FINAL DECISION

Energex
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 consumers 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.

Energex is the electricity distribution network service provider for Brisbane and South-East Queensland. On 31 January 2019, Energex 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, Energex submitted its revised regulatory proposal on 10 December 2019.

This overview sets out our final decision for Energex'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 Energex is the total revenue it can recover from consumers 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. Energex'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 Energex'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

[1] NEL, s. 7.

service and the energy market plays an important role in protecting and supporting 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 Energex.

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 Energex'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 Energex 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.

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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)

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 the decision open for an extended time creates uncertainty for all. With an extended delay, Energex 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 Energex 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 Energex 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 sharing benefit 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 18 – Tariff structure statement

Attachment A – Negotiating framework

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Executive summary

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

Energex can recover $6009.6 million ($ nominal) from consumers in the 2020–25 regulatory control period.

Energex's network charges make up about 35 per cent of a standard residential retail bill (28 per cent for small businesses).

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.[4]

Our decision involves us assessing how much money Energex 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 $6009.6 million ($ nominal) Energex can recover from consumers ensures households and businesses are paying no more than necessary for safe and reliable services.

Energex's distribution area represents the metropolitan area of South East Queensland with a network of poles and wires spanning over 52,466 kms, servicing 1,463,494 consumers.

We have accepted what Energex says it needs to run the operational side of its business (known as operating expenditure). But it did not initially provide sufficient justification for its capital spending (known as capital expenditure) plans, and it was only after Energex provided additional material that we accepted its proposal.

We support Energex'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 tariff arrangements 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

4 Compared to the current level, holding all other components of the bill constant and adopting the current estimate of future energy consumption as forecast by Energex.

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 Energex's regulatory proposal and revised proposal, submissions from stakeholders and undertook our own analysis. Additionally we met with Energex representatives, our consumer challenge panel and other stakeholders to discuss the material put to us.

Energex provided us with a reasonable revised proposal, which balances consumer's concerns about affordability with the need for investment in the network.

In our draft decision, we asked Energex to provide additional supporting information to justify its capital expenditure (capex) program. We assessed the additional information provided and found that it justified the revised capex forecast. As a result, we have accepted Energex's capex program. In assessing the additional information, we applied our standard assessment approaches including trend analysis, replacement capex modelling and business case assessment.

Energex accepted our draft decision on its operating expenditure (opex) forecast, which means its forecast opex will fall with savings being passed on to consumers.

Energex’s engagement with its consumers

Energex demonstrated its commitment to consumers through its extensive engagement program, giving consumer groups the opportunity influence its proposals. Consumers also appreciated the attendance of key executives, who answered questions and addressed concerns during Ergon Energy’s engagement events. Through these engagement events, Energex’s consumers had identified affordability as a key priority. To demonstrate its commitment to increased affordability, Energex accepted our draft decision on opex, allowing them to pass the savings on to consumers.

Despite its commitment, and efforts to engage with consumers, Energex's initial tariff structure statement was not up to standard and it was also lacking in consumer support. Energex improved its engagement closer to our draft decision and enhanced it further before submitting its revised proposal. While consumer groups appreciate Energex accepting our draft decision suggestions, they submitted to us that the purpose of the proposed tariff changes and potential consumer impacts are yet to be fully explained.

Energex 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.

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

Our final decision includes capital expenditure to build Energex'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 Energex to recover a total revenue of $6009.6 million ($ nominal) from its customers from 1 July 2020 to 30 June 2025.[5]

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

Energex 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] Energex's 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 15.8 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 14.9 per cent in the first year of the next regulatory control period. After that, Energex's revenue allowance is a smaller 1.56 percent decrease per year.

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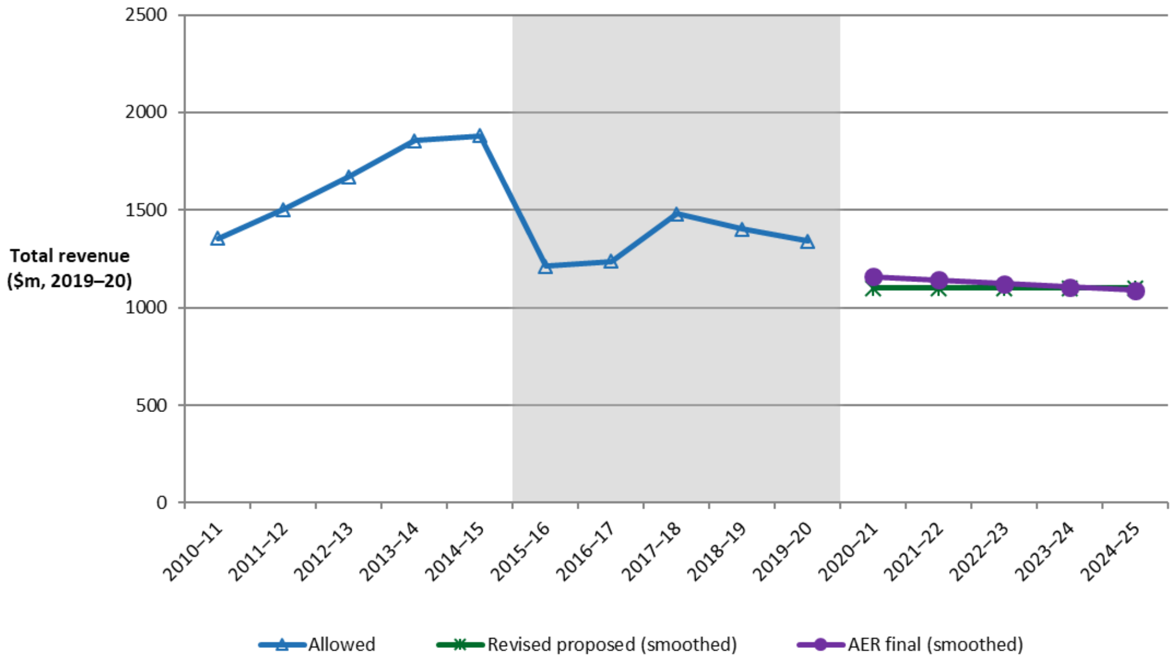
[5] This is the total smoothed revenue and Table 2 below sets out both smoothed and unsmoothed revenue.

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

[7] Our distribution determination for Energex includes an approved negotiating framework and negotiated distribution service criteria, as required by the NER. Because Energex 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.

