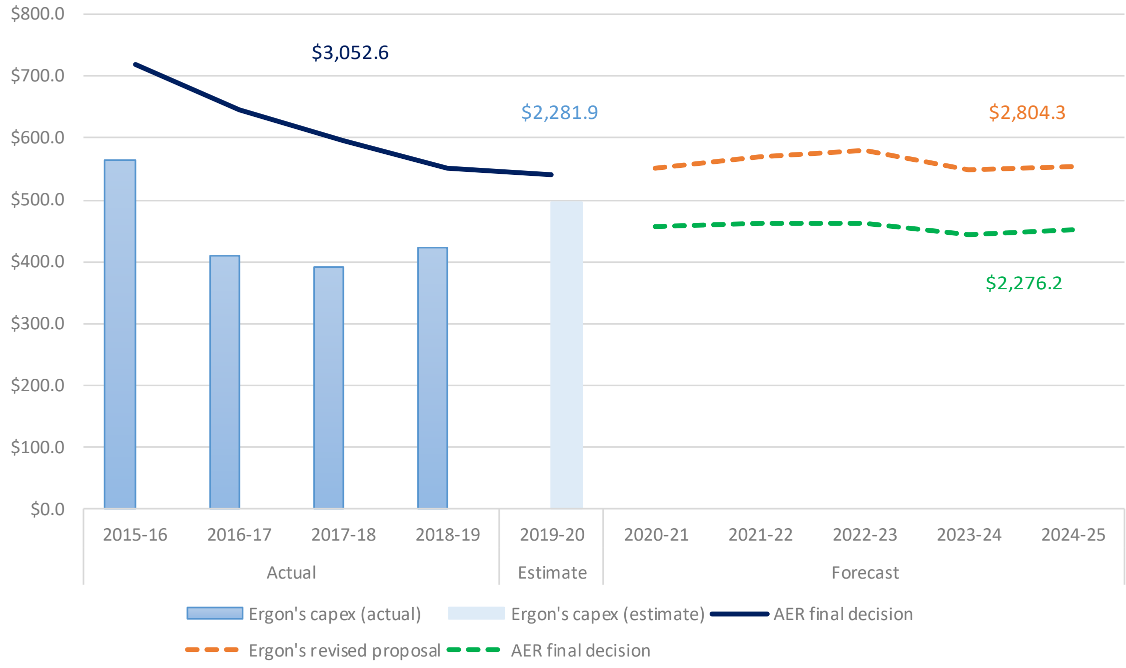
	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Ergon Energy's revised proposal	551.6	568.8	580.7	549.5	553.7	2804.3
AER final decision	457.5	461.6	462.7	442.7	451.8	2276.2
Difference ($)	-94.1	-107.2	-118.0	-106.8	-101.9	-528.1
Percentage difference (%)	-17%	-19%	-20%	-19%	-18%	-19%

Source: AER analysis and Ergon Energy.

Note: Numbers may not sum due to rounding. The figures above do not include equity raising costs, capital contributions and asset disposals. See attachment 3 for our assessment of equity raising costs.

Figure 7 shows our capex final decision compared with Ergon Energy's revised proposal. It also shows our 2015–20 regulatory period final decision and actual capex.

Figure 7 AER's final decision on total forecast capex ($ million, 2019–20)



Source: Ergon Energy's revised proposal and AER analysis.

Note: Ergon Energy's actual and estimated capex is based on its recast category analysis RIN data, which reflects Ergon Energy's new CAM that will apply for the 2020–25 regulatory period. The 2015–20 AER final decision allowance therefore is not directly comparable with the historical and forecast capex amounts shown.

Our assessment looks at the main factors that influence the need for capex. We do not determine which programs or projects a distributor should or should not undertake. Rather, once we set a capex forecast, it is up to the distributor to prioritise its capex program over the course of the regulatory period.

A key part of our assessment has been examining the reasons that led Ergon Energy to propose a step up in its capex spending compared to last period. In particular, Ergon Energy did not provide adequate material in support of its forecast repex of $1289.6 million ($2019–20), which was 43 per cent higher than its actual repex of $899.1 million ($2019–20) over the current regulatory period. Based on the information before us, our alternative forecast provides Ergon Energy a sufficient amount for repex to address its mandatory safety and non-safety obligations over the forecast period.

We have included a repex forecast of $891.8 million ($2019–20) in our substitute estimate of total capex, which is 31 per cent lower than Ergon Energy's revised repex forecast. A repex forecast that is broadly in line with Ergon Energy's revealed historical costs is appropriate, because repex is largely recurrent in nature. Further, Ergon Energy's material underspend of almost $300 million over the current period indicates that it does not require a large increase to its capital expenditure over the forecast period. In addition, Ergon Energy’s high-level network performance has not changed and we do not expect there to be any significant change in performance over the forecast period given business-as-usual repex spend.

