SA ENERGY TRANSFORMATION RIT-T

Consolidated Non-interconnector Option

ENTURA-ECA29
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Executive summary

On 7 November 2016, ElectraNet initiated the South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T). The purpose of the SAET RIT-T is to identify and then implement the best solution to facilitate the transformation of South Australia's energy sector, help lower power prices, improve system security and lower carbon emissions. Options to be evaluated highlighted in the SAET Project Specification Consultation Report (PSCR) include new interconnections between South Australia and the eastern seaboard states and an alternative solution that does not involve an interconnector (a non-interconnector solution).

This report summarises the investigation of the non-interconnector solution. A key premise of the non-interconnector solution is that it has to have similar performance to an additional interconnector in managing the non-credible loss of the Heywood interconnector. It is worth noting that the base case for all options considered in the SAET RIT-T includes a set of synchronous condensers that are being procured now by ElectraNet for system strength purposes[1].

Eighteen submissions to the SAET PSCR were received from proponents of potential network support technologies. We used these submissions in combination with our information to develop a consolidated least cost non-interconnector solution for South Australia, which comprises the following recommended supports:

1. Pumped storage

   A contract to provide voltage, frequency and inertia support to the network. The study has assumed the proposed EnergyAustralia project at Cultana would be suitable but alternatives may be considered.

2. Low load CCGT operation

   A contract to provide voltage, frequency and inertia support to the network. The study has assumed that this would be provided by the ATCO Power Australia operated Osborne CCGTs but alternatives may be considered.

3. Solar thermal

   A contract to provide voltage, frequency and inertia support to the network. The study has assumed that this would be provided by the proposed SolarReserve solar thermal plant near Davenport but alternatives may be considered.

4. Battery storage

   A contract to provide voltage, frequency and fast frequency response to the network. The study has assumed that Tailem Bend would be an appropriate location.

5. Murraylink frequency control

   Murraylink to provide frequency control across the Murraylink HVDC inter-connector. This requires a control upgrade of the existing plant.

6. Minimum load control

   A wide area control of embedded storage and/or rooftop solar such that SA demand does not fall below such a level that positive grid demand cannot be maintained when the SA network is islanded.

[1] https://www.electranet.com.au/what-we-do/projects/power-system-strength/

7. Battery storage

   A contract to provide controlled MW response. While aggregated demand response would work well, it is considered that a battery can deliver this requirement, (which would only be required under islanded conditions) for a lower cost/MW.

The total cost of the non-interconnector solution is estimated to be about $830 million (NPV). It should be noted this estimated cost does not represent the total capital recovery related to the installation of these non-network supports.

ElectraNet defined minimum and preferred system performance levels for the non-interconnector solution. These system performance criteria cannot be met by the solution under all conditions. The performance is summarised as follows:

Requirements		Minimum	Preferred
Description of operating requirements	Normal operation	Partial compliance	Partial compliance
	Islanded operation	Complies	Complies
Service requirements specification	Inertia	Complies	Not compliant
	FCAS	Partial compliance	Partial compliance
Fault level		Complies	Not compliant

While full compliance with the minimum performance requirements is technically feasible we do not consider the additional cost of supports provides sufficient value. That is, the standards achievable through a second interconnector are not always exactly replicable by a single interconnector coupled with supports.

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1. Introduction

On 7 November 2016, ElectraNet initiated the South Australian Energy Transformation (SAET) Regulatory Investment Test for Transmission (RIT-T) by publishing a Project Specification Consultation Report (PSCR). The purpose of the SAET RIT-T is to identify and then implement the best solution to facilitate the transformation of South Australia's energy sector, help lower power prices, improve system security and lower carbon emissions. Options to be evaluated highlighted in the PSCR include new interconnections between South Australia and the eastern seaboard states and an alternative solution that does not involve an interconnector (a non-interconnector solution).

This report is intended to describe the least cost non-interconnector option (NIO) capable of meeting the minimum technical criteria set down in the SAET Supplementary Information Paper (SIP) [1] and repeated here in Table 2.1.

In order to determine an appropriate design for an NIO and to estimate its cost, a conceptual framework has been developed to aid in understanding what network supports are particular to the NIO and which would occur in either a NIO and/ or second interconnector option (2ICO). We have used information provided in submissions received to the SAET PSCR as well as our own information to develop a consolidated least cost non-interconnector solution to meet (as far as possible) the technical criteria defined in the SIP.

NIO principles

We first define the following principles for the NIO:

1. The base case for the NIO and 2ICO is the same
2. Performance must meet at least the minimum system security requirements
3. Performance meets the preferred system security requirements (equivalent to that provided by a 2ICO) where it is cost effective to do so
4. Only additional supports required to meet the minimum performance target are considered
5. Performance for credible contingencies should be comparable
6. Credible contingency management may require supports
7. Performance for non-credible contingencies is to be assessed in an holistic manner[2]

These principles are explored in this report as we define the technical and economic limits of the NIO.

Comparison of 2ICO and NIO for support requirements

System supports are required for both the 2ICO and NIO. This section discusses how the additional support costs and requirements can be treated in each option.

- Inertia

[2] A range of PSS/E studies were performed to test system performance for the non-credible loss of both Heywood interconnector circuits

A second AC interconnector is expected to reduce the need for inertia to be dispatched in South Australia in two ways:

(a) a separation event becomes more remote

(b) A stronger AC connection should allow for larger generation contingencies in SA before loss of synchronism is a risk and so the need for system integrity protection schemes (SIPS) or at least the frequency that such a scheme might operate would be reduced.

A non-interconnector solution must manage both these requirements to survive or prevent loss of the interconnector or provide equivalent bounds of network operation within SA

- Fault level

  A second AC interconnector will provide localised increases to fault level around its point of connection to the SA network. This may or may not be sufficient to reduce the need for additional fault level support in more remote regions of SA. More fault level support is required in the single AC interconnector case. The quantity of additional support will depend on the nature of the second interconnector and in particular its point of connection.

- Voltage regulation

  Similar to fault level, a second interconnector will provide only modest additional voltage control in SA. Most voltage regulation requirements will be common to both network and non-interconnector solutions.

- Frequency regulation

  Setting aside operation as an island, frequency regulation should be managed effectively with one or two interconnectors. While there may be other market benefits to providing regulation of flow on a single interconnector in close to real time there does not appear to be a security driver for sourcing frequency regulation solely within SA.

- Frequency control

  Management of large credible contingency events with a single interconnector is more difficult to achieve. The spot price will often drive the interconnector flow towards a thermal or stability limit. While still possible in the two interconnector case, it is less likely. Additional frequency control in SA, therefore, is likely to provide a market benefit in the single interconnector case where the alternative is to constrain flow on the interconnector.

Non-credible contingencies

Non-credible contingencies are rare but it is arguable that loss of interconnection and the associated system security risks such as a system blackout are more likely in the single interconnector case. If we take the example of a double circuit outage of an interconnector we might expect the interconnector to be forced out of service for an hour a year or a probability of 0.01 % as an example. If the second interconnector was equally likely to be forced out of service then the combined probability is 0.0001 %. A hundred times less likely. Based on this simplistic analysis it is concluded that the use of load interruption to manage frequency must be minimised as part of a non-interconnector solution in order to make the NIO comparable to a 2ICO.

The cost of achieving this minimisation of load shedding must, however, be considered within the overall system reliability standard. It would be expected that this standard is being met now. The challenge for the NIO then is to ensure that the reliability standard can be met even as the SA region NEM dispatch becomes more and more dominated by renewable (and more critically) non-synchronous generating units.

2. Basis of study

The dynamic nature of the South Australian electrical energy sector makes any study into current network performance difficult and future network conditions very speculative. The SAET PSCR and associated SIP described the required technical characteristics of network support technologies that could address the identified need of the RIT-T. The SIP elaborated on the likely nature of the services required as well as aggregate power system targets for service levels from network support solutions.

ElectraNet received 18 submissions from proponents of potential network support technologies in response to the PSCR and SIP. The high-level options proposed were varied in terms of technology and included standalone battery solutions, storage and generation combinations, standalone generation projects, the use of network support agreements, contracted demand management as well as other technologies.

We have used the information provided in these submissions as well as our own information to develop a consolidated least cost non-interconnector solution to meet (as far as possible) the aggregate power system targets for service levels defined in the SIP.

2.1 System security requirements

While the NER and ESCOSA have provided system requirements, increasingly these requirements are found to not adequately define a workable technical envelope for the power system in SA. The following table provides a description of the technical envelope adopted for this study.

Table 2.1: Aggregate system security requirements[3]

		Minimum system target	Preferred system target[4]
Description of operating requirements	Normal operation	Withstand the loss of the Heywood interconnector up to 650 MW without resulting in a system black condition.	Withstand the loss of the Heywood interconnector up to 750 MW without a system black condition.
		Less than or equal to 3 Hz/s RoCoF for a contingency size of up to 650 MW that results in separation from the rest of the NEM – effectively would result in removal of current RoCoF constraint on the Heywood Interconnector.	1 Hz/s average RoCoF over 500 ms for any contingency size up to 750 MW that results in separation from the rest of the NEM– effectively results in removal of RoCoF constraint on the Heywood Interconnector.
		Capability to operate South Australia when connected to the rest of the NEM with no local synchronous generators online.	2 Hz/s maximum RoCoF for the first 250 ms.

[3] Based on Table 1 – Aggregate system security requirements, https://www.electranet.com.au/wp-content/uploads/resource/2017/02/SAET-Supplementary-Information-Paper-Final-13-Feb-2017.pdf

[4] The minimum system requirement must also be maintained.

		Minimum system target	Preferred system target[4]
	Islanded operation	Capability to operate islanded for 1 hour in a **satisfactory** manner –any further contingency events could lead to a system black event. Sufficient regulation FCAS in South Australia to manage "small" perturbations in the network for 1 hour. Maintain minimum fault levels across the islanded transmission system.	Capability to operate islanded system indefinitely in a **secure** manner. Secure operation restored within 30 minutes from the time of separation Sufficient regulation FCAS in South Australia to manage "small" perturbations indefinitely
Service requirements specification	Inertia	**Inertia**: 4,065 MWs (4Hz/s back stop) + sufficient **FFR**	Inertia: 9,375 MWs (2 Hz/s back stop) +Sufficient **FFR**
	FCAS	Sufficient contingency FCAS or equivalent services to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 650 MW. 35 MW or local regulating frequency (or equivalent) available within 30 minutes and required for no longer than 1 hour following separation.	Sufficient contingency FCAS services to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 750 MW. 35 MW or local regulating frequency available and required continuously. With SA islanded, sufficient raise contingency FCAS services for a 270 MW generator contingency. With SA islanded, sufficient lower contingency FCAS for a 200 MW load event
	System strength	2 kA across the system at 275 kV.	4 kA across the system at 275 kV.

