



Minimum operational demand thresholds in South Australia

May 2020

Technical Report

Advice prepared for the Government of South Australia

Important notice

PURPOSE

This document summarises the results of AEMO's preliminary investigation into minimum operational demand levels in South Australia, in response to a request for information from the South Australian Government.

This document has been prepared by AEMO using information available as at April 2020.

DISCLAIMER

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed advice about the National Electricity Law, National Electricity Rules or any other applicable laws, procedures or policies. AEMO has made every effort to ensure the quality of the information in this document but cannot guarantee its accuracy or completeness.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this document; and
- are not liable (whether by reason of negligence or otherwise) for any statements or representations in this document, or any omissions from it, or for any use or reliance on the information in it.

VERSION CONTROL

Version	Date	Changes
1	7 May 2020	Report – handed to SA Government

Executive summary

The Government of South Australia has requested advice from AEMO on the risks of electricity supply disruption associated with reducing minimum operational demand levels in South Australia's network, which is contained within this technical report.

Distributed photovoltaic (PV) installations are growing rapidly, with more than 200 MW per year being installed in South Australia at present, tracking in line with AEMO's "High DER" scenario¹. With growth continuing in line with that scenario, operational demand could reach zero in South Australia within the next 1-3 years. To AEMO's knowledge, South Australia is the first gigawatt-scale power system in the world to approach zero operational demand due to such high proportions of demand met by distributed resources.

AEMO has conducted a preliminary investigation of operational challenges under low load, high distributed PV generation periods. Given the novel nature of power system operation under these conditions, AEMO's work to explore system security will be an ongoing process. This technical report presents findings to date, covering the development of new dynamic models that capture the behaviour of load and distributed PV during system disturbances, and initial analysis of impacts on power system security. Dispatch studies were also undertaken to explore the minimum load required for operation of a South Australian island.

Scope of analysis

The holistic development of markets, power systems, and customer engagement mechanisms that effectively integrate distributed energy resources (DER) is a considerable exercise. AEMO has launched a program to work towards this objective². The DER program seeks to ensure a smooth transition from a one-way energy supply chain (starting with large-scale generation units to consumers) to a world-leading system harnessing electricity and energy-related services from DER devices distributed throughout Australian homes and businesses into the electricity grid. The aim is to maximise the value of DER for Australia's energy consumers, while supporting energy system reliability and security.

This report represents a contribution to that program under the DER Operations stream³. It will be integrated into the broader body of work, as one piece of the puzzle that helps to inform solutions, market design, and enduring policy frameworks. The scope of this analysis primarily focuses on:

- **The South Australian region** – analysis is also progressing in parallel for Western Australia and is underway for other National Electricity Market (NEM) regions.
- **System security impacts** – market design, regulatory frameworks, and customer engagement in two-way markets are essential complementary aspects which will eventually provide many of the long-term solutions to these challenges. These aspects are being explored in parallel in the Markets and Framework workstream in AEMO's DER program⁴.
- **Actions required prior to 2023** – the Markets and Framework stream is informed by these short-term challenges, and is developing enduring policy frameworks that deliver efficient design and solutions to the identified challenges in the medium and long term.
- **Management of credible contingency events** – the impacts of distributed PV on non-credible events (such as the double-circuit loss of the Heywood interconnector) is under investigation, but could not be completed in time for this advice.

¹ Based on the 2020 Integrated System Plan (ISP).

² AEMO, Distributed Energy Resources Program, at <https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program>.

³ AEMO, DER Operations, at <https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/operations>.

⁴ AEMO, Markets and Framework, at <https://aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework>.

The findings outlined in this report have contributed to AEMO's broader work streams on DER integration, reflected in AEMO's other publications such as the Renewable Integration Study⁵. They support and echo the recommendations identified there as priorities, including:

- Continuing the design and deployment of the Energy Security Board's (ESB) Market 2025 reform program with particular focus on day-ahead and system security services markets;
- New standards and settings to maximise the potential contribution of distributed solar PV; and
- Construction of required transmission resources identified in the Integrated System Plan.

System security challenges identified

Two key challenges have been identified.

Disconnection of distributed PV

There is now considerable evidence that many distributed PV inverters disconnect in response to voltage disturbances. Analysis in this report demonstrates that a severe but credible fault near the Adelaide metropolitan area could cause disconnection of up to half the distributed PV in the South Australian region. This could occur coincident with the sudden loss of a large generating unit, such that the disconnection of distributed PV increases the size of the largest credible contingency.

The possible net loss of distributed PV in South Australia is estimated to already be in the realm of 100–300 MW, and could reach as high as 200–400 MW by the end of 2020 with the continuing growth in distributed PV installations projected in AEMO's High DER scenario.

To maintain power system security and reduce the risk of separation related to a large loss of distributed PV, imports on the Heywood interconnector need to be limited in some periods. A preliminary constraint has been implemented, and ElectraNet is completing analysis to refine the network limit advice.

When South Australia is operating as an island, it is now almost impossible to maintain the frequency operating standard for certain credible fault events if they cause distributed PV disconnections. This means that AEMO may no longer have the means to operate a South Australian island securely at times of high distributed PV generation, and as such, mitigation actions are required urgently. Security risks will grow rapidly as more distributed PV is installed if the mitigating actions discussed below are not implemented.

Minimum load required to operate under islanded conditions

When South Australia is operating as an island, there is a need for sufficient demand to match the minimum output of the synchronous generating units needed to provide required levels of system strength, inertia, frequency control and voltage management. AEMO estimates that under some conditions, the threshold level of operational demand required will be around 550 MW in late 2020 (with two synchronous condensers installed), reducing to around 450 MW from late 2021 (with four synchronous condensers installed). This level of demand allows for island operation with a subset of possible generating unit combinations, depending on system conditions.

South Australia has already experienced operational demand as low as 458 MW⁶, and this is expected to reduce further by spring 2020. That means there is an urgent need to establish a back-stop that allows AEMO to curtail distributed PV when extreme and unusual operational circumstances arise. The need for generation shedding capability should be considered analogous to load shedding capability – it is a last resort mechanism used to maintain system security in exceptional circumstances. All large-scale generation output is controllable. This is now an essential capability for distributed resources, given they supply a large proportion of generation in South Australia at some times.

⁵ AEMO (April 2020) Renewable Integration Study, at <https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris>.

⁶ Occurring on 10 November 2019.

Back-stop mechanism

Frameworks for efficient integration of DER will require two elements:

1. Mechanisms for the daily operation of active two-way markets, engaging customers and unlocking value from DER assets.
2. A back-stop mechanism that retains AEMO's ability to manage power system security when most of the generation is being provided by DER. This allows AEMO to shed generation from DER in abnormal system conditions, when necessary for system security.

Both are essential elements of a secure, reliable and efficient power system with high DER. AEMO is working towards establishing enduring frameworks for two-way markets in the Markets and Framework stream of the DER program. This report focuses on establishment of the back-stop generation shedding mechanism, and seeks to quantify how large this back-stop needs to be to allow adequate levers for the power system to be operated securely.

Demand recovery reserves as back-stop

This analysis shows that demand recovery reserves need to be urgently established in South Australia to provide this back-stop mechanism. Demand recovery reserves involve either increasing load (perhaps utilising storage), or decreasing distributed generation.

Demand recovery reserves will only be required when South Australia is operating as an island, when there are unusual power system outages or other abnormal conditions, or if unexpected major load reduction occurs. If the other mitigating actions recommended in this report are implemented, they should not need to be activated on a regular basis.

AEMO estimates that around 200-500 MW of demand recovery reserve is required as a back-stop by spring 2020, and up to 1 GW may be required as a back-stop by spring 2024 if distributed PV growth continues at current rates.

The quantity of demand recovery reserve required for this back-stop is very large (achieving 200-500 MW of response by spring 2020 is ambitious, and 1 GW of response by spring 2024 is large in absolute terms), but as noted above, will rarely be activated. This has implications for the economics and feasibility of different solutions, as discussed below.

Increasing load

Options for increasing load were explored. This included shifting customer hot water and pool pumps to daytime, shifting or increasing the loads of large industrial customers, moving water pumping loads, and flexibility of desalination plant operation. A range of challenges were identified that are likely to limit the potential back-stop response from these sources. There are many complexities in engaging customers, and limitations on the flexibility of customer loads. Customers may not want (or be able) to move or increase load when required. There will also be interactions with retail offerings, and possible impacts on customer amenity. Given these challenges, securing a guaranteed 200-500 MW of load increase response by spring 2020, and up to 1 GW by spring 2024 is unlikely to be technically feasible (by comparison, the total demand in South Australia is typically in the range of 1-3 GW).

It is important to distinguish between the narrow objective of ensuring a generation shedding back-stop (allowing AEMO to maintain system security even in extreme abnormal conditions), and the ultimate holistic objective of establishing flexible loads and two-way markets as an underpinning component of future efficient markets that fully integrate distributed resources. Allowing customers to actively participate and benefit from aligning their load with power system needs will unlock efficiencies on a daily basis. Large quantities of flexible customer response may become available to participate if the right frameworks are in

place. This is under development in AEMO's Markets and Framework stream in the DER program, seeking to establish enduring policy frameworks to access this potential.

In the longer term, options for increasing flexible load in South Australia could include introducing customer incentives to invest in electric vehicles, establishment of hydrogen technologies, and supporting the opening or expansion of large industrial customers. The benefits of such approaches are well understood, and will assist in creating efficient, flexible markets.

Thus, activating load response is clearly a valuable objective, but it is not suitable in isolation to achieve the narrow objective of establishing a back-stop generation shedding mechanism (which is the need identified by the analysis in this report). Approaches for enabling flexible load response should be pursued in parallel with establishment of a generation shedding back-stop mechanism, with both parts complementary towards the broader goal of creating the markets and frameworks to effectively integrate DER for the long term.

Storage as a "solar soak"

Battery Energy Storage Systems (BESS) and Virtual Power Plants (VPPs) can provide a "solar soak", allowing the excess energy generated by distributed PV to be utilised at other times. This provides a valuable support to system normal operation, facilitating daily shifting of load and generation. This analysis has assumed that the capacity of VPPs in South Australia doubles each year over the next few years, and contributes to power system management. The utility-scale BESS in South Australia were also assumed to deliver their full suite of valuable system services.

Although they provide valuable solar soak services for system normal periods, BESS and VPPs cannot provide an economic substitute for the back-stop generation shedding capabilities identified as necessary in this analysis. The storage capacity of most BESS and VPPs is far less than required to reliably store excess distributed PV generation for 6-8 hours a day, under all conditions. For example, the Hornsdale Power Reserve provides up to 100 MW of capacity with a ~1 hr duration, at a total construction cost of \$90 million. More than 10 times this amount would be required to fully deliver the necessary 200-500 MW of guaranteed load increase response by spring 2020, and up to 1 GW by spring 2024. Furthermore, if commissioned for this purpose, BESS operation in the market would need to be heavily restricted to ensure they are in an appropriate state of charge on the rare occasions when required for system security.

As for load response, it is important to distinguish between the need to establish a back-stop generation shedding mechanism to give AEMO the tools to maintain system security even in abnormal conditions (which is the need identified in this study), versus the objective of developing holistic frameworks and markets for efficient DER integration. Investment in further BESS and VPPs in the NEM will undoubtedly bring considerable benefits to the power system, in a myriad of ways. BESS technologies can provide many system security benefits. As one example, this report demonstrates the considerable value of fast frequency response (FFR), which is already essential for management of frequency control in South Australia, and forms a critical component of emergency frequency response schemes. BESS can also assist with managing ramping, load shifting and fast response to dispatch signals, in addition to daily solar soak capabilities and other benefits. Distributed storage can also provide valuable system services; for example, AEMO's trials of Virtual Power Plants (VPPs) have demonstrated that they too can deliver effective frequency response services⁷.

BESS and VPPs should be considered valuable contributors of solar soak and other services in periods of normal daily operation, to be implemented in parallel with establishing generation shedding capabilities that provide the essential back-stop to manage system security in abnormal power system conditions.

Generation shedding

Curtailment of distributed PV is clearly unfavourable as a daily management mechanism, due to impacts on customers. The objective of efficient power system operation should be to allow customer assets to operate with as little restriction as possible, according to customer preferences. However, establishing generation

⁷ AEMO (March 2020) "AEMO Virtual Power Plant Demonstration", at <https://aemo.com.au/-/media/files/electricity/nem/der/2019/vpp-demonstrations/aemo-knowledge-sharing-stage-1-report.pdf?la=en&hash=50B02E668A57A9B5257951537F431134>.

shedding capabilities for distributed PV is highly suitable as a “back-stop” mechanism, to be used very rarely for system security. It can be achieved at low cost, can deliver a large capacity of response rapidly, and the impacts on customers are very low since this will be utilised very rarely.

AEMO’s preliminary exploration indicates that utilising and improving standard smart meter remote energisation capabilities could mean that any future distributed PV installed can be actively managed when required. It appears likely that this can be implemented towards the end of 2020, applying to any new PV installed from that date. SA Power Networks (SAPN) is also implementing sophisticated “smart” Flexible Export capabilities for new DER from 2023 (as part of their regulatory proposal), and proposes a suite of complementary measures that would provide generation shedding capabilities for a proportion of the legacy distributed PV installed, and streamline the management of larger customers. This has the potential to provide almost 300 MW of generation shedding response by late 2020, and almost 1 GW of response by late 2024.

These options are very cost effective as a generation shedding back-stop for the purpose of managing rare periods where unusual conditions arise and can deliver the level of response required in the timeframe required.

Establishing generation shedding capabilities as a system security back-stop should be viewed as an essential complement to ongoing investment in BESS and VPP capacity, and ongoing efforts to establish effective two-way markets and dynamic load response. Storage and flexible load will deliver daily benefits and services, and generation shedding will be utilised on very rare occasions where this additional capability is required for system security.

Recommended actions

The recommended actions are outlined below. These are designed to address the immediate security issues identified in this analysis, specifically focused on mitigating the identified impacts of disconnection of distributed PV, and on establishing generation shedding back-stop capabilities in South Australia. A wide range of other measures will also be required to ultimately achieve effective holistic system design for full DER integration in efficient two-way markets. These broader design questions are being examined across AEMO’s DER Program, of which this report forms just one component.

Essential foundational measures

AEMO recommends the following crucial “no regrets” measures are implemented during 2020-23. These are essential measures that provide the fundamental underpinnings for future power system operability:

- **DER performance standards** – improve DER performance standards, particularly targeting improved disturbance ride-through capabilities. Improving the capability of DER to sustain operation through power system disturbances is essential for secure power system operation with high levels of DER. If DER performance standards are not rapidly improved, AEMO will no longer be able to operate a secure power system (and this is already the case in South Australia when operating as an island). AEMO has initiated a review of AS/NZS4777.2 to collaboratively develop the new standards required.
- **Compliance processes** – develop improved processes for monitoring, encouraging and enforcing compliance with DER performance standards. Evidence from DER behaviour in recent power system disturbances suggests that 30-40% of inverters are not behaving as specified in the existing standards, which must be addressed in parallel with improving the standards themselves. AEMO will lead a consultation process with key stakeholders to develop a plan for addressing and improving compliance.
- **Feed-in management** – introduce “smart” capabilities for actively managing the generation from all new distributed resources in real time. This will facilitate DER participation in two-way markets, and is also an essential underpinning for future power system security. Feed-in management (also called flexible exports) provides AEMO and Distribution Network Service Providers (DNSPs) with a crucial capability to actively manage distributed PV when this is necessary for system security (such as when South Australia is operating as an island and operational demand is too low to allow operation of essential units for system

strength, inertia and frequency control, or when other abnormal conditions arise). SAPN is proceeding with introduction of flexible export capability as part of their regulatory determination for 2020-25, and AEMO strongly supports this program. SAPN has advised that the earliest date when these capabilities could come to fruition is 2023; AEMO recommends that rollout is accelerated as much as possible (discussed further below).

- **EnergyConnect** – ensure that the EnergyConnect interconnector proceeds, connecting South Australia to New South Wales. This reduces the likelihood of South Australia islanding, and alleviates the most challenging system security issues identified in this analysis. If EnergyConnect does not proceed, extensive further measures (beyond those outlined in this report) will be required to address identified system security risks. Potential further measures could include commissioning significant utility-scale storage to provide FFR, retrofit of a large number of distributed PV systems to improve disturbance ride-through capabilities, resistor banks for managing excess distributed generation, and possibly a moratorium on new distributed PV connections.

Implementation prior to spring 2020

In addition to the essential foundational measures outlined above, AEMO recommends the following measures be delivered prior to spring 2020 if possible (or as soon as feasible). These are required to address the immediate operational challenges identified.

- **Stakeholder engagement** – coordinated stakeholder engagement with customers and industry participants to transparently share the identified system security risks, and proposed mitigation approaches. Consistent messaging from AEMO, the SA Government, SAPN, ElectraNet, the AER, the AEMC and other key decision makers is required.
- **Constraints on the Heywood Interconnector** – in response to the findings in this report, AEMO has introduced constraints that limit imports on the Heywood interconnector in high PV generation periods, taking into account the potential for a large loss of distributed PV in the South Australian region caused by a fault and synchronous unit trip in the Adelaide metropolitan area. A constraint for system normal conditions has been implemented and is being further refined with assistance from ElectraNet and SAPN. This constraint reduces the risk of South Australia separating from the NEM in response to a credible fault.
- **PV shedding capability** – as rapidly as possible, enable PV shedding capabilities for all new distributed PV installed in South Australia. One possible approach that utilises existing infrastructure and is likely to be low cost would involve enabling use of smart meter functionality to facilitate targeted load and distributed PV generation shedding (when required as a security back-stop in abnormal conditions). The first step would involve specifying an improved meter configuration for all new smart meters installed in South Australia, placing distributed resources (such as distributed PV and batteries), controlled loads (such as hot water), and other customer load on separate switchable elements of the meter. This would mean that Metering Coordinators would have the ability to use the smart meter to separately de-energise distributed PV systems (and energise controlled loads) if required for system security. Trials should be conducted to verify real-time efficacy and coordination with the AEMO control room. Further investigation is required to determine the pathways for enabling this in real-time, and how this should be coordinated with NSPs. The most suitable regulatory frameworks for supporting rollout of this capability also need to be determined. Subject to the above, PV shedding capabilities should be implemented in parallel with flexible export capabilities (interoperability) via DNSP connection agreements as recommended above. The DNSP flexible exports arrangements support long-term sophisticated DER integration arrangements, while PV shedding capabilities can be implemented more rapidly, and provide a foundational security back-stop.
- **Accelerated test for DER voltage ride-through** – introduce a new performance test for voltage ride-through, as a condition of connection for all new distributed PV inverters installed in South Australia. The required capability is being defined by AEMO in consultation with stakeholders, and can be required as a new and additional condition of connection by SAPN. This should be introduced ahead of (and eventually included under) the broader suite of changes being implemented in the AS/NZS 4777.2 review. This will limit further growth of the amount of distributed PV that disconnects during disturbances. AEMO also

recommends exploring mechanisms for retrofit of improved capabilities for legacy inverters, where economically and practically feasible (such as through remote firmware upgrades).

- **Enhanced voltage management** – SAPN has identified that introducing dynamic fine-grained voltage control capability would improve distribution voltage management and reduce customer impacts related to high voltages. As a side benefit, this also introduces the capability to improve system security through the ability to induce a temporary slight increase in voltages to cause a controlled shedding of distributed PV. It is anticipated this would be enabled very rarely for short periods, under abnormal conditions only. SAPN's initial trials of this capability indicate that it is effective, safe, and has minimal customer impact. SAPN estimates that this could provide a large aggregate response, delivered rapidly (some available by Spring 2020), with minimal complexity in implementation. The unique benefit of this approach is that it can facilitate shedding capabilities for legacy distributed PV, without the cost and complexity of retrofitting individual customer sites. AEMO strongly recommends that this is pursued for rollout across SAPN's network as extensively as possible, contingent on SAPN trial outcomes.

Implementation during 2020-23

Full deployment of the above proposed measures will extend beyond spring 2020, into the 2020-23 period. The following additional actions could also be explored over the subsequent period:

- **Frequency control** – improve frequency control arrangements in South Australia, to allow effective management of the increased size of credible contingencies. AEMO is implementing this at present.
- **BESS for Fast Frequency Response (FFR)** – consider ways of encouraging further investment in BESS in South Australia should insufficient market investments occur, to deliver increased FFR. The FFR contributions of BESS are particularly valuable for maintaining system security in South Australia.
- **Load shifting** – explore options for shifting load to daytime. Around 80-120 MW of load has been identified that may be flexible and feasible to shift to high PV periods, subject to further analysis.
- **Demand response mechanism** – a demand response market mechanism could be developed to encourage increased customer load during high PV generation periods, subject to further analysis. This could include tariff reform to improve alignment of customer incentives with system security needs, for example considering the structure of distributed PV Feed-in Tariffs.

These mechanisms do not replace the need for DER generation shedding capabilities as a back-stop for secure power system operation (or reduce the need to eliminate distributed PV disconnection behaviour), but they could reduce the amount of generation shedding that needs to be enabled in abnormal conditions. They are therefore proposed as second tier priorities.

Development of enduring policy frameworks

Beyond the near-term measures outlined above, holistic NEM-wide enduring policy frameworks for successful integration of DER are required. The Markets and Frameworks workstream is developing a two-way energy market, the concept for which was developed in consultation with DNSPs through an initiative called Open Energy Networks⁸. This aims towards a future market and power system where distributed assets participate actively. The above measures will support and complement these efforts.

Next steps

The full list of recommended actions is listed in Section 13, in Table 9. AEMO looks forward to collaborating with the South Australian Government, SAPN and ElectraNet to develop and execute a detailed plan to deliver these actions, and to continue working together to maintain a secure and reliable power system for South Australian consumers and market participants.

⁸ AEMO, "Open Energy Networks – joint consultation with Energy Networks Australia", at <https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework/open-energy-networks-joint-consultation-with-energy-networks-australia>.

Contents

Executive summary	3
System security challenges identified	4
Back-stop mechanism	5
Recommended actions	7
1. Background	13
1.1 Context	13
1.2 Request for advice	14
1.3 Structure of this report	14
2. Minimum demand forecasts	16
3. Approach	22
3.1 Factors for consideration	22
3.2 Power system dynamic studies	23
3.3 Minimum load thresholds	24
3.4 The evolving South Australian power system	24
3.5 Advice from Network Service Providers	26
4. Behaviour of distributed resources	27
4.1 Evidence of distributed PV disconnection	27
4.2 Assumptions	28
4.3 Findings	28
5. Distributed PV impacts on system security	33
5.1 Operation as an island	33
5.2 Credible risk of separation	36
5.3 Normal operating conditions	40
6. Minimum load thresholds	44
6.1 Approach	44
6.2 Findings	47
7. Separation events	52
7.1 Frequency control provision following non-credible separation	54
8. Mitigation: essential foundational measures	55
8.1 EnergyConnect interconnector	55
8.2 DER disturbance withstand standards	57
8.3 Compliance with DER standards	58
8.4 Feed-in management for DER	59

9.	Mitigation: distributed PV disconnection	60
9.1	Reduce PV disconnection	60
9.2	Improve frequency control	62
9.3	AEMO's system management	71
10.	Mitigation: demand recovery reserves	74
10.1	Distributed generation shedding capability	74
10.2	Increasing load	81
10.3	Reduce frequency control requirements	82
10.4	Real-time procedures for low load periods	82
11.	Other mitigation actions	85
11.1	Managing unit availability	85
11.2	Investigate transmission voltage management	85
12.	Enduring policy frameworks	86
13.	Next steps	88
A1.	Abbreviations	93

Tables

Table 1	Anticipated relevant changes to the South Australian power system	24
Table 2	Assumptions applied	25
Table 3	Net distributed PV & load contingency sizes (PV loss – load loss) – High DER forecast for PV growth	30
Table 4	AEMO records of voltage disturbances (NEM – past two years)	35
Table 5	PSCAD study findings for periods with a credible risk of separation	37
Table 6	PSCAD study findings for system normal conditions in South Australia	41
Table 7	Utility-scale BESS in South Australia	66
Table 8	Factors relevant for monitoring and assessment of low demand period risks	84
Table 9	Summary of recommended mitigation measures	88
Table 10	Recommended actions for addressing distributed PV impacts on UFLS (from previous report)	92

Figures

Figure 1	Actual and projected capacity of distributed PV in South Australia	17
----------	--	----

Figure 2	Effect on South Australian operational demand from increasing distributed PV generation (10 November 2019)	18
Figure 3	Minimum operational demand projections for South Australia	19
Figure 4	Minimum operational demand in South Australia	20
Figure 5	Percentage of distributed PV sites in a region observed to disconnect following historical voltage disturbances	27
Figure 6	Reduction of distributed PV and underlying load in response to a severe credible fault in PSS®E studies	29
Figure 7	Net distributed PV and load contingency sizes (PV loss – load loss) – High DER forecast for PV growth	30
Figure 8	Example aggregate response of distributed PV (left) and load (right) in PSS®E model	32
Figure 9	Heywood flow limits – preliminary assessment (system normal)	42
Figure 10	Minimum operational demand for secure islanded operation, for a range of possible generating unit combinations	48
Figure 11	Minimum demand requirements as a function of PV disconnection sizes (spring 2020)	49
Figure 12	“Demand Recovery Reserves” required to meet Planning Threshold of operational demand	50
Figure 13	Increase in minimum operational demand if utility-scale batteries cannot offer contingency lower services	65
Figure 14	State of charge of utility-scale batteries during South Australia islanding event (20 days)	66
Figure 15	Required state-of-charge of utility-scale batteries to provide frequency response	67
Figure 16	Change in minimum operational demand by commissioning a new 100 MW BESS	70
Figure 17	Response of controllable distribution connected generation to AEMO directions	77

1. Background

1.1 Context

Minimum operational demand⁹ has been consistently reducing in South Australia over the past years.

In 2012, minimum operational demand occurred for the first time in the daytime, influenced by growing generation from distributed rooftop photovoltaic (PV). Since that time, minimum operational demand has declined by an average of 80 MW per year, reaching a record minimum of 458 MW at 2.00 pm AEST on Sunday, 10 November 2019.

The installed capacity of distributed PV is continuing to grow rapidly across the Australian National Electricity Market (NEM), and particularly in South Australia. Distributed PV increased in South Australia by 185 MW in the 2018-19 financial year, and by 219 MW in the 2019 calendar year. This equates to 15-20 MW of new installations per month, on average. There is now more than 1,200 MW of distributed PV installed behind the meter (on consumers' premises) in the distribution network in South Australia.

Projecting forward with a simple assumption of continuing growth of distributed PV at the 2018-19 financial year rate of 185 MW per year, South Australia could reach zero operational demand within the next three to four years. Operational challenges are likely to be encountered before operational demand reaches zero. This indicates the timeliness of investigating power system operability in low demand conditions, so appropriate action can be taken if required.

This report focuses on South Australia, to address the request for information from the South Australian Government. However, challenges related to increasing levels of distributed PV will be experienced in all NEM regions. The situation in Western Australia is highlighted below, and other NEM regions are anticipated to follow in the near future.

Western Australia case study

In a number of aspects, minimum demand trends in South Australia mirror the experience of the South West Interconnected System (SWIS) in Western Australia.

In March 2019, AEMO released a report¹⁰ indicating that operational limits in the SWIS could be breached within five years unless measures are taken to accommodate increasing volumes of distributed energy resources (DER) and utility-scale renewable resources. The report advised that if no remedial action was taken:

1. Voltage in the SWIS could not be controlled within technical limits as the level of minimum operational demand (referred to as market load) approaches 700 MW¹¹.
2. Emergent system security risks would increase as utility-scale renewable generation continued to displace the dispatchable thermal generators presently providing all essential system security services such as inertia, frequency control, system strength and voltage control.

⁹ Scheduled demand in a region is demand that is met by local scheduled and semi-scheduled generation and by generation imports to the region. Operational demand in a region is equal to scheduled demand plus demand met by non-scheduled wind/solar generation of aggregate capacity ≥ 30 MW and excludes the demand of local scheduled loads. Underlying demand means all the electricity used by consumers, which can be sourced from the grid but also, increasingly, from other sources including consumers' rooftop PV and battery storage. For more information on demand terms, see AEMO, 'Demand Terms in EMMS Data Model', at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

¹⁰ AEMO (March 2019), Integrating Utility-scale renewables and distributed energy resources in the SWIS, at https://www.aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf?la=en&hash=3A7FEB1F00F0FDE97DB8213AD58D488.

¹¹ This was provided as an indicative level, based on an assessment of the voltage control capability, system inertia, and dispatch limitations in the SWIS. Refer to Appendix 3 of the report.

The report highlighted that the technical standards, regulatory framework and market constructs needed urgent but careful redesign to enable new technologies like synchronous compensators, energy storage and improved inverter capabilities to be used to manage system security through the efficient utilisation of existing and future electricity sources.

The Western Australian Government Energy Transformation Taskforce recently released a “DER Roadmap”¹², identifying a number of DER integration challenges that need to be solved to set the system up for a high- DER future. AEMO is contributing to delivery of this Roadmap, including through analysis of similar challenges to those identified in South Australia, such as DER impacts on minimum load thresholds, emergency frequency control schemes, and system restart.

The SWIS reached an all-time record minimum market load of 1,119 MW on 4 January 2020, and minimum load is anticipated to continue to reduce over time as more distributed PV is installed.

Like the SWIS, all NEM regions will require analysis similar to that presented in this report, with holistic approaches to DER integration. South Australia is the first NEM region to approach very low levels of operational demand, but should not be considered unique. Enduring policy frameworks will ultimately be required for all regions.

1.2 Request for advice

The Government of South Australia has requested AEMO’s advice on minimum demand operating thresholds that the South Australian network can operate at in a secure and reliable state, and potential conditions that, when coupled with minimum demand, would put South Australia at a risk of the supply of electricity being disrupted to all or part of the South Australian community.

This report provides AEMO’s formal advice. In some areas, AEMO is only able to provide high level advice at this stage. For example, AEMO is not yet able to provide detailed advice on the minimum operational demand threshold that will be sufficient for the power system to ride through a non-credible loss of the Heywood interconnector. This requires extensive modelling, which could not be completed in time for this report. The primary focus of the advice in this report is on managing credible contingency events.

This report does aim to provide a preliminary indication of the lowest minimum operating demand threshold that South Australia’s network can operate at in a secure and reliable state, and the potential conditions that, when coupled with minimum demand, would put South Australia at risk of major electricity supply disruption. It is anticipated that these findings may change as the South Australian power system evolves, and as AEMO completes further analysis.

1.3 Structure of this report

This report is structured as follows:

- Section 2 discusses AEMO’s forecasts for minimum demand in South Australia.
- Section 3 outlines the approach AEMO has applied for this analysis to determine the minimum demand threshold in South Australia, and explore system security issues.
- Section 4 summarises findings on the behaviour of distributed energy resources during power system disturbances.
- Section 5 summarises findings on system security impacts of the behaviour of distributed PV during power system disturbances.
- Section 6 summarises findings on minimum demand thresholds for operation of South Australia as an island.

¹² Western Australian Government (December 2019) “Distributed Energy Resources Roadmap”, at <https://brighterenergyfuture.wa.gov.au/www.wa.gov.au/government/distributed-energy-resources-roadmap/>

- Section 7 discusses potential considerations for South Australia’s ability to survive a non-credible separation event. As the focus of this report is on the management of credible contingency events, this section provides initial high level observations only.
- Section 8 outlines recommended mitigation measures that should be considered essential and foundational. These are “no regrets” measures that should proceed to maintain future secure operation of the South Australian power system.
- Section 9 outlines recommended mitigation measures that assist further with managing disconnection of distributed PV.
- Section 10 outlines recommended mitigation measures that provide demand recovery reserves, to assist with secure operation of a South Australian island under low load conditions.
- Section 11 outlines several further recommended mitigation actions.
- Section 12 provides comment on the need for enduring policy frameworks.
- Section 13 outlines next steps, and summarises the recommended mitigation actions.
- Acronyms and abbreviations are summarised in Appendix A1.

2. Minimum demand forecasts

In determining when operational challenges are likely to emerge, AEMO needs to determine both the minimum demand threshold at which security challenges may occur, and the time at which demand may fall to that level. This section therefore explores AEMO's forecasts for minimum demand in South Australia.

Demand definitions

Demand is referred to by a number of different definitions¹³:

- **Underlying demand** means all the electricity used by consumers, which can be sourced from the grid but also from DER.
- **Operational demand** is demand that is met by local scheduled generation, semi-scheduled generation and non-scheduled wind/solar generation of aggregate capacity ≥ 30 MW, and by generation imports to the region, excluding the demand of local scheduled loads.
- **Scheduled demand** is demand that is met by local scheduled and semi-scheduled generation and by generation imports to the region. Scheduled demand differs from the other key demands in that it excludes the demand met by non-scheduled (wind/solar and non-wind/non-solar) generation and exempt generation, and includes the demand of local scheduled loads.

Underlying demand is relatively unaffected by growth in distributed PV. Operational demand and scheduled demand will both reduce as more distributed PV is installed. Scheduled demand is the type of demand that AEMO needs to operate a secure power system, and maintain sufficient units online to provide system strength, inertia, frequency control and other system services. If AEMO can curtail larger non-scheduled generation (≥ 30 MW), scheduled demand can be recovered to the level of operational demand. Therefore, forecasts of operational demand are the most useful in understanding the emergence of operational challenges.