In coming to our position on repex, we had regard to several factors including:

- Recognising the importance of safety related expenditure. Consistent with our previous decisions, we acknowledge and have funded network businesses to address safety risks where the network business provides evidence to support its forecast. However, in this case, Ergon Energy has not provided sufficient information to support its proposed expenditure. In particular, Ergon Energy’s risks particularly the safety risks associated with the network were significantly overstated. Many of these risks were not justified adequately in its business cases. An overstatement of risk in turn means that the repex cost to mitigate that risk is also overstated. For instance, we did not accept Ergon Energy’s proposed LV safety program as these risks were not based on actual performance. In that case, while not accepting the program, we acknowledge that there is a broken neutral problem with its service lines. We have therefore included Ergon Energy’s proposed step up in repex to replace service lines, which directly addresses the broken neutral problem.
- Results from our repex modelling which indicate that, on average, Ergon Energy’s units costs, are higher than the industry average and it replaces its assets sooner than other businesses. For instance, for its clearance to ground and structure program, Ergon Energy did not provide evidence for its forecast unit costs which were more than 80 per cent higher than it is currently incurring. Therefore, while we have accepted Ergon Energy’s proposed volume of compliance works for this program, we have not accepted the unit costs.
- A review of Ergon’s high-level network performance which has not deteriorated, indicated by publicly available long-term network performance measures (SAIDI, SAIFI and asset failure data).
- The majority of stakeholders including the ECA, CCP14 and other consumer groups did not support Ergon’s significantly higher revised repex forecast.

Other key aspects of our final decision are:

- We accept Ergon Energy's revised connections, ICT capex and other non-network capex forecasts subject to minor adjustments.
- For augmentation capex, we have included $212.9 million ($2019–20) in our final decision compared with Ergon Energy's revised forecast of $239.5 million. In our draft decision, we did not accept a range of sub transmission growth, power quality and network communications projects. This was primarily due to insufficient supporting information and Ergon Energy not appropriately quantifying risk. Ergon Energy’s revised proposal addressed the information shortfall to a large extent, but the intelligent grid enablement (IGE) program and three other network communications projects remain insufficiently supported.

- For property capex, Ergon Energy's revised proposal includes $103.8 million ($2019–20), which is $24.7 million lower than its initial proposal. We have included $65.8 million ($2019–20) for property in our substitute estimate of total capex. We are satisfied that Ergon Energy has demonstrated that most of its property capex is prudent and efficient. However, we are not satisfied Ergon Energy has justified some of its proposed refurbishment and security upgrade capex.
- Our capitalised overheads forecast is 11 per cent lower than Ergon Energy's revised proposal. Ergon Energy accepted our capitalised overheads methodology and our reduction is driven by necessary adjustments to ensure consistency across elements of our final decision.

2.5 Operating expenditure

Operating expenditure (opex) is the forecast of operating, maintenance and other non-capital costs incurred in the provision of standard control services.

Our final decision is to accept Ergon Energy's revised opex proposal of $1834.6 million ($2019–20), including debt raising costs, for the 2020–25 regulatory control period. For its revised proposal, Ergon Energy adopted the opex in its initial proposal, which we accepted in our draft decision. We have tested Ergon Energy's proposal by comparing it to our alternative estimate of total opex of $2017.7 million ($2019–20).[51] Our alternative estimate is $183.0 million (or 10.0 per cent) higher than Ergon Energy's opex proposal. There are a number of drivers of the difference between our alternative estimate and Ergon Energy's revised proposal, including our efficiency and other adjustments to base opex, which are set out in attachment 6. Figure 8 shows the opex included in Ergon Energy's revised proposal, its past AER approved forecast and past actual expenditure.

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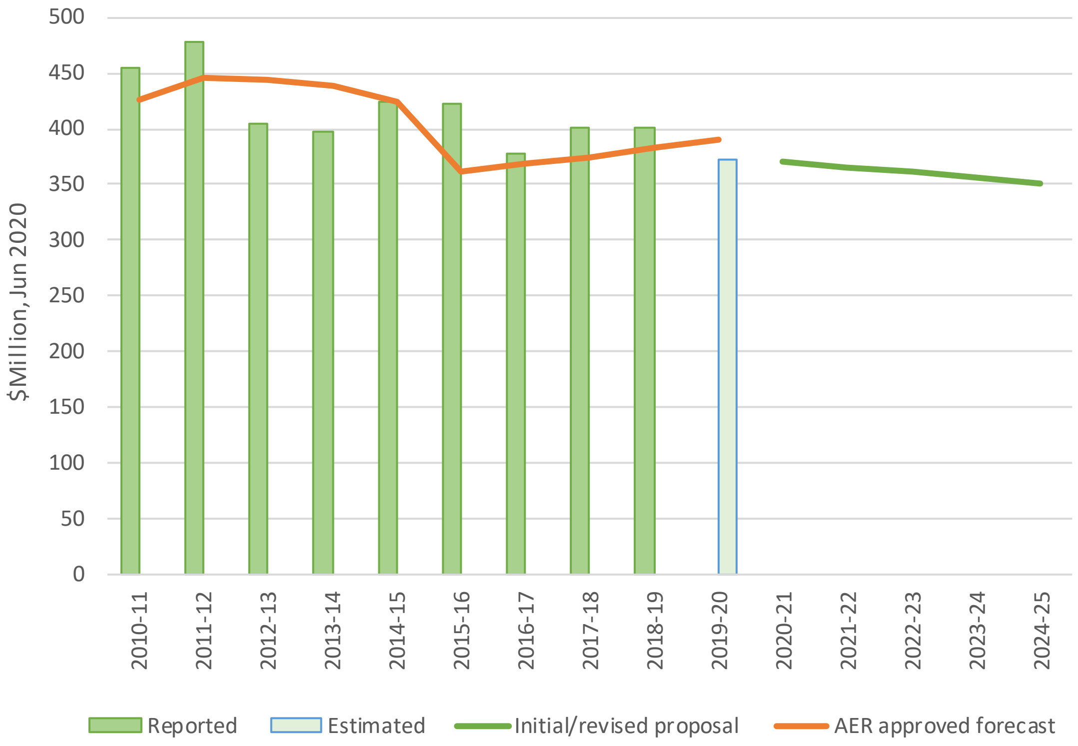
51 Includes debt-raising costs. We use the RBA's May 2020 SMP trimmed mean inflation forecasts for the year ending June 2020. See section 2.2 – Rate of return, expected inflation and value of imputation credits for more details.