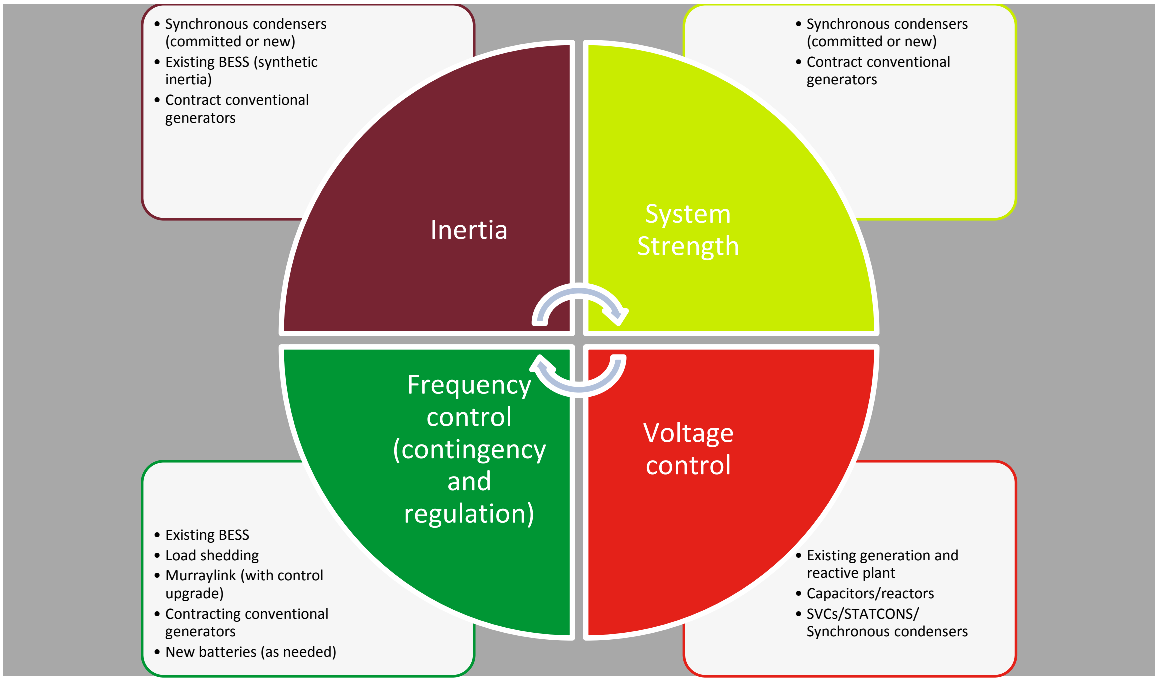
In addition to the requirements outlined in the table above the following additional assumptions were made to form the study base case:

- In the next 10-years:
  - TIPS A and B may retire,
  - Although gas-fired power stations may not remain economically viable, it is assumed that the current fleet (or equivalent) will remain available for the planning horizon of this study. This is necessary to make the South Australian island operable under all circumstances.
  - Maximum system demand is not expected to significantly exceed current levels, and
  - 0 MW or even negative demand is expected to occur in South Australia during daylight hours.
  - 6 x synchronous condensers to address the system strength NSCAS gap declared by AEMO on 13 October 2017 are installed by ElectraNet.
  - System strength requirements will be maintained in accordance to AEMO's transfer limit advice - May 2018

2.2 System supports and likely suitable technologies

The NIO considers four fundamental elements of system control depicted in Figure 2.1. This figure identifies technologies capable of providing the required services.

Figure 2.1: Indicative optimisation process for non-interconnector option



The costs for these technologies vary widely and are changing rapidly in some cases.

In developing a consolidated non-interconnector solution Entura used cost information provided with submissions received as well as our own information to create a high-level ranking of network support technologies in terms of cost effectiveness. The following table provides an indicative hierarchy of costs.

Table 2.2: Hierarchy of Costs

	Technology	**Comments**
Low cost	Load shedding (per NER) at no cost	UFLS, OFGS
	Existing BESS (without additional costs)	SIPS, FFR
	Any committed generation offering relevant service at incremental cost	Solar thermal or pumped hydro energy systems
	Murraylink control upgrade	
	Installing additional synchronous condensers	
	Directing existing generators during system emergencies	Per AEMOs arrangements and costs
	Contracting existing generators	
	Installing additional BESS/generators	
High cost	Contracted demand response	

2.3 System operation and demand or criticality of system supports

The following sections provide a view of system requirements across the range of interconnected and islanded SA demand and interconnector flow scenarios. We include them here to highlight the system conditions that are likely to give rise to the highest and lowest demands on particular system supports. The tables also identify option specific and option independent support requirements.

2.3.1 Inertia FFR to manage RoCoF

		Inter-connected state (import to SA)			Double-circuit I/C trip ⇨	Islanded state (possible Murraylink transfers)	Double-circuit I/C trip ⇦	Inter-connected state (export to Vic)		
		max	**medium**	**low**				**low**	**medium**	**max**
General comments		Inertia only required for double-circuit I/C trip and so is always a non-network support			See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.	Some inertia requirement to allow fast acting frequency controls to operate stably	See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.	Inertia only required for double-circuit I/C trip and so is always a non-network support. While SA remains interconnected, inertia can be sourced from the eastern states.		
SA Demand	**low**	NA			Lightest possible SA system and so likely limiting case for inertia support	Size of credible contingencies and Inertia availability must be managed.	Lighter SA system but heavier than many import scenarios – likely PSH pumping scenario	NA		
	medium				Decreasing need for inertial support	Increasing capacity for larger single contingency events and so need for Inertia	Decreasing need for inertial support			

		Inter-connected state (import to SA)			**Double-circuit I/C trip ⇨**	**Islanded state (possible Murraylink transfers)**	**Double-circuit I/C trip ⇦**	**Inter-connected state (export to Vic)**		
		max	**medium**	**low**				**low**	**medium**	**max**
	high				Lowest demand for additional inertia due to possible contingency size relative to system size	Higher capacity for large single contingency events and so need for inertia.	Lowest demand for inertia due to possible contingency size reduction			
Issues		• Inertia only required for double-circuit I/C trip and so is always a non-network support. While SA remains interconnected, inertia can be sourced from the eastern states. • Likely balance required between actual inertia and FFR • Consideration of maximum contingency size for islanded operation. Trade-off between non-network cost and market cost of constrained operation of renewables.								

2.3.2 Frequency control - contingency

		Inter-connected state (import to SA)			Double-circuit I/C trip ⇨	Islanded state (possible Murraylink transfers)	Double-circuit I/C trip ⇦	Inter-connected state (export to Vic)		
		max	**medium**	**low**				**low**	**medium**	**max**
General comments		All FCAS-raise sourced in SA	Raise and lower available from VIC		See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.	All FCAS sourced in SA	See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.	Raise and lower available from VIC		All FCAS-lower sourced in SA
SA Demand	**low**	Any remaining synchronous machines at low load, likely negligible wind/solar in SA and so low risk of large contingency size implying low demand for FCAS – raise.	Minimal contingency requirement in SA		Only fast acting response such as batteries or load tripping are suitable for managing loss of high import in a light system, e.g. SIPS	Flexibility to minimise size of credible contingencies and sourcing Raise and Lower should be high, especially where energy storage is occurring.	Surplus generation can be tripped or 'govern down' with support of faster – acting controls such as batteries, including OFGS	Minimal contingency requirement in SA		New wind/solar plus synchronous machines and batteries can provide FCAS-lower

		Inter-connected state (import to SA)			Double-circuit I/C trip ⇨	Islanded state (possible Murraylink transfers)	Double-circuit I/C trip ⇦	Inter-connected state (export to Vic)		
		max	**medium**	**low**				**low**	**medium**	**max**
	medium	Increasing capacity for larger single contingency events and so need for FCAS-raise increases			Decreasing severity of event due to higher likelihood that synchronous machines such as pumped hydro and solar thermal will be on-line and available to provide raise services.	Increasing capacity for larger single contingency events and so need for FCAS-raise increases				
	high	Higher capacity for large single contingency events and lower likelihood that FCAS – raise can come from synchronous units.				Higher capacity for large single contingency events and lower likelihood that FCAS – raise can come from synchronous units.				
Issues		• Amount of non-network frequency support should be calculated (paid for) based on additional service required over and above FCAS dispatch in market • Potential market deficit for single I/C solution where FCAS must be sourced in SA • Consideration of maximum contingency size for islanded operation. Trade-off between non-network cost and market cost of constrained operation of renewables.								

2.3.3 System strength and voltage control

<table>
<tr><th colspan="2" rowspan="2"></th><th colspan="3">Inter-connected state (import to SA)</th><th rowspan="2">Double-circuit I/C trip ⇨</th><th rowspan="2">Islanded state (possible Murraylink transfers)</th><th rowspan="2">Double-circuit I/C trip ⇦</th><th colspan="3">Inter-connected state (export to Vic)</th></tr>
<tr><th>max</th><th>medium</th><th>low</th><th>low</th><th>medium</th><th>max</th></tr>
<tr><td colspan="2">General comments</td><td colspan="3">Higher levels of import at low demands will lead to the highest need for additional system security supports.</td><td>See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.</td><td></td><td>See transition chapter for description of services and supports required to affect transition from satisfactory to secure islanded operation.</td><td colspan="3">Increasing export suggests higher levels of network flows and so higher demand son system strength. Higher generation is likely to mean lower prices and so pumped storages are likely to pump and solar thermal are likely to store under these network conditions. That suggests that system strength requirements will be met through energy dispatch in some way.</td></tr>
<tr><td rowspan="2">SA Demand</td><td>low</td><td colspan="3">High levels of additional supports will be required to provide dispatch flexibility.</td><td rowspan="2">Location of synchronous condensers to the West of the interconnector should provide sufficient buffering for the loss of system strength from the I/C trip.</td><td>Additional supports most likely to be required due to high possibility of 100 % renewable dispatch for energy.</td><td rowspan="2">Location of synchronous condensers to the West of the interconnector should provide sufficient buffering for the loss of system strength from the I/C trip.</td><td>Support requirement are likely to increase as export decreases due merit order dispatch of synchronous machines.</td><td colspan="2">Lower levels of additional supports will be required since it is likely that some pumped storage will choose to store.</td></tr>
<tr><td>medium</td><td colspan="3">Lower levels of additional supports will be required since it is likely that some synchronous sources will be required.</td><td>Some system strength may come from synchronous generation</td><td colspan="3">Minimal levels of system strength over and above the energy market dispatch are required.</td></tr>
</table>

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		Inter-connected state (import to SA)			**Double-circuit I/C trip ⇨**	**Islanded state (possible Murraylink transfers)**	**Double-circuit I/C trip ⇦**	**Inter-connected state (export to Vic)**		
		max	**medium**	**low**				**low**	**medium**	**max**
	high					Likely to be lowest demand for additional supports for system strength due to higher demand and need for synchronous peaking plant.				
Issues		• N/A								

3. Non-Interconnector Solution Description

Entura has described a preferred list of possible supports in the following sections. The selection of supports is motivated in descending order of priority by: our view of how much support is required, the approximate area in which a support would be useful and the types of supports that are likely to be available in the market and informed by responses to the PSCR.

