City West Substation

Attachment 5

Capital Expenditure

Revenue Proposal 2023-24 to 2027-28

31 JANUARY 2022

ElectraNet

Company Information

ElectraNet Pty Ltd (ElectraNet) is the principal electricity transmission network service provider (TNSP) in South Australia.

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Note

This attachment forms part of our Revenue Proposal for the 2023-24 to 2027-28 regulatory period. It should be read in conjunction with the other parts of the Revenue Proposal.

Our Revenue Proposal comprises the overview and attachments listed below, and the supporting documents that are listed in Attachment 14:

- Revenue Proposal Overview
- Attachment 1 – Maximum allowed revenue
- Attachment 2 – Regulatory asset base
- Attachment 3 – Rate of return
- Attachment 4 – Regulatory depreciation
- Attachment 5 – Capital expenditure (this document)
- Attachment 6 – Operating expenditure
- Attachment 7 – Corporate income tax
- Attachment 8 – Efficiency benefit sharing scheme
- Attachment 9 – Capital expenditure sharing scheme
- Attachment 10 – Service target performance incentive scheme
- Attachment 11 – Pricing methodology
- Attachment 12 – Pass through events
- Attachment 13 – Demand Management Innovation Allowance
- Attachment 14 – List of supporting documents

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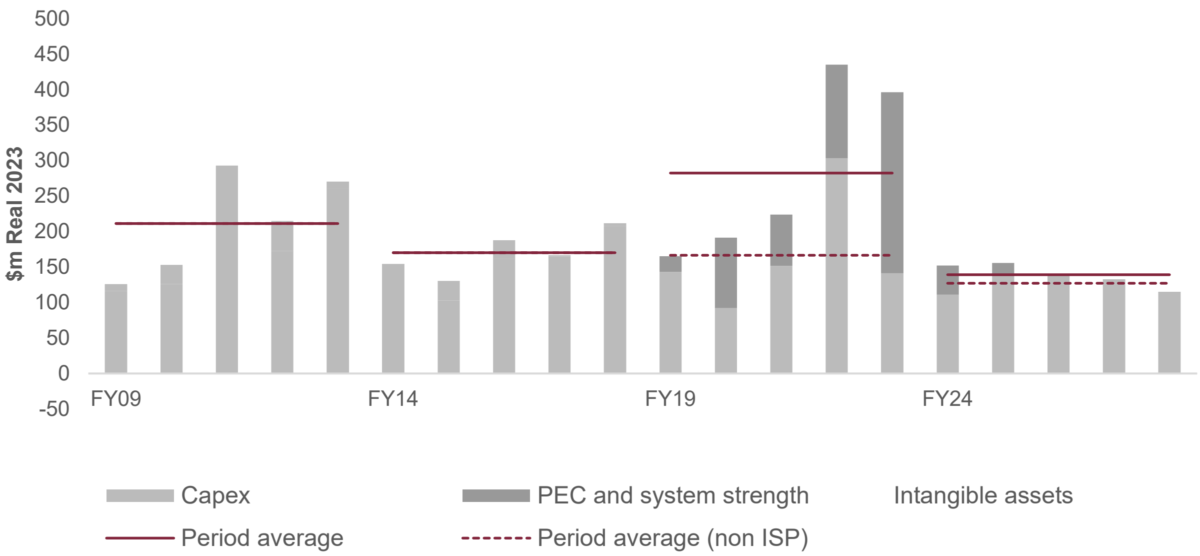
5 Capital Expenditure

5.1 Key points

- We have undertaken the Main Grid System Strength Project and are building the Project EnergyConnect interconnector in the current regulatory period, each of which facilitate the renewable energy transition and help drive substantial overall cost savings for customers. These projects were actionable projects in AEMO's Integrated System Plan (ISP).
- Following these landmark projects, we are forecasting a smaller capital program for the next regulatory period focused on managing the network. Our underlying capital expenditure, excluding ISP projects, is forecast to be about 18% lower than the current period, in addition to being lower than the two previous regulatory periods. When an additional adjustment is made to account for the impact of new accounting standards relating to intangible assets in our IT expenditure program, our proposed capital expenditure falls to approximately 24% below current levels.
- Figure 5-1 shows forecast capital expenditure for the forthcoming regulatory period against recent historical levels of expenditure.

Figure 5-1: Actual and forecast capital expenditure ($m 2022–23)[1]



- Our consumer engagement program has provided valuable input to our capital expenditure plans for the forthcoming regulatory period. Following extensive engagement, we reduced our total capital expenditure forecast over the 5 year period by approximately 12% or $100 million from our indicative forecast of $842m[2] in our Preliminary Revenue Proposal (excluding the impact of the new accounting standards).

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1 Excludes NCIPAP expenditure.

2 This is expressed in June 2023 terms and is equivalent to $832m in December 2023 terms as shown in the Preliminary Revenue Proposal.

- Our expenditure plans have three principal components:
  - **Refurbishment and replacement** – the majority of our capital investment program (57% after adjusting for intangible assets) focuses on the replacement of deteriorating high risk assets.
  - **Security and safety** – changes to Commonwealth legislation and a host of other factors mean that we need to continue to invest in the physical and cyber security of our network to maintain public safety and security of supply.
  - **Technology and systems** – the power system will continue to transform over the forthcoming regulatory period requiring that ElectraNet's systems and processes continue to evolve. As part of this, we are proposing to make investments to support the ongoing uptake of renewable energy, both grid scale and distributed, and to harness new technologies for the benefit of our customers.
- In addition to our forecast capital expenditure, we have identified three contingent projects that may be triggered in the forthcoming regulatory period, being the Eyre Peninsula Upgrade, Interconnector Upgrade and Power Quality Management.
- These contingent projects are subject to separate approval and stakeholder consultation by the AER, if pre-defined trigger events occur. In addition to these projects, actionable ISP projects or system strength projects may arise during the forthcoming regulatory period, which will also be classified as contingent projects under the Rules. Our forecast capital expenditure in this Revenue Proposal does not include any allowance in respect of these contingent projects.
- Our capital expenditure forecasting approach is consistent with our Expenditure Forecast Methodology previously submitted to the AER[3] and reflects best practice. Our input assumptions are reasonable and soundly based.
- The AER's latest annual benchmarking report indicates that our total capital and operating expenditure is efficient. In addition, we have introduced a number of measures to drive further efficiencies over time, which are built into our capital expenditure forecasts.
- Our forecast capital expenditure will enable us to deliver the services that our customers expect, while also delivering cost savings compared to previous regulatory periods. As such, our forecasts comply with the Rules requirements and will promote outcomes that are consistent with the National Electricity Objective.
- Recent accounting treatment changes require us to report intangible assets as operating expenditure moving forward. This results in a net transfer of $46m from our capital expenditure forecast to our operating expenditure forecast, principally impacting on our technology investments. Our Revenue Proposal Overview presents our expenditure forecasts <u>prior to</u> this adjustment for like comparison, while the remainder of this attachment presents our forecasts <u>after</u> this adjustment unless otherwise specified.

5.2 Introduction

This attachment presents our capital expenditure forecasts for the forthcoming regulatory period in accordance with the Rules requirements. In particular, clauses 6A.6.7(a) and (c) specify the

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3 ElectraNet, *Expenditure Forecast Methodology Regulatory Control Period 2023-24 to 2027-28,* 30 June 2021.

capital expenditure objectives and *capital expenditure criteria*. If our forecasts satisfy these the AER must accept them and approve our Revenue Proposal. To summarise, these provisions require us to submit a forecast total capital expenditure that satisfies the following objectives:

- meet or manage the expected demand for prescribed transmission services over the forthcoming regulatory period;
- comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services[4]; and
- maintain the safety of the transmission system through the supply of prescribed transmission services.

Our forecast must be limited to the expenditure necessary to supply prescribed transmission services as allocated using our approved Cost Allocation Methodology. The Rules require the AER to determine whether our total forecast capital expenditure reasonably reflects the efficient and prudent costs of meeting these objectives and, if so, to accept it.

Our forecasting methodology, which is described in Section 5.7, is designed to deliver capital expenditure forecasts that satisfy these Rules requirements. The information presented in this attachment explains how we have applied our forecasting methodology and why the forecasts should be accepted by the AER. Our expenditure categories and the services they provide are unchanged from the current regulatory period, as detailed in Appendix A of this attachment.

In accordance with the Rules requirements, we confirm that our capital expenditure forecasts only include expenditure that has been properly allocated to prescribed transmission services in accordance with our approved Cost Allocation Methodology[5]. We also confirm that there has not been any change in our capitalisation policy.[6]

The remainder of this attachment is structured as follows:

- Section 5.3 describes our current environment and key challenges facing South Australia's electricity transmission network;
- Section 5.4 explains the outcomes of our engagement with customers on the capital program;
- Section 5.5 presents our forecast capital expenditure;
- Section 5.6 explains how our forecast capital expenditure compares with our historical capital expenditure, and the drivers for our lower expenditure requirements in the forthcoming regulatory period;
- Section 5.7 describes our network capital expenditure forecasting methodology, together with the key inputs and assumptions;

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4 In our case, the Electricity Transmission Code and schedule 5.1 of the Rules specify the applicable obligations in relation to quality, reliability and security of supply. Therefore, clause 6A.6.7(a)(3) is not applicable.

5 Available at www.electranet.com.au/wp-content/uploads/resource/2016/06/20081508-Report-Cost-Allocation-Methodology.pdf.

6 We also confirm that none of our historical prescribed capital expenditure has been under arrangements that do not reflect arm's length terms. Further, none was incurred in transactions with related parties.

- Section 5.8 presents information relating to proposed contingent projects; and
- Section 5.9 concludes by outlining the benefits and risks to customers that arise from our proposed capital expenditure program.

The following information is also appended to this attachment:

- Appendix A sets out our capital expenditure categories and services
- Appendix B details our principal network projects and programs
- Appendix C details our proposed contingent projects

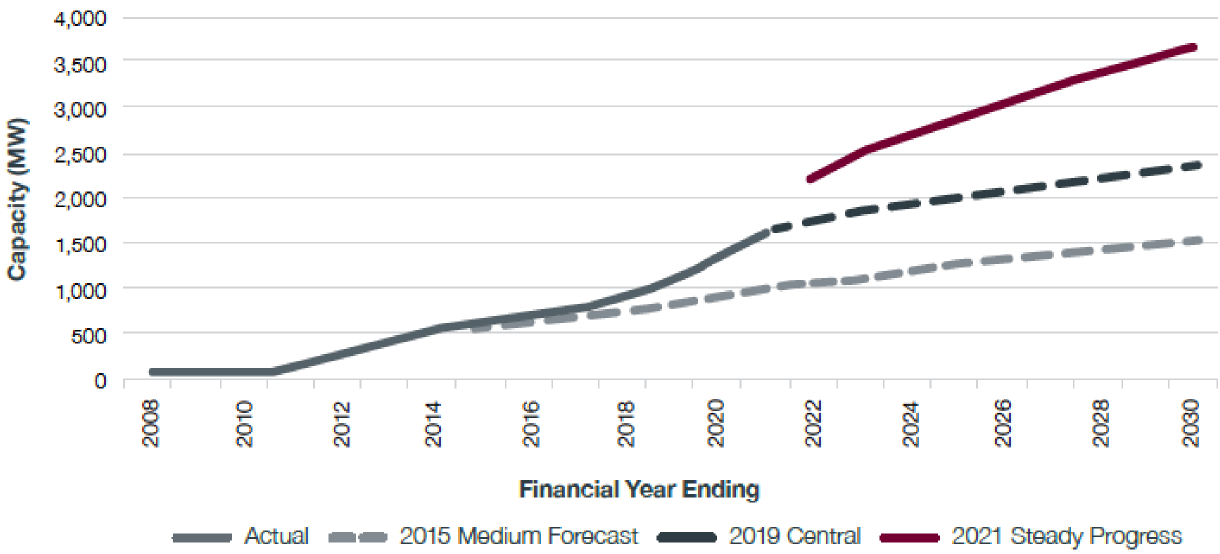
5.3 Current environment and key challenges

5.3.1 South Australia remains at the forefront of change

South Australia is in the midst of a substantial transformation in the way that electricity is generated and used. This transformation is driven by responses to climate change and by changing technology. As the energy transformation continues, South Australia's transmission network will play an increasingly important role, responding to the challenges and opportunities this creates.