Figure 8 Historical and forecast opex ($ million, 2019–20)



Source: AER analysis; Ergon Energy*, Regulatory Accounts 2010–11 to 2018–19*; Ergon Energy, *Economic Benchmarking RIN responses 2010 to 2019,* Ergon Energy, *6.008 - Opex forecast - SCS*, January 2019; Ergon Energy, *Post Tax Revenue Model (PTRM) PTRM Distribution*, December 2019.

Note: Excludes debt raising costs

2.6 Corporate income tax

The building block approach to the calculation of revenue includes an allowance for the estimated cost of corporate income tax payable by Ergon Energy. Under the post-tax framework, corporate income tax allowance is calculated as part of the building block assessment using our post-tax revenue model (PTRM). Our final decision on Ergon Energy's estimated cost of corporate income tax is $0.8 million ($ nominal) over the 2020–25 regulatory control period. This is $0.8 million higher than Ergon Energy's revised proposal of zero corporate income tax. This is based on:

- Our final decision to apply a higher rate of return on equity (attachment 3).[52]
- Our final decision to reduce the immediately expensed capex for tax purposes to $556.5 million from $622.0 million.[53]

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[52] All else equal, a higher rate of return on equity will increase the cost of corporate income tax because it increase the return on equity, a component of the taxable income.

[53] All else equal, a higher amount of capex that are immediately expensed for tax purposes will increase the tax expense and lower the cost of corporate income tax.

- Our final decision to increase the revised proposed opening tax asset base (TAB) value as at 1 July 2020 by $4.0 million to $7774.0 million.[54]
- Our final decisions on the regulatory depreciation (attachment 4) and forecast capital expenditure (attachment 5) affect the calculation of the estimated taxable income, which in turn impacts the tax allowance.

The combination of the above decisions resulted in a positive forecast taxable income for Ergon Energy in 2020–21, but forecast tax losses for the remaining four years of the 2020–25 regulatory control period.[55] For this reason, our final decision is to set the 2020–21 cost of corporate income tax based on the forecast taxable income for that year, but set the cost of corporate income tax at zero for 2021–25 for Ergon Energy. We have determined that $22.5 million in tax losses as at 30 June 2025 will be carried forward to the 2025–30 regulatory control period.

We accept Ergon Energy's revised proposal on the standard tax asset lives for all of its asset classes, consistent with our draft decision. We have updated Ergon Energy's remaining tax asset lives as at 1 July 2020 to reflect our amendment to the opening TAB value.[56] Further detail on our final decision regarding corporate income tax is set out in attachment 7.

2.7 Revenue adjustments and incentive schemes

Incentive schemes are a component of incentive based regulation and complement our approach to assessing efficient costs. These schemes provide important balancing incentives under the revenue determination to encourage Ergon Energy to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

In its initial proposal Ergon Energy elected not to claim the rewards it accrued from the operation of the efficiency benefit sharing mechanism (EBSS) and capital expenditure sharing scheme (CESS) during the current regulatory control period (2015–20), subject to us accepting its regulatory proposal. Accordingly, in our draft decision we did not include any EBSS or CESS increments or decrements in Ergon Energy's allowed revenues.

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[54] All else equal, a higher opening TAB value will increase the tax depreciation, a component of the tax expense, and lower the cost of corporate income tax.

[55] A forecast tax loss occurs when the forecast taxable income is lower than the forecast tax expense. In this event no tax is payable. Any residual amount of tax loss will be carry forward over to future regulatory control periods to offset future taxable income until the full amount is exhausted.

[56] The opening TAB value update reflects our updated value of the legacy ICT assets to be rolled into the opening TAB and our correction for errors in the reported actual capex for 2015–16 to 2018–19. Both are inputs to the calculation of the remaining tax asset lives as at 1 July 2020. Further details are set out in attachment 7 of this final decision.

