SA Transmission Network Voltage Control

RIT-T Project Specification Consultation Report

DECEMBER 2022

ElectraNet

Executive Summary

South Australia remains at the forefront of the global energy transformation. This is bringing with it a range of challenges as renewable energy sources such as solar, wind and storage and distributed energy resources in homes and businesses continue to displace traditional generation and drive two-way power flows across the network.

The transmission network is playing an essential role in helping to manage an increasingly complex power system, providing important system services, that are being lost as conventional thermal generation decommits, to ensure safe, secure, reliable and affordable supply of electricity to customers into the future.

The **identified need** of this RIT-T is to ensure sufficient static and dynamic voltage control capability within South Australia to satisfy S5.1a.4, S5.1.4 and S5.1.8 of the National Electricity Rules (NER).

This is a reliability corrective action requiring ElectraNet to identify the lowest cost technically feasible option that meets the identified need.

A forecast shortfall in reactive power management capability is emerging across the network due to a range of factors as the energy system continues to evolve, including:

- The need to offset 1200 Mvar of transmission line charging on the transmission network during low or zero demand conditions caused by distributed solar PV offsetting demand (at higher load levels, transmission line charging is typically offset by transmission line reactive power losses and by inductive customer demand)
- An increasingly frequent need to offset transmission line charging by using up the reserve dynamic capability on the network that is needed to manage credible and non-credible contingency events
- An emerging trend of connected loads becoming less inductive (to the point of becoming capacitive) across the day reducing the network's capability to offset line charging
- An increase in rapid daily load fluctuations caused by intermittent distributed solar PV (e.g. due to rapidly changing cloud cover) as well as the more predicable forecast daily load profile dominated by distributed solar PV, which requires increased automation of reactive and voltage control plant to manage the consequent voltage changes
- Forecast closures of metropolitan thermal generators leading to a loss of voltage control capability

The gap in voltage control capability is estimated as 200-400 Mvar reactive power support capability in the Adelaide Metropolitan region and 50-100 Mvar in the South East of South Australia.

We have identified **three credible network options** that are technically and economically feasible and meet the identified need. These options include transmission and distribution connected static and dynamic reactive power control.

We consider that **non-network options** may also be able to assist in meeting the identified need. The identified need could be supported by the following, connected in the right locations on the South Australian network:

- Virtual power plants providing an aggregated voltage control response, and
- Generators or Battery Energy Storage Systems providing a service in excess of their Generator Performance Standards.

ElectraNet welcomes written submissions on this Project Specification Consultation Report (PSCR) by 17 March 2023. Submissions are sought on the options presented, any other credible options available to address the identified need, the classification of this identified need for reliability corrective action and the assessment of materiality of market benefit categories.

Submissions should be emailed to consultation@electranet.com.au. Submissions will be published unless a proponent marks their submission (or part of it) as confidential at the time of the submission.

The Project Assessment Draft Report (PADR), which is the second stage of the RIT-T process, will include a full options analysis. We expect to publish it by the end of June 2023.

Contents

1. Introduction 8

1.1. Reason that ElectraNet considers this RIT-T necessary 8

1.2. Submissions and Next Steps 8

2. Context 9

2.1. Overview of the existing South Australian transmission network 9

2.2. Existing voltage control capability 10

2.3. Transmission Line Charging 12

2.4. Capacitive loads 12

2.5. Dynamic reactive device utilisation 13

2.6. Manually operated voltage control equipment 15

2.7. Joint planning of transmission and distribution voltage control needs 15

2.8. Emergency Transmission Network Voltage Control project 16

3. Identified Need 17

3.1. Voltage control requirements 18

3.2. Assumptions made in relation to the identified need 19

3.3. Related needs that may be impacted by the selection of the preferred option to meet the identified need considered in this RIT-T 23

3.4. Required technical characteristics of non-network solutions 24

3.5. Requirement to apply the RIT-T 25

4. Credible Options to Address the Identified Need 26

4.1. Option 1: Transmission connected 275 kV reactors 26

4.2. Option 2: Transmission connected 275 kV or 66 kV dynamic reactive devices . 27

4.3. Option 3: Distribution connected reactive plant 27

4.4. Non-network solutions 27

4.5. Options considered but not progressed 29

4.6. Material inter-network impact 29

5. Materiality of Market Benefits for the RIT-T Assessment 31

5.1. Market Benefits that are material for this RIT-T 31

5.2. Market benefits that are not material for this RIT-T 31

Tables

Table 1 Potential locations and capacities for non-network solutions 28

Figures

Figure 1 South Australian electricity transmission system map 9

Figure 2 Daily average reactive demand of Adelaide Metropolitan connection points 13

Figure 3 Para SVCs and metropolitan generators reactive power output 14

Figure 4 Forecast reactive power capability available from conventional generators 14

Figure 5 Permissible percentage overvoltage after a credible contingency event by duration, as defined in NER Figure S5.1a.1 18

Figure 6 South Australia Minimum Demand Forecast 21

Appendices

Appendix A Compliance checklist 34

Abbreviations

AER	Australian Energy Regulator
DER	Distributed Energy Resources
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
PADR	Project Assessment Draft Report
PSCR	Project Specification Consultation Report
PV	Solar Photovoltaic
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
STATCOM	Static Synchronous Compensator
SVC	Static VAR Compensator
TNSP	Transmission Network Service Provider

1. Introduction

1.1. Reason that ElectraNet considers this RIT-T necessary

This Project Specification Consultation Report (PSCR) has been prepared by ElectraNet in accordance with the requirements of the National Electricity Rules (NER) clause 5.16.4. This report represents the first stage of the formal consultation process set out in the NER in relation to the application of the Regulatory Investment Test for Transmission (RIT-T).

This PSCR:

- describes the identified need which ElectraNet is seeking to address, together with the assumptions used in identifying this need
- sets out the technical characteristics that a non-network solution would be required to deliver in order to address this identified need
- describes the credible options that ElectraNet currently considers that would address the identified need
- discusses specific categories of market benefit which in the case of this RIT-T assessment are unlikely to be material.

Section 4.2 of the AER Application Guidelines for RIT-T provides more detail on the requirements for the PSCR.[1]

1.2. Submissions and Next Steps

ElectraNet welcomes written submissions on this PSCR, which are due on or before 17 March 2023. Submissions are sought on the credible options presented, options to address the need, the classification of this identified need as for reliability corrective action and the assessment of materiality of market benefit categories.

Submissions should be emailed to consultation@electranet.com.au. Submissions will be published on the ElectraNet website. If you do not wish your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

A Project Assessment Draft Report (PADR), including full option analysis, is expected to be published by end of June 2023.

[1] AER Application Guidelines RIT-T August 2020 page 61

2. Context

2.1. Overview of the existing South Australian transmission network

Figure 1 is a map of South Australia's electricity transmission network.