South Australians have adopted rooftop solar generation faster than anyone in the world. Figure 5-2 below shows that the 2015 forecast solar PV capacity in 2030 is on track to be exceeded in 2021 i.e. only 6 years into a 15-year projection.

Figure 5-2: Forecast and actual solar PV capacity in South Australia



World leading levels of grid scale wind generation and increasingly solar generation continue to be developed in South Australia. Grid scale storage is also emerging to support the increased uptake of intermittent renewable generation.

This allows solar generation to provide electricity after dark and smooths the output of wind. It has also demonstrated the potential to provide essential system services and to enhance the capabilities of the network. South Australia pioneered the use of grid scale storage with the installation of the Hornsdale battery near Jamestown in 2017 and ElectraNet's Dalrymple battery in 2018 as the first grid forming battery, and its role is expected to increase substantially in the coming years.

New technologies are emerging at the residential level as well. In years to come we expect customers to take increased control over their energy costs with ongoing investment in small scale storage and rooftop solar generation. Recent activity to capitalise on these installations by forming Virtual Power Plants will continue to grow. In addition, electric vehicles will increase domestic electrical consumption and create a major mobile electrical load and supply source that presents both a challenge and an opportunity.

Ongoing growth in rooftop solar PV output is driving demand levels ever lower on the grid, with reverse flows now occurring in certain periods, adding to the challenges to be managed by the network.

As conventional generators continue to retire, the essential system services they provide such as system strength and inertia, are being lost. The renewable supply sources that replace them operate with different technology that currently does not offer this range of services. The complexity of operating and modelling the grid accurately as it evolves is also increasing. There is also a growing need for additional reactive support to manage higher voltages as flows on the network decline around midday before ramping up again for the evening peak.

As the market further evolves to meet energy supply needs and deliver essential system support services at the lowest long run cost, the transmission network can be expected to have an increasing role to coordinate and deliver these services alongside market- based approaches, to ensure the most efficient mix of solutions for customers.

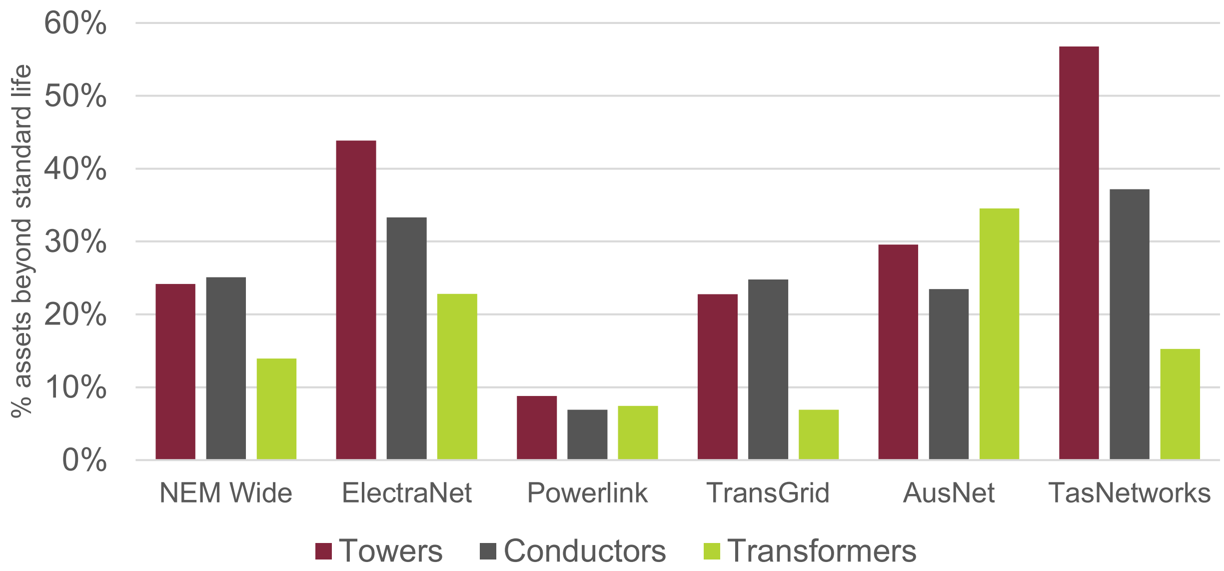
5.3.2 Underlying network challenges

In addition to the transformational changes that need to be accommodated by South Australia's transmission network, the network itself has unique characteristics that affect its service potential and the costs of delivering transmission services. In considering our capital expenditure forecasts, it is important to understand these characteristics and the resulting network challenges.

These underlying challenges can be expressed across three key metrics:

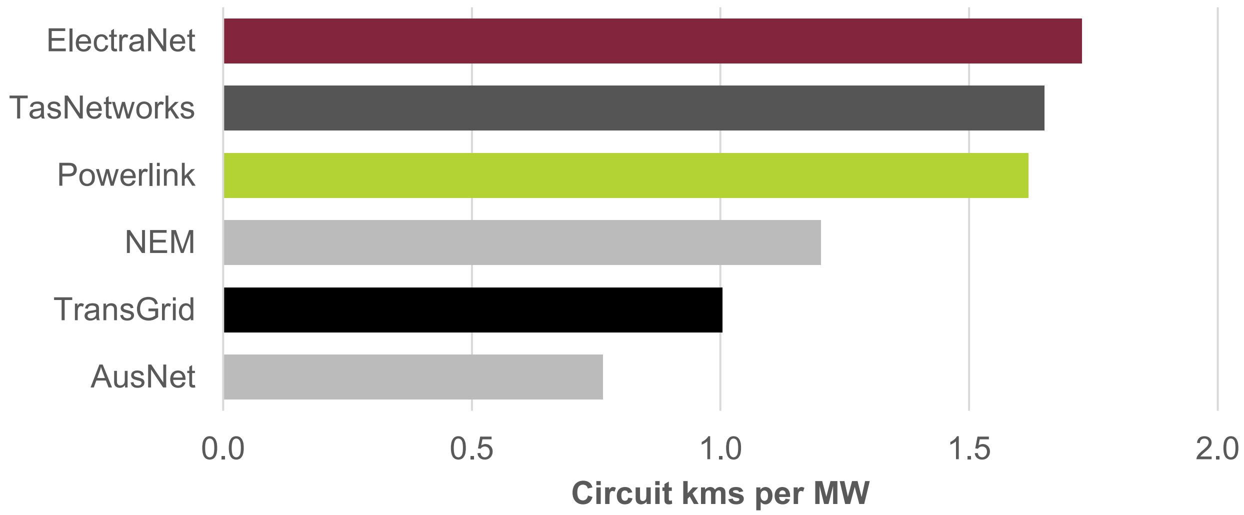
Age. South Australia has one of the oldest transmission networks in the NEM. Over 40% of transmission towers, 30% of conductors and 20% of transformers are beyond their standard asset life. While age is not a direct driver of capital expenditure, it is correlated with asset condition and increasing risk of asset failure, which are drivers of expenditure to replace assets at risk of failure and extend asset life through targeted refurbishment to avoid wholesale rebuilds.

Figure 5-3: Age profile comparison across TNSPs



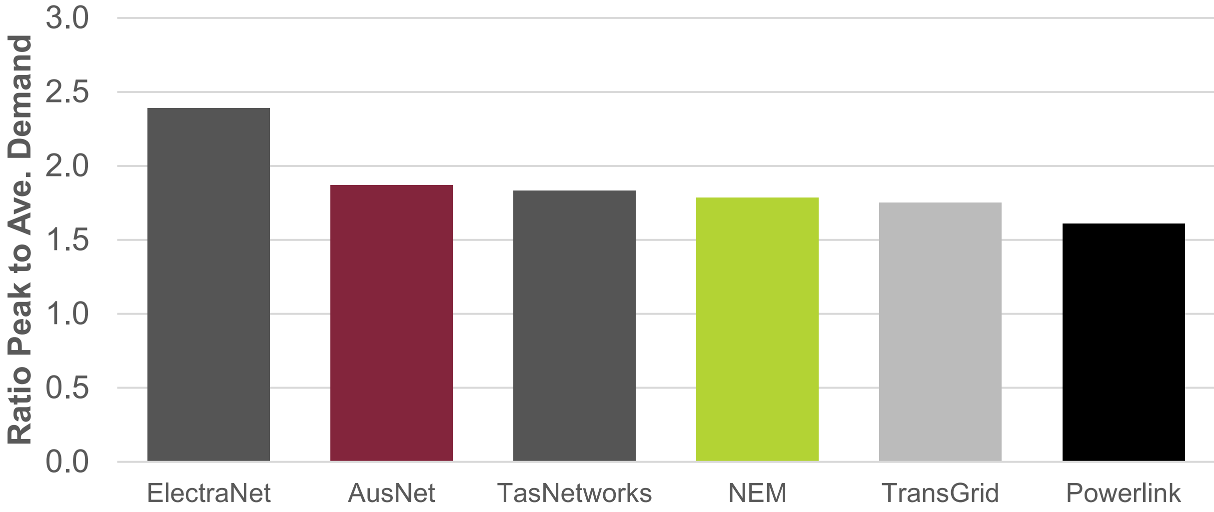
Geographic Spread. South Australia has the longest network per unit of peak demand in the NEM so more assets are required to supply a thinly spread population. While this does not necessarily affect the performance of the South Australian transmission network, it does affect its unit costs.

Figure 5-4: Circuit length comparison across TNSPs



Peakiness of Demand. South Australia has the highest ratio of peak demand to average demand in the NEM. Similar to the impact of circuit length, this feature of the South Australian transmission network also has cost implications as more assets are required per unit of energy transmitted.

Figure 5-5: Ratio of peak to average demand across TNSPs



As the network continues to age, reliability centred maintenance will remain at the core of our efforts to efficiently maintain the network. Increasing rooftop solar will reduce the utilisation of the network in the middle of the day producing an increase the ratio of peak demand to average demand. The adoption of electric vehicles may offset this reduction. Technologies such as VPPs, and coordinated EV charging and discharging will provide new opportunities to improve network utilisation and promote affordability.

Another key difference is that the boundary between the high voltage transmission network and lower voltage distribution network differs across the NEM. South Australia's transmission network includes assets that would be considered distribution elsewhere.

5.3.3 Network Vision – key themes

As part of our planning process, we have reviewed our Network Vision, published in 2016, to establish a broad direction for the development of the transmission network over a 5-10 year planning horizon. Our Network Vision has regard to the transformational changes and the particular network challenges in South Australia, described earlier. Stakeholder input in developing the Network Vision proved invaluable in testing our approach, assumptions and analysis and identifying the updated directions and priorities that inform our planning.

In the remainder of this Section we summarise each of the four themes and the priorities identified in our Network Vision to guide our future expenditure plans.

Theme 1 - The network will continue to provide an important role into the future

The transmission network will play an increasingly important role in the ongoing transformation of the electricity supply system. Forecasts over the next ten years point to maximum demand remaining broadly the same, so ElectraNet will need to maintain the network's capability to transmit power.

AEMO's ISP highlights the expected retirement of coal generators (this has already happened in South Australia) and their replacement with intermittent generation sources and large-scale storage. It also highlights a greater role for transmission as electricity supply sources become more spread out.

Our priorities to address this theme are:

- Deliver cost effective solutions for customers, using scenario-based approaches that consider uncertainty and value flexibility for future decision making.
- Manage any major and uncertain transmission network investment requirements (e.g. mining loads, renewable energy zones, future system security challenges) as contingent projects within the regulatory framework.
- Show leadership in helping to continue to drive down the delivered price of energy.
- Build trust through ongoing genuine engagement with customers and their representatives and other stakeholders.
- Focus on prolonging asset life and deferring major asset replacement wherever it is efficient to do so while maintaining reliability.
- Maintain network reliability as safely and efficiently as possible through a risk-based Reliability Centred Maintenance approach.

Theme 2 - The ongoing uptake of distributed energy resources by customers is changing the role of the network

The uptake of distributed energy resources in South Australia continues at world leading levels. South Australia has around 1,600 MW of solar PV connections as at May 2021 and periods of zero grid demand have already occurred, with increasing need for the transmission system to support residential customers trading power across the NEM. Electrification of transportation is introducing large mobile loads to the grid and may appear as mobile VPPs.

Our priorities to address this theme are:

- Actively monitor and respond to trends, and expectations to ensure the grid is ready to meet the needs of customers as distributed energy technology is adopted.
- Plan for the impacts of customer technologies to maintain safe, reliable, and secure supply under a range of reasonably foreseeable demand and supply conditions.
- Actively engage with DER providers to understand capabilities and improve forecasts of uptake.
- Develop a wide area monitoring system to maintain adequate operation, modelling and control of the changing power system during system disturbances.
- Increase engagement with SA Power Networks to improve alignment and early identification of emerging network issues.

