REVISED REVENUE PROPOSAL

2018–19 to 2022–23

22 DECEMBER 2017

ElectraNet

In our revised Revenue Proposal, unless otherwise indicated, forecast and historical expenditure is expressed in real terms (excluding inflation) in 2017-18 dollars to enable comparison of trends over time, while the Regulated Asset Base (RAB) and revenue 'building blocks' are presented in nominal terms (including inflation) consistent with the Australian Energy Regulator's (AER's) Post Tax Revenue Model (PTRM).

Contents

OVERVIEW

1. Our revised Revenue Proposal continues to balance safety, security, reliability and affordability

On 28 March 2017, we submitted our Revenue Proposal for the 2018-19 to 2022-23 regulatory period to the Australian Energy Regulator (AER) following our extensive program of early engagement with our customers and other stakeholders.

The AER published its Draft Decision on 26 October 2017, which accepted most aspects of our Revenue Proposal, including the capital and operating expenditure forecasts.

The main difference between the Draft Decision and our Revenue Proposal relates to two technical financial inputs (namely, the inflation forecast and the value of imputation credits).

The approval of most elements of our Revenue Proposal reflects our strong ongoing commitment to engaging with electricity customers, to ensure we understand their views and priorities, which we have continued to build upon in developing our revised Revenue Proposal.

This revised Revenue Proposal explains how we have accepted and applied the Draft Decision. This includes a minor revision to our forecast operating expenditure to reflect the net resource impacts of new obligations recently applied to ElectraNet, and other updates.

Our revised Revenue Proposal delivers increased price reductions for customers.

This is carefully balanced against the need to deliver safe, secure and reliable transmission services and play a central role in South Australia's ongoing energy transformation.

The key elements of our revised Revenue Proposal are summarised on page 6.

Our forecasts

	REVENUE PROPOSAL[1]	REVISED REVENUE PROPOSAL	WHAT'S CHANGED
Electricity transmission prices[2]	↓10% drop in average transmission prices in 2018-19 to around 2.51c/kWh	↓12% drop in average transmission prices in 2018-19 to around 2.46c/kWh	The increased price reduction reflects adjustments to the financial building blocks and updated rate of return
	↓$17 & $33 in annual savings in transmission prices for the average residential and small business customer respectively	↓$20 & $41 in annual savings in transmission prices for the average residential and small business customer respectively[3]	
Maximum allowed revenue	↓11% lower in the first year of the 2018-19 to 2022-23 regulatory period at $312m	↓12% lower in the first year of the 2018-19 to 2022-23 regulatory period at $306m	The further revenue reduction reflects adjustments to the financial building blocks and updated rate of return
Capital expenditure[4]	↓39% lower than anticipated expenditure in the 2013-14 to 2017-18 regulatory period at $459m	↓39% lower than anticipated expenditure in the 2013-14 to 2017-18 regulatory period at $461m	No material change
Operating expenditure	↓11% lower than trend expenditure allowance[5] in the 2013-14 to 2017-18 regulatory period at $440m.	↓9% lower than trend expenditure allowance in the 2013-14 to 2017-18 regulatory period at $453m	Minor targeted increases primarily to address new obligations and other updates to apply the AER's Draft Decision, resulting in a slightly smaller reduction
Rate of return	↓6.02% down from 7.50% in the 2013-14 to 2017-18 regulatory period (Indicative rate based on prevailing market data)	↓5.75% down from 7.50% in the 2013-14 to 2017-18 regulatory period (Indicative rate based on prevailing market data)	Approach remains based on AER standard methodology Rate has decreased based on market movements

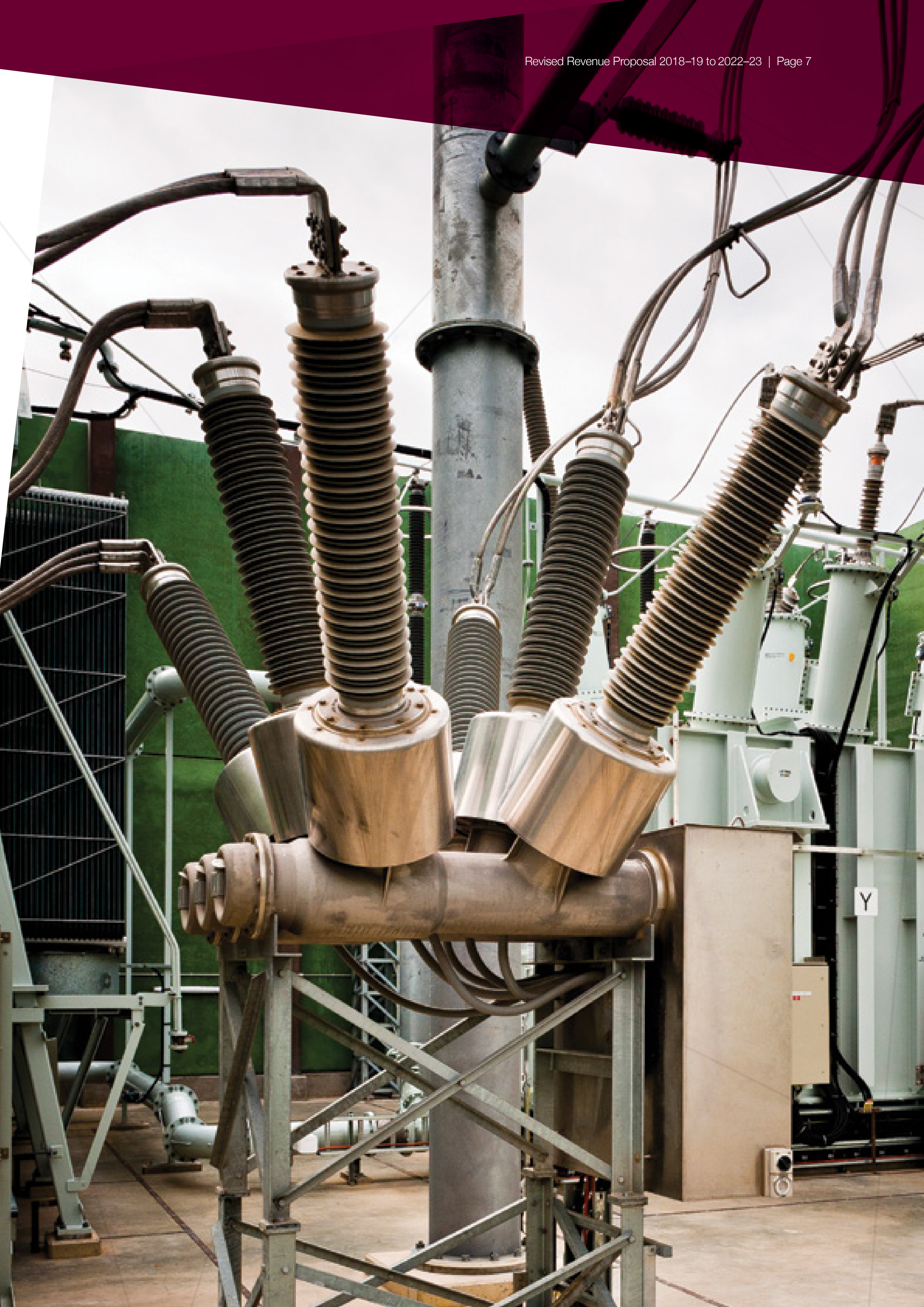
1 As reported in the AER Draft Decision, 26 October 2017.

2 The calculation of the indicative price path is consistent with the methodology used by the AER in the Draft Decision for comparison. Forecast annual MAR has been divided by the forecast annual energy delivered in South Australia published by AEMO in its annual National Electricity Forecasting Report: For the National Electricity Market, June 2016 available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

3 The calculation of the estimated impact on average annual electricity bills is consistent with the methodology used by the AER in the Draft Decision for comparison. The typical residential bill is based on standing offers at 1 July 2017 from Energy Made Easy for an average residential customer's consumption of 5,000 kWh per year. Annual movements and percentages are indicative. They are derived by varying the transmission component of 2017–18 bill amounts in proportion to yearly expected revenue divided by AEMO's forecast energy delivered for South Australia. Transmission charges are assumed to represent approximately 7% of a typical annual residential electricity bill as reflected in the AER's Draft Decision (p1-21) based on reported Revenue Reset Regulatory Information Notice data. Actual bill impacts will vary depending on electricity consumption and tariff class.

4 Does not include the potential for contingent projects, which are subject to a separate cost-benefit test and revenue approval by the AER.

5 Trend expenditure allowance refers to the projected expenditure allowance from the current regulatory period.



OUR REVISED REVENUE PROPOSAL

2. We are accepting and applying the AER's Draft Decision

Table 1 outlines how we have accepted and applied the AER's Draft Decision in this revised Revenue Proposal, including where we have been required to update and adjust our forecasts.

Table 1: How we have applied the AER's Draft Decision

Element	AER Draft Decision	Our response
1. Maximum Allowed Revenue (MAR)	The AER's decisions on our proposed 'building block' costs produced an annual revenue requirement that was approximately 8.6% lower than we proposed.	This revised Revenue Proposal sets out how we have applied the AER's Draft Decision in relation to each of the revenue 'building blocks' that impact on the MAR. Our revised proposed MAR is set out in section 7.9.
2. Regulatory Asset Base (RAB)	The AER accepted our proposed RAB values, apart from an adjustment to reflect higher expected inflation, changes in forecast depreciation and other minor input adjustments. The AER also requires us to update the RAB to reflect actual 2016-17 capital expenditure and our latest forecast 2017-18 capital expenditure.	We accept the AER's Draft Decision on the RAB. We have updated our RAB value as required to reflect: • 2016-17 actual capital expenditure • our latest capital expenditure estimates for 2017-18. Our revised proposed RAB is set out in section 7.1.
3. Rate of return and expected inflation	The AER accepted our proposed approach to calculating the rate of return, subject to updating the risk free rate. It also accepted our nominated averaging periods. The placeholder estimate in the AER's Draft Decision produced a Weighted Average Cost of Capital (WACC) of 5.75% compared to our proposal of 6.02%, reflecting prevailing market data.	We accept the AER's Draft Decision on WACC, noting the risk free rate will be updated in the final revenue determination based on the agreed averaging period. For simplicity, we have maintained the AER's placeholder estimate for the purpose of this revised Revenue Proposal.
	The AER did not accept our market based inflation approach or estimate of 1.97% per annum, and instead used its geometric average approach - relying on the Reserve Bank of Australia's (RBA's) forecast and target bands - to derive a placeholder estimate of 2.50%. The AER has separately undertaken a review of its inflation forecast method, recently confirming that it will continue to apply its existing approach.	While we maintain our preference for a market based approach, we accept the AER's position to apply the outcome of its current inflation review in its final decision. We have applied the AER's current inflation forecast as a placeholder estimate. Further information is set out in section 7.4.

Element	AER Draft Decision	Our response
4. Value of imputation credits	The AER did not accept our proposed gamma of 0.25 and applied a value of 0.4, consistent with the recent decision of the Federal Court.	We accept the AER's Draft Decision on gamma. However, we remain of the view that it would be preferable for consideration to be given to market based estimates, as well as estimates derived from ATO taxation statistics, as explained in section 7.3.
5. Regulatory depreciation	The AER accepted our application of a straight-line approach, year-by-year tracking method, and accelerated depreciation of unused assets. It also applied a longer standard asset life to our transmission line refit asset class.	We accept the AER's Draft Decision in relation to depreciation. For line refit projects undertaken in the current period, we will continue to apply the AER's approved standard asset life of 27 years. Our revised depreciation allowance is set out in section 7.5.
6. Capital expenditure	The AER accepted our proposed capital expenditure forecast.	We accept the AER's Draft Decision on forecast capital expenditure, with the minor updates required below.
	The AER requires our revised Revenue Proposal to account for the revised timing of the Dalrymple energy storage project[6] and corresponding project deferrals.	We have updated the timing of the affected projects in accordance with the AER's Draft Decision, as set out in section 5.2.
	The AER accepted our proposed cost escalation rates for labour, and obtained updated estimates for the Draft Decision. It also noted forecast real labour costs will be updated in our revised Revenue Proposal and the AER's final revenue determination.	We have applied the updated labour escalation forecasts obtained by the AER to our capital expenditure forecast, as set out in section 5.2.
	The AER accepted our proposed contingent projects, but required minor changes to our proposed trigger events.	We accept these revisions and propose some further clarifications, as explained in section 5.4.
7. Operating expenditure	The AER accepted our proposed operating expenditure forecast. The AER also noted that the operating expenditure forecast is likely to change in our revised Revenue Proposal due to obligations arising from recent market reviews and Rule changes. The AER accepted our debt raising cost methodology and estimate of $0.8 million, noting that its own benchmark estimate was $6.3 million. The AER also obtained updated labour cost escalation rates, noting these will be updated in our revised Revenue Proposal and in its final revenue determination, and calculated an adjusted network support allowance.	We accept the AER's Draft Decision on forecast operating expenditure, subject to the updates required below. As foreshadowed in the AER's Draft Decision, we have updated our operating expenditure forecast to address the net cost impacts of the new obligations recently imposed on the business. We have also applied the debt raising cost allowance, labour cost escalators and network support costs determined by the AER. Further details are provided in Chapter 6.