Integrated System Plan

The Integrated System Plan (ISP) is an outcome of AEMO's primary planning process. It aims to set out the optimal development path for Australia's energy future. AEMO uses scenario planning to capture the potential breadth of plausible futures impacting the energy sector¹⁴. Scenario modelling does not set out to suggest that any one scenario is more likely or more preferred than others, but rather seeks to effectively manage risks when planning in a highly uncertain environment.

This report draws from two scenarios modelled in the 2019-20 ISP; the Central scenario and High DER scenario. The Central scenario reflects the current transition of the energy industry under current policy settings and technology trajectories, while the High DER scenario reflects a more rapid consumer-led transformation of the energy sector relative to the Central scenario.

For each scenario, AEMO develops input assumptions such as potential changes in underlying demand, growth in distributed energy resources of different types, and the resulting impacts on minimum demand. These assumptions and scenarios have been used as the basis for this report.

¹³ AEMO (January 2019) "Demand terms in the EMMS Data Model", at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

¹⁴ More information on the scenarios used in AEMO planning is at <https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies>.

Growth in distributed PV

For the 2019-20 ISP, AEMO engaged the CSIRO to develop projections of possible uptake of DER in each scenario. The capacity of distributed PV in South Australia forecast in the Central and High DER scenarios is shown below in Figure 1. A simple forward projection calculated by SA Power Networks (SAPN) by extrapolating current installation rates is also included, for comparison. This SAPN projection is used for internal analysis to understand implications of current installation rates continue.

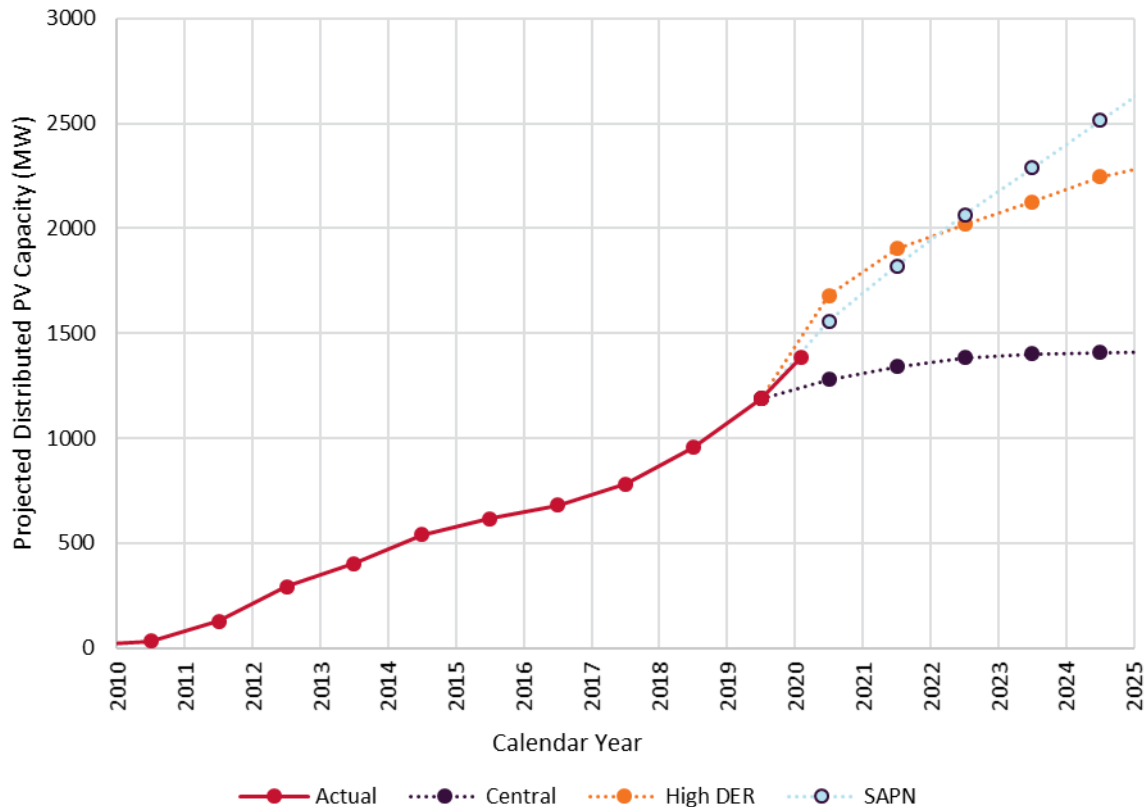
There is a significant difference between the two ISP scenarios:

- The Central scenario shows distributed PV growth slowing and plateauing in the near future, reaching a total installed capacity around 1,400 MW by 2024-25.
- In contrast, the High DER scenario shows a short-term acceleration in distributed PV growth, followed by continued growth similar to historical rates. It reaches a total installed capacity around 2,200 MW by 2024-25.

As discussed further below, the COVID-19 pandemic may result in significantly lower than anticipated demand levels. This may mean that even if distributed PV installations slow, underlying demand may fall to lower levels, even in the Central scenario.

SAPN's extrapolation of current growth rates is based on linear growth at a rate similar to that experienced in the 2019 calendar year, and shows distributed PV capacity reaching 2,700 MW by 2024-25. Uncertainty around the possible growth in distributed PV capacity in South Australia is therefore a significant source of uncertainty in estimating the possible timing of challenges related to minimum demand in South Australia.

Figure 1 Actual and projected capacity of distributed PV in South Australia



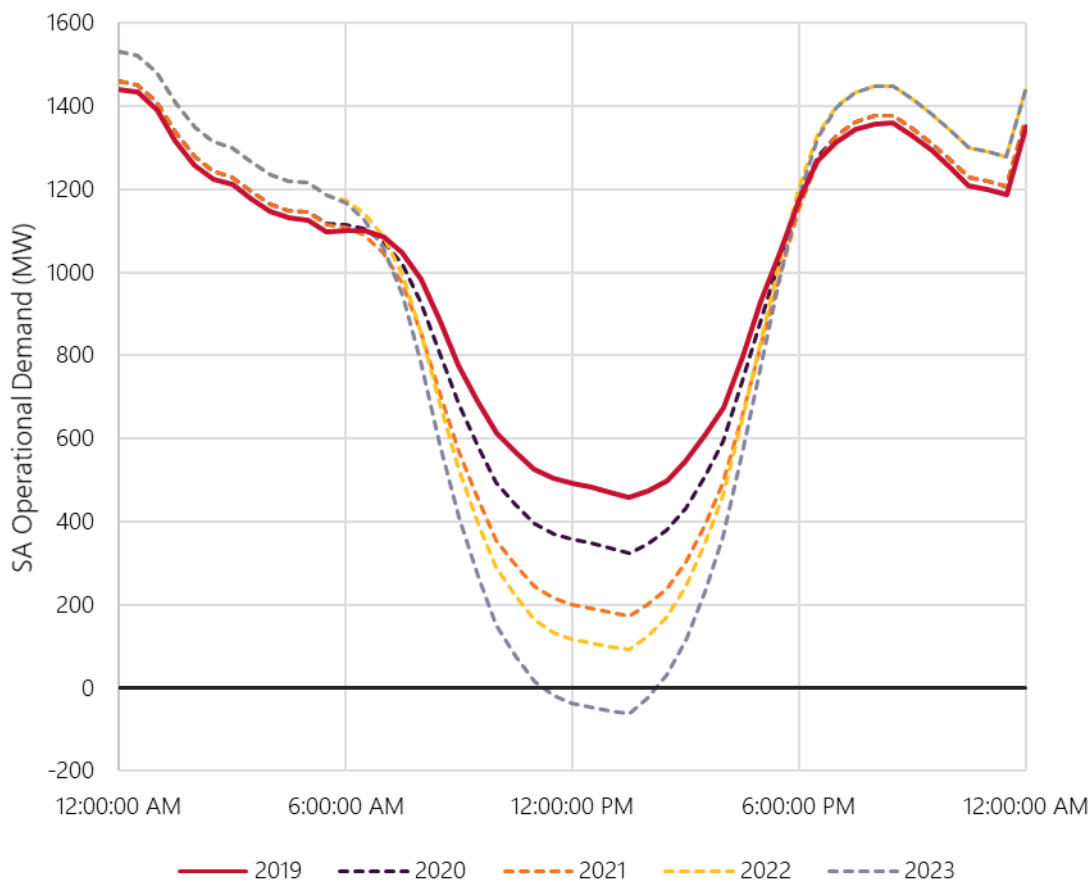
Source: Clean Energy Regulator, SAPN, AEMO forecasts

The latest installation data for distributed PV, which includes the period up to and including January 2020, indicates distributed PV is growing faster than projected in the Central scenario and at a rate closer to that projected in the High DER scenario. SAPN's observations on distributed PV connection applications and their internal extrapolation is roughly consistent with AEMO's High DER scenario. This suggests that PV installation

rates appear to be proceeding in line with the High DER scenario at present (in line with SAPN’s extrapolation).

In 2019–20 to date, the minimum operational demand of 458 MW occurred at 1:30pm AEST on Sunday 10 November 2019. The impact on operational demand from increasing amounts of generation from distributed PV is shown below in Figure 2. This figure shows the operational demand on 10 November 2019 projected forward with an annual growth rate in distributed PV of 219 MW. On this basis, South Australian operational demand in the middle of the day is projected to continue to decrease as distributed PV levels increase, potentially reaching zero by late 2022.

Figure 2 Effect on South Australian operational demand from increasing distributed PV generation (10 November 2019)



Minimum demand projections

These distributed PV growth projections were used as inputs to estimating minimum demand levels. AEMO’s minimum demand forecasts aim to present the minimum demand with a 90% probability of exceedance across the simulations conducted for each scenario¹⁵.

These projections are shown in Figure 3, for the Central and High DER scenarios. The High DER scenario includes the significant projected growth in distributed PV discussed above, and also assumes growth in distributed storage, which is assumed to be partially charging at times of minimum demand, and therefore somewhat increase minimum demand levels.

Minimum demand levels can show significant interannual variability. If there is a coincidence of mild temperatures, clear skies, and low economic activity (such as on a public holiday), minimum demand levels

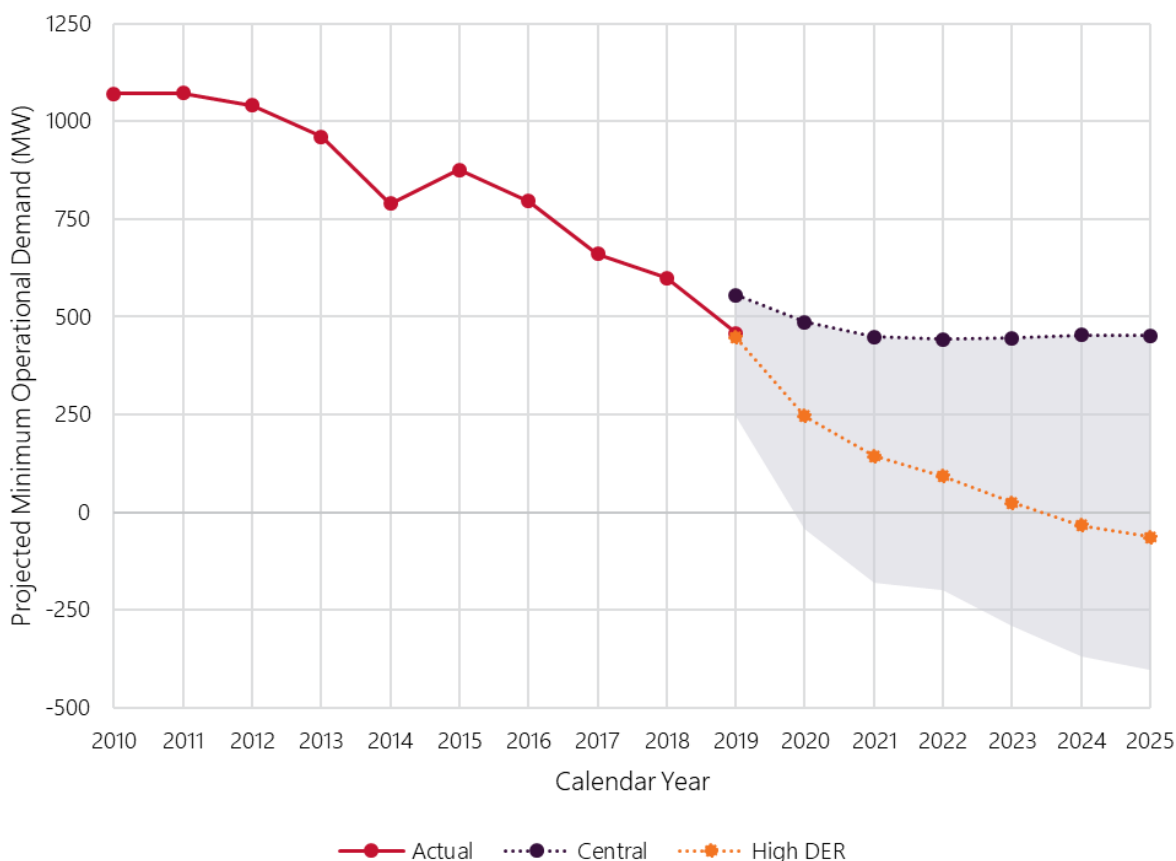
¹⁵ More information on the methodology used in AEMO’s demand forecasts is at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

can be considerably lower. This means the minimum demand experienced in any given year can be highly dependent on weather conditions that occur on a select number of public holidays in spring and early summer¹⁶ (or on Sundays, to a lesser extent). If temperatures are hotter or cloud cover predominates on public holidays and Sundays, the lowest possible minimum demand levels may not eventuate.

For this analysis, it is important to capture the absolute minimum possible demand that could be achieved in each year, so that South Australia’s power system can be prepared for such an eventuality. For this purpose, the weather and underlying demand conditions on 2 October 2017 were used, with distributed PV generation scaled up according to forecast capacity. The conditions on this day typify an extreme low minimum demand day: it was a public holiday (Labour Day) with mild temperatures and clear skies. The resulting range of possible minimum demand levels is shown in the shaded grey area in Figure 3.

This shows that under the most extreme conditions (a coincidence of mild temperatures and clear skies with a public holiday), with ongoing distributed PV growth as per the High DER scenario, operational demand in South Australia could reach zero as soon as late 2020.

Figure 3 Minimum operational demand projections for South Australia



The minimum operational demand experienced in the 2019-20 financial year was 458 MW, occurring at 2.00pm AEST on Sunday, 10 November 2019. This is below the minimum operational demand of 555 MW that was forecast in the Central scenario and is consistent with the higher growth in distributed PV observed.

Scheduled demand has reached as low as 405 MW (on Sunday 3/11/2019) in South Australia. As discussed above, if required for system security, scheduled demand can be increased to the level of operational demand by curtailing non-scheduled generation. This can make a substantial contribution in some periods in South Australia, where there is 389 MW of non-scheduled wind generation. For this reason, operational

¹⁶ Late summer/autumn appears less likely to deliver extremely low demand records, despite a higher number of public holidays compared with the spring period. This is possibly due to the sun being further from the solstice in late summer/autumn than it is from mid spring to early summer.

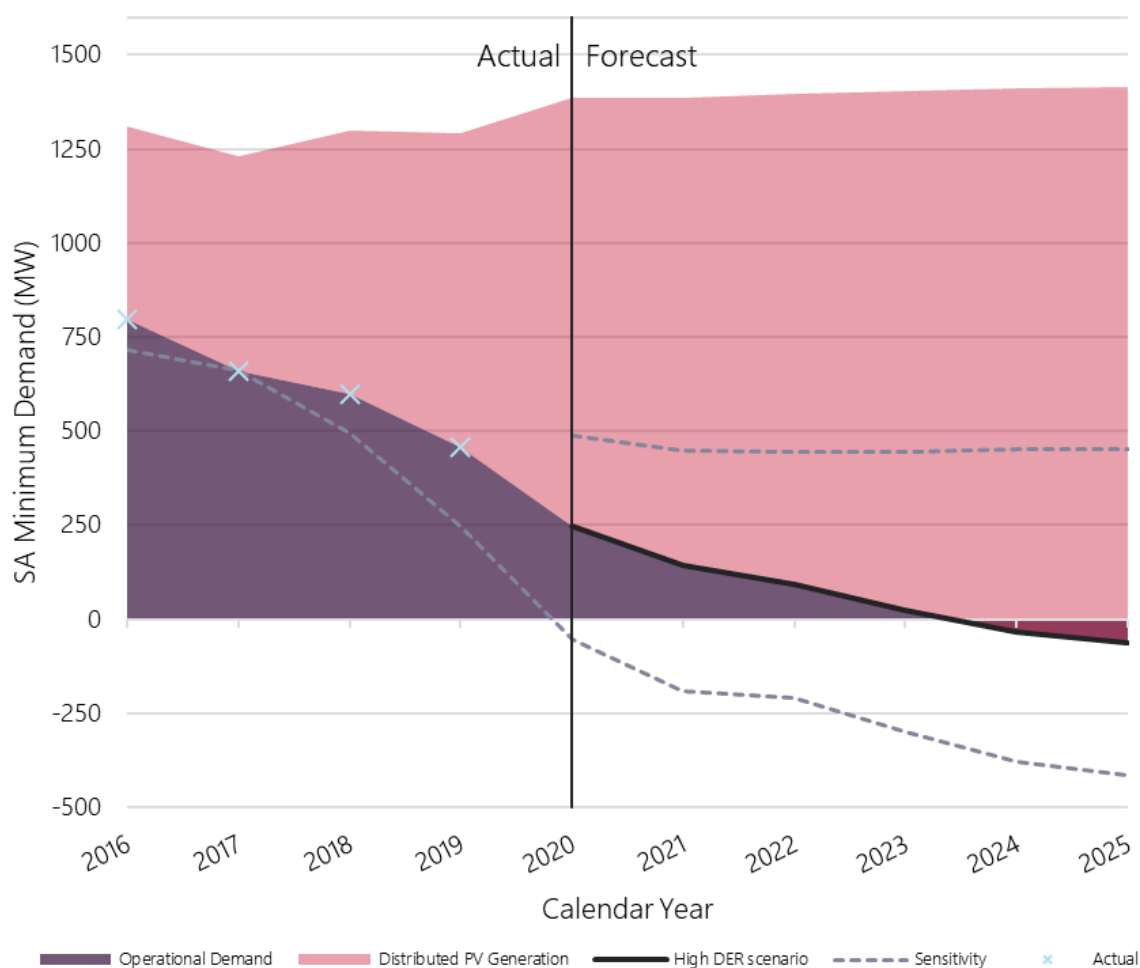
demand is the more relevant measure of minimum demand thresholds, and is referred to throughout this report.

These forecasts are also illustrated in Figure 4:

- The middle forecast is an estimate of the 90% probability of exceedance (POE) minimum demand based on the High DER scenario from the 2019-20 Integrated System Plan (ISP).
- The upper sensitivity (dotted line) is an estimate of the 90% probability of exceedance minimum demand based on the Central scenario from the 2019-20 Integrated System Plan (ISP).
- The lower sensitivity (dotted line) is an estimate of the lowest minimum demand that could occur, if there was a coincidence of mild temperatures and high solar insolation on a summer public holiday (as was observed on Christmas Day 2017), and PV installations proceed as per the High DER scenario. The lower sensitivity has been calculated for the previous historical years (2018 and 2019), indicating how low South Australian operational demand could have been, if the same conditions had occurred in those years, based on the amount of distributed PV installed.

As indicated in the lower sensitivity, there is a possibility that operational demand could reach close to zero in South Australia by late 2020, if the installation of distributed PV continues at present rates, and if mild temperatures and high solar insolation occur on a spring or summer public holiday.

Figure 4 Minimum operational demand in South Australia



Impact of COVID-19 pandemic

The impact of the evolving COVID-19 pandemic on minimum demand has not been explicitly modelled in this analysis. The potential impacts remain unclear at this stage, but could include:

- **Lower demand** – lower levels of economic activity due to the pandemic will likely reduce demand. Minimum demand levels fell approximately 10-30% in Northern Italy, Spain, and California in the weeks following enforced social distancing measures. In the industrial region of Northern Italy, midday operational demand has fallen 37%, though this region does not record its minimum demand in daylight hours due to a lower level of distributed PV uptake.
- **Distributed PV uptake** – the weakening Australian dollar, reduced consumer confidence, and increasing unemployment may slow PV uptake in the residential sector. However, the safety of investment in distributed PV relative to other asset classes may increase interest.
- **Government stimulus** – government responses to the pandemic, particularly to stimulate economic activity and support businesses, could have varying impact. Some of the stimulus may be directed towards the industry sector and could act to increase demand in South Australia.
- **Infrastructure commissioning delays** – there may be delays in the delivery and commissioning of major infrastructure, such as the synchronous condensers, and the Battery Energy Storage Systems (BESS) assumed to be delivered in the forecast horizon. The assumed entry dates of these assets underpin AEMO's analysis and any material changes will affect the outcomes.
- **Generation outages** – COVID-19 infections could affect essential operational staff at power stations and in the fuel supply chain, creating potential for outages or reduced operation of certain generators or groups of generators. Some generation assets are extremely important to provide dispatch flexibility in minimum load periods.

AEMO is in the process of examining these potential impacts and developing management strategies.

Olympic Dam expansion

BHP has advised AEMO of plans to increase electricity consumption at Olympic Dam due to a planned expansion of its operations (the 'Brownfield Expansion Project'). This expansion has been included in the ISP forecast minimum demand and the possible range of minimum demand levels (as illustrated in Figure 3 and Figure 4). This was calculated by increasing the underlying demand in each year according to the expansion plans (as outlined in Table 1). If the expansion does not proceed or is delayed, or if Olympic Dam is consuming less power than usual, the minimum demand may be lower than forecast.

Distributed battery energy storage systems (BESS) and electric vehicles (EVs)

Distributed BESS and EVs can increase minimum demand levels by charging during times of high distributed PV output. The expected contribution to load from forecast distributed BESS and EVs has been factored into the ISP forecast minimum demand levels. An uptake of distributed BESS or EVs that is lower than forecast would increase the likelihood of minimum demand also being lower than forecast for that scenario (possibly in the grey shaded area shown in Figure 5). However, the contribution from distributed BESS and EVs to increasing minimum demand levels is expected to be mild due to its shallow storage capacity.

3. Approach

3.1 Factors for consideration

Determining minimum demand thresholds for the South Australian power system requires consideration of the system needs for secure and reliable operation in different types of periods:

- **System normal** – operation when fully connected to the rest of the NEM in an intact system.
- **Credible risk of separation** – operation when there is a credible risk of islanding (such as when only one circuit of the Heywood interconnector is available).
- **Separation events** – the process of separation of South Australia from the rest of the NEM at the Heywood interconnector and the correct functioning of relevant control schemes during that event.
- **Islanded operation** – operation of South Australia as an island, possibly for an extended period (for example, if there is damage to interconnector assets).

For each of these types of periods, the following aspects are relevant:

- Combined flow limits on the Heywood and Murraylink interconnectors, and any constraints that may affect those flow limits.
- The ability to maintain a sufficient quantity of synchronous generating units online for minimum levels of system strength and grid forming capability.
- The ability to meet the frequency operating standards (FOS), which requires:
 - Sufficient inertia.
 - Adequate headroom to operate the units required for frequency control, when this needs to be provided locally in South Australia. When operating as an island, this includes regulation, and contingency raise and lower services, delivered in 6 second, 60 second and 5 minute timeframes.
 - Fast Frequency Response (FFR) can assist with maintaining frequency within required limits, particularly when inertia levels are lower.
- The ability to maintain voltage stability and steady-state voltages within required limits.
- The effectiveness of under frequency load shedding (UFLS) and other emergency frequency control schemes during a separation process.
- The behaviour of distributed energy resources (DER) during power system disturbances, and how this may affect each of the above security requirements.

All the relevant factors are complex and multifaceted. To AEMO's knowledge, South Australia is the first gigawatt scale power system in the world to approach zero operational demand due to such high proportions of demand met by distributed resources. Analysing these types of periods requires the development of new sophisticated models and pioneering of new approaches. Within the short timeframe requested, AEMO has aimed to provide the best advice possible from the studies it has been able to conduct. However, AEMO expects that this work will be ongoing and assessments will be refined over time as better models and more information become available.

Some aspects also require investigation by ElectraNet and SAPN. These include:

- Interconnector limit advice.
- The ability to maintain voltages within transmission and distribution networks.
- The efficacy, costs, and implementation pathways for various mitigation measures.

AEMO has sought advice on these topics from ElectraNet and SAPN, and anticipates collaboration will be ongoing.

3.2 Power system dynamic studies

Power system dynamic studies are used to determine whether the power system remains stable for credible faults and other power system disturbances. AEMO uses dynamic models extensively to examine system stability in a wide range of operational conditions, validate planned transmission network development, assess the system security impact of new market participant connections, and develop operational constraints.

In very low demand periods, distributed PV is a large component of the power system, and its behaviour has a significant impact on power system outcomes. This means it is important to accurately capture the behaviour of distributed PV and load in disturbances.

There is now considerable evidence that large quantities of distributed PV and load disconnect from the power system following voltage disturbances¹⁷. Distributed PV tripping in response to a voltage disturbance associated with a generating unit trip within the Adelaide metropolitan area could increase the size of the contingency, which affects measures for frequency control.

Since mid-2017, AEMO has had a program of work to establish data sources to understand and analyse the behaviour of distributed PV and load during disturbances, and develop suitable power system models of this behaviour, for incorporation into standard planning and operational studies. A preliminary version of these models has now been developed and validated in PSS®E (AEMO's simpler type of power system simulation based on RMS-type modelling¹⁸), but not yet in PSCAD™ (AEMO's more sophisticated type of power system simulation based on EMT-type modelling). EMT-type studies are important to conduct this analysis accurately, given the low system strength and inertia conditions at times of minimum load. To achieve this, studies were run initially in PSS®E to determine the disconnection behaviour of distributed PV and load, and this was then emulated in PSCAD models.

The approach applied can be summarised as follows:

1. Detailed models for load and distributed PV dynamic behaviour during power system disturbances were developed and validated in PSS®E.
2. Dynamic power system studies were conducted in PSS®E. Various levels of load and DER generation were explored, as well as different levels of Heywood interconnector flows, different combinations of synchronous generating units operating, and various levels of reactive power support from wind farms. A unit trip and credible two phase to ground fault was simulated in various locations.
3. The quantity of distributed PV and load disconnecting during each of these scenarios was quantified.
4. Dynamic power system studies were then conducted in PSCAD. The basic distributed PV and load responses observed in the PSS®E studies were replicated. These PSCAD studies were used to examine power system stability and operational outcomes, given the higher level of accuracy and sophistication of the PSCAD model, and the improved ability to model low inertia and low system strength conditions.

The following criteria were used in PSCAD studies, to determine system stability:

- After a contingency the FOS are maintained.
- The high voltage transmission network voltage profile at key transmission buses settles within 0.90 p.u. to 1.10 p.u., based on operational practice¹⁹.

¹⁷ AEMO (April 2019) Technical Integration of Distributed Energy Resources – Improving DER capabilities to benefit consumers and the power system, at <https://www.aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Technical-Integration/Technical-Integration-of-DER-Report.pdf>.

¹⁸ RMS (Root mean square) models do not explicitly represent all three phases, or have the ability to accurately represent phenomena at very fast timescales. In contrast, EMT (Electromagnetic transient) models are more sophisticated and do represent all three phases, and can more accurately capture phenomena on very fast timescales.

¹⁹ A brief excursion outside 0.90 p. u and 1.1 up is permitted, but was not observed in this analysis.

- All online generators returned to steady-state conditions following fault clearance.
- After a contingency, the terminal voltages at all online generators settle within 0.90 pu to 1.1 pu.

All power system models represent a simplified and aggregated view of the power system. AEMO's PSS®E distributed PV model represents voltage tripping behaviour to within $\pm 7\%$ or less, validated across six observed disturbances. The load model is accurate for some events investigated, with work ongoing to improve accuracy for all operating conditions. Load modelling is inherently challenging, due to the constantly changing composition of NEM load and the wide range of customer load devices which behave in different ways in response to disturbances. Capturing this diverse behaviour has been a challenge facing power system operators around the world for decades. This means the load model is a significant source of uncertainty in this analysis. This uncertainty has been represented explicitly throughout the report, and results presented can be considered a reasonable approximation of the range of possible outcomes, including the possible most pessimistic response of the South Australian power system. It is prudent to explore and model the worst-case outcomes, so that reasonable endeavours can be developed to address any identified risks. AEMO has an ongoing work program to continue to develop and improve the accuracy of these models.

PSCAD is not currently capable of simulating conditions with zero or negative load, and whether PSS®E can accurately represent periods of zero or negative load is yet to be verified. The development of detailed models for load and distributed PV behaviour in PSCAD is required, and AEMO is proceeding with this work. Studies presented in this report are restricted to analysis of periods of low load only (with operational demand above 200 MW).

3.3 Minimum load thresholds

In addition to the power system dynamic studies outlined above, AEMO has analysed the minimum operational demand required for secure operation of South Australia as an island. This is the most onerous operational condition, and therefore defines the highest threshold for operational demand that may be required to maintain system security. A range of possible combinations of generating units necessary for maintaining system security accounting for aspects such as system strength, inertia, frequency control and other system services were determined, and the minimum load for each combination of units calculated. The approach for this analysis is outlined in detail in Section 6.1.

3.4 The evolving South Australian power system

In conducting this analysis, AEMO has taken into account anticipated changes to the South Australian power system that could be expected to affect minimum load thresholds, including those listed in Table 1. No allowance has been made for any commissioning delays or other changes to the power system that may result from the COVID-19 pandemic.

Table 1 Anticipated relevant changes to the South Australian power system

Event	Anticipated date	Main impact
Retirement of Torrens Island A units	May be revised due to COVID-19 or other factors, but below dates assumed for this analysis: <ul style="list-style-type: none"> • A2 & A4 unavailable from mid 2020 • A1 & A3 unavailable from mid 2021 	Decreases number of system strength combinations and frequency control availability
Commissioning of ElectraNet synchronous condensers	<ul style="list-style-type: none"> • Units 1&2 – Q4 2020 (Davenport) • Units 3&4 – Q2 2021 (Robertstown) 	<ul style="list-style-type: none"> • Provides system strength and inertia capability • Provides voltage control capability • May mean fewer synchronous generating units are operating in many periods, reducing available frequency control if islanding occurs.

Event	Anticipated date	Main impact
Commissioning of new battery storage and other frequency control providers	<ul style="list-style-type: none"> • Lake Bonney – 25 MW (now fully commissioned) • Lincoln Gap – 10 MW • Virtual Power Plants • Hornsdale Expansion – 50 MW (committed) • Other new entrants 	<ul style="list-style-type: none"> • Increases frequency control availability • New batteries assumed to register similarly to Hornsdale (providing fast frequency response)
Commissioning of EnergyConnect interconnector	2023 to 2024	<ul style="list-style-type: none"> • Substantially reduces risk of islanding • Increases system strength • Increases import and export capabilities • Reduces risks associated with non-credible contingencies (such as loss of the Heywood interconnector) • Reduces need for local frequency and inertia services
Expansion of Olympic Dam load	The Brownfield Expansion Project may increase demand at the Olympic Dam site over the coming years ²⁰ . A modest increase has been assumed, commencing from 2021.	<ul style="list-style-type: none"> • Affects minimum demand forecasts. • May affect requirements for contingency lower services, depending on their ability to curtail load if South Australia islands.

Analysis has focused on the spring period (October to December) each year. Based on observations from the past two years, this is when minimum demand typically occurs (on a sunny Sunday or public holiday with mild temperatures). AEMO has applied the following assumptions for each year, as listed in Table 2 below. EnergyConnect is tentatively projected for commissioning in July 2023. The analysis for October to December 2023 has been conducted assuming a possible delay in commissioning this interconnector, to explore the possible measures that may need to be in place for secure operation under that eventuality.

Table 2 Assumptions applied

Event	Oct-Dec 2019	Oct-Dec 2020	Oct-Dec 2021	Oct-Dec 2022	Oct-Dec 2023
Frequency control providers	As registered	As registered +BIPS – 2 x TIPSA	As registered +BIPS -4 x TIPSA	As registered +BIPS -4 x TIPSA	As registered +BIPS -4 x TIPSA
Utility-scale batteries (providing frequency control)	<ul style="list-style-type: none"> • Hornsdale (100MW) • Dalrymple (30 MW) 	<ul style="list-style-type: none"> • Hornsdale • Dalrymple • Hornsdale Expansion (+50MW) • Lake Bonney (25 MW) 	<ul style="list-style-type: none"> • Hornsdale • Dalrymple • Hornsdale Expansion • Lake Bonney • Lincoln Gap (10 MW) 	<ul style="list-style-type: none"> • Hornsdale • Dalrymple • Hornsdale Expansion • Lake Bonney • Lincoln Gap 	<ul style="list-style-type: none"> • Hornsdale • Dalrymple • Hornsdale Expansion • Lake Bonney • Lincoln Gap
Virtual Power Plants (providing frequency control)	2 MW	5 MW	10 MW	15 MW	20 MW
Synchronous condensers	None	Two installed (Davenport)	All four installed	All four installed	All four installed

²⁰ BHP, <https://www.bhp.com/our-businesses/minerals-australia/olympic-dam/>

3.5 Advice from Network Service Providers

AEMO relies on advice from network service providers (NSPs) on a number of matters, including their ability to maintain network voltages within the required limits, and limit advice for interconnectors. AEMO has sought advice from ElectraNet and SAPN on these matters.