Theme 3 - The generation mix is changing creating new challenges for the resilient, secure and reliable operation of the grid

The South Australian power system is changing, with the ongoing withdrawal of traditional synchronous generation sources and continuing investment in renewable wind and solar energy sources and storage. This has led to our investment in synchronous condensers to provide system strength and inertia services and the connection of multiple grid scale batteries.

As the grid continues to evolve with less conventional generation and declining midday demand as well as other changes, operational challenges will increase the need for system security services and new control schemes to manage the secure operation of the power system.

Our priorities to address this theme are:

- Develop efficient solutions to maintain a secure and reliable network with less conventional generation.
- Deliver Project EnergyConnect to help drive down prices, increase renewable generation exports and reduce the risk of state-wide outages after rare interconnector separation events.
- Monitor and adopt new technology to maintain secure and reliable power supply at lowest whole-of-system cost to customers, including the expansion and review of protection and control schemes.
- Undertake targeted investments to maintain expected levels of power quality.

Theme 4 - New technologies are creating opportunities to change the way network services can be delivered

Rapidly changing technologies are creating both challenges and opportunities for the delivery of transmission services and the evolution of the electricity supply system. This potentially opens new options to provide network services at lower cost and unlock more capacity to connect new generation and support the transition to a low carbon future.

Our priorities to address this theme are:

- Improve visibility of the behaviour of the grid to ensure the network continues to operate in a safe and efficient manner.
- Investigate the potential to alleviate existing network limits with the integration of very fast acting technologies such as grid scale battery storage into the grid.
- Engage with emerging services providers ahead of the identification of needs to maximise involvement in option analysis.
- Adopt best practice data analytics to improve decision making in asset management and network operation.
- Encourage more efficient and transparent pricing arrangements to reflect asset use, provide clarity and certainty.
- Efficiently deliver new transmission services needed for the safe and reliable operation of the grid such as system strength and inertia.

The four themes described above help us shape our expenditure and service plans over the 5-10 year planning horizon. As explained in the next section, the views of our customers and stakeholders are key inputs to our capital expenditure plans for the forthcoming regulatory period.

5.4 The outcomes of our engagement with customers

In July 2021, we published our Preliminary Proposal which set out our indicative expenditure plans for the forthcoming regulatory period. We sought stakeholder feedback on our Preliminary Proposal, including through a public forum held on 12 August 2021. We have also engaged extensively with our Consumer Advisory Panel as we have continued to further develop and test our proposed plans. As part of our ongoing engagement with our direct connect customers, we wrote to each of them providing a copy of the PRP and inviting them to participate in individual or group meetings to discuss it.

Table 5-1 below highlights the feedback we received through our engagement process and describes how we have responded by reviewing and updating our capital expenditure plans for the forthcoming regulatory period. Further information on the outcomes of our early engagement program is contained in the Customer Engagement Outcomes Report[7].

Table 5-1: What we heard from customers and how we responded

What we heard	How we have responded
Capital Expenditure Program	
ElectraNet should be doing everything to keep its costs as low as possible. What lower cost options have been considered in the capital program?	We undertook a line-by-line Management review of the entire capital program, including the project need, scope, cost estimate and economic benefits to customers, reflecting on customer feedback received. This led to the cancellation or deferral of some projects, and scope reductions and cost revisions on others, yielding a total reduction of approximately 12% or $100[8] million in the capital program from our Preliminary Revenue Proposal (excluding the impact of the new accounting standards).
What lower cost options have been considered in the replacement program?	Our line-by-line Management review included the replacement program, which comprises 55% of the overall capital program. The replacement and refurbishment program has been reduced 19% from the Preliminary Revenue Proposal, based on project cancellations and scope reductions and is 36% lower than the program in the current period. Any further reductions would involve unacceptable increases in network and asset risk.
What lower cost options have been considered in the IT program? Delivering a strategy is not sufficient, and increases in data does not necessarily require greater investment. The value to customers must be clear.	We have reduced the Business IT capex forecast from $78m[9] in the PRP to $70m (an 11% reduction)[10] through the cancellation of two projects and cost refinements for others. We have also reprioritised and refocused our overall technology program on the key benefits to be delivered to customers.

7 ElectraNet, Customer Engagement Outcomes Report. January 2022

8 These values are in end of year terms, so differ slightly from those presented in the PRP due to additional inflation.

9 This value is in June terms, so differs slightly from that presented in the PRP due to additional inflation.

What we heard	How we have responded
What are the cost implications of the deferral of Project EnergyConnect (PEC)? Will this deliver a benefit to ElectraNet under the CESS?	Estimated cost savings now expected for PEC and delay into the coming regulatory period result in revenue and prices being lower than otherwise due to lower costs and later capitalisation of the assets. Given this delay we have also rebalanced our capital program and workload through offsetting project timing movements into the current period, minimising any net increase in the capex forecast for the coming period. The PEC deferral has no direct impact on the CESS outcomes because major project timing movements are removed from the CESS calculations. However, the rebalancing described above has brought forward capital expenditure to the current period, which produces an adverse CESS impact for ElectraNet as our expenditure in the current period is higher than would otherwise be the case.
Proposed mining developments continue to progress on the Eyre Peninsula, with the possibility of major loads connecting to the network in the coming regulatory period.	We have proposed a contingent project to enable the upgrade of the new Eyre Peninsula line (as provided for in its design) if new mining loads trigger the need for additional capacity in the forthcoming period.
The probability and potential cost impact of the contingent projects should be carefully considered, and customers should not bear any undue risks.	We have reviewed the five contingent projects identified in the Preliminary Revenue Proposal, which comprised an indicative total capital expenditure of $660 million. We are now proposing three contingent projects, totalling an estimated $360 million. Three of the originally proposed projects have been removed from our final list on the basis that if required by AEMO in future, these will automatically become contingent projects under the Rules. A further contingent project has been added (Power Quality Management), following customer feedback that it should be removed from our ex ante capital expenditure forecast. The contingent project mechanism helps manage risk and reduce costs because customers only pay for the project if it is required. Updated capital expenditure forecasts will be prepared if the projects proceed.

10 These figures exclude the impact of the new accounting standards and are in mid year (December end) terms for ease of comparison with the PRP.

What we heard	How we have responded
How will the trend of increasing transmission costs be managed?	To some extent, recent increases in transmission costs reflect improved understanding of the costs of major line projects. Updated costs are now reflected in AEMO's Integrated System Plan. The costs of other projects have also exceeded initial estimates in recent years, reflecting market price pressures and resource constraints. In response we have implemented improvements in our scoping and estimating approach to provide higher confidence in our estimates for the purpose of the Revenue Proposal. Ongoing prioritisation of the capital program will also ensure we manage risk and maintain service levels. The incentives of the CESS will also drive us to manage our capital program efficiently and avoid any overspend that is not essential.
Specific feedback was provided on a range of projects in the capital program, together with the following overall guidance: • Are we keeping costs as low as possible? • Is this a 'nice to have' or 'must have' project? • Could the project be deferred or partially deferred? • Are there lower cost solutions?	• Tower anti-climb – we sought feedback on this project and concluded by adopting a more staged approach focusing initially on the highest risk areas, with input and support from Lifeline from a suicide prevention perspective. This resulted in a reduction in cost from approximately $36 million to $22 million. • Northern REZ strategic land acquisition – feedback supported the value of this project as a low regrets investment to avoid more expensive future solutions, and we have retained this project in our program. • Power Quality Management – we have considered feedback on this project and propose to install measurement devices to better identify the issues and consider the options, with any specific solutions to be pursued separately as a contingent project, reducing the upfront cost of this project by approximately $54 million. • Substation security projects – our further review of these related projects based on feedback received identified cost savings through careful design and scope changes, resulting in a cost reduction of approximately $10 million.

The CAP provided feedback indicating it was satisfied that our capital planning processes are robust and was strongly supportive of our reduction in total capital expenditure forecast from the $842m[11] indicative forecast in the Preliminary Revenue Proposal to the $742m in like terms ($696m after adjusting for intangible assets).

[11] This is equivalent to the $832m value published in the Preliminary Revenue Proposal but is presented here in June terms for ease of comparison.

5.5 Forecast capital expenditure

A summary of our forecast capital expenditure by category is shown in Table 5-2 both before and after the adjustment for intangible asset accounting. [12]

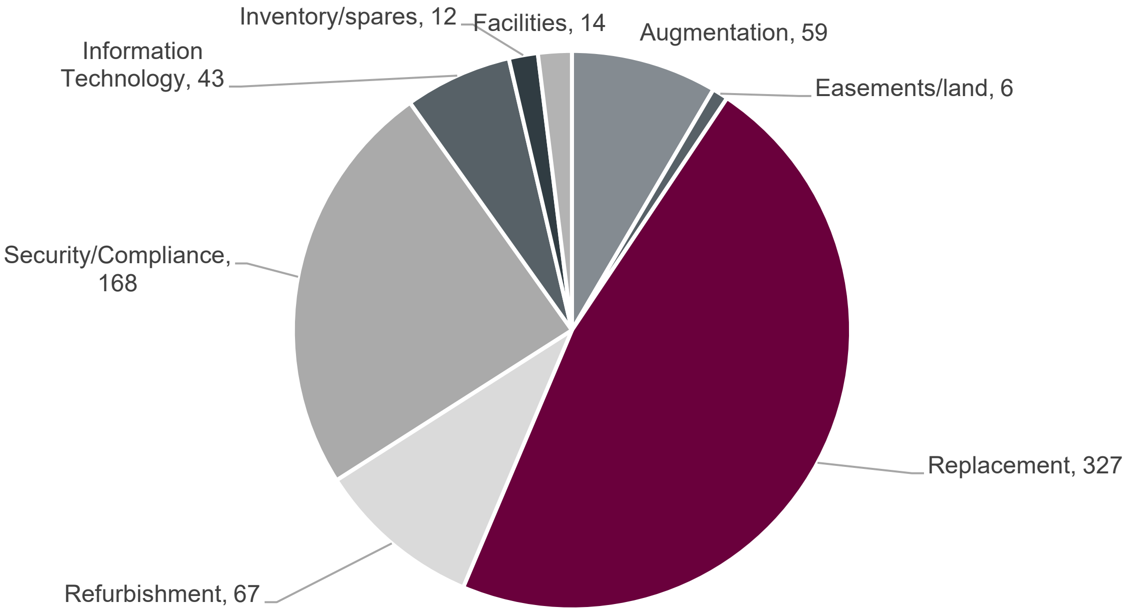
Table 5-2: Capital expenditure in current and forthcoming regulatory period by category

Category	FY 24-28 forecast (pre intangible assets)	Intangible asset adjustment	FY 24-28 forecast (post intangible assets)	Description
Augmentation	59		59	No demand driven investment following completion of Project Energy Connect
Connection	0		0	
Easements/ Land	6		6	Minor Strategic land acquisition
Replacement	339	-12	327	Most of our capital program is focused on ongoing programs to refurbish and replace aging assets
Refurbishment	67		67	
Security / Compliance	176	-8	168	Investment requirements to maintain physical, cyber, and power system security and network safety.
Information Technology	70	-26	44	Investments to maintain capability and harness modern technology driven by our Information Technology Strategy and our need to meet customers future needs.
Inventory/ Spares	12		12	Ongoing requirements to maintain spares and facilities
Facilities	14		14	
Total	**742**	**-46**	**696**	

12 The capital expenditure categories are explained in Appendix A to this attachment to the Revenue Proposal

Figure 5-6 below shows the breakdown of our forecast capital expenditure by category (after the intangible asset accounting adjustment).

Figure 5-6: Breakdown of capital expenditure 2022-23 to 2027-28 ($m 2022–23)



As Figure 5-6 shows, replacement, refurbishment and security / compliance projects make up the majority (approximately 81%) of our total forecast capital expenditure. This expenditure will enable us to maintain a safe, secure and reliable network, in accordance with our customers' needs and our regulatory obligations.

Most of our capital program focuses on targeted asset replacements and refurbishment works. This allows us to extend asset life and defer major investment based on careful monitoring of asset condition and applying a risk based approach.

