# FINAL DECISION ElectraNet transmission determination 2018 to 2023

## Overview

April 2018

AUSTRALIAN ENERGY REGULATOR

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# Note

This overview forms part of the AER's final decision on ElectraNet's transmission determination for 2018–23. It should be read with all other parts of the final decision.

The final decision includes this Overview and the following attachments:

ElectraNet transmission determination 2018–23

Attachment 1 – Maximum allowed revenue

Attachment 2 – Regulatory asset base

Attachment 5 – Regulatory depreciation

Attachment 6 – Capital expenditure

Attachment 8 – Corporate income tax

Attachment A – Negotiating framework

Attachment B – Pricing methodology

As many issues were settled at the draft decision stage or required only minor updates we have not prepared other attachments. The attachments have been numbered consistently with the equivalent attachments to our longer draft decision. In these and other elements of our decision, our draft decision reasons form part of this final decision.

# Contents

# Shortened forms

| Shortened form | Extended form |
|---|---|
| AARR | aggregate annual revenue requirement |
| AEMC | Australian Energy Market Commission |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ASRR | annual service revenue requirement |
| augex | augmentation expenditure |
| capex | capital expenditure |
| CCP | Consumer Challenge Panel |
| CESS | capital expenditure sharing scheme |
| CPI | consumer price index |
| DMIA | demand management innovation allowance |
| DRP | debt risk premium |
| EBSS | efficiency benefit sharing scheme |
| ERP | equity risk premium |
| MAR | maximum allowed revenue |
| MRP | market risk premium |
| NEL | national electricity law |
| NEM | national electricity market |
| NEO | national electricity objective |
| NER | national electricity rules |
| NSP | network service provider |
| NTSC | negotiated transmission service criteria |
| opex | operating expenditure |
| PPI | partial performance indicators |
| PTRM | post-tax revenue model |
| RAB | regulatory asset base |
| RBA | Reserve Bank of Australia |
| repex | replacement expenditure |
| RFM | roll forward model |
| RIN | regulatory information notice |

| Shortened form | Extended form |
|---|---|
| RPP | revenue and pricing principles |
| SLCAPM | Sharpe-Lintner capital asset pricing model |
| STPIS | service target performance incentive scheme |
| TNSP | transmission network service provider |
| TUoS | transmission use of system |
| WACC | weighted average cost of capital |

# 1 Our final 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. Our work is guided by the National Electricity Objective (NEO) which promotes efficient investment in, and operation and use of, electricity services in the long term interests of consumers.[1] We set network revenues so that they reflect efficient costs. By only allowing efficient costs we regulate network prices so that energy consumers pay no more than necessary for the safe and reliable delivery of electricity services.

ElectraNet owns and operates the electricity transmission network in South Australia. We regulate the revenues that ElectraNet can recover from its customers. This final decision concerns the maximum allowed revenue (MAR) that ElectraNet can earn from its regulated services for regulatory control period from 1 July 2018 to 30 June 2023.

Our final decision is to allow ElectraNet to recover a MAR of $1603.2 ($nominal, smoothed) from its customers over the 2018–23 regulatory control period.

ElectraNet has shown a genuine commitment to giving consumers—small and large—a say in what it proposes to us, and to continuing to develop opportunities for this input over time. This is reflected in both the initial and revised proposals that ElectraNet has put to us, and in the way ElectraNet engaged with our review of, and consultation on, those proposals. The success of ElectraNet's engagement program has been reinforced by submissions in this review. The consumer challenge panel (CCP9) has commended ElectraNet for its commitment to consumer engagement:

> CCP9 has been impressed with the ongoing commitment of ElectraNet to applying best practice customer engagement principles and processes throughout its two years of consumer engagement. It has been a journey that both informs and is informed by its consumer base and in particular, consumer representatives. As a result, ElectraNet has delivered a proposal that meets its criteria of 'no surprises' and 'capable of being accepted' and has done through a period of unprecedented turbulence and uncertainty in the SA energy market.[2]

ElectraNet's consumer engagement program was also acknowledged nationally with it being awarded the inaugural consumer engagement award from the Energy Consumers Australia (ECA) in recognition of its leadership and innovation in consumer engagement.

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[1] NEL, s. 7.

[2] CCP9, *Response to Draft Decision and Revised Proposal for Revenue Reset for ElectraNet for 2018–2023*, February 2018, p. 4.

In the sections below we discuss the forecast revenue and expected impact on residential bills. Section 2 outlines some of the key drivers of ElectraNet's revenue over the next five years, including what has changed since our draft decision in October. Our decision approves ElectraNet's proposed reductions to both operating and capital expenditure relative to our previous decision in 2013. At the same time, it still allows ElectraNet to:

- deliver safe, secure and reliable transmission services
- respond to the system black event experienced in South Australia on 28 September 2016–we consider ElectraNet's proposed expenditure in response to this to be considered and proportionate.
- contribute to South Australia's ongoing energy transformation.

This final decision is the product of a long consultation process. This was initiated by consultation on the Framework and Approach in November 2016. In April 2017, we published ElectraNet’s initial proposal on our website and called for submissions. In May we published an issues paper on ElectraNet’s proposal and hosted a public forum in June.

We made our draft decision on 27 October 2017[3] and ElectraNet submitted its revised proposal on 22 December 2017. This revised proposal largely accepted our draft decision, including forecast capex, forecast opex and our approach to inflation, rate of return and imputation credits (gamma). The only key change in the revised proposal impacting on the revenue ElectraNet can earn was an increase in operating expenditure. This was foreshadowed in our draft decision and arose from new obligations as a result of recent market reviews and rule changes.

Having assessed ElectraNet's revised revenue proposal against the rules and our guidelines our final decision is to accept nearly all parts of its revised proposal, including capex and the increase in opex. The increase in opex has resulted in a small decrease in the estimated savings in the transmission component of the average residential electricity bill when compared to our draft decision.[4]

The key aspect that we did not accept was ElectraNet's revised contingent project triggers, which sought to introduce an alternative approval process to the regulatory investment test under the rules.[5]

In addition to our ex-ante forecast of capex, we have approved a number of contingent projects. These are projects identified in ElectraNet’s proposal whose need, cost and scope are not yet sufficiently certain such that they can be included in the MAR. In future, the MAR that ElectraNet can recover from its customers might increase to

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3 AER, *Draft Decision, ElectraNet transmission determination 2018 to 2023, Overview*, October 2017. https://www.aer.gov.au/system/files/AER%20-%20Draft%20Decision%20-%20Overview%20-%2026%20October%202017%20%28amended%203%20Nov%202017%29.pdf

4 See figure 1.2 below, which outlines the indicative transmission price path for our draft and final decisions.

5 This is discussed in Attachment 6, section 6.4.2.

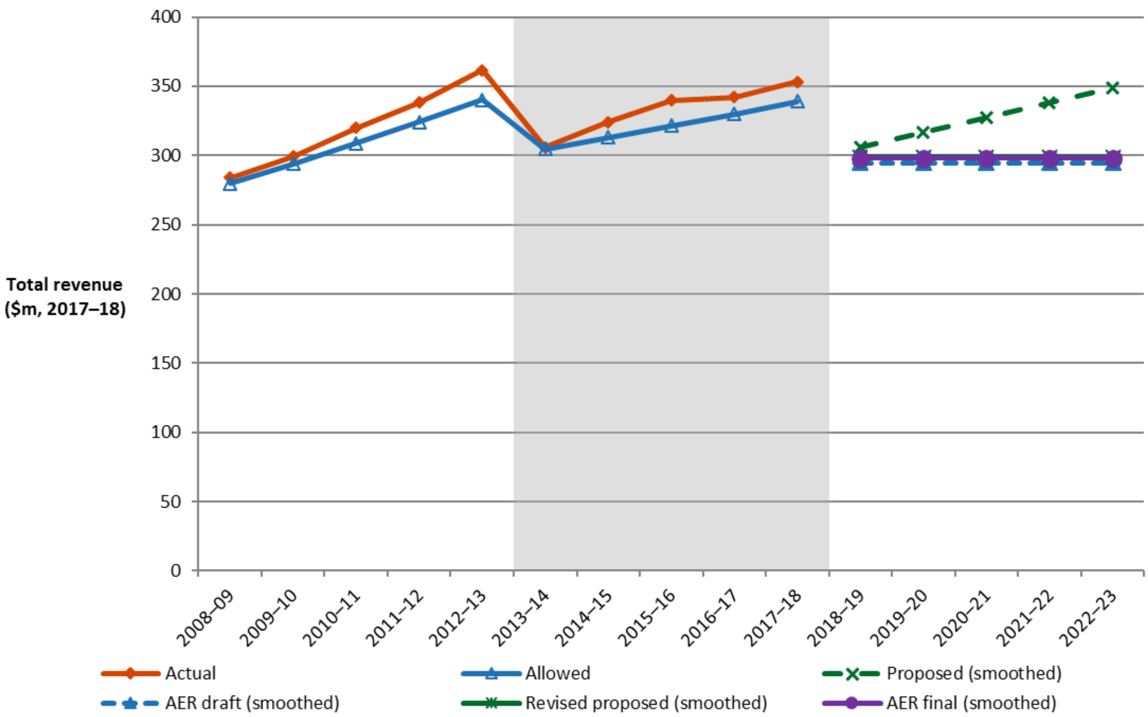
recover the cost of these projects should certain trigger events occur. These tests include the completion of a public RIT-T. The purpose of the RIT-T is to identify the transmission investment option which maximises net economic benefits to the market and, where applicable, meets the relevant reliability standards.

Our assessment of ElectraNet's revised proposal is consistent with our draft decision. We received seven submissions on our draft decision and ElectraNet's revised proposal[6] which are considered in the relevant components of this decision in section 2 below.

## 1.1 What is driving revenue

Figure 1-1 compares our final decision on ElectraNet's revenue for 2018–23 to its proposed revised revenue and to the revenue allowed and recovered during the two previous regulatory control periods of 2008–13 and 2013–18. ElectraNet's annual revenue increased each year during 2009–13 and then again in 2014–17 in real dollar terms. Our final decision allows for annual revenue that is lower in real terms than at the start of the previous regulatory period and remains constant in real terms through the forthcoming period. There will be a slight increase in the transmission component of a customer's bill over the period, as explained in section 1.2.