[6] Also known as the Energy Storage for Commercial Renewable Integration (ESCRI) SA project.

Element	AER Draft Decision	Our response
8. Corporate income tax	The AER accepted our proposed methodology and updated the corporate tax allowance to reflect the AER's gamma value, adjustments to asset lives and reduced overall revenue in the Draft Decision.	Noting our views on gamma above, we accept the AER's Draft Decision on our corporate tax allowance. As required, the tax allowance has been updated for: • actual capital expenditure for 2016-17 and latest estimates for 2017-18 • our revised forecast operating expenditure. Our revised corporate tax allowance is set out in section 7.6.
9. Efficiency Benefit Sharing Scheme (EBSS)	The AER accepted our EBSS proposal for the coming regulatory period. A minor adjustment was applied to carryover payments relating to the current period.	We accept the AER's Draft Decision on the EBSS. As required by the Draft Decision, we have updated the calculation of the carryover amount for our actual 2016-17 operating expenditure. Further details are provided in section 7.7.
10. Capital Expenditure Sharing Scheme (CESS)	The AER confirmed that the CESS is to apply, excluding network capability projects.	We accept the AER's Draft Decision on the CESS, subject to any subsequent model modifications that may be adopted by the AER to ensure the correct application of the scheme.
11. Service Target Performance Incentive Scheme (STPIS)	The AER accepted our proposed STPIS, with some minor amendments to service component caps and floors and the Market Impact Component (MIC) target. Our Network Capability Incentive Parameter Action Plan (NCIPAP) was accepted.	We accept the AER's Draft Decision on the STPIS. As required by the AER, we will update the STPIS targets to reflect actual 2017 data when it becomes available in early 2018. Further details are provided in section 7.8.
12. Pricing methodology	Our Pricing Methodology was approved by the AER.	We accept the AER's Draft Decision on the Pricing Methodology.
13. Pass through events	The AER accepted our nominated pass through events.	We accept the AER's Draft Decision on our nominated pass through events.
14. Negotiated services	Our proposed Negotiating Framework was approved. The AER will also apply the negotiated transmission service criteria published in April 2017.	We accept the AER's Draft Decision on negotiated services, noting that the Negotiating Framework will cease to apply under the Rules on 1 July 2018.

The remainder of this document provides further detail on those areas where we have updated and adjusted our proposal in response to the AER's Draft Decision, as indicated above.

RECENT DEVELOPMENTS

3. Our plans respond to the latest developments

3.1 South Australia remains at the forefront of change in the energy sector

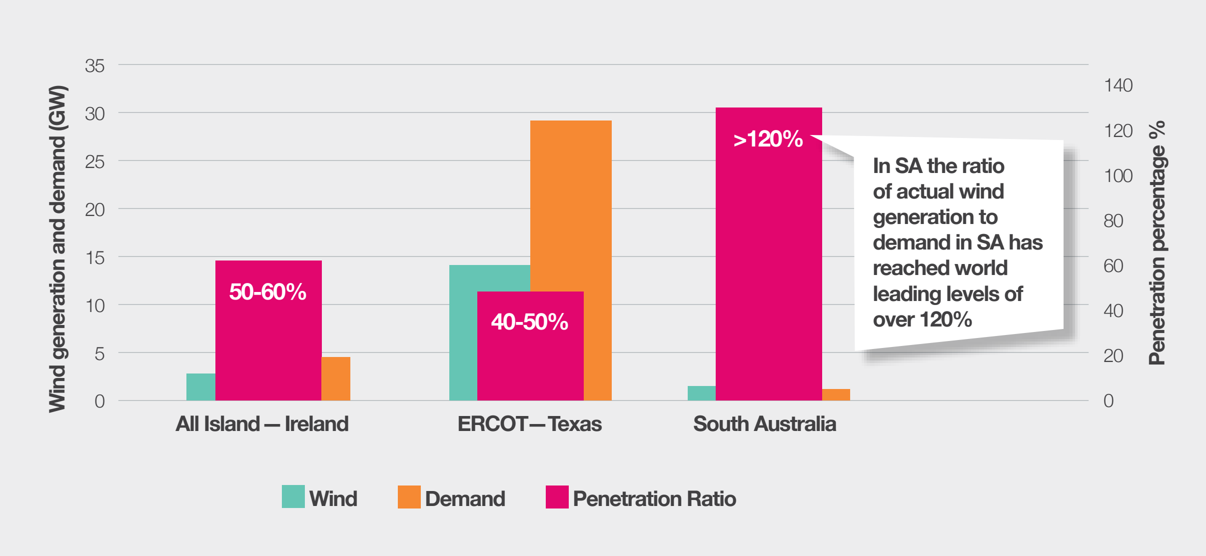
We explained in our Revenue Proposal that South Australia is at the forefront of the global energy transformation, with world-leading levels of renewable energy penetration through large-scale wind generation developments and rooftop solar photovoltaic (PV) installation.

We also explained that a strong, reliable and more interconnected transmission network is more important than ever in this energy transformation.

The high level of renewable generation exposes South Australia to greater system security challenges as the market transitions away from a system of centralised, synchronous generation. As an illustration of this, recent research by the Australian Energy Market Operator (AEMO) confirms that the challenges seen in South Australia in relation to minimum levels of synchronous generation are a first in any large scale power system in the world.

As shown in Figure 1 below, while a number of other major power systems have high levels of wind generation, the penetration level of these non-synchronous generation sources is highest in South Australia.

Figure 1: Maximum historical penetration of non-synchronous generation in selected power systems



Source: AEMO, South Australian System Strength Assessment, September 2017.

Other countries such as Denmark and Germany have similarly high levels of installed wind generation, but are heavily interconnected with neighbouring countries, which improves the security of these power systems.

At the time of our Revenue Proposal, numerous inquiries and Rule change proposals were underway to address questions of system security and resilience. As such, there was a high degree of uncertainty as we finalised our expenditure forecasts for our Revenue Proposal.

In relation to capital expenditure, we revised our preliminary forecasts upwards to include a small number of prudent and targeted investments that were designed to improve system security and network resilience. We also included two contingent projects that may be triggered by system security measures. These components were approved in the AER's Draft Decision.

While we made targeted adjustments to our capital expenditure forecasts, our operating expenditure forecasts were unchanged from our preliminary Revenue Proposal based on the information available to us at that time. Both our operating and capital expenditure forecasts were necessarily based on the prevailing service requirements, standards and obligations for safety, security and reliability.

Our Revenue Proposal, however, made it clear that the various inquiries and reviews could lead to changes in our responsibilities, particularly in relation to system security, and that we would share any new or updated information that becomes available as a result of these developments during the course of the revenue determination process.

In accordance with this commitment and our 'no surprises' approach, we wrote to the AER and our stakeholders on 6 October 2017 to provide an update on the inquiries and reviews and how they are likely to impact on our future operating expenditure.

In particular, we noted that the completion of the following Australian Energy Market Commission (AEMC) reviews and rule changes confirmed that a number of new obligations were being introduced to the business that are placing upward pressure on our operating costs:

- **AEMC System Security Market Frameworks Review**

  This review has led to new obligations for Transmission Network Service Providers (TNSPs) to maintain minimum levels of inertia and system strength. These obligations were introduced respectively through the Managing Rate of Change of Power System Frequency Rule and Managing Power System Fault Levels Rule, which each commenced in September 2017. The resource implications include the need for additional modelling capability, analytical capacity and specialist system planning resources, and associated software systems to ensure that we discharge our new obligations effectively.

- **Transmission Connection and Planning Arrangements Rule Change**

  This Rule change requires us to redesign our transmission connection planning process to facilitate contestability in the provision of connection assets. These obligations will impose additional costs on the business to publish and maintain additional network connection and planning information on an ongoing basis.

- **Replacement Expenditure Planning Arrangements Rule Change**

  This Rule change introduces new obligations for greater rigour, scrutiny and transparency by TNSPs in asset replacement decision making and extends the Regulatory Investment Test for Transmission (RIT-T) to replacement capital expenditure. We will require incremental resources to apply a more rigorous approach to risk cost assessment for capital and operating projects on an ongoing basis to satisfy these new obligations, including additional ongoing reporting requirements in our Transmission Annual Planning Report.

We also noted that other reviews remained ongoing which may also lead to new obligations and resourcing implications, most notably the 'Finkel' Review into the Future Security of the National Electricity Market (NEM). One of its system security and planning measures is the development of an Integrated Grid Plan by AEMO, which requires a significant contribution from ElectraNet.

While we continue our ongoing drive for operating cost efficiencies, it is not possible to absorb all of the associated resource impacts of these new obligations within our existing cost base.

It has therefore been necessary to amend our operating expenditure plans, as foreshadowed by the AER in its Draft Decision, to ensure that we have the necessary resources to meet these new requirements and deliver the associated benefits to our customers.

Importantly, these additional expenditure requirements will have a relatively small impact on overall revenue and price outcomes for customers.

The net impacts of the new obligations on our operating costs are set out in detail in Chapter 6.

3.2 Customer feedback continues to shape our plans and priorities

We remain committed to genuine engagement with electricity customers to provide meaningful opportunities to improve the value of electricity transmission services in South Australia.

In developing our Revenue Proposal, we undertook an extensive program of early engagement with electricity customers and wider stakeholders. This program was designed to promote early engagement with our customers and other stakeholders, build shared understanding and provide customers and stakeholders with opportunities to provide feedback on our plans and priorities.

At the core of our approach is the Consumer Advisory Panel established by ElectraNet, which brings together 12 peak organisations representing a wide range of customer interests and provides a formal mechanism for ongoing engagement.

Our early engagement approach was acknowledged by the AER in its Draft Decision to have led the way and established one of the best practices seen from network service providers. The AER's Consumer Challenge Panel similarly concluded that ElectraNet's consumer engagement sets the current benchmark for other TNSPs.

On 29 November 2017, this was reinforced by ElectraNet receiving the inaugural Energy Network Consumer Engagement Award 2017 from Energy Consumers Australia in recognition of outstanding leadership in consumer engagement.

We have continued to engage with customers and stakeholders on our plans following the submission of our Revenue Proposal. For example, we carefully reviewed the submissions received on our Revenue Proposal in July 2017 in consultation with the Consumer Advisory Panel, and provided further feedback to assist the AER in an issues summary and response document on 14 September 2017.

Submissions were received from the following organisations:

- Business SA
- Consumer Challenge Panel
- Government of South Australia (Department of Premier and Cabinet)
- Iron Road Limited
- Leigh Creek Energy
- South Australian Chamber of Mines and Energy (SACOME)
- South Australian Council of Social Service (SACOSS)
- Uniting Communities

As noted above, in early October 2017 we also provided early advice to our stakeholders of the emerging cost pressures from new obligations expected to impact on our operating expenditure forecast.

We continue to engage with our Consumer Advisory Panel, with planned meetings scheduled throughout the remainder of the revenue determination process. At its most recent meeting on 8 November 2017, we briefed the Panel on the key outcomes of the AER's Draft Decision and presented the focus areas for the revised Revenue Proposal, including the new cost drivers and expected increases in our operating expenditure compared to our Revenue Proposal.

Table 2 below provides a summary of the key issues raised by stakeholders on our Revenue Proposal and how we have addressed them in our revised Revenue Proposal.