Our expenditure plans are guided by our Asset Management Objectives, which are:

- **Safety of people** – ensure the safety of staff, contractors and the public;
- **Protect the environment** – ensure the environmental impact of network operations are minimised;
- **Affordability and reliability** – reduce the overall cost of electricity to customers by removing network constraints, operating the network and delivering our capital and maintenance works as efficiently as possible, while maintaining safety and reliability;
- **Power system security and resilience** – ensure the network is resilient and operates within acceptable parameters in the face of electrical, physical, or cyber disruption, and continues to enable the transition to a low carbon emissions future.

These objectives were developed in consultation with our CAP and are consistent with the National Electricity Objective and the capital expenditure objectives set out in the National

Electricity Rules. Consistent with these objectives, our investment program for the forthcoming regulatory period focuses on:

- risk-based asset replacement and refurbishment projects developed in line with our asset management objectives,
- targeted network and cyber security projects; and
- ongoing investment in the technology, systems and facilities required to operate the network.

At the request of the South Australian Government and as part of its jurisdictional advisory role AEMO conducted a review of our proposed capital expenditure program. Its review report is provided in conjunction with our Revenue Proposal[13]. In its review, AEMO considered a selection of large replacement and future network projects and, in particular, considered:

- the need for each proposed project;
- economic justification of the individual projects; and
- whether South Australia's transmission network is expected to meet the requirements of South Australia's Electricity Transmission Code in the forthcoming regulatory period.

AEMO concluded that:

- there is an ongoing need for all eight of the refurbishment and replacement projects it considered;
- There is a need for four of the six future network projects considered. Of the remaining two:
  - The Northern REZ Strategic Land Acquisition was introduced during the course of the review process (as supported by customer input) and AEMO requires further information before finalising its position;
  - The Power Quality Monitoring Project was removed by ElectraNet from the proposed capital program, supported by customer feedback, and replaced with a measurement and monitoring project, with a final solution to be addressed through a contingent project; and
- The three contingent projects proposed in this Revenue Proposal may become justified during the regulatory period, making them reasonable contingent projects.

This represents Stage 1 of AEMO's independent assessment. Stage 2 will be provided during the AER's assessment of the Revenue Proposal.

The capital expenditure forecast includes expenditure in the first two years of the period to allow for the completion of Project EnergyConnect. Our updated project forecasts now indicate construction of this project will be completed several months later than originally expected, which will push the final stages of construction from the current regulatory period into the next.

[13] Refer ENET 035 - AEMO Independent Planning Review of ElectraNet Capex Proposal, December 2021.

Testing and commissioning are expected to be completed in the following year.[14]

The revised expenditure timing on the project has allowed for reprioritisation of the capital program within the current regulatory period, and avoided the need for deferral of a range of works previously forecast for the forthcoming regulatory period. This has largely offset any net impact on the capital expenditure forecast in the forthcoming period from the movement of Project EnergyConnect.

The major projects in our forecast, other than routine works in progress, are described in the following two Tables and in Appendix B. They represent 53 per cent of our capital forecast.

Table 5-3: Principal projects and programs for the 2023-24 to 2027-28 regulatory period

	Program	$m (2022–23)
1	Project EnergyConnect*	59
2	Transmission Network Voltage Control	54
3	Isolator Unit Asset Replacement	43
4	Transmission Line Insulation System Replacement	33
5	Hummocks to Ardrossan West line rebuild	32
6	Line Conductor and Earthwire Refurbishment*	27
7	Transmission Tower Anti-Climb Installation	22
8	Instrument Transformer Unit Asset Replacement	18
9	Substation Technology System Cybersecurity Uplift	16
10	Circuit Breakers Unit Asset Replacement	15
11	Wide Area Monitoring Scheme	14
12	AC Board Unit Asset Replacement*	13
13	Substation Perimeter Intrusion and Motion Detection Security	12
14	Telecommunications Asset Replacement	11

** denotes expenditure that has satisfied the Regulatory Investment Test for Transmission.*

14 At the time of its contingent project approval, expenditure on Project EnergyConnect was not forecast to continue into the forthcoming regulatory period. As such, the requirements in clauses 6A.6.7(h)-(k) of the Rules, which would otherwise require the unspent amount approved in the current period to be rolled forward, do not apply. Therefore, we have included the remaining expenditure requirement on the project in our forecast.

Table 5-4: Description of required works and drivers for principal projects and programs

	Project	Description	Constraint driver and investment type
1	Project EnergyConnect*	Completion of Project EnergyConnect, which involves the construction of a new 330 kV interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales. Transfer capacity will be up to about 800 MW. Project EnergyConnect will also increase the maximum amount that can be transferred across the Heywood interconnector to a transfer capacity of up to about 750 MW. In June 2021, the AER approved Contingent Project Applications from ElectraNet and TransGrid to provide funding for each business to undertake their portion of the works to create Project EnergyConnect.	Interconnector capacity Augmentation
2	Transmission Network Voltage Control	Install a total of four (4) 60 Mvar 275 kV reactors around the Adelaide metropolitan region at Happy Valley, Munno Para and Cherry Gardens, and a single (1) 50 Mvar 275 kV reactor at South East. This plant will assist in mitigating voltage disturbances caused by the increase in PV generation. The installations will include associated works for reactor connection and switching, monitoring and control, system protection, and site civil works. These and other reactive and voltage control devices on the main 275 kV transmission network will be upgraded to enable coordinated automatic switching of existing and planned reactive power devices. This will require the installation and modification of secondary plant items for monitoring, control and protection covering multiple substation sites including automating Onload Tap Changer operation at SA Power Networks connection points.	Reactive support Augmentation
3	Isolator Unit Asset Replacement	Replace 80 individual substation isolators at 12 substations across the South Australian electricity transmission system that have been assessed to be at end-of-life with a high risk of failure during the 2023-24 to 2027-28 regulatory period as part of an ongoing replacement program.	Asset condition and performance Asset renewal
4	Transmission Line Insulation System Replacement	Replace 2,775 insulator strings on 779 structures on 14 transmission lines across the network that have been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory period. This renewal of line asset components will extend transmission lines life avoiding requirement for full asset replacement. This will be completed as part of an ongoing line refurbishment program.	Asset condition and performance Asset renewal

	Project	Description	Constraint driver and investment type
5	Hummocks – Ardrossan West Line Rebuild	Replace line conductor, earthwire and insulator strings for the entire Hummocks to Ardrossan West 132 kV line, which has been assessed to be at end-of-life during the 2023-24 to 2027-28 regulatory period. This will renew line asset components, extending line operational life.	Asset condition and performance Asset renewal
6	Line Conductor and Earthwire Refurbishment*	Program of projects to replace transmission line conductors and earthwire to extend the life of seven (7) 132 kV transmission lines in the Mid North and Riverland and avoid full replacement, as part of an ongoing line refurbishment program.	Asset condition and performance Asset renewal
7	Transmission Tower Anti-Climb Installation	Install climbing deterrent devices and warning signage on approximately 2100 transmission towers located on 59 high voltage transmission lines that have been assessed as highly vulnerable to unauthorised access as part of a phased approach over multiple regulatory periods.	Safety Asset renewal
8	Instrument Transformer Unit Asset Replacement	Replace 26 capacitor voltage transformers and 75 current transformers at 13 substations across the South Australian electricity transmission system that have been assessed to be end-of-life during the 2023-24 to 2027-28 regulatory period. This will address the increased risk of asset failure as well as poor asset performance observed through a planned ongoing replacement program.	Asset condition and performance Asset renewal
9	Substation Technology System Cybersecurity Uplift	Replace and upgrade substation technology assets identified as being susceptible to cyber-attack breaches by replacing relevant equipment as well and uplifting cyber security of networks and intelligent devices. This work will be carried out progressively during the 2024-2028 regulatory period across the 57 high risk substations identified.	Security Asset renewal
10	Circuit Breakers Unit Asset Replacement	Replace 24 circuit breakers at 13 substations across the South Australian electricity transmission system that have been assessed to be at the end of their technical and economic lives during the 2023-24 to 2027-28 regulatory period as part of an ongoing replacement program.	Asset condition and performance Asset renewal
11	Wide Area Monitoring Scheme (WAMS)	Expand the existing WAMS by installing phasor measurement units (PMUs) as required by AEMO at identified sites across the SA transmission network. The scope of works includes installing hardware and software to integrate new PMUs to existing systems and deploy associated software application analytical tools that will be used to analyse the data collected.	Stability Operational
12	AC Board Unit Asset Replacement*	Replace six (6) individual substation AC switchboards identified as being at the highest risk of failure across the network progressively during the 2024-2028 regulatory period.	Asset condition and performance Asset renewal

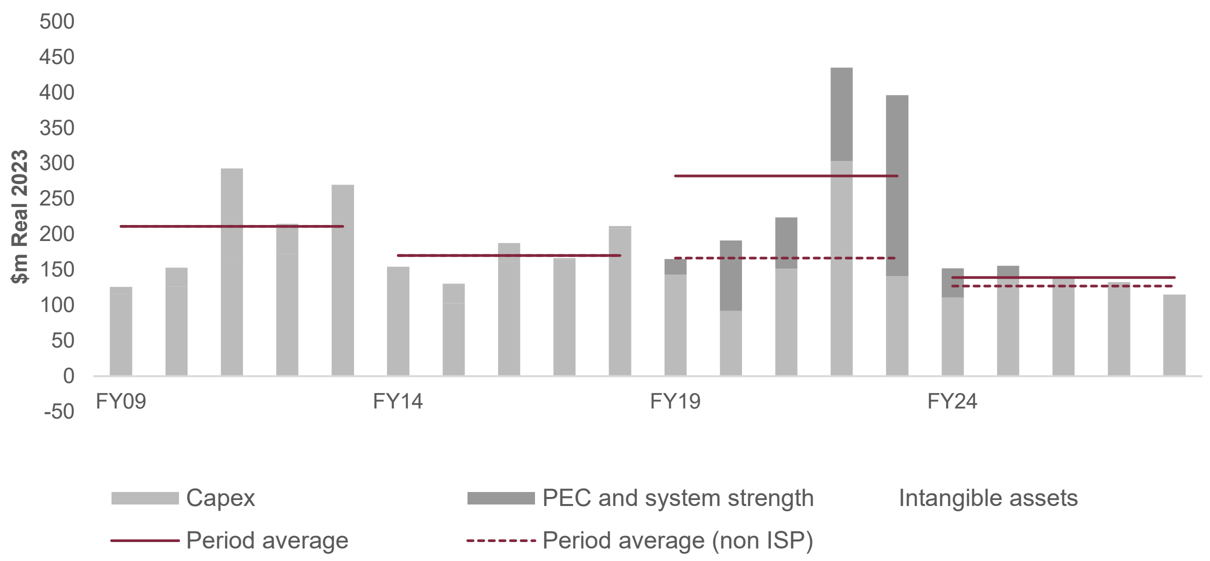
	Project	Description	Constraint driver and investment type
13	Substation Perimeter Intrusion and Motion Detection Security	Upgrade substation security across 35 critical regulated substations by installing perimeter intrusion detection and CCTV systems progressively during the 2024-2028 regulatory period. These external motion detection and CCTV systems will supplement the "deter and delay" primary control measures such as fences and signage with a proactive and responsive secondary system, responding to potential unauthorised presence inside the security fence.	Safety Asset renewal

** denotes expenditure that has satisfied the Regulatory Investment Test for Transmission.*

5.6 Comparison with historical capital expenditure

Figure 5-7[15] and Table 5-5 compare our forecast capital expenditure for the forthcoming regulatory period with our actual expenditure over the previous three regulatory periods. It shows that our underlying capital expenditure (excluding Project EnergyConnect and the Main Grid System Strength project) is forecast to be lower over the 2023-24 to 2027-28 regulatory period than it was in any of the previous three periods.

Figure 5-7: Actual and forecast capital expenditure ($m 2022–23)



Our underlying capital expenditure, excluding ISP projects, is forecast to be about 18% lower than the current period, before adjusting for the impact of the new accounting standards. Following this adjustment, the reduction is approximately 24%.

15 A full breakdown by project category is provided in the capital expenditure model which accompanies this Revenue Proposal.

The CAP Working Group was strongly supportive of the focus we have given to reviewing our capital expenditure forecast, which has resulted in reductions from the indicative level set out in the July 2021 Preliminary Revenue Proposal.

A comparison between our forecasts and historical expenditure is shown in Table 5-5 below, in this case only showing the forecasts *after* the intangible asset accounting change.