### Figure 1-1 ElectraNet's past total revenue, proposed total revenue and AER final decision total revenue allowance ($million, 2017–18)

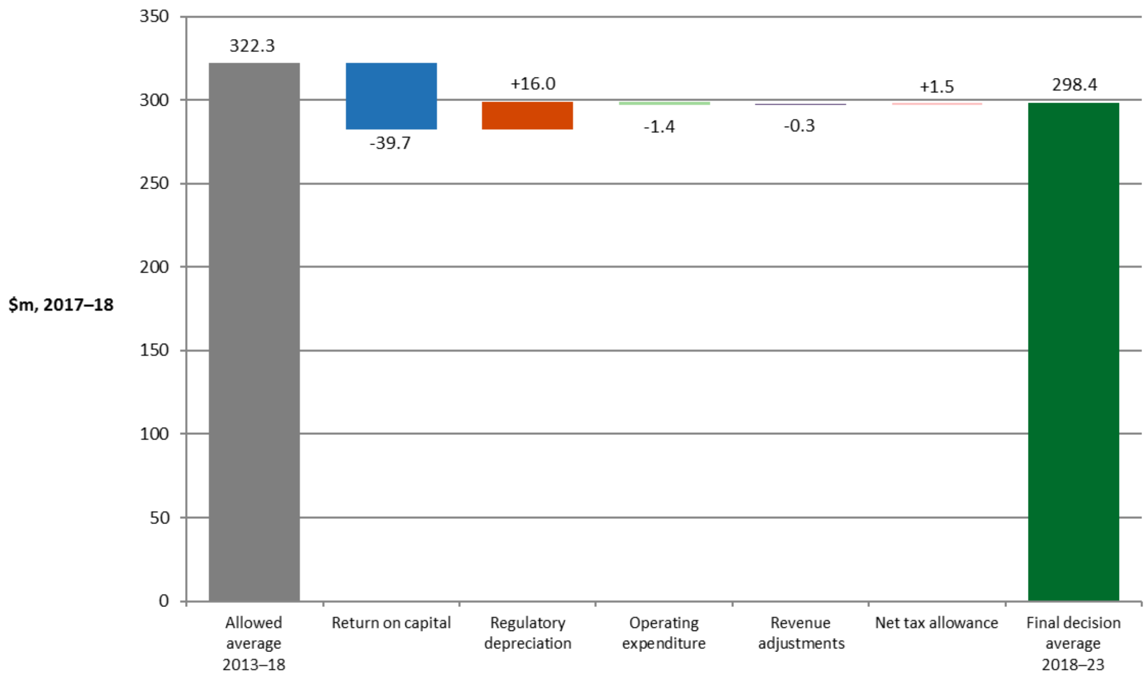



Source: AER analysis.

6 A list of submission is set out in Appendix A.

Figure 1-2 compares our final decision for the 2018–23 regulatory control period with ElectraNet's allowed revenue for the 2013–18 regulatory control period, broken down by the various building block components that make up the forecast revenue allowance. These are annual amounts based on an average of unsmoothed revenues over the two five-year regulatory control periods.

### Figure 1-2 AER's final decision for 2018–23 and ElectraNet's 2013–18 allowed average building block costs ($million, 2017–18)




Source: AER analysis.

This figure highlights that the return on capital is the key difference between our final decision for the 2018–23 regulatory control period and ElectraNet's allowed revenue for the 2013–18 regulatory control period.

The reduction in the return on capital shown in Figure 1-2 is driven by changes in the estimated rates of return on debt and equity. The estimated return on debt and return on equity fell between regulatory periods by around 2.2 and 2.1 percentage points, respectively. The falls were largely caused by a reduction in the risk free rate and the debt risk premium. However, the equity beta used also fell from 0.8 for the 2013–18 regulatory control period to 0.7 for the 2018–23 regulatory control period reducing the estimated equity risk.

The reduction in the return on capital is also driven by a reduction in ElectraNet's capex. ElectraNet proposed substantially lower capex for the 2018–23 regulatory control period than was included in the 2013–18 revenue determination. This is due to reduced demand growth in the 2018–23 regulatory control period and consequent lack of augmentation expenditure.

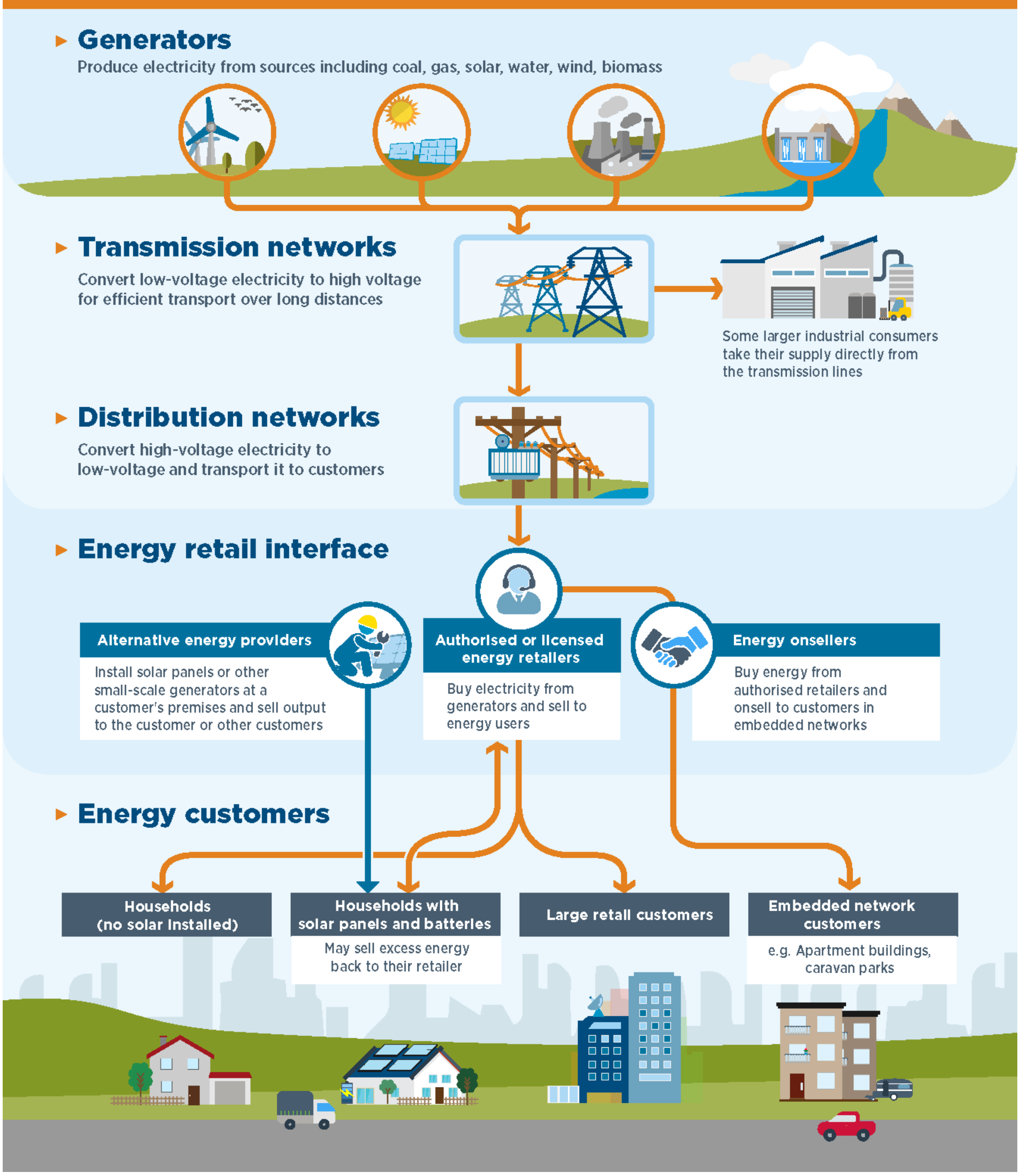
Depreciation is higher in the 2018–23 regulatory control period due to two main factors:

- the opening regulatory asset base (RAB) in the 2018–23 period is higher than the opening RAB in the 2013–18 regulatory control period (see Figure 2-3 below) due to previous capex investments. This means there is additional depreciation costs that need to be recovered in the next period as a result of this higher opening RAB
- Although the RAB is forecast to decline over the 2018–23 period, it is still higher than it was for the most part of the start of the current period. This is because we have approved forecast capex for the 2018–23 period, which adds to the RAB. This means further depreciation costs need to be recovered in this upcoming period.

## 1.2 Expected impact of decision on residential electricity bills

The annual electricity bill for customers in South Australia will reflect the combined cost of all the electricity supply chain components. Infographic 1 below illustrates the different components of the electricity supply chain.

## Infographic 1—Electricity supply chain




Each of the components in the electricity supply chain can affect the electricity charges that customers receive in their bills. Electricity retailers purchase electricity from generators through the electricity market. The costs of electricity transmission are passed on to electricity distributors and then, in turn, passed onto electricity retailers. Our final decision affects the transmission network charges component of the electricity bill for SA, which represent approximately 7 per cent of an average customer's annual electricity bill.[7] This small percentage largely explains the relatively modest impact this draft decision is likely to have on average annual electricity bills.[8]

### 1.2.1 Transmission charges

Figure 1-3 shows our indicative estimate of the combined effect of our final decisions for ElectraNet and Murraylink on forecast average transmission charges in South Australia over the 2018–23 regulatory control period in nominal dollar terms. There are several steps required to translate our revenue decisions into indicative transmission charges.[9] We estimate that our final decisions will result in a slight increase in the average annual transmission charges over the 2018–23 regulatory control period.[10]The average transmission charges are expected to increase slightly from around $28.5 per MWh in 2017–18 to $29.0 per MWh in 2022–23.