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 Energex'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 4.7 per cent for the 2020–25 period.[8] This is because interest rates have decreased markedly since we made our last decision and Energex can obtain the capital it needs to run its business more cheaply. As a result, the total cost of capital had reduced by $895.9 million. 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 Energex 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 $257.2 million.[9] Other changes include:

- increase to forecast regulatory depreciation of 71.4 per cent. Each year, Energex builds new equipment to keep its network running. The cost of this new equipment

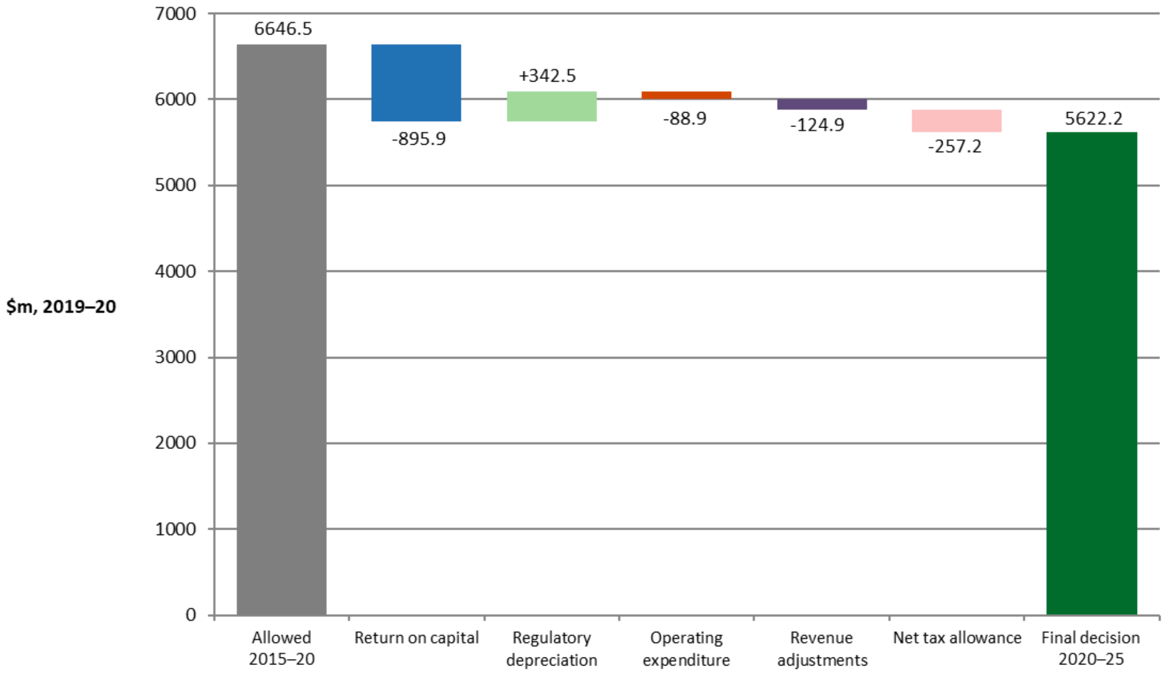
[8] The rate of return is a nominal rate of return unless stated otherwise. The real rate of return has also decreased, but by a smaller amount. Please see section 2.2 for further details.

[9] Please see section 2.6 for further details.

is added to a cumulative total called the regulatory asset base or RAB. Over time, the cost of this equipment is paid back to Energex through our depreciation allowance. Because Energex added new equipment to its network over the last five years, its RAB is increasing and so is its depreciation.[10]

- reduction to forecast opex of 4.7 per cent. Each year, Energex 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.

Figure 3 compares our final decision forecast RAB to Energex's revised proposed and actual RAB. Energex proposed to reduce its capital expenditure going forward which would have led to its RAB being stabilised. We reviewed this proposal carefully and have decided to accept its forecast spending. Energex's RAB is forecast to decrease by around 1.8 per cent in real terms over the 2020–25 regulatory control period. In the previous period, its RAB increased by 5.7 per cent.[12]

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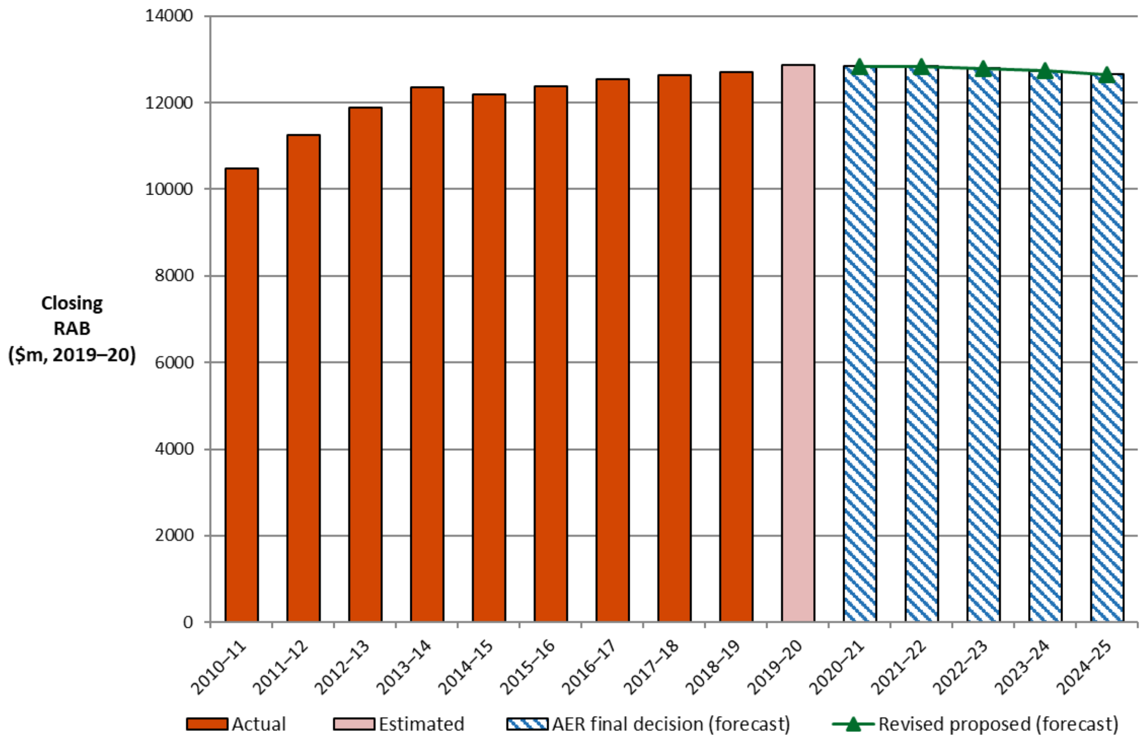
[10] Please see section 2.3 for further details.