In its revised proposal Ergon Energy has elected to claim the rewards from the EBSS and CESS. Therefore, we have added the EBSS and CESS rewards it has accrued in the current period to the final decision total revenue.

- Efficiency benefit sharing scheme—Ergon Energy accrued carryover amounts totalling $98.4 million ($2019–20)[57] from the application of the EBSS in the current regulatory control period. This is $95.5 million ($2019–20) less than Ergon Energy's revised proposal of $193.9 million ($2019–20). We have set out the reasons for this difference in attachment 8. The EBSS is intended to provide a continuous incentive for distributors to pursue efficiency improvements in opex, and provide for a fair sharing of these between network businesses and network users. Consumers benefit from improved efficiencies through lower forecast opex in subsequent periods. Attachment 8 sets out our final decision on Ergon Energy's EBSS.
- Capital expenditure sharing scheme (CESS) — we have included a CESS revenue increment of $48.4 million ($2019–20) for the application of the CESS during the 2015–20 regulatory control period. This amount is different to the $46.1 million included in Ergon Energy's revised proposal. This difference reflects updates to inflation, WACC and the RFM. We have made no further adjustments as we are satisfied our substitute forecast of capex does not include any material deferral of capex. The CESS rewards efficiency gains and penalises efficiency losses, each measured by reference to the difference between forecast and actual capex. Attachment 9 sets out our final decision on Ergon Energy's CESS.
- Service target performance incentive scheme (STPIS) - Our final decision is to apply our national STPIS version 2.0 (November 2018)[58] to Ergon Energy for the 2020–25 regulatory control period. We will not apply the guaranteed service level component to Ergon Energy as the existing jurisdictional arrangements continue to apply. Attachment 10 sets out our final decision on Ergon Energy's STPIS.
- Demand management incentive scheme (DMIS) and Demand management innovation allowance mechanism (DMIAM). Our final decision is to apply the DMIS[59] and the DMIAM[60] to Ergon Energy for the 2020–25 regulatory control period, without any modification. Our draft decision reasons form part of this final decision.
- Table 7 sets out the DMIAM allowance for Ergon Energy for the 2020–25 regulatory control period, based on the final PTRM for Ergon Energy.

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57 We use the RBA's May 2020 SMP trimmed mean inflation forecasts for the year ending June 2020. See section 2.2 – Rate of return, expected inflation and value of imputation credits for more details.

58 AER, *Electricity distribution network service providers—service target performance incentive scheme version 2.0*, November 2018. (AER, *STPIS v2.0*, November 2018).

59 AER, *Demand management incentive scheme*, *Electricity distribution network service providers*, December 2017.

60 AER, *Demand management innovation allowance mechanism*, *Electricity distribution network service providers*, December 2017.

Table 7 AER's final decision on Ergon Energy's demand management innovation allowance ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
DMIAM	1.07	1.05	1.06	1.02	1.01	5.21

Source: AER analysis

3 Tariff structure statement

Ergon Energy's 2020–25 proposal includes the second iteration of its tariff structure statement (TSS). Its current TSS applies from 1 July 2017 to 30 June 2020.

A TSS applies to a distributor's tariffs for the duration of the regulatory control period. It describes a distributor's tariff classes and structures, the distributor's policies and procedures for assigning customers to tariffs, the changing parameters for each tariff, and a description of the approach the distributor takes to setting tariffs in pricing proposals. It is accompanied by an indicative pricing schedule.[61] A TSS provides consumers and retailers with certainty and transparency in relation to how and when network tariff structures will change.

While an indicative pricing schedule must accompany the TSS, Energy Energy's tariff levels for the entire 2020–25 regulatory control period are not set as part of this determination. Rather, tariff levels for 2020–21 and other years will be subject to a separate annual approval process.

The purpose of the TSS process in driving network tariff reform is to:

- provide better price signals to retailers—underlying network tariffs that reflect what it costs to use electricity at different times.
- transition to greater cost reflectivity—requiring distributors to explicitly consider the impacts of tariff changes on customers, and engaging with consumers, consumer representatives and retailers in developing network tariff proposals over time.
- manage future expectations—providing guidance for retailers, consumers and suppliers of services such as local generation, batteries and demand management by setting out the distributor's tariff approaches for the entire duration of the regulatory control period.

The Queensland electricity distributors are at the forefront of the consumer driven and technology enabled transformation of the energy sector in Australia. They are leading the industry in the use of automated load control in the residential and small business customer segment. We support their efforts to expand the use of controlled load products to assist consumers to improve the utilisation of their electricity distribution network.

Ergon Energy has proposed some significant changes to its tariffs and tariff structures for the 2020–25 regulatory control period, including:

- Introducing a transitional demand tariff on 1 July 2020.
- Introducing a time of use energy tariff on 1 July 2020. This tariff will be offered on a voluntarily opt-in basis to all customer connections with a smart meter installed.