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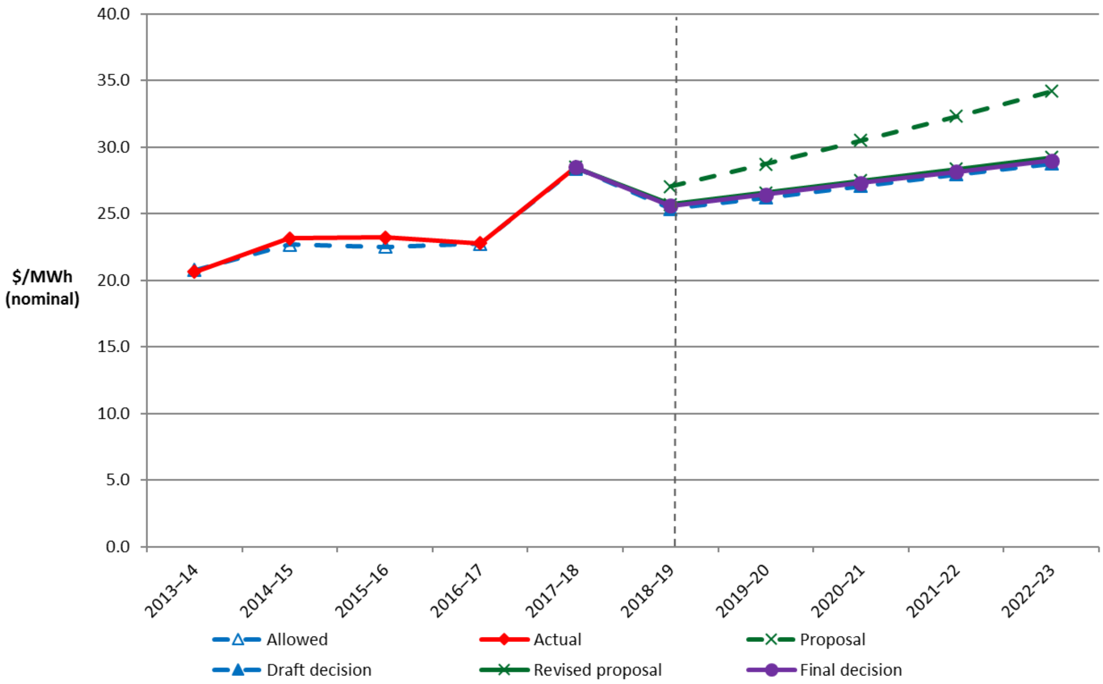
7 ElectraNet, Reset RIN - Table 7.6.1, October 2015.

8 ElectraNet is the main transmission network service provider for South Australia. Therefore, our final decision on ElectraNet's expected MAR will ultimately affect the annual electricity bills paid by customers in South Australia. In addition to ElectraNet's network, Murraylink operates a transmission network linking Victoria and South Australia, which is a small part of the transmission networks in these states. ElectraNet, as coordinating network service provider for South Australia, takes the portion of Murraylink's expected MAR for developing the applicable transmission charges to apply to customers. Based on Murraylink's current pricing methodology, 45 per cent of its regulated revenue will be recovered through transmission charges from South Australian customers. We have assessed Murraylink's revenue proposal for the 2018–23 regulatory control period, which coincides with ElectraNet's period. Our final decision for Murraylink can be found at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/murraylink-determination-2018-23.

9 We estimate the indicative effect of our final decision on forecast average transmission charges in South Australia by 1) taking the sum of ElectraNet's annual expected MAR determined in this draft decision and Murraylink's annual expected MAR apportioned to South Australia, and 2) dividing it by the forecast annual energy delivered in South Australia published by AEMO. Reference: AEMO, *National Electricity and Gas forecasting - 2017 Electricity Forecasting Insights*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational, accessed 21 March 2018.

10 On average, the final decision transmission revenues (the combination of ElectraNet and Murraylink's revenues) will decrease by 0.6 per cent ($nominal) per annum from 2017–18 to 2022–23. The forecast energy delivered in South Australia will decrease by an average of 1.0 per cent per annum across that period. As a result, the indicative transmission charge will increase by 0.4 per cent ($nominal) per annum from 2017–18 to 2022–23.

## Figure 1-3 Indicative transmission price path for SA ($/MWh, nominal)




Source: AER analysis.

### 1.2.2 Potential bill impact

We calculate the expected potential bill impact by varying the transmission charges in accordance with our final decision, while holding all other components constant.[11] This approach isolates the effect of our final decision on the core transmission charges that represent approximately 7 per cent on average of a typical residential customer's annual electricity bill in South Australia.[12] We estimate that our final decision would lead to the transmission component of the average annual residential electricity bill in 2018–19 decreasing by about $17 ($nominal) from the current 2017–18 level (a 0.7 per cent decrease), all else being equal. However, after the initial decrease, the transmission component of the bill will gradually increase and by the end of the regulatory control period, we expect that the average residential customer's annual electricity bills will be $3 ($nominal) higher than the 2017–18 level.

Further detail on our final decision impact on overall bills is set out in attachment 1.

[11] It also assumes that actual energy demand will equal the forecast in our final decision. Since ElectraNet operates under a revenue cap, changes in demand will also affect annual electricity bills across the 2018–23 regulatory control period. While our approach isolates the effect of our decision on electricity prices, it does not imply that other components will remain unchanged across the regulatory control period.

[12] ElectraNet, *Reset RIN - Table 7.6.1*, October 2015.

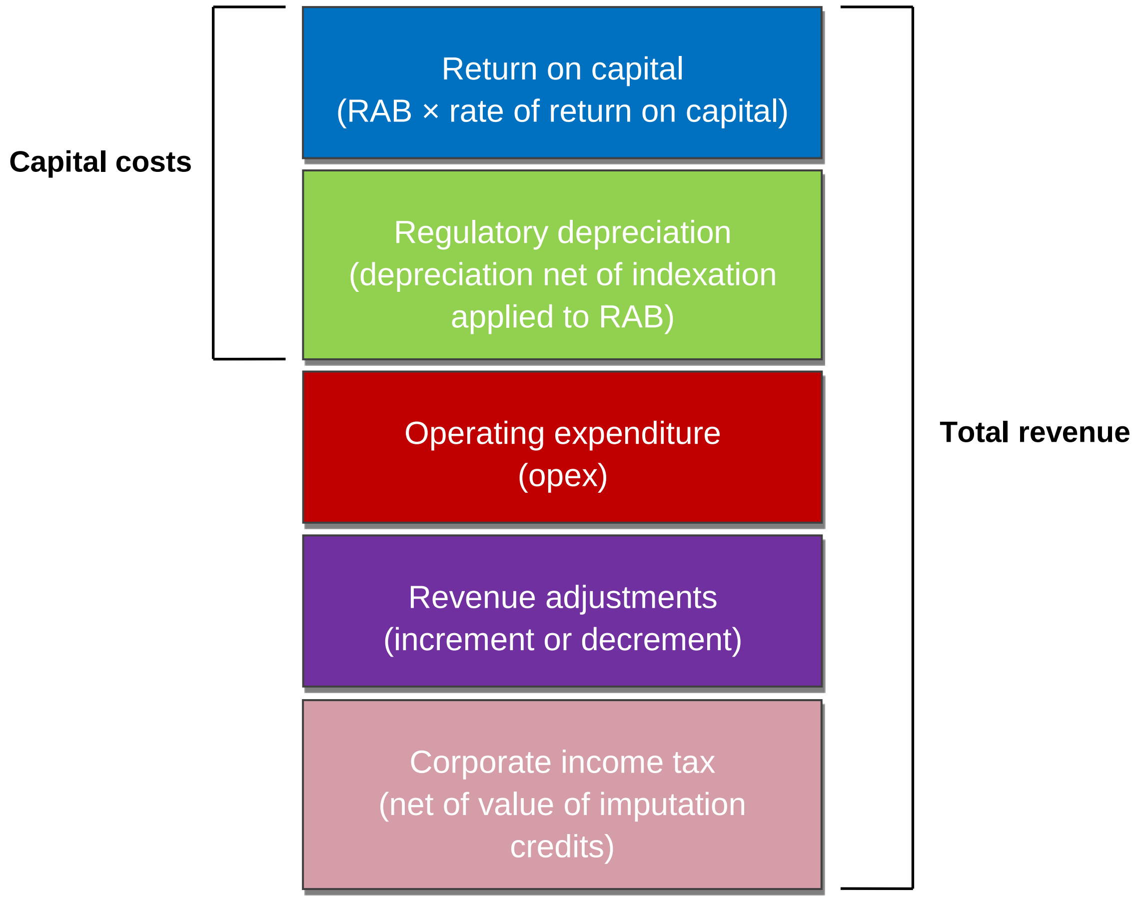
# 2 Key elements of our decision on revenue

In this section, we step through the components of our decision that affect our revenue forecast and examine the drivers of the difference between our draft decision, ElectraNet's revised proposal and revenues in the previous period. To understand what is driving forecast revenues it is necessary to understand the components of our forecast revenue. We use a building block approach to determine ElectraNet's maximum allowed revenue (MAR). The building block approach consists of five costs that a business is allowed to recover through its revenue allowance.

The building block costs are illustrated in Figure 2-1 and include:

- a return on the RAB (or return on capital)
- depreciation of the RAB (or return of capital)
- forecast opex
- revenue adjustments (increments or decrements) resulting from incentive schemes such as the efficiency benefit sharing scheme (EBSS)
- the estimated cost of corporate income tax.

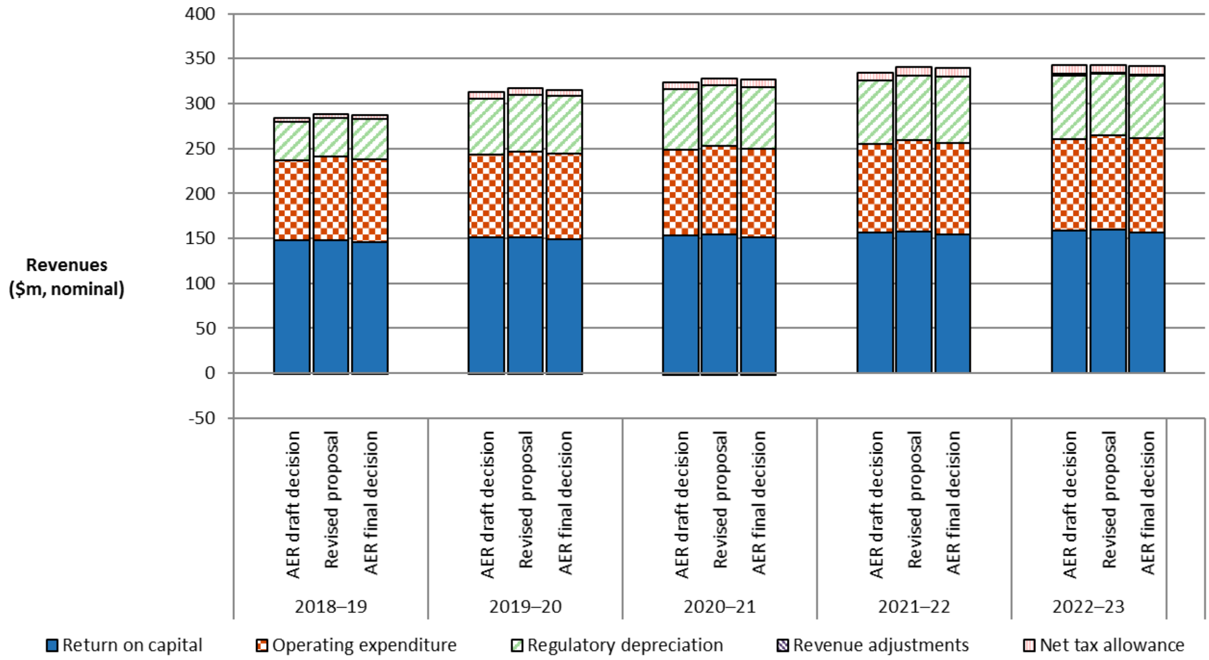
### Figure 2-1 The building block approach for determining total revenue



The building block costs are comprised of key elements that we determine through our assessment process. One key element is ElectraNet's RAB – which is the regulatory value of the assets used by ElectraNet to provide prescribed transmission services. We use the opening RAB for each regulatory year to determine the return on capital and return of capital (regulatory depreciation) building block allowances.