[11] Please see section 2.5 for further details.

[12] Please see section 2.1 for further details.

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



Source: AER analysis.

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

The total revenue we are allowing in our final decision is $6009.6 million ($ nominal) for the 2020–25 regulatory period. This is $109.2 million or 1.9 per cent higher than Energex's revised proposal of $5900.3 million.

We have largely accepted Energex's revenue proposal and the difference is due to us updating the proposed building block amounts using more recent information. Our final decision rate of return of 4.73 per cent is higher than Energex's revised proposed rate of 4.67 per cent because we have used updated estimates of the risk free rate and return on debt.

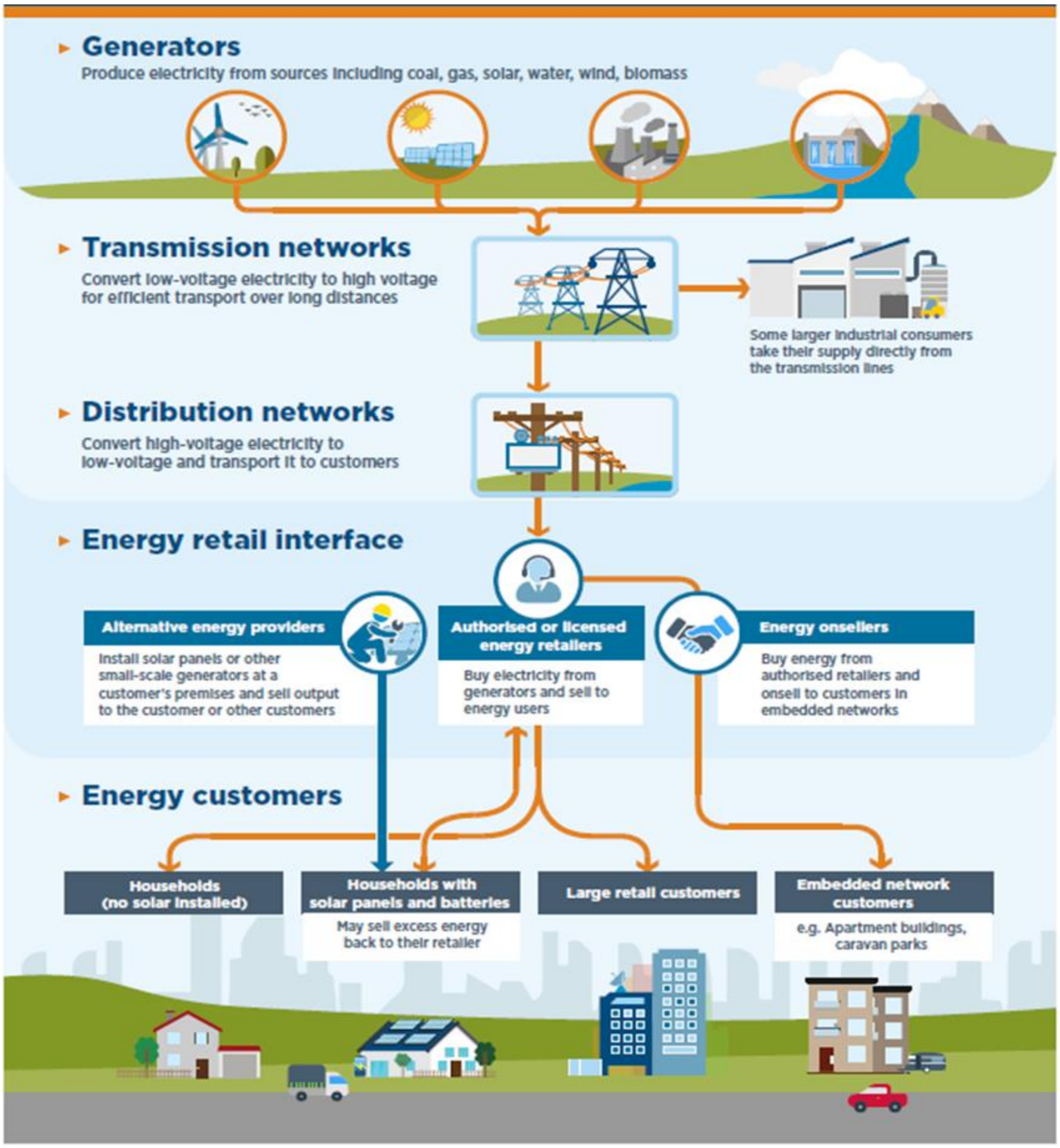
Our final decision total revenue is an increase of $169.6 million ($ nominal) on our draft decision revenue of $5840.0 million. The lower rate of return compared to our draft decision reduced our final decision revenue by $113.7 million. The higher regulatory depreciation compared to our draft decision increased our final decision revenue by $126.3 million. Energex's election in its revised proposal to claim its incentive scheme benefits resulted in an additional $178.4 million compared to our draft decision.[13]

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

1.3 Expected impact of our final decision on electricity bills

Energex's distribution network charges make up around 35 per cent of the total residential bill and 28 per cent of the total small business retail electricity bill.[14] Other components of the electricity bill include environmental policy costs, wholesale electricity costs and retail costs. Figure 4 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.

Figure 4 Electricity supply chain



[14] 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.

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 vary 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.

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 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.[15]

Under the final decision we estimate that compared to current charges, the distribution network charges ($ nominal) in Energex'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,[16] or the household relief package for COVID-19 impacts announced by the Queensland Government, which reduces the residential bill amount by a further $50.[17] It also does not take into account the impact of the Solar Bonus Scheme (SBS) costs currently being funded by the Queensland Government. This subsidy is due to end on 1 July 2020.[18] The end of the subsidy will have an

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

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

17 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.

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

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.

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[a]	1497	1499	1503	1506	1507
Annual change[c]		–73 (–4.6%)	2 (0.1%)	4 (0.3%)	3 (0.2%)	2 (0.1%)
Small business annual bill	2222[b]	2140	2142	2146	2149	2151
Annual change[c]		–82 (–3.7%)	2 (0.1%)	5 (0.2%)	3 (0.1%)	2 (0.1%)
Energex revised proposal						
Residential annual bill	1570 [a]	1473	1482	1494	1505	1515
Annual change[c]		–97 (–6.2%)	9 (0.6%)	12 (0.8%)	11 (0.7%)	10 (0.7%)
Small business annual bill	2222 [b]	2112	2122	2136	2148	2159
Annual change[c]		–110 (–5.0%)	11 (0.5%)	13 (0.6%)	12 (0.6%)	11 (0.5%)

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) 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.