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61 NER cl.6.18.1A(a)

- Reassigning most existing customer connections with smart metering that are currently on the flat tariffs to the transitional demand tariff on 1 July 2021
- Introducing new load control tariffs for business customers.

Our final decision broadly supports the direction of the above changes. However, we have concerns with some aspects of the TSS.[62] In Attachment 18, we have therefore set out a series of changes that we consider necessary for us to approve the TSS. These include amendments to provide a 12 month grace period to existing consumer connections that have their basic accumulation meter replaced due to end of life reasons and to allow some large users to opt-in to a transitional individually calculated tariff where it is necessary to do so for customer impact mitigation reasons.

Further, in light of the uncertainty and impacts of the COVID-19 pandemic on residential and business consumers, we have decided to include transitional arrangements in the first year of the regulatory control period to help consumers and retailers adjust to the new tariff structures. These transitional arrangements are explained in Attachment 18 of this decision.

There are also some minor wording changes we have made to Ergon Energy's TSS to improve clarity in a few areas.

We and Ergon Energy both consider network tariff reform is important. Our reasons for supporting network tariff reform and the majority of Ergon Energy's revised TSS proposal reflects our own views on what we consider to be the key rationale for network tariff reform in Queensland. This is somewhat different to Ergon Energy's reasons for its proposal which, among other matters, was framed in terms of unwinding what Ergon Energy considers to be cross-subsidies between different consumers. Our reasons are framed more in terms of creating the right incentives on retailers and consumers for more efficient and innovative retail products and more efficient and informed end user choices in when and how they utilise the grid. In turn, we expect this to lead to more efficient utilisation of the network and network investment in the long term interests of all consumers. We explain our reasons further below.

The economic benefits of network tariff reform in Queensland are likely to be modest in the short term given the presence of excess network capacity and prospects of modest growth in peak demand. Nevertheless, we consider that the long term interests of consumers are best served by commencing the network tariff reform process in Queensland. This is because delaying tariff reform is likely to mean that consumers will continue to be encouraged to make investment and consumption decisions under the existing legacy flat tariffs, because they are not presented with alternative options. We are concerned that this would have long term efficiency implications because these tariffs reward customers for reducing their overall energy consumption rather than reducing their peak demand for network capacity. It should also be noted that flat tariffs convey no financial incentive to consumers to shift the timing of their solar PV exports

[62] NER, cl.6.18.5

into the electricity network away from the middle of the day, even when these exports are causing electricity distributors to incur costs, such as for voltage management and in some cases potentially denying customers with solar PV the ability to earn income from these exports through the imposition of export limits. Broader energy system transition challenges from low minimum demand can also arise in needing a fleet of generators and storage that are flexible enough to ramp up generation output from the midday lows to evening peaks in demand.

To be clear, we consider residential and small business consumers should continue to have the option of simple flat retail tariffs. The point is they should also have additional retail options which are enabled by network tariff reform. In the absence of network tariff reform, retailers will have little commercial incentive to encourage their consumers to make more efficient decisions in regard to energy investments and how they use the electricity network by passing through efficient network price signals, encouraging consumers to take-up alternative tariff options, such as controlled load tariffs, or the pursuit of well targeted localised demand management initiatives.

In light of the potential long term prospects of an upturn in electric vehicle ownership, network tariff reform can also contribute to reducing the growth in peak demand which might result, and therefore reduce the localised network congestion and need to invest in additional peak network capacity that would otherwise occur. This can be achieved through introducing more efficient peak price signals that incentivise consumers (or retailers acting on behalf of customers) to better manage the timing of their electric vehicle charging.

It is important to note that distributors charge retailers for the network services provided to end-consumers and there is no obligation on market retailers to pass the network tariff structure through to their end-customers. In Ergon Energy's distribution network area, the majority of consumers are on regulated retail offers, though they can also choose a market offer. The retail tariff structure for those regulated retail offers is determined by the Queensland Competition Authority, and may not necessarily reflect the same structure as the underlying network tariff structure.

Ergon Energy and Energex are both part of the Energy Queensland group and have based their separate revised TSS proposals on a largely common tariff strategy across the two networks. As a result, our assessment is also largely common across both proposals. We have published a single Attachment 18 that covers our assessment of both revised TSS proposals. This attachment distinguishes elements that specifically relate to Ergon Energy, such as the tariff arrangements designed to mitigate the impact of changes in regulated retail tariff arrangements in regional Queensland.

4 Other price terms and conditions

In this section, we consider the other aspects of our determination. These may be described as the terms and conditions of our determination that cover how Ergon Energy must set its prices. These include the classification of services, the conditions under which we may grant Ergon Energy additional revenues to cover unforeseen circumstances and the framework for Ergon Energy's negotiated services and customer connections.

4.1 Classification of services

Service classification determines the nature of economic regulation, if any, that is applicable to specific distribution services. Classification is important to customers as it determines which network services are included in basic electricity charges, the basis on which additional services are sold, and which services we will not regulate. Our decision reflects our assessment of a number of factors, including existing and potential competition to supply these services.