Figure 2-2 compares the average annual building block revenue from our final decision to that proposed by ElectraNet for the 2018–23 regulatory control period, and to the approved average amount for the 2013–18 regulatory control period. Figure 2-2 shows that ElectraNet has proposed a lower return on capital to that which we allowed in the previous period. This is driven by ElectraNet's lower capex and its adoption of our approach to forecasting the rate of return.

### Figure 2-2 AER's final decision on constituent components of average annual revenue ($million, 2017–18)




Source: AER analysis.

Table 2-1 shows our final decision on ElectraNet's revenues including the building block components.

### Table 2-1 AER's final decision on ElectraNet's revenues ($million, nominal)

| | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2022–23 | Total |
|---|---|---|---|---|---|---|
| Return on capital | 145.6 | 148.9 | 151.3 | 154.3 | 156.5 | 756.6 |
| Regulatory depreciation[a] | 44.2 | 63.8 | 68.5 | 73.3 | 69.9 | 319.8 |
| Operating expenditure[b] | 92.6 | 95.4 | 98.6 | 101.9 | 104.9 | 493.4 |
| Revenue adjustments[c] | –1.3 | –1.2 | –1.6 | 0.0 | 0.3 | –3.7 |
| Net tax allowance | 4.9 | 7.5 | 8.2 | 9.9 | 9.9 | 40.3 |
| Annual building block revenue requirement (unsmoothed) | 286.1 | 314.3 | 325.1 | 339.4 | 341.5 | 1606.5 |
| **Annual expected MAR (smoothed)** | 305.3 | 312.8 | 320.4 | 328.3 | 336.3 | **1603.2**[d] |
| X factor[e] | n/a[f] | 0.00% | 0.00% | 0.00% | 0.00% | n/a |

Source: AER analysis.

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

(b) Operating expenditure includes debt raising costs.

(c) Includes efficiency benefit sharing scheme and shared asset amounts.

(d) The estimated total revenue cap is equal to the total annual expected MAR.

(e) 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.

(f) ElectraNet is not required to apply an X factor for 2018–19 because we set the 2018–19 MAR in this decision. The MAR for 2018–19 is around 14.9 per cent lower than the approved MAR for 2016–17 in real terms, or 12.8 per cent lower in nominal terms.

The following sections summarise our final decision on key elements of the building blocks, including:

- RAB (section 2.1)
- Forecast inflation (section 2.2)
- Rate of return and the value of imputation credits (section 2.3)
- Depreciation allowance (section 2.4)
- Efficient level of capex (section 0)
- Efficient level of opex (section 2.6)
- Forecast level of corporate income tax (section 2.7)

Incentive schemes including the STPIS, EBSS and CESS are covered in section 3.

The other components of our determination including the pricing methodology, cost pass throughs and negotiated framework are covered in section 4.

## 2.1 Regulatory asset base

Our revenue determination includes ElectraNet's opening RAB value as at 1 July 2018 and projected RAB value for the 2018–23 regulatory control period.[13] The value of the RAB substantially impacts ElectraNet'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.[14]

Our final decision is to determine an opening RAB value of $2560.2 million ($ nominal) as at 1 July 2018 for ElectraNet.

Using the opening RAB as at 1 July 2018, we roll forward that RAB over the 2018–23 regulatory control period with forecast capex, inflation and depreciation to arrive at a forecast closing value for the RAB at the end of the 2018–23 regulatory control period.

Table 2-2 sets out our final decision on the forecast RAB values for ElectraNet over the 2018–23 regulatory control period.

### Table 2-2 AER's final decision on ElectraNet's RAB for the 2018–23 regulatory control period ($million, nominal)

| | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2022–23 |
|---|---|---|---|---|---|
| Opening RAB | 2560.2 | 2617.2 | 2661.0 | 2712.1 | 2752.0 |
| Capital expenditure[a] | 101.3 | 107.5 | 119.7 | 113.2 | 61.5 |
| Inflation indexation on opening RAB | 62.7 | 64.1 | 65.2 | 66.4 | 67.4 |
| *Less*: straight-line depreciation[b] | 107.0 | 127.9 | 133.7 | 139.8 | 137.3 |
| **Closing RAB** | **2617.2** | **2661.0** | **2712.1** | **2752.0** | **2743.7** |

Source: AER analysis.

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

(b) Based on as-commissioned capex.

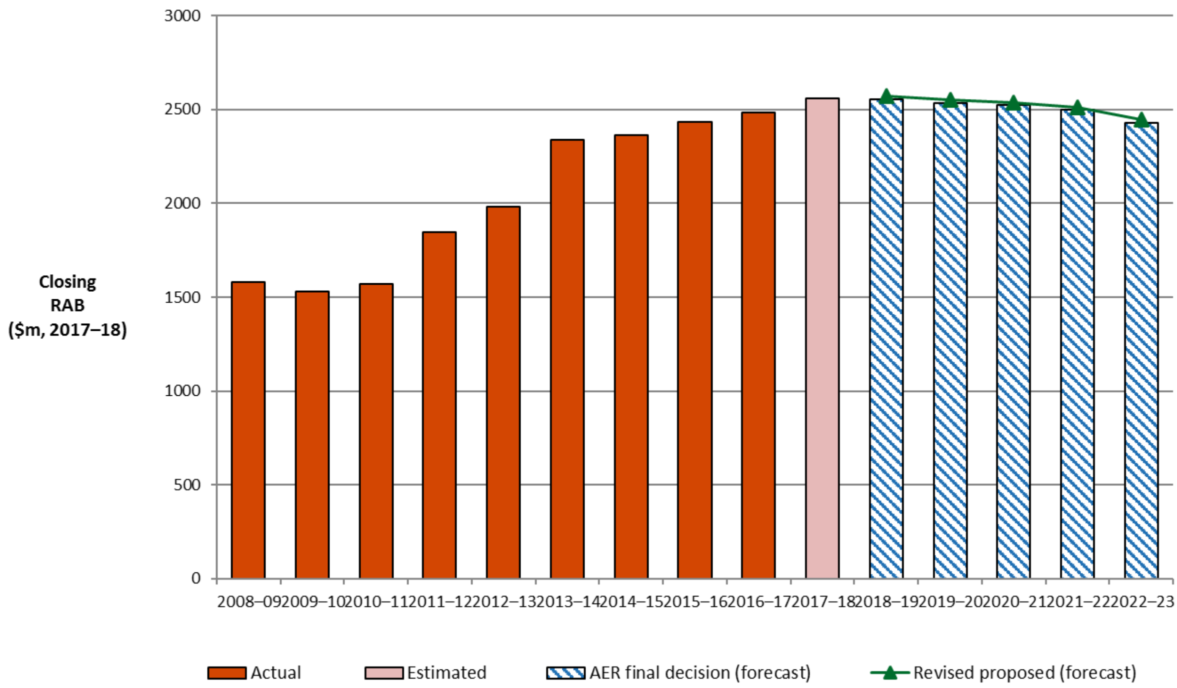
Figure 2-3 compares our final decision on ElectraNet's forecast RAB to ElectraNet's revised proposal and actual RAB in real dollar terms ($2017–18). The key highlight is ElectraNet's RAB is expected to decline over the 2018–23 regulatory control period, reversing the trend from the past 10 years. However, there is the potential for ElectraNet's RAB to increase in the 2018–23 regulatory control period. This may happen if one or more of ElectraNet's contingent projects proceed.

13 NER, cl. 6A.5.4(a)(2) and (3).

14 The size of the RAB also impacts the benchmark debt raising cost allowance. However, this amount is usually relatively small and therefore not a significant determinant of revenues overall.

Further detail on our final decision on ElectraNet's RAB is set out in attachment 2.

### Figure 2-3 ElectraNet's actual RAB, proposed forecast RAB and AER final decision forecast RAB ($million, 2017–18)




Source: AER analysis.

## 2.2 Forecast inflation

Forecast inflation affects almost every component of our revenue determination for ElectraNet. However, the most significant impact is on our depreciation allowance. Given that we apply a nominal rate of return, and also annually index the RAB, we make a negative adjustment to our depreciation building block to avoid double counting inflation. If the estimate of expected inflation is not accurate, the result will be a potential under-recovery of costs (if the forecast of inflation is too high) or an over-recovery (if the forecast is too low).

The regulatory treatment of inflation was considered through a separate consultation process during the course of making our draft decision and the submission of ElectraNet's revised proposal. In our draft decision, we did not accept ElectraNet's market based inflation forecast approach.[15] We adopted our current approach[16],

[15] AER, *Draft Decision: ElectraNet transmission determination 2018 to 2023, Attachment 3 - Rate of return*, October 2017, p. 136.

[16] We use the Reserve Bank of Australia's (RBA's) two year forecast of inflation (which is as far as the RBA forecasts) and combines these two values with the midpoint of the RBA's target band for inflation (currently 2.5 per cent) to extend the series out to ten years.

pending the outcome of the inflation review. This concluded on 20 December 2017 prior to ElectraNet submitting its revised proposal. Our final position in that review was that we will continue our current approach to the regulatory treatment of inflation in our determination of revenues and prices for electricity and gas network services.[17]

ElectraNet's revised proposal accepted our approach.[18]

## 2.3 Rate of return (return on capital) and imputation credits (gamma)

The allowed rate of return provides the business with a return on capital to service the interest on its loans and give a return on equity to investors.[19] The return on capital building block is calculated as a product of the rate of return and the value of the RAB. Our allowed rate of return is a weighted average of our return on equity and return on debt estimates determined on a nominal vanilla basis that is consistent with our estimate of the value of imputation credits.