Table 2: How we are responding to customer feedback

What we heard	Our response
ElectraNet should adopt a gamma value of 0.40 rather than 0.25 based on the recent Federal Court decision.	We note that recent appeal outcomes have largely removed the uncertainty over this parameter, and accept a value of gamma of 0.40 as the prevailing approach for the purposes of our revised Revenue Proposal.
ElectraNet should maintain its estimation of debt costs based on the standard transition to the trailing average method.	We have accepted the standard transition approach to the trailing average cost of debt approved by the AER in the Draft Decision.
The current AER approach to estimating 10-year inflation expectations should be applied pending the outcome of its inflation review.	We note that the AER has now concluded its inflation review and confirmed its prevailing approach, which will apply for the purposes of our revenue determination.
The basis for including the Dalrymple energy storage project in the proposed capital expenditure forecast for the coming period should be reconsidered.	With the support of the AER, the Dalrymple energy storage project has been accelerated into the current regulatory period as a NCIPAP project. The consequential deferral of other projects has been reflected in the revised capital expenditure forecast for the coming period.
The potential impact of contingent projects on revenue and price outcomes should be explicitly considered.	We have included updated indicative customer price impacts of the most prospective contingent projects in this revised Revenue Proposal – namely the Eyre Peninsula project and Main Grid System Strength project (see section 5.4).
ElectraNet should continue its customer engagement through the consultation processes associated with contingent projects and RIT-T evaluations.	We remain fully committed to continuing to provide genuine opportunities for ongoing engagement with customers and wider stakeholders through our RIT-T and contingent project processes.

CUSTOMER PRICES

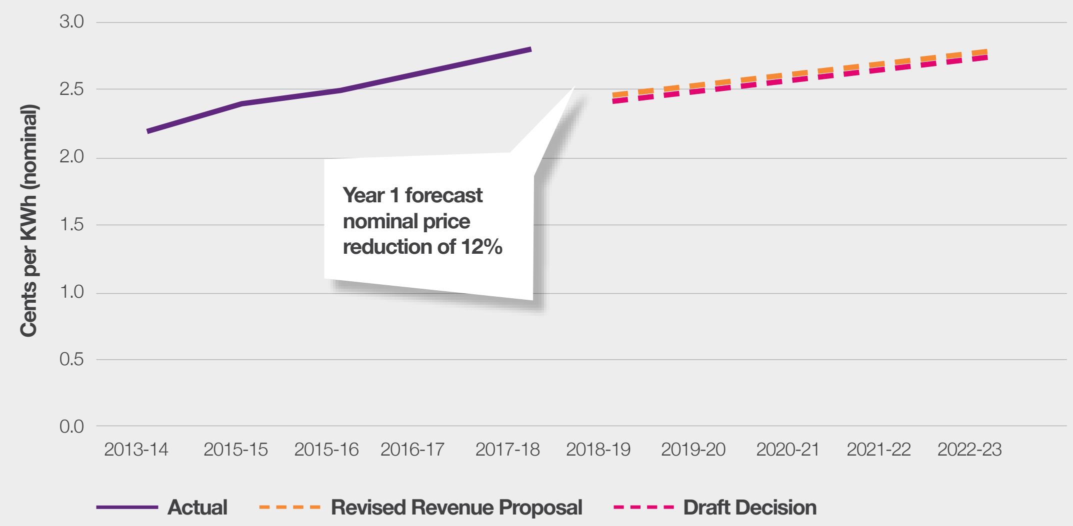
4. Our revised Revenue Proposal delivers a reduction in transmission prices of 12%

Transmission represents a small and declining share of the delivered cost of electricity, and is projected to fall to around 6% of an average residential electricity bill by the end of the coming regulatory period. [7]

We continue to work to deliver the levels of safety, security and reliability expected across our network while delivering price reductions for our customers.

This revised Revenue Proposal delivers a reduction in transmission prices of 12% as shown in Figure 2, which exceeds the 10% reduction in our Revenue Proposal.

Figure 2: Indicative transmission price path[8]



Holding all other factors constant, we estimate that the transmission component of the average annual residential electricity bill in 2018-19 will decrease by around $20 ($nominal) from current 2017-18 levels based on our revised forecasts.[9]

This compares to a reduction of $22 estimated by the AER in its Draft Decision, confirming that the adjusted operating expenditure forecast and other updates required in response to the Draft Decision in this revised Revenue Proposal will have minimal impact on overall revenue and price outcomes for customers.

For a typical small business customer this equates to an initial transmission price reduction of $41.[10]

7 Transmission charges are assumed to represent approximately 7% of an average residential electricity bill as reflected in the AER's Draft Decision (p1-21) based on reported Revenue Reset Regulatory Information Notice data. The forward trend is based on published data for average residential electricity usage, including $2,463 per annum per average annual bill based on standing offers as at 1 July 2017 from Energy Made Easy at http://energymadeeasy.gov.au/ as obtained by the AER for the purposes of its Draft Decision and 5,000kWh annual consumption as per ESCOSA Energy Retail Offers Comparison Report 2016-17, August 2017 available http://www.escosa.sa.gov.au/ArticleDocuments/540/20170831-Energy-RetailOffersComparisonReport2016-17.pdf.aspx?Embed+Y and assuming annual real price growth of 1.4% as per Jacobs, Retail electricity price history and projected trends, 21 September 2017, prepared for AEMO and available at: http://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning and Forecasting/EFI/Jacobs-Retail-electricity-price-history-and-projections Final-Public-Report-June-2017.pdf.

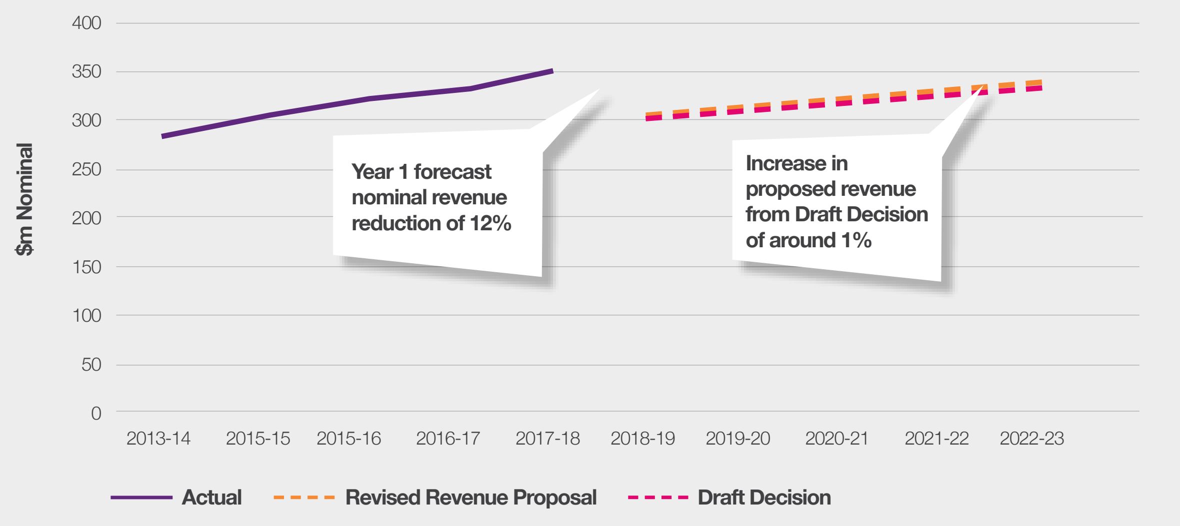
8 The calculation of the indicative price path is consistent with the methodology used by the AER in the Draft Decision for comparison. Forecast annual MAR has been divided by the forecast annual energy delivered in South Australia published by AEMO in its annual National Electricity Forecasting Report: For the National Electricity Market, June 2016 available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

9 The calculation of the estimated impact on average annual electricity bills is consistent with the methodology used by the AER in the Draft Decision for comparison. The typical residential bill is based on standing offers at 1 July 2017 from Energy Made Easy for an average residential customer's consumption of 5,000 kWh per year. Annual movements and percentages are indicative, derived by varying the transmission component of 2017–18 bill amounts in proportion to yearly expected revenue divided by AEMO's forecast energy delivered for South Australia. Transmission charges are assumed to represent approximately 7% of a typical annual electricity bill. Actual bill impacts will vary depending on electricity consumption and tariff class.

10 Assumes a typical average small business customer consumption of 10,000 kWh per year.

The price outlook is based on the revenue forecast shown in Figure 3. In real terms, this represents a stable revenue outlook, with revenue forecast to rise annually with inflation. This follows an initial fall in annual revenue of 12% in 2018-19.[11]

Figure 3: Revised revenue path - smoothed



Actual revenue and price outcomes by the end of the period will be influenced by annual movements in energy consumption, inflation and the prevailing rate of return as the cost of debt is updated annually throughout the period (in accordance with the AER standard approach).

These revenue and pricing outcomes exclude the impact of additional capital projects that may be separately approved by the AER if certain trigger events are met, as contingent projects. Further information on these potential impacts is provided in section 5.4.

[11] Our total smoothed revenue across the five-year period commencing 1 July 2013 is forecast at $1,589 million compared with a forecast of $1,610 million for the five-year period commencing 1 July 2018.


ATHOL PARK TELEPHONE
TERRACE

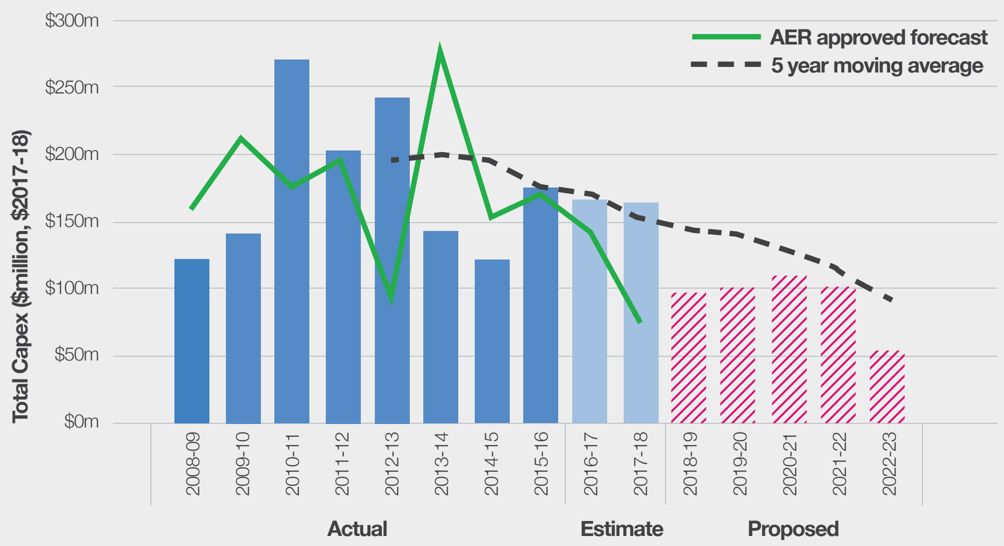
CAPITAL EXPENDITURE

5. We are delivering a 39% reduction in our capital program while investing in security and reliability

5.1 Overview of the AER's Draft Decision

Figure 4 below shows our actual and forecast capital expenditure, together with the AER approved forecast for the current and previous regulatory period.[12]

Figure 4: Capital expenditure outlook



Source: AER Draft Decision, Attachment 6 – Capital Expenditure, October 2017, p24.

Figure 4 shows that in our Revenue Proposal we proposed a substantial decrease (39%) in capital expenditure for the coming regulatory period compared to the current period, while still investing to maintain South Australia's transmission network to support the safe, secure and reliable supply of electricity into the future.

This proposed reduction was largely driven by projections of declining grid demand in South Australia, which has removed the need for demand-driven network augmentation.

This builds on savings we are delivering for customers in the current regulatory period of approximately 7% compared with our capital expenditure allowance.

In its Draft Decision, the AER accepted our forecast capital expenditure for the coming regulatory period. The AER noted that in reaching this view, it took into account our early and extensive process of consumer engagement to ensure our Revenue Proposal adequately reflects the preferences of our customers.

[12] The figures presented in this section are expressed in real terms ($2017-18) unless otherwise indicated.