(b) 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.

(c) 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 Energex's consumer engagement

The NEO puts the long term interests of consumers at the centre of our decisions. It is important that Energex 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 Energex working openly and collaboratively with consumers and providing opportunities for their views and preferences to be heard and to influence Energex's decisions. Apart from one exception, we accept that Energex has undertaken a good consumer engagement process. It has been well informed of consumers' interests in framing its revenue proposals and key executives attended most of its community engagement events.[19]

While both Energex and Ergon Energy have submitted individual regulatory proposals to us, 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 Energex'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".[20] The Energy Queensland proposals have focussed on the four key themes identified in its initial consumer engagement of: safety; affordability; security; and sustainability.[21] 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.[22]

The area where Energex's consumer engagement was less effective was around the structure of its tariffs. Energy Queensland acknowledged that it should have done more work consulting on the structure of its tariffs before it submitted its proposal.[23] Accordingly, it held an extensive round of consultations with its Tariff Structure Statement Working Group, who met several times during the development of the revised proposal.[24] 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*".[25]

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.[26] The QCOSS observed that Energy Queensland has

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19 QCOSS*, Submission on Energex's Regulatory Proposal 2020–25*, 31 May 2019; CCP14, *Submission on Energex's Regulatory Proposal 2020–25*, 31 May 2019, p.15.

20 CCP14, *Submission on Energex's draft decision and revised proposal 2020–25 - revised*, March 2020, p.14.

21 Energy Queensland, *2.001 Customer Engagement Strategy* - Regulatory Proposal 2020-25, January 2019, p. 22.

22 CCP14, *Submission on Energex's draft decision and revised proposal 2020–25 - revised*, March 2020, p.4.

23 Energex, *Revised regulatory proposal – Overview* – December 2019, p. 9.

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

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

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

not set out a clear rationale for the proposed tariffs or tariff reform more broadly.[27] 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.[28]

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

[27] QCOSS, *Submission on Energex's draft decision and revised proposal 2020–25*, January 2020, p.1.

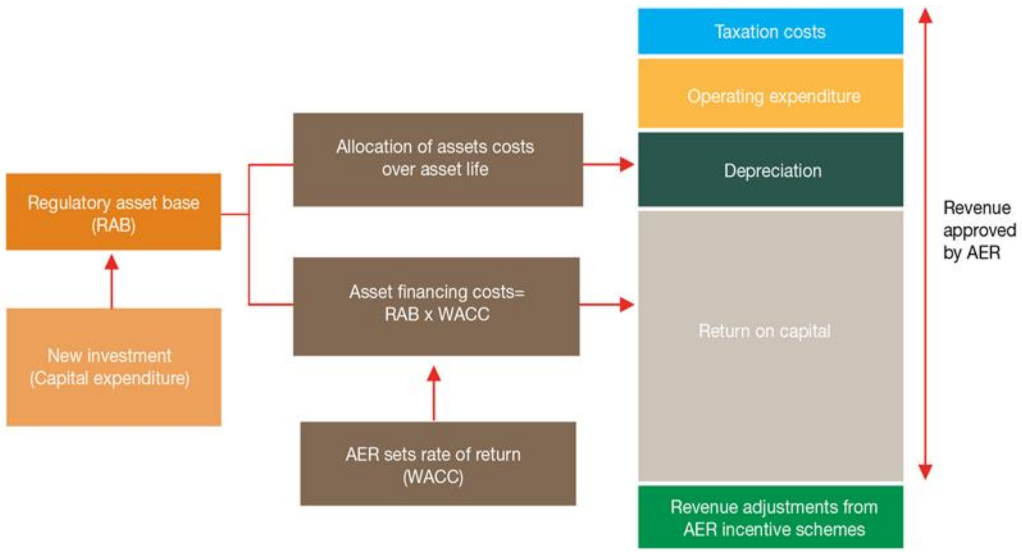
[28] QCOSS, *Submission on Energex's draft decision and revised proposal 2020–25*, January 2020, p.3.

2 Key components of our final decision on revenue

The total revenue Energex proposed reflects its forecast of the efficient cost of providing its distribution network services over the 2020–25 regulatory control period. Energex'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 Energex's distribution revenues for the 2020–25 regulatory control period is set out in Table 2.

Table 2 AER's final decision on Energex'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	608.8	604.7	600.3	594.8	587.5	2996.1
Regulatory depreciation[a]	158.2	147.3	169.3	192.1	215.6	882.5
Operating expenditure[b]	373.4	379.6	386.2	393.3	399.9	1932.3
Revenue adjustments[c]	–14.6	59.8	58.9	56.9	22.9	183.9
Net tax allowance	5.9	1.7	2.1	4.0	8.9	22.5
Annual revenue requirement (unsmoothed)	1131.7	1193.0	1216.7	1241.1	1234.8	6017.2
Annual expected revenue (smoothed)	**1185.7**	**1193.8**	**1201.9**	**1210.0**	**1218.2**	**6009.6**
X factor[d]	n/a[e]	1.56%	1.56%	1.56%	1.56%	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) Energex 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 14.9 per cent lower than the approved total annual revenue for 2019–20 in real terms, or 13.0 per cent lower in nominal terms.

2.1 Regulatory asset base

The RAB is the value of assets used by Energex to provide regulated distribution services. The value of the RAB substantially impacts Energex’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 Energex's revenue for 2020–25, we make a decision on Energex'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 $12874.5 million ($ nominal) as at 1 July 2020 for Energex. This amount is $14.0 million (or 0.1 per cent) higher than Energex's revised proposed opening RAB of $12860.5 million ($ nominal) as at 1 July 2020.[29] While we largely accept the proposed methodology for calculating the opening RAB, we made the following revisions to Energex's proposed inputs to the roll forward model (RFM):

- The 2019–20 inflation input in the RFM with actual CPI for this year, which became available after Energex 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 Energex's RAB for 2015–20 regulatory control period ($ million, nominal)

	2015–16	2016–17	2017–18	2018–19	2019–20 [a]
Opening RAB	11172.5	11544.5	11865.4	12195.0	12482.5
Capital expenditure[b]	530.6	519.8	493.4	475.8	469.1
Inflation indexation on opening RAB	188.7	170.4	226.5	217.6	229.7
Less: straight-line depreciation[c]	347.2	369.3	390.4	405.8	427.7
Interim closing RAB	11544.5	11865.4	12195.0	12482.5	12753.6
Difference between estimated and actual capex in 2014–15					–0.0
Return on difference for 2014–15 capex					–0.0
Roll-in of legacy ICT assets					120.9
Closing RAB as at 30 June 2020					**12874.5**

Source: AER analysis.

