FINAL DECISION ElectraNet Contingent Project

Main Grid System Strength

August 2019

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Contents

Shortened forms

Shortened form	Extended form
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
the application	the contingent project application ElectraNet submitted to the AER on 28 June 2019 for the MGSS project
ATO	Australian Tax Office
capex	capital expenditure
CESS	capital expenditure sharing scheme
EBSS	efficiency benefit sharing scheme
GHD	GHD Advisory
MAR	maximum allowed revenue
MGSS	Main Grid System Strength
NEL	National Electricity Law
NEM	national electricity market
NEO	national electricity objective
NER	national electricity rules
NSCAS	Network Support and Control Ancillary Services
NTNDP	National Transmission Network Development Plan
opex	operating expenditure
PTRM	post-tax revenue model
RAB	regulatory asset base
RIT–T	regulatory investment test for transmission
SACOSS	South Australian Council of Social Service
TNSP	transmission network service provider
WACC	weighted average cost of capital

Executive Summary

On 28 June 2019, ElectraNet submitted a contingent project application to the Australian Energy Regulator (AER) for the Main Grid System Strength (MGSS) contingent project (the application). The application sought an adjustment to ElectraNet's revenue allowance of $34.8 million[1] over the 2018–23 regulatory control period for the installation of four high-inertia synchronous condensers in South Australia.

The MGSS was identified as a contingent project in our 30 April 2018 final decision on ElectraNet's transmission determination for the 2018–23 regulatory control period. In that determination we noted that if, during the regulatory control period, ElectraNet considered that the trigger events for an approved contingent project had occurred, then it may apply to us to amend its revenue determination.

The synchronous condensers will address a system strength gap (Network Support and Control Ancillary Services (NSCAS) gap) in South Australia that the Australian Energy Market Operator (AEMO) identified in December 2016 and confirmed in September 2017 in its updated 2016 National Transmission Network Development Plan (NTNDP).[2] By addressing the system strength gap, the MGSS project will materially reduce the need for market directions, thereby reducing costs to electricity consumers and distortions in the National Electricity Market (NEM).[3]

ElectraNet's application sought to recover projected capital expenditure (capex) of $185.2 million[4] for the MGSS project. The incremental contingent project capex sought for the delivery of the MGSS project (net of avoided or replaced projects) was $169.4 million. The proposed capex relates to the procurement and installation of four high-inertia synchronous condensers and associated equipment. It also includes associated substation works, project delivery costs and project risk costs.[5]

ElectraNet also sought to recover expected incremental operating expenditure (opex) of $2.9 million between 2018–19 and 2022–23.[6]

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1 $nominal, unsmoothed revenue.

2 AEMO, *NTNDP*, December 2016, pp. 98–99; AEMO, *Update to the 2016 NTNDP*, September 2017. Also see AEMO, *Second update to the 2016 NTNDP*, October 2017.

3 ElectraNet adopted the conservative assumption that the MGSS project would reduce annualised market direction costs to provide system strength in SA from $34 million to $12 million in ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, p. 25.

4 ElectraNet, *Main grid system strength project: Contingent project application*, p. 21, 28 June 2019, p. 19. All dollar amounts in this document are in real, mid-year $2017–18 unless otherwise stated. All references to $2017–18 in this document refer to mid-year figures (that is, 30 December 2018) unless stated otherwise.

5 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 18. ElectraNet estimated that there would be $0 in equity raising costs associated with the MGSS project.

6 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 22.

Our determination is that ElectraNet can recover $31.7 million[7] in additional revenue through charges during the remainder of the 2018–23 regulatory control period to reflect the efficient cost of the MGSS project.

In determining the efficient cost, we reduced ElectraNet's proposed forecast capex by $3.4 million to exclude a portion of the project risk allowances which we do not consider to be prudent and efficient costs required to undertake the MGSS project. We accept that there are project risks associated with delivery of the MGSS project for which allowance should reasonably be made in the allowed expenditure forecasts. However there are other project risks that ElectraNet should mitigate itself – either through its own operations, terms and conditions of contracts, or insurance. Therefore, we have not provided risk cost allowances for risks that we consider should be under ElectraNet's control or normally managed under ElectraNet's business as usual activities, or risks that should reasonably be covered by contract terms or insurance.

Otherwise, we found that ElectraNet's forecast capex generally reflected expenditure that would be incurred in respect of a contingent project by an efficient and prudent operator in the circumstances of that TNSP.[8] We formed this view on the following basis:

- ElectraNet's proposed scope of works reflected prudent and necessary works that we would anticipate as being required to deliver the four 129 MW synchronous condensers at the two sites.
- ElectraNet's proposed cost items generally accorded with the costs we would anticipate for those items, and we consider that they reflect reasonable and realistic estimates of the likely cost of the proposed work.
- The majority of the capital cost estimates for the MGSS project were based on tender prices derived from competitive market tendering.[9] Having reviewed ElectraNet's procurement and contracting approach, we consider that the unit rates used in the capital cost estimates are likely to represent reasonable values that represent realistic expectations of the likely costs to be incurred.[10]

The smoothed expected maximum allowed revenue (MAR) over the 2018–23 regulatory control period will increase by $32.0 million to $1634.1 million ($nominal).[11] This will increase transmission charges by about 1.6 per cent in 2020–21, 3.1 per cent in 2021–22, and 4.7 per cent in 2022–23.[12] Transmission charges

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7 $nominal, unsmoothed.

8 NER cl. 6A.8.2(g)(4)

9 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 18.

10 ElectraNet, *Attachment 3 – Response to RFI, Tender evaluation report*, Received 19 July 2019 (CONFIDENTIAL).

11 The total smoothed MAR as determined in the 2018–23 revenue determination is $1602.1 million ($nominal) after updating for the 2019–20 return on debt.

12 We have included 45 per cent of Murraylink's MAR to provide an estimate of the combined effect of ElectraNet's contingent project decision and Murraylink's 2018–23 revenue determination on the forecast

represent about 8 per cent of a typical annual electricity bill in South Australia. We estimate that, excluding the impact of avoided market direction costs, this additional revenue will increase the average annual electricity bill by about:

- $2 (or 0.1 per cent) in 2020–21, $5 (or 0.3 per cent) in 2021–22 and $8 (or 0.4 per cent) in 2022–23 ($nominal) for a residential customer.[13]
- $12 (or 0.1 per cent) in 2020–21, $23 (or 0.3 per cent) in 2021–22 and $36 (or 0.4 per cent) in 2022–23 ($nominal) for a small business customer.[14]

In making our determinations we consider the National Electricity Objective (NEO), which is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to price, quality, safety, reliability, and security of supply of electricity; and the reliability, safety and security of the national electricity system.

We consider this decision will promote the NEO because the MGSS project:

- Will provide minimum levels of system strength in South Australia, in accordance with levels determined independently by AEMO. Minimum levels of system strength are important for the security of electricity supply as they are required to keep remaining generators stable and connected to the power system following a major disturbance. The Australian Energy Market Commission (AEMC) recognised this when making its rule to require transmission network service providers (TNSPs) to maintain minimum levels of system strength.[15]
- Has been demonstrated as economically efficient through an economic assessment that is equivalent to a cost–benefit analysis under the regulatory investment test for transmission (RIT–T), but proportionate to the nature of the identified need. In its economic assessment, ElectraNet explored the range of options to provide minimum levels of system strength in South Australia and found that four high inertia synchronous condensers would have the highest net economic benefit across the NEM.[16]
- Will, by providing for a high inertia solution, also provide 4,400 MWs of synchronous inertia and therefore an efficient means of meeting synchronous inertia requirements in South Australia that AEMO declared on 21 December 2018.[17]

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average transmission charges in South Australia. See attachment A for further information on the estimated transmission price and customer bill impact.

13 Based on an average annual electricity bill of $1941 for residential customers using the AER's 2019–20 Default Market Offer for SA.

14 Based on an average annual electricity bill of $9120 for small business customers using the AER's 2019–20 Default Market Offer for SA.

15 AEMC, *Rule determination: National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September 2017.

16 AER, *Letter to ElectraNet – Re: System strength gap in South Australia*, 18 February 2019; ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019.

17 AEMO, *NTNDP*, 21 December 2018, p. 20.

The allowance we have provided for in this decision will enable ElectraNet to meet these objectives while also ensuring the costs incurred are prudent and efficient.

Contingent project trigger event

Our revenue determination for ElectraNet's 2018–23 regulatory control period included four cumulative triggers for the MGSS project:[18]

1. Confirmation by AEMO of the existence of a NSCAS gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region.
2. Successful completion of the RIT–T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified.
3. Determination by the AER that the proposed investment satisfies the RIT–T (or equivalent economic evaluation).
4. ElectraNet Board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the National Electricity Rules (NER).

As set out in section 3.1, we consider that these requirements have been satisfied.

Assessment approach

We detail our assessment approach in section 2. In summary, in reaching our decision we relied on the following information:[19]

- ElectraNet's application;
- submissions received from Business SA, EnergyAustralia and the South Australian Council of Social Service (SACOSS) during public consultation;
- ElectraNet's responses to our questions and related comments; and
- our own analysis and technical expertise.

AER determination

In accordance with clause 6A.8.2 of the NER, our determination in respect of the MGSS contingent project is that:

- The project as described is consistent with the contingent project approved in ElectraNet's 2018–23 revenue determination.

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[18] AER, *Final decision: ElectraNet transmission determination 2018 to 2023: Attachment 6 – Capital expenditure*, April 2018, p. 6-20.

[19] This information is available on our website under: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-main-grid-system-strength-contingent-project/initiation.