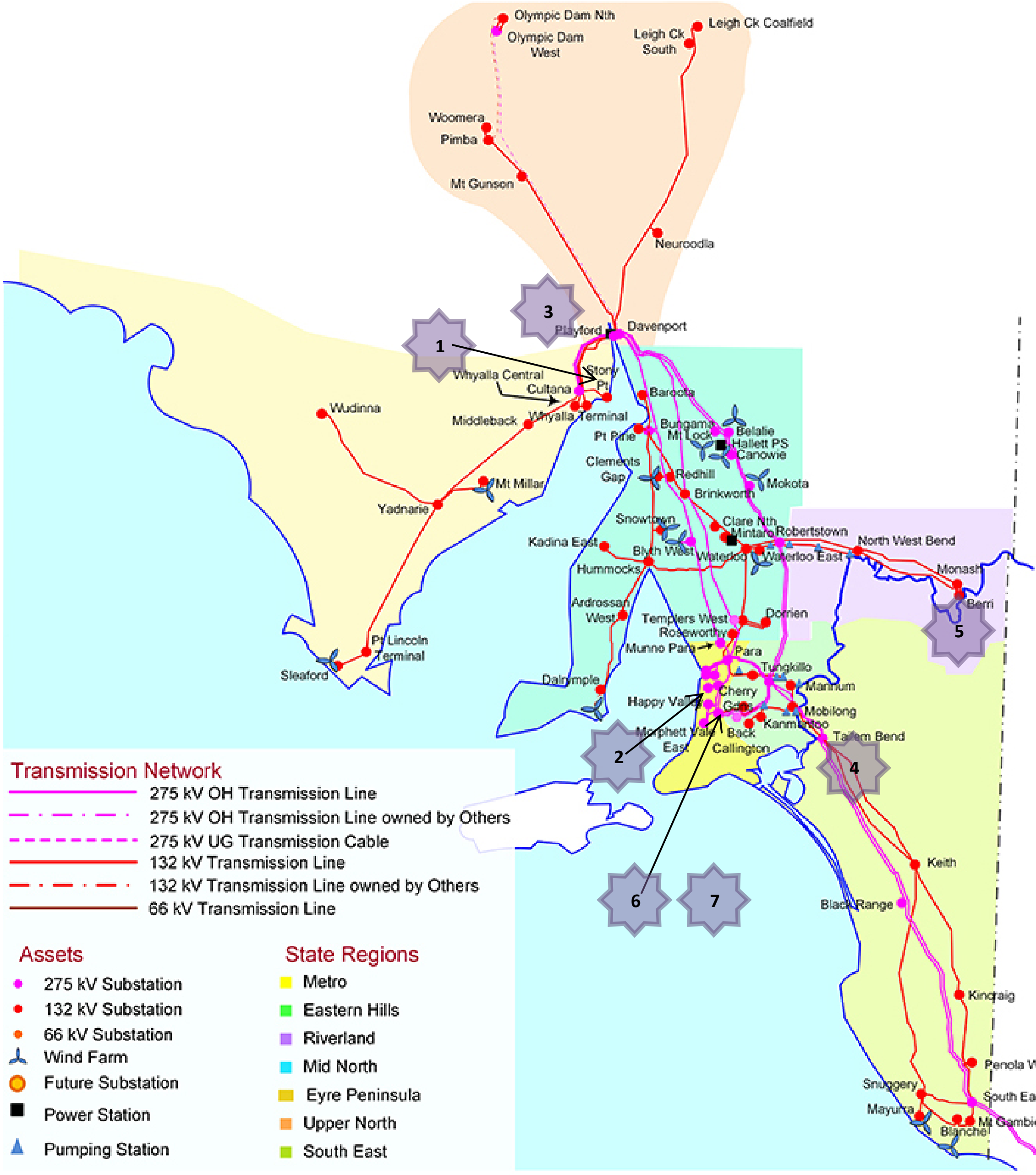
The placement of supports in a geographical sense is based on the need to spread voltage control and to improve fault level across the SA region. Where a required support is available from a possible project, we have notionally accepted that support. There are always alternatives. This gives ElectraNet sufficient flexibility to ensure commercially competitive tendering for the provision of these supports.

The inclusion of ElectraNet's planned synchronous condensers provides a starting point that removes some of the geographic requirements. Inertia, fast frequency response (FFR) and FCAS are quantities that are not localised and so support can be drawn from a variety of sources. We have chosen to provide a possible mix of technologies that contribute across the range of requirements that the NIO must meet in particular and specific ways. There may be no steady state requirement for a particular support once the island network is formed but that support may be critical to the transition. That is, a non-credible contingency (loss of the interconnector) requires a network support but there is no requirement for that support either before or after that contingency.

Having established a starting point, we then proceeded to augment to the extent that load-shedding for the loss of the interconnector is minimised. The resultant South Australian islanded system can run in a secure state and with sufficient operational flexibility provided to allow efficient operation of the region without the interconnector or at times when the interconnector requires outages for maintenance.

Entura have proposed the list of supports in Table 3.1 and performed network simulations to demonstrate their effectiveness in meeting the system performance criteria of the NIO. The list of supports and the regional requirements are discussed in this section. The performance of the system is discussed in the next section.

Figure 3.1: SA network and placement of RIT-T proposals (numbers refer to Table 3.1)[5]



[5] Map courtesy of ElectraNet

Table 3.1: Summary table of required

			Contribution to:				
Ref	**Technology/location**	**Nameplate**	**Inertia or FFR[6] inertia equivalent**	**Fast FCAS**	**System strength**	**Voltage control**	**Region**
1.	Pumped storage – Cultana	120 MW[7]	420 MWs	15 MW	600 MVA		Eyre Peninsula
2.	Osborne Cogeneration	180 MW	550 MWs	30 MW	150 MVA		Metropolitan
3.	Solar thermal – Davenport	120 MW	660 MWs	60 MW	600 MVA		Upper North
4.	Battery – Tailem Bend	150 MW	Expected to exceed 1,000 MWs (FFR)	75 MW	0 MVA		South East
5.	Murraylink – Berri	200 MW		40 MW	0 MVA		Riverland
6.	Battery – Tailem Bend	150 MW	Expected to exceed 1,000 MWs (FFR)	75 MW	0 MVA		South East
7.	Minimum load control						

[6] FFR – fast frequency response

[7] The RIT-T submission is for 100-250 MW and any value in this range would be useful.

These system supports can be considered on a regional basis since influence on voltage control and fault level are local considerations. The following sections describe how the proposed projects and others are required to provide adequate support. The supports proposed in this section were studied using PSS/E simulations and the technical performance of the proposed solution is discussed in Section 3.8. Detailed studies will be completed using PSCAD before any specific solution is implemented.

Eyre Peninsula

The Cultana pumped storage schemes and the solar thermal plant at Davenport provide adequate fault level while in-service. The pumped storage scheme should be encouraged to include synchronous condenser mode as should the solar thermal, although much depends on the storage associated with the solar thermal as to the utility of this function at that site.

The pumped storage proposals will contribute approximately 3-5 MVA to the fault level per MW of installed capacity.

Upper North

The solar thermal and synchronous condensers at Davenport can influence the Upper North area from a voltage control and system strength perspective.

Mid North

The Mid North should be well catered for voltage support given the large number of windfarms in the region and the ESCOSA requirements for dynamic voltage control for those farms. The addition of the battery at Hornsdale wind farm will improve this further in the north of the sub-region. This may not be true of the area south west of Blyth. From a fault level perspective, the addition of the Davenport solar thermal and the synchronous condensers at Davenport and Robertstown can provide adequate coverage with some redundancy. The south east of the region may also be supported from the thermal generation and/or the synchronous condensers in the Metro region.

Riverland

Voltage control for this region is adequately supported by synchronous condensers at Robertstown and the Murraylink controls. It is unclear to what extent Murraylink presently provides voltage regulation, but the technology would suit the provision of this service.

Fault level for this region has always come via Robertstown. The synchronous condensers there will enhance the fault level above current levels and maintain it into the future.

South East

Voltage control for this region is generally available from the existing generation, the close link to the Metro area, the battery at Tailem Bend and the interconnector to Victoria in the South East of the region.

Fault level will predominantly flow from Victoria and the Metro region.

Metro

Some synchronous generation will remain connected in the Metropolitan region under most scenarios. This generation coupled with the synchronous condenser in the metropolitan area will provide adequate voltage support and fault level within the region.

Eastern Hills

The Eastern Hills are well supported by the surrounding regions both from a voltage control and fault level perspective.

3.1 Synchronous Condensers

While most synchronous generator and motor designs can be converted to synchronous condensers, standard synchronous condenser solutions are available from several MVA to several hundred MVA. Horizontal shaft designs are commonly used because they cost less than other designs.

The use of synchronous condensers is increasing rapidly. They are used in applications in which an increased fault level is of benefit in addition to the reactive support provided. Further synchronous condensers will be required, to stop fault levels falling, as levels of renewable generation increase.

While increased inertia is a commonly recognised benefit, the inertia provided by synchronous condensers is typically quite low with inertia constants of less than 1.6 MWs/MVA. Unless installed in large numbers, this is not sufficient on its own for sufficient frequency control and rate of change of frequency reduction. High inertia designs with flywheels that provide inertia constants of greater than 5 MWs/MVA are now available from at least one OEM. Designs with even larger inertia constants are under development.

The use of synchronous condensers will generally improve grid stability due to both the inertia and fault level benefits. However, some care needs to be taken in their placement to maximise the benefit and to prevent cases in which stability limits are decreased. Placing a synchronous condenser too far from other inertia in the system may unintentionally set up transient instabilities under fault scenarios that result in decreased network capacity.