Table 5-5: Capital expenditure forecast by category ($m 2022-23)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Augmentation	33	13	45	14	23	11	6	11	123	256	40	19	0	0	0
Connections	20	23	3	4	1	3	0	0	0	0	0	0	0	0	0
Easements/Land	7	6	5	8	2	1	2	3	0	0	0	0	2	2	3
Replacement	72	62	79	82	80	40	38	119	235	107	58	64	64	75	66
Refurbishment	2	12	28	22	22	28	25	10	16	12	12	18	11	13	13
Security/Compliance	8	4	16	15	42	46	109	68	40	6	24	43	48	33	21
Inventory/Spares	1	2	2	6	5	1	1	1	3	7	2	2	2	2	2
Other	0	1	1	1	2	2	0	0	0	0	0	0	0	0	0
Facilities	1	1	1	2	7	5	-1	0	5	3	5	1	3	2	2
Business IT	12	7	8	14	28	22	15	15	18	10	11	8	10	5	8
Subtotal: Load driven capital	**60**	**42**	**53**	**26**	**25**	**15**	**8**	**14**	**124**	**256**	**40**	**19**	**2**	**2**	**3**
Subtotal: Non-load driven capital	**83**	**81**	**126**	**126**	**151**	**117**	**172**	**198**	**293**	**132**	**96**	**127**	**126**	**123**	**102**
Subtotal: Non-network capital	**14**	**8**	**9**	**15**	**35**	**27**	**14**	**16**	**22**	**13**	**16**	**10**	**13**	**8**	**10**
Total Capital expenditure	**156**	**131**	**189**	**168**	**211**	**159**	**194**	**227**	**439**	**401**	**152**	**156**	**140**	**133**	**115**
Annual allowance	**253**	**183**	**222**	**159**	**81**	**131**	**235**	**228**	**459**	**379**					
Period total					**855**					**1421**					**696**
Period allowance					**899**					**1433**					

Totals may not add due to rounding. Totals for FY14 to FY18 include NCIPAP.
Totals above for the forthcoming regulatory period exclude expenditure on intangible assets

Table 5-6 provides a breakdown of the reduction across the expenditure categories,[16] together with a brief explanation of the drivers for the change.

Table 5-6: Actual and forecast capital expenditure by category ($m 2022–23)

Category	Forecast Expenditure 2019–2023	Forecast Expenditure 2024–2028	Change	Drivers
Augmentation	407	59	-348	Minimal new load driven capital investment requirements in the declining demand environment.
Connection	3	0	-3	
Easement/land	6	6	0	
Replacement	538	327	-211	Most of our capital forecast relates to replacement, driven by the ongoing need to manage safety, security and reliability risks associated with ageing assets, with a reduced requirement following the completion of the major Eyre Peninsula line replacement in the current period.
Refurbishment	92	67	-25	Key expenditure drivers are ongoing works to extend the useful life of ageing transmission lines and manage network safety, security, reliability and fire start risk.
Security / Compliance	268	168	-100	Safety, power system security/ resilience and environmental protection, contributing to lowest long-term cost outcomes, with a reduced expenditure requirement following the installation of synchronous condensers in the current period.
Information Technology	79	43[17]	-36	Supports power system security/ resilience and reliability at lowest long-term cost. Also supports efficient business operation and therefore affordability.
Inventory/ spares	13	12	-1	Ongoing stock replenishment program.
Facilities	12	14	2	Ongoing minor asset replacement
Total*	**1,419**	**696**	**-723**	**Reduction of 51%**

** Totals may not add due to rounding*

[16] This is after the impact of the accounting treatment of intangible assets.

This reduction partly reflects a change in accounting standards that reclassifies capital expenditure as operating expenditure. Setting aside this change in accounting, our forecast IT capital expenditure is lower than the previous period. Further details are provided in Appendix C.

Figure 5-8: ElectraNet's historical capital expenditure and allowance 2014 – 2021

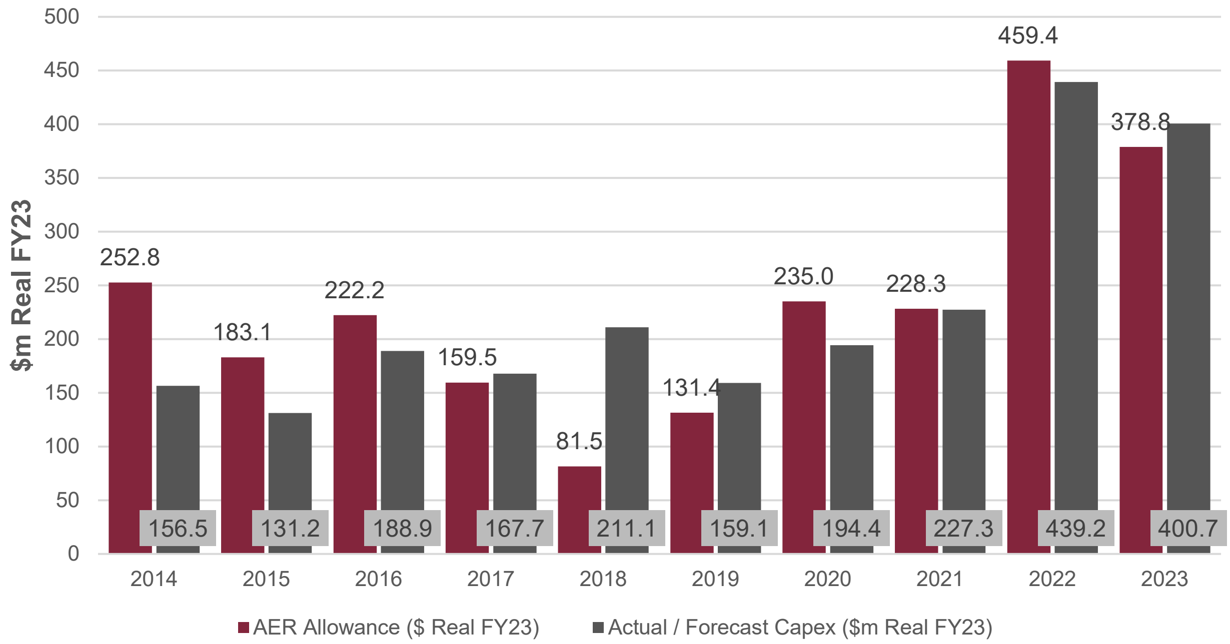


Figure 5-8 shows that, in the current regulatory period, our capital expenditure is expected to be closely aligned with the AER's allowance, with our aggregate expenditure expected to be approximately $10m below the AER's allowance. Similarly, our capital expenditure in the previous regulatory period was well below the AER's allowance. While we note that our capital expenditure in the period from 2017 to 2021 exceeded the sum of the annual allowances in those years by approximately 15%, this is not a systemic overspend, but purely a timing issue[18].

We maintain active governance in the planning and delivery of our capital program to ensure that our expenditure is prudent and efficient. Further, in response to the incentives provided by the Capital Expenditure Sharing Scheme we strive to deliver an efficient program of investment within the allowance for which we are funded.

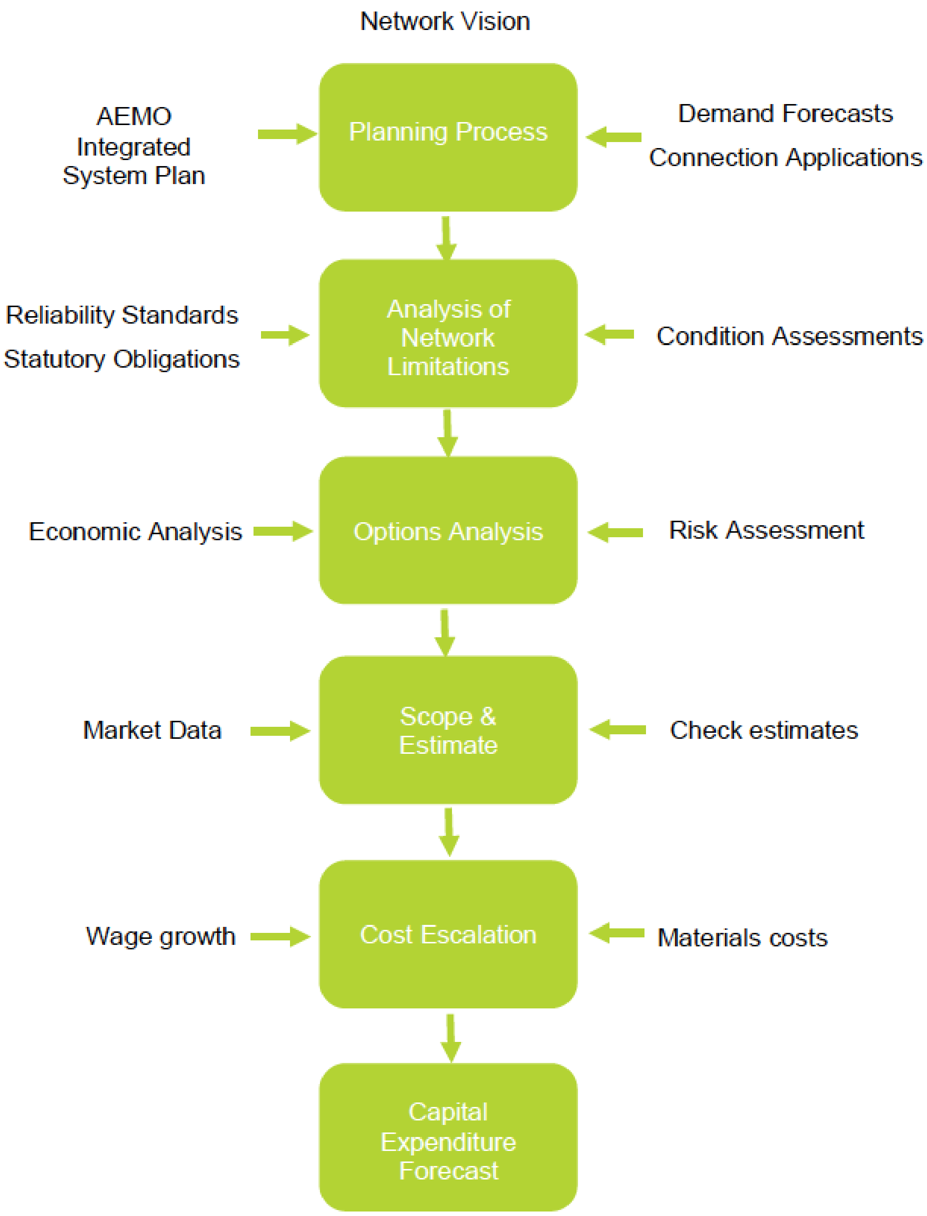
In the remainder of this attachment we explain how the forecasts have been developed and why we consider that they should be approved by the AER.

18 This corresponds with the reference period for ex post review of historic capital expenditure, which does not appear warranted in this instance.

5.7 Expenditure forecasting methodology, inputs and assumptions

Our capital expenditure forecasts have been developed though a rigorous application of our forecasting methodology, together with a careful consideration of key inputs and assumptions for the 2023-24 to 2027-28 regulatory period. Our forecasting methodology is consistent with the approach notified to the AER in June 2021 in accordance with the Rules requirements, as illustrated in Figure 5-9.

Figure 5-9: Capital expenditure forecasting methodology, inputs and assumptions



The overarching objective of our forecasting methodology is to produce prudent and efficient estimates of the capital expenditure we require to meet our customers' requirements and our compliance obligations.

As such, the starting point for our forecasting approach is to understand our customers' requirements through effective engagement, as explained in Section 5.4 and in our Customer Engagement Outcomes Report, which is provided as a supporting document to this Revenue Proposal.

Our capital expenditure forecasting process is integrated with our business as usual budgetary, planning and governance processes. In addition to the internal controls governing these processes, the key inputs and assumptions are subject to rigorous review and approval. These quality assurance steps provide confidence that our inputs and assumptions are soundly based and consistent with efficient expenditure.

In the remainder of this section, we explain each step of our methodology in turn, highlighting the key inputs and assumptions that have been adopted for the forthcoming regulatory period.

5.7.1 Planning process

We adopt a systematic process to develop plans and initiate projects to deliver a safe, reliable and sustainable transmission network to meet our customers' future needs in the most cost-effective manner.[19]

The planning process operates within a strategic framework informed by our Network Vision and industry planning documents prepared by AEMO, most notably its ISP and ESOO. The planning process relies on inputs such as generation developments and demand forecasts, which we discuss below. We confirm that our forecast capital expenditure presented in this Revenue Proposal is consistent with the inputs and assumptions of the draft ISP, which was published in December 2021.