Based on preliminary modelling, ElectraNet has advised that the present export limit for South Australia remains valid for system normal operating conditions, with South Australian network demand reaching as low as zero megawatts. On this basis, AEMO has applied present network limits for this analysis.

AEMO understands that ElectraNet's advice does not take into account the behaviour of distributed PV and load, because detailed models of this behaviour were not available at the time of analysis.

Further analysis is required to validate these results. In particular the import limit on the Heywood Interconnector may be affected by the behaviour of distributed PV.

4. Behaviour of distributed resources

This section describes findings from PSS®E studies on load and distributed PV behaviour in response to severe faults.

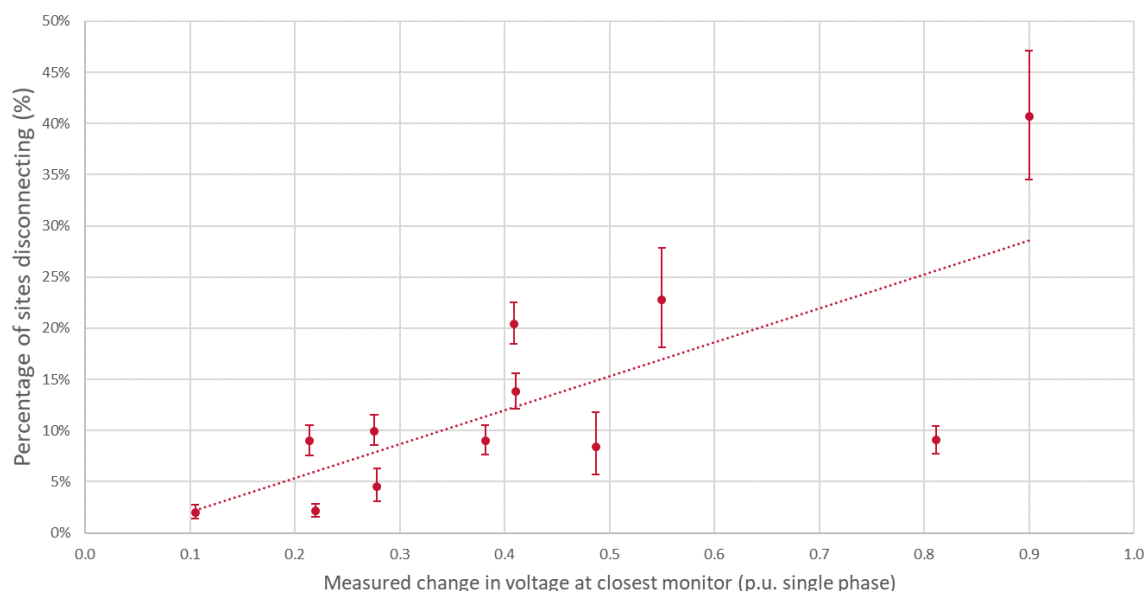
4.1 Evidence of distributed PV disconnection

Solar Analytics data from historical disturbances

AEMO analysed distributed PV disconnection behaviour from historical voltage disturbances that occurred in periods with meaningful levels of distributed PV operating during 2016 to 2020. For each disturbance, data from a sample of hundreds of individual distributed PV inverters was provided by Solar Analytics, under a joint ARENA funded project²¹. Data was anonymised to ensure that system owner and address could not be identified. Many inverters were observed to reduce power to zero (indicative of disconnection) immediately following a voltage disturbance. The proportion of distributed PV inverters demonstrating this behaviour in each historical event was calculated. Inverters were categorised by installation prior to October 2015 (under the AS/NZ4777.3:2005 standard), or after October 2016 (under the AS/NZ4777.2:2015 standard). Both categories showed similar disconnection behaviour.

Distributed PV disconnection behaviour was confirmed to be related to the severity of the voltage disturbance, as illustrated in Figure 5²².

Figure 5 Percentage of distributed PV sites in a region observed to disconnect following historical voltage disturbances



²¹ ARENA, Enhanced Reliability through Short Time Resolution Data, at <https://arena.gov.au/projects/enhanced-reliability-through-short-time-resolution-data-around-voltage-disturbances/>.

²² Uncertainty estimates in Figure 5 are based on the Solar Analytics sample sizes compared to the installed capacity in the region, with a 95% confidence interval.

In the most severe voltage disturbance analysed, disconnection of more than 40% of distributed PV in the region was observed. Individual cases may deviate from the linear trend line if the fault location was electrically remote from distributed PV centres, or if the high speed monitor used to estimate the severity of the fault was remote from distributed PV centres (therefore providing a less accurate estimate of the voltage experienced by distributed PV during the disturbance).

The amount of distributed PV disconnection observed in each voltage disturbance was used to calibrate AEMO's PSS®E model. Individual disturbances were used to validate the PSS®E model on a case by case basis, with distributed PV modelled at individual load buses, and taking into account the proximity of the fault to metropolitan centres (where distributed PV is located). The disturbance modelled in the PSS®E studies described in the following section involves a two-phase-to-ground fault. AEMO has not yet observed a fault of this severity occurring in a period with high PV generation, close to metropolitan centres. AEMO examined this fault for these modelling studies because it is the most onerous voltage disturbance that is considered credible.

Laboratory bench testing of inverters

Distributed PV disconnection behaviour was further validated by bench testing of individual inverters under laboratory conditions, conducted by UNSW Sydney²³. Their analysis has shown that 14 out of 25 inverters tested (including a mix across both the 2005 and 2015 standards) disconnected or significantly curtailed when exposed to a 100 ms voltage sag to 50 V. The detailed behaviours observed during these laboratory studies were used as a key input to calibrate AEMO's PSS®E model, and used to determine many of the model parameters.

4.2 Assumptions

PSS®E studies were conducted, modelling a 100 ms line-line-ground (two phase) fault on the high voltage (275 kV) side of the generator transformer for a Torrens Island Power Station B (TIPS B) unit, or a Pelican Point gas turbine unit²⁴. This network fault causes disconnection of the relevant generating unit. This fault occurs close to the Adelaide metropolitan area, and the resulting voltage disturbance therefore has the potential to lead to significant disconnection of load and distributed PV. AEMO examined this fault because it is the most onerous voltage disturbance that is considered credible.

Different levels of underlying demand and distributed PV generation were explored, with combinations resulting in operational demand levels at 200-300 MW.

The baseline dispatch of synchronous generators was assumed to be the same as the minimum demand period in 2019 (10 November), with two Torrens Island B units, and one Pelican Point gas turbine (GT) and steam turbine (ST) online and operating at minimum loading levels (with other combinations considered where indicated). This does not necessarily reflect the minimum number of units that may be online at a time of minimum demand, but does represent one possible dispatch in these periods.

It was assumed that the four new synchronous condensers were fully commissioned (two at Davenport, two at Robertstown). Reactive power support from South Australian wind farms, solar farms and the Hornsdale power reserve BESS²⁵ was also assumed.

4.3 Findings

The amount of distributed PV and load reduction observed in PSS®E studies in various power system snapshots is illustrated in Figure 6. Each point on the chart represents a simulation case, with varying levels of distributed PV and underlying load prior to the disturbance. The studies indicate a linear relationship for the

²³ UNSW Sydney, Addressing Barriers to Efficient Renewable Integration – Inverter Bench Testing Results, at <http://pvinverters.ee.unsw.edu.au/>.

²⁴ The assumed duration of the fault is based on transmission protection clearance times for 275 kV (NER Table S5.1a.2, Column 2).

²⁵ The Hornsdale Power Reserve was assumed to be operating in voltage control mode. Other BESS in South Australia were not modelled in these PSS®E studies.

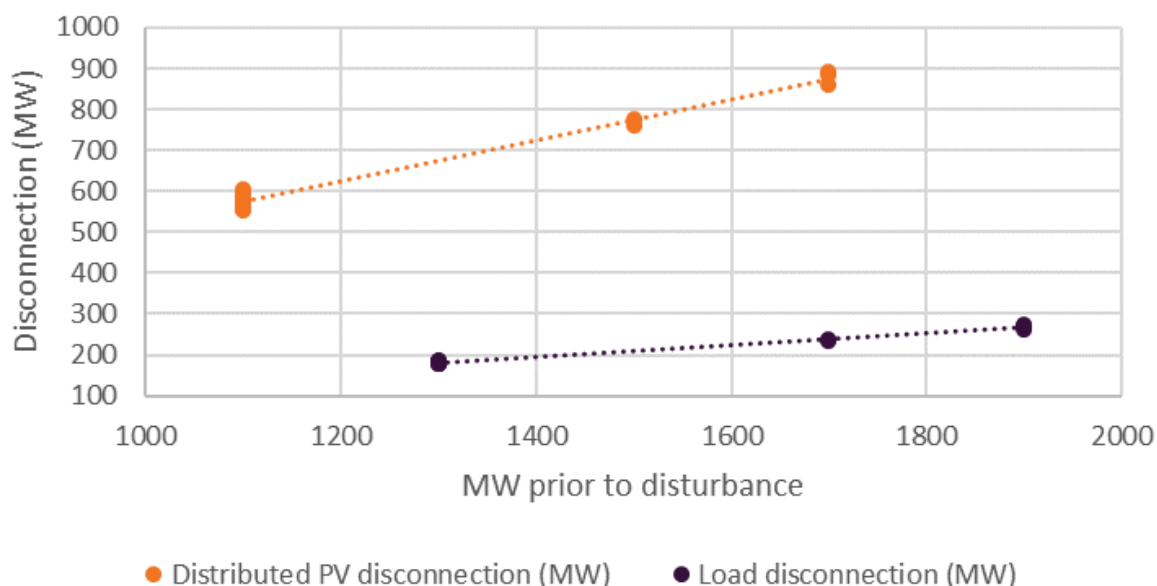
quantity of distributed PV and load reduction, which suggests that for this particular fault and set of units operating, the amount of distributed PV and load reduction can be reasonably predicted based on a percentage of the distributed PV generation and underlying load prior to the disturbance. The percentage ranges quoted are based on the estimated uncertainty in the dynamic load model and distributed PV model respectively, determined from validation studies.

PSS®E studies indicate that the most onerous credible fault in the Adelaide metropolitan area, with this set of units dispatched, causes:

- 14-28% of underlying load in the South Australian region to disconnect.
- 49-53% of distributed PV generation in the South Australian region to disconnect.

In some periods, with a large amount of generation from distributed PV, the loss of distributed PV can be larger than the loss of load, meaning that this can result in a fault causing a net loss of generation.

Figure 6 Reduction of distributed PV and underlying load in response to a severe credible fault in PSS®E studies



In this figure, “Distributed PV disconnection” represents a loss of generation, and “Load disconnection” represents a loss of load.

A number of sensitivity cases were explored. The load and distributed PV disconnection behaviour was found to be relatively insensitive to the following variables:

- Flows on the Heywood interconnector.
- Whether there are two synchronous condensers (at Davenport) or four synchronous condensers (two at Davenport and two at Robertstown) operating.
- System strength in the Adelaide metropolitan area, tested by bringing additional synchronous generation online (such as dispatching the Osborne gas and steam turbines), and also exploring the addition of four more synchronous condensers installed in the Adelaide metropolitan area (two at City West, and two at Northfield), with identical characteristics to those being installed at Davenport and Robertstown.
- Comparing low generation from large scale wind farms versus no generation from large-scale wind farms.

AEMO will undertake further exploration of other possible factors²⁶ that may influence this behaviour.

²⁶ For example, impacts of network outages such as 275 kV or 66 kV transformers.

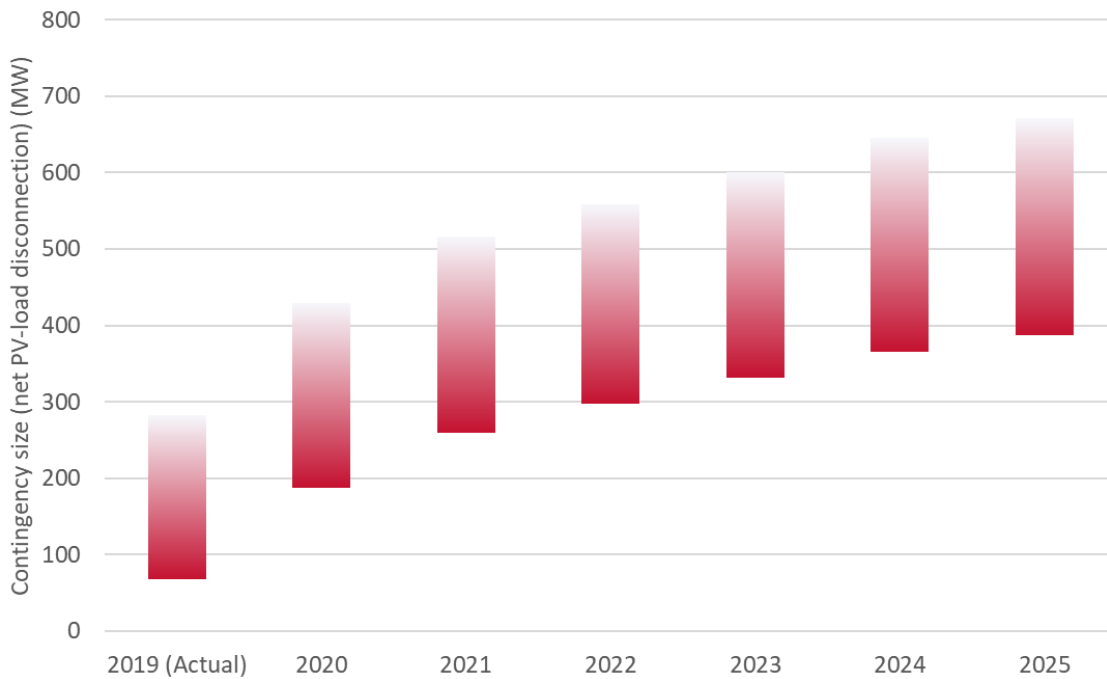
Forward projection of contingency sizes

To calculate a forward projection of contingency sizes, the percentages above were applied to each half hour of underlying load and PV generation in AEMO’s High DER forecasts for distributed PV installations from the 2019-20 ISP, assuming underlying load and distributed PV generation patterns as observed in 2019. This leads to the net contingency sizes (due to disconnection of load and distributed PV) shown in Table 3 and Figure 7 below. In these periods, the quantity of distributed PV disconnecting exceeds the quantity of load disconnecting, meaning that the combined (distributed PV-load) contingency is a net loss of generation in these periods. In the worst case, these values could be additional to the loss of a synchronous generating unit, if they occurred as a result of a fault at the large generator’s transformer.

Table 3 Net distributed PV & load contingency sizes (PV loss – load loss) – High DER forecast for PV growth

	85th percentile case	Extreme worst case
2019 (actual)	70	280
2020	190	430
2021	260	520
2022	300	560
2023	330	600
2024	370	650
2025	390	680

Figure 7 Net distributed PV and load contingency sizes (PV loss – load loss) – High DER forecast for PV growth



The extreme worst case estimate is shown (with maximum PV loss, minimum load loss, and in the most severe period of the year), as well as a more moderate estimate of the 85th percentile case (assuming a middle

projection of possible load and DER loss, and the 85th percentile of half-hourly periods in the year by severity of the possible net contingency size). The 85th percentile case could be expected to be exceeded on 55 days of the year.

The 85th percentile case also assumes that all >200 kW distribution connected PV has been curtailed (AEMO requested that SAPN do this in some periods during the extended islanded operation in February 2020, when operational demand reduced below 700 MW). In contrast, the extreme worst case assumes that distributed PV has not been curtailed, which may be the case in system normal conditions, or where operational conditions do not require curtailment for system security.

These contingency sizes are comparable with (and soon exceed) the maximum size of credible contingency for which the South Australian power system is currently planned and operated. For comparison, at present the largest generation contingency in South Australia in any period is around 280 MW. Furthermore, it is credible for these net PV-load contingencies to be added to a unit trip, making the total contingency size even larger. At present, AEMO has limited effective tools available in real time to be able to reasonably manage such large contingency events in South Australia.

Section 5 outlines the system security implications of contingency sizes growing to these levels. AEMO recommends that measures are taken to prevent these very large contingency sizes from eventuating. They are provided here as an indication of what could occur if no action is taken, as a basis for analysis. It is not recommended that the South Australian power system is operated with such large credible contingencies becoming feasible. Recommended mitigation measures are discussed in Section 9.

Based on these findings, the most severe distributed PV-load contingencies are likely to occur in periods that have the highest levels of distributed PV generation, with moderate underlying demand. These represent shoulder periods (not the minimum demand interval). For example:

- The lowest operational demand period has occurred at 1.00 pm AEST on 10 November 2019, with an operational demand of 458 MW. In this period, underlying demand was 1,296 MW, and distributed PV was generating at 838 MW, at a capacity factor of around 71%. Under these conditions, the possible net distributed PV-load contingency in the event of a severe credible fault is estimated to be in the range 44 MW – 245 MW, and the Heywood interconnector would very likely be exporting by at least 70 MW (assuming large-scale solar farms in South Australia are operating at a similar capacity factor to distributed PV, the operation of a minimum of three Torrens Island units dispatched at 60 MW each, and flows on the Murraylink interconnector 0 MW). Exporting on the Heywood interconnector reduces risk, by reducing the likelihood of triggering the SIPS in the event of a large generation contingency in South Australia, and also reducing reliance on UFLS in the event of a double circuit loss of the interconnector (because the loss of the interconnector is unlikely to cause an under frequency event).
- In contrast, the 2019 period that shows the largest potential net distributed PV-load contingency occurred at 1.00 pm on 7 December 2019, when distributed PV was operating at the higher level of 923 MW with a capacity factor around 78%. Underlying load in this period was also higher, at 1,548 MW. Operational demand was 625 MW, significantly higher than in the minimum operational demand period described in the previous example. Under conditions like this “shoulder” period, the possible net distributed PV-load contingency is estimated to be in the range 16 MW – 254 MW, and the Heywood interconnector could be importing as much as 30 MW (applying the same assumptions as described above). Importing on the Heywood interconnector creates a higher risk of relying on the SIPS or UFLS to manage a large non-credible generation contingency, or the double circuit loss of the Heywood interconnector, respectively.

The comparison of these two periods serves to illustrate that the highest risk periods may not be those periods with the minimum operational demand, but rather periods with higher levels of distributed PV generation, combined with moderate underlying demand.

Uncertainty

There are several sources of uncertainty in these estimates:

- The first is the continuing rate of installation of distributed PV in South Australia. As discussed in Section 2, to date, distributed PV installations are closest to the ISP's High DER scenario. The Central scenario in the ISP is considered unlikely to eventuate, given past and observed distributed PV uptake, and therefore has not been explicitly included in the figure above.
- The second is in the PSS®E dynamic load model, around the quantity of load (and to a lesser extent the quantity of distributed PV) that will disconnect during a disturbance, leading to the wide band of uncertainty within each scenario.
- The third is the characteristics of the period in which a severe fault may occur. The level of load and distributed PV generation in that period strongly affects the net contingency size that could eventuate.

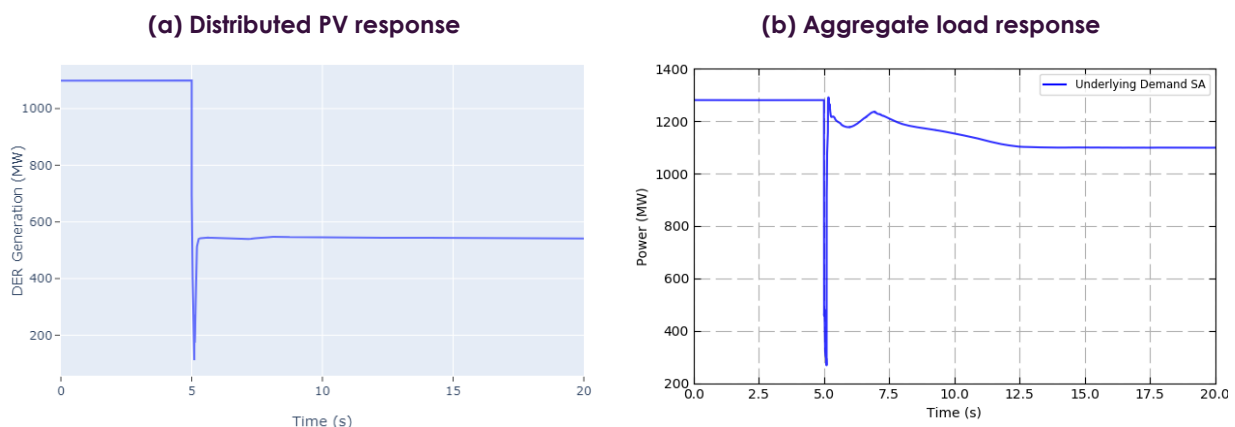
Given this considerable uncertainty, a precautionary approach is recommended, taking reasonable steps early to address the most pessimistic outcomes. This is particularly important given the potentially severe consequences of being under-prepared, and the long timelines required to implement most solutions. This approach aims to ensure the South Australian power system is as resilient as it reasonably can be to a wide range of possible eventualities.

Dynamics of load and distributed PV responses

The dynamics of the response of load and distributed PV are also important for power system stability outcomes, and have been examined in AEMO's analysis.

An example is illustrated in Figure 8. Based on observations from bench testing of a selection of inverters²⁷, and high speed distribution network data²⁸, distributed PV has been observed to disconnect rapidly following a voltage disturbance. This immediate disconnection behaviour has been replicated in AEMO's model, as illustrated in Figure 8(a). In contrast, load is more likely to reduce gradually due to motor stalling behaviour (a period of approximately seven seconds is illustrated in the example in Figure 8(b)). This behaviour was initially simulated in PSS®E (as shown in the Figures below), and then emulated in PSCAD studies using multiple blocks in the Adelaide metropolitan area, disconnecting at different time periods following fault clearance.

Figure 8 Example aggregate response of distributed PV (left) and load (right) in PSS®E model



²⁷ Bench testing has been conducted by UNSW Sydney, under an ARENA-funded project with partners ElectraNet, TasNetworks and AEMO. See <https://arena.gov.au/projects/addressing-barriers-efficient-renewable-integration/>.

²⁸ Data was supplied by Energy Queensland from three distribution network locations during 2017-19 and ongoing.

5. Distributed PV impacts on system security

This section outlines findings from AEMO's power system dynamic studies in PSCAD, assessing the impacts of distributed PV disconnection on system security.

5.1 Operation as an island

Although South Australia rarely operates as an island, it is the most onerous operational condition for the region, and is therefore addressed first. The ability to operate South Australia as an island determines the earliest timelines on which action may be required to facilitate secure operation in periods with low load and high levels of distributed PV generation.

South Australia can separate from the rest of the NEM at any time. If separation occurs, AEMO will take whatever reasonable actions are available, as soon as practicable²⁹, to restore all the required system strength, inertia, frequency control, voltage control, and other system security services required for stable and secure islanded operation in South Australia.

5.1.1 Assumptions

AEMO performed PSCAD studies for the South Australian island. Various dispatch combinations of synchronous generating units were considered, including combinations of Torrens Island Power Station B units (TIPSB), Quarantine Power Station Unit 5, and a Pelican Point GT and ST combination). Synchronous units were dispatched with at least 20 MW of headroom / lower room available, and were assumed to have governors enabled with a ± 0.1 Hz frequency deadband, to deliver a frequency response. This is more onerous than unit commitments for contingency FCAS requirements, and is intended to better represent the physical capabilities of each unit. Implementation of the recent mandatory primary frequency response rule change, which will mandate a deadband as narrow as ± 0.015 Hz, should lead to increased delivery of frequency response³⁰. Various unit trips were considered.

5.1.2 Findings

When South Australia is operating as an island, the FOS³¹ require that frequency is maintained above 49 Hz for credible contingency events, and that reasonable endeavours are made to keep frequency above 47 Hz for non-credible (including multiple) contingencies. As discussed in Section 9.3.1, AEMO's interpretation of the National Electricity Rules (NER) is that disconnection of distributed PV at the same time as a large generating unit trip should be considered part of the same credible contingency (that is, the 49 Hz lower frequency bound applies).

PSCAD studies with the assumptions outlined above showed that when distributed PV-load contingency sizes exceed around 150 MW (net generation loss), combined with the loss of a large-scale generating unit, frequency is likely to fall below 49 Hz. Enabling more FCAS provides minimal benefit, due to the rapid rate of change of frequency, and the comparatively slow response of a typical FCAS provider. This means that activation of automatic load shedding is inevitable. This is undesirable not only because it represents

²⁹ NER 4.2.6(b) states: Following a contingency event (whether or not a credible contingency event) or a significant change in power system conditions, AEMO should take all reasonable actions to adjust, wherever possible, the operating conditions with a view to returning the power system to a secure operating state as soon as it is practical to do so, and, in any event, within 30 minutes.

³⁰ AEMC (26 March 2020), Mandatory Primary Frequency Response, at <https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>.

³¹ Reliability Panel, AEMC, Frequency Operating Standard, at <https://www.aemc.gov.au/sites/default/files/2020-01/Frequency%20operating%20standard%20-%20effective%201%20January%202020%20-%20TYPO%20corrected%2019DEC2019.PDF>.

customer disconnection, but because it is unclear whether the existing UFLS scheme is capable of arresting a frequency decline in these conditions. Analysis indicates there could be very little net load available to shed in periods with high levels of distributed PV operating. This means that disconnecting a large number of customers may have very little impact on arresting the frequency decline. Further, at present the UFLS relays operate at a feeder level without regard to the direction of flow. Some UFLS feeders already experience reverse flows in high PV periods, when operation of the relays could accelerate a frequency decline, rather than helping to arrest it.

As indicated in Figure 7, net contingency sizes resulting from a severe fault may have already exceeded 150 MW in some periods, with the level of distributed PV already installed in South Australia. This suggests that it will not be possible to maintain the frequency in a South Australian island above 49 Hz for certain contingencies, during periods with high distributed PV generation, and therefore requires urgent mitigation.

Preliminary studies also suggest that when distributed PV-load contingency sizes exceed around 300-400 MW, frequency may fall outside the 47-52 Hz range. As discussed further below, the addition of incrementally more inertia or FCAS enablement is found to provide minimal benefit under these circumstances, due to the very fast rate of change of frequency. Cascaded tripping and major supply disruption might be inevitable under these circumstances. As indicated in Figure 7, in the worst case, net contingency sizes could exceed 300 MW from late 2020 onwards, under AEMO's High DER scenario projections.

The action of the UFLS scheme has not been explicitly included in this modelling. UFLS may assist in arresting a frequency decline below 49 Hz or may accelerate a frequency decline below 49 Hz if reverse flows are sufficiently high on multiple UFLS feeders. AEMO is conducting further analysis on the operation of the South Australian UFLS at these times.

This indicates that AEMO may no longer have the ability to operate South Australia in a secure state while islanded, at times of high distributed PV generation, and therefore urgent mitigation is required.

5.1.3 Likelihood of occurrence

It is noted that the operating conditions discussed in this section are anticipated to occur rarely. For these circumstances to arise, South Australia would need to experience all of the following, in combination:

- A separation event.
- A period of high distributed PV generation and moderate to low load.
- A severe fault in or close to the Adelaide metropolitan area, causing a large synchronous unit to trip.

The possible incidence of each of these is discussed below.

Incidence of periods with distributed PV contingency sizes exceeding 150 MW

Based on half-hourly historical underlying load and distributed PV generation patterns in 2019, and PV growth forecast in the ISP High DER scenario, periods where the net PV-load contingency sizes could exceed 150 MW were estimated. The "worst case" was calculated, applying the maximum amount of distributed PV disconnection that could occur (~50%), combined with the minimum amount of load disconnection that could occur (~14%).

On this basis, periods with possible distributed PV-load contingency sizes exceeding 150 MW are estimated to occur around 12% of the time in 2020, increasing to around 20% of the time by 2023. In these periods, if South Australia were operating as an island, AEMO may no longer be able to maintain frequency above 49Hz for the largest credible contingency. Since market start in 1998, South Australia has separated from the rest of the NEM 16 times, although six have occurred in the past four years.

If EnergyConnect proceeds as proposed in 2023, this risk should be largely eliminated beyond that date.

Incidence of severe faults

AEMO investigated the incidence of voltage disturbances of the kind that might cause disconnection of distributed PV, over the past several years (2017 to 2019). Relatively severe transmission network faults or

similar events were observed at a rate of at least once a week across the NEM (of sufficient severity for AEMO to deem it a reviewable operating incident³²). In South Australia, control room logs suggest an average of around 35 unplanned line or transmission network outages per year (although around one third of these were relatively minor).

AEMO has high speed data for a subset of voltage disturbances (most network faults are not investigated in detail, and high speed data for most events is therefore not warehoused beyond a period of two weeks). Over a period of around two years, across the NEM, AEMO has records of the voltage disturbances listed in Table 4.

Table 4 AEMO records of voltage disturbances (NEM – past two years)

Threshold (pu)	Disturbances less than threshold on one phase	Disturbances less than threshold on two phases
0.8	42	17
0.7	30	14
0.6	21	5
0.5	12	3
0.4	5	2

Voltages below 0.7 pu (measured as positive sequence, combined across the three phases) would be expected to lead to some distributed PV disconnection, voltages below 0.6 pu (positive sequence) are anticipated to lead to around 10% of distributed PV disconnecting across the region, and voltages below 0.4 pu (positive sequence) are expected to lead to significant DER disconnection (40% of regional distributed PV or greater).

Although Table 4 indicates that most severe faults of the kind that would lead to considerable distributed PV disconnection (voltages less than 0.4pu on two phases) are currently occurring about once per year across the NEM, South Australia may be more vulnerable to these kinds of disturbances than other regions. This is due to the concentration of generating units and network equipment in and near to the Adelaide metropolitan area, co-located with most of the region’s distributed PV.

For the severe consequences outlined in this section to apply, this type of voltage disturbance would need to occur in a period with high distributed PV generation, during islanded operation. This suggests that it might be appropriate to plan for high risk faults in relevant locations in South Australia at a rate of roughly once per year or less.

5.1.4 Mitigation approaches

AEMO has very limited real-time options to reduce risk in these periods. AEMO’s studies suggest that options used to improve system security in other circumstances, such as application of network constraints, increasing enablement of conventional frequency control, or the dispatch of additional synchronous generators, do not offer much improvement for this type of severe contingency.

Dispatching more synchronous generating units is often helpful for many types of security risks, because it increases system inertia, increases system strength, and provides increased frequency response. However, in this case, dispatching additional synchronous generating units assists only marginally, because the contingency sizes are extremely large compared with the size of the South Australian island, and the disconnection of distributed PV occurs near instantaneously. When a large and near instantaneous contingency occurs in a power system with low inertia, the rate of change of frequency (RoCoF) is very fast,

³² Reviewable operating incidents include the occurrence of a non-credible contingency, multiple credible contingency events, or one of a wider set of more extreme events, such as the activation of over-frequency protection schemes, as defined in NER 4.8.15(a).

and frequency response from synchronous generating units cannot act in time to arrest the frequency decline. The capabilities of emergency frequency control schemes can also be compromised.

Adding more conventional frequency response from synchronous generating units therefore assists only marginally with improving frequency outcomes for such a large and rapid contingency in the South Australian island. Similarly, adding incrementally more inertia (such as, for example, adding the equivalent of another synchronous condenser similar to those being installed at Davenport and Robertstown) does not significantly slow the frequency decline when the contingency is large and near instantaneous.

FFR from inverter-connected resources such as batteries and utility-scale solar farms can contribute more rapidly than frequency response from synchronous generating units, and provides more assistance. FFR has been assumed to be provided by the battery energy storage systems (BESS) in South Australia for this analysis, and contributes significantly to improving outcomes. In the absence of the FFR provided by batteries, the ability to meet the frequency operating standards is diminished. A number of important mechanisms are recommended in Sections 9 and 10 to help maximise the availability of FFR when required.

AEMO now considers that FFR is necessary for enhanced frequency control when South Australia is operating as an island. The recent rule change introducing a mandatory primary frequency response from all units, including inverter connected resources such as BESS and solar farms,³³ will be an important component of delivering this response.

The most important actions to mitigate the identified risks include:

- Ensuring the EnergyConnect interconnector is commissioned as soon as possible. This significantly reduces the likelihood of South Australia operating as an island.
- Improving voltage ride-through capabilities of distributed PV, as rapidly as possible. This reduces the size of the contingency associated with disconnection of distributed PV.
- Enabling further fast frequency response from BESS and utility-scale solar. This contributes meaningfully to arresting the frequency decline.
- Enabling feed-in management capabilities for as much distributed PV as possible, where it is suspected that these units may not ride through a disturbance. This allows vulnerable distributed PV to be curtailed when South Australia is operating as an island, reducing the possible contingency size.

These actions are discussed further in Section 8 and Section 9.

5.2 Credible risk of separation

This section summarises power system studies investigating the impacts of distributed PV behaviour in periods where South Australia is at credible risk of separation from the rest of the NEM.

5.2.1 Conditions for credible risk of separation

South Australia is defined as being at credible risk of separation from the rest of the NEM when the occurrence of a single credible contingency event would result in the loss of its synchronous connection to Victoria. This risk arises, for example, during outages of certain of transmission lines, including either of the two South East – Heywood 275 kV lines or any 500 kV line between Sydenham and Heywood terminal stations in Victoria. South Australia is also considered to be at credible risk of separation when the loss of any dual-circuit transmission lines between South East and Sydenham terminal stations is reclassified as a credible contingency.

Operational practice when there is a credible risk of separation

When South Australia is operating with a credible risk of separation from the NEM:

- AEMO maintains a minimum inertia in South Australia of 4,400 MWs.