- The trigger events specified for this project have occurred.
- The capex amount sought exceeds the threshold specified in rule 6A.8.1(b)(2)(iii).
- The opex reasonably required for the purpose of undertaking the MGSS project in each year of the regulatory period is $2.9 million in total.
- The capex reasonably required to complete the MGSS project is $166.0 million.
- A standard asset life of 40 years is assigned for the synchronous condenser assets in respect of the MGSS project.
- The smoothed annual expected MAR should be adjusted to $1634.1 million ($nominal) in total for the 2018–23 regulatory control period based on an unsmoothed annual revenue requirement of $1637.1 million ($nominal) for this period. The annual transmission charges are forecast to increase from around $27.0 per MWh in 2019–20 to $29.6 per MWh in 2022–23.
- The amended X-factor is –1.60 per cent per annum for 2020–21, 2021–22 and 2022–23.
- The project commenced 1 July 2018 and the likely completion date is 28 February 2021.[20]
- ElectraNet's 2018–23 revenue determination is amended accordingly.

Structure of this document

This document sets out our determination on the timing and amount of capex and incremental opex reasonably required within the current regulatory control period to undertake the MGSS contingent project.

The decision is structured in sections that set out the following:

1. background information, the application, and our consultation process;
2. our assessment approach;
3. our assessment of ElectraNet's application;
4. our calculation of the annual revenue requirement; and
5. our determination.

[20] ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 16.

1 Introduction

This section provides relevant background information to our determination. Our determination covers whether the contingent project trigger has been met and how ElectraNet's revenue allowance should be amended to allow ElectraNet to address a declared gap for system strength in South Australia.[21] It also takes into account information provided in the three public submissions received on the application.

1.1 What is a contingent project

On 30 April 2018, we released our final decision on ElectraNet's revenue determination for the 2018–23 regulatory control period. The determination identified the MGSS project as a contingent project.

We noted that if, during the regulatory control period, ElectraNet considers that the trigger events for an approved contingent project have occurred, then it may apply to us to amend its revenue determination.

Contingent projects are significant network augmentation projects that may arise during the regulatory control period but the need and or timing is uncertain. While the expenditures for such projects do not form part of our assessment of the total forecast capex that we approve in a revenue determination, the cost of the projects may ultimately be recovered from customers in the future if:

- pre-defined conditions (trigger events) are met, where these project specific conditions are specified in our revenue determination for the network business;
- the network business submits an application for a contingent project, and we are satisfied that the pre-defined triggers have been met; and
- we are satisfied that the proposed project is consistent with the contingent project specified in our revenue determination.

If these conditions are met, we are also required to assess whether the forecast capex is reasonably likely to reflect prudent and efficient costs. If we are not satisfied that this is the case, we are required to determine a substitute forecast.

1.2 Our role in the process

The AER is the economic regulator for electricity transmission and distribution services in the NEM, including in South Australia.[22] Our electricity-related powers and functions are set out in the National Electricity Law (NEL) and NER.

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[21] AEMO, *NTNDP*, December 2016, pp. 98–99; AEMO, *Update to the 2016 NTNDP*, September 2017. Also see AEMO, *Second update to the 2016 NTNDP*, October 2017.

[22] In addition to regulating NEM transmission and distribution, we also monitor the wholesale electricity and gas markets to ensure suppliers comply with the legislation and rules, taking enforcement action where necessary,

When we receive a contingent project application, we publish the application and seek public comment. We assess the application to determine whether it contains the information required by the NER.[23] We examine evidence provided to determine if the mandatory predefined trigger event/s has/have occurred. We also examine whether the project outlined in the application is consistent with the contingent project approved in the revenue determination.

We analyse the application to determine if the costs proposed represent a reasonable forecast of the capex and incremental opex required to undertake the contingent project, both overall and in each year remaining in the regulatory control period. If we are not satisfied that this is the case, we must determine a substitute forecast. Where we have departed from the network business' application, we apply our adjustments to the post-tax revenue model (PTRM) to calculate the revenue the network business may charge customers for the remainder of the regulatory control period.

1.3 Who is ElectraNet

ElectraNet is responsible for providing electricity transmission services in South Australia. We regulate the revenues that ElectraNet and other TNSPs can recover from their customers through determinations that cover the span of a regulatory control period. ElectraNet's current revenue determination is for the 2018–23 regulatory control period.

1.4 Requirements to maintain system strength

On 19 September 2017, the AEMC made a rule placing an obligation on TNSPs to maintain minimum levels of system strength.[24] The AEMC made the rule on the basis that TNSPs are the parties best placed to manage the risks associated with fulfilling that responsibility. The NER now require TNSPs to maintain system strength at levels determined by AEMO, under a range of operating conditions specified by AEMO.

The rule was introduced because system strength in some parts of the power system had been decreasing as conventional synchronous generators were operating less or being decommissioned. If system strength is too low, it becomes difficult to keep remaining generators stable and connected to the power system following a major disturbance. The relative stability of the power system can also reduce when additional non-synchronous generators connect to the network. Given this, in addition to the obligations on TNSPs, the NER now also require new

and regulated retail energy markets in Queensland, NSW, the ACT, SA and Tasmania (electricity only) under the National Energy Retail Law.

23 NER cl. 6A.8.2(b).

24 AEMC, *Rule determination: National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September 2017.

connecting generators to 'do no harm' to the level of system strength necessary to maintain the security of the power system.

When AEMO declares a system strength gap, the relevant TNSP must specify the details of the system strength services it is making available to AEMO. The TNSP must seek AEMO approval for the technical specifications and performance standards for those services and for the information necessary for AEMO to enable or cease the provision of those services. AEMO must approve this information or advise the TNSP of the reasons for withholding its approval, and the changes it requires to be made.[25]

1.4.1 Declaration of a system strength gap in South Australia

In December 2016, AEMO published its 2016 NTNDP, which determined that at least two large synchronous generating units must be online in South Australia to ensure that a sufficient fault level is available to maintain a secure operating state.[26] In September 2017, AEMO updated its 2016 NTNDP. Considering the available equipment presently installed in South Australia, and following a series of in-depth power system simulation studies, AEMO determined that more complex combinations of large synchronous generating units must be online.[27]

On 13 October 2017, AEMO published a second update of its 2016 NTNDP to declare a new NSCAS gap for system strength in South Australia. This permitted the new framework to be utilised to provide system strength in accordance with clause 11.101.6 of the NER.[28]

AEMO specified that system strength services were required on an ongoing basis from 30 March 2018 (on a reasonable endeavours basis), with the proposed solution to be verified through detailed system studies.[29] On 8 March 2019, AEMO approved the basic technical specifications for ElectraNet's proposed four synchronous condenser solution.[30]

1.4.2 Declaration of an inertia gap in South Australia

AEMO’s inaugural Integrated System Plan in July 2018 also recommended that immediate investment in transmission should be undertaken to remedy system strength in South Australia. AEMO identified the need for synchronous condensers in South Australia to supply both system strength and inertia as a 'Group 1' investment to be pursued as an immediate priority.

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[25] NER cl. 5.20C.4(d).

[26] AEMO, *NTNDP*, December 2016, pp. 8, 97.

[27] AEMO, *Update to the 2016 NTNDP*, September 2017, p. 4.

[28] AEMO, *Second update to the 2016 NTNDP*, October 2017, p. 3.

[29] AEMO, *Second update to the 2016 NTNDP*, October 2017, p. 6.

[30] AEMO, *Letter to ElectraNet: Proposed complete solution for system strength in South Australia*, 8 March 2019.

In December 2018, AEMO declared an inertia shortfall in South Australia as part of its 2018 NTNDP and recommended that ElectraNet fit flywheels to the proposed synchronous condensers and consider opportunities for developments that provide fast frequency response.[31]

1.5 ElectraNet's application

On 28 June 2019, ElectraNet submitted a contingent project application to fund the MGSS project. The MGSS project entails:

- Procuring, installing and commissioning four synchronous condensers and associated equipment, with two units installed at the Davenport 275 kV substation and two units installed at the Robertstown 275 kV substation, each unit providing 575 MVA nominal 275 kV fault capability and 1,100 MWs of inertia contribution.
- Substation works to integrate the synchronous condensers into the transmission network and associated civil, primary and secondary works. Associated works involve extending both substations to accommodate the relevant buildings and associated equipment, and requiring the further expansion of the Robertstown substation by two 275 kV diameters based on the current site layout.
- Purchasing land adjacent to the Robertstown substation to accommodate the synchronous condensers and required substation expansion.

The expenditure associated with the above works was not included in ElectraNet's revenue allowance for the 2018–23 regulatory control period. Instead, the AER's revenue determination specified that the MGSS project would be a contingent project (that is, a project whereby capex is probable in the regulatory control period, but either the cost, or the timing of the expenditure is uncertain).

Table 1 sets out ElectraNet's proposed contingent project incremental revenue requirement for the 2018–23 regulatory control period.

Table 1: Proposed incremental revenue requirement ($m, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Return on capital	0.0	0.9	8.4	10.9	10.6	30.8
Return of capital (regulatory depreciation)	0.0	–0.4	–3.8	2.0	2.3	0.1
Operating expenditure	–0.0	–0.0	0.9	1.2	1.2	3.2
Revenue adjustments	0.0	0.0	0.0	0.0	0.0	0.0

[31] AEMO, *2018 NTNDP*, December 2018, pp. 4–5.

Net tax allowance	–0.0	0.0	0.2	0.2	0.2	0.6
Annual building block revenue requirement (unsmoothed)	–0.0	0.5[a]	5.6	14.3	14.3	34.8
Annual expected MAR (smoothed)	0.0	0.0	5.6	11.5	17.9	35.0
Increase to annual expected MAR (smoothed)[a]	0.0%	0.0%	1.7%	3.5%	5.3%	2.2%

Source: ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, Table 6-5, p. 27; ElectraNet, *System Strength Contingent Project PTRM (PUBLIC)*, 28 June 2019; AER analysis.