(a) Based on estimated capex provided by Energex. 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.

[29] Energex, Attachment 5-1 – Distribution roll forward model, December 2019.

For this final decision, we determine a forecast closing RAB value at 30 June 2025 of $14153.9 million ($ nominal) for Energex. This is $61.8 million (or 0.4 per cent) lower than Energex's revised proposal of $14215.7 million ($ 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).[30] Table 4 sets out our final decision on the forecast RAB values for Energex over the 2020–25 regulatory control period.

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

	2020–21	2021–22	2022–23	2023–24	2024–25
Opening RAB	12874.5	13144.8	13424.0	13693.1	13934.5
Capital expenditure[a]	428.5	426.4	438.4	433.4	435.1
Inflation indexation on opening RAB	292.8	298.9	305.3	311.4	316.9
Less: straight-line depreciation	451.0	446.2	474.5	503.5	532.5
Closing RAB	**13144.8**	**13424.0**	**13693.1**	**13934.5**	**14153.9**

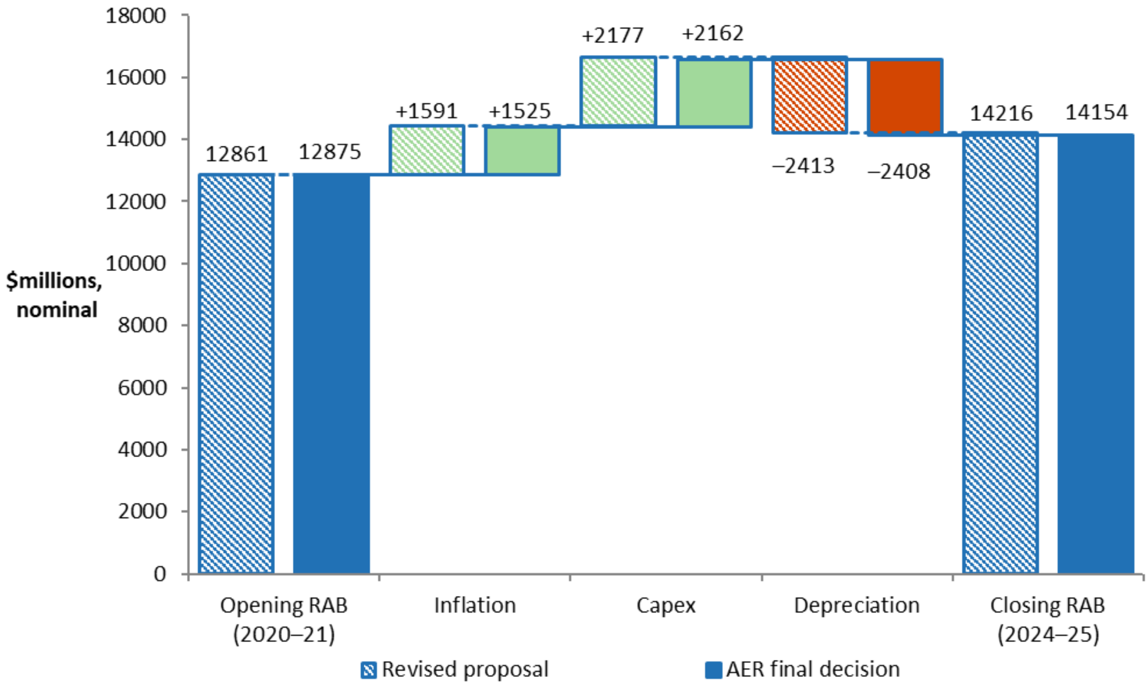
Source: AER analysis.

(a) Net of forecast disposals and capital contributions. In accordance with the timing assumptions of the 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 Energex'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 9.9 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 16.8 per cent, while expected inflation increases it by 11.8 per cent. Forecast depreciation, on the other hand, reduces the RAB by 18.7 per cent.

[30] 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 Energex's actual, revised proposed and AER final decision RAB ($ million, 2019–20)



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 returns from the two sources of funds for investment: equity and debt. This allowed rate of return provides the distributor 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 Energex.[31]

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).[32]

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.[33]

We also note that Energex's proposed risk free rate[34] and debt averaging periods have been (and will be) used to estimate its rate of return because they complied with the conditions set out in the 2018 instrument.[35]

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31 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.

32 AER, *Draft Decision, Energex Distribution Determination 2020–25,* October 2019, Overview, p. 27.

33 This is the reason why, in Energex'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.

34 This is also known as the return on equity averaging period.

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

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

	AER draft decision (2020–25)	Energex'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 (%)

Sources: AER analysis; Energex, *Revised regulatory proposal 2020–25*, December 2019, p. 39.

(a) Calculated using a placeholder averaging period of 20 business days ending 31 July 2019.

(b) Calculated using an averaging period of 20 business days 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 set out how we are to apply the PTRM and the expected inflation estimation method in the model in our electricity determinations.[36]

Energex 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:

- 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 SMP is

[36] NER, r. 6.4.2(a) and (b)(1).

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).[37] However, we delayed our decision to allow us to use the RBA's May SMP as we expected it 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).[38] Our usual implementation is to use the (headline) consumer price index (CPI) forecasts for these periods.[39] 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 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.[40]

We have considered Energex's revised proposal and Energy Queensland'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 opex forecast because these are regular and ongoing costs. We include equity raising costs in the capex forecast because these costs are only incurred once and would be associated with funding the particular capital investments.

Energex's revised proposal adopted the total opex forecast in our draft decision including our approach to estimate debt raising costs.[41] Therefore, our final decision is to accept Energex's revised (total) opex proposal including debt raising costs.

Energex's revised proposal calculated equity raising costs using our benchmark approach in the PTRM. Using this approach Energex forecast zero equity raising costs.[42] Therefore, we have updated our estimates for this distribution determination

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

38 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).

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

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

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

42 Energex, *2020–2025 Revised Regulatory Proposal*, December 2019, p. 44; Energex, *Revised Proposal – 4.002 – PTRM,* December 2019.