Our network planning and investment analysis process ensures that we optimise our capital and operating expenditure. From a forecasting perspective, we do not expect our capital expenditure plans to have a material impact on our operating expenditure forecasts. The interaction between operating and capital expenditure forecasts is discussed further in Section 6.5 of Attachment 6.

5.7.2 Demand forecasts

Growth in customer peak demand has historically been the principal driver of transmission system augmentation and connection point reinforcement. However, in the forthcoming regulatory period, demand growth is not expected to drive network investment. Rather, falling minimum demand levels on the network are revealing network limitations that need to be addressed.

ElectraNet receives 10-year demand forecasts from SA Power Networks and direct connect customers annually. A description of the load forecasting process used by SA Power Networks is provided in SA Power Networks' 2020 Distribution Annual Planning Report. ElectraNet and SA Power Networks collaborate to determine and agree on any adjustments required to account for embedded generators and major customer loads connected directly to the distribution network.

In August 2021, AEMO produced and published demand forecasts for South Australia to support the 2021 Electricity Statement of Opportunities (ESOO). For the purpose of this Revenue Proposal, we have adopted AEMO's Central Scenario for 10% Probability of Exceedance (PoE) maximum demand and 90% PoE minimum demand forecasts.

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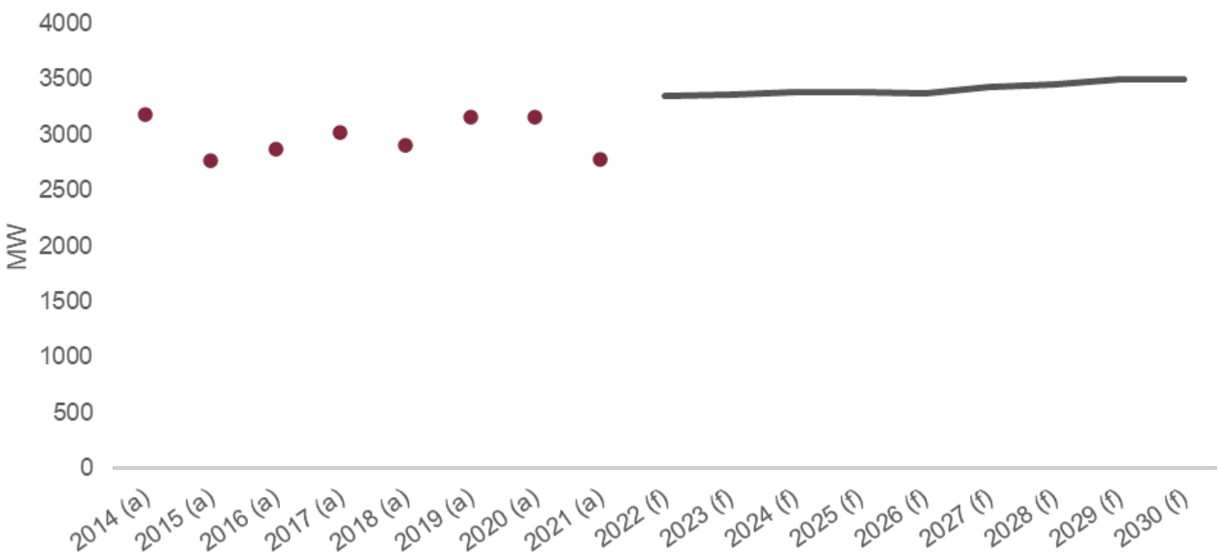
19 For reference, a map of South Australia's transmission network is included in our Revenue Proposal Overview.

In its 2021 ESOO, AEMO makes the following observations about these forecasts[20]:

- Over the short term (0-5 years), maximum operational demand is expected to be consistent with the 2020 ESOO as the influence of higher distributed PV uptake on maximum operational demand reduces and high demand periods are experienced in the early evening. Minimal changes in maximum operational demand are expected, as influencing drivers such as electrification and EV uptake do not act to materially increase maximum demand during this period.
- Over the medium to long term (5-30 years), maximum operational demand is expected to increase across all scenarios, largely driven by increased EV uptake and electrification.

Figure 5-10 below shows the South Australian maximum demand forecasts prepared by AEMO for the step change scenario.

Figure 5-10: Forecast summer 10% POE maximum operational demand (sent-out) by scenario, South Australia [21]



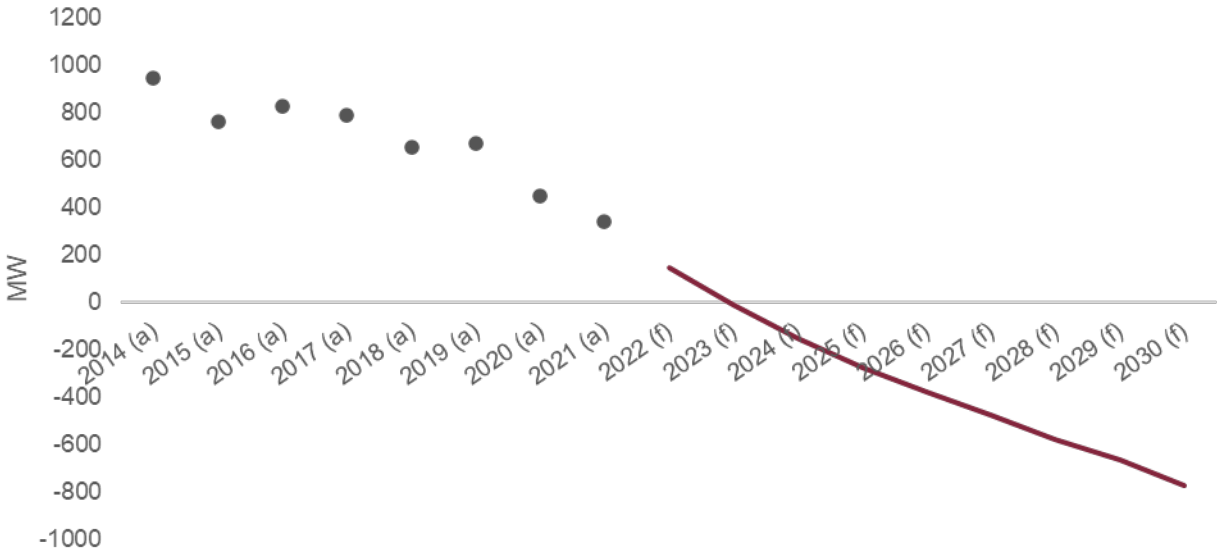
The forecasts show that AEMO expects maximum demand in South Australia to be relatively flat over the next 5 years. There is the potential for more significant increases in the medium to long term, but this potential growth does not affect our capital expenditure plans for the forthcoming regulatory period.

It is more relevant to this Revenue Proposal to note that the changing pattern of generation and demand on our network – including the declining minimum demands noted by AEMO – raises important issues regarding the resilience of the network. Figure 5-10 below shows the South Australian minimum demand forecasts prepared by AEMO for the step change scenario.

20 AEMO, 2021 Electricity Statement of Opportunities, August 2021, p. 87.

21 AEMO, 2021 Electricity Statement of Opportunities, August 2021, Figure 47, p.87.

Figure 5-11: Forecast annual 50% POE minimum operational demand (sent-out) by scenario, South Australia[22]



In the short term, AEMO forecasts minimum operational demand to continue to decline across all scenarios, primarily driven by the uptake of distributed PV. Negative 50% POE minimum operational demand events are expected as early as 2022-23, earlier than anticipated in the 2020 ESOO.[23]

5.7.3 Analysis of network limitations

In developing our forecast capital expenditure, we consider projected network limitations, the condition and performance of the existing assets and the associated supporting facilities and business systems required to efficiently operate the network over the forecast period. The application of this approach differs by expenditure category, as follows:

- Load and market benefit driven network investment requirements are identified through modelling of future power system capability and analysis of network constraints. In this case we identified no such investment in the forthcoming period aside from the need to acquire an easement to facilitate future expansion of transfer capacity between Robertstown and the Adelaide metropolitan area, and the completion of Project EnergyConnect.
- Non-load and non-market benefit driven network investment requirements are determined in accordance with our asset management framework, which takes a risk-based approach to the replacement or refurbishment of assets based on assessed risk, condition and performance.
- Non-network investment requirements are largely determined in accordance with the strategic priorities for information technology, which provides for the efficient development

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22 AEMO, 2021 Electricity Statement of Opportunities, August 2021, Figure 48, p.88. Negative demand periods are already being experienced in South Australia in periods shorter than the 30 minute demand intervals forecast here.

23 AEMO, 2021 Electricity Statement of Opportunities, August 2021, p. 88.

and operation of the business systems and supporting facilities required to efficiently manage the network and supporting business functions and respond to the changing needs of the power system.

The result is a set of potential projects that are likely to be required by one or more of the above drivers. These projects are further developed and assessed in the following steps.

5.7.4 Options analysis

Credible options are considered to address an identified need to ensure that our expenditure plans represent an efficient outcome for our customers. Economic analysis and risk assessment techniques are applied to investigate the potential options. The preferred solution must be technically and economically feasible, be deliverable in the timeframe required and minimise long-run total costs.

The options considered vary with each project, but will typically include:

- deferral of the project to future periods, noting that this prolongs and potentially increases the risk the project in question is intended to address;
- non-network alternatives; and
- alternative specifications, including specifying smaller capacities, if this is consistent with medium term demand forecasts.

An economic assessment is undertaken to determine whether the benefits of undertaking the project exceed the costs, including review of all available options. This also considers the optimal timing of the project, to ensure maximum net benefit from the proposed expenditure. Inputs considered in these assessments include:

- capital and operating costs of alternative options;
- reliability benefits;
- cost savings - for example avoided maintenance costs;
- risk reduction - as measured by the quantified value of the risk reduced or avoided through the project (for example avoided environmental contamination or safety impacts on both ElectraNet staff and contractors and the broader community);
- standard discount rate assumptions; and
- optimal timing – including the potential for deferral of an investment to a subsequent regulatory period.

We consider the scope for non-network alternatives when we address identified needs on the network. Overall, given the flat demand outlook, there are no load driven projects in our capital expenditure forecast, with a focus on individual component asset replacement, life extension works, and targeted network security measures. The nature of these requirements limits the scope for efficient non-network alternatives to provide a technically and economically viable solution.

Sensitivity testing is also conducted to determine the robustness and level of confidence in the outcomes of these economic assessments.

The overriding objective of options analysis is to identify a set of projects that minimises the total costs to our customers. This assessment requires us to consider the costs and benefits of different options, having regard to the implications for safety, security, reliability and resilience.

Our technology projects are forecast using broadly the same approach, informed by a five yearly Information Technology strategy, which is attached to this Revenue Proposal.[24]

5.7.5 Asset condition and risk assessments

ElectraNet continues to apply a risk-based approach to asset replacement decision making, driven by detailed asset condition assessment, risk, and reliability considerations, balanced against cost. This cost-risk analysis considers:

- probability of an asset failure;
- likelihood of adverse consequence(s); and
- likely cost(s) of the consequence(s).

This is based on a systematic process for collecting, recording and analysing detailed information on the condition of network assets, and balances the expected risk reduction against the costs of the proposed expenditure to ensure safety and reliability requirements are met at lowest cost.

This framework both aligns with and informed the AER's Industry Practice Note, Asset Replacement Planning, published in January 2019, and builds on the approach endorsed by the AER in our 2017 Revenue Proposal.

ElectraNet has relied upon detailed asset condition and risk information to develop specific plans for capital replacement and refurbishment projects for different asset categories and key risk areas, such as asset operational integrity, and safety and environmental issues.

The key input assumptions to our asset risk cost evaluation framework include, amongst other factors:

- adoption of a Value of Statistical Life (VSL) of $4.9m ($2020) based on the Australian Government's Best Practice Regulation Guidance Note, Value of Statistical Life (August 2019) together with appropriate disability weights and disproportionate factors; and
- adoption of a Value of Customer Reliability (VCR) published by the AER in its Value of Customer Reliability Report published in December 2019 and last indexed annually in December 2020 including a value for residential customer load of $30,520 ($2020) / MWh; and
- other key cost inputs with respect to potential bushfire property damage and environmental costs.