Note: '–0.0' reflects small negative incremental change.

(a) This incremental revenue requirement for 2019–20 does not flow into the expected MAR for this year and is instead smoothed into the expected MARs for 2020–21 to 2022–23.

The proposed total capex is $185.2 million[32] in the current regulatory period for the MGSS project. The incremental capex sought for the delivery of the MGSS project (net of avoided or replaced projects) is $169.4 million.

Table 2 shows the expenditure and revenue requirements ElectraNet proposed for delivering the MGSS contingent project.

Table 2: Proposed amended revenue requirement ($m, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
AER annual building block revenue requirement (unsmoothed)[a]	286.1	314.1	324.9	339.1	341.3	1605.4
MGSS project revenue requirement	–0.0	0.5	5.6	14.3	14.3	34.8
Amended annual building block revenue requirement (unsmoothed)	286.1	314.6	330.5	353.4	355.6	1640.2
Amended annual expected MAR	305.3	312.5	325.8	339.6	354.0	1637.1

32 ElectraNet, *Main grid system strength project: Contingent project application*, p. 21, 28 June 2019, p. 19. All dollar amounts in this document are in real, $2017–18 in line with the ElectraNet's revenue determination unless otherwise stated.

(smoothed)						
X factors	n/a	0.08%	–1.75%	–1.75%	–1.75%	n/a

Source: ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, Tables 6-6 and 6-7, pp. 27–28; ElectraNet, *System Strength Contingent Project PTRM (PUBLIC)*, 28 June 2019; AER analysis.

(a) Updated for 2019–20 return on debt.

Note: '–0.0' reflects small negative incremental change.

1.6 Our consultation process

We publish contingent project applications as soon as practicable after we receive them. We seek public comment on contingent project applications, which we consider in making our decision on the application.[33]

We published the application for public comment on 1 July 2019. Consultation closed on 15 July 2019.

1.6.1 Submissions

We received written submissions from the following stakeholders:

- Business SA;
- EnergyAustralia; and
- SACOSS.

These submissions are available on our website.[34] A summary of and our response to these submissions is included in Attachment B.

[33] NER clauses 6A.8.2(c) and (d) also apply.

[34] https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-main-grid-system-strength-contingent-project/initiation.

2 Assessment approach

Our assessment of ElectraNet's application occurs in two phases. Firstly, we assess the application for compliance with NER clause 6A.8.2(b). Secondly, we examine the detail of the proposal for compliance with the further requirements of NER clause 6A.8.2, particularly in relation to prudent and efficient costs.

We examined ElectraNet's application and assessed it to be compliant under clause 6A.8.2(b) of the NER.

To complete the review of the application we issued an information request to ElectraNet and examined its response to:[35]

- Investigate whether an indoor synchronous condenser installation is the most efficient option compared with an outdoor solution.
- Determine the reasonableness of the proposed project risk costs.
- Determine the reasonableness of the proposed 30 year asset life for synchronous condensers.
- Assess the reasonableness of the proposed project costs in light of the project scope and technical specifications, and having regard to the outcomes of ElectraNet's procurement and contracting processes.

2.1 National Electricity Rules requirement

The NER state that a contingent project application must contain the following information:[36]

- an explanation that substantiates the occurrence of the trigger event;
- a forecast of the total capex for the contingent project;
- a forecast of the capex and incremental opex, for each remaining regulatory year which the TNSP considers is reasonably required for the purpose of undertaking the contingent project;
- how the forecast of the total capex for the contingent project meets the threshold as referred to in clause 6A.8.1(b)(2)(iii);
- the intended date for commencing the contingent project (which must be during the regulatory control period);
- the anticipated date for completing the contingent project (which may be after the end of the regulatory control period); and

35 AER, *Letter to ElectraNet – Request for information – Re: Request for determination – Main grid system strength contingent project*, 12 July 2019.

36 NER cl. 6A.8.2(b).

- an estimate of the incremental revenue which the TNSP considers is likely to be required to be earned in each remaining regulatory year of the regulatory control period as a result of the contingent project being undertaken as described in subparagraph (3), which must be calculated:
    - in accordance with the requirements of PTRM referred to in clause 6A.5.2;
    - in accordance with the requirements of the roll forward model referred to in clause 6A.6.1(b);
    - using the allowed rate of return for that TNSP for the regulatory control period as determined in accordance with clause 6A.6.2;
    - in accordance with the requirements for depreciation referred to in clause 6A.6.3; and
    - on the basis of the capex and incremental opex referred to in subparagraph (b)(3).

In assessing contingent project applications, we must have regard to:[37]

- the information included in or accompanying the application;
- submissions received in the course of consulting on the application;
- such analysis as is undertaken by or for us;
- the expenditure that would be incurred in respect of a contingent project by an efficient and prudent operator in the circumstances of TNSP;
- the actual and expected capex of the TNSP for contingent projects during any preceding regulatory control periods;
- the extent to which the forecast capex for the contingent project is preferable to arrangements with a person other than the TNSP that, in our opinion, do not reflect arm's length terms;
- the relative prices of operating and capital inputs in relation to the contingent project;
- the substitution possibilities between opex and capex in relation to the contingent project; and
- whether the capex and opex forecasts for the contingent project are consistent with any incentive scheme or schemes that apply to the TNSP under clauses 6A.6.5, 6A.6.5A, 6A.7.4 or 6A.7.5.

In making this decision, we applied clause 6A.8.2(e), which specifies the determination we must make on a contingent project application. In making this determination, we had regard to the factors in clause 6A.8.2(g) listed above. We

37 NER cl. 6A.8.2(g).

also considered clause 6A.8.2(f), which specifies particular circumstances in which we must accept the relevant amounts and dates in the contingent project application. We also considered clause 6A.8.2(h), which specifies that amendments to a revenue determination must only be to the extent necessary to reflect the new expenditure requirements (and resulting revenue requirements and X factors) due to the contingent project.

2.2 Our approach to ElectraNet's application

To assess ElectraNet's application for a contingent project, we followed the process set out in NER clauses 6A.8.2. Specifically we:

- verified that the project trigger events had occurred;
- tested that the amount sought exceeded the threshold for a contingent project as set out in clause 6A.8.1(b)(2)(iii); and
- reviewed the application and public submissions.

We then investigated whether the proposed project scope and forecast costs reasonably reflected the capex and opex criteria under the NER.[38] Where we were not satisfied by the information presented in ElectraNet's application, we then sought further information, including on the following matters:

- Whether an indoor synchronous condenser installation is the most efficient option compared with an outdoor solution.
- The reasonableness of the proposed project risk costs.
- The reasonableness of the proposed 30 year asset life assigned to synchronous condensers for depreciation purposes.
- The reasonableness of the proposed project costs in light of the project scope and technical specifications, and having regard to the outcomes of ElectraNet's procurement and contracting processes.

We examined these matters in correspondence with ElectraNet, sought further information and considered its responses. We had regard to ElectraNet's procurement and contracting approaches when assessing its application against the benchmark of a prudent and efficient TNSP, given the bespoke nature of the synchronous condensers.

During the course of our assessment, ElectraNet requested that commercially sensitive information remain confidential. We granted its request on the understanding that:

- The project involves substantial new works that have yet to be put to tender, and that publishing the information will provide price signals to prospective tenderers which may lessen competitive pricing pressure.

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[38] NER cl. 6A.6.7(c)(1)–(3) and NER cl. 6A.6.6(c)(1)–(3) set out the capex and opex criteria, respectively.

- Although in general, our preference is to publish all relevant information, on balance we consider that maintaining the confidentiality of the specific estimates in this project will better serve the long-term interests of consumers. This approach is also consistent with our confidentiality guideline.

We sought advice from our internal technical and engineering experts, the Technical Advisory Group to assist us in making this determination. They examined the basis and breakdown of cost estimates and identified some concerns with ElectraNet's application, which we addressed in our information request to ElectraNet.

Having assessed ElectraNet's response to our information request, we considered ElectraNet's proposed project risk cost allowances included certain risks that would not be prudent or efficient for consumers to bear through the ex-ante expenditure allowances for this project. For instance, these included risks that should be under ElectraNet's control or normally managed under ElectraNet's business as usual activities, or risks that should reasonably be covered by contract terms or insurance. On this basis, we reduced ElectraNet's proposed capex by reducing its forecast project risk allowance by $3.5 million (nominal) or $3.4 million ($2017–18) to reflect a reasonable assessment of the likely prudent and efficient project risk costs required to undertake the MGSS project. We also determined that the synchronous condensers in the MGSS project would have a standard asset life of 40 years rather than the proposed 30 years. A higher standard asset life reduces the incremental revenue provided to ElectraNet in this decision by reducing the allowance for the return of capital (depreciation) as summarised in table 10.

Having determined the capex necessary to complete the project, as well as the appropriate standard asset life for the synchronous condensers, we modified the proposed PTRM to reflect the allowances we consider appropriate. All other parameters proposed by ElectraNet remained unchanged.

3 Our assessment

This section sets out our assessment of ElectraNet's application, which entails:

- Verifying that the project trigger events had occurred (section 3.1).
- Verifying that the proposed capex met the contingent project threshold (section 3.2).
- Assessing whether the proposed capex was efficient and prudent, where we specifically considered the efficiency of the proposed indoor solution, risk costs, asset life and cost estimates more generally (section 3.3).
- Assessing whether the proposed opex was efficient and prudent (section 3.4).