Our final decision is to retain the classification structure and the services list as published in our draft decision for Ergon Energy.[63] The list of classified services Ergon Energy will provide for 2020–25 is set out in Attachment 12.

4.2 Pass through events

Ergon Energy's revised proposal included four nominated pass through events (insurance cap, insurer credit, risk natural disaster and terrorism). Our draft decision accepted these nominated pass through events, but with amended definitions so that the pass through events that apply to Ergon Energy were consistent with recent decisions for other network service providers.

Ergon Energy's revised proposal adopted our amended definitions. We approve the insurer credit risk, natural disaster and terrorism nominated pass through events in its revised proposal for the final decision. We also approve an insurance coverage event, previously referred to as an insurance cap event. This reflects further amendments to this nominated pass through event that take into account potential changes in insurance liability market conditions that may lead to insurance coverage gaps. We consulted with Ergon Energy about these changes and it stated it was comfortable with adopting them. We are also making these changes for other network service providers. Our final decision for these four nominated pass through events is set out in Attachment 14.

[63] AER, *Draft decision Ergon Energy Distribution Determination 2020 to 2025*, Attachment 12 Classification of services, October 2019. The services list can be found in Attachment A.

4.3 Negotiating framework and criteria

In our draft decision, we approved Ergon Energy's proposed distribution negotiating framework for the 2020–25 regulatory control period.[64] We did not receive any objections or submissions on our draft decision.

Our final decision is to approve Ergon Energy's negotiating framework. The distribution negotiating framework that will apply to Ergon Energy for the period of this determination is set out in Attachment A.

We are also required to make a decision on the negotiated distribution service criteria (NDSC) for the distributor.[65] Our final decision is to retain the NDSC that we published for Ergon Energy in October 2019[66] for the 2020–25 regulatory control period. The NDSC gives effect to the negotiated distribution services principles.[67]

4.4 Connection policy

In our draft decision, we did not approve Ergon Energy's proposed connection policy for the 2020–25 regulatory control period.[68] We modified Ergon Energy's connection policy nominated in its original proposal, to the extent necessary in order that the approved policy would be consistent with the rules' requirements.

We did not receive any submission on our draft decision.

In its revised proposal, Ergon Energy did not accept our draft decision on its connection policy.[69]

Our final decision is to maintain our draft decision. We do not approve Ergon Energy's revised connection policy because its proposed upstream shared network augmentation rates are not consistent with the connection charge principles in chapter 5A of the NER. Attachments 17 of our draft and final decisions set out our reasons.

The approved connection policy for Ergon Energy's 2020–25 regulatory control period is appended to attachment 17 of our draft decision.

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64 AER, *Draft Decision, Ergon Energy Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-5.

65 NER, cl. 6.12.1(16).

66 AER, *Draft Decision, Ergon Energy Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-10, 11.

67 NER, cl. 6.7.1.

68 AER, *Draft Decision, Ergon Energy Distribution Determination 2020–25,* October 2019, Attachment 17.

69 Ergon Energy, *Revised Regulatory Proposal*, December 2019, pp. 56-58.

5 The National Electricity Law and Rules

The (NEL and NER) provide the regulatory framework governing electricity distribution networks. Our work under this framework is guided by the National Electricity Objective (NEO):[70]

> "…to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to—
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system."

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[71] The focus of the NEO is on promoting efficient investment in, and operation and use of, electricity services (rather than assets) in the long term interests of consumers.72 This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[73]

Electricity determinations are complex decisions. In most cases, the provisions of the NER do not point to a single answer, either for our decision as a whole or in respect of particular components. They require us to exercise our regulatory judgement. Where there are choices to be made among several plausible alternatives, we have selected what we are satisfied would result in an overall decision that contributes to the achievement of the NEO to the greatest degree. [74]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[75] These are set out in appendix A and the relevant attachments. In coming to a decision that contributes to the achievement of the NEO, we have considered interrelationships of the constituent components of our final decision in the relevant attachments. Examples include:

- underlying drivers and context which are likely to affect many constituent components of our decision. For example, forecast demand affects the efficient levels of capex and opex in the regulatory control period (see attachment 5 and 6).
- direct mathematical links between different components of a decision. For example, the level of gamma has an impact on the appropriate tax allowance; the benchmark

70 NEL, s. 7.

71 NEL, s. 16(1)(a).

72 This is also the view of the Australian Energy Markets Commission (the AEMC). See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

73 Hansard, *SA House of Assembly,* 26 September 2013, p. 7173. See also the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 7–8.

74 NEL, s. 16(1)(d).

75 NER, cl. 6.12.1.

efficient entity's debt to equity ratio has a direct effect on the cost of equity, the cost of debt, and the overall vanilla rate of return (see attachments 3 and 7).

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa (see attachments 5 and 6).