In our draft decision, we applied an updated rate of return of 5.75 per cent compared to ElectraNet's estimate of 6.02 percent based on more recent market data.[20] ElectraNet has accepted our draft decision on the rate of return.[21] Our final decision provides for a further update for prevailing market rates based on ElectraNet's averaging period.

Our final decision rate of return is 5.69 per cent (nominal vanilla) for the first year of the 2018-23 regulatory control period.

A key difference in ElectraNet's revised proposal was the value of imputation credits (gamma). ElectraNet had initially proposed a value of 0.25. In our draft decision, we applied a value of 0.4.[22] ElectraNet's revised proposal accepted our value of 0.4.[23]

Table 2-3 sets out our final decision on the rate of return for ElectraNet.

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17 AER, *Regulatory treatment of inflation, Final position*, December 2017, p. 7.

18 ElectraNet, *Revised revenue proposal*, December 2017, p. 43.

19 We are currently reviewing the rate of return guideline, and the AER has issued several discussion papers in this process. A draft decision is due in June 2018.

20 AER, *Draft Decision: ElectraNet transmission determination 2018 to 2023, Overview*, October 2017, p. 22.

21 ElectraNet, *Revised revenue proposal*, December 2017, p. 42.

22 This is consistent with the approach we adopted in recent decisions, which has been upheld by the Federal Court of Australia; Federal Court of Australia, *Australian Energy Regulator v Australian Competition Tribunal (No 2) [2017] FCAFC 79*, May 2017, p. 216.

23 ElectraNet, *Revised revenue proposal*, December 2017, p. 42.

### Table 2-3 AER final decision on ElectraNet's rate of return (per cent, nominal)

| | AER previous decision (2014–18) | ElectraNet proposal (2018–23) | AER draft decision (2018–23) | AER final decision (2018-23) | Allowed return over 2018–23 regulatory control period |
|---|---|---|---|---|---|
| Return on equity (nominal post–tax) | 9.51 | 7.4 | 7.2 | 7.4 | Constant (7.4%) |
| Return on debt (nominal pre–tax) | 6.79 | 5.1 | 4.78 | 4.55 | Updated annually |
| Gearing | 60 | 60 | 60 | 60 | Constant (60%) |
| Nominal vanilla WACC | 7.87 | 6.02 | 5.7 | 5.69 | Updated annually for return on debt |
| Forecast inflation | 2.45 | 1.97 | 2.5 | 2.45 | Constant (2.5%) |
| Value of imputation credits (gamma) | 0.25 | 0.25 | 0.4 | 0.4 | Constant (0.4) |

Source: AER analysis; ElectraNet, *Transmission Revenue Review 2017–2022 regulatory proposal*, 30 October 2015; AER, *Final Decision: SP AusNet Transmission determination 2014-2017*, January 2014.

## 2.4 Regulatory depreciation (return of capital)

In our final decision, we include an allowance for the depreciation of ElectraNet's asset base (otherwise referred to as return of capital). Regulated service providers invest in large sunk assets to provide electricity transmission services to customers. While some of the cost of such assets may be recovered from customers upfront, a greater proportion is recovered over time. The depreciation allowance is used for this purpose.

The changes to the regulatory depreciation allowance reflect our adjustments to the opening RAB as at 1 July 2018 (section 2.1), expected inflation rate (section 2.2) and forecast capital expenditure (section 2.5).

Table 2-4 shows our final decision on ElectraNet's depreciation allowance for the 2018–23 regulatory control period.

### Table 2-4 AER's final decision on ElectraNet' depreciation allowance for the 2018–23 period ($million, nominal)

| | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2022–23 | Total |
|---|---|---|---|---|---|---|
| Straight-line depreciation | 107.0 | 127.9 | 133.7 | 139.8 | 137.3 | 645.7 |
| *Less:* inflation indexation on opening RAB | 62.7 | 64.1 | 65.2 | 66.4 | 67.4 | 325.9 |
| **Regulatory depreciation** | **44.2** | **63.8** | **68.5** | **73.3** | **69.9** | **319.8** |

Source: AER analysis.

Further detail on our final decision on ElectraNet's regulatory depreciation is set out in attachment 5.

## 2.5 Capital expenditure

Capital expenditure (capex) refers to the capital expenses incurred in the provision of network services. The return on and return of forecast capex are two of the building blocks we use to determine ElectraNet's total revenue requirement.[24]

In its revised proposal, ElectraNet proposed total forecast capex of $461.5 million ($2017–18) for the 2018–23 regulatory control period.[25] This is slightly higher than our draft decision on total forecast capex of $459.1 million.[26]

ElectraNet proposed a substantial decrease in forecast capex for the 2018–23 regulatory control period. This is largely driven by projections of declining demand in South Australia, which means there is currently no need to augment the network to meet expected demand.

The majority of ElectraNet's forecast capex relates to asset replacement and refurbishment work driven by the need to manage the safety, security and reliability risks associated with ageing assets. Following the system security and reliability issues experienced in South Australia over the last 12 months, ElectraNet has also proposed a small number of specific projects to improve the ability of the network to withstand extreme weather events and to maintain and enhance the security of the network.

For this final decision, we are satisfied that ElectraNet's forecast capex is consistent with the drivers of investment need and reasonably reflects the efficient costs that a prudent operator would incur in the 2018–23 regulatory control period.

Our final decision approves $461.5 million ($2017-18) total forecast capex for the 2018–23 regulatory control period.

Figure 2-4 shows ElectraNet's revised proposal and our draft and final decisions for the 2018–23 regulatory control period, as well as the actual capex incurred by ElectraNet in previous regulatory control periods. There is little difference between ElectraNet's proposed capex and our draft and final decisions on total forecast capex.

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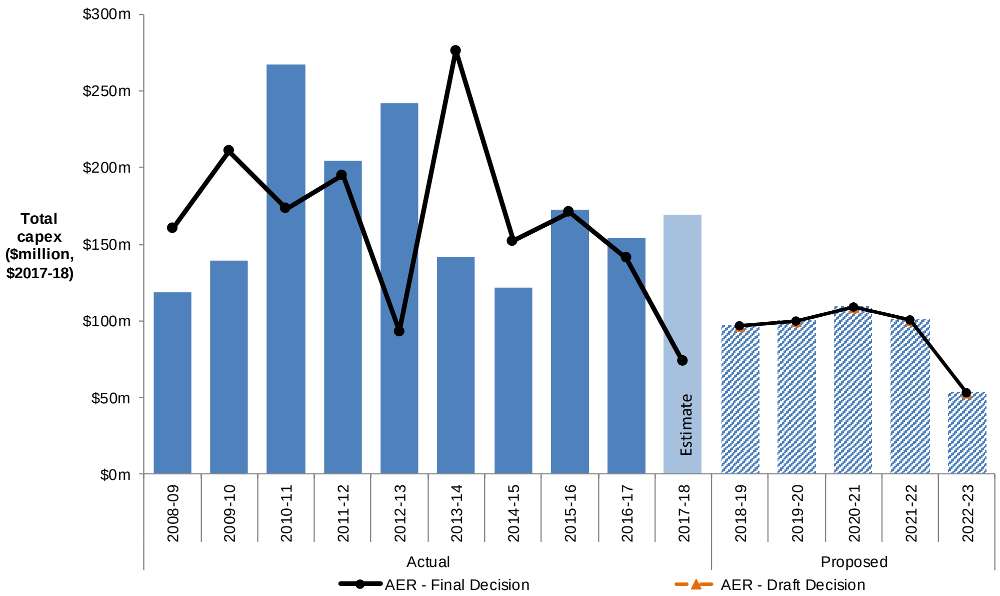
[24] NER, cl. 6A.5.4(a).

[25] ElectraNet, *Revised regulatory proposal*, December 2017 p. 25.

[26] AER, *Draft Decision: ElectraNet transmission determination 2018 to 2023, Overview*, October 2017, p. 24.

**Figure 2-4 AER final decision capex and ElectraNet's total actual and forecast capex ($million, 2017-18)**




ElectraNet accepted the AER's draft decision on total forecast capex. The difference between ElectraNet's revised capex proposal and our draft decision is due to ElectraNet updating its forecasts to account for:

- the revised timing of the Dalrymple energy storage project and associated capital works deferrals
- updated estimates of forecast labour cost escalation in the 2018–23 regulatory control period.

ElectraNet also proposed some amendments to the trigger events for its proposed contingent projects in the 2018–23 regulatory control period. ElectraNet proposed $630 million to $950 million for five contingent projects for the 2018–23 regulatory control period. The five proposed contingent projects are:

- Eyre Peninsula Reinforcement ($200 million)
- South Australian Energy Transformation ($200-500 million)
- Upper North-East Line Reinforcement ($60 million)
- Upper North-West Line Reinforcement ($110 million)
- Main Grid System Strength Support ($60-80 million).

If, during the regulatory control period, ElectraNet considers that the trigger events for an approved contingent project have occurred, then it may apply to us to amend its revenue determination.[27] At that time, we will publish the application and invite written

[27] NER, cl. 6A.8.2 (a).

submissions.[28] We will then assess whether the defined trigger events have occurred and the project meets the materiality threshold. If satisfied that this is the case, we will determine the amount of capex and incremental opex that we consider is reasonable to undertake the project and therefore the efficient incremental revenue which is likely to be required in each remaining year of the regulatory control period as a result of undertaking the contingent project.[29] Any revenue adjustments as a result of a contingent project will be reflected in future prices.

We are satisfied that ElectraNet's proposed five contingent projects may be reasonably required to be undertaken in the 2018–23 regulatory control period.[30] We have reviewed ElectraNet's amended triggers in relation to the possibility of a new approval pathway for transmission development following from the Finkel review and the new NEM Integrated System Plan, but do not accept this aspect of ElectraNet's proposed trigger events. While we recognise that the final report of the Finkel review and the Integrated System Plan contemplate new pathways for transmission development, a RIT remains a legal requirement for projects above the threshold of $6 million that cannot be circumvented through trigger events.

Our final decision on ElectraNet's proposed contingent projects and further detail on capex is set out in attachment 6.

## 2.6 Operating expenditure

Operating expenditure (opex) is the operating, maintenance and other non-capital expenses incurred in the provision of network services. Forecast opex for prescribed transmission services is one of the building blocks we use to determine a service provider's annual total revenue requirement.

Our final decision is to accept ElectraNet's total opex forecast of $458.4 million ($2017–18) as set out in table 2-5.