In accepting our forecast capital expenditure, the AER noted that[13]:

> *ElectraNet proposed a total capital expenditure forecast of $459.1 million ($2017–18). We are satisfied that this forecast reasonably reflects the capital expenditure criteria. We have therefore accepted ElectraNet's forecast as the total forecast capital expenditure for the 2018–23 regulatory control period.*

In its Draft Decision, the AER also noted that following the submission of our Revenue Proposal:

- the timing of the Dalrymple energy storage project had been brought forward in order to implement the project by the end of 2017-18
- the effect of advancing the Dalrymple energy storage project would be offset through the deferral of specific, lower risk project works from the current period as a consequence of resource constraints on the delivery of substation projects.

The AER's Draft Decision requires our revised Revenue Proposal to account for the revised timing of both the Dalrymple energy storage project and the projects consequently deferred from the current period, in terms of both the total forecast capital expenditure and the individual asset categories of the Post Tax Revenue Model (PTRM) and Roll Forward Model (RFM).

The Draft Decision also noted that real labour costs will be updated in the revised Revenue Proposal and in the final revenue determination.[14]

5.2 How is ElectraNet responding?

We accept the AER's Draft Decision. As required by the AER, we have updated our forecasts to account for the revised timing of the Dalrymple energy storage project and the corresponding capital works deferred from the current period and other minor project movements. We have also updated our labour escalation rates with the updated estimates obtained by the AER.

Our labour escalation was based on the average of two independent forecasts:

- Deloitte Access Economics' (DAE) forecasts as published in the AER's May 2016 Final Determination for Australian Gas Networks in South Australia
- BIS Shrapnel's South Australian Utilities Wage Price Index growth forecast as at January 2017.[15]

The AER obtained more recent estimates of labour escalation rates from DAE for its Draft Decision. Our updated labour cost escalation assumptions maintain the same methodology and apply this latest information as shown in Table 3.

Table 3: Revised real labour cost forecast (%)

Labour escalation estimates	2018-19	2019-20	2020-21	2021-22	2022-23	Average
Deloitte Access Economics (AER Oct 2017)	0.73	0.97	0.88	0.91	0.98	0.89
BIS Shrapnel - January 2017	0.70	0.80	1.10	1.50	1.60	1.14
Average	0.72	0.89	0.99	1.21	1.29	1.02

[13] AER, Draft Decision: ElectraNet transmission determination 2018 to 2023, Attachment 6 - Capital Expenditure, October 2017, Figure 6.3 page 10.
[14] AER, Draft Decision: ElectraNet transmission determination 2018 to 2023, Attachment 6 - Capital Expenditure, October 2017, p29.
[15] BIS Shrapnel, Report on Expected Wage Changes to 2022/23: Prepared by BIS Shrapnel for ElectraNet, Final Report, February 2017 (ENET057).

5.3 Revised capital expenditure forecast

Our revised capital expenditure forecast is set out in Table 4 below.[16] The required updates discussed in section 5.2 result in a minor movement in the forecast from $459 million to $461 million.[17]

Table 4: Revised capital expenditure forecast by category

Capital expenditure ($m 2017-18)	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Augmentation	7.4	2.0	0.1	0.0	0.0	**9.6**
Connection	0.1	1.3	5.0	0.0	0.0	**6.4**
Easement/Land	0.0	0.0	0.0	0.0	0.0	**0.0**
Load driven capital expenditure	**7.5**	**3.3**	**5.2**	**0.0**	**0.0**	**15.9**
Replacement	34.0	35.0	37.0	41.5	19.2	**166.7**
Refurbishment	10.0	38.4	49.3	43.1	21.9	**162.8**
Security/Compliance	27.2	12.6	4.9	3.5	3.0	**51.2**
Inventory/Spares	2.3	2.3	2.3	2.3	2.3	**11.6**
Non-load driven capital expenditure	**73.6**	**88.4**	**93.5**	**90.4**	**46.4**	**392.2**
Business IT	14.6	7.6	9.1	9.4	6.6	**47.3**
Facilities	1.5	1.2	1.5	1.1	0.7	**5.9**
Non-network capital expenditure	**16.1**	**8.8**	**10.6**	**10.5**	**7.3**	**53.3**
Total	**97.2**	**100.4**	**109.3**	**101.0**	**53.7**	**461.5**

Totals may not add due to rounding.

[16] As required under the Rules, an updated certification of the reasonableness of the key assumptions that underlie the capital expenditure forecast by the Directors of ElectraNet also accompanies this Revised Revenue Proposal.

[17] It is noted that these forecasts remain consistent with the latest state-wide demand forecasts published by AEMO in its Electricity Forecasting Insights Report in June 2017 and updated connection point forecasts provided by SA Power Networks in October 2017.

5.4 Contingent projects

The AER's Draft Decision accepted our five proposed contingent projects, with some minor amendments to the trigger events, which we accept.

We propose the following further refinements to the trigger events for specific contingent projects to reflect developments that have occurred subsequent to our Revenue Proposal.

Eyre Peninsula Reinforcement contingent project

Included among the recommendations of the Finkel Review, which reported in June 2017, is the development of an Integrated Grid Plan by AEMO to facilitate the efficient development and connection of renewable energy zones across the NEM.[18]

The Review also recommended this Plan include a list of potential priority transmission projects governments could support to enable development of these zones if the market does not deliver the required investment. The AEMC is to develop a rigorous evaluation framework for such projects to provide guidance on circumstances that would warrant government intervention to facilitate specific investments.

The Eyre Peninsula Reinforcement potentially contributes strongly to the development of such renewable energy zones.

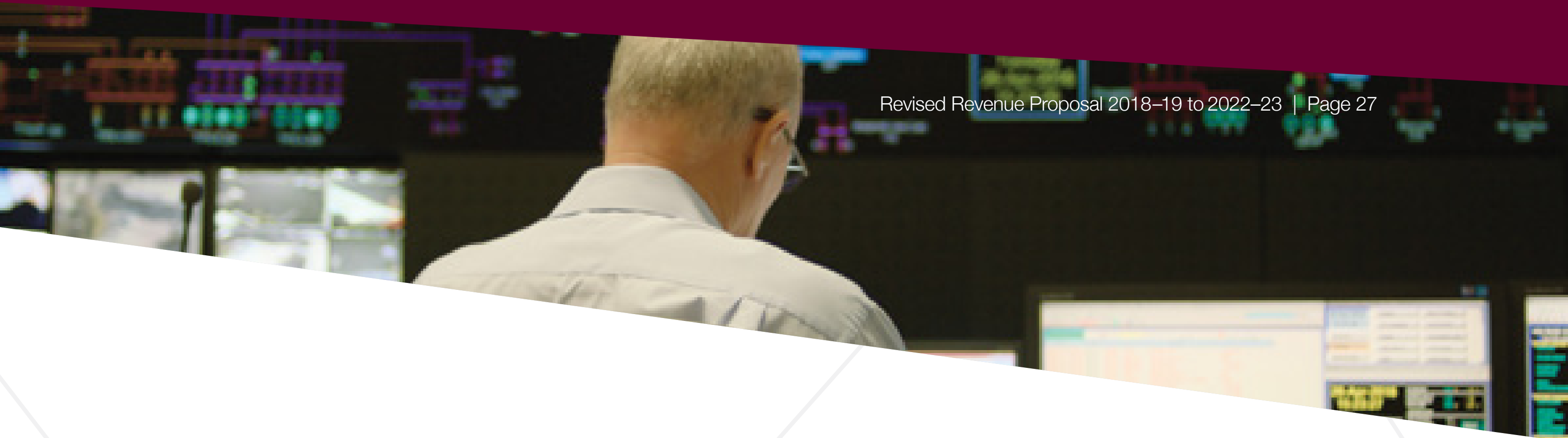
On 18 December 2017, AEMO published a consultation document for its inaugural Integrated Grid Plan (now known as the Integrated System Plan) that recognises a number of renewable energy zones on the Eyre Peninsula, and identifies expanding transmission capacity to the Eyre Peninsula in its priority list of eight potential transmission development options across the NEM.[19]

Accordingly, in the expectation that an alternative path for the approval of transmission investments in the NEM may be developed in the near future, we therefore propose that the relevant triggers for this contingent project be amended as follows to provide for this possibility, while preserving the role of the AER in determining that such a process has been successfully completed:

> **1a.** Successful completion of the RIT-T including an assessment of credible options identifying the duplication or replacement of the existing Cultana to Yadnarie and/or Yadnarie to Port Lincoln transmission lines as the preferred option.
>
> OR
>
> **1b.** A decision by a government or regulatory body that results in a requirement for ElectraNet to undertake an augmentation of the transmission network serving the Eyre Peninsula as a prescribed transmission service.
>
> **2.** Determination by the AER that the proposed investment satisfies the RIT-T or alternative applicable decision-making framework.
>
> …

[18] Dr Alan Finkel AO, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017, pp123-127.

[19] Further details are available on AEMO's website at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.



South Australian Energy Transformation contingent project

Similarly, the South Australian Energy Transformation project potentially contributes strongly to the development of renewable energy zones in the NEM. In its Integrated Grid Plan consultation document, AEMO recognises up to 11 potential renewable energy zones covering parts of South Australia, and identifies increasing interconnection from South Australia in its priority list of eight potential transmission development options across the NEM.[20]

It is therefore proposed that the relevant triggers for this contingent project be amended accordingly as follows in the expectation that an alternative path for the approval of transmission investments will be developed in the near future:

> **1a.** Successful completion of the South Australian Energy Transformation RIT-T with the identification of a preferred option or options:
>
> (i) demonstrating positive net market benefits; and/or
>
> (ii) addressing a reliability corrective action.
>
> OR
>
> **1b.** A decision by a government or regulatory body that results in a requirement for ElectraNet to deliver a solution involving increased interconnection (and/or non-interconnector alternatives) from South Australia as a prescribed transmission service.
>
> **2.** Determination by the AER that the proposed investment satisfies the RIT-T or alternative applicable decision-making framework.
>
> ...

Main Grid System Strength Support contingent project

The second trigger event for this project recognises that the RIT-T may not apply in relation to this project, consistent with new Rules[21] which took effect in September 2017, and therefore allows for an equivalent economic evaluation to be undertaken.

For consistency, we therefore propose that the third trigger event be amended to the following:

> ...
>
> **3.** Determination by the AER that the proposed investment satisfies the RIT-T (or equivalent economic evaluation).
>
> ...

[20] Further details are available on AEMO's website at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[21] AEMC, Rule Determination: National Electricity Amendment (Managing power system fault levels) Rule 2017, 19 September 2017, available at: http://aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels#.

Status of contingent projects

For the information of stakeholders, an update on the status of the contingent projects the AER has accepted in its Draft Decision is provided in Table 5 below.

Should any of these projects proceed, the associated revenue allowance will be determined by the AER through a separate process in consultation with stakeholders.

Table 5: Status of contingent projects

Project	Driver	Status
Eyre Peninsula Reinforcement	Sufficient benefits to customers to justify the full replacement of the Cultana to Port Lincoln transmission line. If this project were to proceed, it would replace approximately $80 million of expenditure provided in our accepted forecasts for conductor replacement on this transmission line.	A RIT-T assessment is currently in progress, with a Project Assessment Draft Report released on 16 November 2017, identifying a new transmission line to be the most cost effective solution at an indicative cost of $300 million. A Project Assessment Conclusions Report is expected to be published in April 2018, which would be followed by a determination from the AER on whether the final solution satisfies the RIT-T. If the project proceeds, only the costs exceeding the $80 million already included in our forecasts would be sought from the AER.
South Australian Energy Transformation	Sufficient benefits to customers from addressing network limitations and system security challenges due to the changing generation mix.	A RIT-T assessment commenced in November 2016 with the release of a Project Specification Consultation Report. Extensive feedback has been received during our consultation to date. We are undertaking additional modelling work and continue to assess the credible options in the context of the changing external environment and will release a further update in due course.
Upper North West Line Reinforcement & Upper North East Line Reinforcement	Mining load increases which trigger the need for augmentation to address network limitations on the Davenport-Pimba or Davenport-Leigh Creek 132 kV lines.	We have not received a firm customer commitment for additional load that would trigger a need for network augmentations at these locations at this time, but continue to receive interest from potential connection applicants.
Main Grid System Strength Support[22]	Confirmation by AEMO of the existence of a Network Support and Control Ancillary Services (NSCAS) gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region.	AEMO formally declared an NSCAS gap relating to system strength in the South Australian region on 13 October 2017. We are required to use our reasonable endeavours to address this shortfall by 30 March 2018. We are currently undertaking an economic evaluation to identify the most cost effective solution(s) to address this ongoing requirement over the short and longer-term.