3.1 Trigger events

ElectraNet submitted four cumulative trigger events for the MGSS contingent project:[39]

1. Confirmation by AEMO of the existence of a NSCAS gap relating to system strength, or other requirement for ElectraNet to address a system strength requirement, in the South Australian region.
2. Successful completion of the RIT–T (or equivalent economic evaluation) including an assessment of credible options showing a transmission investment is justified.
3. Determination by the AER that the proposed investment satisfies the RIT–T (or equivalent economic evaluation).[40]
4. ElectraNet board commitment to proceed with the project subject to the AER amending the revenue determination pursuant to the NER.

In our final decision on ElectraNet's 2018–23 revenue determination, we approved the MGSS project as a contingent project.[41]

We are satisfied that all four of these requirements have occurred and that ElectraNet's application is compliant. Specifically:

- On 13 October 2017, AEMO declared a system strength gap in South Australia.[42]

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39 ElectraNet, *Revenue proposal 2019–2023: Attachment 6 capital expenditure*, 28 March 2017, p. 48; ElectraNet, *Revised revenue proposal 2018–19 to 2022–23*, 22 December 2017, p. 27.

40 ElectraNet amended this third trigger in its revised revenue proposal. ElectraNet had initially proposed the trigger, 'Determination (if applicable) by the AER under clause 5.16.6 of the NER that the proposed investment satisfies the RIT–T'.

41 AER, *Final decision: ElectraNet transmission determination 2018 to 2023: Attachment 6 – Capital expenditure*, April 2018, p. 6-20.

42 AEMO, *Second Update to the 2016 NTNDP*, October 2017.

- On 18 February 2019, we confirmed that an equivalent economic evaluation to a RIT–T had been undertaken, including an assessment of credible options showing a transmission investment is justified.[43]
- On 18 February 2019, we determined that the proposed high inertia synchronous condenser investment satisfied an economic evaluation equivalent the RIT–T.[44]
- On 30 May 2019, ElectraNet's board made a commitment to proceed with the MGSS project subject to the AER amending the revenue determination pursuant to the NER. ElectraNet provided evidence of this commitment in its application.[45]

3.2 Expenditure threshold

The NER currently stipulates the capex threshold for a contingent project — namely, that the proposed capex exceeds either $30 million or 5 per cent of the value of the MAR for the relevant TNSP for the first year of the relevant regulatory control period, whichever is the larger amount.[46]

ElectraNet's application proposed capex of $185.2 million for the MGSS project (or $169.4 million in incremental capex, net of other avoided capex projects). Both of these values exceed $30 million. Also, 5 per cent of ElectraNet's first year revenue is $15.3 million (smoothed). Hence, the capex threshold has been met.

3.3 Capital expenditure

Table 3 summarises ElectraNet's contingent project application capex requirements.

Table 3: Proposed capex forecast ($m 2017–18)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
MGSS project	18.8	125.9	40.5	0.0	0.0	185.2
Robertstown Circuit Breaker Arrangement	–3.0	–3.9	0.0	0.0	0.0	–6.9
Para Reactor	0.0	0.0	–0.3	–2.8	–1.4	–4.5
Blyth West Reactor	0.0	–1.3	–3.0	–0.1	0.0	–4.4
Incremental contingent project capex	15.8	120.7	37.2	–2.9	–1.4	169.4

Source: ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, Table 4-2, p. 19.

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43 AER, *Letter to ElectraNet re: System strength gap in South Australia*, 18 February 2019; ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019.

44 AER, *Letter to ElectraNet re: System strength gap in South Australia*, 18 February 2019.

45 ElectraNet, *MGSS project: Contingent project application*, 28 June 2019, p. 32.

46 NER cl. 6A.8.1(b)(2)(iii).

We investigated whether the proposed project scope and forecast costs reasonably reflected the capex and opex criteria under the NER.[47] Where we were not satisfied by the information presented in ElectraNet's application, we sought further information to investigate the following matters:

- Whether an indoor synchronous condenser installation is the most efficient option compared with an outdoor solution.
- The reasonableness of the proposed project risk costs.
- The reasonableness of the proposed 30 year asset life for synchronous condensers.
- The reasonableness of the proposed project costs in light of the technical specifications and having regard to the tender evaluation approach.

3.3.1 Efficiency of an indoor solution

Our determined forecast capex for the MGSS project is consistent with adopting an indoor synchronous condenser solution.

We asked ElectraNet to provide further details and justification to demonstrate that an indoor synchronous condenser installation is the most efficient option compared with an outdoor solution. We requested this information because we considered that ElectraNet's decision to procure synchronous condensers that need to be housed indoors ought to have had regard to the relative costs of the required buildings, the incremental costs of procuring synchronous condensers designed for outdoor conditions, and the expected impact on the asset life and maintenance costs.

In response, ElectraNet advised that its decision to provide an indoor synchronous condenser solution was driven by several considerations, including that it was:[48]

- advised by equipment manufacturers;
- consistent with international practice;
- able to support optimal operating conditions;
- better able to avoid derating the synchronous condensers during periods of high ambient temperatures. It would also better avoid decay from the saline environment (for the Davenport substation) and from moisture;
- able to provide a more controlled environment for maintenance;
- able to provide better noise control capability, avoiding the need for noise containment enclosures; and
- more likely to reduce commissioning delays due to weather.

[47] NER cl. 6A.6.7(c)(1)–(3) and NER cl. 6A.6.6(c)(1)–(3) set out the capex and opex criteria, respectively.

[48] ElectraNet, *Main grid system strength contingent project: Response to AER information request dated 12 July 2019*, 19 July 2019, p. 2 (redacted non-confidential version).

We concur with these reasons. While we also note that suitably designed outdoor equipment would exhibit many of these features, equipment designed for outdoor conditions would have higher capital costs (potentially including costs associated with building the equipment to order). It is also likely that sourcing equipment for outdoor installation would have resulted in project delays and a continuing need for AEMO market directions.

For these reasons, we are satisfied that ElectraNet's expenditure on indoor rated-equipment reasonably reflects the capex criteria.

We have also taken ElectraNet's considerations listed above into account when determining an appropriate standard asset life for the synchronous condensers in the MGSS project (see section 3.3.3).

3.3.2 Project risk costs

Project risk costs reflect the likely cost impact of both mitigating risks (mitigation costs) and bearing residual risks after mitigation (contingency costs).[49] An allowance for project risk cost should only include risks that would be prudent or efficient for consumers to bear through the ex-ante expenditure allowance. We consider that such risks would meet the following criteria:

- Risks that relate to a realistic latent condition with the site.
- Risks associated with the actions or requirements of a third party not under contract to the TNSP and hence the risk cannot be addressed through enforcing contract terms.
- Not include risks that:
    - Are under the TNSP's control.
    - Would normally be managed by the TNSP as part of its business as usual practices.
    - Are, or should be, reasonably covered by contract terms.
    - Are, or should be, covered by insurance.

We considered ElectraNet's proposed project risk cost allowance included certain risks that would not be prudent or efficient for consumers to bear. Before forming this view, we requested ElectraNet define what costs were included in, or what cost variances are represented by, the ‘project risk’ costs included in its proposed capital cost forecasts. We requested ElectraNet define the risks and set out how it calculated its proposed risk allowances given its proposed costs were material and it was unclear what was driving them.[50]

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[49] ElectraNet, *Main grid system strength contingent project: Response to AER information request dated 12 July 2019*, 19 July 2019, pp. 4–5 (redacted non-confidential version).

[50] These risk costs were included in ElectraNet, *System Strength Contingent Project: Capital Cost Inputs File* (CONFIDENTIAL).

In response, ElectraNet submitted a confidential project risk assessment spreadsheet that identified 127 risk line items (70 in Robertstown and 57 in Davenport).[51] For each line item, ElectraNet calculated the expected risk mitigation cost, and then used the likelihood and consequence after mitigation (informed by an identified contingency plan) to calculate an expected contingency cost. Its proposed risk costs are the sum of expected risk mitigation and contingency costs across the 127 line items.

We assessed ElectraNet's project risk assessment by assessing each of ElectraNet's proposed 127 risk line items against our criteria for determining whether a risk would be prudent or efficient for consumers to bear through the ex-ante expenditure allowance. We then accepted ElectraNet's proposed risk allowance as calculated for all line items representing risks that:

- related to a realistic latent condition with the site(s) (for example, encountering rock on the site); or
- were associated with the actions or requirements of a third party not under contract to ElectraNet and hence the risk cannot be addressed through enforcing contract terms (for example, council approval or environmental conditions).

We also determined that it would not be prudent to provide a risk cost allowance for risk items that:

- were under ElectraNet's control (for example, deficient policies and procedures);
- would normally be managed by ElectraNet as part of its business as usual practices (for example, delays in appointing contractors);
- were, or should have been, reasonably covered by contract terms (for example, contractor delay); or
- were, or should have been, covered by insurance (for example, fire).

After applying this approach, we consider a forecast of approximately $3.1 million (nominal) for mitigation and contingency costs would reflect forecast project risk costs that are prudent and efficient in the context of this project. This is a lower forecast than ElectraNet's proposal of $6.6 million (nominal) in project risk costs, which it included in its confidential capital cost inputs file.[52]

3.3.3 Standard asset life for 'Synchronous condensers' asset class

We have determined that a standard asset life of 40 years be assigned to the 'Synchronous condensers' asset class for regulatory depreciation purposes. This is

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51 ElectraNet, *Response to AER information request of 12 July 2019: Attachment 2 – Project Risk Assessment* (CONFIDENTIAL).