In general, we consider that the long-term interests of consumers are best served where consumers receive a reasonable level of safe and reliable service that they value at least cost in the long run.[76] A decision that places too much emphasis on short term considerations may not lead to the best overall outcomes for consumers once the longer term implications of that decision are taken into account. [77]

There may be a range of economically efficient decisions that we could make in a revenue determination, each with different implications for the long term interests of consumers.[78] A particular economically efficient outcome may nevertheless not be in the long term interests of consumers, depending on how prices are structured and risks allocated within the market. [79] There are also a range of outcomes that are unlikely to advance the NEO, or advance the NEO to the degree that others would. For example, we consider that:

- the long term interests of consumers would not be advanced if we encourage overinvestment which results in prices so high that consumers are unwilling or unable to efficiently use the network.[80]
- equally, the long-term interests of consumers would not be advanced if allowed revenues result in prices so low that investors do not invest to sufficiently maintain the appropriate quality and level of service, and where customers are making more use of the network than is sustainable leading to safety, security and reliability concerns.[81]

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[76] Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

[77] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, pp. 6–7.

[78] *Re Michael: Ex parte Epic Energy* [2002] WASCA 231 at [143].

[79] See, for example, the AEMC, *'Applying the Energy Objectives: A guide for stakeholders'*, 1 December 2016, p. 5.

[80] NEL, s. 7A(7).

[81] NEL, s. 7A(6).

A Constituent decisions

Our final decision on Ergon Energy's distribution determination for the 2020–25 regulatory control period includes the following constituent components:

Constituent decisions
In accordance with clause 6.12.1(1) of the NER, the AER's final decision is that the classification of services as set out in Attachment 12, and unchanged from our draft decision, will apply to Ergon Energy for the 2020–25 regulatory control period.
In accordance with clause 6.12.1(2)(i) of the NER, the AER's final decision is not to approve the annual revenue requirement set out in Ergon Energy's building block proposal. Our final decision on Ergon Energy's annual revenue requirement for each year of the 2020–25 regulatory control period is set out in attachment 1 of the final decision.
In accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve Ergon Energy's proposal that the regulatory control period will commence on 1 July 2020. Also in accordance with clause 6.12.1(2)(ii) of the NER, the AER's final decision is to approve Ergon Energy's proposal that the length of the regulatory control period will be 5 years from 1 July 2020 to 30 June 2025.
The AER did not receive a request for an asset exemption under clause 6.4.B.1 (a)(1) and therefore has not made a decision in accordance with clause 6.12.1(2A) of the NER.
In accordance with clause 6.12.1(3)(i) and acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is not to accept Ergon Energy's proposed total net forecast capital expenditure of \$2804.3 million (\$2019–20). Our final decision includes a substitute estimate of Ergon Energy's total net forecast capex for the 2020–25 regulatory control period of \$2276.2 million (\$2019–20). The reasons for our final decision are set out in attachment 5 of the final decision.
In accordance with clause 6.12.1(4) and acting in accordance with clause 6.5.6(c) of the NER, the AER's final decision is to accept Ergon Energy's proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of \$1834.6 million (\$2019–20). This is discussed in attachment 6 of the final decision.
Ergon Energy did not propose any contingent projects and therefore the AER has not made a decision under clause 6.12.1(4A) of the NER.
In accordance with clause 6.12.1(5) of the NER and the 2018 Rate of Return Instrument, the AER's final decision is that the allowed rate or return for the 2020–21 regulatory year is 4.73 per cent (nominal vanilla), as set out in attachment 3 of the final decision. The rate of return for the remaining regulatory years 2021–25 will be updated annually because our decision is to apply a trailing average portfolio approach to estimating debt which incorporates annual updating of the allowed return on debt.
In accordance with clause 6.12.1(5A) of the NER and the 2018 Rate of Return Instrument, the AER's final decision on the value of imputation credits as referred to in clause 6.5.3 is to adopt a value of 0.585. This is discussed in section 2.2 of this final decision overview.

Constituent decisions

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on Ergon Energy's regulatory asset base as at 1 July 2020 in accordance with clause 6.5.1 and schedule 6.2 is $11533.8 million ($ nominal). This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(7) of the NER, the AER’s final decision on the estimate of Ergon Energy's corporate income tax is $0.8 million ($ nominal) over the 2020–25 regulatory control period. This is discussed in attachment 7 of the final decision.

In accordance with clause 6.12.1(8) of the NER, the AER's final decision is not to approve the depreciation schedules submitted by Ergon Energy. Our final decision substitutes alternative depreciation schedules that accord with clause 6.5.5(b) and this is discussed in attachment 4 of the final decision.

In accordance with clause 6.12.1(9) of the NER, the AER makes the following final decisions on how any applicable efficiency benefit sharing scheme (EBSS), capital expenditure sharing scheme (CESS), service target performance incentive scheme (STPIS), demand management incentive scheme(DMIS), demand management innovation allowance mechanism (DMIAM) or small-scale incentive scheme is to apply:

- We will apply version 2 of the EBSS to Ergon Energy in the 2020–25 regulatory control period. This is discussed in attachment 8 of the final decision.
- We will apply the CESS as set out in the Capital Expenditure Incentives Guideline to Ergon Energy in the 2020–25 regulatory control period. This is discussed in attachment 9 of the final decision.
- We will apply our STPIS to Ergon Energy for the 2020–25 regulatory control period. This is set out in attachment 10 of the final decision.
- We will apply the DMIS and DMIAM to Ergon Energy for the 2020–25 regulatory control period. This is discussed section 2.7 of this final decision overview.