³³ AEMC (26 March 2020), Mandatory primary frequency response, at <https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>.

- The maximum export limit on the Heywood interconnector is 250 MW and flows are also limited by inertia in South Australia such that the RoCoF upon loss of the Heywood interconnector remains ≤ 1 Hz/s.
- Contingency lower FCAS are enabled in South Australia, sufficient to meet the loss of the Heywood interconnector when exporting. Limited availability of contingency lower services in South Australia in low demand periods could mean that co-optimised exports on the Heywood interconnector are limited to as low as 100 MW³⁴.
- The Murraylink interconnector has a nominal export limit of 220 MW. However, Murraylink exports can be limited to lower levels due to thermal and voltage stability constraints on surrounding 132 kV lines³⁵. These limits can change depending on flows on surrounding lines. On previous occasions with a credible risk of separation, the Murraylink export limit has been observed at around 170 MW or lower³⁶. Murraylink is not impacted by FCAS availability.

These operating procedures aim to manage the increased level of risk associated with a credible risk of separation.

5.2.2 Modelling assumptions

PSCAD studies were performed to assess system security, emulating the disconnection of distributed PV and load observed in PSS®E studies. An outage of one of the two 275 kV lines between South East and Heywood terminal stations was assumed, creating a credible risk of separation. This is one of the most severe outages that limits the transfer capability of the Heywood interconnector.

It was assumed that the four new synchronous condensers were fully commissioned. Various synchronous unit dispatch combinations were considered, as outlined in Table 5. These unit combinations do not necessarily represent the minimum combinations of units that could be dispatched in these periods, but rather represent “possible” dispatch combinations.

5.2.3 Findings

Table 5 shows PSCAD study findings for periods with a credible risk of separation from the rest of the NEM (only one Heywood circuit available).

Table 5 PSCAD study findings for periods with a credible risk of separation

Net contingency from distributed PV & load (distributed PV loss – load loss)	Operational demand	Synchronous generating units operating	Heywood flows	Outcome
300 MW	450 MW	2 x TIPSb + QPS5 + OSB	50 MW Import	No adverse system security impact observed
300 MW	450 MW	2 x TIPSA + 2 x TIPSb	50 MW Import	No adverse system security impact observed
400 MW	200 MW	2x TIPSb + 1PELGT+ST	50 MW Export	Separation from rest of the NEM is likely
400 MW	200 MW	2x TIPSb + 1PELGT+ST	100 MW Export	No adverse system security impact observed

In this Table, the “Net contingency from distributed PV and load” represents a net loss of generation.

³⁴ This has been observed on previous occasions. For example, on 1 May 2019, 30 April 2019, 11 April 2019, and 9 April 2019, when South Australia was at credible risk of separation from the rest of the NEM, NEMDE was observed to co-optimize Heywood exports to approximately 100 MW, with L6 and L60 constraints binding.

³⁵ For example, the Robertstown-North West Bend and North West Bend-Monash 132kV lines, relating to thermal constraints S>V_NIL_NIL_RBNW and S>NIL_NIL_NWMH2.

³⁶ For example, on 1 May 2019, 30 April 2019, 11 April 2019, and 9 April 2019, when South Australia was at credible risk of separation from the rest of the NEM, Murraylink exports were limited to 170 MW or lower. This has been observed in low demand conditions, as well as higher demand conditions.

These studies show that if a 400 MW distributed PV-load contingency occurs, separation from the rest of the NEM could occur when Heywood is importing into South Australia, or exporting 50 MW or less. However, South Australia remains secure if the Heywood Interconnector is exporting at least 100 MW from South Australia.

This can be managed in many periods with a new constraint to require a minimum level of export from South Australia in periods with a credible risk of separation. It is present operational practice to enable contingency lower services when there is a credible risk of separation, and flows on the Heywood interconnector are co-optimised with the availability and cost of this lower service. This often means that exports on the Heywood interconnector are limited to around 100 MW when there is a credible risk of separation. This suggests that in some periods, particularly over a longer time horizon, it may become difficult to apply interconnector constraints that simultaneously manage the credible loss of the Heywood interconnector to within contingency lower availability, and also reduce the risk of separation if there is a large disconnection of distributed PV.

Contingency sizes in this range could occur from as early as spring 2020, in the worst case, based on AEMO's forecast of distributed PV installations from the High DER scenario. However, there is only a risk to system security if the Heywood interconnector is importing, or exporting less than 100 MW. This is less likely in periods with high distributed PV generation, because the low demand in South Australia tends to lead to exports on Heywood. AEMO estimates that even in the worst case, the conditions where the net disconnection of distributed PV and load could exceed 400 MW, and the Heywood interconnector could be exporting less than 100 MW is likely to occur approximately 0.3% of the time in 2020, 1% of the time in 2021, and 3% of the time in 2022 and 2023. The highest risk periods are not the minimum demand periods, but rather those with moderate demand levels, and high generation from distributed PV. The percentage of periods at risk increases somewhat over the next few years due to the growth in distributed PV causing a possibility of large amounts of PV disconnection in a larger proportion of moderate demand periods.

In summary, these studies have shown that there is some risk of a large disconnection of distributed PV causing a separation event when the Heywood Interconnector is operating with a single circuit. However, these conditions rarely coincide, and can be managed with constraints (which should bind very rarely and therefore have minimal market impact and cost). It should also be possible to schedule network maintenance away from these periods, to further reduce the need to operate with a credible risk of separation during moderate demand and high PV generation periods.

The System Integrity Protection Scheme (SIPS) was designed to reduce the likelihood of non-credible separation in system normal periods, when both Heywood circuits are available. The first stage of the SIPS (a fast injection from the Hornsdale BESS) is activated when imports on Heywood exceed 750 MW. AEMO and ElectraNet are exploring the potential to expand the effectiveness of the scheme to further minimise risk in periods with a credible risk of separation. It may be possible to modify the design to also trigger this first stage when only a single Heywood circuit is in service, if Heywood flows exceed a lower threshold, and incorporating the 50 MW Hornsdale Expansion BESS.

Further analysis is required to assess:

- The nature of the constraint on Heywood flows that may assist with minimising risks.
- Different types of outages that may lead to a credible risk of separation. Other outages may be less severe.

5.2.4 Likelihood of occurrence

For these risks to arise, South Australia would need to experience all of the following, in combination:

- Operation with only a single Heywood circuit available (or other network outages that lead to a credible risk of separation).
- Importing into South Australia on the Heywood interconnector (or exporting at low levels).
- A high distributed PV generation and moderate to low load period

- A severe fault in or close to the Adelaide metropolitan area, causing a large synchronous unit to trip.

The possible incidence of each of these is discussed below.

Incidence of operation with a credible risk of separation

Between March 2019 and February 2020, South Australia was at credible risk of separation for 689 hours owing to 65 transmission outages. This corresponds to around 8% of the year.

All but one outage was planned, indicating that most periods with a credible risk of separation can be planned for lower risk periods (with lower levels of solar insolation) if required. However, the majority of these outages took place during daylight hours, with more than 15% of days in the past year having outages causing a credible risk of separation at midday (when solar insolation levels are highest). Rescheduling outages to low solar insolation periods may incur additional costs, and have other barriers. For example, conducting maintenance in daytime periods has advantages in labour force scheduling, and safety from working without the need for external lighting.

Furthermore, most outages in the past year occurred during July to November, with the highest number of outages occurring in September. This is the period when the lowest minimum demand levels typically occur. Network businesses already avoid outages during summer peak demand periods; it may become increasingly difficult to schedule the necessary outages for commissioning and maintenance as the number of high risk periods increases.

Of the outages leading to a credible risk of separation in the past year, 97% were on the Ausnet 500 kV network. Most outages during this period were due to the commissioning of a new terminal station connecting to Victoria's 500 kV network. This highlights that managing the scheduling of outages is important for both ElectraNet (South Australia) and AusNet (Victoria).

The ongoing commissioning activity related to continuing growth in wind and solar generation and associated network equipment in both South Australia and Victoria is likely to continue to result in a high incidence of periods with a credible risk of separation.

Incidence of periods with distributed PV contingency sizes exceeding 400 MW

Based on half-hourly historical underlying load and distributed PV generation patterns in 2019, and PV growth forecast in the ISP High DER scenario, periods were identified where the net PV-load contingency sizes could exceed 400 MW in the worst case³⁷, and where exports on the Heywood interconnector could be less than 100 MW under some dispatch conditions³⁸. These are periods that may be of risk if the network is operating with a credible risk of separation (operating with only a single Heywood circuit). These periods occur rarely, because intervals with high generation from distributed PV in South Australia are generally associated with exports on the Heywood interconnector.

This analysis suggests that these periods could emerge under rare circumstances from 2020 (around 0.14% of the time), growing to around 1% of the time by 2021. These periods will only be problematic if South Australia is at a credible risk of separation. Planned network outages can be scheduled to avoid these periods (although unplanned network outages can occur at any time).

If network outages cannot be avoided or rescheduled, most of these periods can be managed with a suitable network constraint that ensures exports to a sufficient level.

This analysis indicates that this risk manifests very rarely, although it remains prudent to introduce network constraints to avoid operating the network in a way that allows this risk to arise. Market impacts are anticipated to be very low, since this constraint should bind very rarely.

³⁷ The "worst case" was calculated, applying the maximum amount of distributed PV disconnection that could occur (~50%), combined with the minimum amount of load disconnection that could occur (~14%).

³⁸ Maximum likely Heywood flows were estimated assuming utility-scale solar is generating at same capacity factor as distributed PV, all wind generation is at 0 MW, Murraylink has flows at 0MW, and three Torrens Island B units are operating at 60 MW each, with a total online capacity of 180 MW.

Incidence of severe faults

The possible incidence of severe faults of the kind that can lead to disconnection of distributed PV and load is discussed in Section 5.1.3.

5.2.5 Mitigation options

The most important mitigation options include:

- Ensure the EnergyConnect interconnector is commissioned as rapidly as possible to remove the incidence of periods with a credible risk of separation.
- Improve the ride-through capabilities of distributed PV through improvements to performance standards.
- Implement a constraint to ensure Heywood is exporting to a sufficient degree in periods with a credible risk of separation, when distributed PV levels are high
- Enhance the design of the SIPS to provide increased protection against separation in periods with a credible risk of separation
- Work with NSPs to schedule planned outages that lead to a credible risk of separation at lower risk times when distributed PV generation is low.

These are discussed further in Sections 8 and 9.

5.3 Normal operating conditions

Under normal operating conditions (with no transmission line outages), South Australia currently has an export limit of 700 MW (combined across the Heywood and Murraylink interconnectors).

ElectraNet is conducting further studies to explore operation under conditions of high generation by distributed PV, to investigate whether the present South Australian export limits remain valid, particularly taking into account the disconnection behaviour of distributed PV.

This section investigates possible security challenges that may arise in periods with low load, and high generation from distributed PV under normal operating conditions (with the Heywood interconnector fully intact, and no other significant transmission outages).

5.3.1 Assumptions

PSCAD studies were performed for system normal conditions, with 200 MW of operational demand, and with the same synchronous generators operating as on the most recent minimum demand period (10 November 2019): two Torrens Island power station B units (TIPSB), and one Pelican point gas turbine and steam turbine. This is not intended to represent a minimum synchronous generating unit combination that could be operating; instead, it represents a "possible" dispatch combination that could occur. Findings may differ for different combinations of synchronous generating units operating, and will be explored as a part of AEMO's implementation of mitigation measures, as discussed in Section 9.3.1.

A number of wind farms and solar farms were assumed to be operating at 50% and providing reactive power support. The four synchronous condensers were assumed to be commissioned and available.

The disturbance modelled was a fault at a Pelican Point gas turbine.

5.3.2 Findings

Table 6 shows findings for periods in normal operating conditions (both Heywood interconnector circuits fully available). Larger contingency sizes were explored in this analysis (compared with the earlier sections on islanded conditions and periods with a credible risk of separation) to allow exploration of the conditions under which risks might emerge, particularly in future years. AEMO recommends that such large contingency sizes are never allowed to eventuate (and these scenarios are modelled here only as a counterfactual to investigate potential outcomes if no action is taken). Mitigation methods, such as implementing new

standards for voltage ride-through for distributed PV inverters, are strongly recommended, as discussed in Section 9.1.

Table 6 PSCAD study findings for system normal conditions in South Australia

Net contingency from distributed PV & load (distributed PV loss – load loss)	Heywood flows	Outcome
400 MW	150 MW Import	No adverse system security impact observed
500 MW	150 MW Import	Inadvertent load shedding and system separation likely
500 MW	50 MW Import	No adverse system security impact observed
600 MW	0 MW Export	Inadvertent load shedding and system separation likely
600 MW	100 MW Export	No adverse system security impact observed
700 MW	100 MW Export	Inadvertent load shedding and system separation likely
700 MW	200 MW Export	No adverse system security impact observed

In this Table, the “Net contingency from distributed PV and load” represents a net loss of generation.

These studies show:

- Under system normal conditions (with two Heywood circuits fully available), if the net contingency from distributed PV and load exceeds 500 MW, and the Heywood Interconnector is importing 150 MW or more, inadvertent load shedding and system separation is likely. However, if the Heywood interconnector is importing less than 50 MW, the scenario passes all required stability criteria.
- If the distributed PV-load contingency size exceeds 600 MW, the scenario passes all required stability criteria with Heywood exports at 100 MW, but fails with exports at 0 MW.
- If the distributed PV-load contingency size exceeds 700 MW, the scenario passes all required stability criteria with Heywood exports at 200 MW, but fails with exports at the lower level of 100 MW.

As indicated in Table 3, distributed PV-load contingency sizes could exceed 500 MW from as early as 2021, exceed 600 MW from as early as 2022, and exceed 700 MW from as early as 2024, in the High DER scenario.

A power system should not be operated such that a credible contingency event could lead to inadvertent load shedding and system separation. Load shedding is intended as a “last resort” mechanism to prevent separation in the event of a large non-credible loss of generation.

5.3.3 Likelihood of occurrence

For these risks to arise, South Australia would need to be operating with high distributed PV generation and moderate to low load period, and then experience a severe fault causing the trip of a large synchronous generating unit in or close to the Adelaide metropolitan area.

Based on half-hourly historical underlying load and distributed PV generation patterns in 2019, and PV growth forecast in the ISP High DER scenario, periods were identified where the conditions outlined above could apply (net PV-load contingency sizes could exceed 500 MW, 600 MW or 700 MW in the worst case³⁹, and flows on the Heywood interconnector could be in the risk zone under some dispatch conditions⁴⁰). These are periods that could have a potential risk of inadvertent load shedding and possible separation from the NEM if the Heywood interconnector is not exporting at a sufficient level.

³⁹ The “worst case” was calculated, applying the maximum amount of distributed PV disconnection that could occur (~50%), combined with the minimum amount of load disconnection that could occur (~14%).

⁴⁰ Maximum likely Heywood flows were estimated assuming utility-scale solar is generating at same capacity factor as distributed PV, all wind generation is at 0 MW, Murraylink has flows at 0MW, and three Torrens Island B units are operating at 60 MW each, with a total online capacity of 180 MW.

This analysis indicates that these conditions will occur less than 0.01% of the time in 2023, because high generation from distributed PV is likely to coincide with exports on the Heywood interconnector.

These rare periods can be managed with the introduction of a suitable constraint, which is expected to bind very rarely and therefore will have very low market impacts.

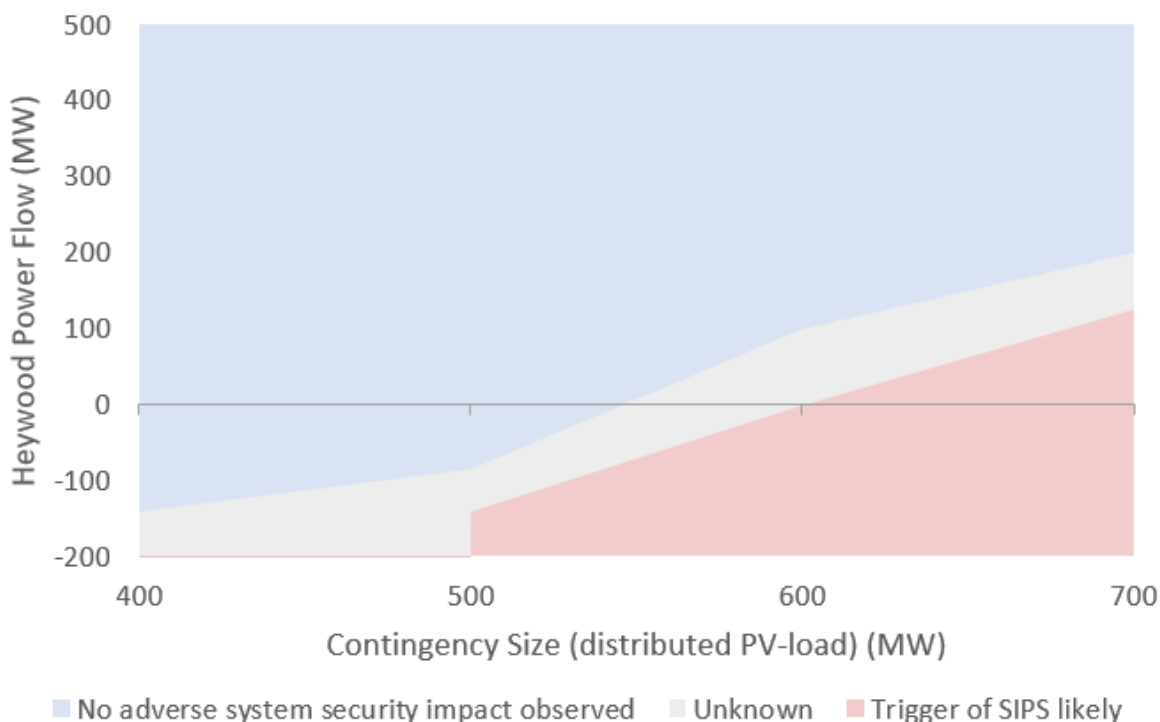
AEMO recommends that action is taken to prevent conditions in the South Australian power system from evolving such that distributed PV-load contingency sizes in the realm of 500, 600 or 700 MW could eventuate. Measures such as implementing improved disturbance ride-through requirements for distributed PV inverters will minimise the likelihood of these extreme credible contingencies arising.

5.3.4 Mitigation options

This analysis suggests that under system normal conditions, introducing a constraint on Heywood flows may be a suitable management strategy in the near term. If Heywood is exporting to a sufficient level, studies suggest the risk of separation from the NEM can be minimised. The level of the network constraint depends on the anticipated contingency size, which is influenced primarily by the quantity of distributed PV operating. A preliminary indication of the level of the network constraint which could be applied to manage this risk is illustrated in Figure 9. Further detailed analysis is required to determine this limit more precisely, and under a wider range of operational conditions. ElectraNet is investigating this with further detailed studies, and will use this to develop limit advice, for AEMO's due diligence.

It is likely that this constraint will not bind often or affect market outcomes significantly, because the Heywood interconnector is more likely to be exporting in periods of low operational demand. However, full NEM dispatch simulations are required to fully assess potential market impacts, and it is possible that Victoria and other NEM regions may have similarly high levels of distributed PV and low load at these times, limiting Heywood exports to Victoria.

Figure 9 Heywood flow limits – preliminary assessment (system normal)



For this chart, a negative flow on the Heywood Interconnector should be interpreted as imports into South Australia.

5.3.5 Voltage management

Transmission voltages

Voltage management challenges can be encountered under low load conditions. For example:

- AEMO currently encounters challenges related to high voltage management under low load conditions in Victoria, which necessitates switching out of up to two 500 kV transmission lines at times. Switching out transmission lines has market impacts, and reduces the robustness of the power system⁴¹.
- Assessment has indicated that in the absence of intervention, voltages in the South-West Interconnected System (SWIS) in Western Australia cannot be controlled within technical limits as the level of minimum operational demand (market load) approaches 700 MW⁴². This was calculated as an indicative level, based on an assessment of the voltage control capability, system inertia, and dispatch limitations in the SWIS.

NSP planning processes, and appropriate network investment, should reduce the likelihood of similar challenges in South Australia.

ElectraNet has advised that their preliminary studies indicate system voltages on the main 275 kV network can be regulated sufficiently using all existing reactive power support plants and the new synchronous condensers being installed at Davenport and Robertstown 275 kV substations, with demand as low as zero megawatts. However, they note that their studies show higher operating voltages throughout the network, and that most SVCs are close to reactive absorption limits following certain contingencies. This suggests that further studies may be required to examine whether there is adequate reactive power capability, particularly under outage conditions. ElectraNet emphasises that these studies are preliminary and, most significantly, do not consider the behaviour of distributed PV. As illustrated by AEMO's studies, the behaviour of distributed PV has a significant influence on power system stability.

The ability to manage system voltages with negative demand has not been examined at this stage, and requires further analysis.

This is recommended as an area for further analysis by ElectraNet, as outlined in Section 11.2.

Distribution voltages

AEMO notes that possible issues could arise relating to distribution network voltages, which could have flow-on effects for the transmission system. AEMO has limited visibility of the distribution network, and therefore limited ability to model issues of this nature.

SAPN has advised AEMO that they are progressing a range of initiatives to better manage distribution voltages at times of high distributed PV generation. They anticipate these measures will successfully offset the potential for high voltages with growing levels of distributed PV, resulting in no significant change in distributed PV curtailment. They estimate that the curtailment of distributed PV at minimum demand times due to distribution over-voltages is approximately 2% at present, and suggest they expect this to continue at the present level.

⁴¹ AEMO currently utilises NMAS (non-market ancillary services) generator contracts for reactive support to maintain system security under these low demand conditions, and is also conducting a Regulatory Investment Test (RIT-T) for additional reactive support to ensure a longer-term economic solution will be implemented.

⁴² AEMO (March 2019), Integrating Utility-scale renewables and distributed energy resources in the SWIS. Refer to Appendix 3, at https://www.aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2019/integrating-utility-scale-renewables-and-der-in-the-swis.pdf?la=en&hash=3A7FEBFC1F00F0FDE97DB8213AD58D488.

6. Minimum load thresholds

The previous section summarised findings on the impacts of distributed PV disconnection behaviour on system security. Findings showed that there are significant emerging risks, and AEMO has limited options for management of this risk in real time.

This section complements that analysis by investigating the minimum threshold of operational demand required for operation of South Australia as an island, assuming a moderate contingency size (including disconnection of up to 130 MW of distributed PV). This disturbance is less severe than the contingencies considered in the previous section, and represents a contingency that AEMO can take “reasonable endeavours” to manage in real time. It is therefore investigated to determine the threshold of operational demand required to allow AEMO to manage this milder contingency event.

The severe voltage disturbances with large quantities of distributed PV disconnecting (as considered in the previous section) are relatively rare, occurring perhaps once per year in high risk locations in South Australia. Milder disturbances, such as single unit trips with a milder voltage disturbance, are generally more common. Based on records from the past two years, AEMO estimates that large synchronous generating units trip at a rate of approximately 100 per year (twice a week), across the NEM. In South Australia, records suggest large synchronous generating units trip at a rate of approximately 10 per year (around one per month). Many unit trip events are not associated with a sufficiently severe voltage disturbance to result in extensive disconnection of distributed PV. This makes it important to consider operational procedures that need to be implemented to allow management of this more common but less severe event.

6.1 Approach

AEMO applied the following approach to calculate the minimum demand threshold in periods where South Australia is operating as an island, for unit/load trips where the net disconnection of distributed PV and load remains less than 130 MW:

1. AEMO conducted PSCAD studies to determine the minimum combinations of synchronous generating units that meet stability requirements in South Australia. A minimum of three large synchronous generating units was assumed during daytime periods (post installation of the synchronous condensers)⁴³. AEMO notes that these system requirements were in the process of being investigated and confirmed at the time of development of this analysis; AEMO’s understanding of system requirements may change as further modelling is completed.
2. A range of possible combinations of three large synchronous generating units were determined. The units considered in these combinations were Torrens Island A⁴⁴ and B units, Pelican Point, Osborne, and Quarantine Unit 5. Combinations containing both Pelican Point gas turbines, or containing both Pelican Point and Osborne were not included, because they are much larger and are therefore considered unlikely to be dispatched during periods of islanded operation with low load. The range of combinations considered offer a degree of dispatch flexibility, so that it is possible to manage various network or unit outages or other unforeseen circumstances.

⁴³ “Large” synchronous generating units are considered to be those that are included in the present system strength combinations, and are registered to provide contingency raise and lower six second services. This includes the Torrens Island A & B units, Osborne, Pelican Point and Quarantine. It excludes Mintaro and the Dry Creek units, which are not registered for the six second contingency service.

⁴⁴ The retirement of the Torrens Island A units was taken into account, as outlined in Section 3.4.

3. For each possible minimum combination of synchronous generating units that could be operating, the dispatch of those units was optimised to meet minimum requirements for inertia and frequency control, allowing for additional units to be dispatched if necessary to meet requirements. The following operational procedures were taken into account:
- a) Meeting the minimum inertia requirements (updated to account for introduction of the synchronous condensers, as appropriate in each time frame).
 - b) Sufficient headroom is allowed in unit dispatch to enable all frequency control services locally in South Australia. This includes a minimum of ± 35 MW of regulation, and adequate raise and lower contingency services on six second, sixty second, and five-minute response timeframes⁴⁵.
 - c) Maximum contingency sizes were determined based on the size of the largest load (assumed to be Olympic Dam operating at 150 MW), and the size of the largest generating unit dispatched⁴⁶.
 - d) A net distributed PV and load disconnection of 130 MW was assumed, and added to the largest generation contingency.
 - e) For this analysis, it is assumed that Olympic Dam load is curtailed to around 150 MW if South Australia is operating as an island, to reduce contingency lower requirements to the level of lower services available (taking into account power system inertia).
 - f) Six second contingency requirements were calculated as a function of the inertia in the South Australian island, based on a single mass model⁴⁷. A lower system inertia increases the amount of six second contingency service that needs to be enabled to maintain the frequency nadir above 49 Hz (or below 51 Hz), due to the faster Rate of Change of Frequency (RoCoF) that occurs following a contingency event.
 - g) Fast Frequency Response (FFR) from battery storage systems was assumed to be delivered as per the droop response parameters for each unit (100 MW raise and 80 MW lower from Hornsdale, 25 MW from Lake Bonney, and 50 MW raise and 40 MW lower from the Hornsdale Expansion). Dalrymple BESS also provides 30 MW of frequency response, although this response is slower and more similar to a synchronous governor, and was modelled as such. This was included explicitly in the single mass model, and acted to reduce the requirement for six second contingency service.
 - h) Sixty second and five minute contingency requirements were calculated as the largest contingency minus load relief (and minus 35 MW of regulation in the case of the five minute service).
 - i) Load relief was assumed to be 0.5%, as per AEMO's recent analysis⁴⁸.
 - j) The frequency control capabilities for each unit in South Australia were based on their registered "FCAS trapeziums". Wind farms were excluded, because their availability in low load periods cannot be

⁴⁵ The Mandatory Primary Frequency Response rule change (<https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>) may lead to increased delivery of frequency response from many units, and may somewhat improve findings compared with those modelled in this analysis.

⁴⁶ At present, Pelican Point is assumed to set contingency sizes based on the dispatch of the gas turbines only. In practice, when one Pelican Point gas turbine is operating, the loss of this gas turbine will be followed by the loss of the steam turbine over the following minute. This has been accounted for in this analysis by determining sixty second and five minute raise requirements based on the combined dispatch of the gas turbine and steam turbine. This increases minimum load requirements.

⁴⁷ The Single Mass Model assumed that only those units registered for FCAS supplied a frequency response, in line with the Market Ancillary Services Specification (MASS). Under the Mandatory Primary Frequency Response rule change, all units will be required to enable a frequency response in line with their individual capabilities. This has not been modelled in this analysis, and would be expected to improve outcomes. The implementation of this rule change may take some time, and the frequency capabilities of each unit is relatively unknown at this time, so it is difficult to quantify the additional benefit that will be provided at minimum load times. This can be considered in future analysis.

⁴⁸ AEMO (August 2019) Changes to Contingency FCAS Volumes, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Frequency-and-time-error-reports/2019/Update-on-Contingency-FCAS-Aug-2019.pdf. Load relief was calculated based on operational demand, as per the existing constraint equations. In future, it may be preferable to calculate load relief based on underlying demand.

guaranteed. Solar farms and battery systems were considered likely to be fully available, although there are no solar farms registered for FCAS in South Australia at present⁴⁹.

- k) Batteries were assumed to deliver their full frequency response capacity in all timeframes⁵⁰. Batteries were modelled in this manner for this analysis because it was thought to better represent their potential contributions to system security.
 - l) Regulation FCAS from batteries was limited to ± 5 MW each, as per operation in the recent South Australian islanding event. This acts to maximise battery availabilities for contingency frequency control.
 - m) All synchronous generating units were dispatched to at least 20 MW above their respective lower FCAS trapezium breakpoint for fast lower service, except Osborne which is dispatched at 10 MW above its breakpoint. This is as per operation in the recent South Australian islanding event.
4. The minimum operational demand required for secure operation of South Australia when islanded was then calculated according to the expression below. The "Planning Threshold" represents the level of operational demand that AEMO should plan to be able to recover in a future year, to be able to operate a secure South Australian island in any of the wide range of possible operational circumstances that may eventuate. This level is based on a relatively larger synchronous generating unit combination that could be operating at the time of separation. This level, in combination with AEMO's minimum demand forecasts, dictates the amount of reserves that need to be procured to enable secure islanded operation in future years. This is different to the "real-time trigger threshold", which represents the level of operational demand where activation of reserves is likely to be required in real time (to increase load or decrease distributed generation) if South Australia is operating as an island. The real-time trigger threshold will depend on the precise circumstances occurring at the time of islanded operation, including the specific generating unit combinations operating at the time, the level of Olympic Dam operation, and the availability of Murraylink exports. Other factors may also need to be taken into account.

Planning Threshold

$$= \text{Minimum load of synchronous generators} + \text{Olympic Dam curtailment} \\ - \text{Murraylink Exports} + \text{FCAS recovery buffer} - \text{Controlled distributed PV}$$

The parameters are as follows:

- **Minimum load of synchronous generators** – the minimum load of synchronous generators is calculated for islanded conditions, as outlined above.
- **Largest load curtailment** – when the largest load has to be curtailed to reduce contingency lower requirements, the operational demand in South Australia will fall below the forecast minimum demand. The largest load reduction is therefore subtracted from the minimum demand threshold. The calculation of the real-time trigger threshold, is based on actual largest load operation at the time, and the level to which it needs to be curtailed. For the calculation of the Planning Threshold, there is an expected increase in load in future years, which in turn increases the amount of curtailment required to match contingency lower service availability. AEMO assumed that the largest load operates at these increased levels in future years, and will need to be curtailed to around 150 MW.
- **Murraylink exports** – calculation of the real-time trigger threshold is based on actual Murraylink availability at the time. For the calculation of the Planning Threshold, Murraylink exports were assumed to be limited to the same level as Olympic Dam load (due to co-optimisation with contingency lower services availability), up to a maximum of 170 MW (often observed due to thermal constraints in the surrounding

⁴⁹ The Mandatory Primary Frequency Response rule change (<https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>) will require that scheduled and semi-scheduled solar farms deliver a frequency response if they are dispatched above 0 MW. However, when curtailed to 0 MW (as may be the case in very low demand periods, particularly under islanded conditions) they will not be required to deliver a frequency response. This is discussed further in Section 9.2.1.

⁵⁰ This means that the BESS were assumed to contribute more frequency response than their registered FCAS quantities. Future commercial arrangements for batteries to deliver fast frequency response are yet to be determined, but may result in better alignment of battery capabilities with the prescribed FCAS contribution calculations outlined in the Market Ancillary Service Specifications (MASS).

network). This means Murraylink exports are limited to 150 MW in most scenarios considered in this analysis.

- **Return to secure buffer** – increasingly, battery storage systems are providing a large proportion of the frequency control in South Australia. If batteries are providing five minute contingency lower services, when a load contingency occurs it's important that they can be relieved of charging duty by changes to dispatch before they reach a full state of charge. This can be challenging at times of minimum demand, where there are few units operating, and units are already close to minimum loading levels. To ensure adequate dispatch flexibility for de-loading batteries, a recovery buffer equal to the size of the largest load contingency has been allowed (assumed to be 150 MW for this analysis). This indicates an additional quantity of dispatchable load required to be recovered within 30 minutes of a load contingency. This assumes that frequency could remain close to 50.5Hz for an extended period following a load contingency event, such that the BESS providing the five minute contingency service may need to continuously charge for up to 30 minutes before additional distributed PV can be curtailed. This would necessitate BESS charging at approximately half the size of the load contingency (eg. charging at 75 MW). To allow them to then return to an optimal state of charge in the following 30 minutes, an additional buffer of half the size of the load contingency would then be required (to allow BESS to discharge at 75 MW), such that the BESS can then gradually discharge and return to a state of charge suitable to continue to provide frequency control. This provides increased confidence that the South Australian islanded power system can return to a secure state (with all frequency control services enabled) within 30 minutes following a credible contingency. This is examined in more detail in Section 9.2.2.
- **Controlled distributed PV** – SAPN advises that in minimum load periods, they typically have around 60 MW of controllable distribution connected PV (non-market generators). If suitable control room protocols are introduced, this generation can be curtailed within 30 minutes to recover demand if islanding occurs. It is assumed that this distributed PV generation will be operating close to full capacity at the time of minimum demand. This capacity only accounts for existing controllable distribution connected PV; any new installations in this category remain somewhat uncertain, and therefore are accounted for in the demand forecasts for this analysis.