52 ElectraNet, *System Strength Contingent Project: Capital Cost Inputs File* (CONFIDENTIAL).

different to ElectraNet's proposed 30 years for this asset class.[53] This is because we consider a 40 year standard asset life better reflects the economic life of the synchronous condensers installed for the MGSS contingent project.[54]

We have previously approved a 40 year standard asset life for AusNet Services' broad asset category for reactive plant, which includes synchronous condensers, capacitor banks and Static VAR compensators.[55] Also, in our 2018–23 revenue determination for ElectraNet, we did not approve ElectraNet's proposed standard asset life of 30 years for the 'Synchronous condensers' asset class. We raised some concerns with the proposed 30 year standard asset life. However, we did not determine a standard asset life for this asset class at the time because the assets to be allocated to this asset class only related to the MGSS contingent project. We stated that we would determine a standard asset life for this asset class once the contingent project trigger for this project is met.[56]

As part of its contingent project proposal, ElectraNet provided a report by GHD Advisory (GHD).[57] While GHD outlined reasons for assigning a standard asset life of 30 years for the synchronous condensers, on balance, we consider the information in GHD's report better supports a standard asset life of 40 years for synchronous condensers. As well as considering the information provided in GHD's report, we requested ElectraNet provide the technical specifications for the synchronous condensers and flywheels. This additional information complements the information that ElectraNet already provided in its consultant report from GHD.[58] After considering GHD's report and the technical specifications of the relevant assets, our view is that a 40 year standard asset life better reflects the economic life of the synchronous condensers than a 30 year standard asset life. Our reasons for this view are discussed below.

Industry examples

GHD's report provided examples of the standard asset lives applied by other electricity networks in Australia (AusNet Services) and overseas (Transpower and SP Energy Networks). We consider the examples provided in the report provide

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[53] ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 25.

[54] Under NER cl. 6A.8.2((b)(9)(iv), contingent project applications must estimate the incremental revenue in accordance with the requirements for depreciation referred to in clause 6A.6.3. NER cl. 6A.6.3(b)(1) requires that depreciation schedules use a profile that reflects the nature of the assets or categories of assets over their economic life.

[55] GHD highlighted this in *Synchronous Condenser Asset Life Review*, March 2017, p. 3. Also see AER, *Draft decision: AusNet Services transmission determination 2017–18 to 2021–22, Attachment 5 – Regulatory depreciation*, July 2016, 5-30.

[56] AER, *ElectraNet transmission final determination 2018–23, Attachment 5 – Regulatory depreciation*, April 2018, pp. 5-7.

[57] GHD*, MGSS Contingent Project – Economic life Advice, 28 June 2019. This* report is available on our website.

[58] ElectraNet, *Attachment 4 – Response to RFI, Synchronous condenser design information*, Received 19 July 2019.

more support for a 40 year asset life than they do for the proposed 30 years. For instance, GHD found that:[59]

- AusNet Services' synchronous condensers located at Brooklyn, Fishermans Bend and Templestowe terminal stations were built in the 1960s and were in operation until they failed between October 2016 and April 2017 after it was determined to be prudent to retire the assets. According to AusNet Services' asset management strategy, these synchronous condensers had a technical life of between 40 to 50 years. AusNet Services reported that half-life refurbishment was required when these synchronous condensers were 36 to 40 years old.[60]
- Transpower installed a fleet of synchronous condensers in New Zealand between 1955 and 1965 that were expected to have an in-service life of 70–80 years.[61] While these assets required major refurbishments in the 1990s, GHD did not provide sufficient evidence to support why this would reflect the end of the assets' lives. Rather, it was economic to refurbish rather than to retire the assets, which suggests that the refurbishment date should not represent the end of the assets' economic lives.
- In SP Transmission's plan to operate a synchronous condenser with a hybrid co-ordinated control system combined with a static condenser, a 40 year asset life was applied for newly installed synchronous condenser.[62]

We note that the only example provided by GHD that suggested a 30 year asset life was the Australian Tax Office's (ATO's) effective life of 30 years used for taxation purposes. However, we consider that the standard asset life assigned for regulatory depreciation purposes should reflect the economic life of the asset consistent with the requirements of the NER,[63] which may be different to the ATO's effective life for tax purposes.

Asset utilisation

While GHD had previously recommended a 40 year asset life for synchronous condensers,[64] it recommended a shorter asset life in the MGSS project. However, its primary reason for this is that ElectraNet's synchronous condensers will be required to operate continuously, whereas synchronous condensers are typically operated on an as-needed basis. GHD also stated that machines that are subject to variation in mechanical and thermal stresses such as when being started and stopped are more prone to wear. We agree that asset utilisation is a relevant point for considering a

59 GHD, *Economic life for ElectraNet synchronous condensers*, 28 June 2019, Section 4.4, pp. 13–15.

60 AusNet Services, *Electricity transmission regulatory reset 2008/09–2013/14, Appendix E: Asset management strategy*, 2007, p. 70.

61 Transpower, *ACS Reactive Power Fleet Strategy, document no. TP.FS 32.01*, October 2013, p. 12.

62 Ofgem, *SP Transmission: Phoenix – System security & Synchronous compensators, RIIO NIC 2016*, p. 55.

63 NER, cl. 6A.6.3(b)(1).

64 GHD, *Economic life for ElectraNet synchronous condensers*, 28 June 2019, pp. 18–19.

realistic assessment of the economic asset life as it relates to the physical and electrical conditions that will be imposed on these machines.

However, we note that ElectraNet's synchronous condensers will be operated in a continuous mode and are designed to operate in such a manner. As these synchronous condensers use a hydro-dynamic bearing system and are brushless design, there are no significant components that are subject to wear. Moreover, these synchronous condensers will only be subject to occasional mechanical and thermal stresses when they are stopped for scheduled maintenance outages,[65] or are called upon to provide fault current or inertia. We note that under the continuous operating mode, the synchronous condensers will operate with no load other than the relatively modest flywheel losses and when called on to operate in generating mode to provide fault current or inertia.

Consequently, we consider that it is more likely that ElectraNet's synchronous condensers will be under less mechanical or thermal stress than a typical synchronous condenser used in reactive power management.

Design life

GHD stated that manufacturers have typically advised ElectraNet that synchronous condensers have a life of 25 to 30 years before major plant related refurbishment work may be expected.[66] We accept that future refurbishment requirements are a factor in determining economic life. However, we consider that this is not an estimate of the economic life of the asset. We have previously recognised that an asset's economic life may be significantly longer than its minimum design life, which can be surpassed through good maintenance practices, prudent refurbishment, or where the asset is subject to less operational stress than for what it was designed.[67]

Further, ElectraNet submitted that by installing the synchronous condensers indoors, it will provide a controlled environment for maintenance. It will also avoid derating the assets during periods of high ambient temperatures and avoid decay from the saline environment (for the Davenport substation) and from moisture (see section 3.3.1). We note that this entails that ElectraNet's synchronous condensers will have a more favourable operating environment, which supports a longer operating life than synchronous condensers that are continuously exposed to the outside environment.

Summary

On balance, we consider the economic life observed for other synchronous condensers installed in Australia and overseas should provide a reasonable basis

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[65] GHD, *Economic life for ElectraNet synchronous condensers*, 28 June 2019, p. 15.

[66] GHD, *Economic life for ElectraNet synchronous condensers*, 28 June 2019, p. 15.

[67] AER, *Draft decision: ElectraNet transmission determination 2018 to 2023, Attachment 5 – Regulatory depreciation*, October 2017, pp. 18–19.

for ElectraNet's synchronous condensers. ElectraNet's synchronous condensers should have a relatively long economic life due to the nature of their operating mode (continuous), the purpose of their application (inertia and fault current), their design (brushless and hydro-dynamic bearings), and their installation in an indoor environment. That said, we agree that adding flywheels to provide inertia services may cause some additional wear and tear on the assets.

We consider the industry examples provided in GHD's report (AusNet Services, Transpower and SP Energy Networks) provide more support for a 40 year standard asset life than they do for the proposed 30 years.[68] Therefore, we do not consider that ElectraNet's proposed standard asset life of 30 years reflects the economic life of the synchronous condensers installed for the MGSS contingent project.[69] Instead, we determine a minimum standard asset life of 40 years for the 'Synchronous condensers' asset class.

We accept the proposed standard tax asset life of 30 years for the new 'Synchronous condensers' asset class for tax depreciation purposes. This is because the proposed standard tax asset life is consistent with the effective life for condensing assets for tax purposes as determined by the ATO.[70] We consider that the standard tax asset life for the purpose of calculating the corporate income tax building block should be consistent with the relevant tax ruling for depreciating assets, which may be different to the economic life for regulatory depreciation purposes.

3.3.4 Overall cost estimates

Apart from the forecast project risk costs (see section 3.3.2), we found that ElectraNet's forecast capex generally reflected expenditure that would be incurred in respect of a contingent project by an efficient and prudent operator in the circumstances of that TNSP.[71]

We formed this view after requesting more detailed cost estimates from ElectraNet so we could better understand the asset types, quantities, and unit rates it used and thereby relate the costing items to the scope of work.[72] We also requested further information on the technical specifications for the synchronous condensers and flywheels to assist our assessment of ElectraNet's proposed project costs.[73]

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68 GHD, *Economic life for ElectraNet synchronous condensers*, 28 June 2019, Section 4.4, pp. 13–15.