In accordance with clause 6.12.1(10) of the NER, the AER's final decision is that all other appropriate amounts, values and inputs are as set out in this final determination including attachments.

In accordance with clause 6.12.1(11) of the NER and our framework and approach paper the AER's final decision on the form of control mechanisms (including the X factor) for standard control services is a revenue cap. The revenue cap for Ergon Energy for any given regulatory year is the total annual revenue calculated using the formula in attachment 13 plus any adjustment required to move the DUoS unders and overs account to zero. This is discussed in attachment 13 of the final decision.

In accordance with clause 6.12.1(12) of the NER and our framework and approach paper, the AER's final decision on the form of the control mechanism for alternative control services is to apply price caps for all services. This is discussed in attachment 13 of the final decision.

In accordance with clause 6.12.1(13) of the NER, to demonstrate compliance with its distribution determination, the AER's final decision is that Ergon Energy must maintain a DUoS unders and overs account. It must provide information on this account to us in its annual pricing proposal. This is discussed in attachment 13 of the final decision.

Constituent decisions

In accordance with clause 6.12.1(14) of the NER, the AER's final decision is to apply the following nominated pass through events to Ergon Energy for the 2020–25 regulatory control period in accordance with clause 6.5.10:

- Terrorism event
- Insurance coverage event
- Natural disaster event
- Insurer credit risk event

These events and their definitions are set out in attachment 14 of the final decision.

In accordance with clause 6.12.1(14A) of the NER, the AER's final decision is to not approve the tariff structure statement proposed by Ergon Energy. This is discussed in attachment 18 of the final decision.

In accordance with clause 6.12.1(15) of the NER, the AER's final decision is that the negotiating framework as proposed by Ergon Energy, and approved in our draft decision, will apply for the 2020–25 regulatory control period. This is as set out in section 4.3 of this final decision overview, with the negotiating framework in attachment A of the final decision.

In accordance with clause 6.12.1(16) of the NER, the AER's final decision is to apply the negotiated distribution services criteria as published in our draft decision, in October 2019 to Ergon Energy. This is set out in section 4.3 of this final decision overview.

In accordance with clause 6.12.1(17) of the NER, the AER's final decision on the procedures for assigning retail customers to tariff classes for Ergon Energy is set out in attachment 18 of the final decision.

In accordance with clause 6.12.1(18) of the NER the AER's final decision is that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of Ergon Energy's regulatory control period as at 1 July 2025. This is discussed in attachment 2 of the final decision.

In accordance with clause 6.12.1(19) of the NER, the AER's final decision on how Ergon Energy is to report to the AER on its recovery of designated pricing proposal charges is to set this out in its annual pricing proposal. The method to account for the under and over recovery of designated pricing proposal charges is discussed in attachment 13 of the final decision.

In accordance with clause 6.12.1(20) of the NER the AER's final decision is to require Ergon Energy to maintain a jurisdictional scheme unders and overs account. It must provide information on this account to us in its annual pricing proposal as set out in attachment 13 of the final decision.

In accordance with clause 6.12.1(21) of the NER, the AER's final decision is to not apply the connection policy proposed by Ergon Energy. Our final decision is to maintain our draft decision and to apply the modified connection policy contained in attachment 17 of our draft decision.

B List of submissions

We received 17 public submissions in response to our draft decision and Ergon Energy's revised proposal. These are listed below:

Ergon Energy	Date received
AGL	15/01/2020
Bundaberg Regional Irrigators Group	15/01/2020
Bundaberg Walkers Engineering	15/01/2020
Chamber of Commerce & Industry Queensland	15/01/2020
CCP14	14/01/2020
Cotton Australia	15/01/2020
Energy Consumers Australia	23/01/2020
Electrical Safety Office (Qld)	21/01/2020
Electrical Trades Union	15/01/2020
National Seniors Australia	15/01/2020
Origin Energy	15/01/2020
Queensland Council of Social Service	15/01/2020
Queensland Farmers Federation	15/01/2020
We are Peak	15/01/2020
Canegrowers	02/02/2020
Queensland Electricity Users Network	02/02/2020
White Industries	15/01/2020

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
augex	augmentation expenditure
capex	capital expenditure
CCP14	Consumer Challenge Panel, sub-panel 14
CESS	capital expenditure sharing scheme
CPI	consumer price index
DMIAM	demand management innovation allowance mechanism
DMIS	demand management incentive scheme
distributor	distribution network service provider
DUoS	distribution use of system
EBSS	efficiency benefit sharing scheme
ECA	Energy Consumers Australia
F&A	framework and approach
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER or the rules	National Electricity Rules
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
repex	replacement expenditure
RFM	roll forward model
STPIS	service target performance incentive scheme
WACC	weighted average cost of capital