This approach has been used to calculate minimum demand thresholds for secure operation of the island, based on present operational practice.

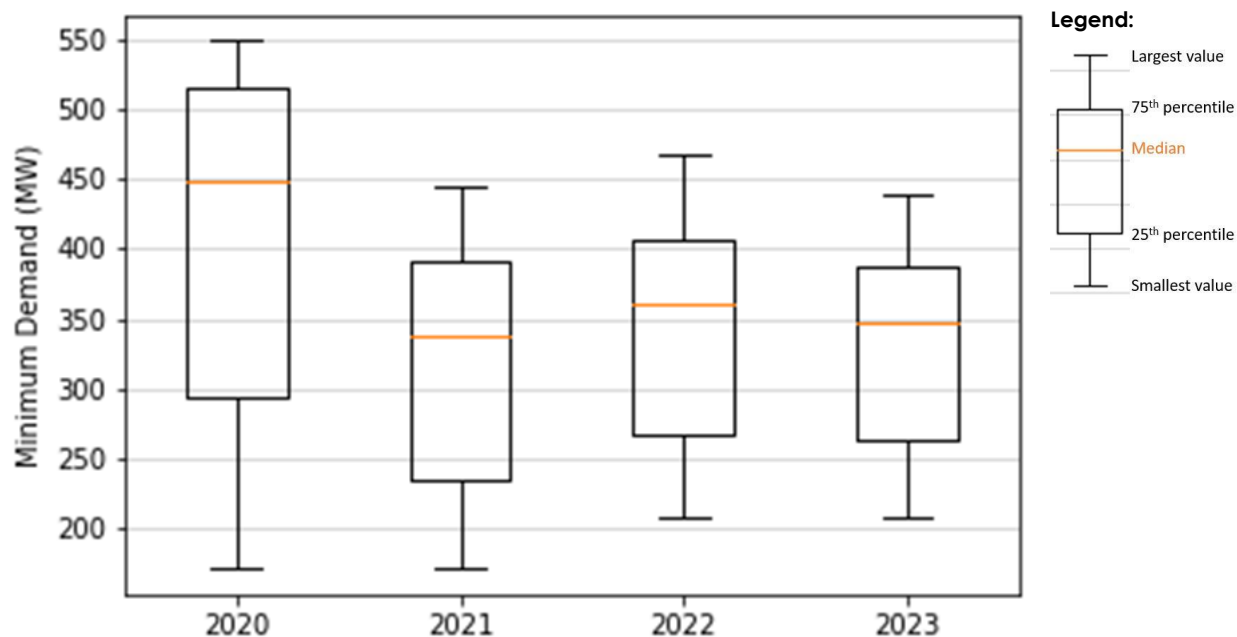
The Mandatory Primary Frequency Response rule change⁵¹ may lead to increased delivery of frequency response from many units, and may somewhat improve findings compared with those modelled in this analysis. Implementation of improved frequency response will be delivered in tranches, and will take some time to proceed to completion, with the timeline uncertain at this point. There may be possible further delays related to the COVID-19 pandemic. The ultimate capabilities of each unit are also uncertain at this stage. For these reasons, this analysis has assumed unit frequency responses as per their individual FCAS registered capabilities, with the exception of BESS, which are assumed to deliver their full known fast frequency response.

6.2 Findings

Figure 10 below shows an estimate of the minimum operational demand (the Planning Threshold) required for operation of South Australia, when operating as an island, to be secure for the loss of any single unit or single load, assuming up to 130 MW of distributed PV disconnections. The range indicates the range of minimum operational demand that AEMO needs to operate securely with the various possible synchronous generating unit combinations that could be operating.

⁵¹ AEMC (26 March 2020), Mandatory primary frequency response, at <https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>

Figure 10 Minimum operational demand for secure islanded operation, for a range of possible generating unit combinations



Different generating unit combinations require very different amounts of load. The smallest generating unit combination uses only Torrens Island units. Due to the low minimum load requirements of these units, and their strong frequency control capabilities, a minimum South Australian operational demand of ~150-200 MW suffices in this case (assuming some Murraylink exports, and other factors as outlined above). However, in order to maintain the dispatch flexibility to operate generating unit combinations that include the larger units, such as Pelican Point or Osborne, much larger amounts of load are required. For the largest unit combination considered in this analysis, around 550 MW of load is required to operate in a secure state (under the power system conditions assumed in spring 2020). Having the larger units online leads to larger contingency sizes, which then require more units online to provide adequate inertia and frequency control to manage their possible loss.

Given the small selection of generating units in South Australia, AEMO has conducted this analysis assuming it is prudent to allow the ability to recover sufficient demand to operate the larger units (including Pelican Point and Osborne), in some combinations, if necessary. This allows for various network or generating unit outages, and provides a degree of dispatch flexibility. The larger unit combinations are not considered optimal under islanded conditions, but are included as a prudent planning measure.

Minimum load requirements change year to year, as the system operational requirements and capabilities evolve over time. Under the assumptions applied in this analysis, the load needed to operate the larger generating unit combinations is expected to reduce from spring 2021, primarily due to the entry of the inertia from the four synchronous condensers, and further BESS capacity providing FFR. The power system in South Australia is evolving rapidly, and this analysis is very sensitive to the frequency control arrangements in place. As operating procedures evolve, new units enter, and other units exit, these findings will change. For example, AEMO recently conducted a review of load relief (discussed further in Section 7), and determined that it should be reduced from 1.5% to 0.5%⁵². This has been reflected in this analysis. Frequency control frameworks in the NEM are under broader review at present, and further changes will affect the minimum load requirements presented here.

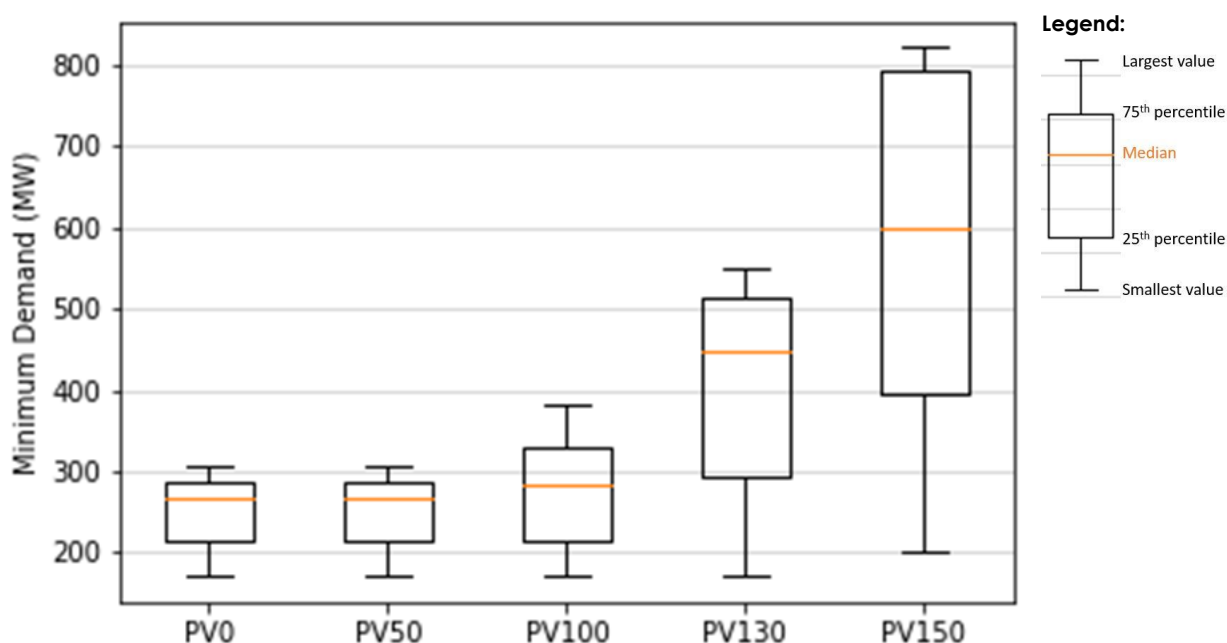
⁵² AEMO (November 2019), Review of NEM Load Relief, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/2019/Update-on-Contingency-FCAS-Nov-2019.pdf.

The operational demand required to operate the largest unit combination considered determines the Planning Threshold – the amount of operational demand that AEMO needs to be able to recover for secure operation of South Australia as an island, with a prudent level of dispatch flexibility. As shown in Figure 10, this level is around 550 MW in spring 2020. This reduces to around 450 MW from spring 2021, related the additional inertia from the commissioning of further synchronous condensers, the assumed entry of the 10 MW Lincoln Gap BESS, and the retirement of the Torrens Island A units.

Commissioning of the EnergyConnect interconnector (in the period 2022 to 2024) reduces the risk of South Australia islanding. This reduces the need to prepare to operate South Australia as an island, and considerably reduces the amount of reserves that will be required.

Figure 11 provides an indication of the challenges in managing increasing levels of distributed PV disconnection under islanded conditions. The minimum demand required for each generating unit combination is shown, with different levels of net PV-load disconnection assumed, ranging from 0 MW (no disconnection of distributed PV or load), to 150 MW. The amount of demand required for secure operation increases almost exponentially for the larger unit combinations, related to the additional frequency control units required to address the increasing contingency size. For this analysis, AEMO has assumed an ability to manage a 130 MW net disconnection of distributed PV and load. Larger contingencies become very difficult to manage, even with almost all units dispatched.

Figure 11 Minimum demand requirements as a function of PV disconnection sizes (spring 2020)



6.2.1 Comparison against demand forecasts

This analysis suggests that AEMO needs to be able to recover operational demand to around 550 MW when required, if islanding occurs. Operational demand has already fallen below this level historically, reaching a minimum of 458 MW on 10 November 2019. This indicates that further reserves are required to recover to this level of operational demand, preferably before spring 2020 when lower demand levels are likely to occur.

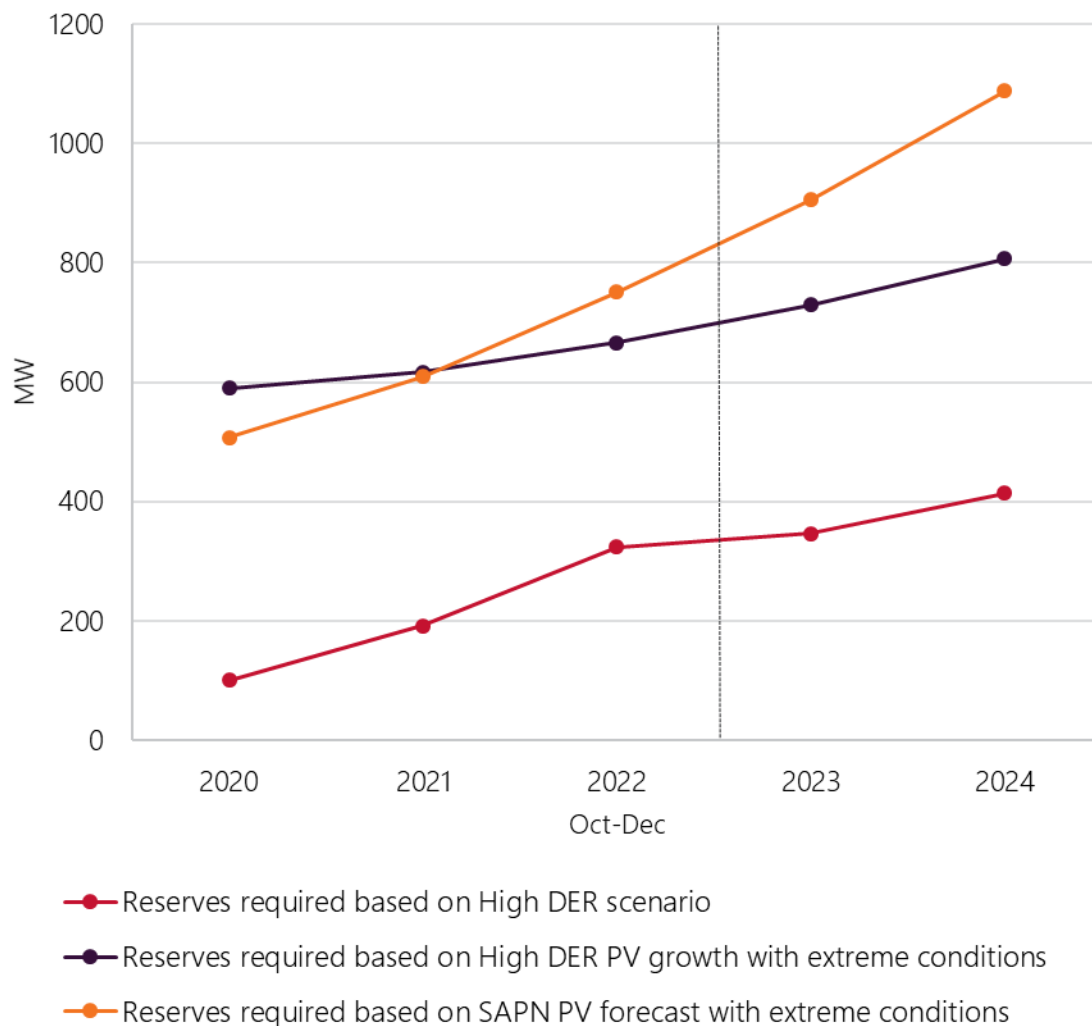
Figure 12 below shows the amount of additional “demand recovery reserves” required to increase operational demand (or decrease distributed PV generation), in each future year, based on AEMO’s minimum demand forecasts. These represent an estimate of the *additional load* that is required, or generation shedding capability required, to meet the identified Planning Threshold.

As noted in Section 2, minimum load levels are inherently difficult to forecast, given the influence of inter-annual variability, the uncertainty around distributed storage operation at these times, and the uncertainty around the co-occurrence of summer public holidays with mild temperatures and high solar insolation levels. The future installation of distributed PV is also highly uncertain. AEMO has therefore provided three forecasts to indicate the possible range of reserve that may be required:

- Red – minimum load levels projected as per the 2019 ISP High DER scenario.
- Purple – a sensitivity projecting possible minimum load levels that could occur if distributed PV growth proceeds as per the High DER scenario in the 2019 ISP, but there is a coincidence of summer public holidays with mild temperatures and high solar insolation levels, similar to what was observed in 2017.
- Orange – a sensitivity projecting possible minimum load levels that could occur if distributed PV growth proceeds as per SAPN’s projections (continuing growth at present rates), and there is a coincidence of summer public holidays with mild temperatures and high solar insolation levels, as occurred in 2017.

The various projected minimum load levels are combined with the minimum operational demand requirements from Figure 10 (to meet the Planning Threshold for the largest generating unit combination) to calculate the amount of additional reserves required in each year. The dotted line indicates the announced timing of the EnergyConnect interconnector commissioning, which should reduce the probability that South Australia needs to operate as an island, and mitigate the need for further growth in reserves to manage minimum demand periods.

Figure 12 “Demand Recovery Reserves” required to meet Planning Threshold of operational demand



This analysis suggests that action is required immediately to increase the level of reserves available. Suitable actions could include any measures that increase minimum demand, or reduce the minimum demand threshold. This could include:

- Implementing generation shedding capabilities for distributed PV, so that distributed PV can be shed when necessary for system security (such as when islanding occurs). This allows recovery of the necessary demand levels when required. Further discussion is provided in Section 10.1.
- Increasing minimum demand, through dispatchable loads, or shifting load. Further discussion is provided in Section 10.2.
- Increasing the supply of frequency control in South Australia. This reduces the minimum demand threshold for secure operation. Further discussion is provided in Section 9.2.

It is likely that these measures would only be activated in the event of islanding (and possibly in some cases if there is a credible risk of islanding), if operational demand is below the threshold required for secure operation. Island operation may or may not coincide with periods of low demand. This means that these demand recovery reserves are likely to be used very rarely (but will be essential for system security when they are required, especially if islanded operation is extended).

Note that the analysis in this Section assumes that South Australia has survived a non-credible islanding event, and then needs to operate as a frequency island for some period of time. For example, a separation event could occur at a time of low PV generation (such as in the early morning), but operational demand could reduce below minimum thresholds as solar insolation levels rise over the course of the day. This makes it important to provide options for secure operation of the island in low load conditions.

Analysis of South Australia's capacity to survive the initial non-credible islanding event in a period of high PV generation is provided in Section 7.

7. Separation events

The South Australian Government has requested that AEMO provide advice on the minimum operational demand threshold that will be sufficient for the power system to ride-through a non-credible loss of the Heywood Interconnector (letter dated 3 February 2020, Ref D20003485).

AEMO agrees that this is an important aspect for understanding security risks in South Australia, but has not yet been able to complete sufficient studies to provide detailed advice on this topic. This requires detailed modelling of emergency frequency control schemes (EFCS) such as UFLS, OFGS, and special protection schemes such as the SIPS. To accurately model the action of these schemes at times of minimum demand, the behaviour of distributed PV needs to be explicitly modelled, and incorporated into the behaviour of these schemes. This is non-trivial. AEMO is working to improve its models to take these aspects into account.

Some high level observations are provided below.

Emergency Frequency Control Schemes

SIPS, UFLS, and OFGS schemes are mechanisms that either minimise the likelihood or manage the consequences of South Australia's separation from the NEM.

The load available to be shed under the UFLS scheme is now significantly reduced at times of high PV generation. This in turn reduces the capability of the power system to survive severe disturbances. The SIPS is likely to be similarly affected. Risks may be mitigated somewhat by the low probability of high imports into South Australia on the Heywood interconnector at times of high distributed PV generation. As part of that advice, AEMO has made the following recommendations:

- Implement a constraint to limit imports on the Heywood interconnector in periods where there is inadequate load available on the UFLS to manage loss of the interconnector within the FOS. This will require:
 - Dynamic studies to determine the operational envelope for Heywood flows in low UFLS load periods.
 - Declaration of a protected event (by the Reliability Panel) or another regulatory mechanism providing AEMO with the ability to implement the constraint.
 - The establishment of a new SCADA feed from SAPN to AEMO providing a real-time estimate of the aggregate load on the UFLS.
 - Improvements to SAPN metering to allow accurate estimation of UFLS load, taking into account reverse flows on major feeders that do not have adequate bidirectional metering at present.
- Increase the amount of load on the South Australian UFLS. This includes:
 - Adding new customers to the UFLS.
 - Investigating moving controlled hot water to daytime (exploring barriers, risks and costs and potential customer impacts).
 - Negotiating with and incentivising large customers to move load to daytime, subject to assessment of feasibility.
 - Exploring potential for large customers to provide up to 100% of their load to the UFLS (rather than just a smaller proportion).
- Increasing the emergency frequency response from other sources, including:
 - Promoting changes to AS/NZ4777.2:2015 to specify an increased emergency response from distributed storage when frequency falls below 49 Hz.
 - Explore augmentation of the Murraylink interconnector to add frequency control capabilities.

- Implementing dynamic arming of UFLS feeders in reverse flows:
 - AEMO will collaborate with SAPN to determine a threshold for the amount and duration of reverse flows that should trigger implementation of dynamic arming at each relay.
 - SAPN will monitor flows and implement dynamic arming as individual relays reach reverse flows.
- Implement suitable long-term measures:
 - AEMO will explore potential long-term frameworks to deliver a suitable emergency frequency response in a power system with very high levels of DER generation.

This work program is underway.

The capability of the South Australian OFGS scheme may also be reduced at times of high distributed PV generation, when fewer large-scale generators are dispatched. This may increase the difficulty of managing a non-credible separation event at times when South Australia is exporting close to the interconnector limits.

AEMO is completing further studies on the capabilities of these schemes at present.

Load relief

AEMO's recent analysis has also revealed that there is less "load relief" in the NEM than previously assumed⁵³. Load relief is an assumed change in load that occurs when power system frequency changes. It relates to how particular types of load (such as traditional motors, pumps and fans which use induction machines) draw less power when frequency is low, and more power when frequency is high. As load is becoming less dependent on frequency (for instance, motor load is increasingly connected via variable speed drives that decouple the speed of the motor from system frequency), load relief has been declining. This reduces the natural response of the power system to assist in arresting a frequency disturbance.

This reduced estimate of load relief has been taken into account in the analysis in this report (a load relief value of 0.5% has been assumed throughout).

Over-frequency droop response from DER

A possible partial mitigating factor may be the over-frequency droop response from distributed PV. Distributed PV systems installed after October 2016 under Australian Standard AS/NZS 4777.2-2015 are required to provide an over-frequency droop response when frequency rises above 50.25 Hz. If enough distributed PV responds quickly enough, this may assist in managing a severe over-frequency event.

Analysis from the Queensland and South Australia separation event on 25 August 2018, and further validated based on South Australian separation events on 16 November 2019 and 31 January 2020 indicated that some post-2015 distributed PV systems did demonstrate this behaviour, although at least 30-40% of sampled systems in South Australia did not deliver the over-frequency droop as specified⁵⁴. This suggests material non-compliance with relevant standards. AEMO is working with SAPN to investigate possible pathways to improve compliance. Analysis of more recent separation events is also underway, to explore whether the same trends are observed.

Primary Frequency Response

Primary frequency response from generating units is an important component of successfully managing a non-credible separation. This means that the mandatory primary frequency response rule change⁵⁵ recently determined by the AEMC is an important contribution to system security in South Australia.

⁵³ AEMO (November 2019) Review of NEM Load relief, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/2019/Update-on-Contingency-FCAS-Nov-2019.pdf.

⁵⁴ AEMO (10 January 2018) Final Report – Queensland and South Australia system separation on 25 August 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/QLD---SA-Separation-25-August-2018-Incident-Report.pdf.

⁵⁵ AEMC (26 March 2020), Mandatory primary frequency response, at <https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>.

If no primary frequency response is available in the case of a non-credible separation of a region, the power imbalance following separation can cause the frequency to rise or decline to the point where UFLS or over-frequency generator tripping is initiated. As the load or generation tripped is in discrete sized blocks, the power balance can sometimes be over-corrected. This means that the frequency can swing in the other direction and cause tripping when it reaches the opposite extremity. This pattern could continue in an uncontrolled way until widespread loss of generation on over-frequency or under-frequency protection results in a cascading failure.

The new rule should help maintain some level of primary frequency response in each region to reduce this possibility.

7.1 Frequency control provision following non-credible separation

AEMO's preliminary report indicated that the commissioning of the four synchronous condensers in South Australia will assist considerably by allowing operation with fewer synchronous generating units needed to be online for system strength and inertia, consequently reducing the threshold for minimum demand required to balance that generation. However, AEMO noted that "a complicating factor is that, with fewer synchronous generating units operating under system normal conditions, it is more difficult (or impossible) to provide all the required FCAS within an acceptable timeframe after a non-credible separation event".

The South Australian Government subsequently requested information confirming the required FCAS, and defining the "gap" in resourcing FCAS.

For secure operation of South Australia as an island, all of the following frequency control services must be provided locally:

- ± 35 MW of regulation.
- Sufficient contingency raise service to cover the loss of the largest unit, in 6 second, 60 second, and 5 minute timeframes.
- Sufficient contingency lower service to cover the loss of the largest load, in 6 second, 60 second, and 5 minute timeframes.

Following a non-credible separation event, AEMO aims to establish these services as soon as reasonably practicable, with a target of 30 minutes after islanding, where possible. However, if the large synchronous generating units online at the time of a non-credible separation event cannot supply all the frequency control required for secure operation of the island, more units must be brought online to supply frequency control. Only a subset of units in South Australia have start up times shorter than 30 minutes, and many of these units are not registered to provide FCAS (or offer limited frequency control services). This means that it may take longer to enable all the frequency control services for secure islanded operation when a non-credible separation event occurs, after the synchronous condensers are installed.

This is an existing issue, unrelated to low demand levels. For example, following the non-credible separation event on 16 November 2019, FCAS constraints violated for one hour and 40 minutes before sufficient frequency control could be provided. The number of frequency control providers in South Australia with short start-up times (particularly BESS) is growing, and this will help to address this issue over time.

The most practical and useful measures to contribute to an adequate supply of frequency control in the South Australian island following a non-credible islanding event are likely to include:

- The addition of fast-start flexible frequency control providers in South Australia (such as BESS).
- Valuing and encouraging further fast frequency response from BESS.
- Implementation of the mandatory primary frequency response rule change⁵⁶.

These measures have been recommended in this report, as outlined in Section 9.2.

⁵⁶ AEMC (26 March 2020), Mandatory primary frequency response, at <https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response>.

8. Mitigation: essential foundational measures

Mitigation measures are presented in the following categories:

- **Essential foundational measures** – these are crucial “no regrets” actions that will underpin the future operability of the South Australian power system. They should all be progressed as a priority, as rapidly as possible. All other actions will be complementary to these foundational measures.
- **Additional measures to address disconnection of distributed PV** – these are additional measures recommended to reduce risks associated with disconnection of distributed PV.
- **Additional measures to provide demand recovery reserve** – these are additional measures recommended to allow generation shedding and/or recovery of sufficient operational demand when necessary to operate a secure power system if South Australia is operating as an island.
- **Other mitigation actions** – some additional recommended actions that are also beneficial.
- **Enduring policy frameworks** – transitioning towards a long-term, NEM-wide framework that holistically provides a foundation for secure power system operation with high levels of distributed resources.

This section discusses the essential foundational measures.

8.1 EnergyConnect interconnector

The results presented in this report highlight the increasing difficulty of operating South Australia as an island. With the growth in distributed resources anticipated over the next few years, it is likely to become infeasible to operate a secure island in an increasing number of periods, if distributed PV growth is allowed to continue.

The proposed EnergyConnect interconnector will substantially reduce the risk of South Australia separating from the rest of the NEM, and therefore the likelihood that AEMO will need to operate South Australia as an island. Completion of the interconnector on the current proposed commissioning timelines should be considered crucial for the ongoing security of South Australia’s power system.

The AER recently approved the regulatory investment test for transmission (RIT-T) for the EnergyConnect project, but estimated far lower net benefits than the original proposal⁵⁷. This means that if estimated project costs increase (which is not uncommon for a large project of this nature), the RIT-T may be reassessed.

AEMO will share the results of this analysis with the AER, to emphasise the importance of EnergyConnect for ongoing security of the South Australian power system. This modelling was not completed in time for the EnergyConnect proposal, and therefore has not been taken into account in its assessment to date. AEMO and ElectraNet are working on quantifying the security value of the interconnector, which falls across a number of areas, including:

- When AEMO has to constrain Heywood flows in periods where the UFLS load is inadequate to manage the double circuit loss of the interconnector⁵⁸, EnergyConnect will act to alleviate this constraint, reducing impacts on market participants.

⁵⁷ AER (24 January 2020), “AER approves South Australia – NSW interconnector regulatory investment test”, at <https://www.aer.gov.au/news-release/aer-approves-south-australia-%E2%80%93-nsw-interconnector-regulatory-investment-test>.

⁵⁸ AEMO will propose a protected event in order to implement this constraint.

- When AEMO has to constrain Heywood flows in periods where distributed PV disconnection could cause inadvertent load shedding and possible separation from the rest of the NEM, EnergyConnect will act to alleviate this constraint, reducing impacts on market participants.
- Operating South Australia as an island is expensive. For example, in the extended island operation, the cost of directions to scheduled participants in the SA region could be around \$9m⁵⁹, with FCAS costs to customers summing to \$36.5m. By reducing the likelihood of islanding, EnergyConnect would reduce the incidence of these costs.
- It is becoming increasingly infeasible to operate South Australia as a secure island in periods with high levels of distributed PV generation. EnergyConnect considerably reduces the probability-weighted cost of a black system event, associated with a synchronous unit trip associated with a severe credible fault and disconnection of distributed PV, when South Australia is operating as an island.

Much of the security benefit from EnergyConnect can be delivered even if the interconnector never has flows above 0 MW (and are therefore additional to any benefits related to energy transfer). Its timely commissioning should be considered critical for the ongoing secure operability of the South Australian power system. If EnergyConnect does not proceed⁶⁰, extreme measures such as an immediate moratorium on new distributed PV installations will likely be required (from 2020). A broad (and expensive) program of retrofit of legacy distributed PV systems may also be necessary, to improve voltage ride-through capabilities and introduce feed-in management capabilities.

If EnergyConnect does not proceed, additional measures will be required to maintain system security in South Australia. This analysis has assumed that EnergyConnect will be commissioned as proposed, and extensive further analysis is required to determine precisely what may be required in its absence. However, a preliminary indication suggests this could involve:

- Investment in a large capacity of utility-scale BESS (perhaps of the order of hundreds of megawatts required to manage credible contingency events), to provide frequency control, especially if new voltage ride-through standards for distributed PV are delayed, or compliance is imperfect (this is considered likely).
- Possible investment in a large capacity of resistor banks, to provide additional demand recovery reserve if implementation of feed-in management is imperfect or delayed (this is considered likely).
- Possible investment in retrofit of a large proportion of legacy distributed PV systems to improve voltage ride-through capabilities and implement crude feed-in management capabilities. Given the necessity of a site visit in most cases, and the need to visit a very large number of small sites, this is likely to be expensive and will have high risks associated with customer engagement and perceptions.
- A moratorium on all new distributed PV may become necessary, until strict arrangements for feed-in management and voltage ride-through are implemented, including improved compliance procedures. This has significant risks for customer engagement. The most significant concern to AEMO is that if a heavy-handed approach is applied, customers could permanently reject the possibility of feed-in management, which is essential for long-term system operability.
- The ongoing absence of EnergyConnect may mean that South Australian consumers are exposed to a higher level of system security risk that cannot be managed by other “reasonable endeavours”. This could mean customers are subject to a higher possibility of black system events and other high cost, low probability events.

AEMO understands that the South Australian government has supported the development of EnergyConnect by enabling early works such as line route identification and stakeholder engagement. Seeking ongoing opportunities to underpin the successful delivery of this project on the fastest timeline possible should be considered a priority.

⁵⁹ Initial formula-based compensation for SA directions was \$4.3m. A number of directed participants have made additional compensation claims, which are in the process of independent expert determination.

⁶⁰ The AER has approved the EnergyConnect project. However, the AER’s estimate of net benefits was significantly reduced compared with ElectraNet’s.

8.2 DER disturbance withstand standards

Evidence of distributed PV disconnection behaviour

AEMO has now collected considerable evidence consistently showing that a significant proportion of distributed PV disconnects in response to voltage disturbances:

- Laboratory bench testing of a selection of inverters (conducted by UNSW Sydney in an ARENA-funded partnership with AEMO) indicates that around one third of inverters tested on the AS/NZ4777.2:2015 standard do not have the ability to ride through short duration voltage sags, of the type that might occur in typical transmission faults⁶¹.
- Solar Analytics has provided AEMO with field data from hundreds of distributed PV systems⁶² for sixteen transmission level voltage disturbances occurring during daylight hours from 2017 to 2019, which consistently show voltage disconnection behaviour as a function of the depth of the disturbance⁶³.
- High speed data provided by Energy Queensland for selected distribution feeders with high levels of distributed PV shows that under high solar insolation conditions, apparent load increases on a feeder following a voltage disturbance, consistent with distributed PV disconnecting.

This broad body of evidence has been used to develop accurate dynamic models of this PV disconnection behaviour in PSS®E that have formed the basis of the analysis in this report.

Ride-through capabilities

It is essential that new distributed PV installed in South Australia has improved capabilities to ride through power system disturbances. This analysis has particularly focused on the implications of evidence of poor distributed inverter abilities to ride through voltage disturbances.

The NER require voltage ride-through behaviour of all large-scale generation connecting to the NEM, and this capability is now similarly essential for distributed resources when they are supplying a large proportion of regional load. The results in this report show the infeasibility of operating a power system with the disconnection behaviour observed at present, if distributed PV levels grow.

Passive anti-islanding requirements for inverter-connected DER are defined in Australian Standard AS/NZS 4777.2, and imply voltage ride-through capability for short duration disturbances. However, the testing procedure in AS/NZS 4777.2:2015 does not sufficiently determine whether an inverter remains connected for short duration voltage steps. Therefore, manufacturers have not prioritised designing inverters that deliver this capability, and the tests for compliance with AS/NZS 4777.2:2015 do not identify whether inverters meet this requirement. This means that many inverters have demonstrated compliance with the standard test procedures even though they may not have these ride-through capabilities. Laboratory testing of inverters suggests that around one half to two thirds of the existing inverters available in the Australian market do ride through short duration voltage disturbances, demonstrating that this capability can be incorporated without additional costs, if inverters are appropriately designed.

AEMO has launched a program of work on DER standards⁶⁴, and released a report in April 2019 to initiate collaboration with stakeholders on improvement of AS/NZS 4777.2:2015. This work has been progressing, with Standards Australia approving a project that includes AEMO's proposed scope of work in June 2019, and a committee now working on drafting proposed changes.

This committee is currently working on the following relevant aspects:

⁶¹ UNSW Sydney, Addressing Barriers to Efficient Renewable Integration – Inverter Bench Testing Results, at <http://pvinverters.ee.unsw.edu.au/>.

⁶² Data was anonymised to ensure that system owner and address could not be identified.

⁶³ This work was supported by an ARENA funded project, "Enhanced Reliability through Short Time Resolution Data", in a partnership between AEMO, Solar Analytics and WattWatchers. Further information at <https://arena.gov.au/projects/enhanced-reliability-through-short-time-resolution-data-around-voltage-disturbances/>.

⁶⁴ AEMO, "Standards and Protocols", at <https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/standards-and-protocols>.