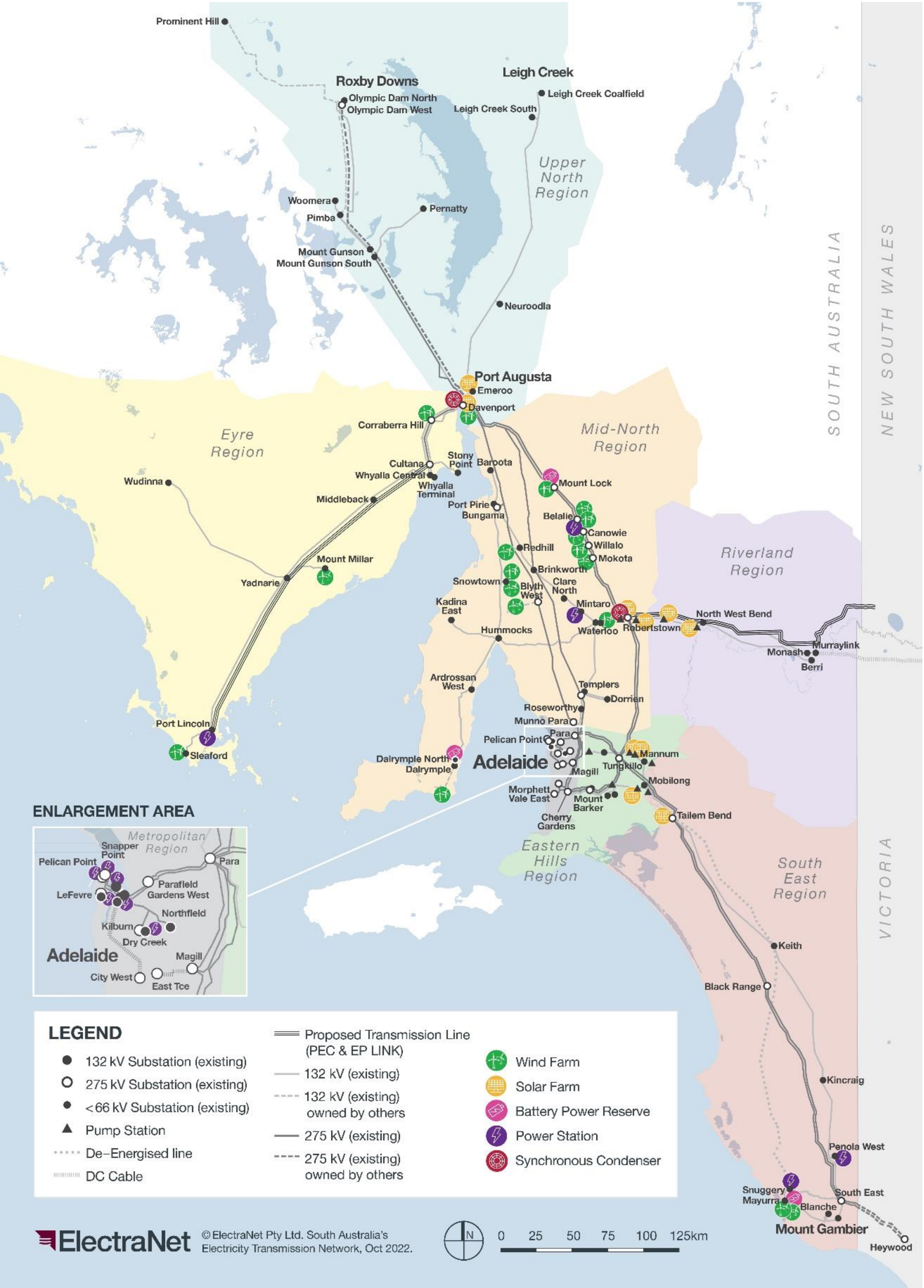

Figure 1 South Australian electricity transmission system map

The South Australian electricity transmission network consists primarily of transmission lines operating at 275 kV and 132 kV. It connects the major South Australian load centres with various sources of generation.

The Main Grid is a meshed 275 kV network that extends from Cultana substation (near Whyalla) to South East substation (near Mount Gambier). It covers seven regions: Metropolitan, Eastern Hills, Mid North, Riverland, South East, Eyre Peninsula and Upper North.

Most base load and intermediate conventional generators are gas-fired and located in the Adelaide metropolitan area, while peaking power stations are spread across the electricity network. Renewable supply of electricity comes from a large and growing fleet of grid connected wind and solar farms and distribution system connected solar photovoltaic (PV) installations.

South Australia has two interconnectors that connect South Australia to the Victorian region of the National Electricity Market (NEM):

- Heywood High Voltage AC (HVAC) interconnector (established in 1989) in the state's South East
- Murraylink High Voltage DC (HVDC) interconnector (established in 2002) in the Riverland.

South Australian generation has typically been supplemented by imported energy from Victoria since these interconnectors were established, especially at times of high demand. In recent times, due to the high penetration of renewable generation in South Australia, surplus generation is increasingly exported through the two interconnectors.

A third interconnector, Project EnergyConnect, will be a HVAC interconnector running in parallel to the Murraylink interconnector and extending into New South Wales to Wagga Wagga. It remains on track to be delivered in two stages:

- Stage 1: the completion of construction from Robertstown in South Australia to Buronga in NSW, energisation and commissioning in late 2023, with inter-network testing and release of initial transfer capability up to 150 MW over the following six months
- Stage 2: the completion of the second section from Buronga to Wagga Wagga in NSW, energisation and commissioning in late 2024, with inter-network testing and release of transfer capacity up to 800 MW over 12-18 months, subject to market demand.

2.2. Existing voltage control capability

ElectraNet operates a range of static voltage control devices including fixed and switchable reactors, capacitors and dynamic reactive plant that provide voltage control capability.

Reactors are inductive devices that absorb reactive power and reduce voltage levels whilst capacitors are capacitive devices that generate reactive power and raise voltage levels.

Utilising the capability of reactors and capacitors to absorb and produce reactive power is part of the voltage control strategy to maintain satisfactory operating margins of dynamic reactive devices.

The dynamic reactive devices that provide voltage control at key points on the transmission network include:

- static var compensators (SVCs) at Para substation (Metropolitan region) installed in 1989

- SVCs at South East substation (South East region) installed in 1989
- synchronous condensers at Davenport substation (Upper North region) installed in 2021
- synchronous condensers at Robertstown substation (Riverland region) installed in 2021.

Static reactive power devices that provide voltage control include fixed and switched reactors and capacitors and are spread across the 275 kV and 132 kV network substations. These include:

- Four 275 kV reactors at Davenport substation (Upper North region) installed progressively from 2009
- A 275 kV reactor at Tempers West substation (Mid North region) installed in 2018
- A 275 kV reactor at Para substation (Metropolitan region) installed in 2016
- 275 kV reactors at City West substation (Metropolitan region) installed in 2011.

Permanently in-service 275 kV reactors are also installed at each end of the Tailem Bend-South East 275 kV lines (South East region) established in 1989.

There are also small lower-voltage switched reactors installed on the transmission system, for example on the tertiary windings of transformers.

Voltage control is also available from varying levels of reactive power support from generators, battery storage systems and the Murraylink HVDC interconnector.

The total reactive power absorb capability of these ElectraNet-owned devices is 660 Mvar, consisting of:

- 390 Mvar of transmission connected switched reactors
- 200 Mvar of dynamic reactive power capability from dynamic reactive plant (SVCs and synchronous condensers)
- 70 Mvar of transmission connected fixed reactors (including those committed).

To manage critical state-wide and regional contingencies, we reserve an additional total of 332 Mvar of dynamic reactive power absorb capability on the dynamic reactive plant, consisting of 150 Mvar of capability on the SVCs and 182 Mvar on the synchronous condensers.

Transformers are also an important source of voltage control for regional 132 kV systems and for individual connection points. Most 275/132 kV transformers and connection point transformers have a range of selectable tap positions, and the operating tap position can be adjusted by the operation of an on-load tap changer (OLTC) either by operator action or controlled by an automatic voltage regulating relay.

In addition to ElectraNet's devices, synchronous and renewable generators and grid connected BESS are also sources of reactive power and voltage control capability. The capabilities of generators are usually only available when the generators are dispatched.

However, increasingly, some renewable generators can provide reactive capability without providing active power, and BESS capability is available under most operating conditions. The availability or unavailability of this capability is considered in our planning based on respective performance standards.

2.3. Transmission Line Charging

Transmission lines that are lightly loaded produce capacitive reactive power, usually referred to as line charging or line capacitive charging. If the line charging is not offset by sources of inductive reactive power, the excess line charging leads to voltage rise. The amount of line charging is affected by the transmission network's operating voltage level and the length of transmission lines. The higher these parameters and the lower the power flows on the transmission network, the more the line charging that needs to be managed.

The South Australian transmission network generates up to 1,200 Mvar of line charging if there are near-zero flows on the transmission network.

Falling minimum demand levels due to the continuing growth in distribution connected solar PV is resulting in reduced demand on the transmission network under sunny mild weather conditions. In the Adelaide metropolitan area, the electrical energy supplied by distribution connected solar PV can at times meet or even exceed the underlying demand. This is leading to times of very low power flows on transmission lines.