### Table 2-5 AER final decision on total opex ($million, 2017–18)

| | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2022–23 | Total |
|---|---|---|---|---|---|---|
| Total opex, excluding debt raising costs and network support costs | 80.7 | 81.2 | 82.1 | 82.9 | 83.3 | **410.2** |
| Network support costs | 8.4 | 8.4 | 8.4 | 8.4 | 8.4 | **41.9** |
| Debt raising costs | 1.3 | 1.3 | 1.3 | 1.3 | 1.2 | **6.3** |
| **Total opex** | **90.4** | **90.9** | **91.7** | **92.5** | **92.9** | **458.4** |

Source: ElectraNet, *Revised regulatory proposal, opex model and PTRM*.

Note: Numbers may not add up due to rounding.

28 NER, cl. 6A.8.2 (c).

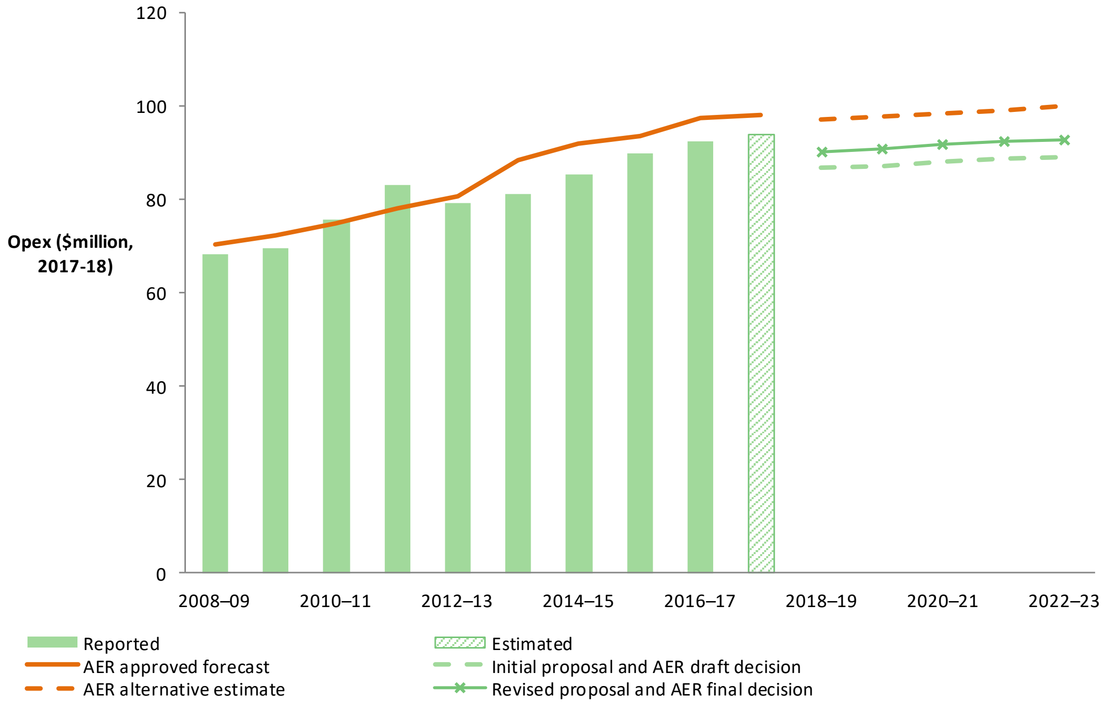
29 NER, cl. 6A.8.2 (e).

30 NER, cl. 6A.8.1(b)(1).

We are satisfied that ElectraNet's total opex forecast of $458.4 million ($2017–18) reasonably reflects the criteria set out under the NER for accepting forecast opex and is efficient. We have tested ElectraNet's revised proposal by comparing it to our alternative estimate of total opex forecast, which we have updated. Our alternative estimate is 1.4 per cent higher than ElectraNet's total opex forecast.

Figure 2-5 compares ElectraNet's forecast opex with its historical opex, historical allowance, our draft decision and our alternative opex forecast.

### Figure 2-5 ElectraNet's actual and forecast opex ($million, 2017–18)




Source: ElectraNet, *Regulatory accounts 2003–04 to 2015–16*; ElectraNet, *Revenue proposal, PTRM*, 31 January 2017; ElectraNet, Revised *revenue proposal, PTRM*, 1 December 2017; AER, *Final decision PTRM*, April 2013; AER, Final decision 2013–18, *Adjusted PTRM - Heywood contingent project application revised_MDL_v1;* AER analysis.

Note: Includes debt raising costs and connection charges.

ElectraNet's revised proposal is higher than its initial proposal of $440.1 million ($2017–18), which we accepted in our draft decision. Prior to making our draft decision, ElectraNet advised that it was likely to amend its opex forecast in its revised proposal to reflect new obligations arising from recent market reviews and rule changes.[31] We noted in our draft decision that we would consider the cost impacts of these new obligations before making our final decision.[32]

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31 ElectraNet, *ElectraNet's Revenue Proposal 2018–23 – Update on Cost Pressures*, 6 October 2017. See late submissions on the ElectraNet proposal section on our website.

32 AER, *ElectraNet transmission determination 2018–23 Draft decision Overview*, October 2017, p. 27.

ElectraNet proposed seven new step changes totalling $12.8 million ($2017–18) over five years in its revised proposal.[33] ElectraNet stated that these step changes reflect forecast of cost increases required to comply with new regulatory requirements imposed by changes to the NER and other requirements, including:[34]

- Emergency frequency control schemes rule March 2017
- Transmission connection and planning arrangements rule May 2017
- Integrated grid planning (outcome of the Finkel Review) June 2017
- Replacement expenditure planning arrangements rule July 2017
- South Australian generator licensing arrangements August 2017
- Managing rate of change of power system frequency rule and managing power system fault levels rule September 2017
- Generating system model guidelines rule September 2017.

Further, ElectraNet updated its forecast of debt raising costs, network support costs and labour price growth to reflect the forecasts of these costs that we included in our draft decision alternative estimate.[35]

To test ElectraNet's revised proposal, we have revised our alternative estimate of total opex by updating:

- our forecast of price growth to reflect the input price weights set out in our 2017 benchmarking report,[36] and Deloitte Access Economics' (DAE) most recent labour price forecasts[37]
- our forecast of inflation for 2017–18 to reflect the Reserve Bank of Australia's latest *Statement on Monetary Policy*.[38]

We also identified and corrected an error in how we treated inflation in the opex model we used to calculate our alternative estimate.

We note that we have not included in our alternative estimate any of the step changes ElectraNet included in its revised proposal. ElectraNet's revised proposal is lower than our alternative estimate of total opex even when we do not include these step changes in our alternative estimate. Consequently we have not formed, and did not need to form, a view on whether these step changes are required since it would not change our decision to accept ElectraNet's revised opex forecast.

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33 ElectraNet, *Revised revenue proposal: opex model*, December 2017.

34 ElectraNet, *Revised revenue proposal*, December 2017, p. 35.

35 ElectraNet, *Revised revenue proposal*, December 2017, pp. 36–37.

36 Economic Insights, *Economic Benchmarking Results for the Australian Energy Regulator's 2017 TNSP Benchmarking Report*, November 2017, pp. 6-7.

37 Deloitte Access Economics, *Labour Price Forecasts: Prepared for the Australian Energy Regulator*, February 2018, p. xiv.

38 Reserve Bank of Australia, *Statement on Monetary Policy*, February 2018.

Our estimate of $464.8 million ($2017–18) is 1.4 per cent higher than ElectraNet's revised proposal.[39] As a result, we are satisfied ElectraNet's proposed total opex forecast reasonably reflects the criteria set under the rules[40] and is efficient.

We have received two submissions on opex, which supported our draft decision.[41] However, they had conflicting views on whether we should accept ElectraNet's revised proposal, particularly its step changes. The Government of South Australia submitted that we should reject ElectraNet's revised proposal whereas the consumer challenge panel (CCP9) supported ElectraNet's proposal, including its proposed step change.[42] The Government of South Australia considered that base opex trended by the rate of change is sufficient for ElectraNet to cover the increased costs forecast related to compliance with the new regulatory obligations. However, it also acknowledged that our task is to determine whether ElectraNet's total opex forecast reasonably reflect the opex criteria.[43]

As stated earlier, we have tested ElectraNet's revised proposal and we are satisfied that its revised opex forecast of $458.4 million ($2017–18) reasonably reflects the opex criteria. ElectraNet's revised opex forecast, with the proposed new step changes is lower than our alternative estimate, which does not include the proposed new step changes. Consequently we do not consider that the addition of the step changes provides grounds to not accept the revised proposal. Again, we have not formed a view on whether these step changes are required because it was not necessary to accept the proposal. Our opex model, which calculates our alternative estimate of opex, is available on our website.

## 2.7 Corporate income tax

Our revenue determination includes the estimated cost of corporate income tax for ElectraNet's 2018–23 regulatory control.[44] This allows ElectraNet to recover the costs associated with the estimated corporate income tax payable during the regulatory control period.

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39 Our assessment of opex proposed by a business involves developing an alternative estimate of total opex, which we compare with that of the business. Our assessment approach is set out in: AER, *ElectraNet transmission determination 2018–23 Draft decision, Attachment 7–Operating Expenditure*, October 2017 pp. 7–9 to 7–11.

40 NER, cl. 6A.6.6(c).

41 The Consumer Challenge Panel Subpanel 9 (CCP), *Response to Draft Decision and Revised Proposal for Revenue Reset for ElectraNet for 2018–2023*, February 2018; Government of South Australia, *Submission on ElectraNet's revised proposal*, January 2018.

42 The Consumer Challenge Panel Subpanel 9 (CCP), *Response to Draft Decision and Revised Proposal for Revenue Reset for ElectraNet for 2018–2023*, February 2018, pp. 6–7; Government of South Australia, *Submission on ElectraNet's revised proposal*, January 2018, p. 2.

43 The Consumer challenge Panel Subpanel 9 (CCP), *Response to Draft Decision and Revised Proposal for Revenue Reset for ElectraNet for 2018–2023*, February 2018, pp. 6–7; Government of South Australia, *Submission on ElectraNet's revised proposal*, January 2018, p. 2.

44 NER, cl. 6A.6.4.

Our final decision on the estimated cost of corporate income tax is $40.3 million ($nominal) for ElectraNet over the 2018–23 regulatory control period. This amount represents an increase of $2.8 million (or 7.4 per cent) from the $37.5 million ($nominal) in ElectraNet's revised proposal. The increase from the revised proposal reflects our adjustments on the return on capital (section 2.3) and regulatory depreciation (section 2.4) building blocks, which affect revenues, and in turn impacts the tax calculation.