Synchronous condensers located close to load centres (such as cities) and fitted with power system stabilisers or other auxiliary controllers can indirectly modify the system loading for up to the time delay setting of transformer tap changers. The synchronous condenser acts to reduce the system voltage in either a sustained or a cyclic way, which causes many loads to reduce their power demand.

The reactive power output of synchronous condensers is continuously controllable, but the fault level and inertia contribution are not. Multiple smaller units (as opposed to single, large units) would allow improved management of inertia and fault level if required.

3.2 Pumped Hydro Storage

Around the world, pumped storage hydropower projects make up the vast majority of grid energy storage and have traditionally been used by energy utilities to supply additional power to the grid during times of highest demand. Pumped storage projects also provide network support in various forms; including inertia, fault level, voltage and frequency control.

Pumped storage can be part of a traditional hydropower station, such as in the Tumut scheme[8], or it can be a dedicated station built for storage and with no net energy capability. Traditional stations with storage can be economic despite much larger capital costs per megawatt installed. In the South Australian context it is most likely that stations will be dedicated storage-only stations.

Most pumped storage stations can also operate in synchronous condenser mode and sometimes do this to reduce the time taken from observing an electricity pool price spike until full load output. During synchronous condenser operation the pumped storage also provides inertia and fault level support. It is possible that a pumped storage operator could put their plant in synchronous condenser mode to participate in the FCAS raise market or in a future inertia market.

Given the scarcity of freshwater resources in South Australia, the use of seawater for pumped storage projects offers a possible solution. The only existing precedent for a seawater pumped storage project is the Yanburu Pumped Storage Project in Japan. With a 30MW installed capacity, this project is considered a demonstration of the concept. The 300MW Espejo de Tarapacá project in Chile is in the final stages of development and will be the first deployment of a seawater pumped storage project at scale. While the concept of seawater pumped storage is not significantly different to that of traditional pumped storage, such a project must expect far greater environmental scrutiny than other possible projects. Implementing measures to overcome the environmental risks of a seawater pumped storage project are likely to be of significant construction and maintenance costs. Further, protecting metals from the corrosive seawater is also likely to add significant cost. It remains to be seen whether pumped storage project opportunities in Australia can overcome these hurdles.

A seawater pumped storage station would most likely be sited to take advantage of a natural geography that allows a manmade upper reservoir to be constructed that provides maximum head with minimum earthworks.

Depending on the location of the project, cycle efficiency for a pumped storage project can exceed 80%.

Pumped storage projects are capital intensive and require long lead times for development – typically anywhere from 4 years to 10 years from conception to power-on depending on the scale of the investment. The lower end of the scale is likely for smaller projects with at least one existing storage, a short distance between storages, few environmental risks and a developer familiar with the requirements of lenders for similar projects.

There are a number of proposed developments in the Mid North around Davenport[9]. The NIO need not include all these proposed supports since there is a high degree of overlap. We have included one pumped storage scheme and one solar thermal scheme as much to show the compatibility to the NIO of either technology as to specify an exact solution in this area.

[8] Part of the wider Snowy Mountain scheme.

[9] ElectraNet has received a PHES submission from EnergyAustralia, which has been used in this analysis. https://www.energyaustralia.com.au/about-us/energy-generation/energy-projects/pumped-hydro

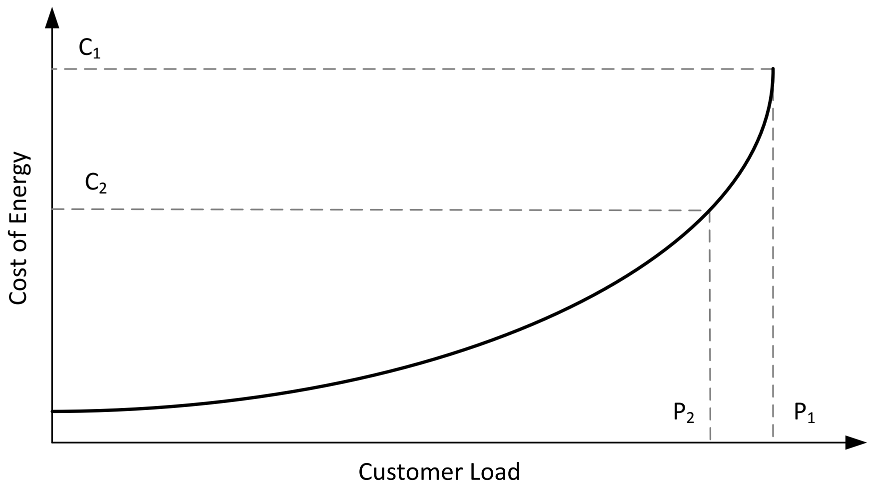
3.3 Demand Response

Controlling power system demand for the purpose of maintaining power system stability is a long-established practice. Shedding a small part of the load by disconnecting part of the power system could prevent losing the whole power system due to an adverse and temporary influence. All modern power systems still follow the practice of under-frequency load shedding as a last-resort measure to prevent a whole-of-system collapse. This technique is effective but crude as it may not differentiate what consumers consider to be priority loads.

In recent decades, the concept of controlling loads according to consumer priority has emerged, prompted by new load-response technologies and industry communication protocols. By the end of the twentieth century, the deregulation of energy utilities and creation of energy markets opened the possibility of consumer demand response driven by economic dispatch.

The system operator has discretion to trip customer load for certain events. Generally these events are rare and without load shedding would lead to wider and longer disturbances. This form of load control is mandated under the Rules and is used in under frequency and under voltage load shedding schemes. It is distinct from controlled customer demand response that is a contracted service for particular purposes such as load control during times of generation resource shortfall in the period after an interconnector trip.

Demand response can be used to maintain power system stability, but utilities still tend to focus on demand response as a way to leverage the cost of energy or the cost of providing reliability. The figure below presents a typical graph of cost of electricity versus served consumer load in a modern electrical energy market. For smaller loads, served by baseload generation, the cost of energy is low. As the load increases and costly peaking plant needs to be switched on, the cost of energy rapidly rises.



It is no surprise that demand response has received a lot of attention from energy utilities in the last two decades. During the peak hours of the Californian electricity crisis in 2000/01, lowering demand by 5% was estimated to reduce the energy price by 50%.

Concerns about the effects on power systems of the increasing penetration of intermittent renewable energy generation since the early 2000s is now leading to greater interest in the ability of demand response to preserve power system stability.

The current concept of demand response can be described as a response of demand and/or generation to signals from the central power system or potentially the market.

For a power system operator, or a transmission or distribution utility, demand response can be used as follows:

- large industrial load control – some large industrial customers have large loads, and their operation, or parts of it, can be interrupted at certain times
- targeted load shedding – shedding of a large number of small loads (such as domestic hot-water boilers) via specialised devices (e.g. through the established technology of ripple control)
- demand aggregation – distribution utilities may choose to sign up a large number of customers in a demand response program, which enables utilities to limit their exposure to energy market volatility. Independent companies may do the same, and then on-sell their aggregated demand load control to other participants in the energy market. Most demand response companies are now operating in this category
- microgrids and supply areas that are thinly connected to the grid – uniting demand response with distributed local generation can create small power systems within a power system, which could potentially export the surplus of energy into the larger power system, or operate without the larger power system for limited periods of time. This concept is developing rapidly and being tested around the world.

Entura have determined that using batteries to inject power into the system, thus increasing supply, is likely to be more cost-effective than using demand response to reduce demand. Batteries are also more flexible in terms of providing other supports.

3.4 Murraylink

High voltage direct current links using voltage source converters (VSC HVDC) are now an established technology with maximum ratings in excess of 1000 MW, for transporting bulk power between two networks sometimes over great distances. VSC based links have the advantage, compared to classic (line commutated) HVDC links in that they can connect to networks with a relatively low short circuit level, they can make a current contribution to network faults and they can provide reactive power / voltage control.

The Murraylink interconnector is a VSC HVDC link.

Historically, HVDC links have operated to a MW set point and have only been used for bulk power transmission between two points. However, the potential Murraylink has to provide frequency control by regulating the power flow across the link based on the difference in frequency between the two ends is the critical factor. ElectraNet have been advised that the Murraylink controls can be upgraded to allow the transfer of significant amounts of fast FCAS and emergency fast frequency response from the eastern sea board. These controls have been factored into the NIO. As these supports are frequency based (and therefore AC grid based), they are not necessarily provided by Murraylink.

3.5 Batteries

Battery energy storage density has improved significantly in the last couple of decades, driven largely by the increase in portable consumer electronics. Because of the high cost of batteries, their poor energy storage capacity and their inefficient energy conversion and control systems, there was previously no role for batteries in the modern power system. Efficient power conversion (DC to AC and AC to DC) technology has only recently became available and, along with improvements in battery technology, has allowed battery systems to become competitive with traditional generation sources.

Modern battery energy storage system (BESS) technology has two essential components, batteries and power convertors, and each defines how a BESS behaves when connected to the grid. Power converters define the maximum BESS power output (MW), and batteries define potential energy output (MWh).

Two main types of BESS include power-storage (grid-supporting) and energy-storage (time shifting). The primary purpose of the power-storage type of BESS is a short-term, high-energy output for grid stabilisation. The batteries are capable of rapid charging/discharging cycles and the power converters are equipped with fast-acting functions capable of supporting grid stability. The energy-storage type of BESS is typically used for energy shifting, or to store energy during times of surplus renewable power generation, and then to release it during an energy deficit. This type needs battery technology which is capable of slow and long-term charging/discharging cycles, and its inverters do not need to be as sophisticated.

Energy storage and renewable energy make a perfect fit. Geography permitting, some energy can be stored in large pumped hydro schemes. On the other hand, locally stored electrical energy offers the benefits of low transmission costs, and inherently higher reliability.

There are, however, some hurdles for battery technology to overcome in order to gain dominance in the power and transport industry. The cost per unit of stored energy needs to be reduced by an order of magnitude and the storage energy density still needs to be significantly increased. Batteries need to be safe and reliable, and power conversion technology also needs to be improved to successfully compete with traditional generators both in terms of cost and in services. There is very little doubt that battery energy storage will soon be able to compete with traditional generation technologies.

Three battery installations have been installed or committed within the last twelve months in South Australia. These installations are the 100 MW/129 MWHr Tesla installation at Hornsdale, the 10 MW /10 MWHr installation at Lincoln Gap and the 30 MW/8 MWHr battery at Dalrymple. The proposed solution includes further energy storage and power batteries notionally located at Tailem Bend.