[22] The Rules also allow for the specific pass through of material costs associated with a fault level shortfall event to recover the forecast costs of providing system strength services, and for the annual true-up of actual system strength service payments under the network support pass through mechanism. Subject to the outcomes of our economic evaluation, we will seek to recover the costs of an efficient solution through the most appropriate cost recovery options.

Potential pricing impacts

In order to keep customers informed of the pricing implications of these potential developments, the indicative impact of the most advanced of these contingent projects on the transmission component of the average annual residential electricity bill in South Australia in the coming regulatory period would be as follows, in comparison with our expected initial reduction of $20 in 2018-19.

A full rebuild of the Eyre Peninsula line at an indicative cost of $300 million, should this prove the most economic solution for customers, would represent an additional capital cost of $220 million in the coming period and be partly offset by operational expenditure savings through avoided generation support payments. In net terms, this project would be expected to add less than $3 per annum to the transmission component of the average residential bill.

The installation of synchronous condensers on the South Australian transmission network to provide system strength at an indicative cost of $80 million, should this prove the most economic solution for customers over the longer-term, would be expected to add approximately $3 per annum to the transmission component of the average residential bill. In the interim, it is likely that separate costs associated with system strength service payments for generation solutions will be incurred, should this prove to be the most economic short term solution to address the NSCAS gap that has been declared under the Rules.

In each case, before any investment can proceed, the AER must be satisfied that the most economically efficient solution has been identified that will maximise net market benefits and therefore be in the best interests of customers.

We remain fully committed to ongoing engagement with our stakeholders as our work in relation to the above contingent projects progresses.

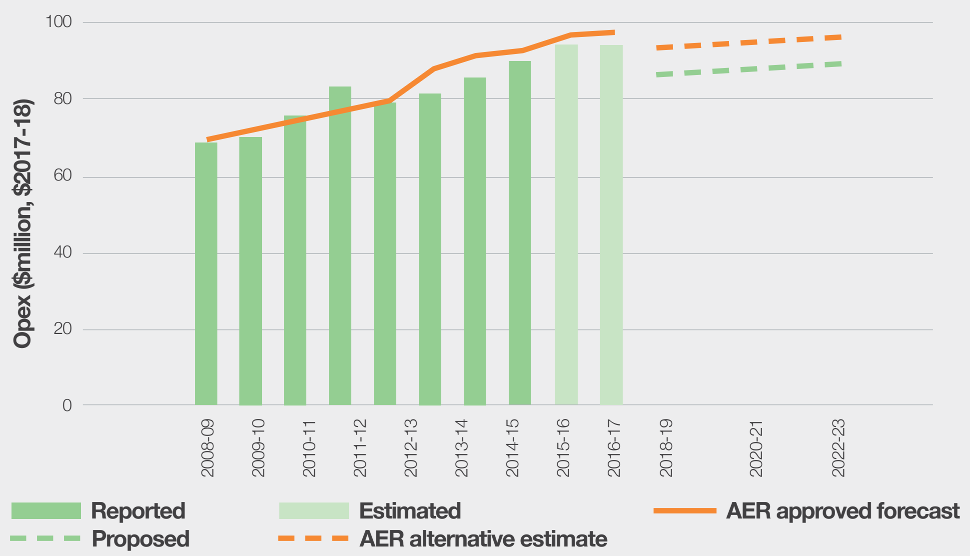
OPERATING EXPENDITURE

6. We continue our drive for operating efficiency while addressing new obligations

6.1 Overview of the AER's Draft Decision

Figure 5 below shows our historical and forecast operating expenditure compared to the AER approved forecast for the current and previous regulatory period and its efficient benchmark estimate for the coming period.[23]

Figure 5: Operating expenditure outlook



Source: AER Draft Decision, Attachment 7 – Operating Expenditure, October 2017, p7.

As shown in this figure, we have worked hard to deliver efficiencies within the AER's operating expenditure allowance. The AER's 'base-step-trend' forecasting approach ensures that customers benefit from these savings in the coming regulatory period.

For the coming regulatory period, we originally forecast a total operating expenditure allowance of $440.1 million[24]. This is significantly lower (by $34.2 million or 7.2%) than the AER's efficient benchmark estimate of $474.4 million, as shown in Figure 5.

This confirms that our operating expenditure outlook represents a prudent and efficient forecast.

In its Draft Decision, the AER accepted our forecast operating expenditure for the coming regulatory period, also noting that it expected there will be changes in our operating expenditure forecast arising from recent power system security reviews into the South Australian energy market that have occurred subsequent to us lodging our Revenue Proposal.[25]

The AER also calculated updated estimates of debt raising costs and network support expenditure, and noted that real labour costs will be updated in the revised Revenue Proposal and in the final revenue determination.[26]

[23] The figures presented in this section are expressed in real terms ($2017-18) unless otherwise indicated.

[24] This value includes additional escalation to produce end of year real ($Jun 2017-18) values, as required by the AER's PTRM. More accurately, for comparison in like-for-like terms, this corresponds to a mid-year real ($Dec 2017-18) value of $435.8 million, which is $38.6 million (or 8.1%) below the AER's efficient benchmark estimate of $474.4 million.

[25] AER, Draft Decision: ElectraNet transmission determination 2018 to 2023, Overview, p30.

[26] AER, Draft Decision: ElectraNet transmission determination 2018 to 2023, Attachment 6 - Capital Expenditure, October 2017, p29.

6.2 How is ElectraNet responding?

We continue to apply a 'top-down' and 'bottom-up' approach to forecasting our efficient operating expenditure requirements, consistent with the AER's established base-step-trend approach.

Following the submission of our Revenue Proposal, a number of new obligations have been applied to us to address the growing system security challenges in South Australia.

Consistent with our 'no surprises' approach, we advised the AER and our stakeholders in early October 2017 of the nature of these additional obligations, and explained that we expected our forecast operating expenditure would increase.

As foreshadowed by the AER in its Draft Decision, we have adjusted our operating expenditure forecast to meet these new requirements, and applied other updates arising from the Draft Decision.

Our forecasting methodology and range of assumptions remain the same as that applied in our Revenue Proposal.

From a 'bottom-up' perspective, the following aspects of our operating expenditure forecast have been updated to address specific matters in the Draft Decision:

- **debt raising costs** – to correctly apply the AER's benchmark allowance presented in its Draft Decision
- **new obligations** – to ensure that we have sufficient resources to address our new obligations relating to the system security challenges in South Australia, as anticipated in the AER's Draft Decision
- **labour escalation** – to ensure that our operating expenditure forecast reflects the latest available information presented in the AER's Draft Decision
- **network support** – to reflect the adjusted forecast presented in the AER's Draft Decision.

We address each of these elements in turn in the following sections. The remaining inputs and assumptions to our operating expenditure forecast remain unchanged.

The 'top-down' efficiency of our overall operating expenditure forecast is discussed in section 6.3.

6.2.1 Debt raising costs

Debt raising costs are transaction costs incurred each time debt is raised or refinanced, and include underwriting fees, legal fees, company credit rating fees and other transaction costs. Debt raising costs are an unavoidable aspect of raising debt that are incurred by an efficient business, and data exists such that these costs can be estimated by the AER.

While generally preferring a 'revealed cost' approach for forecasting operating expenditure, a benchmark approach is considered more appropriate by the AER for debt raising costs because an efficient allowance can be set independently of each business. This benchmarking approach also provides for consistency with the forecast of the cost of debt in the rate of return building block, which is set on an efficient benchmark basis.

The AER's accepted approach involves calculating a benchmark bond size, and the number of bond issues required to rollover the benchmark debt share (60%) of the RAB. Benchmarked up-front debt raising costs are then amortized over a 10-year period and expressed in basis points per annum as an input to the PTRM. This rate is multiplied by the debt component of the projected RAB to determine the efficient benchmark debt raising cost.

In our Revenue Proposal, we adopted the standard benchmark methodology approved by the AER and calculated a debt raising cost estimate of $0.8 million by applying the input data contained in the AER's PTRM.

In its Draft Decision, the AER applied the same methodology to calculate a total debt raising cost allowance of $6.3 million, using updated input assumptions to correctly apply the standard benchmark calculation.

However, the AER did not separately update our estimate of debt raising costs. As a result, ElectraNet's operating expenditure allowance in the Draft Decision did not include the total efficient debt raising costs as calculated by the AER.

Our operating expenditure allowance should include a correct benchmark allowance to recover efficient debt raising costs. If it does not, ElectraNet will not be able to recover at least its efficient costs, as contemplated by the revenue and pricing principles in the National Electricity Law.

We have therefore updated our debt raising costs to reflect the AER's benchmark allowance of $6.3 million in its Draft Decision by accurately applying its accepted methodology.

6.2.2 New obligations

Our Revenue Proposal highlighted the system security challenges facing South Australia, and the possibility of additional resource impacts from the actions being taken in response, noting the range of reviews and Rule changes underway at that time.

A number of new obligations have now been introduced on the business through these reviews as explained in section 3.1.

The AER's Draft Decision noted that it expected us to update our operating expenditure forecasts in our revised Revenue Proposal as a result of obligations arising from these recent market reviews and Rule changes.

Table 6 on the next page, sets out the drivers for these new requirements, and the benefits they are expected to provide for customers.

Table 6: New requirements and benefits for customers

Development	New requirements	Benefits for customers
Emergency Frequency Control Schemes Rule[27] March 2017	Establishes a new framework for AEMO and TNSPs to review emerging power system frequency risks and implement appropriate controls.	These controls are essential to maintain the security of the power system for customers in a changing power system environment.
Transmission Connection and Planning Arrangements Rule[28] May 2017	Obligations for TNSPs to provide additional network connection information to enable competition in the connection process.	Contestability helps maintain downward pressure on connection costs, flowing through to lower delivered energy costs for customers.
Integrated Grid Planning[29] (outcome of the Finkel Review) June 2017	A national Integrated Grid Plan[30] to be developed by AEMO and TNSPs, including renewable energy zones supported by new transmission route and interconnector options.	Integrated grid development enables efficient location of renewable generation investment across the NEM to support improved energy security, reliability and affordability for customers.
Replacement Expenditure Planning Arrangements Rule[31] July 2017	Obligations for greater rigour, scrutiny and transparency by TNSPs in asset replacement decision making.	Ensures an efficient risk-based approach to asset replacement to help drive lowest long-run cost outcomes for customers.
SA Generator Licensing Arrangements[32] August 2017	Technical conditions to be met by new generators connected to the SA network by ElectraNet.	These conditions are needed to ensure a secure and resilient power system for customers in the face of an evolving generation mix.
Managing Rate of Change of Power System Frequency Rule[33] & Managing Power System Fault Levels Rule[34] September 2017	New obligations for TNSPs to maintain levels of system strength and inertia on the power system.	These services are essential to maintain the secure operation of the power system for customers in the face of a changing generation mix.
Generating System Model Guidelines Rule[35] September 2017	Strengthened requirements for provision of modelling data by connecting generators and analysis by TNSPs.	Enables more complex modelling to help maintain system strength and ensure the secure operation of an evolving power system for customers.

[27] AEMC, Rule Determination: National Electricity Amendment (Emergency frequency control schemes) Rule 2017, 30 March 2017, available at: http://aemc.gov.au/Rule-Changes/Emergency-frequency-control-schemes-for-excess-gen.

[28] AEMC, Rule Determination: National Electricity Amendment (Transmission Connection and Planning Arrangements) Rule 2017, 23 May 2017, available at: http://aemc.gov.au/Rule-Changes/Transmission-Connection-and-Planning-Arrangements.

[29] Dr Alan Finkel AO, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future, June 2017 available at: https://www.energy.gov.au/sites/g/files/net3411/f/independent-review-future-nem-blueprint-for-the-future-2017.pdf.

[30] AEMO has now commenced consultation on this document, which is now known as the Integrated System Plan. Further details are available on AEMO's website at: http://aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

[31] AEMC, Rule Determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017, 18 July 2017, available at: http://aemc.gov.au/Rule-Changes/Replacement-Expenditure-Planning-Arrangements.