5.7.6 Scope and estimate

All network solutions are designed to comply with legislated safety, environmental and technical obligations. These solutions are based on scopes of work which identify the inputs required to

[24] Refer ENET054 – ElectraNet Technology Strategy 2020 to 2028

deliver each project. Project cost estimates are developed for each solution based on a detailed database of materials and transmission construction costs, and recent outturn cost information from delivered projects.

Increased focus has been applied on detailed project scope development for increased estimating accuracy for the purposes of the 2022 Revenue Proposal based on experience in the delivery of similar projects in the current and prior periods.

The estimates produced at this stage generally have the following characteristics:

- Class 4 estimates (which are accurate to a margin of +/- 30%);
- Free issue plant as per current contract rates for current unit asset replacement projects
- Major plant costs are based on the average of previous similar plant or rates provided by suppliers.
- Construction costs are from the internal estimating library based on historical contractor offers for similar works. Unit asset replacement construction costs are derived from current contracts.
- Delivery costs are based on historical resource data for similar project types, grouped by size and context.
- No risk allowance has been included.
- Real cost escalation is addressed separately including labour, materials and land.
- No allowance made for future currency fluctuations.

The projects included in the capital expenditure forecast are at different stages of development. Approved projects that are currently in progress are subject to a higher level of forecasting accuracy than those in the concept phase which have yet to commence.

We exclude from our capital expenditure forecast any significant network projects that are not considered sufficiently certain in terms of timing, scope or cost. Where the requirement for such a project is considered probable during the regulatory period, that project is included as a Contingent Project.

For non-network projects, cost estimates are generally developed based on independent expert advice and market cost information.

5.7.7 Cost escalation

Cost escalation involves adjusting estimates for expected changes in input costs, being wages, contractor rates and materials. Forecasts of cost escalation rates are derived from independent expert sources. Where efficient to do so, projects are also combined for delivery purposes to ensure that efficiencies are captured through combining related works and coordinating timing of implementation.

The primary cost components of the capital expenditure forecasts are:

- internal and external labour costs; and
- materials (i.e. plant and equipment) which generally include various commodity inputs such as copper, aluminium and steel.

In recent revenue determinations, the AER has included an allowance for real price changes in the operating expenditure forecasts, comprising:

- Labour price escalation calculated as the average of forecasts prepared by BIS Oxford Economics, on behalf of the relevant network business, and Deloitte Access Economics, on behalf of the AER; and
- Material cost escalation of zero, an assumption that material costs will change in in line with CPI.

BIS Oxford Economics' forecast obtained by ElectraNet is that the South Australian Electricity, Gas, Water and Waste Services (EGWWS or 'Utilities') sector — expressed in Wage Price Index (WPI) terms – will increase by slightly less than 1% per annum in real terms over the forthcoming regulatory period, as shown in Table 5-7. In its Draft Decision for AusNet Services, the AER commissioned Deloitte to prepare labour forecasts for the period 2023-2027. Deloitte's labour growth forecasts averaged 0.1% per annum over that period, i.e. very close to zero. While we do not consider these forecasts to be realistic, as a placeholder we have adopted zero as a proxy for the AER's labour forecast.

Therefore, while BIS OE's forecasts are the best available to us at this time, our Revenue Proposal assumes that labour costs will grow at approximately 0.5% per annum, as shown in Table 5-7. This is calculated as the average of:

1. the BIS estimates
2. the proxy value of zero we have assumed for the AER's forecasts.

Table 5-7: Real labour cost escalation forecast (%)

	2023-24	2024-25	2025-26	2026-27	2027-28	Average 2024-28
BIS OE forecast (inc. SGC)	0.90%	1.20%	1.30%	0.80%	0.60%	0.96%
Halved	0.45%	0.60%	0.65%	0.40%	0.30%	0.48%

In relation to real material price escalation, we have maintained the approach consistently applied by the AER in recent revenue determinations of zero real price increase[25].

In considering real price escalation for the forthcoming regulatory period, it is important to note that the inflation outlook is now substantially different from recent years, as are the conditions in the markets for specialist labour and materials.

The significant growth in transmission capital expenditure, driven by the transformational change in the electricity sector and the range of investments identified in the ISP, is already putting upward pressure on the cost of labour and materials. In these circumstances, we are concerned that the continued application of standard estimating approaches adopted in recent regulatory decisions may substantially underestimate the future increases in labour and material costs.

25 The same approach of zero real price escalation has also been applied to land costs.

Given the above observations, we urge the AER to carefully consider the cost estimates for labour and material costs in its Draft Decision.

Our proposed labour and materials escalators for the purposes of this Revenue Proposal are set out in Table 5-8 below. In applying these we have applied weightings of labour to materials at a ratio of 70.4% labour to 29.6% materials. [26]

Table 5-8: Real labour and material cost forecast (%)

	2023-24	2024-25	2025-26	2026-27	2027-28	Average 2024-28
Labour	0.45%	0.60%	0.65%	0.40%	0.30%	0.48%
Materials	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Weighted Average	0.32%	0.42%	0.46%	0.28%	0.21%	0.34%

5.7.8 Efficiency initiatives and benchmarking

In line with our continuous improvement approach, we have implemented several initiatives to improve the efficiency of our capital expenditure program. These outcomes are built into our historic costs and are reflected in our benchmark performance, as set out in the AER's 2021 annual benchmarking report[27], which provides assurance our capital expenditure is prudent and efficient. We discuss the AER's benchmarking in detail in relation to our operating expenditure forecasts (Attachment 6).

5.8 Proposed contingent capital expenditure projects

A contingent project must be reasonably required in order to achieve the capital expenditure objectives specified in the Rules. However, unlike other proposed capital expenditure projects, there is less certainty as to whether the contingent project will be required during the regulatory period. As such, the expenditure for contingent projects does not form part of the total forecast capital expenditure approved by the AER.

The Rules provide for contingent projects to be defined with reference to a project-specific 'trigger event'. The occurrence of the trigger event must be probable during the relevant regulatory period. If the trigger event for an approved contingent project occurs, the TNSP makes an application to the AER for a cost allowance to be included in an amended revenue determination.

Contingent projects are also required to exceed a threshold of the greater of $30m or 5% of the maximum allowed revenue for the first year of the regulatory period (which equates to approximately $17m). The applicable threshold is therefore $30m.

As part of its jurisdictional role, AEMO has reviewed and endorsed the contingent projects we are proposing for the forthcoming regulatory period.[28]

26 This is consistent with the AER's Annual TNSP Benchmarking Reports.

27 AER, Annual Benchmarking Report - Electricity Transmission Network Service Providers, November 2020 available at the AER's website: www.aer.gov.au

28 Refer ENET035

Our proposed contingent projects are summarised below. Appendix D provides further information on each proposed contingent project, together with an explanation of how each project satisfies the requirements of clause 6A.8.1 of the Rules.

Table 5-9: Proposed contingent projects

Project Name	Description	Indicative Cost ($m Nom)
Power Quality Management	This project allows for the installation of the relevant equipment to maintain power quality standards across the transmission network in relation to voltage harmonic requirements.	30-60
Eyre Peninsula Upgrade	The project allows for the upgrade of the northern section of the Eyre Peninsula line from 132 kV to 275 kV to serve higher loads, which is accommodated in the design and/or augmentation of power transfer capacity between Davenport and Cultana.	50-150
Interconnector Upgrade	This project allows for an increase in inter-regional transfer capacity through such measures as control schemes and/ or frequency response capability.	100-150

In addition to the three contingent projects noted above, others may be triggered automatically by AEMO's ISP or as a system strength project in accordance with clauses 5.16A.5 and 11.143.18 of the Rules. At this stage, we have identified two projects that might arise:

- South East SA REZ Expansion (ISP Project)[29]
  - The project would increase transfer capacity between Tailem Bend and Adelaide to allow for greater imports and exports of renewable energy.
- Main Grid System Strength Support
  - This project would allow for the delivery of additional system strength on the transmission network.

If these or other contingent projects emerged during the 2022-23 to 2027-28 regulatory period we would follow the regulatory processes mandated by the Rules and ensure that customers are consulted in accordance with those provisions.

5.9 Benefits and risks for customers

Our capital expenditure program will provide the following benefits for customers:

- Safety – Our capital expenditure plans aim to deliver services that are safe for the communities we serve and the environment.

29 As discussed further in Attachments 6 and 12, the contingent project costs of constructing a future REZ are separate from the cost of preparing REZ design reports we may be asked to prepare in future and the ongoing planning cost associated with this and other recent rule changes.

- Network security and reliability – Our capital program is aimed at delivering a secure and reliable network.
- Efficiency – We will continue to drive improvements in our capital cost performance, building on the significant achievements achieved to date.
- Affordability – We are proposing a significant reduction in our capital program, which will feed through to lower prices for our customers as will the benefits delivered by various projects.
- Choice – Our capital plans to manage the challenges of an increasingly complex power system support the differing choices being made by customers over the way energy will be produced and consumed in the future.
- Long term sustainability – We are continuing to plan and invest in the transmission network to accommodate the changing nature of generation and demand as we move to a low carbon economy, and to deliver the outcomes sought by customers into the future.

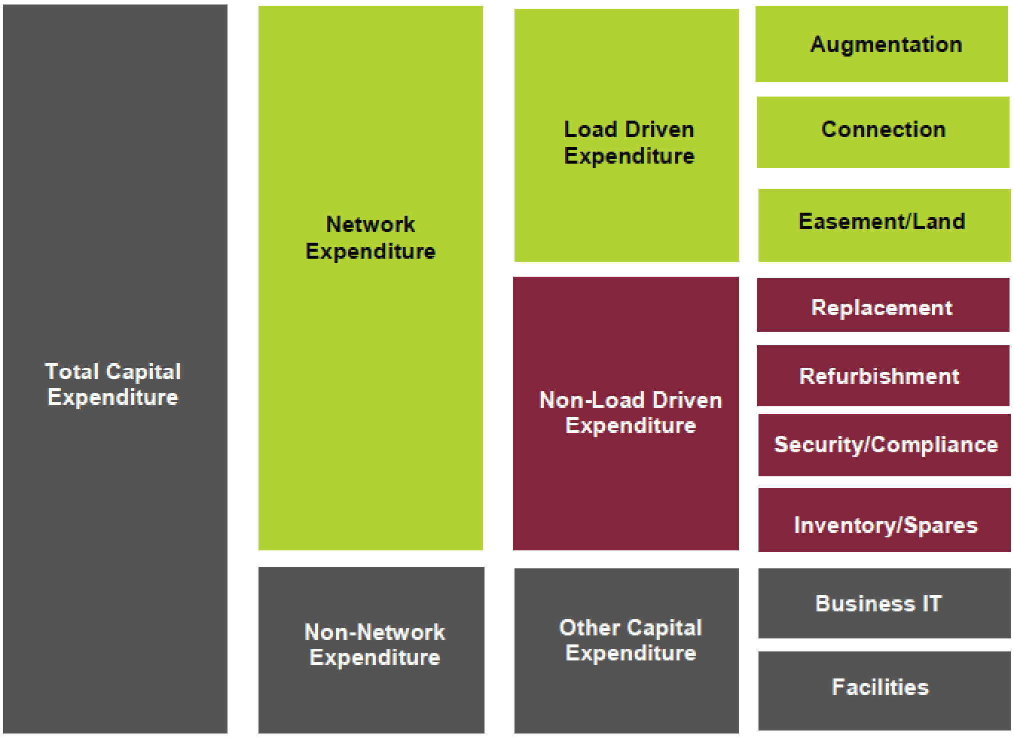
We are aiming to manage the following risks to customers in relation to our capital expenditure program:

- Additional investment requirements – we are managing the potential cost impact to customers of uncertain events that may trigger the need for additional capital expenditure through identified contingent projects. If and when further investment is required, our revenue requirement and transmission prices will be higher than set out in our proposal, but only if the benefits to customers can be shown to exceed the costs.
- New obligations – our capital expenditure plans reflect new obligations regarding system strength and inertia. It is possible that further obligations are introduced that drive increases in our capital program.
- While our plans are based on the best available information, there remains a possibility that new information may come to light that results in a need for additional unforeseen capital expenditure requirements.

Appendix A : Capital expenditure categories and services

As noted in Section 5.2, we have retained the same capital expenditure categories as the current regulatory period, as set out in the figure below.

Figure 5-12:Capital Expenditure categories



The table below describes each of the 9 expenditure categories presented in the right-hand column of the above figure. For each category, we also identify the associated transmission services, in accordance with clause S6A.1.1 of the Rules.