3.6 Existing Synchronous Units

ATCO Power Australia own and operate a 180 MW combined cycle gas turbine (CCGT) plant at Osborne near Adelaide comprising a 120 MW gas turbine, heat recovery steam generator (HRSG) and 60 MW steam turbine. Until 2013 the steam turbine typically did not operate and instead the available steam was used by a neighbouring industrial plant.

The plant presently provides voltage control in line with the NER requirements and participates in all eight FCAS markets.

ATCO Power Australia have examined the technical viability of making the following modifications to their plant that would allow them to provide additional ancillary services:

- Add a steam turbine bypass; this modification would contribute to reducing the station minimum loading and increasing station loading rate from standstill
- Add gas turbine inlet bleed heating; this modification reduces the minimum stable load of the gas turbine and therefore reduces minimum loading
- HRSG bypass stack; converts the combined cycle turbine station into an open cycle station to allow faster loading of the gas turbine
- Protection control and governor adjustments; to allow the station to island therefore improving black start service, improved ramp rates and other services.

These plant modifications are expected to have relatively low cost. The largest benefits are increased loading rates and reduced minimum loading. Reduced minimum loading means that the station can be in service a higher proportion of the time (perhaps all of the time), even when market prices are supressed due to high availability of renewable energy. During these times the Osborne plant would operate at low MW output and would provide ancillary services.

The services provided by Osborne during high wind and solar generation would include:

- Reactive power
- Inertia
- System strength
- FCAS in all eight services

This service is included as part of the least cost solution for South Australia to provide inertia and frequency control.

3.7 Solar Thermal

Solar thermal is a relatively new solar technology based around a traditional thermal turbine and synchronous generator. This technology has all of the positive characteristics of a synchronous condenser plus:

- high inertia consistent with the inertia of a coal fired power station
- ability to shift energy generation from times of low demand to periods of low demand similar to pumped storage
- ability to generate at any time of day subject to quantity of energy stored at the time when generation is needed

This technology includes a traditional synchronous generator, which can be connected to the grid 24 hours a day/ seven days a week. The generator provides system strength, inertia, FCAS services and fast frequency raise services comparable with any conventional gas or coal powered station.

For the purpose of this study a 135 MW solar thermal plant has been included at Davenport as part of the least cost solution.

3.8 Minimum demand control

It is anticipated that during the next 5-10 years there will be periods where rooftop solar generation exceeds South Australian demand thereby placing a net negative demand on the South Australian transmission system. The least cost solution includes controls to reduce the output of roof-top solar and other embedded generation sources to maintain a minimum net load on the transmission system of at least 100 MW.

The challenge here is to maintain voltage control with low levels of flow on the transmission network. There are 3 likely causes for system issues with respect to negligible demand in the islanded condition:

1. Limited capacity to absorb surplus generation.

   Pumped hydro and batteries (transmission or embedded) will be able to absorb generation surpluses for a limited period of time until such time as their storage is at capacity. Once this point is reached surplus generation will have the effect of increasing system frequency.

2. Insufficient ability to regulate frequency quickly enough.

   The speed of load changes and the likely slow speed of controls curtailing embedded solar generation suggest some requirement to have a buffer between zero demand and actual demand.

3. Voltage control of unloaded distribution and transmission networks

   Active management of distribution network voltages is presently required due to the changes in power flows from embedded solar generation. Considerations of power factor control of solar inverters may provide some compensation for over-voltages experienced at low net power flows. This leads to the conclusion that curtailment of generation rather than disconnection may be the most appropriate approach.

   The SA transmission system is well placed to manage voltage rise due to low loads and we expect that, with the addition of the system supports proposed in this report, this will continue to be the case even when loads are significantly lower than they are now. Similarly to point 2, operating protocols relating to switched shunt reactors and capacitors may need review. The use of voltage control mode as typically used by wind and solar farms to ensure voltage profiles remain within requirements under N and N-1 conditions will also require review.

Essentially, the ability to regulate roof-top solar outputs to manage minimum demand will be required at some time in the near future. The ability of the SA network to operate islanded at low net demand will rely on these controls at times of low wind in particular. A control system that co-ordinates between the transmission or market dispatch and the distribution level, embedded generation, will be required to achieve this.

4. Solution Technical Performance

Ten dispatch scenarios were considered for the interconnected case and the network performance determined for a double circuit trip of the Heywood interconnector. All cases were stable with evidence that the system frequency would trend back towards nominal.

Cases 1 – 6 represent system scenarios that include existing synchronous generating units. Cases 7 – 10 are constructed such that no large existing synchronous plant is used. The peaking plant at Hallett and the modified Osborne CCGT are included in these latter cases where required. The rationale behind each of the 10 cases studies is provided in the following table:

Table 4.1: Case descriptions

Case	Description
Case 1	This case represents a low SA load case with some wind generation and modest **export** to Victoria.
Case 2	This case represents a modest SA load case with some wind generation and modest **import** from Victoria.
Case 3	This case represents a significant SA load case without much wind or synchronous generation and high **import** from Victoria.
Case 4	This case represents higher SA load than case 3 with correspondingly more synchronous generation and still high **import** from Victoria.
Case 5	This case represents higher SA load than case 3 with high availability of wind and only modest inertia. The high load in this case suggests that SIPS should be armed
Case 6	This case is similar to case 5 with more SIPS armed in the hope of reducing involuntary load shedding
Case 7	This case operates with no thermal generation in service except for the Osborne station with its proposed minimum load reduction. This case has 750 MW of **import** from Victoria.
Case 8	This case is similar to case 7 with load reduced to give an interconnector flow of 650 MW
Case 9	This case is similar to case 7 with an additional battery in service at Tailem Bend
Case 10	This case is similar to case 8 with an additional battery in service at Tailem Bend

Table 4.2: Pre interconnector trip, dispatch (MW)

		Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Case 10
Base case information	Total SA Load[10] (MW)	779	1435	1842	2317	2790	2871	2260	2182	2260	2182
	Interconnector Flow to SA (MW)	-229	393	643	649	651	761	753	653	752	653
	Synchronous inertia (MWs)	2811	1800	1800	3535	6584	6584	0	0	0	0
	Inertia from base case new sync cons (MWs)	2400	2400	2400	2400	2400	2400	2400	2400	2400	2400
	TIPS (MW)	555	246	370	615	370	370	OOS	OOS	OOS	OOS
	Wind (MW)	513	769	784	1078	1485	1485	1485	1485	1485	1485
	Hornsdale Battery	-30	-3	3	0	-50	-50	-50	-50	-50	-50
	Dalrymple Battery	-5	-21	10	-10	10	10	10	10	10	10
	SIPS Armed	0	0	200	0	125	230	0	0	0	0
Additional supports Units MW unless stated otherwise	Cultana Pumped Hydro	-90	30	30	sync	-90	-90	sync	sync	sync	sync
	Osborne Cogen	88	OOS	OOS	OOS	88	88	88	88	88	88
	Davenport Solar Thermal	OOS	sync	OOS	OOS	45	45	sync	sync	sync	sync
	Tailem Bend Battery	OOS	OOS	0	0	0	OOS	OOS	OOS	0	0
	Inertia from supports(MWs)[11]	2173	1307	712	712	2768	27408	2173	2173	2173	2173
	Battery Response	OOS	OOS	OOS	OOS	OOS	OOS	OOS	OOS	OOS	OOS
	MurrayLink	In	In	In	In	In	In	In	In	In	In
Reserve (MW)[12]		406	470	364	492	781	627	355	355	509	509
Simulated performance	U/F Load Shed (MW)	22	304	500	455	497	783	1021	788	759	788
	Frequency minimum[13] (Hz)	50	48.85	48.9	48.85	48.39	48.35	48.0	48.4	48.3	48.4
	Approx. df/dt @ 0.5 sec post event (Hz/sec)	0.50	-0.90	-0.90	-1.28	-0.71	-1.12	-2.18	-1.86	-1.95	-1.86
	df/dt averaged over 0.25 sec post event (Hz/sec)	0.65	-1.4	-2.15	-1.80	-1.30	-1.54	-3.25	-2.87	-2.97	-2.87
	df/dt averaged over 1.0 sec post event (Hz/sec)	0.24	-0.51	-0.74	-0.66	-0.39	-0.49	-1.18	-1.03	-1.03	-1.03
	Generation trips	0	0	0	0	0	0	66	66	66	66

[10] These demand levels are limited to below current peak demands because the stability of the network becomes higher at higher demand since more SA generation must be dispatched. See Section 2.3 for more details.

[11] Inertia from supports includes solar thermal, pumped hydro and Osborne CCGT when in service.

[12] Sum of reserve from existing and additional supports

[13] All frequencies and all df/dt measured at Tailem Bend

Having islanded the system would be reconfigured during the hour following separation to re-establish a secure operating state. Three islanded states were considered as shown in Table 4.3 below. These cases are based on Cases 1, 4 and 10 of the pre-islanding cases.

Table 4.3: Islanded cases, dispatch (MW)

		Case 1A	Case 4A	Case 10A
Base case information	Total SA Load (MW)	754	2267	1989
	Interconnector Flow to SA (MW)	OOS	OOS	OOS
	Synchronous inertia (MWs)	900	5157	562
	Inertia from base case new sync cons (MWs)	2400	2400	2400
	TIPS (MW)	185	800	OOS
	Wind (MW)	513	1078	1485
	Hornsdale Battery	0	30	80
	Dalrymple Battery	-5	5	10
	Hallet	0	100	168
Additional supports Units MW unless stated otherwise	Cultana Pumped Hydro	11	3	110
	Osborne Cogen	130	152	46
	Davenport Solar Thermal	OOS	120	110
	Tailem Bend Battery	0	0	0
	Inertia from supports (MWs)	2173	2886	2886
	Battery response	OOS	OOS	150
	MurrayLink	In	In	In
Reserve (MW) [14]		514	590	364
Simulated performance (most severe result)	U/F Load Shed (MW)	0	0	194
	Frequency minimum[15] (Hz)	>49	>49	48.3[16]
	df/dt averaged over 0.25 sec post event (Hz/sec)	-0.95	-0.58	-1.78
	df/dt averaged over 1.0 sec post event	-0.69	-0.39	-0.39
	Generation trips	0	0	66

[14] Sum of reserve from existing and additional supports

[15] All frequencies and all df/dt measured at Tailem Bend

[16] Trip of the Hallet station

The three islanded scenarios were able to ride through the following power system disturbances, with load shedding only required in the case with no traditional steam plant, indicating a reasonably secure power system operating state:

- Sudden addition of a lumped load of 250 MW at TIPS 275 kV
- A L-L fault on TIPS 275 kV cleared after 120 ms by the tripping of one TIPS 200 MW machine
- A L-L fault on Tailem Bend 275 kV cleared after 120 ms by the tripping of the loaded battery
- A L-L fault on the Davenport to Robertstown line cleared by tripping of the line segment closest to Davenport
- A L-L fault on the Davenport to Robertstown line cleared by tripping of the line segment closest to Robertstown
- A L-L fault on the 275 kV system close to Hallett followed by tripping of all in service Hallett machines
- Tripping of either a TIPS machine or the proposed solar thermal machine (whichever was in service)

4.1 Inertia, FFR and RoCoF

For each of the interconnector tripping scenarios the system frequency remained above 47.5 Hz throughout the event. This implies that system black (which typically occurs below 47.0 Hz) can be avoided with a small margin. The interconnector trip scenarios were in general more onerous than the contingency events while operating as an island.