[32] ESCOSA, Inquiry into the licensing arrangements for generators in South Australia: Final Report, 17 August 2017, available at: http://www.escosa.sa.gov.au/projects-and-publications/projects/inquiries/inquiry-into-licensing-arrangements-under-the-electricity-act-1996-for-inverter-connected-generators/inquiry-into-licensing-arrangements-under-the-electricity-act-1996-for-inverter-connected-generators.

[33] AEMC, Rule Determination: National Electricity Amendment (Managing the rate of change of power system frequency) Rule 2017, 19 September 2017, available at: http://aemc.gov.au/Rule-Changes/Managing-the-rate-of-change-of-power-system-freque.

[34] AEMC, Rule Determination: National Electricity Amendment (Managing power system fault levels) Rule 2017, 19 September 2017, available at: http://aemc.gov.au/Rule-Changes/Managing-power-system-fault-levels#.

[35] AEMC, Rule Determination: National Electricity Amendment (Generating System Model Guidelines) Rule 2017, 19 September 2017, available at: http://aemc.gov.au/Rule-Changes/Generating-System-Model-Guidelines.

Table 7 below sets out the forecast net resource impacts arising from these new obligations. In a number of instances, we will absorb the upfront establishment costs in the current year, rather than passing these costs onto our customers. In total, we will absorb upfront costs of $2.2 million. We are also absorbing the ongoing costs of the new obligations to the extent possible.

Table 7: New obligations and operating expenditure forecasts ($m 2017–18)

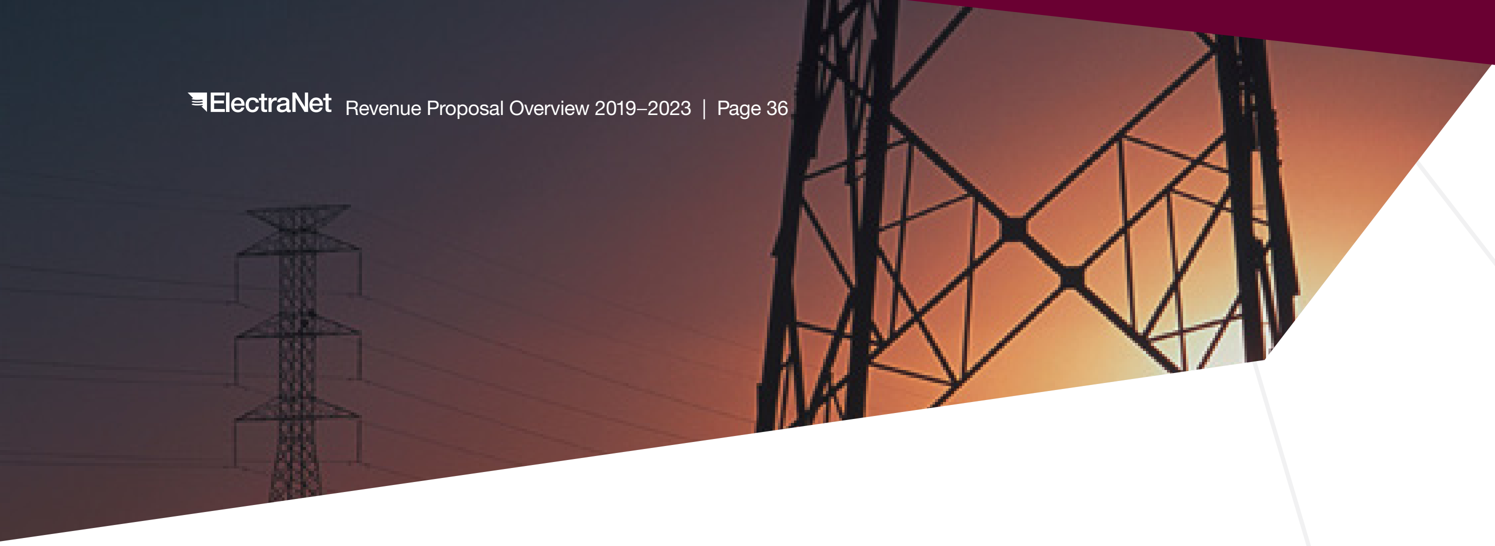
New obligations	Up-front costs absorbed	Annual forecast costs	Resource requirements
Emergency Frequency Control Schemes Rule March 2017	0.1	0.1	Specialist resources for ongoing analysis of system frequency risk and control schemes.
Transmission Connection and Planning Arrangements Rule May 2017	1.4	0.3	Up front effort to revise and publish connection standards. Ongoing effort for maintenance of standards and publication of additional planning information.
Integrated Grid Planning (outcome of the Finkel Review) June 2017	0.3	0.3	Additional ongoing specialist resources to provide input and analysis for the development of the Integrated Grid Plan and associated planning work.
Replacement Expenditure Planning Arrangements Rule July 2017	0.1	0.6	Up front effort to revise and develop the RIT-T approach for investment planning. Ongoing incremental resources to maintain a more rigorous approach to risk assessment for capital and operating projects.
SA Generator Licensing Arrangements August 2017	-	-	Resource impacts to be absorbed.
Managing Rate of Change of Power System Frequency Rule and Managing Power System Fault Levels Rule September 2017	0.2	1.2[36]	Ongoing software licensing fees. Additional ongoing specialist resources for model development and maintenance, new modelling capability and ongoing fault protection system review.
Generating System Model Guidelines Rule September 2017	-	-	Resource impacts to be absorbed.
Total	**2.2**	**2.5**	

Totals may not add due to rounding.

In the context of the AER's operating expenditure forecasting methodology, the annual forecast impact of $2.5 million is considered to be a 'step change' that is not compensated by base year operating expenditure or the rate of change. In this case, the step change relates to new obligations which require us to undertake the activities listed above to provide the system security that our customers expect.

Our proposed allowance reflects our best estimate of the prudent and efficient net cost impact of complying with these obligations, after allowing for the costs we are able to absorb.

[36] This represents the additional, underlying costs associated with the new capabilities required by ElectraNet to comply with these new obligations moving forward. Actual service costs would be sought separately as required under the Rules, under the contingent project mechanism and/or cost pass through arrangements as appropriate, and approved separately by the AER.



6.2.3 Labour escalation

In our Revenue Proposal, we proposed a real average price change of 0.6% per annum to address the expected increase in labour costs over the coming regulatory period. The labour escalation was derived from the average of forecasts from BIS and DAE, as explained in section 5.2. Material costs were assumed to increase in line with the Consumer Price Index (CPI).

The AER in its Draft Decision obtained more recent estimates from DAE, noting that real labour costs will be updated in the revised Revenue Proposal and in the final revenue determination.[37]

Accordingly, in this revised Revenue Proposal, we have maintained the same forecasting approach[38] and applied the updated labour cost escalators obtained by the AER.

These updated labour cost escalation assumptions and the resulting weighted average price escalator is shown in Table 8 below.

Table 8: Revised real labour cost forecast (%)

Labour escalation estimates	2018-19	2019-20	2020-21	2021-22	2022-23	Average
Deloitte Access Economics (AER Oct 2017)	0.73	0.97	0.88	0.91	0.98	0.89
BIS Shrapnel - January 2017	0.70	0.80	1.10	1.50	1.60	1.14
Average	**0.72**	**0.89**	**0.99**	**1.21**	**1.29**	**1.02**
Weighted average	**0.48**	**0.59**	**0.66**	**0.81**	**0.86**	**0.68**

6.2.4 Network support

Network support payments fund non-network solutions contracted by us as cost effective alternatives to network augmentation, such as local generation or demand management arrangements.

The Rules require the pass through of network support costs subject to the relevant factors set out in clause 6A.7.2 of the Rules. A forecast amount may also be included for this purpose in our operating expenditure forecasts.

In our Revenue Proposal, we included a forecast of our expected network support costs consistent with the 'base-step-trend' approach. In the AER's Draft Decision, it adopted an adjusted network support forecast based on our actual expenditure incurred in the base year.

In this revised Revenue Proposal, we have adopted the AER's adjusted estimate for network support costs, being based on a more accurate reflection of base year costs.

[37] AER, Draft Decision: ElectraNet transmission determination 2018 to 2023, Attachment 6 - Capital Expenditure, October 2017, p29.

[38] As explained in our Revenue Proposal, this includes the application of a labour cost proportion of 67% across our operating expenditure, which reflects our average historical cost split.

6.3 Revised operating expenditure forecast

The incremental impacts of the updates described in section 6.2 in response to the Draft Decision on the revised operating expenditure forecast are summarised in Table 9 below.

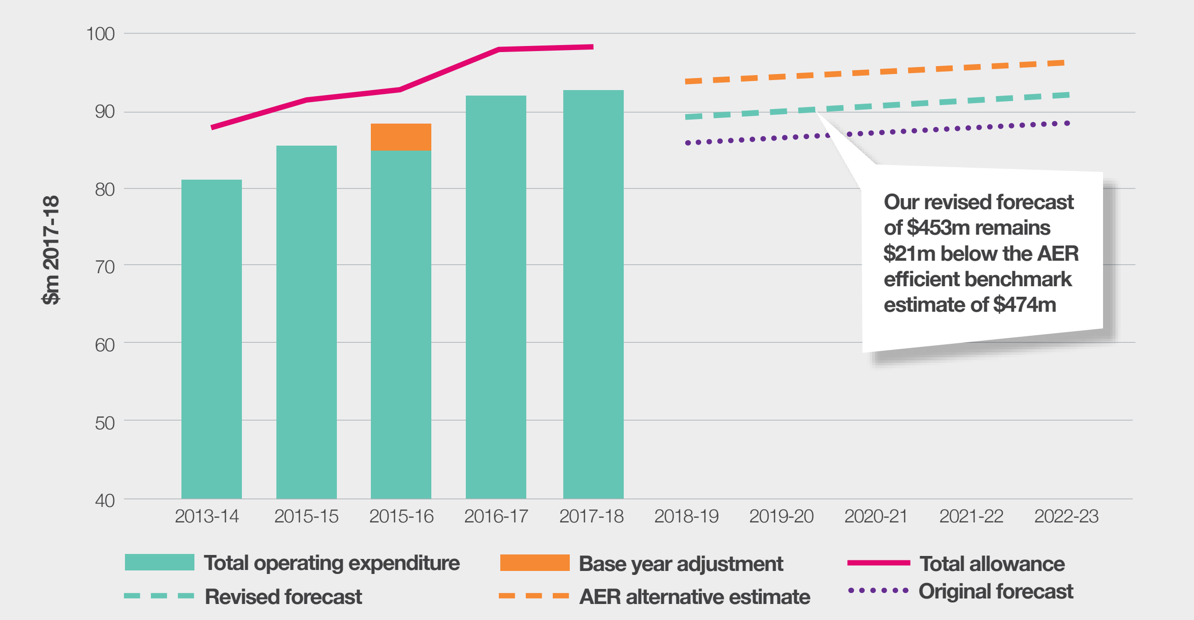
Table 9: Revised operating expenditure forecast: Movements from Revenue Proposal

Cost movement ($m 2017-18)	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Debt Raising Costs	1.1	1.1	1.1	1.1	1.1	**5.5**
New obligations	2.5	2.5	2.5	2.6	2.6	**12.7**
Labour escalation	0.0	0.1	0.2	0.2	0.3	**0.8**
Network support	-0.4	-0.4	-0.4	-0.4	-0.4	**-2.0**
Net increase	**3.3**	**3.3**	**3.4**	**3.5**	**3.5**	**17.0**
Original operating expenditure forecast[39]	**85.9**	**86.4**	**87.2**	**87.9**	**88.4**	**435.8**
Revised operating expenditure forecast	**89.3**	**89.7**	**90.6**	**91.4**	**91.8**	**452.8**

Totals may not add due to rounding.

Figure 6 below shows our revised operating expenditure forecast compared to the Revenue Proposal and the efficient benchmark estimate in the AER's Draft Decision.

Figure 6: Revised operating expenditure forecast



[39] This forecast has also been updated by adjusting the Draft Decision operating expenditure model to correctly apply the revised inflation estimate of 2.50% to escalate operating expenditure into real 2017-18 dollars, rather than the estimate of 2.25% applied in the Draft Decision. These figures are also re-presented in mid-year real ($Dec2017-18) terms for consistency with the AER's benchmark efficient forecast and for accurate comparison with historic actual operating expenditure and the approved allowance.