- Designing appropriate under-voltage ride-through requirements, which provide acceptable power system stability, but also meet distribution network requirements for safety and suitable anti-islanding protection.
- Drafting the standard in a way that is unambiguous to manufacturers.
- Improving the accuracy and stability of measurement systems used in these inverters to improve reliable performance characteristics for a range of grid disturbances.
- Designing suitable testing procedures that clearly show when an inverter is performing as required, or not.
- Exploring optimised arrangements for delivery of grid support functions (such as volt-var and frequency-watt capabilities), which will assist with power system management in a range of conditions.

This work must be done collaboratively, because a wide range of stakeholders are affected (including AEMO, NSPs in all Australian regions, the Clean Energy Council, the Clean Energy Regulator, all inverter manufacturers, installers, solar customers and others).

AEMO understands that the committee has completed preliminary drafting of the standard. Standards Australia then has an extensive public consultation process. They have advised that this will be completed with publication of the standard at the earliest by December 2021, noting that the specification of standards is a consensus-based process. There would then need to be a delay period before the new standard is mandatory, to allow manufacturers to adjust their inverter design. The last time AS/NZS 4777.2 was changed (in 2015), this period was one year. This would suggest that new standard would not apply until December 2022, although a reduced timeframe may be achieved by ensuring that many of the functional amendments of the standard are consistent with international practice. As illustrated in this analysis, this timeline results in unacceptable risks to the South Australian power system, and must be accelerated.

AEMO has proposed an alternative consultation timeline which would allow publication of the new standard by February 2021, and is working with Standards Australia to find any further possible avenues for the consultation process to be accelerated. This must be balanced with the need to ensure all affected parties are properly involved, and have adequate opportunity to review and provide input to the process. There are a wide range of proposed changes (voltage ride-through is only one component). The other changes proposed as part of the AS/NZ 4777.2 review are also important for power system operation, and the risks of delaying implementation of these other important components until late 2022 needs to be taken into consideration.

As highlighted in this report, risks are emerging in South Australia already, and are likely to increase in the coming years, so this timeline need to be accelerated for the most important capabilities, as outlined in Section 9.1.1.

8.3 Compliance with DER standards

AEMO's analysis of field data from distributed PV systems during frequency disturbances indicates that a significant proportion (at least 30-40%) of legacy inverters are not behaving according to the standards under which they should have been installed⁶⁵. This is consistent with limited audits that have been conducted, and with anecdotal evidence from NSPs. This means that defining improved requirements may not, by itself, significantly improve aggregate behaviour of distributed PV. Existing compliance processes require review, including promoting installer compliance with installation procedures, reviewing testing and certification processes, and possibly other aspects. This requires further investigation.

It is unclear which organisation is best placed to take action to address this issue. Further work is required to determine possible courses of action, and which organisations should have primary accountability for their delivery. AEMO proposes to lead the following actions, as a first step to initiate the required work program:

⁶⁵ AEMO (10 January 2019) Final Report – Queensland and South Australia system separation on 25 August 2018, at https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf?la=en&hash=49B5296CF683E6748DD8D05E012E901C. Also observed in subsequent analysis of separation events on 16 November 2019 and 31 January 2020, soon to be published in incident reports.

- AEMO to engage with industry on how standards compliance could be improved, and how different data sources (from original equipment manufacturers (OEMs), distribution network service providers (DNSPs), Clean Energy Regulator (CER), data vendors, and so on) could be better leveraged to identify non-compliance.
- AEMO to develop a Rule change proposal to strengthen the regulatory framework for the identification and remediation of non-compliance with technical standards.

Improving compliance with DER standards should be viewed as a critical underpinning of future power system operability, in parallel with improving the standards themselves.

8.4 Feed-in management for DER

Another DER capability that is fundamental for power system operability during low load periods is the introduction of feed-in management for distributed PV, and other types of DER. This increases the “smart” capabilities of DER, allowing them to be actively curtailed in rare periods when required for management of power system security. This would allow AEMO to rapidly recover the required levels of demand when necessary, without ongoing operational restrictions on DER output at other times. For example, if South Australia unexpectedly separates from the rest of the NEM, distributed PV could be curtailed to the necessary level to minimise security risks, under that more challenging operational condition. With this capability, customers can then continue to install and fully utilise their distributed PV assets in most periods, and AEMO retains the ability to maintain a secure power system.

Introducing feed-in management for DER can be thought of as retaining AEMO’s ability to actively dispatch and manage enough of the system with a sufficient degree of flexibility to manage system security in the event of unplanned outages and other power system events. As the proportion of power system load met by passive (unmanaged) DER grows, AEMO is progressively losing the ability to actively dispatch and manage the units supplying the system. Long term, if feed-in management is not introduced for DER, power system operation will become extremely challenging, and eventually, impossible.

Feed-in management for DER is not standard practice at present. SAPN currently requires this capability only from distribution-connected generation that exports more than 200 kW. It has proposed a staged program of work to progressively introduce this capability (termed “Flexible Exports”) for smaller DER during 2021 to 2023. AEMO strongly supports this proposal proceeding, and recommends that the rollout of this capability is accelerated as much as possible.

Complementary recommendations for more rapidly establishing basic generation shedding capabilities are outlined in Section 9.1.

Interoperability in AS/NZS 4777.2

AEMO is also pursuing NEM-wide implementation of feed-in management capability for all new DER through the AS/NZS 4777.2 review process, via introduction of requirements for “interoperability”. This will be introduced in a second stage of the AS/NZS 4777.2 review, following completion of the improved ride-through requirements discussed above. This will likely involve adding high-level requirements for interoperability in AS/NZS 4777.2, with reference to other standards such as IEEE 2030.5 for the specific protocol details and requirements. This approach allows an accelerated timeline for introducing the simpler (and critically urgent) ride-through requirements, and a longer timeline for design of the more complex interoperability requirements.

9. Mitigation: distributed PV disconnection

This section summarises additional measures that are recommended to assist with managing the disconnection of distributed PV. These are discussed in several categories:

- **Reduce PV disconnection** – actions that can minimise the growth in PV disconnection behaviour.
- **Improve frequency control** – these measures increase the frequency control capabilities in the South Australian power system, improving the ability to manage increasing contingency sizes.
- **AEMO system management** – actions that AEMO can take under the existing regulatory framework to minimise risks.

Each category is discussed further below.

9.1 Reduce PV disconnection

9.1.1 Fast-tracked test for voltage ride-through in South Australia

Due to the urgency of this issue in South Australia, AEMO proposes that special measures be implemented in South Australia in the interim, while AS/NZS 4777.2 is updated. These special measures would introduce a new test for voltage ride-through as a condition of connection, effective as rapidly as possible (ahead of the full suite of changes in AS/NZS 4777.2).

The following approach is recommended:

- Extensive consultation to engage with industry and consumer representatives about the urgent need for this new capability. This will require consistent messaging from AEMO, the AEMC, the AER, the ESB, and the South Australian Government.
- AEMO works with key stakeholders to define a compliance test that specifically determines whether an inverter meets the existing defined voltage ride-through provisions in AS/NZS 4777.2:2015. This test would likely involve demonstrating that an inverter remains connected and in sustained, continuous operation for a short duration voltage step reduction (for example, 50 V or 20% retained voltage for a duration of 200 ms). AEMO would publish the test procedure on its website.
- AEMO formally communicates with SAPN about the need for this new capability to support system security, and requests that it be included as a requirement of connection to assist AEMO to meet and carry out its power system security responsibilities under the NER.
- SAPN updates its connection requirements to only allow distributed inverters to connect if they meet this new test, in addition to the standard testing procedures for AS/NZS 4777.2:2015. This would become an additional condition of connection in South Australia.
- To continue to install inverters in South Australia, manufacturers will need to have their inverters tested for this new requirement by an AS/NZS 4777.2:2015 accredited testing provider. The certificate demonstrating compliance of each inverter with this new test will be provided to the Clean Energy Council, who will maintain a register of those inverters that meet this additional requirement and are therefore approved for installation in South Australia.
- AEMO will work with SAPN, the Clean Energy Regulator (CER), and other stakeholders to develop a plan for introducing processes to monitor compliance with this new requirement, expanding auditing and

assessment of compliance and utilising new data sources where possible (such as the DER Register), acknowledging the inherent challenges in compliance assessments.

This process maps the existing compliance and testing process as closely as possible, and therefore should be able to be implemented reasonably rapidly by organisations that already have suitable experience in similar roles. It is recommended that this process is implemented as rapidly as possible; preferably in place for all new connections from Q1 2021.

Based on a sample of 17 inverters, developed against the 2015 version of AS/NZS 4777.2, and tested by UNSW Sydney (as a part of a joint ARENA project with AEMO, ElectraNet and TasNetworks), AEMO believes that around one half to two thirds of the existing inverters available in the Australian market already meet the new requirement, and are likely to pass the new test without any changes required to the inverter design. These 17 tested inverters represent 8% of the South Australian installed capacity of inverters. If the remaining inverter models show performance capabilities in similar proportions to those that have been tested, South Australian consumers should continue to have access to a wide range of market options, albeit reduced from the present market.

It is noted that the new test will only verify compliance with a requirement that is already defined in the existing AS/NZS 4777.2:2015 (given the present standard does not include a specific test for this capability). This new process will be a temporary measure that can be removed once the new AS/NZS 4777.2 standard comes into force in all Australian regions, as it is expected to include a comprehensive suite of compliance tests including tests for voltage ride-through.

Requiring a new compliance test for inverters installed in South Australia, ahead of changes to AS/NZS 4777.2:2015 represents a significant intervention in the South Australian distributed PV market, and will have impacts on consumers. However, AEMO's assessment indicates that South Australia is close to the point where a complete moratorium on new distributed PV would be prudent, if measures of this kind are not implemented. Implementation of this new test should be sufficient to allow South Australian consumers to continue to access the benefits of installing distributed PV, while adequately maintaining power system security until the EnergyConnect interconnector is commissioned.

If adequate changes are not implemented quickly, it may become necessary to launch a program of work to retrospectively adjust the ride-through capabilities of previously installed distributed PV systems. This is likely to be very expensive and difficult. In some cases, it may not be possible to retrofit inverters for improved ride-through capability with a firmware update (replacement of physical equipment may be required).

9.1.2 OEM firmware upgrades

Some OEMs may have the ability to remotely update firmware for legacy installations. In some cases, it may be possible to improve voltage disconnection behaviour.

AEMO has liaised with five inverter OEMs to better understand their technical capabilities. Of these, three indicated they presently have the capability to remotely update undervoltage protection settings on some existing systems. This action may reduce the amount of distributed PV that disconnects during a severe fault and therefore reduce the contingency size that AEMO needs to manage.

OEMs expressed concerns about enabling this capability and it requires further investigation to understand feasibility, barriers and risks, costs, and the capacity of legacy systems that could be addressed.

AEMO continues to explore this matter.

9.1.3 Increasing system strength

AEMO investigated the possibility of increasing system strength by dispatching additional synchronous generators, or adding further synchronous condensers in South Australia in the Adelaide metropolitan area, to explore whether this could assist with reducing the disconnection of distributed PV. Analysis indicated this is of limited benefit for the severe faults under investigation. The severity of the fault, and the close proximity of many transmission network elements to the bulk of the distributed PV, limits the potential of this approach.

This is therefore not recommended at this stage as a strategy for reducing the disconnection of distributed PV.

9.2 Improve frequency control

This section outlines a suite of measures that increase the frequency control capabilities in the South Australian power system. AEMO's analysis has shown that increasing frequency control capabilities offers significant benefit for maintaining system security in low load periods, particularly for larger contingencies caused by disconnection of distributed PV.

Primary Frequency Response rule change

The recent Mandatory Primary Frequency Response rule⁶⁶ will require all new and (progressively) existing scheduled and semi-scheduled generators to provide frequency response whenever they are dispatched above 0 MW and frequency is outside a narrow deadband. The maximum deadband (as narrow as 49.985 Hz - 50.015 Hz) and response specifications will be detailed in Primary Frequency Response Requirements (PFRR) to be published by AEMO. The draft PFRR⁶⁷ specifies a droop less than or equal to 5%, with no delay beyond that inherent in the plant controls.

These requirements will apply for three years from June 2020. The AEMC is consulting on a longer-term mechanism to incentivise and reward delivery of the required frequency response beyond that date.

As these requirements are implemented, they should considerably improve frequency control, assisting with many of the identified challenges in this report. It may also lead to more providers registering to deliver contingency FCAS (since they will need to implement the necessary controls to comply with the new rule).

There are, however, some limitations which are opportunities for improvement:

- The rule does not require a response from BESS (or solar/wind farms) that are dispatched at or below 0 MW. It is anticipated that these generating units are likely to be dispatched at 0 MW at times of low load, and BESS, in particular, have been identified as extremely capable and important providers of frequency control at these times.
- The arrangements beyond June 2023 will be critical for the long-term security of the South Australian power system, and are yet to be determined. Introducing arrangements to reward higher performers would be suitable, while maintaining a minimum requirement that all capable market participants will provide a helpful frequency response to assist with managing rare extreme disturbances.

Implementation of the new arrangements will take some time and will be completed in tranches. Larger units will be transitioned first in late Q3 2020 while smaller units are expected to be transitioned in 2021. COVID-19 may result in delays from the original proposed timetable, given the need to involve generator control rooms, which are currently heavily quarantined.

Some specific opportunities to further improve frequency control arrangements are outlined in the sections below.

9.2.1 Fast Frequency Response from BESS and solar farms

Advantages of battery storage providing frequency control

AEMO's analysis indicates that BESS are becoming an increasingly important provider of frequency control in South Australia. BESS have the following valuable characteristics:

- BESS can ramp very rapidly and can be programmed to provide the desired response profile, and therefore can provide large quantities of FFR.

⁶⁶ AEMC (26 March 2020), "Mandatory primary frequency response", at https://www.aemc.gov.au/sites/default/files/2020-03/ERC0274%20-%20Mandatory%20PFR%20-%20Final%20Determination_PUBLISHED%2026MAR2020.pdf.

⁶⁷ At <https://wa.aemo.com.au/consultations/current-and-closed-consultations/primary-frequency-response-requirements-document-consultation>.

- BESS can start quickly, and therefore can supply frequency control to the South Australian island within 30 minutes of a separation event.
- BESS can provide frequency control services when dispatched at zero MW, and therefore do not require any level of minimum load for provision of frequency control services.

The analysis completed for this report has demonstrated that these BESS frequency response capabilities can be critical to meet the FOS in South Australia when islanded.

Fast Frequency Response

With the low levels of inertia in a South Australian island, six second contingency FCAS (currently defined in the NER as 'fast') are too slow to adequately manage a large contingency. BESS can deliver frequency response much more rapidly. This analysis shows this is extremely important for managing frequency in the South Australian island, particularly with the larger contingency sizes related to disconnection of distributed PV.

The following opportunities for improvement are identified:

- Given the significance of FFR from BESS during a separation event or in island operation, it is important for system security in South Australia to ensure that primary frequency response is provided by these resources at all times, including when dispatched at or below 0 MW. The new primary frequency response rule does not cover those circumstances, although at present all BESS do in fact provide a response in this range.
- Solar farms are also highly capable providers of FFR, as demonstrated by their responses in recent separation events. The new rule does not require a frequency response from solar farms when curtailed to 0 MW. This could be quite likely at times of low demand. Under these conditions, utility-scale solar farms could be important providers of a fast raise response, but there is no requirement for this response to be delivered.
- In addition to implementation of the new rule, considerable work is underway to improve frequency control frameworks and better align the various specifications of FFR across a number of different instruments:
 - In January 2019, AEMO released specifications for BESS registering to provide contingency FCAS⁶⁸, including details of the recommended droop response, etc.
 - AEMO is exploring the potential for incentivising FFR service under the inertia framework in the NER, as an inertia support activity. This may create a framework for ElectraNet to contract with BESS to deliver FFR, as part of meeting the inertia requirement.
 - The Generator development approval procedure published by the Office of the Technical Regulator⁶⁹ in South Australia requires the provision of inertia or FFR, but the specification of FFR defined by this requirement is not necessarily optimal and may be confusing.

Given the growing importance of FFR for system security, it is timely to consolidate and optimise these arrangements, maximising incentives for BESS, solar farms, and other capable providers to deliver this service in the optimal manner to support system security. AEMO is investing considerable resources towards this goal at present.

In summary, the following actions are recommended:

- AEMO's extensive work program to improve frequency control arrangements proceeds as a priority.
- Options for requiring or incentivising a fast frequency response from BESS and solar farms dispatched at or below 0 MW are pursued.

⁶⁸ AEMO (January 2019) Battery Energy Storage System Requirements for Contingency FCAS Registration, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

⁶⁹ Office of the Technical Regulator (1 July 2017) "Generator Development Approval Procedure", at https://www.sa.gov.au/_data/assets/pdf_file/0003/311448/Generator-development-approval-procedure-V1.1.pdf.

- The South Australian Government support measures to improve frequency control in South Australia, including timely implementation of the mandatory primary frequency response rule, and the design of suitable long-term arrangements to apply beyond June 2023.

9.2.2 Management of BESS limitations when delivering frequency control

Limitations of battery storage providing frequency control

BESS also has some important limitations when delivering frequency control services, compared with synchronous generating units:

- The ability of BESS to deliver a frequency response depends on their state of charge; this needs to be managed carefully to ensure they have adequate ability to charge or discharge for the required duration.
- BESS can only deliver a charge or discharge for a limited period of time. Once the battery is full (or empty) it can no longer sustain a load or generation response.

These limitations mean that caution is required when battery storage is relied on for provision of five minute contingency lower service when South Australia is operating as an island at times of low demand.

In addition to utility-scale BESS, this analysis also takes into account the 5 MW of distributed storage coordinated via virtual power plants (VPPs) in South Australia at present, and growing as per Table 2. This VPP capacity is registered to provide FCAS, and is assumed to do so in this analysis. Due to the challenges of rapid frequency response from distributed sources, the VPP is assumed to respond similarly to a synchronous generating unit, and therefore does not provide FFR.

Managing state of charge of BESS for frequency control delivery

The importance of managing BESS state of charge can be highlighted by an example from the South Australia islanding event on 16 November 2019⁷⁰. The Dalrymple battery is registered to provide up to 30 MW of contingency lower FCAS, but its state of charge at the time of the event only allowed the provision of 3 MW of 6 second and 60 second lower services, and 2 MW of five minute lower services.⁷¹ Reserving adequate state of charge to reliably provide and sustain both raise and lower contingency services would be beneficial, especially at times when low load conditions are anticipated.

Figure 13 below shows the difference between the minimum demand threshold for the various generating unit combinations under islanded conditions, assuming that the utility-scale BESS in South Australia⁷² are in a suitable state of charge to deliver their full frequency control capabilities, versus a scenario where the BESS are close to fully charged and unable to offer any material contingency lower FCAS. The minimum demand threshold for secure islanded operation is ~150 MW higher in the case without lower contingency services from the BESS. This demonstrates the importance of managing state of charge carefully under these conditions, where this contribution is important for system security.

Managing state of charge is the responsibility of market participants, who are balancing many priorities to meet commercial requirements. Apart from a proportion of the Hornsdale battery, there is no requirement for batteries to retain a suitable state of charge to offer frequency control under normal conditions⁷³.

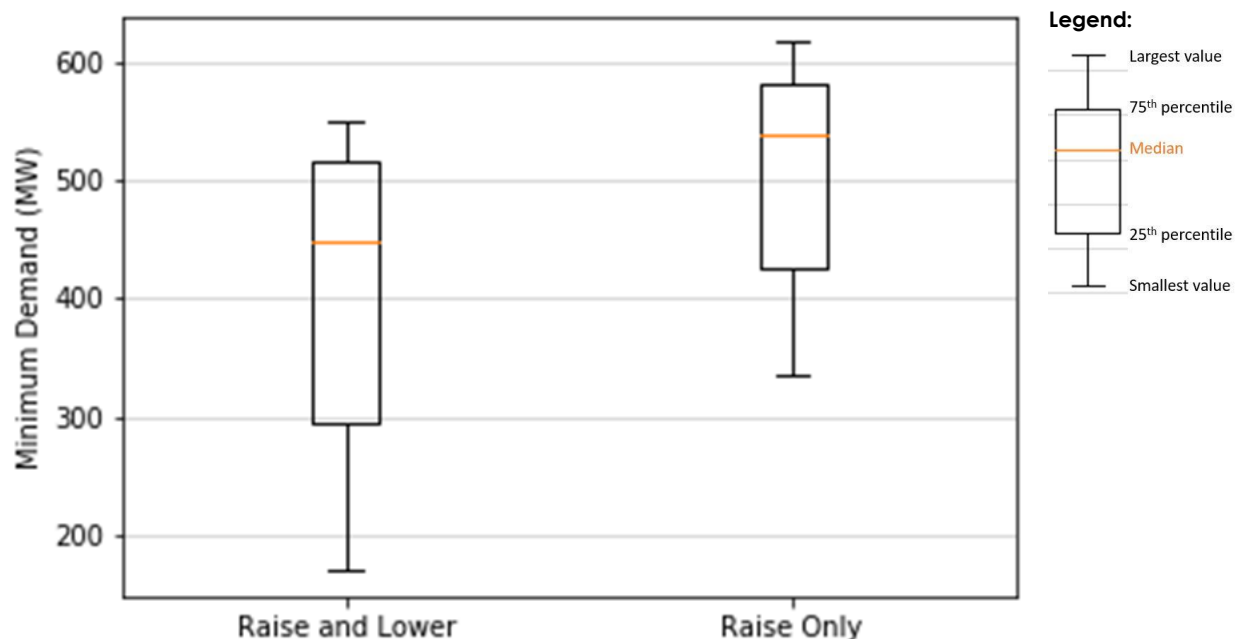
⁷⁰ AEMO (December 2019) Preliminary Report – Non-credible separation event South Australia – Victoria on 16 November 2019, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Preliminary-Incident-Report--16-November-2019---SA---VIC-separation.pdf.

⁷¹ Charging of the Dalrymple BESS is limited after a certain number of cycles in a contract year (refer to “BESS charging rates” in 5.4.16 of <https://www.escri-sa.com.au/globalassets/reports/escri---sa---project-summary-report---the-journey-to-financial-close---may-2018.pdf>), but the limit was not applicable at the time of this event.

⁷² Hornsdale (100 MW), Dalrymple (30 MW), Lake Bonney (25 MW), Lincoln Gap (10 MW) and the Hornsdale expansion (50 MW), assumed to be installed by late 2022.

⁷³ The Dalrymple BESS is subject to minimum SOC limits to ensure it can partially supply load in the Lower Yorke Peninsula in the event of a loss of supply to the area. However, these SOC limits are for a local reliability issue and do not adequately limit the SOC of the BESS to ensure it can deliver its full contingency FCAS capability.

Figure 13 Increase in minimum operational demand if utility-scale batteries cannot offer contingency lower services



Recent operational experience

Recognising the importance of batteries in the delivery of frequency control, AEMO issued directions to the three utility-scale batteries to maintain their state-of-charge (SOC) within a specified range during the most recent islanding event. AEMO issued these directions on two occasions during low demand conditions. The first direction was issued on 2 February 2020 and required batteries to maintain their SOC within 45% - 55%⁷⁴. A second set of directions was issued during low demand conditions on Sunday 4 February. This was the first time that such directions have been issued in the NEM.

Available data⁷⁵ indicates that BESS operators attempted to implement this novel direction within their control systems but did not immediately succeed.

From 5.00 pm AEST on 5 February 2020 until the reconnection of South Australia to the NEM, AEMO managed the SOC of batteries via constraints rather than directions. The required SOC range was subsequently expanded from 45-55% to 30-70% following further operational experience in managing the South Australia island.

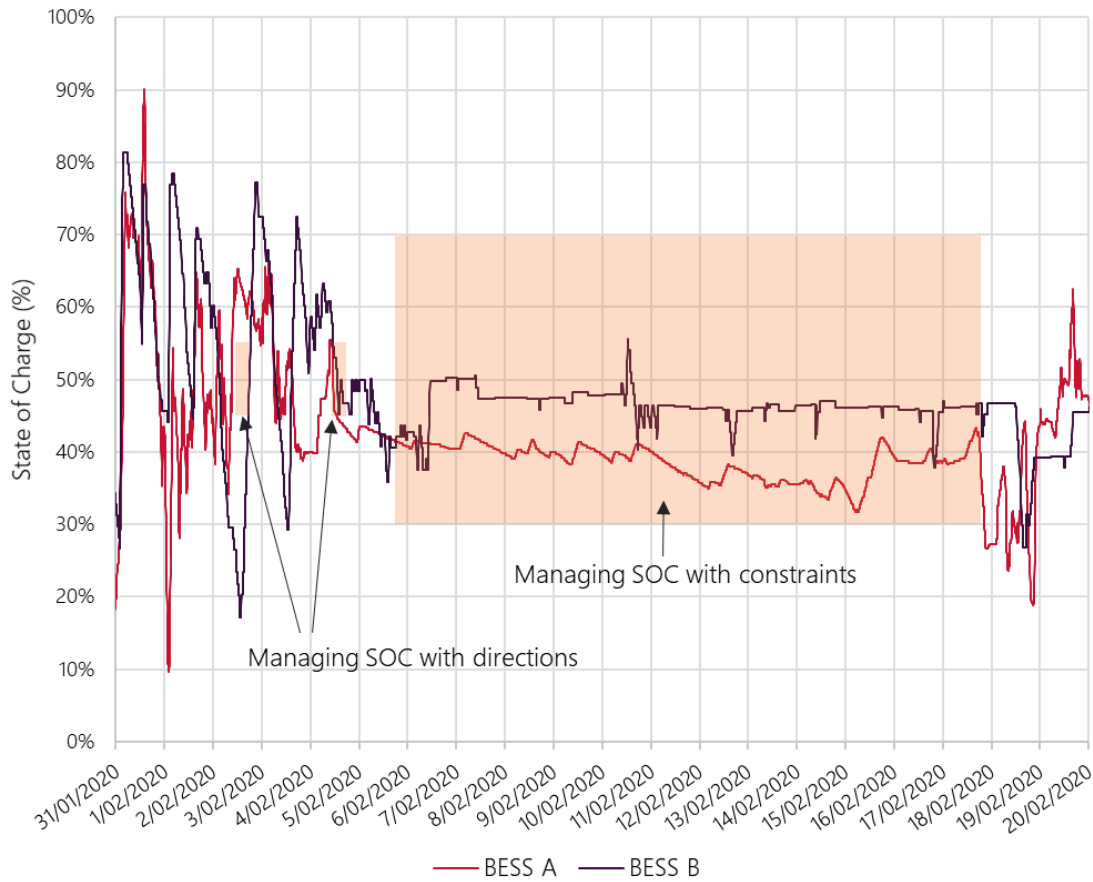
While these constraints were invoked, the performance of the battery operators in maintaining SOC in the required range improved significantly, as illustrated in Figure 14 below.

The extended island operation of South Australia in February 2020 has shown that the utility-scale batteries have the technical capability to maintain SOC within a required range, and provided a valuable learning experience for AEMO and the BESS operators.

⁷⁴ Directions to maintain SOC issued on 2 February 2020 applied to Hornsdale Power Reserve between 1100–1610 hrs, Dalrymple between 1220–1615 hrs, and Lake Bonney BESS between 1245–1620 hrs AEST.

⁷⁵ Due to data quality issues, the information presented in this report only incorporates the SOC for two of the three BESS in South Australia.

Figure 14 State of charge of utility-scale batteries during South Australia islanding event (20 days)



Required state-of-charge range

The minimum and maximum SOC required for a BESS to deliver its maximum frequency response depends on the ratio of its storage capacity to its response. A BESS with high storage capacity (MWh) relative to its maximum frequency response (MW) will have a wider SOC range in which it can provide its full response and hold that response for the required duration. A summary of existing and proposed BESS and their capacity to power ratios is provided in Table 7 below.

Table 7 Utility-scale BESS in South Australia

		Maximum power (MW)	Capacity (MWh)	Capacity/power ratio
Existing	Lake Bonney	25	49.6	1.98
	Hornsedale Power Reserve	100	129	1.29
	Dalrymple North	30	12 ⁷⁶	0.40
Proposed	Lincoln Gap	10	10	1.00
	Hornsedale Power Reserve Expansion	50	64.5	1.29

The minimum and maximum SOC for the various existing and proposed batteries to deliver each frequency control service, considering its droop characteristic, is shown in Figure 15 below.

⁷⁶ The capacity of Dalrymple North will be approximately 8 MWh at the end of its 12-year design life, but its capacity in 2020 is approximately 12 MWh.

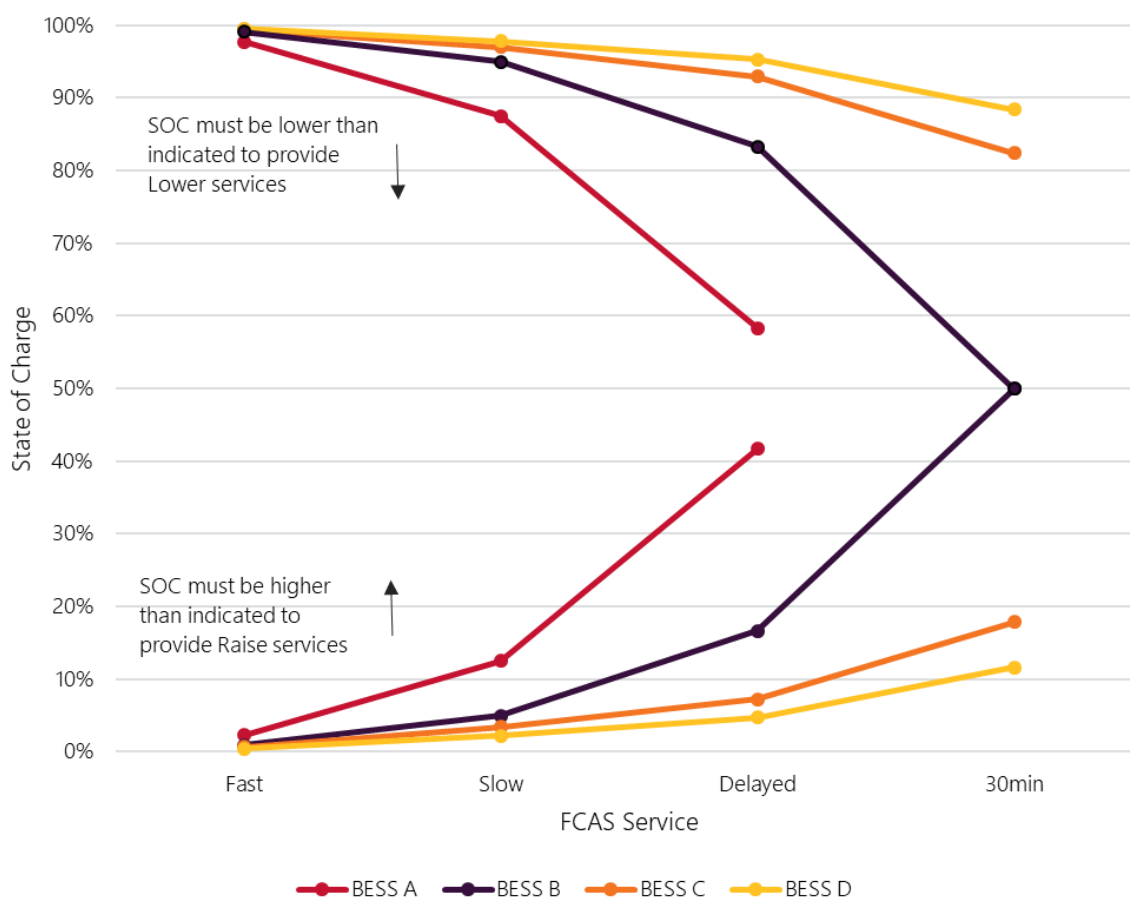
The calculated SOC requirements assume the worst-case frequency deviation and recovery period for a credible contingency in an island system (frequency is contained to 49 Hz - 51 Hz and recovers to 49.5 Hz - 50.5 Hz at 5 minutes). The analysis does not include any buffer which battery operators may maintain to avoid degradation of their unit. Based on this analysis:

- BESS A can only deliver frequency response for a maximum of 10 minutes, and only if maintained within a SOC of 40-60%.
- BESS B can deliver frequency response for up to 30 minutes if it is at exactly 50% SOC
- BESS C & D can deliver frequency response for up to 30 minutes if they are within a SOC of 20-80%.

As discussed further below, although market participants are only incentivised to deliver delayed (5 minute) contingency FCAS for up to 10 minutes, under islanded conditions it could be important to maintain this response for up to 30 minutes, to allow for the more difficult challenge of dispatch adjustment in the small South Australian island.

This analysis suggests that there is potential for more nuanced management of SOC for BESS, based on individual BESS characteristics. It may be prudent for some BESS with very small storage reservoirs to be excluded from providing five-minute contingency service under islanded conditions.

Figure 15 Required state-of-charge of utility-scale batteries to provide frequency response



Incentive frameworks also need review. The present approach of using constraints to manage SOC has undesirable financial impacts on BESS market participants. Ideally, market participants providing a valuable service would instead be rewarded and incentivised. Although this may have limited impact when it only applies under islanded conditions, it may also be prudent to more actively manage SOC in periods with a credible risk of separation, particularly under low load conditions with few FCAS-capable units online.