69 NER cl. 6A.6.3(b)(1).

70 ATO, TR 2018/4; https://www.ato.gov.au/law/view/document?LocID=%22TXR%2FTR20184%2FNAT%2FATO%2FatTABLE-Electricity%22&PiT=99991231235958#TABLE-ELECTRICITY

71 NER cl. 6A.8.2(g)(4)

72 ElectraNet, *MGSS Contingent Project – Scope of Works*, 21 June 2019.

73 ElectraNet, *Attachment 4 – Response to RFI, Synchronous condenser design information*, Received 19 July 2019.

In general, we were satisfied with ElectraNet's proposed cost estimates on the following basis:

- We assessed the proposed scope of works and concluded that they reflected prudent and necessary works that we would anticipate as being required to deliver the four 129 MW synchronous condensers at the two sites.
- ElectraNet's proposed cost items generally accorded with the costs we would anticipate for those items, and we consider that they reflect reasonable and realistic estimates of the likely cost of the proposed work.
- The majority of the capital cost estimates for the MGSS project were based on tender prices derived from competitive market tendering. For instance, the cost estimates associated with procuring and installing the synchronous condensers and associated equipment, as well as substation works were based on tender pricing.[74] Having considered this, along with having reviewed the procurement and contracting approach taken by ElectraNet as summarised in its confidential tender evaluation report, we have formed the view that the unit rates used in the capital cost estimates are likely to represent reasonable values that represent realistic expectations of the likely costs to be incurred.[75]

3.4 Operating expenditure

Table 4 summarises ElectraNet's contingent project application incremental opex requirements. The proposed annual incremental opex in table 4 represents 0.5–0.6 per cent of the proposed incremental capex of $169.4. ElectraNet noted that its incremental opex forecast lies well within the indicative estimate of 1.0 per cent of the total capital cost per annum included in its economic evaluation report for modelling purposes (equivalent to a range of $1.4–1.8 million per annum).[76]

Table 4: Proposed incremental opex forecast ($m, 2017–18)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Controllable opex	0.0	0.0	0.7	1.0	1.0	2.7
Network support	0.0	0.0	0.0	0.0	0.0	0.0
Debt raising costs	0.0	0.0	0.1	0.1	0.1	0.2
Total opex	0.0	0.0	0.8	1.1	1.0	2.9

Source: ElectraNet, *MGSS contingent project – PTRM*, 'Contingent projects' AA885:AM895.

74 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 18.

75 ElectraNet, *Attachment 3 – Response to RFI, Tender evaluation report*, Received 19 July 2019 (CONFIDENTIAL).

76 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 23.

Our assessment of the proposed costs in table 4 are that they reasonably reflect expenditure that would be incurred in respect of a contingent project by an efficient and prudent operator in the circumstances of that TNSP.[77]

ElectraNet's forecast opex mainly consists of controllable opex, which it has based on:[78]

- routine maintenance costs for the synchronous condensers and substation assets (based on market pricing);
- internal costs associated with the additional specialist engineering resources required to manage the new assets (based on established rates); and
- insurance costs (based on market pricing).

We consider that an estimate of approximately $0.8–1.1 million per annum for maintenance opex is likely to represent a realistic value of expected maintenance costs on new equipment. As the synchronous condensers are uncommon and specialised plant, there are few comparators available to provide an estimate based on benchmarking specific to this type of asset. However, when compared to the ongoing maintenance costs for a modest size substation, we would anticipate annual maintenance opex in the range of $0.8–1.2 million for the four synchronous condenser installations, particularly given that these installations are new, but also include rotating machinery such as pumps and motors that typically require more maintenance than most substation equipment.

ElectraNet's forecast opex also includes debt raising costs, which is a function of the higher regulatory asset base (RAB) resulting from the MGSS project's forecast capex. ElectraNet have estimated debt raising costs using our approved benchmark based approach. We approve this approach as reflecting the costs that an efficient and prudent operator would incur in the circumstances of that TNSP.[79] We also note that while our revised estimate of debt raising costs is marginally lower than ElectraNet's proposal to reflect our revised capex forecast, table 4 does not show this immaterial reduction due to rounding.

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77 NER cl. 6A.8.2(g)(4).

78 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 22.

79 For an explanation of this approach, see AER, *Draft decision: ElectraNet transmission determination 2018 to 2023: Attachment 3 – Rate of return*, October 2017, pp. 3-379–380.

4 Our calculation of the annual building block revenue requirement

This section sets out our calculation of ElectraNet's revised annual building block revenue requirement, based on our determination on the forecast capex, forecast opex and allowed rate of return. We also set out how the revised capex forecast affects the target capex for the capital expenditure sharing scheme (CESS). Similarly, we set out how the revised opex forecast net of debt raising costs affects the forecast opex for the efficiency benefit sharing scheme (EBSS).

4.1 Capital expenditure

ElectraNet proposed net capex of $169.4 million to deliver the MGSS project. ElectraNet provided supporting evidence and cost estimates as part of its contingent project application and in response to our information request. These costs were not included in the 2018–2023 revenue determination because the MGSS project was proposed as a contingent project due to uncertainty about the relevant trigger events occurring and the expected cost of the project.

We have allowed $166.0 million for capex. This is lower than ElectraNet's proposed capex because we have reduced the forecast of $169.4 million by $3.4 million to reflect a project risk cost allowance that includes only costs that we consider would be prudent and efficient (see section 3.3). As discussed in section 5, to adjust the capex amounts sought by ElectraNet, we calculated the adjustment to the inputs in the PTRM in real, 2017–18 dollars.

4.1.1 Capex impact on CESS target

Table 5 sets out how the proposed incremental contingent project capex would increase the CESS capex target in the 2018–23 revenue determination.

Table 5: Proposed target capex for CESS ($m 2017–18)[a]

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Target capex for CESS in 2018–23 determination	96.4	99.8	108.4	100.2	53.1	457.9
Proposed incremental contingent project capex	15.8	120.7	37.2	–2.9	–1.4	169.4
Proposed revised target capex for CESS (total)	112.1	220.5	145.7	97.2	51.8	627.3

Source: AER analysis; ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, Table 4-2, Table 4-4; ElectraNet, *MGSS contingent project – PTRM*, 'Contingent Project's: G611:Y611, 28 June 2019.

(a) Totals may not sum due to rounding.

Table 6 sets out how the incremental contingent project capex determined in this decision would increase the CESS capex target in the 2018–23 revenue determination.

Table 6: Target capex for CESS ($m, 2017–18)[a]

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Target capex for CESS in 2018–23 determination	96.4	99.8	108.4	100.2	53.1	457.9
Incremental contingent project capex	15.3	118.5	36.6	–2.9	–1.4	166.0
Revised target capex for CESS (total)	111.7	218.2	145.0	97.2	51.8	624.0

Source: AER analysis; AER, *ElectraNet final decision - PTRM - Update for MGSS contingent project*, 'Contingent projects': T611:AM611, 15 August 2019.

(a) Totals may not sum due to rounding.

The MGSS project increases the target capex allowance because the capex allowance for calculating efficiency gains and losses is based on our approved allowance (as determined prior to the start of the regulatory control period), plus any adjustments we allow from pass-throughs, reopening of capex or contingent projects.[80]

4.2 Operating expenditure

ElectraNet forecast $2.9 million in incremental opex to deliver the MGSS project.[81] These costs were not included in the 2018–23 revenue determination because the MGSS project was proposed as a contingent project due to uncertainty about the relevant trigger events occurring and the project costs.

We consider the opex reasonably required for undertaking the MGSS project in the regulatory control period is $2.9 million in total.

4.2.1 Opex impact on EBSS target

Table 7 sets out how the incremental contingent project opex would increase the forecast opex for the EBSS as set out in the 2018–23 revenue determination. These figures align with the forecast opex proposed in ElectraNet's application.[82]

80 AER, *Better regulation: Capital expenditure incentive guideline for electricity network service providers*, November 2013, p. 6.

81 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 22.

82 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, Table 5-2.

Table 7: Forecast opex for EBSS ($m, June 2018)[a]

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Forecast opex for EBSS in 2018–23 determination	80.7	81.2	82.1	82.9	83.3	410.2
Incremental opex excluding network support and debt raising costs	0.0	0.0	0.8	1.0	1.0	2.7
Revised forecast opex for EBSS (total)	80.7	81.2	82.8	83.8	84.3	412.9

Source: AER analysis; AER, *ElectraNet final decision - PTRM - Update for MGSS contingent project*, 'Contingent projects': G385:AM385, 15 August 2019.

(a) Totals may not sum due to rounding

The MGSS project results in an adjustment to the forecast opex for the EBSS. Under the EBSS, we are to adjust forecast opex to add any approved revenue increments or subtract any approved revenue decrements made after the initial revenue determination for the regulatory control period, including approved pass-through amounts or opex for contingent projects.[83]

4.3 Time value of money

The NER require the incremental revenue that the TNSP is likely to require as a result of the contingent project be calculated using the allowed rate of return for that TNSP for the regulatory control period as determined in accordance with NER clause 6A.6.2 (which sets out the return on capital for a regulatory year).[84]

The allowed rate of return allows us to take into account the time value of money and is based on the most recent rate of return for ElectraNet, as set out in the 2018–23 revenue determination. Since the return on debt is calculated using a trailing average approach, the updated value for the return on debt from 2019–20 now applies, consistent with the averaging period approved in our 2018–23 revenue determination for ElectraNet.

83 AER, *Better regulation: Efficiency benefit sharing scheme for electricity network service providers*, November 2013, p. 7.

84 NER, cl 6A.8.2(b)(9)(iii), and 6A.8.2(e)(2)(viii)

As such, we accept the nominal vanilla weighted average cost of capital (WACC) of 5.68 per cent set out in ElectraNet's application for 2019–20 reflecting our most recent annually updated trailing average cost of debt in March 2019.[85]

4.4 Calculation of the revenue requirement

Table 8 sets out our calculation of our ElectraNet's revenue requirement for the MGSS project, which we calculated by allocating the incremental opex amount to the opex inputs and the incremental capex amount to the capex inputs in the PTRM. We also updated the PTRM for the approved standard asset life assigned to the 'Synchronous condensers' asset class.