Based on the new obligations imposed on us and other required updates, from an overall perspective our revised operating expenditure forecast represents our best estimate of the efficient costs we reasonably expect to incur in the coming regulatory period in order to meet our obligations and service requirements.

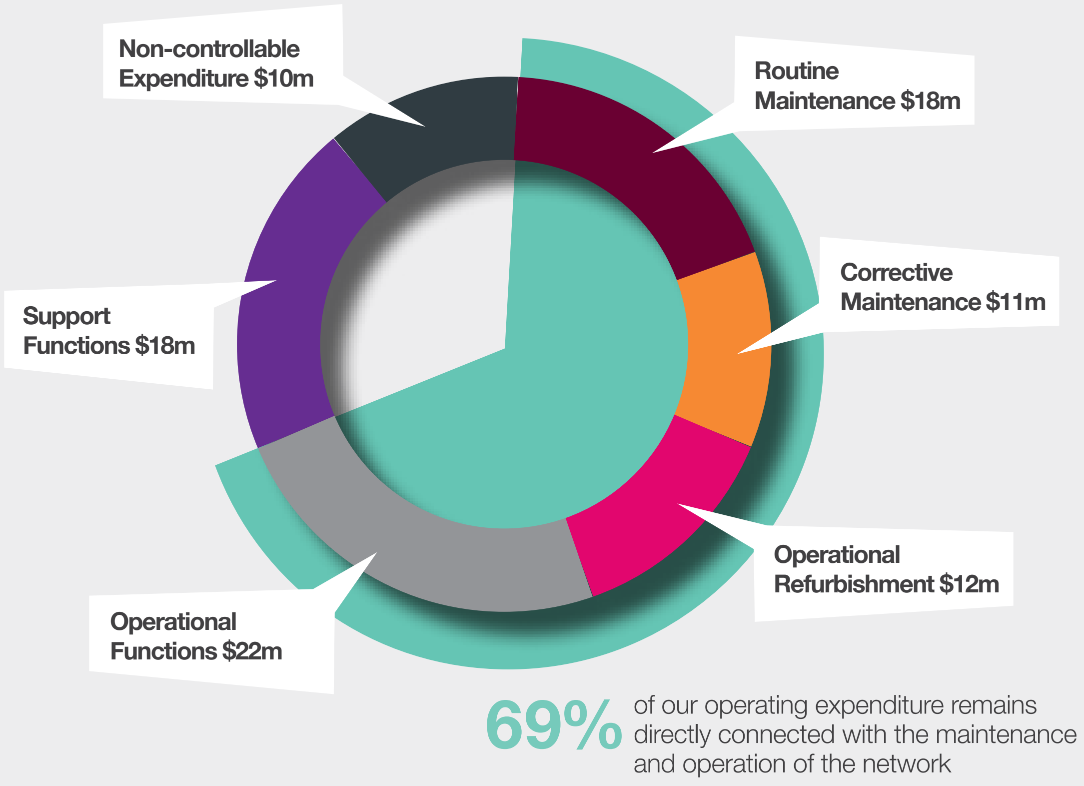
Our updated operating expenditure forecast remains well below the AER's efficient benchmark estimate in its Draft Decision, noting that the AER's estimate included no allowance for the new obligations described above.

Our revised forecast also delivers ongoing savings for customers of 9% compared with our trend allowance.

We therefore remain confident that our updated operating expenditure forecast reasonably reflects our prudent and efficient costs from a 'top-down' perspective.

Our revised total operating expenditure forecast by category is set out in Figure 7 below.[40]

Figure 7: Revised annual operating expenditure 2018-19 to 2022-23 by category ($m 2017-18)



The net impact of the revised operating expenditure forecast, when combined with the other minor updates and adjustments required elsewhere in this revised Revenue Proposal, is a decrease in the estimated savings in the transmission component of the average residential electricity bill from $22 per annum in 2018-19 in the AER's Draft Decision, to $20 per annum in the revised Revenue Proposal.

[40] As required under the Rules, an updated certification of the reasonableness of the key assumptions that underlie the operating expenditure forecast by the Directors of ElectraNet also accompanies this revised Revenue Proposal.

FINANCIAL BUILDING BLOCKS

7. We continue to apply accepted methods to the financial revenue building blocks

The following section sets out the remaining revenue building blocks, which have been adjusted and updated where required in accordance with the AER's Draft Decision.[41]

7.1 Regulatory Asset Base

The AER did not accept our proposed opening RAB of $2,552.0 million ($ nominal) as at 1 July 2018 in its Draft Decision and instead proposed a slightly increased opening RAB of $2,569.3 million ($ nominal).

The AER's opening RAB corrected some input data and also reflected actual inflation for 2016-17, whereas our opening RAB calculation included forecast inflation for that year.

The AER also proposed adjustments to our forecast RAB to include its revisions to our depreciation forecast.

The Draft Decision requires us to update the RAB for actual capital expenditure incurred in 2016-17 and to update the capital expenditure forecast for 2017-18 as required.

Accordingly, we have applied these updates and revised our opening RAB for 1 July 2018 is as set out in Table 10.

Table 10: Revised opening RAB as at 1 July 2018 ($m nominal)

Regulatory Asset Base	2013-14	2014-15	2015-16	2016-17	2017-18
Opening RAB	2,069.5	2,187.8	2,242.4	2,337.5	2,438.5
Capital expenditure as incurred	136.6	117.1	165.4	154.7	181.2
Straight line depreciation	(78.9)	(91.6)	(99.7)	(103.3)	(104.0)
Inflation adjustment	60.6	29.1	29.4	49.7	61.0
Closing RAB	2,187.8	2,242.4	2,337.5	2,438.5	2,576.7
Adjust for difference in 2012-13 actual capital expenditure (and disposals)					**(1.0)**
Adjust for return on difference in 2012-13 actual capital expenditure (and disposals)					**(0.4)**
Opening RAB at 1 July 2018					**2,575.3**

Totals may not add due to rounding.

[41] The figures presented in this section are expressed in end of year terms ($June) consistent with the outputs of the PTRM, unless otherwise indicated.

We accept the AER's Draft Decision in relation to the RAB for the coming regulatory period. Table 11 below sets out our updated RAB to reflect our revised capital expenditure forecast and depreciation forecast.

Table 11: Revised RAB roll-forward from 1 July 2018 to 30 June 2023 ($m nominal)

Regulatory Asset Base	2018-19	2019-20	2020-21	2021-22	2022-23
Opening RAB	2,575.3	2,633.5	2,678.4	2,731.0	2,772.4
Net capital expenditure	101.4	107.9	120.3	113.9	62.0
Straight line depreciation	(107.6)	(128.8)	(134.6)	(140.8)	(138.3)
Inflation adjustment on RAB	64.4	65.8	67.0	68.3	69.3
Closing RAB	**2,633.5**	**2,678.4**	**2,731.0**	**2,772.4**	**2,765.4**

Totals may not add due to rounding.

7.2 Rate of return

The Draft Decision accepted our approach for estimating the WACC including our nominated averaging periods. The AER applied an updated rate of return of 5.75% compared to our estimate of 6.02% based on more recent market data. The Draft Decision explained that this updated estimate is a placeholder only, and will be updated in the final decision for prevailing market rates based on the agreed averaging period.

We accept the AER's Draft Decision in relation to WACC. For simplicity, we have adopted the AER's placeholder estimate in this revised Revenue Proposal, pending the AER's update of the WACC in the final revenue determination.

7.3 Gamma

In its Draft Decision, the AER adopted a value for gamma of 0.40 compared to our proposed value of 0.25. The AER's Draft Decision is consistent with the position that it has adopted in recent determinations and with the subsequent findings of the Full Federal Court and recent Tribunal decisions.

While we remain of the view that market value estimates of gamma are preferable, we accept the outcome of the recent legal reviews, finding no error in the AER's utilisation rate approach.

In estimating the utilisation rate, the AER considers both the equity ownership approach and ATO taxation statistics, but places most reliance on the equity ownership approach. We suggest that greater reliance on the evidence from tax statistics should be considered.

However, for the purposes of this determination, we accept the AER's value of gamma of 0.40.

7.4 Expected inflation

In its Draft Decision, the AER did not accept our market based inflation forecast approach or estimate of 1.97% per annum, and applied its geometric average approach, which relies on the Reserve Bank of Australia's (RBA's) forecast and target bands, to derive a placeholder inflation estimate of 2.50%.

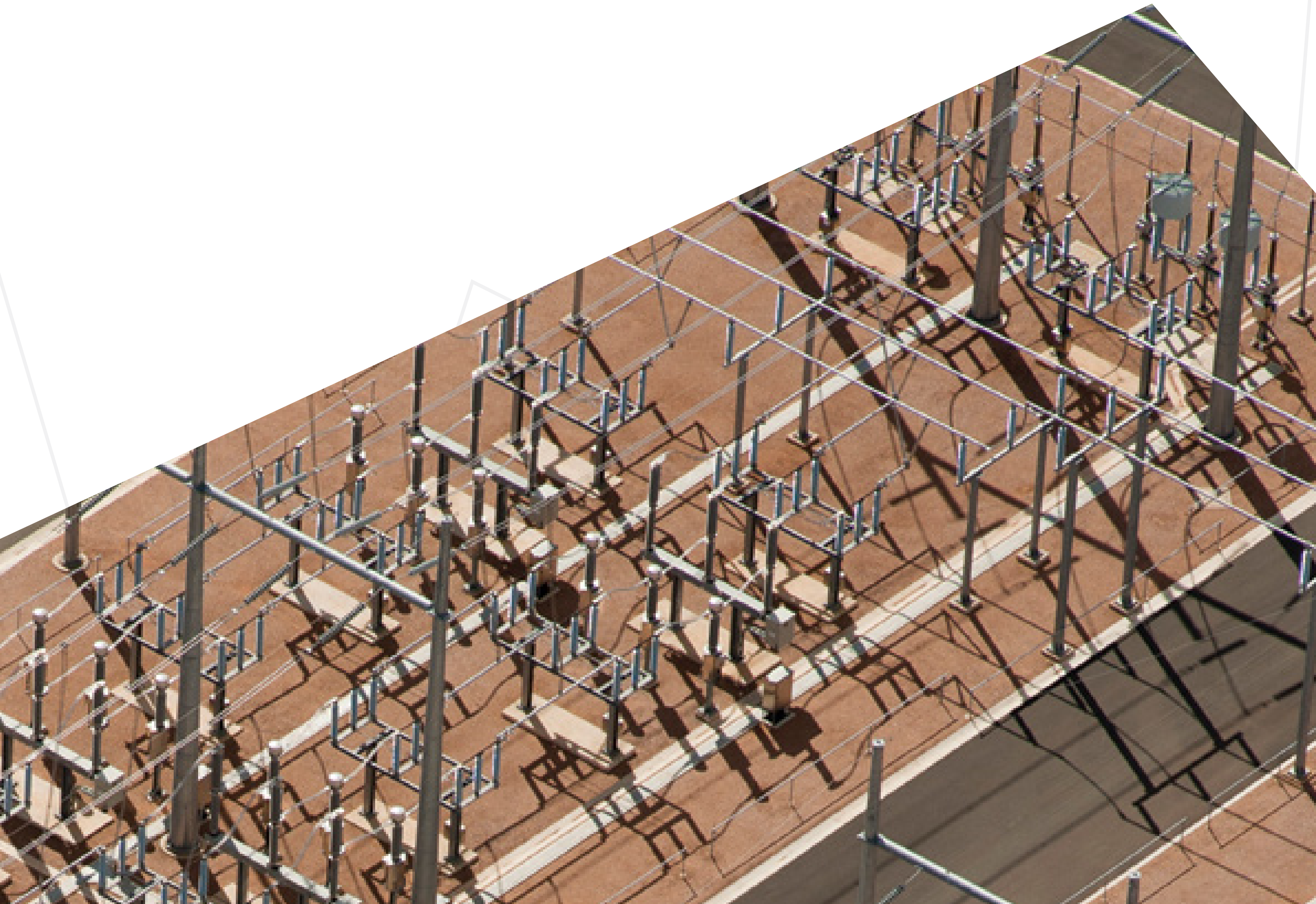
The AER has separately been undertaking a review of the treatment of inflation under the regulatory framework, as the method for estimating expected inflation has been a matter of debate in recent electricity and gas regulatory determinations.