Non-credible separation events are by nature unexpected and can occur at any time. Under the present framework, in system normal conditions there is no mechanism to require or incentivise BESS to maintain SOC at a level that allows delivery of their full frequency control capabilities. This could mean that there are insufficient frequency control providers when a non-credible separation occurs, and South Australia may not be secure for an extended period. AEMO does not have the ability to intervene in system dispatch to prepare for a non-credible separation event (although the declaration of a protected event may provide a framework for this kind of action). It is also unclear whether and to what extent this kind of intervention can be justified, balancing the potential impacts on BESS market participants with the degree to which this action would minimise risks to consumers.

Preliminary options for further consideration could include:

- Contracting with BESS market participants to ensure adequate SOC is reserved when periods below the defined demand thresholds are forecast. The NER does not provide AEMO with powers to do this, but it may be an option available to the South Australian government. AEMO may have some powers to direct units to maintain suitable SOC levels when the risk of separation is credible.
- Suitable arrangements could possibly be introduced as an OTR or ESCOSA licensing condition for new plant installed in South Australia. This would require that if units are operating, they are in a suitable operational state to deliver their full frequency control capability if demand is forecast below a certain threshold defined by AEMO.

AEMO's analysis undertaken for this report has assumed that BESS are always fully available and at an appropriate SOC to offer their full registered quantity of frequency control in low load periods.

AEMO appreciates that introducing SOC requirements to BESS creates an investment risk, especially if it is applied retrospectively, and would prefer that suitable commercial arrangements are introduced to reward and incentivise BESS for their superior capabilities.

Allowance of an additional demand recovery reserve

The Market Ancillary Service Specification (MASS)⁷⁷ requires providers of delayed (five minute) contingency FCAS to "sustain their response until central dispatch can take the changed generation requirement into account". The amount they can bid into the FCAS market is explicitly calculated using a window that extends up to ten minutes. If a BESS is enabled for five-minute lower FCAS, when a disturbance occurs the BESS will detect the change in frequency, and commence charging. BESS have a limited ability to sustain this response; once the BESS is full, it cannot continue charging. This means that there is a limited timeframe for central dispatch to take the changed generation requirement into account, and this timeframe will depend on the state of charge of the battery at the time of the disturbance.

In typical periods, this is not usually a concern, because there will be many units across the interconnected NEM with the ability to move upwards or downwards as necessary to correct the imbalance within a reasonable timeframe. However, in a South Australian island at times of minimum demand there may only be two or three units operating, and they may already be dispatched close to minimum loading levels. This means that the following hypothetical sequence of events could occur:

1. South Australia is operating as a secure island in a minimum demand period. As an example, this could mean it is dispatched as follows:
 - a) The minimum synchronous generating units are dispatched at minimum loading levels to provide system strength, grid formation, primary frequency response and inertia.
 - b) Olympic Dam load is curtailed to around 150 MW and Murraylink exports are limited to around 150 MW to allow contingency lower requirements to be met.
 - c) BESS units are providing all the required frequency control, dispatched at zero megawatts.

⁷⁷ AEMO (30 June 2017), at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Market-Ancillary-Service-Specification-V50--effective-30-July-2017.pdf.

- d) All scheduled, semi-scheduled and non-scheduled units not required for security services are dispatched at zero megawatts (or curtailed to zero), because of the low level of demand.
2. The largest load trips. The BESS units provide a contingency lower response and commence charging, delivering this response in the required six second, sixty second, and five-minute timeframes. This arrests and stabilises power system frequency.
3. In the next five-minute dispatch interval, NEMDE attempts to correct the 150 MW imbalance through dispatch changes, to relieve the BESS units from their charging response. However, in this dispatch scenario, due to the very low load level and limited units operating in the South Australian island, there is limited further ability to increase load or decrease generation (without losing required security services). The batteries continue to charge to address the lost load.
4. The batteries reach a full state of charge and can no longer continue charging. They move back to zero MW dispatch. NEMDE will seek emergency options, but if no safe options can be found, power system frequency will rise again due to the uncorrected imbalance. Frequency may move outside of the normal operating frequency band, and possibly outside of the normal operating frequency excursion band⁷⁸. The power system is no longer in a satisfactory state. EFCS may be triggered.
5. It may not be possible to return the power system to a satisfactory state (or a secure state) until one of the following occurs:
 - a) Demand increases (possibly hours later when solar insolation levels reduce).
 - b) The largest load is reconnected.
 - c) The Heywood interconnector is restored.

To prevent this eventuality, AEMO has completed this analysis requiring an additional buffer of recoverable demand reserve. This would be activated to recover further load if a load contingency occurs, allowing dispatch the ability to correct the imbalance caused by a credible load loss within 30 minutes, even if battery storage is providing all frequency control. A further allowance has been made to allow sufficient demand for batteries to gradually discharge following a load contingency event, so they can return to providing the necessary contingency lower service (and the power system has the ability to return to a secure state).

If AEMO has the ability to recover demand to the levels indicated in this analysis within 30 minutes, it should be possible to correct the imbalance within the required timeframe. Based on the assumptions applied, battery storage units offering a five minute contingency lower service will need to reserve adequate state of charge to continuously charge at the necessary level for up to 30 minutes.

In summary:

- BESS have some important limitations that need to be carefully managed, given that they are increasingly relied on for frequency control and system security in South Australia.
- Improved arrangements (both technical and regulatory) should be explored for rewarding appropriate management of the state of charge of BESS.

9.2.3 Commission more BESS for frequency control

A further option for improving frequency control capabilities in South Australia would be to commission further fast frequency response capabilities.

Figure 16 shows the reduction in minimum demand requirements with the addition of:

⁷⁸ It is possible that an over-frequency droop response from the proportion of distributed PV installed after October 2016 will assist with limiting frequency rise, but this response is untested, and should not be relied on for management of credible contingencies. Previous analysis has indicated that compliance to deliver this response may be low. AEMO (10 January 2019) "Final Report – Queensland and South Australia system separation on 25 August 2018", at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/QLD---SA-Separation-25-August-2018-Incident-Report.pdf.

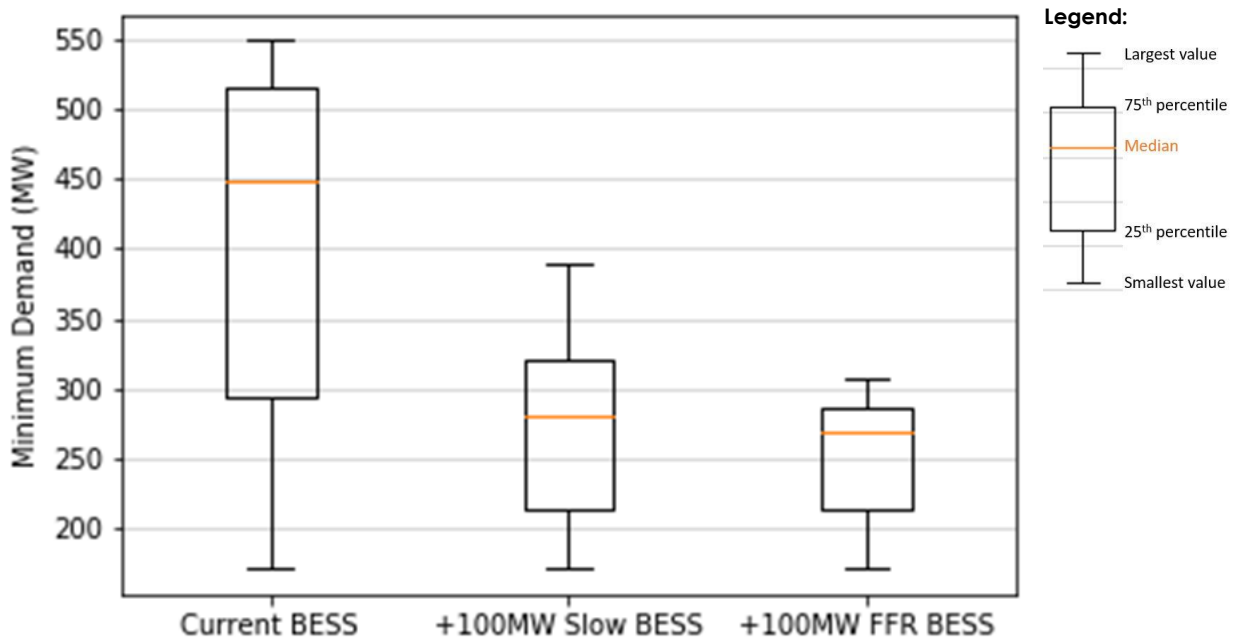
- **+100 MW Slow BESS** – an additional 100 MW BESS, programmed to respond similarly to a synchronous governor. This could represent virtual power plants⁷⁹ (VPPs) providing frequency control services with a response designed according to the FCAS Market Ancillary Services Specifications (MASS), or introducing a frequency response from the Murraylink interconnector if it cannot respond as quickly as a utility-scale BESS. The Dalrymple BESS also responds in this way (although AEMO recommends that future BESS installations apply faster response settings).
- **+100 MW FFR BESS** – an additional 100 MW BESS delivering a full fast frequency response and contingency services on all response timeframes. The Hornsdale Power Reserve responds in this way (for example). AEMO’s specifications for BESS providing frequency control now outline these capabilities⁸⁰.

These results suggest that a new “slow” BESS could deliver a ~200 MW reduction in the minimum demand requirements for the largest unit combinations, by replacing many synchronous generating units which were required to deliver frequency control. BESS can deliver frequency control when dispatched at 0 MW, considerably reducing minimum load requirements (although, as noted above, under the new rule change BESS are not required to deliver frequency response when dispatched at or below 0 MW).

A new 100 MW FFR BESS (behaving similar to Hornsdale Power Reserve) reduces minimum demand requirements even further (by a total of ~300 MW compared with the “current BESS” case). The additional supply of FFR and contingency services on all timeframes allows system security to be maintained with a much smaller set of generating units online, with the BESS dispatched at 0 MW. Other sources of fast frequency response may achieve similar effects, such as from utility-scale solar farms (if appropriate headroom/lower room is reserved).

This assumes BESS maintain SOC sufficient to deliver frequency control.

Figure 16 Change in minimum operational demand by commissioning a new 100 MW BESS



Other opportunities for introducing further sources of frequency response include:

⁷⁹ This modelling assumes entry of VPPs to a total installed capacity of 2 MW in 2019, 5 MW in 2020, 10 MW in 2021, 15 MW in 2022, and 20 MW in 2023.

⁸⁰ AEMO (14 January 2019) Battery Energy Storage System Requirements for contingency FCAS registration, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Ancillary_Services/Battery-Energy-Storage-System-requirements-for-contingency-FCAS-registration.pdf.

- **Murraylink** – at present, the Murraylink interconnector does not provide frequency control services in South Australia. However, other DC links include this capability (most notably, the Basslink interconnector). Adding frequency response to Murraylink could be equivalent to installing a new BESS of equivalent size, if the appropriate behaviour can be supported by the Murraylink converters. It is noted that under the present operating procedures, this frequency control capability is only required when South Australia is operating as an island.
- **Demand side providers** – certain loads have some dispatch flexibility, and may be able to provide some quantity of contingency lower services, particularly on slower timeframes. Demand side aggregators could also be encouraged. Delivery of a five-minute contingency service can assist, particularly as a complement to faster resources such as BESS, which may not have the storage capacity for the longer duration response.

These market participants may be able to upgrade their control facilities and provide a helpful frequency response, subject to technical feasibility, any unforeseen barriers or costs, and their willingness and interest.

A part of the \$50 million Grid Scale Storage Fund (GSSF), has been allocated to secure services from the Hornsdale Power Reserve 50 MW expansion, which has been considered in this analysis and found to significantly assist with frequency control in South Australia. Additional private investment in expanding BESS capacity further would also assist.

Increasing the capacity of BESS providing FFR in South Australia needs to be carefully managed. Factors such as local voltage issues, coordination with emergency frequency control schemes, and coordination with NEM-wide frequency control and interconnector limits need to be properly considered in the design and implementation.

Investment in dedicated utility-scale BESS for FFR is considered beneficial but not essential at this stage. However, if some of the other actions recommended in this report are delayed (for example, if the EnergyConnect interconnector does not go ahead), it may become necessary to consider funding the implementation of some of the options above. It is important to monitor potential market investments in BESS in this regard.

9.3 AEMO's system management

9.3.1 Interconnector constraints to manage disconnection of distributed PV

New interconnector constraints should be introduced to reduce the risk of South Australia separating from the NEM due to disconnection of distributed PV. These constraints would act to limit imports into South Australia, and require increasing levels of exports, as a function of the amount of distributed PV operating in South Australia. Constraints will be required to limit imports on the Heywood interconnector in periods with a credible risk of separation, and also in system normal periods.

These constraints would only actively influence dispatch in periods with high levels of distributed PV operating. The market impacts of these constraints are anticipated to be very low; in typical periods with high distributed PV generation, the Heywood interconnector is likely to be exporting, meaning these constraints should bind very rarely.

These constraints are an essential measure to operate the power system in a manner that does not risk load shedding and possible separation from the rest of the NEM due to a credible fault.

AEMO has recently introduced a preliminary version of this constraint in system normal periods. ElectraNet is undertaking further modelling and analysis to refine their limit advice, which will be used to progressively update the constraint definition.

Regulatory frameworks

AEMO's modelling explored the following power system disturbance:

1. A two-phase-to-ground fault occurs on the high voltage side of a generating unit transformer.

2. The resulting voltage dip causes distributed PV and load in the surrounding area to disconnect, near instantaneously.
3. Protection acts to isolate the fault, tripping the generating unit.

This sequence of events is all directly attributable to the initial fault, which suggests they should all be considered part of the same event. AEMO therefore believes this should be considered a credible event under the NER (NER 4.2.3).

AEMO's power system responsibilities include maintaining power system security (NER 4.3.1), which includes, *to the extent practicable*, operating the power system such that it is and will remain in a secure operating state (NER 4.2.6). The power system is defined as secure if it is in a satisfactory state, and will return to a satisfactory state following the occurrence of *any credible contingency event* or protected event (NER 4.2.4). A satisfactory operating state refers to frequency levels (as defined in the FOS), voltage levels, current flows on transmission lines, fault levels, and system stability being within required limits. AEMO must use *reasonable endeavours* to ensure that the FOS are achieved (NER 4.4.1).

The disturbance discussed above could be classified in one of two ways under the FOS. If the disconnection of distributed PV does not result in separation of South Australia from the rest of the NEM then it would be considered a generation event. This could occur if the distributed PV disconnection contingency size is relatively small, the pre-disturbance level of Heywood flows isn't in the realm that would lead to separation, or the SIPS functions correctly to prevent separation. In this case, the NER requires AEMO to use reasonable endeavours to maintain frequency in all regions within 49.5 to 50.5 Hz.

However, the analysis presented in this report shows that under some circumstances, the disconnection of distributed PV could result in separation of South Australia from the rest of the NEM. In this case, this disturbance would be classified as a separation event, and AEMO would be required to use reasonable endeavours to maintain frequency within 47 – 52 Hz in South Australia⁸¹, and within 49 - 51 Hz in the remaining mainland regions.

With high levels of distributed PV operating, AEMO cannot be confident that the SIPS will be adequate to prevent a separation event, or that the UFLS scheme will be adequate to maintain frequency within 47-52 Hz if a separation event occurs. The amount of load on the SIPS and UFLS is known to be diminished at these times, resulting in a reduced capability for both schemes.

Further, AEMO does not believe it is consistent with prudent operation of a power system to rely on EFCS, designed as "last resort" mechanisms involving customer disconnections, to manage credible contingency events.

Therefore, AEMO considers that its power system security responsibilities require it to establish operational conditions such that the South Australian power system is secure for the potential size of this credible contingency event, as far as practicable. This could be achieved through constraints to limit Heywood flows, both in system normal periods, and in periods with only one Heywood circuit available.

As noted above, AEMO has implemented a preliminary version of this constraint. ElectraNet is conducting further modelling and analysis to refine their limit advice, and AEMO will refine the constraint formulation on that basis. AEMO is working with ElectraNet at present to share the latest models of DER and load behaviour, for incorporation into ElectraNet's studies to develop this advice.

Constraints should be defined at a level where AEMO has high confidence that separation will be avoided, and reliance on emergency frequency control schemes (SIPS and UFLS), which likely have compromised capabilities at these times, is minimised.

9.3.2 Network outage assessments

Certain infrastructure elements are becoming increasingly essential for secure power system operation in low load periods, as secure operation during separation events (and periods with a credible risk of separation) is

⁸¹ The South Australian Jurisdictional system coordinator has advised that the applicable containment frequency band for any event that resulted in the substantial separation of the South Australian power system is 47 Hz to 52 Hz. (Reference: SO_OG_SA_12).

more challenging when operational demand is very low. This includes network elements that lead to a credible risk of separation on the Heywood interconnector, the synchronous condensers, the BESS and the Murraylink interconnector.

AEMO currently works with transmission network service providers (TNSPs) to mitigate the risk to power system security and reliability when scheduling outages during high demand summer periods. This analysis highlights an increasing need to similarly assess network outages for certain elements for security risks during low demand periods. AEMO will explore incorporating this into outage assessment processes.

Assessments also increasingly need to take into account the impacts of reducing demand on local areas, such as Port Lincoln, during network outages. Sub-regions that are supplied by limited network infrastructure may also find challenges emerging as demand reduces. This has not been explored as part of this analysis, but should be considered by NSPs.

If there is a need to avoid scheduling outages in very low demand periods due to associated challenges, there will be fewer opportunities for planned outages for maintenance and commissioning.

EnergyConnect will alleviate many of the challenges related to scheduling of network outages.

10. Mitigation: demand recovery reserves

This section outlines recommended actions for putting in place “demand recovery reserves”. These are reserves that can be activated when necessary (such as when network outages or islanding events occur) to shed distributed generation, or otherwise recover the necessary levels of operational demand for secure operation. It is assumed that all of these options will need to be available within 30 minutes of an islanding or unplanned network outage event.

Recommended actions are categorised as follows:

- **Distributed generation shedding capability** – actions to accelerate the timeline and available capacity of distribution connected PV that can be shed when necessary as a last resort for system security.
- **Increasing load** – measures to increase load in low load periods.
- **Reducing frequency control requirements** – measures that could decrease the system requirements for frequency control, and thereby decrease the need for triggering demand recovery reserves.
- **Real-time procedures for low load periods** – continually refining operating procedures that streamline the management of low load periods, incorporating new approaches as they become available, and are agreed between relevant stakeholders.

Each is discussed further in the following sections.

10.1 Distributed generation shedding capability

This section outlines recommended actions to establish generation shedding capabilities, ahead of SAPN’s proposed work program to implement “Flexible Exports”.

10.1.1 PV shedding capability

There is a clear need to establish PV shedding capability for all new distributed PV installed in South Australia, as rapidly as possible. One possible approach that utilises existing infrastructure and is likely to be relatively low cost would be to utilise the capabilities of the smart meter.

Since December 2017, all new distributed PV installations in South Australia have been installed with a smart meter as mandated by the Power of Choice reform. These meters have the capability to provide remote meter readings, and can also accept signals to remotely de-energise and re-energise contactors (switches) within the meter. At present, meters are typically wired in the lowest cost manner, which involves aggregating all distributed PV at the site together with the customer’s general load. This means that the Metering Coordinator has an existing ability to individually disconnect and reconnect whole customer sites, but cannot de-energise and re-energise the distributed PV system separately from the customer’s load.

Smart meters can have more than one metering element and contactor and are therefore able to measure and operate several separate circuits independently of each other. A change from single element metering to two or three element metering with the associated meter wiring will allow Metering Coordinators to separately operate these circuits at a customer level. Customers’ sites would then be configured to have flexible loads, general loads and distributed generation separated, allowing Metering Coordinators to separately de-energise the customers’ distributed PV systems while allowing the customers’ loads to remain operating unaffected.

Currently, a large portion of the metering being installed in South Australia has two element metering which means that by simply wiring smart meters differently (placing distributed PV on one of these separate elements), it could be possible to provide the essential generation shedding back-stop that AEMO requires for system security, for any new distributed PV installed in South Australia.

This approach has the following advantages:

- In most cases, customers do not need to install any additional devices. The full capability required is included in the smart meter. This means that customer experiences are unaffected, minimising potential complications in customer engagement.
- The communications systems and software systems for aggregate dispatch are already existing. This approach utilises existing capabilities available to Metering Coordinators.
- Only a small number of stakeholders would need to change practices for this to be implemented. There are three main Metering Coordinators that provide non-DNSP metering services for the majority of residential customers in South Australia (and nine in total). This should assist with high levels of compliance with new specifications.
- This approach could capture all new PV systems installed in South Australia, from as soon as the new meter installation requirements could be specified and implemented.
- Using the smart meter does not rely on customer internet systems being available and has cyber security within the minimum specification of metering from the Power of Choice reform. This provides a more robust backup to the flexible exports systems being implemented by SAPN, which is appropriate for a back-stop that AEMO is relying on for essential security services.

If controlled loads are also placed on their own meter element and contactor, it may be possible to use this mechanism to decrease (or increase) controlled loads at customer sites when this assists with system security. A range of matters must be considered in implementation.

Implementation steps

AEMO proposes that this is pursued as a priority, as rapidly as possible.

Distribution voltage issues will need to be carefully monitored during the trial process. Based on trials, SAPN may also be able to anticipate the required tap changes and implement those ahead of the shedding process. The implementation of the enhanced voltage management technology proposed in Section 10.1.5 should also assist.

In the immediate future, it would also be beneficial to explore the option of selectively shedding customers. AEMO recommends that this is explored as part of the implementation process, and operational protocols established for this capability to be accessed if necessary.

Enabling generation shedding via smart meters may also unlock other potential security benefits for DER integration. For example:

- **Under frequency load shedding** – it may be possible for smart meters to directly detect a severe drop in frequency below 49 Hz, and respond by selectively shedding a customer's load while leaving the distributed PV operating. If this response is sufficiently reliable and fast (e.g. with sub-second activation) it could provide a long-term solution to replace under frequency load shedding (UFLS) capability. At present, UFLS relays shed customers at the aggregated whole substation level; this approach would allow separate shedding of loads and generation.
- **System restart** – it may be possible for smart meters to selectively prevent re-energisation of distributed PV during a system restart condition. If successful, this could be an essential capability that facilitates an uninterrupted restart process by providing sufficient stable load for restart of the large synchronous units required, under high PV generation conditions.
- **Data** – separating the customer load from distributed PV would allow collection of a rich dataset that could support many operational functions. For example, operational forecasting could be improved, and it

may be possible to monitor distributed PV system compliance with standards based on their behaviour during power system disturbances.

These capabilities require further investigation, which should be explored as part of the implementation process.

NEM-wide implementation

New meter installation requirements that allow separate management of distributed PV should also be explored for implementation NEM wide, possibly through the upcoming Power of Choice review. This capability may provide an important back stop for system operation that will become necessary in all NEM regions.

10.1.2 Streamline management of SCADA controllable distribution connected generation

SAPN advises it has 60 MW of distributed PV capacity with flexible export limit capability (although this may not be operating at maximum capacity at the time of any given event). This is at 24 sites in SAPN's network, connected via SAPN's SCADA system. SAPN also advises that it has a real-time feed showing the total amount of generation that they can control on their network at any time. This distributed generation can be curtailed in the event of South Australia separating from the rest of the NEM, if minimum load is below the threshold for secure operation as an island.

During the operation of South Australia as an extended island in February 2020, AEMO directed the curtailment of this distributed generation on three occasions for between two and four hours. SAPN successfully completed curtailment within 30 minutes of each direction being issued⁸², with generation ramping down over a 10-minute period.

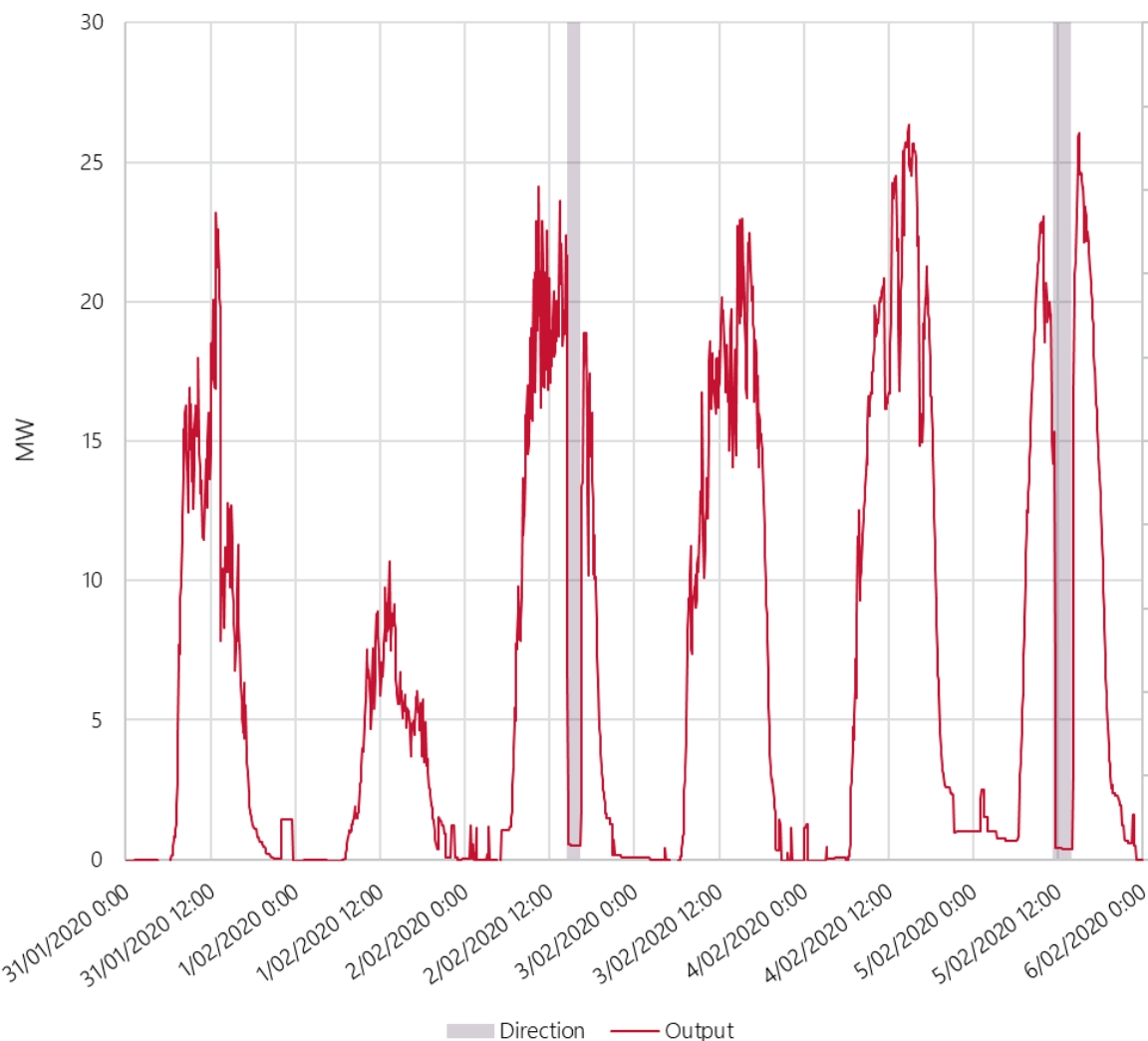
As an example, the response of a subset of the sites (19 of 24 sites) under SAPN's control to two of AEMO's directions is shown below in Figure 17.

SAPN has advised that control of each generator is currently managed independently, and they would need to implement a new control interface within ADMS for generation shedding to occur reliably within expected response times. This interface will assist the control room to execute controls, and manage the generating systems. SAPN has managed to deliver the required response in the previous cases, but does not consider it prudent to rely on this individual control approach in future, particularly as the number of systems under control is anticipated to grow rapidly in the near future.

This is a relatively simple and low cost action that can be pursued immediately. The benefits will grow over time, as the capacity of >200 kW export distribution connected PV grows (SAPN estimates as much as 250 MW capacity connected in this category by spring 2022). The analysis presented in this report has assumed that this action takes place, and this capacity is fully available for curtailment when required.

⁸² Curtailment was completed within 20 minutes of the direction issued on 2 February, within 30 minutes on 5 February, and within 15 minutes on 16 February.

Figure 17 Response of controllable distribution connected generation to AEMO directions



10.1.3 Fast-tracked feed-in management for >30 kW distributed PV

SAPN explored implementing a fast track option for feed-in management to support coarse, gross generation curtailment to zero, for new distributed PV installations. The focus would be on commercial distribution connected PV systems, targeting those in the >30 kW range.

The technology exists for this to be extended to all new distributed PV connections (of any size). This would require prescription of particular technologies for the gateway hardware (leveraging an existing vendor’s product), limiting customer choice, and considerable investment in systems that can support integration with the wide range of popular customer inverters. However, customer and industry engagement is a key risk, and lack of support from customers and industry could lead to low compliance levels. A poor customer experience with the fast-tracked solution risks compromising customer, industry and regulatory support for a future flexible exports scheme. This could undermine the long-term requirements of the power system for this capability to be implemented.

Caution is therefore required, balancing the rapidly rising system security risks with the need for successful customer experiences during the rollout of this essential underpinning technology.

SAPN's advice echoes AEMO's assessment that technical implementation of feed-in management capability can be achieved rapidly if necessary, and has been applied in other power systems (albeit on a much smaller scale, and with coarse technologies that do not unlock many of the long-term benefits)⁸³.

The most challenging aspects of implementation of widespread feed-in management capabilities are centred around managing change in complex human systems, involving a very large number of small stakeholders, including:

- Helping installers and vendors to understand and support the new requirements.
- Creation and maintenance of the compliance and certification chain.
- Managing customer sentiments around external intervention to manage their distributed PV asset.

The framing of this capability, and the way it is communicated and presented to customers, is extremely important. For this reason, SAPN has proposed a gradual implementation, utilising customer options and trials first, before mandatory requirements are introduced. This allows learning around the best ways to engage customers, and also allows the market availability of suitable options to grow over time. Despite the clear urgency around introducing these capabilities to support system security, AEMO is supportive of a measured approach, while urging accelerated implementation as much as possible, and in as many customer sectors as possible. This capability will be an absolutely essential underpinning to future power system operability across the NEM, which means it is essential to introduce it carefully in a manner that does not cause alarm or long-term customer dissatisfaction.

Outcomes can be improved and accelerated if there is a coordinated stakeholder engagement program, with consistent messaging about the need for this capability to support system security from SA Government, AEMO, SAPN, ElectraNet, the Energy Security Board, the Clean Energy Council, Clean Energy Regulator, and other key decision makers. AEMO strongly recommends that a customer engagement program is launched as soon as possible, as a cross-collaborative initiative from all of these organisations.

AEMO relies on advice from SAPN on the degree to which the rollout of controllability of commercial distribution connected PV can be accelerated. At the time of release of this report, SAPN has not recommended fast-tracking feed-in management for commercial customers, although this remains under discussion.

10.1.4 Retrofit of >30 kW PV systems for feed-in management

SAPN explored possible to retrofit commercial distribution-connected PV systems (>30 kW) to introduce feed-in management capabilities. This measure would also capture systems larger than 200 kW that were installed prior to SCADA control being made mandatory for systems of that size. Almost all of the >30 kW legacy systems are capable of having a DRM gateway device fitted to activate DRM0 mode (zero gross generation).

SAPN notes that this approach involves significant stakeholder engagement and customer experience risks. It would be advisable to implement a coordinated stakeholder engagement campaign, coordinating clear messaging on the need for this capability from SA Government, AEMO, SAPN, the Energy Security Board, and other key decision makers. It would also be advisable for the costs of retrofit to not be placed on the customers themselves.

Retrofit of feed-in management capabilities is higher risk and less certain than for new installations. SAPN has work underway to determine the overall feasibility and capacity that may be available via this approach. AEMO relies on advice from SAPN on feasibility. At the time of release of this report SAPN did not recommend proceeding with this option given implementation complexities and costs, although this remains under discussion.

⁸³ EPRI report to AEMO (October 2018), "International Review of Residential PV Feed-in Management – A review of technologies, practices and applications", at <https://aemo.com.au/-/media/Files/Electricity/NEM/DER/2019/Standards-Protocols/EPRI-PV-Feed-in-Management-Report.pdf>.

10.1.5 Enhanced distribution voltage management

SAPN has explored options for improved management of distribution voltages. One option involves introducing SCADA control of voltage set points, and developing a mechanism in their control system to implement dynamic voltage changes in real time. SAPN is conducting a trial of this capability at present, utilising voltage data from customer smart meters to monitor customer impacts. If the trial is successful, this capability could improve quality of supply for customers, limit the high voltage impacts of distributed PV which are now occurring in many locations in SAPN's network, and increase the DER hosting capacity of the network. It represents a move towards "smarter" voltage management in distribution networks, and would help to address customer complaints associated with high voltages.

As an additional side benefit, if this capability is introduced, SAPN has identified the ability to remotely increase substation voltage setpoints, to a level that could cause a controlled reduction in distributed PV generation. This could be done in a managed manner, within 15-30 minutes of AEMO providing an instruction.

SAPN has advised that it intends to roll this capability out across their network gradually over the coming years as network components are replaced over time. However, given the additional security benefits by contributing to a demand recovery reserve, this could be brought forward for implementation across their network. This would immediately improve customer experiences and reduce customer complaints related to high voltage associated with distributed PV, and simultaneously improve system security in low load periods. Enhanced voltage management capability has the double benefit that it allows SAPN to *reduce* the incidence of high voltages when it is undesirable (in the vast majority of periods), and simultaneously provide the capability to induce a temporary period of controlled high voltages in the very rare periods where this is desirable, as a last resort in emergencies. In this way, customer experiences are *improved* on both fronts.