The system RoCoF was less than 3.0 Hz/sec measured over the first 0.25 seconds, for the non-credible interconnector trips. This implies that any machine able to achieve the automatic access standard should remain connected to the network during and following these events.

When SA is operating as an island, the system frequency remained above 48.3 Hz for each contingency event. Under frequency load shedding only occurred in the cases without any heavy steam driven generators in service.

The system RoCoF was less than 1.0 Hz/sec measured over the first 0.25 seconds, for the contingencies during islanded operation. This implies that any machine able to achieve the automatic or the minimum access standard should remain connected to the network during and following these events.

The levels of inertia present in the optimised solution are adequate. Furthermore, it was noticed that the Fast Frequency Response of the batteries in the least cost solution are very effective at reducing the need for physical inertia in the system.

4.2 FCAS

The existing FCAS markets may not be optimal for the supply of frequency (and energy) for the South Australian system over the time frames that must be considered. The markets may also require some optimisation to incentivise storage and power batteries to enter the State and to provide the valuable services that only batteries are able to provide currently.

Energy balance (FCAS) is considered in the following sections over time frames of interest to South Australia. Longer events require all of the additional considerations of shorter events.

4.2.1 Periods exceeding 48 hours

In the event that the South Australian system operates as an island for a period exceeding 48 hours then the average energy infeed from batteries and pumped storage hydro plants will be approximately zero.

For periods exceeding 48 hours the State must be completely self-sufficient using its own renewable energy sources, storage, gas and diesel plant. A risk based approach should be taken to determine how much thermal energy will be required based upon the likelihood of an extended period of low wind and the costs of non-supply of electricity.

This risk assessment is likely to drive the installation of standby gas fired plant, however it is unlikely that current energy markets will provide sufficient incentive for private companies to install this plant.

4.2.2 Periods of six hours to 48 hours

In the event that the South Australian system operates as an island for a period of six hours to 48 hours, it is likely the energy infeed from batteries and pumped storage hydro plants will be equal to their total stored energy at the beginning of the event. The energy stored in pumped hydro may be a significant proportion of the total energy deficit of the State for such an outage. However it is probable that all pumped storage would be exhausted during the first 24 hours. Some limited charging of batteries and pumping may be possible during this period when there is excess wind and/or solar energy available to extend the length of time the State can be supported.

For an interconnector outage of this duration thermal plant can be started and loaded (subject to availability), to provide for the State's energy needs.

4.2.3 Periods of one hour to six hours

In the event that the South Australian system operates as an island for a period of one hour to six hours, the average energy in feed from batteries and pumped storage hydro plants is likely to be almost equal to their stored energy at the beginning of the event. This stored energy in pumped hydro and batteries may be a significant proportion of the total energy deficit of the State for such an outage. For these storages alone to sustain the island past the first discharge cycle, the solar and wind energy must be sufficient to supply the demand AND the storage loads of the batteries and pumps.

For an interconnector outage of this duration only fast start thermal plant such as open cycle gas or diesel can be started and loaded, to provide for the State's energy needs.

4.2.4 Periods of sixty seconds to one hour

In the event that the South Australian system operates as an island for a period of 60 seconds to one hour then the average energy infeed from batteries and pumped storage hydro plants will depend greatly on the design of the plant. Typically a pumped storage plant may provide 20% of its energy capacity (but 100% of its power capacity) while a battery may provide 80% or even more of its energy capacity.

For an interconnector outage of this duration only very fast start thermal plant such as diesel reciprocating engines could be started and loaded to help provide for the State's energy needs.

Battery capacity could be reserved for this timeframe through a contract to allow more time for alternative stored fuel generation to be brought on-line or to ride-through dips in renewable generation. As discussed in previous sections, we expect the economics of batteries to exceed those of demand response for this function.

4.2.5 Periods of six seconds to sixty seconds

In the event that the South Australian system operates as an island for a period of 6 seconds to 60 seconds then the energy infeed from suitably designed batteries can be significant.

Pumped storage hydro plants can increase their power output significantly, provided they were in service at the time of the event. Their usefulness is dependent on their operating mode at the time of the event:

- In pumping mode the pumped hydro can simply turn off, which is equivalent to adding a generator with 100% of the machine’s capacity,
- In synchronous condensing mode, the machine can start to generate. Designs vary considerably but it is likely that the station could start to provide meaningful power output after 6 seconds, ramping up to 50% by 60 seconds and full capacity by 2 minutes,
- In generating mode the pumped storage plant can provide the difference between its pre-event loading and its full capacity over a period of approximately 2 minutes.

Thermal plant that is not in service generating power at the time of the event can provide no support to the event. Machines that are in service can increase their power output typically only after 30 seconds. The proposed Osborne Cogeneration support is likely to come into this category.

4.2.6 Periods less than six seconds

All power system events must survive the first 6 seconds of post event operation. During this time[17] no practical human intervention can occur so all equipment must operate automatically. Events of this type include interconnector trips, sudden application of additional load, unexpected tripping of generators and faults on the transmission network.

During this period the required energy balance can be provided by:

- System integrity protection schemes
- Batteries
- Pumped storage plant that were in service and not generating at full output
- Limited contribution from thermal plant
- Automated load shedding

If the energy balance is not restored during these first few seconds after an event then it is possible that a system black event can occur.

[17] In practice this time can extend to up to 15 minutes depending on the type of event.

4.2.7 The first one second

There is currently no FCAS market in Australia that deals with the energy balance during the first one second after an event occurs. Two key reasons for this are; traditional generators cannot provide any meaningful response in this one second timeframe and traditional generators have considerable inertia, which allows an energy imbalance to be accepted for two - three seconds allowing enough time for governor response to begin reducing the imbalance.

With the entry of inverter based power sources (batteries and some solar or wind), system inertia has reduced in South Australia, thus creating a need to restore energy imbalance in the first one second after an event. Fortunately, power batteries (and perhaps in the future other inverter based renewables) can provide a meaningful response in the periods 0.25 seconds to 1.0 seconds and possibly even faster. Moreover, power batteries can follow power demand signals from a central dispatcher (e.g. AEMO) very precisely.

It was observed during this study that the installation of a Mega Watt of suitably tuned battery capacity in South Australia has a greater effect than removing a Mega Watt of thermal capacity and its associated inertia, thus providing a net benefit to the system. However, there will likely be a limit[18] to how much physical inertia can be displaced by batteries.

Other sources of energy balance that can operate in the first second are:

- System integrity protection schemes
- Automated load shedding
- Contracted demand response

In a low inertia system, such as in South Australia, if the energy balance is not restored during this first second after an event, it is conceivable it may not be possible to restore system stability during the subsequent seconds.

4.3 System Strength

The system fault level has been calculated at each 275 kV busbar for each of the six islanded cases. The results are provided in Table 4.4

Table 4.4: Pre interconnector trip, dispatch

Case	Lowest 275 kV fault level
2A	2,408 A
2B	2,318 A
4A	2,567 A
4B	2,582 A
4C	2,446 A
4D	2,578 A

[18]Technology Capabilities for Fast Frequency Response - GE Energy Consulting

In each case, the fault levels exceed 2000 Amps. Therefore the minimum system target for system strength is achieved. The following busbars have fault levels that fall between the minimum system target (2000 A) and the preferred system target (4000 A):

- SNWF > 3,690 A
- SEAS >2,736 A
- PARA/D1 >3,521 A
- PARA/D2 >3,521 A
- SEAS/D1 >2,318 A
- SEAS/D2 >2,318 A

4.4 Summary Performance against system targets

The proposed suite of power system supports has been selected to maintain the minimum system frequency above 47.5 Hz during the few seconds post interconnector trip. The system was then tested against the system security requirements documented in Table 2.1. Performance against the minimum and preferred targets is documented in Table 4.5and Table 4.6 respectively.

Table 4.5: Solution performance against minimum system security requirements

		Minimum system target	Modelled performance
Description of operating requirements	Normal operation	Withstand the loss of the Heywood interconnector up to 650 MW without resulting in a system black condition.	Exceeds requirement (see Table 4.2)
		Less than or equal to 3 Hz/s RoCoF for a contingency size of up to 650 MW that results in separation from the rest of the NEM – effectively would result in removal of current RoCoF constraint on the Heywood Interconnector.	Meets requirement (see Table 4.2)
		Capability to operate South Australia when connected to the rest of the NEM with no local synchronous generators online.	Partially achieved by Case 10, which includes a modified Osborne CCGT operating at 88 MW.
	Islanded operation	Capability to operate islanded for 1 hour in a **satisfactory** manner –any further contingency events could lead to a system black event.	Meets requirement
		Sufficient regulation FCAS in South Australia to manage “small” perturbations in the network for 1 hour.	Meets requirement
		Maintain minimum fault levels across the islanded transmission system.	Meets requirement (see Table 4.4)
Service requirements specification	Inertia	**Inertia**: 4,065 MWs (4Hz/s back stop) + sufficient **FFR**	Meets requirement (see Table 4.2)
	FCAS	Sufficient contingency FCAS or equivalent services to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 650 MW.	While this is not met in the simulations, this is an extension of the FCAS requirements that exist now. That is, with a single interconnector, loss of 650 MW is non-credible and so FCAS is not the only control mechanism that can be used.
		35 MW or local regulating frequency (or equivalent) available within 30 minutes and required for no longer than 1 hour following separation.	FCAS can be effective in managing contingency sizes of up to 250 MW where sufficient FCAS is available (contrast cases 1A & 4A with case 10A)