At times when there is low overall demand, transmission connected wind farms can be generating at low or zero output, further contributing to low power flows throughout the transmission network. Under these conditions, many wind farms are unable to provide voltage control support.

Exposure to high levels of line charging is increasing the transmission system's overall voltage profile that if not appropriately managed could lead to damaging over-voltages on the network that exceed the limits specified in the NER.

2.4. Capacitive loads

The characteristics of load on the electricity network are changing with an observed trend in load becoming less inductive (more capacitive). This is also driving an increase in voltage levels. AEMO has advised that this trend is likely caused by the increasing use of electronic devices and appliances by customers across the network and increased undergrounding of the distribution network in new estates.

Figure 2 shows that from 2018 inductive loads have declined by about 60 Mvar in the Adelaide Metropolitan. AEMO has advised that inductive loads in this region are forecast to continue to decline[2]. A decline in inductive loads will increase the need to manage increasingly high voltage levels at connection points.

This trend is compounding the increasing voltages observed during the middle of the day as there is a reducing amount of inductive reactive load to contribute towards offsetting line charging.

[2] AEMO, 2022 Network Support and Control Ancillary Services (NSCAS) Report, page 38. Available at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2022/2022-nscas-report.pdf?la=en.

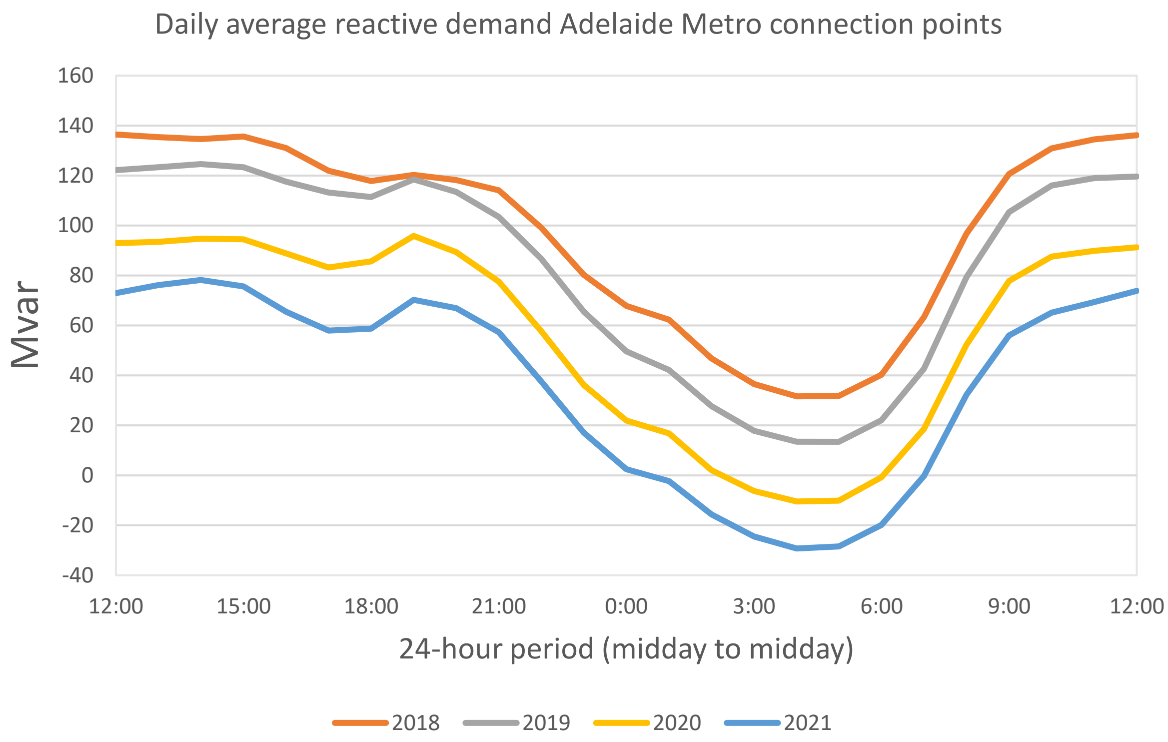

Figure 2 Daily average reactive demand of Adelaide Metropolitan connection points

2.5. Dynamic reactive device utilisation

Sufficient dynamic voltage control capability must be maintained across the transmission network to manage the impact of disturbances on the power system. A portion of dynamic reactive power absorb capability is therefore reserved for the management of critical contingencies as noted in section 2.2. Dynamic reactive plant includes SVCs and synchronous condensers, in addition to the contribution of online synchronous generators, renewable generators and BESS.

The increased exposure to transmission line charging and the reduction in offsetting inductive reactive loads is driving increased voltage levels and causing existing dynamic and static reactive power devices on the transmission network to reach the limits of their ability to keep transmission system voltage levels within limits during system normal conditions.

This is limiting the capacity of dynamic reactive plant to respond to critical contingencies.

Figure 3 shows the historical utilisation of ElectraNet's SVCs at Para (including contributions from metropolitan generators and reactors) highlighting how rapidly the grid has moved in two years from typically inductive to almost always capacitive.

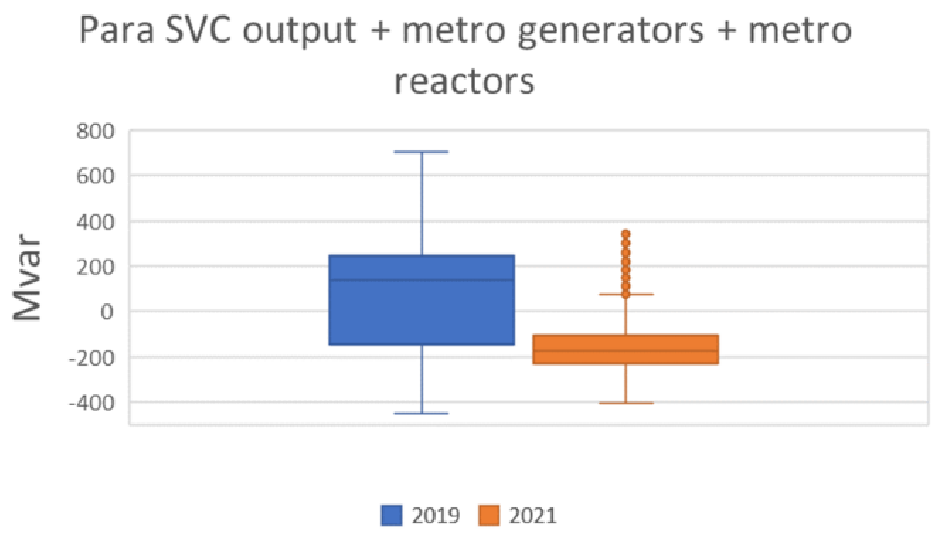

Figure 3 Para SVCs and metropolitan generators reactive power output

As outlined in Section 2.2, a total of 660 Mvar of reactive power absorb capability is available from ElectraNet-owned devices to manage the 1,200 Mvar of transmission line charging. Under certain system conditions we forecast a growing shortfall in the reactive power absorb capability of the grid diminishing the dynamic capability on the network to maintain stability following system disturbances.

Apart from the ElectraNet-connected devices mentioned in section 2.2, reactive power is also managed by utilising the capability of online conventional thermal generators to absorb reactive power. However, we forecast that these generators and their reactive support capability will be increasingly offline at times of low grid demand as the electrical energy supply mix continues its transition from conventional generators to renewable generation sources (Figure 4).