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[43]. This was the result of extensive analysis and consultation conducted as part of the 2018 rate of return review.[44] Energex's revised proposal has adopted the value of gamma set out in the 2018 Instrument.[45]

Further detail on our final decision in regards to Energex'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). Energex 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 Energex's revenue for 2020–25 includes a regulatory depreciation allowance of $882.5 million ($ nominal). This is $60.4 million (7.4 per cent) higher than Energex's revised proposal.

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

We accept Energex's revised proposal to apply the year-by-year tracking approach, subject to minor changes to its depreciation tracking model.

We have also made determinations on other components of Energex's revised proposal, which affect the RAB and in turn impacts the forecast regulatory depreciation allowance. The increase to the regulatory depreciation allowance from the revised proposal primarily reflects our final decision expected inflation rate for the 2020–25

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

44 AER, *Rate of return instrument explanatory statement*, December 2018, pp. 307-382.

45 Energex, *Revised regulatory proposal 2020–25*, December 2019, p. 39.

regulatory control period. Our final decision for Energex’s straight-line depreciation component of regulatory depreciation is lower than the revised proposal by $5.6 million due to our determination of the opening RABs (attachment 2). However, this reduction is offset by our final decision on the indexation of the RAB, which is $66.0 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 Energex’s revised proposal of 2.37 per cent per annum. Subsequently, the net effect is an increase in the regulatory depreciation allowance of $60.4 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 Energex'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.

Our final decision on Energex's total net capex is to accept its revised proposal of $2000 million ($2019–20) for the 2020–25 regulatory control period.[46] We are satisfied that Energex’s revised total capex proposal reasonably reflects prudent and efficient costs. Table 6 shows our total capex final decision for Energex.

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

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
Energex's revised proposal and AER final decision	414.0	403.1	405.5	392.2	385.2	2000.0

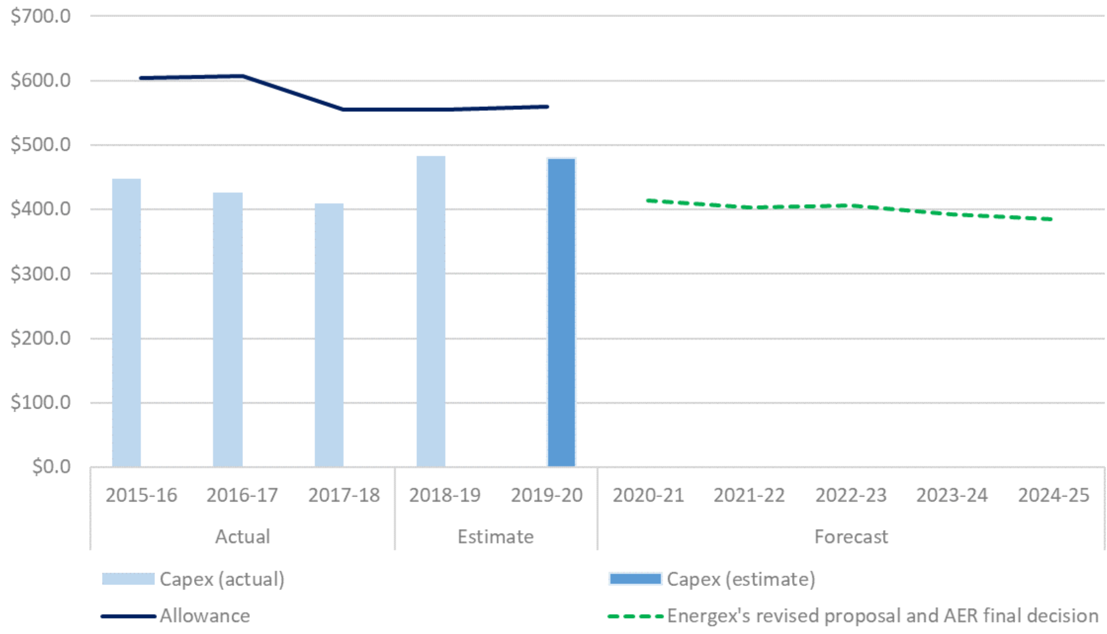
Source: AER analysis and Energex.

Notes: 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 which accepts Energex’s revised proposal. It also shows our 2015–20 regulatory period final decision and actual capex.

46 This figure is $9.9 million lower than Energex's $2010.0 million it forecast for net capex in its revised proposal. Following consultation Energex provided us with a revised forecast which corrected an escalation error in its capex model.

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



Source: AER analysis and Energex.

Notes: Energex's historical allowance is not directly comparable to its recast actual data, initial capex forecast and the AER draft decision due to its cost allocation method and classification of services changes. Final decision net capex forecast is $9.9 million lower than what Energex submitted in its revised proposal. Following consultation Energex provided us with a revised forecast which corrected an escalation error in its capex model.

We acknowledge Energex's extensive consultation with us and subsequent development of quantitative cost-benefit models to support its revised proposed capex program for 2020–25. In our draft decision, we noted that Energex's proposal lacked sufficient supporting material to satisfy us that its proposed capex reasonably reflects the capex criteria. Our draft decision capex forecast was $1793.4 million ($2019–20) or 11 per cent lower than Energex's initial proposal.

In its revised proposal, Energex provided quantitative cost-benefit analysis for its major projects and those areas of its proposal that we did not accept in the draft decision. This additional information has allowed us to better assess the prudency and efficiency of the proposed capex. We applied our standard assessment approaches such as trend analysis, repex modelling and business case assessment to assess the material put to us.

In making our final decision we have also had regard to historical and current capex. Importantly, we note that Energex's net capex forecast is 11 per cent lower than its actual/estimated net capex for 2015–20. We are satisfied that Energex's revised capex proposal reasonably reflects the capex criteria.