Table 4.6: Solution performance against preferred system security requirements

		Preferred system target	Modelled performance
Description of operating requirements	Normal operation	Withstand the loss of the Heywood interconnector up to 750 MW without a system black condition.	Achieved in Cases 6, 7 and 9.
		1 Hz/s average RoCoF over 500 ms for any contingency size up to 750 MW that results in separation from the rest of the NEM– effectively results in removal of RoCoF constraint on the Heywood Interconnector.	In general not achieved
		2 Hz/s maximum RoCoF for the first 250 ms.	In general not achieved
	Islanded operation	Capability to operate islanded system indefinitely in a **secure** manner. Secure operation restored within 30 minutes from the time of separation Sufficient regulation FCAS in South Australia to manage “small” perturbations indefinitely	In general, this is achievable but relies on continued availability of thermal plants (higher inertia) as shown by the contrasting performance of cases 1A & 4A with 10A.
Service requirements specification	Inertia	Inertia: 9,375 MWs (2 Hz/s back stop) +Sufficient **FFR**	Not achieved
	FCAS	Sufficient contingency FCAS services to ensure the SA system can meet the Frequency Operating Standard after separation occurs for a contingency size up to 750 MW. 35 MW or local regulating frequency available and required continuously. With SA islanded, sufficient raise contingency FCAS services for a 270 MW generator contingency. With SA islanded, sufficient lower contingency FCAS for a 200 MW load event	While this is not met in the simulatons, this is an extension of the FCAS requirements that exist now. That is, with a single interconnector, loss of 750 MW is non-credible and so FCAS is not the only control mechanism that can be used. FCAS can be effective in managing contingency sizes of up to 250 MW where sufficient FCAS is available (contrast cases 1A & 4A with case 10A)

The proposed suite of solutions maintains 275 KV system fault levels above the minimum requirement of 2 kA. There are a number of locations in the network where the fault level falls between 2 kA and 4 kA so the “preferred system target” is not achieved.

Additional supports could be proposed to achieve full compliance with the “minimum system standard”. However, it is considered the suite of supports proposed represents the maximum credible set. The cost of the NIO[19] is approaching that of the proposed network solutions and the cost of installing additional supports would conceivably increase the cost to more than the equivalent network solution. In particular, case 10A highlights the limitations of islanded operation in the absence of thermal generation. Alternatives to the spinning reserve offered by this plant will require consideration of additional energy batteries or demand response, both of which add significant cost to the non-network solution for what is likely to be a low-probability scenario. Since this is a future requirement we have not considered this in the suite of non-network supports.

[19] It should be noted the costs referred to here are the direct costs recovered by ElectraNet to pay non-network service providers. These are not the full capital costs of the solutions provided, which will be recovered by other means from the market.

5. Solution Timeline Performance

The NIO must be sufficiently robust to support the inter-connected system during and immediately following the loss of the Heywood interconnector. The amount of time required for the islanded system to survive will vary in practice but for the purposes of this assessment we have identified 4 main periods during which the supports required by or available to the system are subtly different. More detail using a different set of time periods is provided in Section 4.2 for the actual supports considered.

The table below identifies the transition periods as:

- Survive

  The first 10 or so seconds after the Heywood interconnector trips. The power imbalance must be rapidly offset to ensure frequency does not breach the operating standards.

  Power batteries, frequency response from generating units and under frequency load shedding schemes are used to arrest falls in frequency within the frequency standard.

- Stabilise

  Within the first thirty minutes of islanding.

  Transition between power batteries and slower forms of frequency support. This is the critical time for transition. There must be sufficient successfully started fast-start units available to pick up the load from the power batteries while OCGTs spin up ready to support the system. Contracted energy storage batteries, solar thermal and pumped hydro can also play a role in this period so long as they were not already generating at full capacity.

- Steady state

  Within the first hour of islanding.

  Return to normal market operation and secure operation but possibly still sustained through inefficient peaking generation or short-run storages.

- Sustain

  Up to seven days after islanding.

  Normal market operation but heavily dependent on energy supply and demand balance. In particular the availability (or otherwise) of wind and solar generation must be considered.

Table 5.1: Stages of transition to sustained island operation on loss of Heywood interconnector

Survive	Stabilise	Steady	Sustain
0 seconds to 10 seconds	10 seconds to 30 minutes	30 minutes to 1 hour	1 hour to 7 days
Example response sources: • *Inertia/ system strength sources including online synchronous plant response* • *Battery response* • *Other frequency response (e.g. an upgraded MurrayLink)* • *Load shedding and demand response*	*Example response sources:* • *Inertia/ system strength sources including online synchronous plant response* • *Battery response* • *Other frequency response (e.g. an upgraded MurrayLink)* • *Fast start plant* • *Additional load shedding and demand response as required*	*Example response sources:* • *Inertia/ system strength sources* • *Other frequency response (e.g. an upgraded MurrayLink)* • *Peaking and other fast start plant dispatched as required* • *Demand response*	*Example response sources:* • *Inertia/ system strength sources* • *Other frequency response (e.g. an upgraded MurrayLink)* • *Base and intermediate generators (cold start)* • *Other plant dispatched as required* • *Special purpose demand response*

The types of support offered by the elements of the NIO across these timeframes are shown in Table 5.2.

Table 5.2: NN Solution components required at different stages

Stage	Solution Element	In/Out	Service Provided
Start (Pre event)	Murraylink	In	
	Osborne	In	
	Solar Thermal	In	
	BESS #1 Tailem Bend	In	
	BESS #2 Tailem Bend	In	
	Pumped Hydro	In	
Survive (0-10 sec)	Murraylink	In	FFR
	Osborne	In	Inertia Frequency regulation
	Solar Thermal	In	Inertia Frequency regulation
	BESS #1 Tailem Bend	In	FFR Frequency regulation
	BESS #2 Tailem Bend	In	FFR Frequency regulation
	Pumped Hydro	In	Inertia Frequency regulation
	Murraylink	In	Energy (<15 minutes)
	Osborne	In	Frequency regulation Energy (<15 minutes)

Stage	Solution Element	In/Out	Service Provided
Stabilise (10s to 30m)[20]	Solar Thermal	In	Inertia Energy (<15 minutes)
	BESS #1 Tailem Bend	In	FFR Frequency regulation Energy (<15 minutes)
	BESS #2 Tailem Bend	In	FFR Frequency regulation Energy (<15 minutes)
	Pumped Hydro	In	Frequency regulation Energy (<15 minutes)
Steady (30m to 4h)[21]	Murraylink	In	Energy
	Osborne	In	Inertia Frequency regulation
	Solar Thermal	In	Inertia Frequency regulation
	BESS #1 Tailem Bend	In	FFR
	BESS #2 Tailem Bend	In	FFR
	Pumped Hydro	In	Frequency regulation

[20] Other market based energy sources are expected to come on line within 5-10 minutes of the interconnector trip.

[21] Large scale thermal generation is expected to come on line towards the end of this period

5.1 Examples of transition from interconnected to secure island operation

Two scenarios are considered:

- separation with dispatched thermal generation in SA
- separation without dispatched thermal generation in SA

The following table contrasts the two initial conditions.

Table 5.3: Initial dispatch for interconnector stabilisation examples

Generation type	With thermal generation	Without thermal generation[22]
Wind	1026	1182
Solar	0	0
Steam	236	0
Heywood (VIC-SA)	650	650
Load Shedding	0	0
Power Batteries	0	0
Pumped Storage hydro	0	50
Solar Thermal	0	30
Diesels	0	0
OCGT	88	88
Murraylink	0	0
SA Demand	2000	2000

The figures on the following page show the differing transitions required for each case. It must be stressed that these are a set of possible outcomes not the only outcomes. Further, these outcomes may not be the most optimal of the possible outcomes. We merely seek to demonstrate here that stabilisation of the SA system following the non-credible loss of the Heywood interconnector can be achieved with the NIO supports in place.

[22] Other than augmented Osborne support

Figure 5.1: Transition to secure operation – with thermal generation in service pre trip