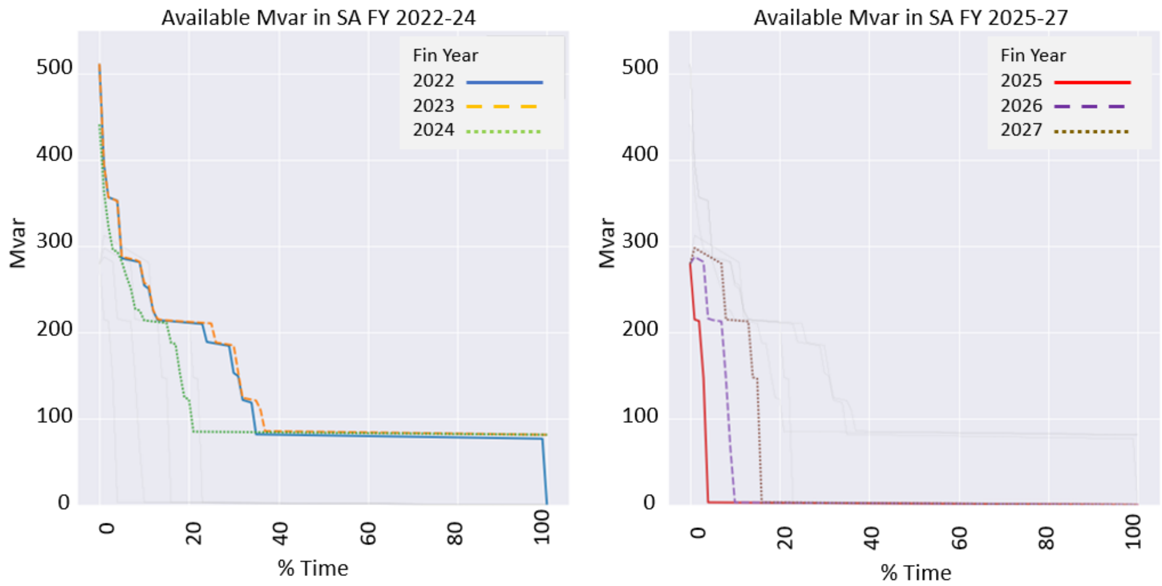

Figure 4 Forecast reactive power capability available from conventional generators

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Beyond 2024-25, without additional investment in reactive power capability, the permissible voltage limits specified in NER S5.1a.4 will at times be exceeded when there are no conventional generators online.

To increase South Australian generator dispatch flexibility, we are currently exploring the ability to operate the South Australian power system with only one large synchronous generating unit in-service. Our analysis is ongoing, but we expect that to manage voltage levels in the metropolitan region during conditions of low system demand two conventional generating units are still required until Project EnergyConnect is in operation. Increasing the amount of available inductive reactive power in South Australia may reduce the load level at which South Australia can be satisfactorily operated with only a single conventional generating unit in-service.

As described in section 2.2, we reserve an additional total of 332 Mvar dynamic reactive power absorb capability is reserved on the dynamic reactive plant, consisting of 150 Mvar of capability on the SVCs and 182 Mvar on the synchronous condensers. Increasingly, we are needing to operate the SVCs and synchronous condensers outside of this target range to offset transmission line charging at times when other offsetting sources are insufficient. At such times this means that they may reach operating limits during normal system conditions, curtailing their ability to respond to potential system disturbances.

Additional sources of inductive reactive power are required, to ensure that the SVCs and synchronous condensers can be operated within their target ranges so that their dynamic capability is available to respond to system disturbances and maintain system security as originally designed.

2.6. Manually operated voltage control equipment

Currently, many of ElectraNet's switched reactive devices and transformer tap changers are manually operated, relying on operator action to maintain adequate voltage levels in response to changing load levels that have in the past occurred gradually and predictably over the course of each day.

Large load fluctuations are becoming increasingly rapid and occurring with increasing frequency, due to increasing distributed solar PV installations and the effect of changing weather patterns (e.g. intermittent cloud cover) on solar PV generation output. This is creating the need for dynamic and frequent switching of voltage control devices. This requirement is forecast to further increase and become more challenging to manage over the foreseeable future as minimum demand levels drop further below zero. This makes manual operator action to maintain adequate voltage control during rapid power swings increasingly challenging.

Soon the increasing rapidity of fluctuations is expected to make manual voltage control unmanageable.

2.7. Joint planning of transmission and distribution voltage control needs

ElectraNet and SA Power Networks regularly conduct joint planning to coordinate efficient voltage management solutions across the South Australian transmission and distribution networks. This is achieved by considering voltage obligations applicable to the transmission and distribution networks, identifying the voltage control facilities available for use, developing and documenting a shared voltage control philosophy and identifying how voltage control performance will be monitored to achieve efficient voltage management.

Voltage control is generally most efficiently addressed close to where it is needed. For example, voltage control issues that arise on the transmission network are usually most efficiently addressed on the transmission network.

Those that arise on the distribution network are usually most efficiently addressed on the distribution network. Voltage control and reactive power interactions also occur between the transmission and distribution networks. These need a coordinated approach.

Voltage control joint planning activities are enabled by a Joint Voltage Control Working Group, which is a forum for ElectraNet and SA Power Networks to collaborate on emerging issues, identify opportunities, and provide oversight on agreed short- and long-term implementation actions for voltage control. The Joint Voltage Control Working Group is comprised of planning and operational representatives from both ElectraNet and SA Power Networks. It enables joint assessment of shared challenges to deliver effective and efficient outcomes for customers as it considers transmission, distribution, operational and network support solutions. It also enables collaborative voltage control performance monitoring, which helps to identify new trends such as the changing reactive power nature of loads supplied by the distribution network.

2.8. Emergency Transmission Network Voltage Control project

On 1 September 2022 we identified an urgent need to mitigate emerging voltage control risks that are forecast to be experienced at times of very low system demand over the 2022-23 summer. These issues are exacerbated by the extended unavailability of Para SVC No. 2, which is expected to return to service in September 2023, as well as higher than expected outages of reactive plant on the network.

Beyond the restoration of the SVC, the expected future reduction of minimum conventional generator dispatch from two units to one unit is also expected to increase the challenge of providing adequate voltage control at times of low demand.

To address the immediate need, we are installing a spare 50 Mvar reactor at Happy Valley as soon as possible – ideally, before the end of summer 2022-23, to address high voltage levels at times of very low demand from autumn 2023 onwards.

The immediate installation of the reactor at Happy Valley is a “no regrets” action that will reduce the total size of the solution needed to meet the identified need of this RIT-T.

To expedite the installation of the reactor at Happy Valley, the existing 275 kV 100 Mvar capacitor at Happy Valley and its associated three-phase ganged circuit breaker will be disconnected, to enable the reactor to be installed in the 100 Mvar capacitor’s current position and utilise the capacitor’s existing connecting plant (e.g. current transformers, surge arrestors, etc., subject to suitability being confirmed).

Our high-level estimate for the Emergency Transmission Network Voltage Control project is $6.8 million. There are no immediate alternatives available to ElectraNet that would be cost competitive with installing the reactor.

The 100 Mvar capacitor is not needed at current maximum demand levels, or at levels that are forecast for the near future. However, forecast load growth within South Australia is expected to result in a need for the Happy Valley capacitor bank to re-emerge within the next 5-10 years. To meet this need, re-connection of the Happy Valley capacitor bank in an alternative arrangement at Happy Valley is included in the scope of the credible options being considered in this RIT-T.

3. Identified Need

This section describes the identified need, the assumptions used in identifying it, and the reason ElectraNet considers reliability corrective action is necessary. It also specifies the technical characteristics of the identified need that a non-network solution would be required to deliver.

The **identified need** of this RIT-T is to ensure sufficient static and dynamic voltage control capability within South Australia to satisfy S5.1a.4, S5.1.4 and S5.1.8 of the NER.

The forecast shortfall in reactive power management capability is emerging across the network due to a range of factors as the energy system continues to evolve including:

- The need to offset 1200 Mvar of transmission line charging during low or zero demand conditions caused by distributed solar PV (at higher load levels, transmission line charging is typically offset by transmission line reactive losses and by inductive customer demand)
- An increasingly frequent need to offset transmission line charging by using up the reserve dynamic capability on the network that is needed to manage credible and non-credible contingency events
- An emerging trend of connected loads becoming less inductive (to the point of becoming capacitive) across the day reducing the network's capability to offset line charging
- An increase in rapid daily load fluctuations caused by intermittent distributed solar PV (e.g. due to rapidly changing cloud cover) as well as the more predicable forecast daily load profile dominated by distributed solar PV, which requires increased automation of reactive and voltage control plant to manage the consequent voltage changes
- Forecast closures of metropolitan thermal generators leading to a loss of voltage control capability.