Table 2-6 shows our final decision on ElectraNet's corporate income tax allowance for the 2018–23 regulatory control period.

### Table 2-6 AER's final decision on corporate income tax allowance for ElectraNet ($million, nominal)

| | 2018–19 | 2019–20 | 2020–21 | 2021–22 | 2022–23 | Total |
|---|---|---|---|---|---|---|
| Tax payable | 8.2 | 12.4 | 13.7 | 16.5 | 16.4 | 67.2 |
| *Less:* value of imputation credits | 3.3 | 5.0 | 5.5 | 6.6 | 6.6 | 26.9 |
| **Net corporate income tax allowance** | **4.9** | **7.5** | **8.2** | **9.9** | **9.9** | **40.3** |

Source: AER analysis.

Further detail on our final decision on ElectraNet's corporate income tax is set out in attachment 8.

# 3 Incentive schemes

Incentive schemes are a component of incentive–based regulation and complement our approach to assessing efficient costs. The incentive schemes that will apply to ElectraNet are:

- the efficiency benefit sharing scheme (EBSS)
- the capital expenditure sharing scheme (CESS)
- the service target performance incentive scheme (STPIS).

Our incentive schemes work together to encourage network businesses to make efficient decisions. They give network businesses an incentive to pursue efficiency improvements in opex and capex, and to share them with consumers. Incentives for opex and capex are balanced with the incentives under our STPIS. The incentive schemes encourage businesses to make efficient decisions on when and what type of expenditure to incur, and meet service reliability targets. Ultimately, the intention of our incentive schemes is to provide customers with better value for money through either improving network performance or lowering electricity bills.

## 3.1 Efficiency benefit sharing scheme (EBSS)

The EBSS provides a constant incentive for service providers to pursue efficiency improvements in opex. Without the EBSS, a network may have a greater incentive to reduce costs in a particular year in a regulatory control period.

Incentive based regulation encourages networks to provide services as efficiently as possible while fulfilling their reliability and security obligations. With MAR locked in at the beginning of the regulatory period networks are incentivised to provide services at lowest possible cost because their returns are based on their actual costs. If the network can reduce its cost to below what we have estimated to be efficient, then it can retain the savings during the regulatory period. Those efficiency savings are then passed on to consumers through lower opex forecasts in the following period. The EBSS ensures that the benefit of opex efficiencies to both networks and consumers is the same regardless of when the network makes those savings within the regulatory period.

Our final decision is to approve carryover amounts totalling –$3.50 million ($2017–18) from the application of the EBSS in the 2013–18 regulatory control period. This is marginally higher ($0.02 million) than ElectraNet's revised proposal of –$3.52 million ($2017–18). ElectraNet adopted our draft decision approach in its revised proposal.[45]

As indicated in the draft decision, we have updated our carryover amounts to reflect actual opex for 2016–17 and inflation numbers as set out in the Reserve Bank of

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[45] ElectraNet, *Revised revenue proposal,* December 2017, p. 11 and pp. 45–46.

Australia's latest *Statement on Monetary Policy*.[46] ElectraNet accepted our draft decision.[47]

Table 3-1 sets out our final decision on the EBSS carryover amounts ElectraNet accrued during the 2013–18 regulatory control period.

### Table 3-1 AER's final decision on ElectraNet's EBSS carryover amounts ($million, 2017–18)

| | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | Total |
|---|---|---|---|---|---|---|
| ElectraNet proposal | –0.9 | –1.2 | –1.6 | – | 1.7 | **–1.9** |
| AER draft decision | –1.4 | –1.3 | –1.6 | – | 2.0 | **–2.2** |
| ElectraNet revised proposal | –1.2 | –1.1 | –1.5 | – | 0.3 | **–3.5** |
| **AER final decision** | **–1.2** | **–1.1** | **–1.5** | **–** | **0.3** | **–3.5** |

Source: ElectraNet, *Revenue proposal, PTRM*, January 2017; ElectraNet, *Revised revenue proposal, PTRM*, December 2017; AER analysis.

Note: Numbers may not add up due to rounding.

Our final decision is to apply version two of the EBSS to ElectraNet in the 2018–23 regulatory control period. This is consistent with our draft decision and ElectraNet's revised proposal. [48] When we apply the EBSS, we will exclude the following cost categories from the scheme:

- debt raising costs
- network support costs
- network capability projects.

The opex forecasts we will use to calculate efficiency gains in the 2018–23 regulatory control period, subject to further adjustments permitted by the EBSS, are set out in Table 3-2.

46 Reserve Bank of Australia, *Statement on Monetary Policy*, February 2018.

47 ElectraNet, *Revised revenue proposal,* December 2017, p. 11 and pp. 45–46.

48 AER, *ElectraNet transmission determination 2018–23 Draft decision, Attachment 9–Efficiency Benefit Sharing Scheme*, October 2017 p. 7; ElectraNet, *Revised revenue proposal,* December 2017, p. 45.

### Table 3-2 AER's final decision on ElectraNet's forecast opex for the EBSS ($million, 2017–18)

| | 2015–16 | 2016–17 | 2017–18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 |
|---|---|---|---|---|---|---|---|---|
| Total opex | 92.6 | 97.6 | 98.0 | 90.4 | 90.9 | 91.7 | 92.5 | 92.9 |
| Less debt raising costs | –1.3 | –1.4 | –1.4 | –1.3 | –1.3 | –1.3 | –1.3 | –1.2 |
| Less network support costs | –9.2 | –9.4 | –9.5 | –8.4 | –8.4 | –8.4 | –8.4 | –8.4 |
| **Target opex for the EBSS** | **82.1** | **86.8** | **87.0** | **80.7** | **81.2** | **82.1** | **82.9** | **83.3** |

Source: ElectraNet, *Revised revenue proposal, PTRM*, December 2017; AER analysis.

Note: Numbers may not add up due to rounding.

## 3.2 Capital expenditure sharing scheme (CESS)

The CESS provides an incentive for service providers to pursue efficiency improvements in capex. Similar to the EBSS, the CESS provides a network service provider with the same reward for an efficiency saving and the same penalty for an efficiency loss regardless of which year they make the saving or loss.

Under the CESS a service provider retains 30 per cent of the benefit or cost of an underspend or overspend, while consumers retain 70 per cent of the benefit or cost of an underspend or overspend. This means that for a one dollar saving in capex the service provider keeps 30 cents of the benefit while consumers keep 70 cents of the benefit. Conversely, in the case of an overspend, the service provider pays for 30 cents of the cost while consumers bear 70 cents of the cost.

Our final decision is to apply our CESS to ElectraNet in the 2018–23 regulatory control period. This is the first time that the CESS has been applied to ElectraNet following the making of our capex incentive guideline. This is to balance the incentives for ElectraNet to pursue opex efficiencies with its incentives to pursue capex efficiencies. The CESS provides an incentive for service providers to pursue efficiency improvements in capex. Similar to the EBSS, the CESS provides a network service provider with the same reward for an efficiency saving and the same penalty for an efficiency loss regardless of which year they make the saving or loss. Under the application of the CESS and EBSS incentives for opex and capex are balanced (30 per cent) and constant.

## 3.3 Service target performance incentive scheme (STPIS)

The STPIS is intended to balance a business's incentive to reduce expenditure with the need to maintain or improve service quality. In simple terms, it penalises networks for cutting costs at the expense of the reliability of their network. It achieves this by providing financial incentives to businesses to maintain and improve service performance where customers are willing to pay for these improvements.

Businesses can only retain their rewards for sustained and continuous improvements to the reliability of supply for customers. Once improvements are made, the benchmark performance targets will be tightened in future years.

ElectraNet accepted our draft decision on the STPIS.[49] This was based on the 2010–2016 audited data. We have updated this using the 2017 audited performance data submitted by ElectraNet.

Our final decision is to apply all components of version 5 of the STPIS to ElectraNet for the 2018–23 regulatory control period. The STPIS parameters for our final decision are set out in section 1.6 of the transmission determination.

49 ElectraNet, *Revised revenue proposal,* December 2017, p. 46

# 4 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 ElectraNet must set its prices, the framework for ElectraNet's negotiated services and the conditions under which we may grant ElectraNet additional revenues to cover unforeseen circumstances.

## 4.1 Pricing methodology

The role of ElectraNet's pricing methodology is to answer the question 'who should pay how much'[50] in order for ElectraNet to recover its costs. The pricing methodology must provide a 'formula, process or approach'[51] that when applied:

- allocates the aggregate annual revenue requirement to the categories of prescribed transmission services that a transmission business provides and to the connection points of network users[52]
- determines the structure of prices that a transmission business may charge for each category of prescribed transmission services.[53]

In our draft decision, we approved ElectraNet's proposed pricing methodology for the 2018–23 regulatory control period. ElectraNet's revised proposal accepted our draft decision, and our final decision is to approve ElectraNet's pricing methodology. ElectraNet's pricing methodology relates to prescribed transmission services only.

The pricing methodology that will apply to ElectraNet for the period of this determination is set out in Attachment B.

## 4.2 Cost pass through

In our draft decision, we approved ElectraNet's nominated pass through events.[54] ElectraNet revised proposal accepted our draft decision.[55]

Our final decision is to approve ElectraNet's nominated pass through events and associated definitions. These will apply to ElectraNet throughout the regulatory control period in addition to the pass through events which are prescribed by the NER, including the events dealing with regulatory change, service standards, tax change and

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50 AEMC, *Rule determination: National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 1.

51 NER, cl. 6A.24.1(b).

52 NER, cl. 6A.24.1(b)(1).

53 NER, cl. 6A.24.1(b)(2).

54 AER, *Draft Decision ElectraNet transmission determination 2018 to 2023, October 2017, Attachment 13*, p. 13–6.

55 ElectraNet, *Revised Revenue Proposal 2018-19 to 2022-23, 22 December 2017*, p. 11.

insurance,[56] and the newly prescribed ‘fault level shortfall event’ and the ‘inertia shortfall event’.[57]

## 4.3 Negotiating framework

In our draft decision, we approved ElectraNet’s proposed negotiating framework for the 2018–23 regulatory control period. ElectraNet’s revised proposal accepted our draft decision, while noting that “the negotiating framework will cease to apply under the rules on 1 July 2018”.[58]

Our final decision is to approve ElectraNet’s negotiating framework, subject to the new rules (as explained below).