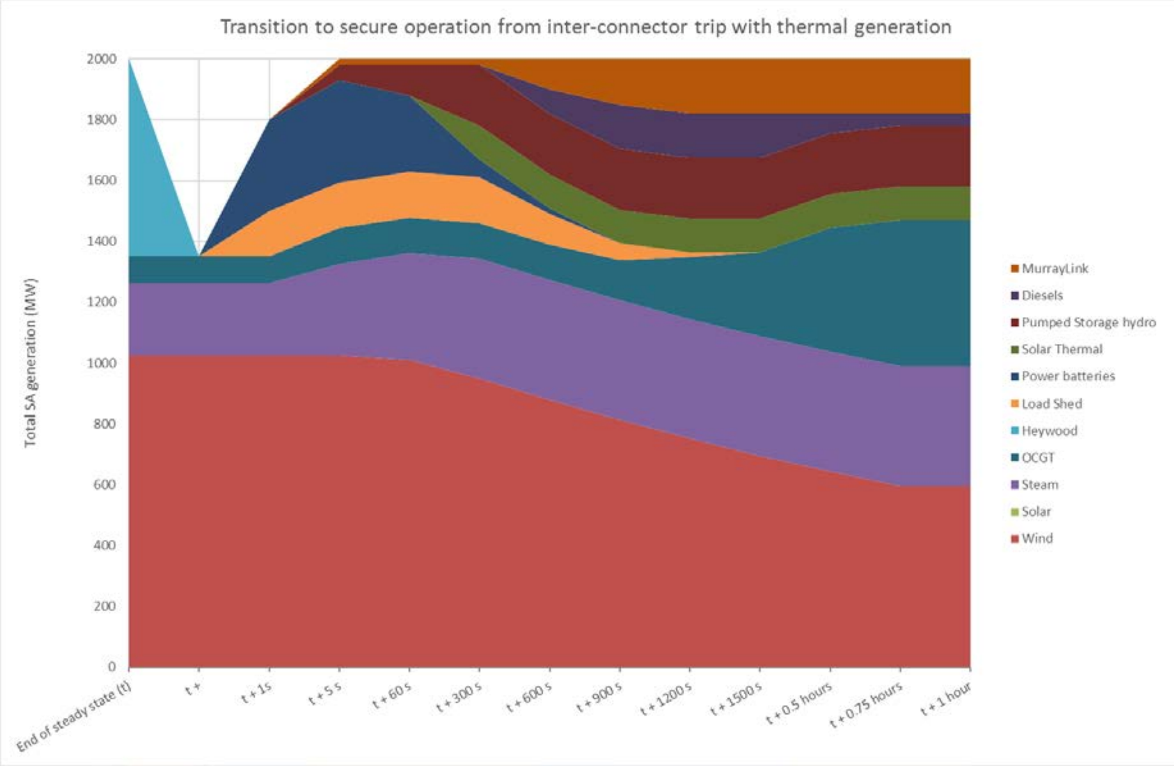
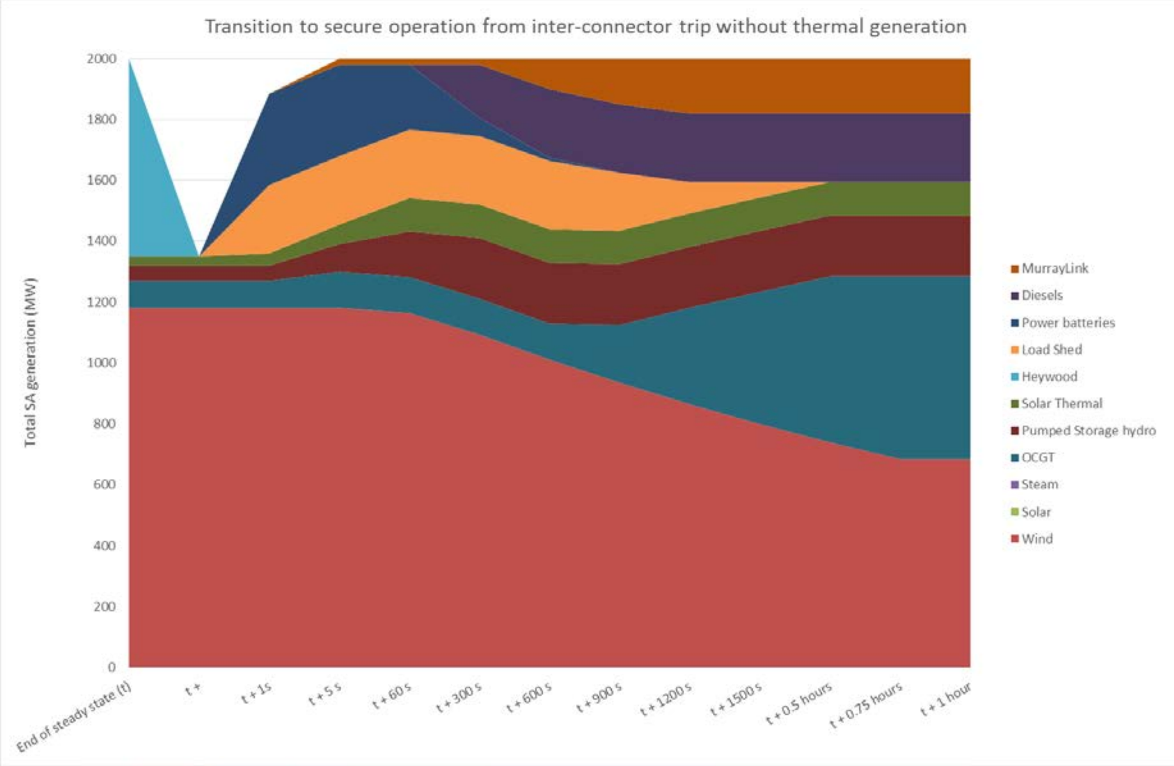


Figure 5.2: Transition to secure operation – without thermal generation in service pre trip



Observations

The main observation from this study is the difficulty to predict what the post-contingency island will look like. We have assumed that all plant survives the transition as does all load. This then allows identification of load shedding quantities through a SIPS that is tailored to the particular scenario. The quantity of load shedding is governed by two things:

- the quantity of fast frequency response available to arrest the fall in frequency post interconnector trip, and
- the amount of slower frequency response and fast start generation that is available within the first 5 – 10 minutes

These issues can be resolved through the availability of more storage but it is not clear if this storage is absolutely warranted as a system support. There is a system requirement for short term demand management. This could be provided by batteries, fast start gas or diesel units, fast operating controls on pumped hydro or solar thermal units, load shedding schemes or contracted demand response. The economics of this are difficult to predict.

Using market-based plant to provide these services may limit their operational flexibility at a cost. Equally using plant that is essentially on hot standby for years at a time does not appear to be cost-effective either. The best alternative appears to be load shedding to manage non-credible contingencies.

A secondary observation is that the output of wind (and solar if it was generating) across this period can vary significantly. The analysis summarised in Figure 5.1 and Figure 5.2 shows a large decrease in wind generation across the first hour. This was modelled to add a level of conservatism to the analysis. It has only minimal effect in the critical 5-10 minute window after the event where fast-start units are dispatched but OCGTs would still spinning up during this period (i.e. not at full load). As more wind is developed and more storage is included in those developments, the effect of this possible decrease in generation will be reduced.

6. Cost of Solution

6.1 General discussion

The cost of the solution is summarised in Table 6.1.

It is worth noting that the cost of batteries has dropped by approximately 10% during the past 12 months. It is reasonable to assume that this cost will continue to fall at a similar rate year-on-year for some time to come. This may make it economic to build power batteries with limited energy storage and to add further battery capacity to them as battery prices fall. In this way the battery will provide frequency stabilisation in the first 60 seconds after an event and after the additional batteries have been installed will become useful for a regulation service. This is more a second order effect. The battery response would be used to offset the requirement for load shedding. The only cost of load shedding is the cost of interruption (an externalised cost).

Our experience in other jurisdictions where load shedding is used to stabilise frequency for single contingencies is that frequent use of this control becomes more costly. That is, if the same customers are continually exposed to load shedding then they become sensitised to it. Use of the SIPS to avoid longer disruptions or the use of UFLS type schemes to manage multiple contingencies must be infrequent. As renewable penetration increases, the ability of renewables and other supports to maintain or reduce the frequency of load shedding events will be important to maintain system performance standards and customer satisfaction.

We have identified a number of supports required to allow the SA power system to operate as near as possible to the standard provided by a second AC interconnector. It is considered these supports chosen represent a plausible least cost set of non-network technologies to meet the various requirements set out in the PSCR and the SIP. These supports vary in cost and cost structure and so it is worth some analysis to show the relative value or cost of each support.

Table 6.1 shows the cost basis and NPVs for the selected supports (refer to Table 3.1).

The results highlight the opportunities and risks that ElectraNet and proponents face in identifying a fair cost for these supports across time.

Table 6.1: NIO cost summary

			Contract	CAPEX	OPEX
Supports	**NPV** (6% discount rate) ($M)	**Supply basis**	$M/year	$M (Note 1)	$M/year (Note 1)
Pumped storage – Port Augusta		Contract			
Osborne Cogeneration		Contract			
Solar thermal - Davenport		Contract			
BESS 1 (Note 2)		Capex + Opex + Margin			
Murraylink – Berri					
BESS 2 (Note 2)		Contract			
Minimum load control (Note 3)		Capex + Opex			
Total	**($827.00)**				

Note 1: Greyed out values do not contribute to the NPV calculation.

Note 2: The cost structure for the two BESS units is based on two different approaches. The first is a cost plus margin approach and the second is based on a contract price. ElectraNet have received a wide range of indicative BESS prices. We have chosen to resolve this variation by choosing suitable, mid-range offers, calculating an average NPV between these offers then back calculating the two modes of delivery (contracted or cost plus) for illustration purposes here.

Note 3: Minimum load control is estimated to begin to be required in 2025.

7. Network Issues

Our assessment of the NIO has shown that there are a number of issues with the SA network that must be managed through the implementation of any augmentation but particularly under the NIO solution during islanded operation.

Voltage regulation

The loss of the Heywood interconnector can change the power flows in SA and hence alter the voltage profile. The voltage profile after the contingency must be managed by maintaining sufficient connected voltage control plant to regulate network voltages. The pre-contingency system voltage profile also needs to be set up such that it can accommodate any changes that an interconnector trip may cause.

This is particularly true in the more remote parts of the 132 kV network (such as Eyre Peninsula). We have found this can be managed but it requires operator vigilance to ensure that the pre-contingency network is operated within a suitable envelope.

Network stability

We have observed transient instability when placing large generating units in remote areas of the network.

For example, with various pumped storage atlases identifying the cliffs to the west of Port Lincoln as an ideal location for a pumped storage hydro facility and with an existing system support requirement in that area we had at one time located a 100 MW facility in this region. This worked well in steady state and under mild remote faults but we observed transient instability for network faults. This is unsurprising given the 132 kV transmission distance to Port Lincoln.

We are not concluding that a pumped hydro scheme cannot be placed at Port Lincoln but rather that careful tuning and investigations would be required to guarantee that such a plant could operate satisfactorily in all conditions.

Retirements

The success of the continued operation of the SA network with a single interconnector or in islanded operation is highly dependent on the presence of synchronous generating units. While a combination of synchronous condensers and batteries can be adequate to ride-through loss of the interconnector or perhaps large contingencies in the island, the synchronous plant will play a crucial role in the energy balance of the island in particular.

Clearly some of the existing units will not continue to operate indefinitely. The solution proposed here will require continual re-evaluation as these retirements occur. Additional costs are likely to be incurred over time to enable more supports or to adapt the service requirements of existing supports to maintain system stability and security. Many of these costs will not be required under a two interconnector solution.

Supply of energy in the islanded network will depend on the balance between solar, wind and storage and any remaining synchronous units. Where a significant volume of peaking plant and some level of large scale thermal or gas plant remains available then the transition to islanded operation and potentially sustained islanded operation should be achievable. It is not expected that this plant will remain available purely because it may be needed under islanded conditions. We have excluded this long term energy supply from our supports in the NIO.

8. Modelling Software

The basis of our validation of the transient performance of the NIO solution has been the PSS/E software supplied by Siemens. There are legitimate doubts about the extent to which PSS/E can accurately simulate power systems with low levels of short-circuit ratio. This is due to a limitation of the software to simulate the sub-cycle high frequency switching and controls in modern inverter controls. Since most wind and all solar is generated using these technologies it is seen as a critical performance issue for the software. This is only material under some conditions, chiefly, short-circuit ratios less than two or when a contingency involves an unbalanced fault.

In this study, we have assumed that system strength must be higher than 2 kA (952 MVA at 275 kV) and preferably 4 kA at all buses. This gives quite healthy SCRs at the bulk transmission level for the plant that we have modelled. This leads us to conclude that PSS/E is an appropriate tool to use for this planning analysis. However, before any specific solution is implemented, more detailed EMT studies will have to be performed to validate to design of the proposed solution.

9. References

1. South Australian Energy Transformation 'PSCR Supplementary Information Paper' January 2017