The gap in voltage control capability is estimated as 200-400 Mvar reactive power support capability in the Adelaide Metropolitan region and 50-100 Mvar in the South East of South Australia.

Meeting this identified need will ensure voltage performance standards are met, the ability to minimise disruption to the South Australian transmission and distribution networks is maintained, and the probability of cascading failure in response to system disturbances is significantly reduced.

Network options are presented in section 4 of this report.

The technical characteristics for network support proponents to respond to address the identified need are available in section 3.4.

3.1. Voltage control requirements

This section presents a summary of the voltage control requirements that relate to the identified need, and how they relate to the NER and other requirements.

3.1.1. NER S5.1a.4 Power Frequency Voltage

S5.1a.4 provides that

except as a consequence of a contingency event, the voltage of supply at a connection point should not vary by more than 10 percent above or below its normal voltage".[3]

S5.1a.4 further provides that

as a consequence of a credible contingency event, the voltage of supply at a connection point should not rise above its normal voltage by more than a given percentage of normal voltage for longer than the corresponding period shown in Figure S5.1a.1 for that percentage".

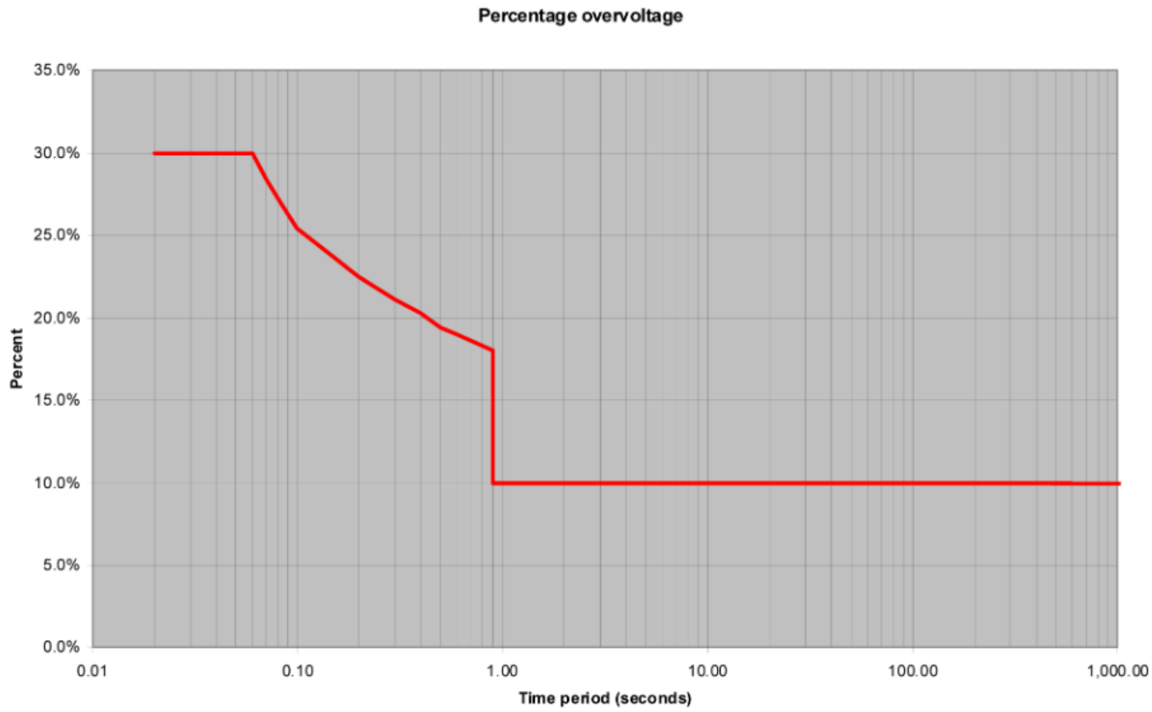

Figure 5 Permissible percentage overvoltage after a credible contingency event by duration, as defined in NER Figure S5.1a.1

[3] The NER Glossary defines normal voltage as "in respect of a connection point, its nominal voltage or such other voltage up to 10% higher or lower than nominal voltage, as approved by AEMO, for that connection point at the request of the Network Service Provider who provides connection to the power system."

3.1.2. NER S5.1.4 Magnitude of power frequency voltage

S5.1.4 requires a TNSP to plan and design the transmission system for control of voltage such that:

- variations in magnitude are consistent with S5.1a.4
- as a consequence of a contingency or protected event voltage varies in accordance with S5.1a.4
- otherwise voltages remain between 95 and 105 percent of the target voltage[4], and
- at all times the supply remains between 90 percent and 110 percent of normal voltage.

3.1.3. NER S5.1.8 Stability

S5.1.8 requires, among other things, that:

> *stable voltage control must be maintained following the most sever credible contingency event. This requires that an adequate reactive power margin must be maintained at every connection point in a network*.

Further,

> *a Network Service Provider must consider non-credible contingency events such as busbar faults which result in tripping of several circuits, uncleared faults, double circuit faults and multiple contingencies which could potentially endanger the stability of the power system.*

Where the consequences of such an event are likely to be severe disruption to "any network or to any Registered Participant", an emergency control must be installed to "minimise disruption to any transmission or distribution network and to significantly reduce the probability of cascading failure."

The emergency control in this case is provided by maintaining the appropriate level of reserve capacity on the dynamic devices in South Australia.

3.2. Assumptions made in relation to the identified need

This section describes the assumptions made in the assessment of the identified need. Power system studies were performed to identify the need considering:

- connection point voltage targets
- dynamic reactive device operating margins
- system demand
- renewable generation dispatch
- battery energy storage systems dispatch
- conventional generation dispatch
- committed network developments
- network redundancy.

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[4] "Target voltage" is as defined in S5.1.4(c) of the NER.

3.2.1. Connection point voltage targets

Connection point voltage targets are defined through joint planning of voltage control between ElectraNet and SA Power Networks. The voltage control targets will ensure that the existing capability of connection point transformers to lower voltage levels (i.e. the on-load tap changer buck range) is appropriately utilised to slightly lower sub-transmission voltage levels and efficiently manage voltage rise on the distribution network, while minimising the impact on transmission system voltage levels of capacitive charging from the distribution network lines and cables.

However, where connection point transformer buck taps are fully utilised, voltage levels on the local distribution network are fully exposed to upward fluctuations of voltage level on the supplying transmission system.

Target voltages are not definitive. The targets may be changed where an increased range is tolerable and does not place system security at greater risk than alternative solutions.

3.2.2. Dynamic reactive device operating margins

SVCs are fast-acting dynamic devices that provide reactive power support and voltage control used to manage credible and non-credible events. Synchronous condensers provide dynamic reactive power support in a manner similar to a conventional generator.

Typically, within Australia and internationally, TNSPs operate dynamic reactive devices at a level close to zero Mvar during normal system conditions to reserve an appropriate dynamic range for them to respond effectively to critical contingencies. This is achieved by switching static dynamic plant, such as reactors and capacitors, in and out of service as needed. Emergency control of the system following disturbances caused by the occurrence of critical contingencies is achieved by maintaining an appropriate level of dynamic reactive power reserve during normal system conditions.

This is a common approach to voltage control planning.

In system normal planning studies (i.e. with all equipment in service), ElectraNet plans to have sufficient switchable reactors and capacitors to ensure that each item of dynamic reactive control plant (i.e. SVCs and synchronous condensers) can typically be operated at an output level of between 25 Mvar (inductive) and 0 Mvar.

3.2.3. System demand

AEMO’s 2022 ESOO forecasts declining minimum demands in South Australia as shown in Figure 6. This will result in more frequent operation of the grid at low, zero or negative demand. It will also increase the rate of change in demand and hence the need to automatically switch voltage control devices to manage the change in demand.