Table 8: AER allowance – ElectraNet contingent project incremental revenue requirement and X factors, 2018–23 ($m, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Return on capital	0.0	0.9	8.2	10.7	10.5	30.3
Return of capital (regulatory depreciation)	0.0	–0.4	–3.7	1.0	1.2	–1.9
Operating expenditure	–0.0	–0.0	0.9	1.2	1.2	3.2
Revenue adjustments	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	–0.0	0.0	0.2	–0.0	–0.0	0.2
Annual building block revenue requirement (unsmoothed)	–0.0	0.5[a]	5.5	12.8	12.9	31.7
Expected MAR (smoothed)	0.0	0.0	5.1	10.5	16.3	32.0
Increase to expected MAR (smoothed)[a]	0.0%	0.0%	1.6%	3.2%	4.9%	2.0%
X factors	n/a	0.08%	–1.60%	–1.60%	–1.60%	n/a

Source: AER analysis.

(a) This incremental revenue requirement for 2019–20 does not flow into the expected MAR for this year and is instead smoothed into the expected MARs for 2020–21 to 2022–23.

Note: '–0.0' reflects small negative incremental change.

[85] ElectraNet, *Main grid system strength: Contingent project application*, 28 June 2019, p. 24.

5 Our determination

On 9 August 2019, the AER determined that ElectraNet's application for contingent project funding lodged on 28 June 2019 was approved with modifications to the amounts sought.

In accordance with clause 6A.8.2(e) of the NER, we have determined that:

- The amount of capex and incremental opex for each remaining year of the regulatory control period that we consider is reasonably required for the purpose of undertaking the contingent project is set out in table 9.
- The total capex we consider is reasonably required to undertake the contingent project is $166.0 million ($2017–18) net of avoided capex.
- The contingent project has commenced and the likely completion date is 28 February 2021.
- The incremental revenue which is likely to be required by ElectraNet for each remaining regulatory year as a result of the contingent project is consistent with the values in table 10.
- ElectraNet's 2018–23 revenue determination is amended accordingly.

ElectraNet submitted its application in real mid-year $2017–18. While the PTRM calculation is expressed in real end-year $2017–18, we present calculations for incremental capex and opex to align with ElectraNet's application.

Table 9: Incremental capex and opex ($m, 2017–18)[a]

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Incremental capex	15.3	118.5	36.6	–2.9	–1.4	166.0
Incremental opex	0.0	0.0	0.8	1.1	1.0	2.9

Source: AER analysis; AER, *ElectraNet final decision - PTRM - Update for MGSS contingent project*, 'Contingent projects': AA611:AM611, AA895:AM895, 15 August 2019.

(a) Totals may not sum due to rounding.

Table 10: Incremental revenue calculation ($m, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Return on capital	0.0	0.9	8.2	10.7	10.5	30.3
Return of capital (regulatory depreciation)	0.0	–0.4	–3.7	1.0	1.2	–1.9
Operating expenditure	–0.0	–0.0	0.9	1.2	1.2	3.2
Revenue adjustments	0.0	0.0	0.0	0.0	0.0	0.0

Net tax allowance	–0.0	0.0	0.2	–0.0	–0.0	0.2
Annual building block revenue requirement (unsmoothed)	–0.0	0.5[a]	5.5	12.8	12.9	31.7
Annual expected MAR (smoothed)	0.0	0.0	5.1	10.5	16.3	32.0
Increase to annual expected MAR (smoothed)[a]	0.0%	0.0%	1.6%	3.2%	4.9%	2.0%

Source: AER analysis.

(a) This incremental revenue requirement for 2019–20 does not flow into the expected MAR for this year and is instead smoothed into the expected MARs for 2020–21 to 2022–23.

Note: '–0.0' reflects small negative incremental change.

In accordance with clause 6A.8.2(h), we have used the capex and incremental opex determined in accordance with clause 6A.8.2(e)(1)(i) to amend the PTRM. In doing this, we determined the values in table 11, which reflect the effect of the resultant increase in forecast capex and opex on:

- the annual building block revenue requirement for each regulatory year in the remainder of the regulatory control period; and
- the X-factor for each regulatory year in the remainder of the regulatory control period.

Table 11: Annual building block revenue requirement, expected MAR and X-factors ($m, nominal)

	2018–19	2019–20	2020–21	2021–22	2022–23	Total
Annual building block revenue requirement (unsmoothed)	286.1	314.6	330.4	351.9	354.1	1637.1
Expected MAR (smoothed)	305.3	312.5	325.3	338.6	352.4	1634.1
X-factors	n/a	0.08%	–1.60%	–1.60%	–1.60%	n/a

Source: AER analysis.

We have determined the incremental contingent project unsmoothed revenue amount to be $31.7 million ($nominal). This is the additional amount that ElectraNet will recover from customers over three years commencing 1 July 2020.[86] This is lower than the $34.8 million ($nominal) proposed by ElectraNet.[87] The overall outcome of this determination is to increase annual transmission charges by 1.6 per cent in 2020–21, 3.1 per cent in 2021–22, and 4.7 per cent in 2022–23.

We further determine the smoothed annual expected MAR should be adjusted to $1634.1 million ($nominal), based on the revenue requirements and X-factors set out in table 11. This corresponds to a total unsmoothed annual revenue requirement of $1637.1 million ($nominal).

We note that the roll-forward model as determined at our 2018 final decision for ElectraNet's revenue determination does not need to be amended for the contingent project. This is because the proposed contingent project only affects the forecast opening RAB for 2020–21, 2021–22 and 2022–23. The forecast opening RABs for these years are calculated in the PTRM and updated to reflect the approved capex for the contingent project.

86 While the cost of capex and opex for the MGSS project is included from 1 July 2019, the impact to revenue occurs from the following regulatory year.

87 ElectraNet, *Main grid system strength: Contingent project application*, 28 June 2019, p. 27.

A Impact on the typical customers bill

Table 12 shows the estimated impact of our decision on ElectraNet's MGSS contingent project on the average residential and small business customers' annual electricity bills. Our estimate is based on the typical annual electricity usage of around 4,000 kWh per annum for a residential customer in South Australia.[88] Therefore, customers with different usage will experience different changes in their bills. We have included 45 per cent of Murraylink's revenue for the contingent project bill impact calculation.[89] The potential impact on small business customers is calculated in a similar way, using an annual electricity usage of 20,000 kWh per annum.[90]

We note that there are other factors, such as transmission network costs, metering, wholesale and retail costs which affect electricity bills. Therefore these bill impact estimates are indicative only, and individual customers' actual bills will depend on their usage patterns and the structure of their tariffs.

Further, we note that our estimated impact on the annual electricity bills does not account for the assumed savings in wholesale market costs from reduced generator direction costs. ElectraNet's proposal has modelled the overall impact on typical residential customer bills. It estimated that the delivery of the MGSS contingent project would provide an indicative net saving of $3 to $5 per year on a typical South Australian residential electricity bill.[91]

Table 12: Estimated impact of ElectraNet's MGSS project on annual electricity bills for 2020–21, 2021–22, 2022–23 ($, nominal)

Impact on customer bill	2019–20	2020–21	2021–22	2022–23
Residential customers				
Transmission component [a]	155	162	163	171
Residential annual electricity bill [b]	1941	1948	1949	1956
Annual change		7	1	7
Annual change (%)		0.3%	0.1%	0.4%
Small business customers				

[88] AER, *Final Determination – Default Market Offer Prices 2019–20*, April 2019, p. 8.

[89] We include Murraylink's revenue because other than ElectraNet, Murraylink also operates a transmission network linking Red Cliffs in Victoria and Berri in South Australia which makes up a small component of the broader transmission networks that serve South Australia and Victoria.

[90] AER, *Final Determination – Default Market Offer Prices 2019–20*, April 2019, p. 8.

[91] ElectraNet, *Main grid system strength: Contingent project application*, 28 June 2019, p. 3.

Transmission component[a]	730	760	767	801
Small business annual electricity bill[c]	9120	9151	9157	9192
Annual change		31	7	35
Annual change (%)		0.3%	0.1%	0.4%

(a) Transmission network proportions are consistent with the AER's 2018–23 revenue determination.

(b) Based on AER Default Market Offer 2019–20 using annual bill for typical consumption of 4000 kWh per year.

(c) Based on AER Default Market Offer 2019–20 using annual bill for typical small business of 20000 kWh per year.

Source: AER analysis.

B Response to submissions

This section discusses our consideration of the written submissions from the following stakeholders:

- Business SA;
- EnergyAustralia; and
- SACOSS.

We note that while written submissions raised some issues relevant to the economic evaluation, the AER's assessment of ElectraNet's application under NER clause 6A.8.2 is limited to determining the prudent and efficient costs of ElectraNet's preferred option, taking both the identified need and preferred option as given.

Table 13 sets out our response to points that Business SA raised. While Business SA recognised the need for the synchronous condensers and acknowledged the system strength gap and the intended benefit of avoiding expensive AEMO market interventions, it also considered that additional information about the project would be valuable.