Table 5-10: Capital Expenditure Categories

Expenditure Category	Definition	Service Category
Network – Load Driven		
Augmentation	Works to enlarge the system or to increase its capacity to transmit electricity. These works include projects to which the RIT-T applies and involve the construction of new transmission lines or substations, reinforcement or extension of the existing shared network. The projects may be driven by reliability or market benefits requirements, and are inclusive of associated supporting communications infrastructure, land requirements and IT systems.	TUOS Services
Connection	Works to either establish new customer connections or to increase the capacity of existing customer connections based on specific customer requirements. Includes projects driven by the Electricity Transmission Code (ETC) reliability standards. Under the Rules, new connection works between regulated networks are treated as prescribed services. Other new connections are treated as negotiated or contestable transmission services.	Exit Services
Strategic Land/ Easements	Strategic land and easement acquisitions for projected augmentation, connection and replacement requirements. Typically, these are long term requirements guided by Government strategic plans or to address risks over the future availability of land.	Common Services
Network Non-Load Driven		
Replacement	Works to replace transmission lines, substation primary plant, secondary systems, communications equipment and other transmission system assets in order to maintain reliability of supply. Replacement projects are generally undertaken due to the increased risk of plant failure as assets age, assessed asset condition, obsolescence or safety issues.	Exit Services and TUOS Services
Refurbishment	Works to replace relevant components of transmission lines to mitigate the risk of failure to the whole asset. Refurbishment works are generally undertaken based on the assessed condition, performance and asset risk, and if deferral of whole asset replacement is more efficient.	TUOS Services
Security / Compliance	Projects that address compliance requirements associated with Government Acts and Regulations, and industry standards. Projects required to ensure the physical and system security of critical infrastructure assets.	Entry Services, Exit Services, TUOS Services and Common Services
Inventory / Spares	Spares holdings required to respond to asset failures in accordance with restoration times specified in the ETC and good electricity industry practice.	Common Services
Non Network		
Business IT	Projects to develop and maintain IT capacity and to improve the functionality of business systems to support business operation.	Common Services
Building / Facilities	Projects to replace and upgrade office accommodation and services to meet business needs.	Common Services

Appendix B : Principal Network Projects and Programs

Appendix C : Contingent Projects

C.1 Proposed Contingent Project Summary

Project Name	Trigger Events	Indicative cost ($m, Nom)
Eyre Peninsula Upgrade	1. Customer commitment for additional load to connect to the transmission network causing the Cultana 275/132 kV transformers to exceed their thermal limit of 200 MW and/or causing a need for augmentation of power transfer capacity between Davenport and Cultana. 2. Successful completion of a RIT-T including an assessment of credible options showing the upgrade of the 132 kV Eyre Peninsula Link to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana is the preferred option a) demonstrating positive net market benefits; and/or b) addressing a reliability corrective action 3. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	50-150
Network Power Quality Remediation	1. Successful completion of a RIT-T including an assessment of credible options showing a transmission investment is justified to address voltage quality requirements on the South Australian transmission network. 2. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	30-60
Project EnergyConnect Upgrade	1. Successful completion of a cost benefit assessment such as a RIT-T with an identified need to increase the capacity of either the combined interconnector limits across Project EnergyConnect and Heywood or an increase in the capability of Project EnergyConnect 2. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.	100-150

C.2 Eyre Peninsula Upgrade

C.2.1 Background

The customer load in the Eyre Peninsula region is primarily related to small scale mining, residential and commercial activities, with seasonal primary industry activity (grain handling). State Government mineral resources forecasts have indicated the prospect of increasing large scale mining activities, such as iron ore extraction. The South Australian Government also highlights the potential for a large hydrogen industry to emerge on the Eyre Peninsula in the coming decades.

The Eyre Peninsula is supplied by a radial 132 kV line that extends from Cultana to Yadnarie, and from Yadnarie to Port Lincoln. A radial line also extends west to Wudinna to supply the West Coast. Mount Millar wind farm is connected at Yadnarie, and Cathedral Rocks wind farm is connected at Port Lincoln.

The underlying distribution network consists of a mixture of 66 kV and 33 kV sub-transmission lines that take power from the Whyalla, Stony Point, Yadnarie, Wudinna and Port Lincoln 132 kV substations.

ElectraNet completed a RIT-T in 2018 to replace the radial connection between Cultana and Port Lincoln with a double circuit 132 kV line rated at 300 MVA. The northern section of the line between Cultana and Yadnarie will be built for 275 kV capability, with a potential rating of 600 MVA.

The upgrade will be energised in 2022.

The RIT-T concluded that there was sufficient likelihood that additional mining loads on the Eyre Peninsula would go ahead to warrant the optionality of 275 kV operation. Feedback received on the Preliminary Revenue Proposal confirms that proposed mining developments continue to progress on the Eyre Peninsula, with the possibility of major loads connecting to the network in the coming regulatory period.

Since the completion of the RIT-T, additional interest has been registered by private investors and the South Australian Government to develop multiple locations on the Eyre Peninsula as hydrogen export hubs. These hubs could potentially be of giga-watt scale.

C.2.2 Trigger Events

The trigger events for this Contingent project will be based on:

1. Customer commitment for additional load to connect to the transmission network causing the Cultana 275/132 kV transformers to exceed their thermal limit of 200 MW and/or causing a need for augmentation of power transfer capacity between Davenport and Cultana.
2. Successful completion of a RIT-T including an assessment of credible options showing the upgrade of the 132 kV Eyre Peninsula Link to 275 kV and/or augmentation of power transfer capacity between Davenport and Cultana is the preferred option
    a. demonstrating positive net market benefits; and/or
    b. addressing a reliability corrective action
3. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

These trigger events are specific and capable of objective verification, relate to a specific location, are sufficient for the revenue determination to be amended, and are probable but are not sufficiently certain to include in the capital expenditure forecast.

C.2.3 Project Requirement

This project would be required if loads on the Eyre Peninsula increase and exceed the thermal capability of the Cultana 275/132 kV 200 MVA transformers.

C.2.4 Contingent Capital Expenditure

The project is estimated to cost between $50m and $150m.

The actual cost of a fully scoped solution would depend on the size of the solution and connection location, subject to the outcomes of the RIT-T.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

C.2.5 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
    a. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
    b. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
    c. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

C.3 Network Power Quality Remediation

C.3.1 Background

The changing nature of the power system (i.e. load and generation mix, system performance characteristics and attributes such as reduced fault levels and high speed switching power electronics) has impacted overall power quality performance.

ElectraNet has obligations as described in the NER Schedule 5.1 and Australian Standards to manage power quality (namely voltage fluctuations, voltage harmonic distortion and voltage unbalance) within compliance limits. The relevant sections are:

1. S5.1.4: Magnitude of power frequency voltage
2. S5.1.5: Voltage fluctuations
3. S5.1.6: Voltage harmonic or voltage notching distortion
4. S5.1.7: Voltage unbalance
5. AS/NZS 61000 (implicitly referenced in the NER); and

6. Other general rules relating to transmission system design and operation set out in Chapters 4, 5 and 6A.

Ongoing monitoring and supporting studies indicate that mitigation actions should be considered at key locations to bring power quality performance to within compliance limits. This is required to ensure appropriate levels of power quality performance in relation to voltage for all network connected customers (load and generation).

This project was initially included in our indicative ex ante capital expenditure forecast in the Preliminary Revenue Proposal. In our engagement with customers, we were encouraged to explore all options on the way forward on this project. In response, we have included a greatly reduced project in our capital expenditure program to install measurement devices to better identify the power quality issues to be addressed and to undertake further analysis develop a more targeted and staged solution.

This contingent project is proposed to respond to the potential solutions identified through the power quality monitoring and studies to be undertaken.

C.3.2 Project Description

This project allows for the installation of relevant equipment to maintain power quality standards across the transmission network in relation to voltage harmonic requirements.

Indicative scope is to install three harmonic filters at Mt Gunson in the far north, Monash in the Riverland and in the South East along the Heywood interconnector, with associated reactors to offset the reactive power of the filters and a 20 Mvar STATCOM.

ElectraNet considers that the project should be accepted as a contingent project because of the current uncertainty over the required size and cost of the project until investigations are complete.

C.3.3 Trigger Events

1. Successful completion of a RIT-T including an assessment of credible options showing a transmission investment is justified to address voltage quality requirements on the South Australian transmission network.

2. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

These trigger events are specific and capable of objective verification, relate to a specific location(s), are sufficient for the revenue determination to be amended, and are probable but not sufficiently certain to include in the capital expenditure forecast.

C.3.4 Project Requirement

ElectraNet will be undertaking further investigation, measurement and analysis of observed harmonic distortions to confirm the magnitude and source of any non-compliances with prevailing technical standards is likely to lead to a need for mitigating works to be undertaken.

Both the timing and scope of this project and therefore the potential expenditure requirements are uncertain at this point in time.

If the trigger events occur the proposed contingent project would be reasonably required to meet the Rules capital expenditure objectives to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services in relation to power quality requirements.

C.3.5 Contingent Capital Expenditure

The proposed contingent project cost is estimated at $30 to $60m.

This estimate is based on the indicative project description.

The actual cost of a fully scoped solution would depend on the size of the solution and connection locations, subject to the outcomes of the RIT-T.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger events occur during the regulatory period.

The proposed contingent capital expenditure exceeds the applicable threshold of $30m.

C.3.6 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
    a. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
    b. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
    c. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

C.4 Interconnector upgrade

C.4.1 Background

Project EnergyConnect is the preferred option from the completed South Australian Energy Transformation RIT-T. Conducted by ElectraNet and commencing in 2016, this RIT-T identified the need to strengthen South Australia's interconnection to the eastern states to enable greater competition between interstate and South Australian connected generators, to improve reliability and resilience of the South Australian system and to connect more variable renewable generation in South Australia and interstate.

Project EnergyConnect connecting Robertstown in South Australia's mid-north to Wagga Wagga in New South Wales was found to demonstrate benefits greater than the costs of the project as well as being the option that delivered the maximum benefits to customers when compared to a range of alternative interconnector options.

Project EnergyConnect will be commissioned in 2025.

Project EnergyConnect will incorporate a Special Protection Scheme to maximise power transfers across Project EnergyConnect and the Heywood interconnector whilst increasing the resilience of the South Australian network to non-credible events across either corridor.

There exists the potential to further enhance the capabilities of the SPS, increasing interstate transfers across Project EnergyConnect and Heywood interconnectors via the integration of additional battery energy storage projects to deliver additional net benefits to customers.

C.4.2 Trigger Events

The following trigger events are proposed for this contingent project:

1. Successful completion of a RIT-T with an identified need to increase the capacity of either the combined interconnector limits across Project EnergyConnect and Heywood
    a. demonstrating positive net market benefits; and/or
    b. addressing a reliability corrective action
2. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the Rules.

These trigger events are specific and capable of objective verification, relate to a specific location, are sufficient for the revenue determination to be amended, and are probable but not sufficiently certain to include the proposed contingent project in the capital expenditure forecast.

C.4.3 Project Requirement

This project would be a 'market benefits' project, that is, it would need to demonstrate that the economic benefits to customers would outweigh the costs of the project to customers.

This project is not currently being considered as part of the draft 2022 ISP.

C.4.4 Contingent Capital Expenditure

The proposed contingent project cost is estimated at $100m to $150m. Based on a battery sized to increase the capability of the interconnector by around 100 to 150 MW.

The actual cost of a fully scoped solution would depend on the size of the solution and connection location, subject to the outcomes of the RIT-T and would include network and non-network option analysis and costings.

A detailed project scope and cost estimate will be required before any amendment to the revenue determination is considered by the AER should the specified trigger event occur during the regulatory period.

C.4.5 Demonstration of Rules Compliance

ElectraNet considers that this project should be accepted as a contingent project for the forthcoming regulatory control period as it complies with the provisions set down in clause 6A.8.1(b) of the Rules as:

1. the proposed contingent project is reasonably required to be undertaken in order to achieve the capital expenditure objectives;
2. the proposed contingent capital expenditure:
    a. is not otherwise provided for (either in part or in whole) in the forecast capital expenditure for the relevant regulatory control period;
    b. reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors; and
    c. exceeds the applicable threshold.
3. the proposed contingent project and the proposed contingent capital expenditure, and the related information provided meets the requirements of the Revenue Reset Regulatory Information Notice; and
4. the trigger events in relation to the proposed contingent project are appropriate.

ElectraNet