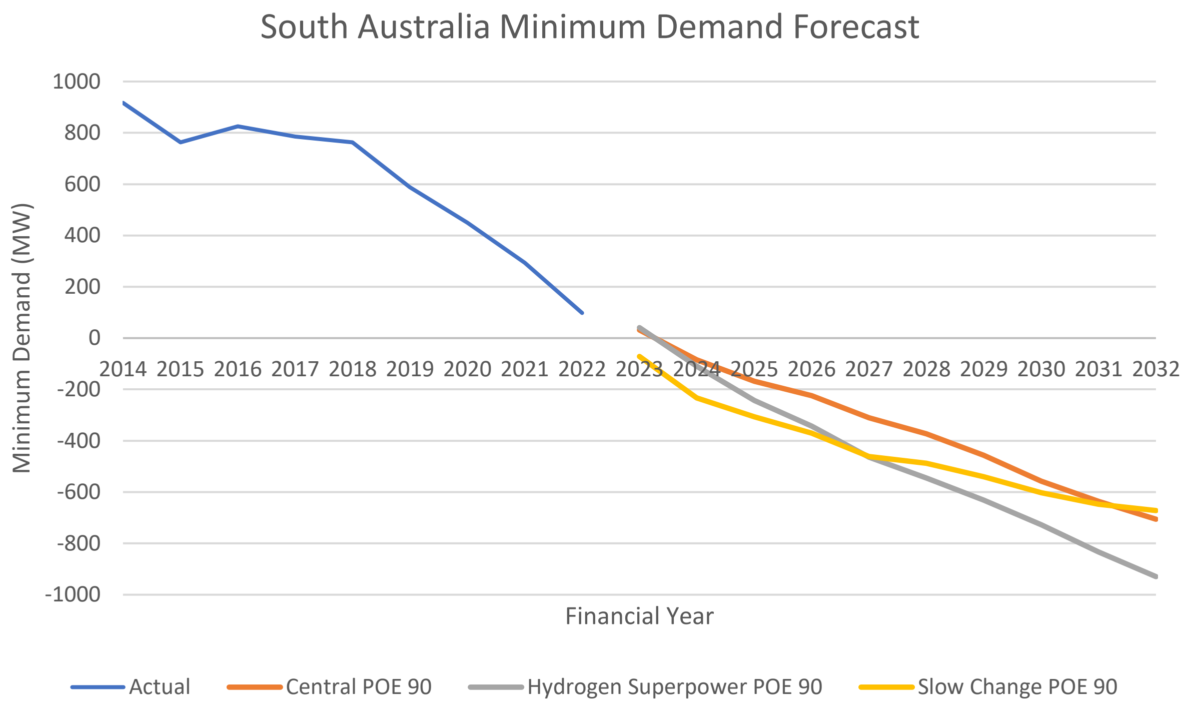

Figure 6 South Australia Minimum Demand Forecast

Source: AEMO, 2022 ESOO

3.2.4. Renewable generation dispatch

In determining the identified need, ElectraNet has tested different plausible levels and combinations of dispatch for grid connected renewable generators. Different combinations of solar and wind generation were assumed either offline, on full capacity output, or at maximum levels allowable subject to the capability to accommodate their output under minimum demand conditions.

Modern wind farms can provide significant reactive support to the grid when generating active power. The level of reactive support that is available depends on the level of active power output on some wind turbines. No reactive support is available when some wind farms operate to very low or zero active power output aside from what is available from their dynamic reactive device (usually a STATCOM) and static reactive plant. However, a small number of existing wind farms can provide reactive power at times of no wind. The studies assumed zero active power output from wind generators, with reactive power support only available from wind generators that have an established capability to provide reactive power under those conditions.

Grid connected solar farms have historically been observed to provide reactive support during daylight hours even at zero MW active power output. Therefore, our analysis assumes they will continue to provide support for voltage control at such times.

In our determination of the identified need, we have assumed a total inductive reactive power contribution of up to 54 Mvar from existing wind farms that are able to provide support at times of zero active power generation, and up to 123 Mvar from existing solar farms.

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3.2.5. Battery Energy Storage Systems dispatch

Battery energy storage systems (BESSs) were assumed in our analysis to be online with zero MW dispatch. Their reactive power support was assumed to be available.

In our determination of the identified need, we have assumed a total inductive reactive power contribution of up to 57 Mvar from existing BESSs.

Torrens Island BESS is an anticipated project.[5] We plan to include it in all scenarios used for assessment in this RIT-T.

3.2.6. Conventional generation dispatch

From 2025, no conventional generation was assumed to be online during low demand conditions. In keeping with Generator Performance Standards, no reactive power support was assumed to be available. See figure 4 for a forecast of reactive support from metropolitan generators.

3.2.7. Committed network developments

ElectraNet's relevant committed projects are described below:

- Eyre Peninsula Link: construct a new double-circuit line from Cultana to Yadnarie initially energised at 132 kV with a rating of about 300 MVA per circuit, with the option to be energised at 275 kV with a rating of about 600 MVA if required in the future. Construct a new double-circuit 132 kV line from Yadnarie to Port Lincoln, rated to about 240 MVA per circuit
- Project Energy Connect: South Australia to New South Wales interconnector - construct a new 330 kV, 800 MW interconnector from Robertstown in South Australia to Wagga Wagga in New South Wales, via Buronga. Turn in the Robertstown to Para 275 kV line at Tungkillo
- Tailem Bend-Cherry Gardens 275 kV line turn-in at Tungkillo.

3.2.8. Network redundancy

ElectraNet's network is aging. To maintain a safe and reliable network, ElectraNet undertakes maintenance activities year-round excluding the highest demand periods where all network assets are required. To enable appropriate maintenance to be carried out, it is necessary to be able to remove any single item of plant from the network under most operating conditions.

The dominant contributing cause of high voltage conditions on the transmission network is low or zero net demand, which is projected to occur with increasing frequency as customers continue to adopt distributed solar PV. This requires that we have a sufficient buffer of voltage control capability over the whole year to enable planned and unplanned maintenance activities.

We have therefore adopted a planning criterion such that satisfactory voltage levels will be maintained under zero and very low demand conditions with any single item of equipment out of service, such that satisfactory voltage levels would continue to be maintained if a credible contingency event was to occur. We consider this to be good electricity industry

[5] AEMO's NEM Generation Information October 2022, October 2022, available at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

practice as defined in the glossary of the NER, and in line with clause 2.1.1 of the SA Electricity Transmission Code.[6]

3.3. Related needs that may be impacted by the selection of the preferred option to meet the identified need considered in this RIT-T

The related needs discussed in this section do not themselves form part of the identified need for this RIT-T. However, the selection of the preferred option to address the identified need considered in this RIT-T may impact on other "related needs" that are discussed in the sections that follow.

3.3.1. Increasing dynamic voltage variability

The reducing dispatch of conventional generators is resulting in a dynamic voltage that is "less stiff" than it was in the past. That is, dynamic voltage responses to system disturbances (such as 275 kV faults) are becoming larger.

At the same time, there is a large population of solar PV systems that disconnect in response to dynamic depressions of the connection voltage level.

275 kV faults close to the metropolitan area have been observed to cause many of these solar PV systems to disconnect, increasing the disturbance to the system.[7] To manage this risk, AEMO applies constraints on imports to South Australia across the Heywood interconnector at times of high solar PV output to maintain stability if such an event were to occur.

Installing dynamic reactive support at key locations across the system may mitigate the depth of the voltage depression that is experienced in response to a 275 kV system fault. Doing so may reduce the amount of solar PV systems that disconnect in response to such system disturbances.

This need is likely to be addressed most effectively at a location between the 275 kV system (where the most onerous faults with the widest impact occur) and the sub-transmission system.

3.3.2. Indistinct events

Indistinct events are weather-related events that impact on the inputs to the power system or the power system itself. Recent experience shows that these events are increasing in short-term variability, unpredictability, and severity. S5.1.8 of the NER states that in planning the network multiple contingency events must be considered that could potentially endanger the stability of the power system. These multiple contingencies could be attributed to indistinct events.

3.3.3. Distribution customer voltage control

SA Power Networks provides supply to LV connections (nominally 230 V) with a voltage level that is permitted to vary between 216 V and 253 V, in accordance with the

6 The SA Electricity Transmission Code is available at https://www.escosa.sa.gov.au/industry/electricity/codes-guidelines/codes.