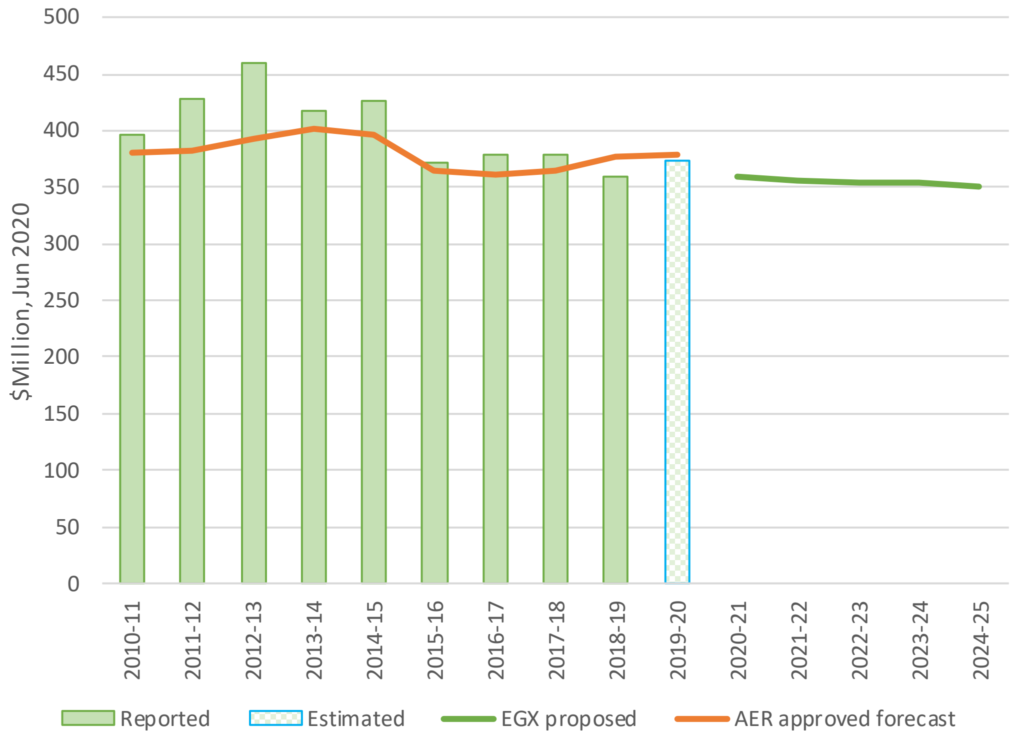
Further detail on our final decision regarding capex is set out in attachment 5.

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 Energex's revised opex proposal of $1805.8 million ($2019–20), including debt raising costs, for the 2020–25 regulatory control period. For its revised proposal, Energex adopted the opex in its initial proposal, which we accepted in our draft decision. We have tested Energex's proposal by comparing it to our alternative estimate of total opex of $1909.9 million ($2019–20).[47] Our alternative estimate is $104.1 million (or 5.8 per cent) higher than Energex's opex proposal. There are a number of drivers of the differences between our alternative estimate and Energex's revised opex proposal, which are set out in attachment 6. Figure 8 shows Energex's revised proposal, its past allowance and past actual expenditure.

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



Source: AER analysis; Energex, *Regulatory Accounts 2010–11 to 2018–19*; Energex, *Economic Benchmarking RIN responses 2010 to 2019,* Energex, *6.007 - Opex forecast - SCS*, January 2019; Energex, *Post Tax Revenue Model (PTRM) PTRM Distribution*, December 2019.

Note: Excludes debt raising costs

[47] 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

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 Energex. 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 Energex's estimated cost of corporate income tax is $22.5 million ($ nominal) over the 2020–25 regulatory control period. This is higher than Energex's revised proposed cost of corporate income tax of zero. The key reasons for this change are:

- Our final decision to reduce the immediately expensed capex for tax purposes to $502.5 million from $748.3 million.[48]
- Our final decision to increase the regulatory depreciation (attachment 4).[49]
- Our final decision to apply a higher rate of return on equity (attachment 3).[50]
- Our final decision to reduce the revised proposed opening tax asset base (TAB) value as at 1 July 2020 by $3.9 million to $8285.2 million.[51]

We accept Energex's revised proposal on the standard and remaining tax asset lives for all of its asset classes, consistent with our draft decision.

Table 7 AER's final decision on Energex's corporate income tax ($ million, nominal)

	2020–21	2021–22	2022–23	2024–24	2024–25	Total
Tax payable	14.1	4.0	5.0	9.6	21.4	54.1
Less: value of imputation credits	8.3	2.4	2.9	5.6	12.5	31.7
Net corporate income tax allowance	**5.9**	**1.7**	**2.1**	**4.0**	**8.9**	**22.5**

Source: AER analysis.

48 Other than the outcomes of our forecast capex assessment, this reduction also reflects our decision to accept a correction by Energex for errors in its calculation of the revised proposed forecast immediately expensed capex and the forecast asset disposals. The corrections reduced the revised proposed forecast immediately expensed capex from $748 million to $502.5 million. All else equal, a lower amount of capex that are immediately expensed for tax purposes will reduce the tax expense and increase the cost of corporate income tax. Energex, *Response to AER information request #IR079*, 10 March 2020.

49 All else equal, a higher regulatory depreciation amount will increase the cost of corporate income tax because it increases the taxable income.

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

51 All else equal, a lower opening TAB value will reduce the tax depreciation, a component of the tax expense, and increase the cost of corporate income tax.

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 Energex to pursue expenditure efficiencies and demand side alternatives while maintaining the reliability and overall performance of its network.

In its initial proposal Energex 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 Energex's allowed revenues.

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

- Efficiency benefit sharing scheme — Energex accrued carryover amounts totalling \$68.1 million (\$2019–20)[52] from the application of the EBSS in the current regulatory control period. Energex included amounts totalling \$68.2 million (\$2019–20) in its revised proposal. 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 Energex's EBSS.
- Capital expenditure sharing scheme — we have included a CESS revenue increment of \$97.1 million (\$2019–20) for the application of the CESS during the 2015–20 regulatory control period. This amount is different to the \$96.4 million included in Energex's revised proposal. This difference reflects updates to inflation and the WACC. We have made no further adjustments as we are satisfied Energex's revised capex proposal 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 Energex's CESS.
- Service target performance incentive scheme (STPIS) — our final decision is to apply our national STPIS version 2.0 (November 2018)[53] to Energex for the 2020–25 regulatory control period. We will not apply the guaranteed service level component to Energex as the existing jurisdictional arrangements will continue to apply. Attachment 10 sets out our final decision on Energex' STPIS.

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52 We use the RBA's May 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.

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

- Demand management incentive scheme (DMIS) and Demand management innovation allowance mechanism (DMIAM) — our final decision is to apply the DMIS[54] and the DMIAM[55] to Energex for the 2020–25 regulatory control period, without any modification. Our draft decision reasons form part of this final decision. Table 8 sets out the DMIAM allowance for Energex for the 2020–25 regulatory control period, based on the final PTRM for Energex.