Other DNSPs have implemented similar enhanced voltage management programs to temporarily change demand on their networks. Victorian DNSPs Powercor, CitiPower, and United Energy temporarily reduce voltage on their networks to reduce demand in response to supply scarcity⁸⁴. United Energy is trialling the technology in providing lower contingency FCAS services⁸⁵.

This is a highly suitable option for demand recovery reserve, for the following reasons:

- It can be implemented reliably, with at least some capacity available in time for spring 2020. Very few other options have been identified that can be implemented in this timeframe. SAPN advises that it can be implemented using existing knowledge and technology, applying solutions at large substations, to rapidly rollout a large capability.
- The capacity available is large. This grows in future years as more distributed PV is installed. It also provides a "back-up" option if other feed-in management approaches cannot be implemented in time, or face unforeseen barriers.
- The ability to implement this option, and the amount of capacity available is relatively more certain than the other options identified. It can be implemented fully within SAPN's network, and does not require access to customer sites (which may be particularly restricted over the coming year due to COVID19 challenges).
- AEMO anticipates that demand recovery reserves will be triggered very rarely (only when operating as an island in low load periods). This means that the overall impact on customers should be an *improvement* in voltage management (and a reduction in customer complaints associated with high voltages), in most normal periods.
- It has the side benefit of improving customer quality of supply across SAPN's network, and reducing customer complaints related to high voltages.

⁸⁴ See <https://www.energynetworks.com.au/resources/fact-sheets/innovation-in-the-electricity-network-sector/>.

⁸⁵ See <https://arena.gov.au/news/united-energy-to-test-voltage-control-improving-grid-stability/>.

- This is a long-term capability that SAPN would be working towards regardless, so the investment is “no regrets” (it does not lead to a stranded asset).

As part of its trial process, SAPN can explore potential customer impacts from a short duration, controlled increase in distribution voltages to a level that is sufficient to reduce distributed PV generation. The voltage level to achieve this is expected to be within those already experienced by some customers on a routine basis. The overall impact of introducing this capability would be to reduce the number of intervals where customers are exposed to high voltages, and to only increase voltages in very rare periods under controlled circumstances where it is beneficial for system security.

SAPN notes that some customers on affected substations will receive voltages outside of regulatory standards. However, it is emphasised that the overall impact on customers from introducing this capability should be to improve voltage management, reducing high voltage impacts in all normal periods.

AEMO anticipates an increase in voltages would only be activated under extreme abnormal situations, just prior to load shedding, as a last resort to allow dispatch of the necessary units for system security under islanded conditions. It would likely only be used for short periods of time to facilitate an additional buffer of power system flexibility to manage rare and extreme situations. This means the impacts on customers should be minor.

AEMO recommends that this proceeds as a priority.

10.1.6 Shedding feeders in reverse flows

In extreme abnormal conditions, it may be possible to recover some demand by shedding feeders that are in large reverse flows. This would mean disconnection of customers for a period of time. This would need further analysis to determine the circumstances under which this would be appropriate.

There may be also be implementation considerations. For example, some SAPN feeders do not have metering that can distinguish the direction of flow, so it may be difficult to identify feeders in significant reverse flows in real time. Upgrades to metering, or implementation of estimation methods may be required. AEMO is discussing possible approaches with SAPN.

Implementation of the feed-in management and enhanced voltage management options above will reduce the amount of benefit from shedding feeders (and will also reduce the necessity to shed whole feeders). This can be assessed on a real-time basis, according to which options have been implemented at the time.

10.1.7 Streamline management of non-scheduled generation

There is significant non-scheduled wind generation capacity in South Australia (386 MW), located at a small number of large installations that would be registered as semi-scheduled if connected today:

- Canunda wind farm (46 MW).
- Cathedral Rocks wind farm (66 MW).
- Lake Bonney Wind Farm (80.5 MW).
- Mount Millar Wind Farm (70 MW).
- Starfish Hill Wind Farm (33 MW).
- Wattle Point Wind Farm (90.8 MW).

At present, these units are not managed through the normal dispatch process. The non-scheduled status of these installations was grandfathered when the semi-scheduled generator framework was introduced.

AEMO is investigating pathways to transition these wind farms to alternative arrangements, so that their dispatch and visibility can be managed in AEMO’s systems in a similar manner to other plant of a similar size and type. This may assist with streamlining the management of these units during low demand periods.

The analysis presented in this report has assumed that this action takes place, and this capacity is fully available for curtailment when required.

10.1.8 Investigate remote control capabilities of OEMs

Some OEMs of inverters for distributed PV may have the technical capability to remotely curtail generation from existing systems. AEMO has liaised with five inverter OEMs to better understand their technical capabilities. Of these OEMs, two indicated they presently have the capability to remotely control output from some existing systems. If performed during low demand conditions due to high distributed PV generation, this action would help to increase operational demand.

All OEMs indicated they have not enabled these capabilities (aside from those in active Virtual Power Plants) citing regulatory, privacy and security, and customer experience concerns. All OEMs that did not have existing capability to remotely control inverter output had plans to introduce this capability in future products.

The aggregate capacity of the existing systems that can be curtailed by OEMs is unknown at this stage. However, the existence of this capability may warrant further investigation with more OEMs to determine if this is a legally and technically viable mitigation approach.

10.2 Increasing load

10.2.1 Moving controlled hot water to daytime

SAPN has estimated that if all hot water loads were shifted to the daytime, minimum demand could be increased by 100-200 MW. SAPN-owned meters would require a site visit to re-program (of varying cost and complexity), whereas retailer smart meters could be reprogrammed via remote update.

Further investigation is required to identify and address the barriers to these actions.

AEMO has engaged a consultant to investigate these factors further. When this analysis is complete, AEMO will work with SAPN, the South Australian Government, and other stakeholders to determine how to proceed, and which hot water customers (if any) should be moved to daytime operation.

10.2.2 Moving residential pool pumps to daytime

It has been estimated that up to 17 MW of load could be sourced from residential pool pumps during low demand conditions. It is estimated that around 80% of the estimated 80,000 pool pumps in South Australia are timer-operated and likely already operate during the day. The remaining pool pumps could be shifted to daytime operation. However, the logistical challenge and costs of changing the operation of thousands of devices impacts the cost-effectiveness of this approach.

These pumps may be aggregated and shifted by a private sector aggregator in the future without intervention from the government. SAPN's introduction of a 'solar sponge' tariff from 1st July 2020 may provide sufficient pricing incentives for private aggregators and/or a change in individual consumer behaviour. However, this cannot be relied on.

Due to cost and complexity, and the availability of other more preferable options, AEMO does not recommend proceeding with this option as a priority at this stage.

10.2.3 Negotiating with large customers to increase load

It may be possible for some large customers in South Australia to somewhat increase load at minimum demand times. A range of candidates were investigated, including water pumping, desalination, transmission connected heavy industrial enterprises, and distribution-connected commercial and government agencies.

The additional load for each load category indicated above was estimated by calculating the difference between 90% of its annual maximum load and typical load in low-demand conditions. The amount of additional load calculated via this approach represents an upper estimate because the load may be seasonal, affected by weather, limited by labour force availability (e.g. on Sundays or public holidays), or may be inflexible.

AEMO has commenced a program of work to investigate these possible actions further during 2020. AEMO will work with SAPN, the South Australian Government, and other stakeholders to determine which actions should be pursued further.

10.2.4 Long-term incentive mechanisms

There may be long-term options to increase load in South Australia. For example, the South Australian Government could consider accelerating uptake of electric vehicles, especially if these include dynamic control and interoperability capabilities, sophisticated disturbance ride-through standards, and participation in security services markets.

This option is unlikely to provide significant capacity in the short term to address the near-term issues identified, but it could provide a valuable contribution to minimise security issues related to low load periods in the longer term.

10.2.5 Resistor banks

If additional reserves are required, resistor banks could be installed to provide additional recoverable load. Resistor banks are often used as part of microgrid solutions, to assist with frequency control (managing variability), and to capture wind and solar spilling.

Resistor banks have several important advantages over utility scale storage when used as a crude “solar soak”. In general, the capital expenditure is lower. They can also operate indefinitely (whereas a BESS will reach a full state of charge, often in a short duration of time).

At this stage, if the other recommended demand recovery reserves are implemented, AEMO does not believe the installation of resistor banks is required. This is likely to be a higher cost option with longer lead times, so the other options identified are preferred.

10.3 Reduce frequency control requirements

10.3.1 Curtailment of loads

AEMO will consider curtailment of loads to reduce frequency control requirements as part of the development of operating procedures for low load periods, exploring the conditions where curtailment should (and should not) be applied.

10.4 Real-time procedures for low load periods

AEMO uses pre-defined procedures to outline appropriate system operation in various operating conditions. Procedures for operation under low demand conditions in South Australia are under continual review as new information becomes available.

AEMO is working with ElectraNet and SAPN to review and update operating procedures in islanded conditions, periods when there is a credible risk of separation, and system normal conditions. The work outlined in this report will progressively provide various new levers for the AEMO control room to manage system security in low load periods, and each of these actions have different levels and types of customer impact. AEMO’s procedures will need to be continually updated as these new mechanisms become available, to specify the order in which actions should be taken, when they should be taken, and how they should be delivered.

Order of enablement

As more options become available for distributed PV curtailment (or increasing demand), it will become important to define the order in which various options should be undertaken. AEMO anticipates the following general principles:

- Larger generation systems will be curtailed first, progressively moving to smaller generation systems.

- The relative ordering of curtailment of distributed PV versus increasing loads should be determined based on relative customer impacts.
- Generation shedding options will be enabled based on their relative impacts on customers. The following indicative ordering could be considered (for discussion with SAPN and other stakeholders), with those listed first being curtailed first:
 - Transmission connected non-scheduled generation.
 - Distribution connected SCADA controlled generation (controlled by SAPN).
 - Distributed PV on flexible export limits (controlled by SAPN).
 - Shedding of distributed PV (potentially via smart meters), where this can be done separately from the customers' general load.
 - Enhanced voltage management (controlled increase in distribution voltages to shed a proportion of distributed PV).
 - Shedding of any remaining customers
 - Shedding of whole feeders in reverse flows (if any remain).

It is anticipated that all Demand Recovery Reserves will be enabled rarely, with those at the bottom of the list enabled extremely rarely, only under extreme abnormal conditions.

Trigger conditions for enablement of demand recovery reserve

It is anticipated that the triggering of demand recovery reserves will be dependent on the power system conditions at the time. This will depend strongly on:

- An islanding event occurring (and possibly when there is a credible risk of separation).
- The combination of synchronous generating units operating at the time.
- The availability of the Murraylink interconnector and any constraints affecting flows on that interconnector.
- The operating level of large loads.
- The availability of frequency control services, particularly from BESS.

AEMO cannot anticipate ahead of time when a non-credible islanding event will occur. This gives limited ability to forecast when triggering of reserves will be required.

Monitoring and notifications

AEMO cannot determine whether islanding, unplanned outages, or contingency events will occur in any particular period, but does monitor the relevant risk factors, as listed in Table 8 below. AEMO provides information on these to market participants via standard market and operational processes.

Operational demand depends strongly on the weather, particularly during low demand periods such as weekends where the proportion of weather sensitive demand is high due to reduced commercial and industrial operations and high distributed PV generation. Temperature and humidity are the strongest factors that affect consumption of electricity. Solar insolation levels are also significant, since cloud cover can considerably reduce generation from distributed PV.

AEMO relies on weather forecasts, which can give some indication of these factors in the week ahead. However, weather can change suddenly and unexpectedly, which means that operational demand forecasts may change on short timeframes. In 2018, AEMO introduced a Forecast Uncertainty Measure (FUM) into its reserve determinations in Projected Assessments of System Adequacy (PASA), helping AEMO manage forecast uncertainty that may impact power system security.

AEMO informs market participants of any changes to forecasts via the mechanisms listed in Table 8.

If there are demand recovery actions that require a triggering notification from AEMO (such as implementation of a demand response mechanism), AEMO will work with the relevant parties to determine the appropriate processes.

Table 8 Factors relevant for monitoring and assessment of low demand period risks

Relevant risk factors	Nature of the risk	Timeline
South Australian operational demand forecast	Operational demand below a threshold	<ul style="list-style-type: none"> Each day for the day ahead, updated half hourly (pre-dispatch) Each day for the period two to seven days ahead, updated every two hours (ST PASA)
Network element outages	Network outages, especially those that cause a credible risk of separation (since these can increase the risk of a separation event).	<p>Planned and unplanned network outages are published in the Network Outage Schedule (NOS). This advises market participants on any outages that may cause a constraint in the dispatch process.</p> <p>Outages may be entered up to two years in advance, or at short notice in response to an emergency.</p>
Factors affecting flows on Heywood	Reduced flows on Heywood, or an escalated risk of separation.	Reclassifications, abnormal events, and circumstances that may trigger actions under a protected event are published as market notices, sent to market participants. The notice period could be very short.
Unit outages	Some unit outages may affect the minimum demand threshold.	<p>Market participants advise AEMO on anticipated unit outages, for incorporation into the Projected Assessment of System Adequacy (PASA). AEMO publishes a disclosure of supply/demand balance, but not individual unit availabilities (this information is commercially sensitive).</p> <p>The Pre-Dispatch PASA (PD PASA) is published every half hour, for the day ahead.</p> <p>The Short Term PASA (ST PASA) is published every two hours, and provides half-hourly information on the supply/demand balance for six days following the next trading day.</p> <p>The Medium Term PASA (MT PASA) is published weekly on Tuesdays and lists the supply/demand balance for the period two years in advance.</p> <p>If a security issue is anticipated on the basis of the advice from Market Participants, AEMO has powers to direct the necessary units to be available when required.</p>

11. Other mitigation actions

A number of other mitigation actions are also recommended, summarised below.

11.1 Managing unit availability

This investigation has highlighted the importance of certain units for managing minimum load periods. In particular:

- The Torrens Island A and B units are important providers of inertia, system strength and frequency control, and have low minimum load requirements. Unit combinations involving the Torrens Island units tend to have much lower minimum load requirements to meet system security needs.
- The BESS are important providers of frequency control services under islanded conditions, and allow management of much larger contingencies.

Special management of the availability of these units may be prudent, especially if extreme abnormal conditions are anticipated. For example, given the possibility of lower than forecast minimum demand levels related to COVID-19, it may be valuable to maximise the availability of these units throughout spring and early summer 2020, when the lowest demand periods may eventuate. AEMO has been advised that these market participants are well prepared.

AEMO, ElectraNet and the South Australian Government should proactively engage with the operators of these assets to discuss plans and any appropriate additional management options.

11.2 Investigate transmission voltage management

Low load periods can cause challenges related to transmission voltage management. This is a concern in low load periods in the SWIS, and also in Victoria. ElectraNet has advised that their studies to date have not identified any problems related to transmission voltage management in low load periods in South Australia. However, these studies have not yet been completed with the most recently available models of distributed PV and load behaviour during power system disturbances. Further analysis is required to explore this more thoroughly, and identify any potential transmission voltage management issues that may eventuate.

AEMO is working with ElectraNet to provide the best models available, to enable ElectraNet to undertake this analysis.

12. Enduring policy frameworks

This report has focused on short-term security challenges arising in the South Australian region. However, operational challenges during periods of minimum demand will emerge throughout the NEM, and holistic NEM-wide frameworks will be required. Enduring policy frameworks for successful integration of DER are being developed through AEMO's DER Program Markets and Frameworks workstream⁸⁶. This involves creation of a two-way energy market, the concept for which was developed in consultation with DNSPs through an initiative called Open Energy Networks⁸⁷.

By creating a two-way electricity grid and associated marketplace with open energy networks, Australian energy consumers will benefit through:

- Access to new value and choices of energy services.
- The ability to integrate more DER in a consistent way across the grid to more efficiently manage grid stability.
- Rewards and incentives in exchange for providing DER services to the grid.
- Increased visibility of energy usage and a better energy future for all Australians.

AEMO's work in this area is occurring across a number of workstreams, summarised below.

Open Energy Networks (OPEN)

Open Energy Networks is a joint project between AEMO and Energy Networks Australia that explores the different framework options to allow for coordination and optimisation of DER in the distribution network. The project has identified a number of pre-requisite or required capabilities that would need to underpin any future framework, including the need for distribution networks to monitor their networks in order to track hosting capacity and communicate any constraints to the market. The market would include AEMO but also aggregators who will act of DER owners' behalf to bring portfolios of DER assets to the market to provide wholesale or network services.

The OPEN project originally explored three possible frameworks to optimise and facilitate the use of DER and deliver best value to customers, in a market characterised by increasingly decentralised and small-scale sources of renewable energy located within distribution networks. The three frameworks were a Single Integrated Platform (SIP), a Two Step Tiered Regulated platform (TST), and an Independent DSO (IDSO).

One of the key recommendations is the adoption of a "hybrid model" which calls for new roles for AEMO and DNSPs as the DMO or Distribution Market Operator and DSO or Distribution System Operator respectively. In order to determine the exact nature of these roles, these roles will form the key design foundation for a series of demonstration projects or trials that will test the functionality required to determine the most appropriate set of arrangements for the operation of DER, the network and system to enable customers to get the best outcomes.

Initially the project determined the following definitions of these roles to help industry gain clarity on what these roles will entail:

⁸⁶ AEMO, "Markets and Frameworks", at <https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework>.

⁸⁷ AEMO, "Open Energy Networks – joint consultation with Energy Networks Australia", at <https://www.aemo.com.au/initiatives/major-programs/nem-distributed-energy-resources-der-program/markets-and-framework/open-energy-networks-joint-consultation-with-energy-networks-australia>.

- **DMO** – the DMO functionality is an extension of the existing AEMO wholesale market optimisation framework to enable DSO inputs and resources to be taken into account. This extended functionality facilitates the efficient operation of the market through the dispatch and settlement of DER in the distribution system in accordance with the security and reliability of the whole of electricity system to the benefit of all customers.
- **DSO** – the DNSP functions of network planning, operations and asset management will be expanded to support the optimal use of DER and operating envelopes of the distribution network. The DSO will optimise its network based on DER to support the delivery of safe, secure, reliable and affordable electricity to facilitate whole of system optimisation by the DMO to benefit of all customers. This includes the provision of bi-lateral contracts with DER.

ESB post-2025 market review

In March 2019 the COAG Energy Council (COAG EC) tasked the Energy Security Board (ESB) with providing advice on a long-term and fit-for-purpose market framework to support National Electricity Market (NEM) reliability that could apply from the mid-2020s. The ESB was tasked with recommending any changes to the existing market design, or an alternative market design, necessary to enable the provision of the full range of services to customers and provide a secure, reliable and lower emissions electricity system at least cost. Any changes to the existing design or recommendation to adopt a new market design must satisfy the national electricity objective.

A project governance structure was published by the COAG EC in March 2019, together with a forward work plan and indicative schedule. Several rounds of stakeholder engagement occurred throughout 2019 and an Issues Paper was published in September 2019. Over 70 stakeholder submissions were evaluated and a three-day Future Electricity Markets Summit was held during October-November 2019. Late in November 2019, the ESB was further tasked with the provision of formal advice on several urgent interim measures to preserve reliability and system security in the NEM during the transition to the post-2025 market design by the COAG EC.

In 2020, the post-2025 market review will look to build on a number of key market design initiatives. DER integration will be an important component of a number of these initiatives – specifically the two-sided market and DER markets initiatives, with the potential for DER to provide both capacity and essential system services in the post-2025 NEM. Further detail on the vision and each market design initiative is expected to be shared by the ESB later in 2020.

The ESB is preparing a two-sided market design for the NEM that has all its participants responding to price based on their cost and value preferences. A two-sided market would provide market signals to end users to increase load at times of peak solar output. The two-sided market would also allow effective DER integration with trials currently under consideration that will test the capability of DER to provide distribution network services and incentivise end users to increase load.

The ESB is also considering a framework for the procurement and dispatch of system services in the NEM. An ahead market, which is under consideration to aid the dispatch of system services, would facilitate the coordination of storage resources and incentivise the shifting of load to periods of peak solar output.

Distributed Energy Integration Program (DEIP) including DER Trials

The Distributed Energy Integration Program (DEIP) is a collaboration of government agencies, market authorities, industry and consumer associations aimed at maximising the value of customers' distributed energy resources (DER) for all energy users.

Led by a steering group including AEMO and ARENA, the forum is driven by the premise that exchanging information and collaborating on DER issues will more efficiently identify knowledge gaps and priorities, as well as accelerate reforms in the interest of customers.

There are four key workstreams – a) Access and Pricing, b) Standards, Data and Interoperability, c) Electric Vehicles, and d) Market Development.

13. Next steps

The following next steps are proposed:

1. AEMO, the South Australian Government, ElectraNet, and SAPN discuss the findings in this report, and agree the preferred and prioritised mitigation approaches.
2. A detailed plan is developed and executed collaboratively.
3. A program of proactive engagement is launched with the South Australian energy industry and South Australian consumer representatives about the identified challenges, and the proposed plan. This particularly needs to communicate the benefits from feed-in management and improved ride-through standards for all new DER in South Australia.

Table 9 below provides a summary of the recommended actions outlined. Many of these streams of work have detailed delivery programs, either underway (such as the assessment of the EnergyConnect project), or in development (such as improving compliance with DER performance standards). These projects are summarised here at a high level, due to their relevance for addressing the issues identified in this report. AEMO will communicate with stakeholders on the development and delivery of these work streams in more detail on an ongoing basis, as they evolve.

AEMO recommends that all of these identified projects are pursued as rapidly as possible. Target completion dates have not been indicated, because there remains considerable uncertainty around the feasible delivery timelines for most projects. The South Australian power system is already facing serious security risks, and deeper record low demands are anticipated in spring 2020. Ideally, some of these projects would be delivering at least some benefits by spring 2020.

All projects listed in Table 9 should be explored further immediately. Indicative relative priorities have been suggested, to highlight those projects where resources should be focused initially. Priority 1 projects are those that are essential, have a high probability of delivering considerable benefits, and/or are likely to deliver meaningful benefits in the timeframes required.

Table 9 Summary of recommended mitigation measures

	Action	Purpose	Regulatory frameworks	Lead	Section
Essential foundational measures	DER Performance Standards: Improve DER disturbance withstand standards (AS/NZS4777.2 review)	Minimise disconnection of future distributed PV installations	AEMO can collaborate with Standards Australia on AS/NZS 4777.2 review, but does not have decision making powers. Australian Standards are developed in a consensus based process	AEMO	8.2
	Compliance processes: Develop improved processes for compliance with DER performance standards	Minimise disconnection of future distributed PV installations, increase compliance with feed-in management	Responsibilities and powers are unclear. AEMO to engage with industry and collaboratively develop a plan	AEMO	8.3

	Action	Purpose	Regulatory frameworks	Lead	Section
	Feed-in management: Introduce flexible exports (interoperability) for DER, as proposed in SAPN regulatory proposal	Allow capability to curtail distributed PV within 30min when required	AEMO can collaborate with SAPN and Standards Australia on including these capabilities, highlight their importance to the AER, and communicate needs to market participants and consumers	SAPN	8.4
	EnergyConnect: Timely commissioning of the EnergyConnect interconnector	Reduce likelihood of South Australia islanding	AEMO can share these findings with the AER, but does not have decision making powers over its approval or funding	All	8.1
Implement by spring 2020 (as far as possible)	Stakeholder Engagement program: Launch a comprehensive and collaborative stakeholder engagement program to communicate to industry and customers the need for new inverter capabilities in ride-through and feed-in management	Ensure customer and industry support for the new measures required	Needs to be a collaborative program with strong buy-in from AEMO, AEMC, AER, ESB, SAPN, ElectraNet, CEC, CER, SA Government and other key decision makers	AEMO	All
	Interconnector constraints: Introduce Heywood interconnector constraints to manage distributed PV disconnections	Reduce likelihood of South Australia islanding.	AEMO has implemented, and is refining with ElectraNet and SAPN	AEMO	9.3.1
	PV shedding capability: Enable PV shedding capability, possibly exploring use of smart meter functionality to facilitate targeted load and distributed PV shedding	Allow capability to shed distributed PV when required as a back-stop measure for system security	Regulatory arrangements require urgent review – collaboration with Metering Coordinators and retailers will be required, and possible funding mechanisms established	AEMO	10.1.1
	Accelerated voltage ride-through test: Fast-track introduction of a new test for voltage ride-through for all new inverters in South Australia	Reduce disconnection of distributed PV installations.	SAPN has powers to implement this as part of their connection agreement, and has obligations under the NER (4.3.4(a) to assist AEMO with system security	AEMO	9.1.1
	Enhanced distribution voltage management: Introduce the capability to dynamically manage voltages in the distribution network, and trial use to shed distributed PV under extreme abnormal conditions	Increase controllable distribution connected generation by up to 246 MW by spring 2021.	Some exemptions from SAPN's regulatory obligations may be required, under abnormal conditions when necessary for system security	SAPN	10.1.5

	Action	Purpose	Regulatory frameworks	Lead	Section
	Streamline management of distribution connected generation: Improve SAPN's arrangements for management of controllable distribution connected PV	Streamline ability to curtail controllable distribution-connected PV.	SAPN has powers to implement this and has obligations under the NER to assist AEMO with system security	SAPN	10.1.2
	Management of >30 MW non-scheduled generation: Introduce improved arrangements and protocols for curtailment of large non-scheduled wind farms in South Australia	Streamline ability to curtail non-scheduled wind farms.	AEMO has powers to implement	AEMO	10.1.7
	Shedding feeders in reverse flows: Implement capability to shed feeders in reverse flows as a last resort	Increase operational demand (last resort measure).	SAPN has powers to implement this, and has obligations under the NER to assist AEMO with system security.	SAPN	10.1.6
	Network outage assessments: Include consideration of security impacts in high PV generation periods	Reduce likelihood of South Australia islanding in periods with low demand.	AEMO has powers to implement	AEMO	9.3.2
	Real-time procedures: Continually adapt real-time procedures for operation of South Australia with low load under islanded conditions, and credible risk of separation, as above options become practically available and further analysis is completed	Streamline operation in low load periods.	AEMO has powers to implement	AEMO	10.4
Additional for implementation 2021-23	Fast Frequency Response: Improve frameworks for delivery of Fast Frequency Response	Improved frequency control capabilities to manage PV disconnections.	Some aspects require collaboration with AEMC	AEMO	9.2.1
	Manage BESS frequency control delivery: Improve operational protocols to manage BESS state of charge and other operational limitations	Improved frequency control capabilities to manage PV disconnections.	AEMO has implemented and is refining	AEMO	9.2.2
	More frequency control providers: Expand the number of contingency frequency control providers in SA	Improved frequency control capabilities.	SA Government initiative, possibly via the Grid Scale Storage Fund	SA Govt	9.2.3

	Action	Purpose	Regulatory frameworks	Lead	Section
	OEM firmware upgrades: Explore the possibility of improving voltage ride-through behaviour for legacy systems with OEMs that have remote firmware upgrade capability	Reduce disconnection of distributed PV installations.	SA Government direction may be required to enable OEM action.	AEMO	9.1.2
	OEM remote control capabilities: Investigate potential for OEMs to remotely control legacy distributed PV	May allow further controllable distributed PV.	SA Government direction would be required to direct OEMs to take this action with legacy customer systems, considering investment risk.	AEMO	10.1.8
	Demand Response Mechanism: Aggregate customers with ability to increase demand, or manually deactivate distributed PV.	Additional demand recovery reserve.	SA Government initiative.	SA Govt	Error! Reference source not found.
	Hot water re-program: Investigate moving some hot water systems (Type 4) to daytime	Increase daytime operational demand by up to 39 MW by spring 2021.	AEMO to explore mechanisms and feasibility	AEMO	10.2.1
	Negotiate with large customers: Negotiate to move larger loads to daytime	May allow increase of operational demand by up to ~200 MW.	SA Government leadership is likely to be required, possibly with funding	SA Govt	10.2.3
	Olympic Dam: Streamline management of Olympic Dam load when islanded	Minimise frequency control requirements when islanded.	Yes, although SA Government support may assist cooperation.	AEMO	10.3.1
	Manage unit availability: Explore actively managing the availability of critical units during extreme abnormal periods	Make sure essential units are available when required	SA Government support would be beneficial	AEMO	11.1
	Transmission voltage management: Further analysis to identify potential issues related to transmission voltage management	Identify emerging challenges early	ElectraNet has responsibility for transmission voltage management	ElectraNet	11.2
Enduring policy frameworks	Enduring policy frameworks: Explore enduring policy frameworks for NEM-wide, two-way markets to enable DER integration	NEM-wide, holistic DER integration frameworks.	AEMO has the ability to investigate frameworks; implementation will require regulatory changes.	AEMO	12

These actions are additional and complementary to those already recommended in AEMO’s advice on impacts of distributed PV on UFLS, provided to the South Australian Government in November 2019. These are summarised below in Table 10 for completeness.

Table 10 Recommended actions for addressing distributed PV impacts on UFLS (from previous report)

Measure	Detail	Actions
Constraint on Heywood Imports	Implement a constraint to limit imports on the Heywood interconnector in periods where there is inadequate load available on the UFLS to manage loss of the interconnector within the Frequency Operating Standards.	<ul style="list-style-type: none"> • Dynamic studies to determine operational envelope for successful UFLS operation (AEMO) • Declaration of a protected event (AEMO) • Establishment of a new SCADA feed providing a real-time estimate of the aggregate load on the UFLS (SAPN) • Improvements to SAPN metering to allow accurate estimation of UFLS load (SAPN)
Increase load in UFLS	Increase the amount of load on the South Australian UFLS.	<ul style="list-style-type: none"> • Add new customers to the UFLS (SAPN) • Investigate moving controlled hot water to daytime (AEMO/SAPN) • Negotiate with and incentivise large customers to move load to daytime (SA Government) • Explore potential for large customers to provide 100% of their load to the UFLS (SA Government)
Increase emergency response	Increase the emergency frequency response from other sources.	<ul style="list-style-type: none"> • Promote changes to Australia Standards to specify an emergency discharge droop from distributed storage when frequency falls below 49 Hz (AEMO) • Explore possible augmentation of Murraylink to add frequency control capabilities (AEMO)
Dynamic arming	Implement dynamic arming of UFLS feeders in reverse flows.	<ul style="list-style-type: none"> • Develop threshold values for magnitude and duration of reverse flows that will trigger implementation of dynamic arming at each relay (AEMO / SAPN) • Implement dynamic arming at locations that exceed threshold values (SAPN)
Long-term measures	Implement suitable long-term measures for replacement of emergency frequency control schemes.	<ul style="list-style-type: none"> • Launch a program of work to explore long-term options for restoring UFLS functionality (AEMO)

AEMO anticipates that the modelling and analysis to fully answer these questions will be ongoing, and continuously refined over time.

AEMO looks forward to ongoing collaborative engagement with the South Australian Government, energy industry, and consumers on these challenges.

A1. Abbreviations

Abbreviation	Definition
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
ARENA	Australian Renewable Energy Agency
AS/NZS 4777.2:2015	Australian Standard 4777.2, which defines performance and safety standards for inverters that are connected to distributed energy resources at the low voltage network.
BESS	Battery Energy Storage System
COAG EC	Council of Australian Governments (COAG) Energy Council
DER	Distributed Energy Resources
Distributed PV	Distributed photovoltaics, referring to generating systems connected to the distribution network.
DNSP	Distribution Network Service Provider
EFCS	Emergency Frequency Control Scheme
ESB	Energy Security Board
ESCOSA	Essential Services Commission of South Australia
FCAS	Frequency Control Ancillary Services
GT	Gas turbine
Hz	Hertz, a measure of frequency
L5	Five minute (delayed) contingency lower service (FCAS)
L6	Six second (fast) contingency lower service (FCAS)
L60	Sixty second (slow) contingency lower service (FCAS)
MASS	Market Ancillary Service Specification, outlines the delivery specifications for FCAS providers
MW	Megawatts, a measure of electrical power.
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine. The software that determines dispatch in the NEM.
NER	National Electricity Rules
NSCAS	Network Support and Control Ancillary Services
NSP	Network Service Provider

Abbreviation	Definition
OFGS	Over-frequency generation shedding, a type of emergency frequency control scheme in the NEM.
PELGTST	Pelican Point Gas turbine and Steam Turbine
PSCAD	A platform for power system dynamic simulations (AEMO's more complex Electromagnetic transient (EMT) type model)
PSS@E	A platform for power system dynamic simulations (AEMO's simpler Root Mean Square (RMS) type model)
PVNSG	Photovoltaic non-scheduled generation
QPS5	Quarantine Power Station Unit 5
R5	Five minute (delayed) contingency raise service (FCAS)
R6	Six second (fast) contingency raise service (FCAS)
R60	Sixty second (slow) contingency raise service (FCAS)
RIT-T	Regulatory Investment Test for Transmission, applied to examine the costs versus benefits of a large network investment.
RoCoF	Rate of change of frequency
SAPN	South Australian Power Networks
SIPS	System Integrity Protection Scheme, a control scheme that aims to reduce the risk of South Australia separating from the rest of the NEM
ST	Steam turbine
SWIS	South West Interconnected System (Western Australia)
TIPSA	A Torrens Island Power Station A unit
TIPSB	A Torrens Island Power Station B unit
TNSP	Transmission Network Service Provider
UFLS	Under Frequency Load Shedding, a type of emergency frequency control scheme in the NEM
UNSW	University of New South Wales