Given this, the Draft Decision indicated that the AER would seek to adopt any change in its approach to forecasting inflation arising from this review in our final revenue determination.

This review concluded on 20 December 2017 with the release of a final positon paper in which the AER confirmed it will continue to apply its existing approach to forecasting inflation.

While our position remains that a market based estimate provides a more representative and appropriate estimate of inflation, we accept the outcome of the AER's review for the purposes of the revised Revenue Proposal.

We have therefore adopted the AER's current approach to forecasting inflation, and have applied the current inflation forecast of 2.50% as a placeholder estimate.



7.5 Depreciation

The AER's Draft Decision accepted most elements of our depreciation forecast, including:

- a reduction in the standard asset life of telecommunication equipment from 15 to 10 years
- the adoption of the year-by-year tracking approach to determine straight-line depreciation
- the accelerated depreciation of certain unused assets and assets due for replacement over the coming regulatory period.

The AER's Draft Decision also made adjustments to our depreciation proposal to address:

- a number of small input errors in the depreciation tracking model
- an approach to depreciating the amount in the 'working capital' asset class from 1 July 2018
- the AER's adoption of a standard asset life for the 'Transmission lines – life extension' asset class of 48.1 years, instead of our proposed 27 years
- the AER's decision not to accept our proposed standard asset life for the 'synchronous condensers' asset class at this time.

We accept the AER's Draft Decision on these matters.

However, we note that the AER has removed the current 'Transmission lines – life extension' asset class with a standard asset life of 27 years.[42]

While we accept the longer asset life of 48.1 years for life extension projects commencing in the coming regulatory period, projects undertaken in the current period should remain subject to the AER's existing approved standard asset life of 27 years.

This standard asset life must be preserved for these assets in order to give effect to the AER's 2013 regulatory determination in relation to historic insulator refits. We have therefore amended the PTRM accordingly.

Our revised depreciation forecast, which also addresses the updated information noted earlier, is set out in Table 12 below.

Table 12: Revised regulatory depreciation forecast ($m nominal)

Depreciation	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Straight line depreciation	107.7	128.7	134.6	140.8	138.3	**650.1**
Inflation adjustment on RAB	(64.4)	(65.8)	(66.9)	(68.3)	(69.3)	**(334.7)**
Regulatory depreciation	**43.3**	**62.9**	**67.7**	**72.5**	**69.0**	**315.4**

[42] AER, Draft Decision: ElectraNet transmission determination 2018–23, Attachment 5 – Depreciation, Table 5-3, p20.

7.6 Corporate tax allowance

The AER's Draft Decision adjusted our corporate tax allowance to reflect the lower value of gamma and address minor changes to our opening Tax Asset Base (TAB) and standard tax asset lives.

The AER also proposed to make an adjustment to the tax allowance to account for our proposal to accelerate the depreciation of certain assets (which the AER has accepted).

In this revised Revenue Proposal, we have updated our forecast tax allowance in accordance with the AER's Draft Decision. Our revised tax allowance in Table 13 below also reflects:

- an updated TAB for actual capital expenditure in 2016-17
- our revised capital expenditure and tax depreciation calculations
- our updated revenue requirements as set out in this revised Revenue Proposal.

Table 13: Revised forecast tax allowance ($m nominal)

Tax allowance	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Tax payable	7.3	11.5	12.7	15.5	15.5	62.6
Less value of imputation credits	(2.9)	(4.6)	(5.1)	(6.2)	(6.2)	(25.0)
Net tax allowance	**4.4**	**6.9**	**7.6**	**9.3**	**9.3**	**37.6**

7.7 EBSS carry over amounts

In our Revenue Proposal, we proposed an EBSS carryover penalty of $1.9 million ($2017–18).

The AER's Draft Decision increases this penalty by $0.2 million ($2017–18) as a result of excluding defined benefit superannuation operating expenditure for the purposes of calculating the EBSS. The Draft Decision also requires us to update this calculation for actual operating expenditure incurred in 2016-17.

The Draft Decision also confirmed the basis on which the EBSS is to apply for the coming regulatory period.

We accept the AER's Draft Decision in relation to the current regulatory period, and have updated the carryover payments accordingly. In doing so, we also applied adjustments for movements in provisions agreed with the AER during the review of our Revenue Proposal. For completeness, we have also excluded NCIPAP operating expenditure incurred in the current regulatory period from these calculations, as required under the scheme. This results in an updated EBSS carryover penalty of $3.5 million ($2017–18).

We also accept the AER's proposed application of the EBSS for the coming regulatory period, including the cost categories excluded by the AER. Consistent with this, to establish the operating expenditure forecasts applicable to the EBSS calculation, we propose the values in Table 14 on the next page.

Table 14: Forecast operating expenditure for EBSS purposes ($m 2017-18 mid-year)

EBSS forecast	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Revised forecast operating expenditure	89.3	89.7	90.6	91.4	91.8	**452.8**
Less debt raising costs	(1.3)	(1.3)	(1.3)	(1.2)	(1.2)	**(6.3)**
Less network support costs	(8.3)	(8.3)	(8.3)	(8.3)	(8.3)	**(41.4)**
Forecast operating expenditure for EBSS purposes	**79.7**	**80.2**	**81.1**	**81.8**	**82.3**	**405.1**

We will also adjust our actual reported operating expenditure for EBSS purposes to exclude network capability projects and movements in provisions in accordance with the AER's Draft Decision.[43]

7.8 Service Target Performance Incentive Scheme

In its Draft Decision, the AER made the following adjustments to our proposed parameter values for the STPIS:

- for the service component, the AER accepted our proposed targets, but set different caps and floors in a small number of cases using alternative statistical distributions
- for the Market Impact Component (MIC), the AER excluded certain force majeure events from our historic performance data and made consequential changes to the performance target
- the AER accepted our Network Capability Incentive Parameter Action Plan (NCIPAP) projects, but removed the incentive payments from our revenue building block calculation.

We accept the AER's Draft Decision in relation to the service components and the amended caps and floors.

We accept the reduced MIC target, on the basis that reported performance in the coming regulatory period will similarly exclude the regulation Frequency Control Ancillary Service (FCAS) constraints that have been removed from the target as a force majeure exclusion, in order to ensure consistent application of the scheme.

As requested in the Draft Decision, we will also update the STPIS targets to reflect our audited 2017 performance data when this information becomes available in early 2018.

In accordance with the Draft Decision, our revised Revenue Proposal excludes NCIPAP payments from the building block revenue requirement in the PTRM.

[43] These items are not included in our operating expenditure forecast and therefore do not appear in the table above.

7.9 Revenue and X factors

Table 15 below presents a summary of the revised revenue building blocks and annual building block revenue requirement.

Table 15: Revised annual building block revenue requirement ($m nominal)

Revenue requirement	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Return on capital	148.1	151.4	154.0	157.0	159.4	**769.8**
Return of capital (regulatory depreciation)	43.3	62.9	67.7	72.5	69.0	**315.4**
Operating expenditure	92.6	95.5	98.8	102.1	105.2	**494.1**
Efficiency payments	(1.3)	(1.2)	(1.6)	0.0	0.4	**(3.7)**
Corporate tax allowance	4.4	6.9	7.6	9.3	9.3	**37.6**
Annual building block revenue requirement	**287.1**	**315.5**	**326.5**	**340.9**	**343.2**	**1,613.2**

Totals may not add due to rounding.

The annual building block revenue requirement is converted into a Maximum Allowed Revenue (MAR) so that the revenue cap can be implemented.

We note that in the Draft Decision, the AER applied smoothing to maintain a flat real revenue outlook over the coming regulatory period. This assists in providing stability in transmission charges.

We have maintained this principle in the X factors we propose in order to provide price stability over the coming period.

Table 16 below shows our revised annual building block revenue requirement, the MAR, the X factors and the total revenue cap for the coming regulatory period. In present value terms, the smoothed and unsmoothed revenue totals are equivalent.

Table 16: Revised smoothed revenue requirement ($m nominal)

Revenue requirement	2018-19	2019-20	2020-21	2021-22	2022-23	Total
Annual building block revenue requirement (Unsmoothed)	287.1	315.5	326.5	340.9	343.2	**1,613.2**
Annual expected MAR (Smoothed)	306.3	313.9	321.8	329.8	338.1	**1,609.8**
X factor	n/a	0.0%	0.0%	0.0%	0.0%	

In total, the adjustments and updates applied in this revised Revenue Proposal in response to the AER's Draft Decision result in an increase in total revenue of around 1% from the Draft Decision.

FURTHER CONSULTATION

8. Where to from here?

8.1 Further information

Further information on the details of our forecasts can be found in the following models which accompany this revised Revenue Proposal:

- PTRM
- RFM
- Operating Expenditure Model
- Capital Expenditure Model
- Depreciation Model
- EBSS Model

An updated Directors' Responsibility Statement also accompanies this revised Revenue Proposal.

It is noted that this revised Revenue Proposal contains no confidential information.

8.2 Next steps

We welcome any queries or feedback on our revised Revenue Proposal, either directly to us or through the AER's consultation process.

The expected timeframes for the conclusion of the revenue determination process are as follows:

Milestone	Timing
Submissions due on Draft Decision and revised Revenue Proposal	29 January 2018
AER to publish final revenue determination	By 30 April 2018

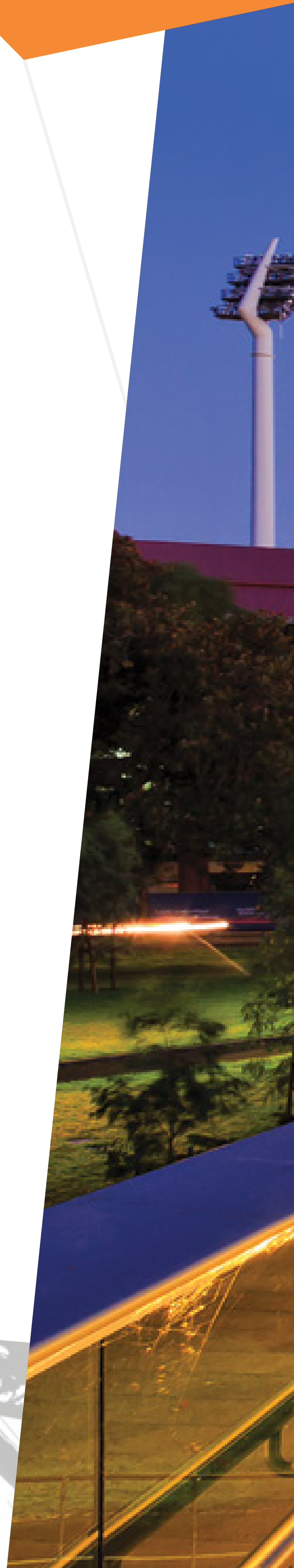
You can provide feedback by:

Emailing your feedback to **consultation@electranet.com.au**

Visiting us online at **electranet.com.au** and completing the online form

Sending your feedback to:
Simon Appleby
Senior Manager Regulation
and Land Management
PO Box 7096
Hutt St Post Office
ADELAIDE SA 5000

Calling us toll-free on **1800 243 853**



Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CESS	Capital Expenditure Sharing Scheme
COAG	Council of Australian Governments
CPI	Consumer Price Index
EBSS	Efficiency Benefit Sharing Scheme
ESCOSA	Essential Services Commission of South Australia
ESCRI	Energy Storage for Commercial Renewable Integration
FCAS	Frequency Control Ancillary Services
MAR	Maximum Allowed Revenue
MIC	Market Impact Component
NCIPAP	Network Capability Incentive Parameter Action Plan
NEM	National Electricity Market
NSCAS	Network Support and Control Ancillary Services
PTRM	Post Tax Revenue Model
PV	Photovoltaic
RAB	Regulatory Asset Base
RBA	Reserve Bank of Australia
RFM	Roll Forward Model
RIT-T	Regulatory Investment Test for Transmission
Rules	National Electricity Rules
STPIS	Service Target Performance Incentive Scheme
TNSP	Transmission Network Service Provider
WACC	Weighted Average Cost of Capital

ElectraNet

Contact Us

If you have a question or would like to discuss any aspects of our revised Revenue Proposal, please contact ElectraNet.

Phone **1800 243 853**
Visit us online **electranet.com.au**