Table 8 AER's final decision on the DMIAM ($ million, 2019–20)

	2020–21	2021–22	2022–23	2023–24	2024–25	Total
DMIAM	1.04	1.07	1.06	1.06	1.04	5.27

Source: AER analysis.

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

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

3 Tariff structure statement

Energex'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 consumers 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.[56] 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, Energex'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 consumers, 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 customer 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 consumer 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.

Energex 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 consumer connections with a smart meter installed.

56 NER cl.6.18.1A(a)

- Reassigning most existing consumer 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.[57] 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 consumer 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 Energex's TSS to improve clarity in a few areas.

We and Energex both consider network tariff reform is important. Our reasons for supporting tariff reform and the majority of Energex's revised TSS proposal reflects our own views on what we consider to be the key rationale for tariff reform in Queensland. This is somewhat different to Energex's reasons for its proposal which, among other matters, was framed in terms of unwinding what Energex 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 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 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 into the

57 NER, cl.6.18.5

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.

To better understand what these network tariff reforms are likely to mean for retail offers, we held a series of one-on-one discussions with retailers. This engagement suggests that retailers are likely to respond through their retail offers in different ways providing end customers with greater choice on how they managing their energy bills.

Our engagement with retailers suggests that responses also depend on retailer size:

- Small retailers are more likely to offer retail tariffs that reflect the underlying network tariff structures
- Large retailers are more likely to continue to offer simple flat rate retail tariffs in addition to some retailers offering retail tariffs that reflect the underlying network tariff structure.
- A couple of retailers are also working on more innovative options in designing retail packages that provide customers with tools to help them manage their energy consumption.

We will shortly be publishing a summary of what we've heard from retailers in a separate document.[58]

[58] This will be available on our dedicated Network Tariff Reform webpage: https://www.aer.gov.au/networks-pipelines/network-tariff-reform

Ergon Energy and Energex are both part of the Energy Queensland group and have based its 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.

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 Energex must set its prices. These include the classification of services, the conditions under which we may grant Energex additional revenues to cover unforeseen circumstances and the framework for Energex'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 Energex.[59] The list of classified services Energex will provide for 2020–25 is set out in Attachment 12.

4.2 Pass through events

Energex'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 Energex were consistent with recent decisions for other network service providers.

Energex'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 Energex about these changes and it stated it was comfortable with adopting them. Our final decision for these four nominated pass through events is set out in attachment 14.

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[59] AER, *Draft decision Energex 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 Energex's proposed distribution negotiating framework for the 2020–25 regulatory control period.[60] We did not receive any objections or submissions on our draft decision.

Our final decision is to approve Energex's negotiating framework. The distribution negotiating framework that will apply to Energex 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.[61] Our final decision is to retain the NDSC that we published for Energex in October 2019[62] for the 2020–25 regulatory control period. The NDSC gives effect to the negotiated distribution services principles.[63]

4.4 Connection policy

In our draft decision, we modified Energex'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.[64] Energex accepted our draft decision in its revised proposal. We did not receive any submission on our draft decision.

Our final decision is to maintain our draft decision on Energex's connection policy. The approved connection policy for Energex for the 2020–25 regulatory period is appended to attachment 17 of our draft decision.

[60] AER, *Draft Decision, Energex Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-5.

[61] NER, cl. 6.12.1(16).

[62] AER, *Draft Decision, Energex Distribution Determination 2020–25,* October 2019, Attachment 16, p, 16-10,11.

[63] NER, cl. 6.7.1.

[64] AER, *Draft Decision, Energex Distribution Determination 2020–25,* October 2019, Attachment 17.

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):[65]

> "…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.[66] 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.[67] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[68]

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. [69]

Our distribution determinations are predicated on a number of constituent decisions that we are required to make.[70] 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
- 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

[65] NEL, s. 7.

[66] NEL, s. 16(1)(a).

[67] 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.

[68] 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.

[69] NEL, s. 16(1)(d).

[70] 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 attachment 5).

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.[71] 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. [72]

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.[73] 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. [74] 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.[75]
- 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.[76]

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71 Hansard, *SA House of Assembly,* 9 February 2005, p. 1452.

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

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

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

75 NEL, s. 7A(7).

76 NEL, s. 7A(6).

A Constituent decisions

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

Constituent decision
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 Energex 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 Energex's building block proposal. Our final decision on Energex'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 Energex'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 Energex'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)(ii) and acting in accordance with clause 6.5.7(d) of the NER, the AER's final decision is to accept Energex's proposed total net forecast capital expenditure of $2000.0 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)(i) and acting in accordance with clause 6.5.6(c) of the NER, the AER's final decision is to accept Energex's proposed total forecast operating expenditure, inclusive of debt raising costs and exclusive of DMIAM of $1805.8 million ($2019–20). The reasons for our decision are set out in attachment 6.
Energex 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 of 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 decision

In accordance with clause 6.12.1(6) of the NER, the AER's final decision on Energex's regulatory asset base as at 1 July 2020 in accordance with clause 6.5.1 and schedule 6.2 is $12874.5 million ($ 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 Energex's corporate income is $22.5 million ($ nominal). 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 to not approve the depreciation schedules submitted by Energex. 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 Energex in the 2020–25 regulatory control period. This is discussed in attachment 8 of the final decision overview.
- We will apply the CESS as set out in the Capital Expenditure Incentives Guideline to Energex in the 2020–25 regulatory control period. This is discussed in attachment 9 of the final decision.
- We will apply our Service Target Performance Incentive Scheme (STPIS) to Energex for the 2020–25 regulatory control period. This is discussed in attachment 10 of the final decision.
- We will apply the DMIS and DMIAM to Energex for the 2020–25 regulatory control period. This is discussed in 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 decision 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 Energex 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 Energex 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 decision
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 Energex 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 Energex. 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 Energex 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 Energex. 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 Energex 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 Energex'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 Energex 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 Energex 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 apply Energex's proposed connection policy, as amended by our draft decision and set out in attachment 17 of the draft decision for Energex. This is discussed in section 4.4 of this final decision overview.

B List of submissions

We received 15 public submissions in response to our draft decision and Energex's revised proposal. These are listed below:

Energex	Date received
AGL	15/01/2020
Chamber of Commerce & Industry Queensland	15/01/2020
CCP14 (revised)	18/03/2020
Energy Consumers Australia	23/01/2020
Electrical Safety Office (Qld)	21/01/2020
Electrical Trades Union	15/01/2020
Gold Coast City Council	13/02/2020
Logan City Council	29/01/2020
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

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