7 AEMO, May 2021, Behaviour of distributed resources during power system disturbances, Appendix A1. Available at https://www.aemo.com.au/-/media/files/initiatives/der/2021/capstone-report.pdf?la=en&hash=BF184AC51804652E268B3117EC12327A.

requirements of AS 60038 Standard Voltages. Voltages at customer connection points vary between these limits during system normal peak and light load conditions.

As described in section 2.7, ElectraNet and SA Power Networks have agreed a set of target voltage levels for connection points. These target voltages complement the ability of zone substations to hold steady-state customer voltage levels within the required range. If connection point voltage levels were to rise above the agreed target voltages, increased investment may be needed to enhance the ability of the distribution network to hold steady-state customer voltage levels within the required range.

3.4. Required technical characteristics of non-network solutions

This section describes the technical characteristics that a non-network solution would be required to deliver to address the identified need.

Power system studies indicate that the most effective locations for adding inductive reactive power capability, or dispatchable load or generation services, energy storage devices, or any other equipment/ services to manage high voltage issues in the SA transmission network are in the Adelaide Metropolitan area.

Additional inductive reactive power capability in the Adelaide Metropolitan area will improve and enhance the ability for the SVCs at Para to maintain fine voltage control regulation at Para, with a beneficial impact on voltage control for the entire 275 kV system.

Power system studies also indicate that additional inductive reactive power capability is required in the South East region.

Section 4.4 provides information about the transmission network's ability to accommodate reactive power control capability at connection points near the Adelaide Metropolitan region and at South East.

The total amount of inductive reactive power required in the Adelaide Metropolitan region is about 200-400 Mvar, depending on where it is provided.[8] The amount required in the South East is about 50-100 Mvar, depending on its location.

The inductive reactive power capability must be

- Over and above any capability defined in agreed performance standards, e.g. Generator Performance Standards
- able to be dispatched within 5 minutes of being requested
- capable of being integrated with an automated control system, and
- capable of being dispatched in and out of service at least three times per day.

The reactive support from any of these services are required to be available and dispatchable at least 95% of the time.

We will also consider proposals for reactive power support of other sizes and in other locations than those specified in this section. We would also consider combining proposals for reactive power support where this is beneficial.

The timing of the identified need is largely driven by a system condition where there are no conventional thermal generators on the transmission network that are available to provide reactive power support. This condition is forecast to occur no later than 2025, but could happen earlier. The full capacity that will address the identified need must be installed before this time.

[8] These specified reactive power quantities are as "seen by" the 275 kV transmission grid.

3.5. Requirement to apply the RIT-T

Results of preliminary studies indicate that low demand conditions - with existing static reactive plant utilised and dynamic reactive plant at or near its limits - would lead to abnormally and unacceptably high voltages across the SA network if not addressed. The studies also revealed that a significant number of overvoltage events are likely to occur breaching the dynamic limits specified in the NER clause S5.1a.4 following a variety of credible and non-credible contingencies. A significant number of renewable generators have been found to be at risk of disconnecting under these conditions. The study also noted that for several contingencies, undervoltage events are likely to occur that could lead to voltage collapse.

This is a reliability corrective action project, requiring ElectraNet to identify the lowest cost solution to meet the identified need.

Under the NER reactive power reserves are required to be maintained in accordance with power system security standards and the power system is to be maintained in a satisfactory operating state.

This project is required to ensure the appropriate amount and type of transmission network voltage control is available on the South Australian network to ensure sufficient static and dynamic voltage control capability within South Australia to satisfy S5.1a.4, S5.1.4 and S5.1.8 of the NER.

4. Credible Options to Address the Identified Need

This section provides a description of three credible options that ElectraNet has identified to address the identified need.

Each of these three options will address the identified need by increasing the amount of reactive power available in the Adelaide Metropolitan and South East regions. During normal system conditions this will enable the SVCs at Para and South East to be operated at an output level of between 25 Mvar (inductive) and 0 Mvar, reserving the remainder of their dynamic reactive power capability for emergency control of the system following disturbances caused by the occurrence of critical contingencies. The options achieve this as follows:

- Option 1 involves the installation of switchable 275 kV reactors in the Adelaide Metropolitan and South East regions. Appropriate switching of these reactors during normal system conditions will enable the Para and South East SVCs to be operated within the desired normal operating range
- Option 2 involves the installation of dynamic reactive devices (such as additional SVCs) in the Adelaide Metropolitan region and a switchable 275 kV reactor installed in the South East region. Appropriate operation of the new dynamic reactive devices and switching of the new South East reactor will enable the Para and South East SVCs to be operated within the desired normal operating range
- Option 3 involves the installation of switchable 66 kV reactors in the Adelaide Metropolitan region and switchable 33 kV reactors installed in the South East region. Appropriate switching of these reactors during normal system conditions will enable the Para and South East SVCs to be operated within the desired normal operating range.

The additional absorbing reactive power support specified for each option assumes no planned outages of the additional reactive power plant during low demand periods.

The required capacity of reactive power support will be further assessed and confirmed in the PADR for this RIT-T. The options available will also be refined in terms of their scopes and cost estimates to determine the optimal scope, including consideration of a combination of transmission and distribution options.

4.1. Option 1: Transmission connected 275 kV reactors

This option involves installing 3 x 60 Mvar switched 275 kV reactors in the Adelaide metropolitan region, and 1 x 50 Mvar switched 275 kV reactor on the transfer corridor between South East and Adelaide. It also includes reconnecting the 100 Mvar switched capacitor bank at Happy Valley that will be removed from service by the Emergency Transmission Network Voltage Control project.

The scope of this option also includes the implementation of automatic control schemes for transmission-connected reactive plant and automation of OLTCs at 32 connection points.

High level cost-estimate: $40 -70 million

Estimated annual operating and maintenance costs: 2% of the capital cost

Estimated construction time and commissioning date: 1 to 2 years to design and construct with commissioning by November 2025

4.2. Option 2: Transmission connected 275 kV or 66 kV dynamic reactive devices

This option involves installing a 275 kV connected SVC (or similar) with at least 250 Mvar reactive absorb range in the Adelaide metropolitan region, and a 50 Mvar switched 275 kV reactor on the transfer corridor between South East and Adelaide. It also includes reconnecting the 100 Mvar switched capacitor bank at Happy Valley that will be removed from service by the Emergency Transmission Network Voltage Control project.

The scope of this option also includes the implementation of automatic control schemes for transmission-connected reactive plant and automation of OLTCs at 32 connection points.

High level cost-estimate: $50 - 90 million

Estimated annual operating and maintenance costs: 2% of the capital cost

Estimated construction time and commissioning date: 1 to 2 years to design and construct with commissioning by November 2025

We will consider whether installing dynamic devices (with 40-80 Mvar capability each) at a range of 66 kV locations across the Adelaide metropolitan region could address the identified need. This option is likely to be the most effective option at addressing the related needs regarding increasing dynamic voltage variability and indistinct events identified in section 3.2.8.

4.3. Option 3: Distribution connected reactive plant

This option involves installing 6 x 30 Mvar switched 66 kV connected reactors in the Adelaide metropolitan area, and 8 x 7.5 Mvar switched 33 kV connected reactors in the South East region of the state. It also includes reconnecting the 100 Mvar switched capacitor bank at Happy Valley that will be removed from service by the Emergency Transmission Network Voltage Control project.

The scope of this option also includes the implementation of automatic control schemes for transmission-connected reactive plant and automation of OLTCs at 32 connection points.

High level cost-estimate: $45 - 85 million

Estimated annual operating and maintenance costs: 2% of the capital cost

Estimated construction time and commissioning date: 1 to 2 years to design and construct with commissioning by November 2024 (to be confirmed)

A selection of dynamic reactive plant installed in the distribution system would provide similar benefits with respect to the related needs regarding increasing dynamic voltage variability and indistinct events as highlighted in Option 2.

4.4. Non-network solutions

Section 3.1 sets out the technical characteristics that a non-network solution would be required to deliver.