Table 13: AER consideration of Business SA's submission

Point raised	AER consideration
All avoided costs associated with the \$180 million network investment should be clearly and consistently presented. While some information is provided about the \$34 million annual cost of AEMO's direct market interventions to maintain system security, this should also be displayed as monthly data over the last two to three years to demonstrate how the cost of interventions is tracking. Moreover, the combined cost of direct AEMO market interventions, and the indirect cost to the wholesale market of limiting low marginal cost energy in the price stack should also be made explicit on a monthly basis.	AEMO typically publishes data on the frequency and cost of market directions quarterly in its Quarterly Energy Dynamics reports. Monthly data was not required for us to verify that the preferred option identified in ElectraNet's economic evaluation report satisfied an economic evaluation equivalent to the RIT–T. While annualised historical direction compensation costs were estimated to be around \$34 million per annum (equivalent to around \$3 million per month), and AEMO had estimated that the indirect costs of intervention pricing produced even higher costs, ElectraNet demonstrated that the preferred option was the lowest cost and would have the highest net economic benefit even if it only avoided direct direction costs of \$22 million per annum.[92]
AEMO should clarify that the synchronous	AEMO has approved the MGSS project as

[92] ElectraNet, *addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, pp. 20–21, 25.

condenser investment would obviate the need for market interventions in the South Australian region.	being able to meet its declared system strength shortfall.[93] To the extent there are additional system strength gaps, we would expect AEMO would declare the gap under the NER rather than rely on market interventions. For example, AEMO has indicated that while the MGSS project would not remove an inertia gap from between 4,400 MWs to a secure operating level of 6,000 MWs, ElectraNet is to consider contracting non-synchronous generation and batteries to provide inertia services up to the secure operating level.[94] We also note that ElectraNet's economic evaluation report assumed that the MGSS project may only reduce market directions by $22m/annum (i.e. $12m/annum in market direction costs would remain) to provide a conservative estimate of the MGSS project's market benefits.[95]
Detail should be provided around what consideration was given to additional market benefits of generation if system strength services were procured from local generation (noting that Torrens A & B, Osborne and Pelican Point generators have been modelled to exit the market upon commissioning the SA–NSW interconnector).	The results of ElectraNet's RIT–T for the SA–NSW interconnector are still under consideration.[96] The market development modelling for that RIT–T provided by ElectraNet states that the exit of these South Australian gas generators would provide positive market benefits as this generation would be replaced by more cost effective generation sources.[97]
Detail should be provided on whether options involving generation required for system security were considered in conjunction with the State Government's current tender for its own electricity demand. If the synchronous condenser investment is about providing system security, not generating energy for the market, then this should be also clarified in relation to how the	The identified need for the investment is limited to addressing the system strength gap declared by AEMO, and not generating energy. The credible options were compared by comparing the costs against the market benefits of avoided generator direction costs and differences in timing of unrelated transmission investment.[98] Moreover, ElectraNet considered whether the proposed

93 AEMO, *Letter to ElectraNet: Proposed complete solution for system strength in South Australia*, 8 March 2019.

94 See AEMO, *NTNDP*, December 2018, p. 20. ElectraNet are currently investigating ways to provide inertia services up to the 6,000 MWs declared secure operating state. See ElectraNet, *Letter to AER Re: Request for extension of time to submit cost as through application*, 7 May 2019.

95 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, p. 25.

96 We are considering this as part of a NER cl. 5.16.6 assessment. Information on this assessment is available under: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-sa-energy-transformation-regulatory-investment-test-for-transmission-rit-t.

97 ElectraNet, *SAET RIT–T: Project assessment conclusions report*, 13 February 2019, pp. 96–99.

98 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, p. 26.

alternative options were compared.	and announced generation developments could address the system strength gap, but found these would not be viable options.[99]
Information should be provided on whether the option of leasing the synchronous condensers was investigated over purchasing given ElectraNet advises the synchronous condensers have a useful life of 30 years, but the investment timeframe was only 10 years.	ElectraNet advised that while an economic assessment over a 10 year period provided a reasonable comparison of costs based on the size, complexity and expected life of the options, the synchronous condensers would still be valuable after 10 years, as the system strength requirement is an enduring local requirement that will not be materially impacted by any foreseeable developments, such as interconnection (unlike inertia, which can be shared between regions).
The AER should consider the bill impacts for businesses, including medium sized users, and not just residential customers.	We have reported bill impacts for typical residential customers and small business customers with an annual electricity bill of $1,941 and $9,120, respectively. Since larger business customers often have individually negotiated contracts, it is difficult to accurately estimate their bill impacts. Our bill impact modelling only looks at the RAB's impact of the transmission investment, and therefore does not reflect the benefit of reduced market direction costs.

Source: Business SA, *Submission on ElectraNet MGSS contingent project*, 15 July 2019.

EnergyAustralia's submission discussed the MGSS project's overall transparency and level of detail provided. Our response to these points are discussed in table 14

Table 14: AER consideration of EnergyAustralia's submission

Point raised	AER consideration
It is unclear why the MGSS project could not have been operational sooner than about three years after AEMO identified the system strength gap.	While the AER is not responsible for the project timing, we responded expeditiously to ElectraNet's contingent project application and to its request for us to determine that the MGSS project satisfied an economic evaluation equivalent to a RIT–T. We also worked with the ESB to progress a rule change that allowed ElectraNet to submit its contingent project application to us earlier.[100]

99 ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, p. 23.

100 See AEMC, *Rule determination: National Electricity Amendment (Application period for contingent project revenue) Rule 2019*, 26 April 2019.

It is unclear why ElectraNet's RIT–T for the SA–NSW interconnector assumed the MGSS project would provide a lower level of inertia that what its contingent project application suggested. Specifically, the RIT–T assumed that only two low inertia synchronous condensers would be installed, which would require at least two additional synchronous units to be online at all times, increasing the cost of the base case.	This observation relates to ElectraNet's RIT–T for the SA–NSW interconnector, rather than to this contingent project application under rule 6A.8.2. We are considering this point as part of our assessment of whether the preferred option that ElectraNet identified in its RIT–T for the SA–NSW interconnector satisfies the requirements of the RIT–T.[101]
ElectraNet's economic evaluation report for the MGSS project had insufficient detail to understand the most efficient solution. There was no analysis of the value of each additional synchronous condenser or whether the new SA–NSW interconnector would render some of the synchronous condensers unnecessary. Similarly, there was no analysis of whether ElectraNet considered any additional non-network options to meet the short to medium term system strength requirements	The four synchronous condenser solution was a function of AEMO's technical advice and approval. Under NER clause 5.20C.4, the technical specifications and performance standards of the system strength solution must be approved by AEMO (similarly for inertia services under NER cl 5.20B.6).[102] In its economic evaluation report, ElectraNet considered the following non-network options in consultation with AEMO: new generation, conversion of existing generation and demand side solutions.[103]

Source: EnergyAustralia, *Submission on ElectraNet MGSS contingent project*, 15 July 2019.

SACOSS's submission emphasised the importance of our assessment and raised issues with the meaningfulness of consultation around the MGSS project. Our response to these points are discussed in table 15.

Table 15: AER consideration of SACOSS's submission

Point raised	AER consideration
The AER should investigate and prove valid ElectraNet's assumptions in supporting cost savings for consumers as part of the MGSS project. ElectraNet based its forecast cost savings for South Australian customers on	We considered ElectraNet's assumptions in supporting the MGSS project's cost savings for consumers when we made our determination on ElectraNet's economic evaluation report.[104] In its contingent project

101 Information on this assessment is available under: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-sa-energy-transformation-regulatory-investment-test-for-transmission-rit-t.

102 For AEMO's approval of the MGSS project, see AEMO, *Letter to ElectraNet: Proposed complete solution for system strength in South Australia*, 8 March 2019.

103 ElectraNet also considered network reinforcement. See ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019, Section 4.4., pp. 22–24.

104 See AER, *Letter to ElectraNet re: system strength gap in SA*, 18 February 2019, ElectraNet, *Addressing the system strength gap in SA: Economic evaluation report*, 18 February 2019 under

avoided direction compensation costs of $22 million per annum and avoided reactor investment costs of $10 million.	application, ElectraNet's requested capex was reduced by the cost of the avoided projects, of which the avoided reactor investment costs were slightly lower than $10 million (these were $8.9 million) but the MGSS project also resulted in avoided circuit breaker arrangement costs of $6.9 million — totalling well over $10 million in avoided capex.[105] Moreover, the $22 million per annum in avoided direction compensation costs assumed in ElectraNet's economic evaluation report were based on annualised historical direction costs of $34 million provided by AEMO and the assumption that residual direction costs would not exceed $12 million per annum based on AEMO advice that at least two synchronous generators must be online in South Australia at all times for frequency control purposes.
The AER should ensure that ElectraNet's forecast of $172.3 million expenditure is prudent and efficient, noting this is at the upper end of the range modelled in its economic evaluation report of between $140–180 million.	We assessed whether ElectraNet's forecast $172.3 million of expenditure ($169.4 million capex + $2.9 million opex) was efficient and prudent as part of this determination. We determined that the capex and opex reasonably required to complete the MGSS project was $166.0 million and $2.9 million, respectively (see sections 3.3 and 4.1).
The meaningfulness of the consumer consultation on this contingent project application is concerning. Consumers face significant challenges with assessing whether the costs in this application are prudent and efficient.	Regarding consultation on the economic evaluation report, we note that ElectraNet was not required to apply a RIT–T for the MGSS project under the new Rules that require TNSPs to maintain minimum levels of system strength.[106] Specifically, clause 5.16.3(a)(11) exempts TNSPs from applying the RIT–T to a proposed network investment in specific circumstances.[107]

Source: SACOSS, *Submission on ElectraNet MGSS contingent project*, 11 July 2019.

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https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/electranet-economic-evaluation-main-grid-system-strength-project-contingent-project-trigger.

105 ElectraNet, *Main grid system strength project: Contingent project application*, 28 June 2019, p. 19.

106 AEMC, *Rule determination: National Electricity Amendment (Managing power system fault levels) Rule 2017*, 19 September 2017.

107 These circumstances include where: (1) AEMO provides a notice to a TNSP declaring a fault level shortfall in a region under the new system strength framework; (2) prior to the declaration, the TNSP is not under an obligation to provide system strength services; and (3) the time for making the system strength services available is less than 18 months after the notice is given by AEMO.