Under the NER, a transmission determination includes a determination in relation to the TNSP’s negotiating framework.[59] The negotiating framework determination must also specify the negotiated transmission service criteria (NTSC) that form part of a transmission determination.[60]

In May 2017, the AEMC made a rule change to amend those aspects of the NER relating to the arrangements for transmission connections.[61] The rule change removes the requirement, on and from 1 July 2018, for TNSPs to develop individual negotiating frameworks for approval by the AER, and for the AER to specify the NTSC that apply to TNSPs. Instead, the rule change elevates what is in the existing approved negotiating frameworks and NTSC into the NER, and expands the existing negotiating principles in the NER.[62]

As a result of the AEMC’s rule change, all negotiating framework determinations the AER has made prior to 1 July 2018, will cease to apply. After this date, any parties seeking connection to the transmission network will do so under the new rules.

Given that our final transmission determination for ElectraNet is to be made by 30 April 2018 which is before the 1 July 2018 commencement date, we will still need to comply with our obligations under the NER and include a negotiating framework determination in ElectraNet’s final transmission determination. However, in light of the AEMC final rule, this negotiating framework determination will cease to apply from 1 July 2018.

Attachment A of our final decision sets out our approved negotiating framework for ElectraNet.

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56 NER, cl. 6A.7.3(a1)(1)–(4). Each of these prescribed events is defined in Chapter 10 (Glossary)

57 National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017 No.9; National Electricity Amendment (Managing power system fault levels) Rule 2017 No.10.

58 ElectraNet, *Revised Revenue Proposal 2018-19 to 2022-23*, 22 December 2017, p. 11.

59 NER, cl. 6A.2.2(3).

60 NER, cl. 6A.9.4.

61 AEMC, *National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017 No. 4*, 23 May 2017. In addition to transmission connections, the rule change also relates to transmission planning.

62 AEMC, *Rule Determination, National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017,* p. 66.

# 5 Understanding the NEO

The NEL requires us to make our decision in a manner that contributes, or is likely to contribute, to achieving the NEO.[63] 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.[64] This is not delivered by any one of the NEO's factors in isolation, but rather by balancing them in reaching a regulatory decision.[65]

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.[66] 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. [67]

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.[68] 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.[69] 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.[70] This could have significant longer term pricing implications for those consumers who continue to use network services
- 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.[71] This could create longer term problems in the network, and could have adverse consequences for safety, security and reliability of the network

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63 NEL, section 16(1).

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

65 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.

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

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

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

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

70 NEL, s. 7A(7).

71 NEL, s. 7A(6).

The legislative framework recognises the complexity of this task by providing us with significant discretion in many aspects of the decision-making process to make judgements on these matters.

## 5.1 Achieving the NEO to the greatest degree

Electricity transmission 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. For example, chapter 6A of the NER requires us to prepare forecasts, which are predictions about unknown future circumstances. Very often, there will be more than one plausible forecast, [72] and much debate amongst stakeholders about relevant costs. For certain components of our decision there may therefore be several plausible answers or several plausible point estimates.

When the constituent components of our decision are considered together, this means there will almost always be several potential, overall decisions. More than one of these may contribute to the achievement of the NEO. In these cases, our role is to make an overall decision that we are satisfied contributes to the achievement of the NEO to the greatest degree.[73]

We approach this from a practical perspective, accepting that it is not possible to consider every permutation specifically. 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.

## 5.2 Interrelationships between constituent components

Examining constituent components in isolation ignores the importance of the interrelationships between components of the overall decision, and would not contribute to the achievement of the NEO. We have considered these interrelationships in our analysis of the constituent components of our draft 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 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.

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72 AEMC, *Rule Determination: National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006*, 16 November 2006, p. 52.

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

- trade-offs between different components of revenue. For example, undertaking a particular capex project may affect the need for opex or vice versa.

# A Constituent components

This overview, together with its attachments, constitutes our final decision on ElectraNet's revised revenue proposal. Our final decision on ElectraNet's transmission determination includes the following constituent components:[74]

| Constituent component |
|---|
| In accordance with clause 6A.14.1(1)(i) of the NER, the AER does not approve the total revenue cap set out in ElectraNet's building block proposal. Our final decision on ElectraNet's total revenue cap is $1603.2 ($nominal) for the 2018–23 regulatory control period. This decision is discussed in Attachment 1 of this draft decision. |
| In accordance with clause 6A.14.1(1)(ii) of the NER, the AER does not approve the maximum allowed revenue (MAR) for each regulatory year of the regulatory control period set out in ElectraNet's building block proposal. Our decision on ElectraNet's MAR for each year of the 2018–23 regulatory control period is set out in Attachment 1 of this final decision. |
| In accordance with clause 6A.14.1(1)(iii) of the NER, the AER has decided to apply the service component, network capability component and market impact component of Version 5 of the service target performance incentive scheme (STPIS) to ElectraNet for the 2018–23 regulatory control period. The values and parameters of the STPIS are set out in section 1.6 of the transmission determination. |
| In accordance with clause 6A.14.1(1)(iv) of the NER, the AER's decision on the values that are to be attributed to the parameters for the efficiency benefit sharing scheme (EBSS) that will apply to ElectraNet in respect of the 2018–23 regulatory control period are set out in section Efficiency benefit sharing scheme (EBSS) section 3.1 of this final decision. |
| In accordance with clause 6A.14.1(1)(v) of the NER, the AER has approved the commencement and length of the regulatory control period as ElectraNet proposed in its revenue proposal. The regulatory control period will commence on 1 July 2018 and the length of this period is five years, expiring on 30 June 2023. |
| In accordance with clause 6A.14.1(2) and acting in accordance with clause 6A.6.7(d) of the NER, the AER has accepted ElectraNet's total forecast capital expenditure of $461.5 ($2017–18). This is discussed in section 2.5 of this final decision. |
| In accordance with clause 6A.14.1(3) and acting in accordance with clause 6A.6.6(d) of the NER, the AER has accepted ElectraNet's total forecast operating expenditure inclusive of debt raising costs of $458.4 ($2017–18). |
| In accordance with clause 6A.14.1(4)(i), the AER has determined that the following proposed projects are contingent projects for the purpose of the revenue determination:<br>• Eyre Peninsula Reinforcement<br>• South Australian Energy Transformation<br>• Upper North-East Line Reinforcement<br>• Upper North-West Line Reinforcement<br>• Main Grid System Strength Support.<br>This is discussed in Attachment 6 of this final decision. |
| In accordance with clause 6A.14.1(4)(ii), the AER is satisfied that the capital expenditure in the range of $630 to $950 million for the five contingent projects as described in ElectraNet's current regulatory proposal reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors. This is discussed in Attachment 6 of this final decision. |
| In accordance with clause 6A.14.1(4)(iii), the AER has determined that the triggers proposed by ElectraNet for the following four contingent projects are inconsistent with the NER: |

[74] NEL, s. 16(1)(c).

| Constituent component |
|---|
| • Eyre Peninsula Reinforcement<br>• South Australian Energy Transformation<br>• Upper North-East Line Reinforcement<br>• Upper North-West Line Reinforcement<br>Our final decision includes revised triggers to provide greater certainty as to our approach should ElectraNet seek to act on these contingent projects. This is discussed in Attachment 6 of this final decision. |
| The AER's final decision is to apply version two of the expenditure benefit sharing scheme (EBSS) to ElectraNet in the 2018–23 regulatory control period. This is set out section 3.1 of this final decision<br>In accordance with clause 6A.14.1(5A) of the NER, the AER has determined that version 1 of the capital expenditure sharing scheme (CESS) as set out the Capital Expenditure Incentives Guideline will apply to ElectraNet in the 2018–23 regulatory control period. This is discussed in section 3.2 of this final decision. |
| In accordance with clause 6A.14.1(5B) and 6A.6.2 of the NER, the AER has decided that the allowed rate of return for the 2018–19 regulatory year is 5.69 (nominal vanilla), as set out in section 2.3 of this final decision. The rate of return for the remaining regulatory years 2018–23 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 6A.14.1(5C) of the NER, the AER has decided that the return on debt is to be estimated using a methodology referred to in clause 6A.6.2(i)(2), and using the formula to be applied in accordance with clause 6A.6.2(l). The methodology and formula are set out in section 1.11 of the transmission determination. |
| In accordance with clause 6A.14.1(5D) of the NER, the AER has decided that the value of imputation credits as referred to in clause 6A.6.4 is 0.4. This is set out in section 2.3 of this final decision. |
| In accordance with clause 6A.14.1(5E) of the NER, the AER has decided, in accordance with clause 6A.6.1 and schedule 6A.2, that the opening regulatory asset base (RAB) as at the commencement of the 2018–23 regulatory control period, being 1 July 2018, is $2560.2 ($nominal). This is discussed in Attachment 2 of this final decision. |
| In accordance with clause 6A.14.1(5F) of the NER, the AER has decided that the depreciation approach based on forecast capex (forecast depreciation) is to be used to establish the RAB at the commencement of ElectraNet's regulatory control period as at 1 July 2023. This is discussed in Attachment 5 of this final decision. |
| In accordance with clause 6A.14.1(6) of the NER, the AER has approved ElectraNet's proposed negotiating framework. This is set out in section 4.3 of this final decision. |
| In accordance with clause 6A.14.1(7) of the NER, the AER has specified the negotiated transmission services criteria for ElectraNet. This is set out in section 4.3 of this final decision. |
| In accordance with clause 6A.14.1(8) of the NER, the AER has approved ElectraNet's proposed pricing methodology. This is set out in section 4.1 of this final decision. |
| In accordance with clause 6A.14.1(9) of the NER, the AER has approved the following nominated pass through events to apply to ElectraNet for the 2018–23 regulatory control period in accordance with clause 6A.6.9:<br>terrorism event<br>insurance cap event<br>natural disaster event<br>insurer's credit risk event<br>These events have the definitions set out in section 5 of the transmission determination. |

# B List of submissions

We received 7 submissions in response to our draft decision and ElectraNet's revised revenue proposal. These are listed below.

| Submission from | Date received |
|---|---|
| City of Port Lincoln | 20 December 2017 |
| Government of South Australia | 8 January 2018 |
| SA Chamber of Mines and Energy | 25 January 2017 |
| SA Council of Social Services | 30 January 2018 |
| Consumer Challenge Panel (CCP9) | 2 February 2018 |
| Uniting Communities | 12 February 2018 |
| ElectraNet | 16 March 2018 |