No specific non-network solutions have been identified by ElectraNet at this stage.

ElectraNet is interested to hear from any party that can provide non-network solutions that meet the identified need (i.e. the technical characteristics outlined in section 3.1) on the costs of providing these services and when they could be implemented.

ElectraNet considers that non-network solutions operating in or near the Adelaide metropolitan region and in the southeast region of the state that may meet the identified need include the following:

- new generator or energy storage systems
- generation support provided by existing generators
- virtual power plants
- demand management.

We have identified potential locations and capacities for non-network solutions in or near the Adelaide metropolitan region and in the southeast region of the state (Table 1). While these sites are expected to be the most effective locations to address the identified need, the ability of proposals to contribute to meeting the identified need will be technically assessed on a case-by-case basis. Non-network solutions at other locations may also be able to contribute.

Table 1 Potential locations and capacities for non-network solutions

Location (nearest 275 kV substation for reference)	Site characteristics and risks	Maximum capacity per site
Para, Torrens Island, Tungkillo	Well-connected to the Adelaide metropolitan area	Uncapped
Magill, Happy Valley, Cherry Gardens	Three or four strong 275 kV connections to Adelaide metropolitan area	180 Mvar per site
South East, Tailem Bend, Mount Barker South, Morphett Vale East	Two strong 275 kV connections to Adelaide metropolitan area	120 Mvar per site
Parafield Gardens West, Pelican Point, Le Fevre	Supply of reactive power at risk under prior outage condition	60 Mvar per site 120 Mvar combined limit
Northfield, Kilburn	Supply of reactive power at risk under prior outage conditions	60 Mvar per site 120 Mvar combined limit
Templers West, Brinkworth	Only one strong 275 kV connection to Adelaide metropolitan area	60 Mvar combined limit
Blyth West, Bungama[9]	Only one strong 275 kV connection to Adelaide metropolitan area	60 Mvar combined limit
City West, East Terrace	Radial connected sites	60 Mvar per site

[9] Robertstown, whilst similar in distance and connection to the metropolitan region, is not considered due to the addition of the recent addition of synchronous condensers

The total amount of inductive reactive power required in the Adelaide Metropolitan region is about 200-400 Mvar, depending on where it is provided.[10] The amount required in the South East region is about 50-100 Mvar, again depending on where it is provided.

Individual switchable static components at all sites are limited to no more than 60 Mvar per component. Dynamic equipment can have up to the full range of specified capacity at each site.

Non-network solutions will be paired with the implementation of automatic control schemes for transmission-connected reactive plant and automation of OLTCs at 32 connection points.

4.5. Options considered but not progressed

This section discusses additional options which ElectraNet has considered but does not find to be technically and/ or economically feasible, and therefore which are not credible options.

ElectraNet considered an option where reactive power support is made available and sourced from existing distributed solar PV installations.

This is technically feasible however it is not economic to implement because this option would require retrofitting a significant number of existing distributed solar PV installations with control schemes and would need opt-in mechanisms for owners of these installations. Therefore, this option will not be progressed.

4.6. Material inter-network impact

In accordance with NER clause 5.16.4(b)(6)(ii), ElectraNet has considered whether the credible options above are expected to have a material inter-network impact.

A 'material inter-network impact', which is defined in the NER as:

"A material impact on another Transmission Network Service Provider's network, which impact may include (without limitation): (a) the imposition of power transfer constraints within another Transmission Network Service Provider's network; or (b) an adverse impact on the quality of supply in another Transmission Network Service Provider's network."

AEMO currently defines the criteria for material inter-network impact[11]. AEMO's suggested screening test to indicate that a transmission augmentation has no material inter-network impact is that it satisfies the following:

- a decrease in power transfer capability between the transmission networks or in another TNSP's network of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in power transfer capability between transmission networks of no more than the minimum of 3 per cent of the maximum transfer capability and 50 MW
- an increase in fault level by less than 10 MVA at any substation in another TNSP's network
- the investment does not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

[10] These specified reactive power quantities are as "seen by" the 275 kV transmission grid.

[11] The screening test is set out in Appendix 3 of the Inter-Regional Planning Committee's Final Determination: Criteria for Assessing Material InterNetwork Impact of Transmission Augmentations, Version 1.3, October 2004.

The credible options set out in this PSCR would not result in a material change in power transfer capability between South Australia and neighbouring transmission networks, as they do not address network constraints between competing generating centres.

Fault levels are not expected to be impacted at any substation in another TNSP's network, and the credible options do not involve either a series capacitor or modification in the vicinity of an existing series capacitor.

Therefore, AEMO's screening criteria indicate that there is no material inter-network impact associated with the credible options included in this PSCR.

5. Materiality of Market Benefits for the RIT-T Assessment

The section outlines the categories of market benefits prescribed in the NER and whether they are likely to be material for this RIT-T.

The NER requires that all categories of market benefit identified in relation to the RIT-T are included in the RIT-T assessment, unless the NSP can demonstrate that a specific category (or categories) is unlikely to be material in relation to the RIT-T assessment for a specific option.

5.1. Market Benefits that are material for this RIT-T

We consider that the following classes of market benefits may be material for this RIT-T assessment:

- changes in costs for parties, other than for ElectraNet (in particular, for SA Power Networks)
- differences in the timing of transmission investment

The credible options may affect the timing of other transmission investments (i.e. transmission investments that may be needed to meet the related needs described in section 3.2.8). Consequently, the market benefits associated with differences in the timing of unrelated transmission investment may be material to the RIT-T assessment.

5.2. Market benefits that are not material for this RIT-T

Under clause 5.16.4(b)(6)(iii) of the NER, the PSCR should set out the classes of market benefit that the NSP considers are not likely to be material for a particular RIT-T assessment.

The Australian Energy Regulator (AER) has recognised that if the credible options considered will not have an impact on the wholesale market, then a number of classes of market benefits will not be material in the RIT-T assessment, and so do not need to be estimated.[12]

The credible options do not address network constraints between competing generating centres. Therefore, ElectraNet does not expect them to result in any change in dispatch outcomes or wholesale market prices.

We therefore consider that the following classes of market benefits are not material for this RIT-T assessment:

- changes in fuel consumption arising through different patterns of generation dispatch
- changes in voluntary load curtailment (since there is no impact on pool price)
- changes in involuntary load shedding
- changes in costs for parties, other than for ElectraNet or SA Power Networks (since there will be no deferral or advancement of generation investment)
- changes in ancillary services costs
- competition benefits
- Renewable Energy Target (RET) penalties.

[12] AER, Regulatory Investment Test for Transmission Application Guidelines, August 2020, p. 29

In addition to the classes of market benefits listed above, NER clause 5.16.4(b)(6)(iii) requires consideration of the following classes of market benefit in relation to each credible option:

- Option value

  Option value is likely to arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change and the credible options considered by the TNSP are sufficiently flexible to respond to that change[13]. None of these conditions apply to the present assessment.

- Changes in network losses

  Given the credible options will be installed at or near the areas where the services will be utilised and the effectiveness of the solution is dependent on these locations, there are not expected to be any material differences in network losses between options.

[13] AER, Regulatory Investment Test for Transmission Application Guidelines, August 2020, p. 91

City West Substation

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Appendices

ElectraNet

Appendix A Compliance checklist

This section sets out a compliance checklist which demonstrates the compliance of this PSCR with the requirements of clause 5.16.4(b) of the NER version 192.

Rules clause	Summary of requirements	Relevant section(s) in PSCR
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	-
	(1) a description of the identified need;	Section 3
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Sections 3.1 and 3.2
	(3) the technical characteristics of the identified need that a network support option would be required to deliver, such as: (i) the size of load reduction or additional supply; (ii) location; and (iii) operating profile;	Sections 3.4 and 4.4
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent Integrated System Plan;	Not applicable
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alternative transmission options, interconnectors, generation, system strength services, demand side management, market network services or other network options;	Section 4
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.15A.2(b)(6), together with reasons of why the RIT-T proponent considers that these classes of market benefits are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	Section 4.1 to 4.3 and 4.6