Government of Western Australia
Energy Policy WA

Low load project

Stage 1 report

An investigation into power system security risks associated with low electricity demand in the SWIS

June 2022

Working together for a **brighter** energy future.

An appropriate citation for this paper is: Low load project: Stage 1 report

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List of abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
ARENA	Australian Renewable Energy Agency
BESS	Battery energy storage system
BTM	Behind the meter
DEBS	Distributed Energy Buyback Scheme
DER	Distributed energy resources
DPV	Distributed photovoltaic
DNSP	Distribution network service provider
DOE	Dynamic operating envelope
EMT	Electromagnetic Transient
ESOO	Electricity statement of opportunities
ESM	Emergency solar management
EV	Electric vehicle
EPWA	Energy Policy WA
ETS	Energy Transformation Strategy
ESS	Essential system services
FCAS	Frequency control ancillary services
GT	Gas turbine
GW	Gigawatt
MDT	Minimum demand threshold
MV	Medium voltage
MW	Megawatt
NCESS	Non co-optimised essential system service
KV	Kilovolt
LV	Low voltage
OEM	Original equipment manufacturer
PU	Per unit
PV	Photovoltaic
PLL	Phase locked loop
POC	Point of connection
PPC	Power plant controller
PSSR	Power system security and reliability
ROCOF	Rate of change of frequency
RY	Reference year

Term	Definition
SCADA	Supervisory control and data acquisition
SCR	Short-circuit ratio
SMIB	Single machine infinite bus
SWIS	South West Interconnected System
TNSP	Transmission network service provider
UFLS	Under-frequency load shedding
VPP	Virtual power plant
WA	Western Australia
WEM	Wholesale Electricity Market
WP	Western Power
WPN	Western Power Network
WOSP	Whole of System Plan

Executive summary

The way in which we produce and consume electricity is rapidly changing and the rate of change is expected to accelerate over the next decade and beyond. Throughout this century the evolution of power system and energy market developments have generally been assessed, planned and documented through an annual planning cycle. In recent years there have been a significant number of additional studies and publications highlighting emerging challenges and signposting the need for a coordinated response to managing the rapid change afoot.

A common theme identified within all recent additional studies and publications is the issue of managing periods of low operational demand on the power system. The purpose of this Low Load Project is to assemble observations and undertake analysis of the specific issues associated with low demand to understand and quantify emerging risks to power system security during periods of low demand and to ensure appropriate responses, frameworks and mechanisms are in place and available to maintain power system security when called upon.

The project team includes government and industry expert representatives from:

- Energy Policy WA, acting as the project coordinator and lead.
- Western Power providing expert network analysis, network modelling development, demand forecasting, and delivery of activities to assess network risks and solutions.
- AEMO providing expert power system analysis, operational experience, forecasting and delivery of activities to assess power system, market risks and solutions.

The Project is being undertaken in two stages. This report provides a summary of findings from Stage 1 (Technical Analysis) which is focussed on defining the nature of the challenge, assembling work packages that are already complete and in progress and establishing a roadmap for steps to be completed in Stage 2 (Response).

Describing and defining the nature of the low demand issue is unavoidably very technical. This report focuses on identifying the inter-related technical areas of frequency stability, system strength, the efficacy of the SWIS UFLS scheme, the impact of DPV disconnection and aspects of system operability such as ramping and voltage management during low demand periods.

Much of the modelling work undertaken in the Low Load Project to date has required developing new methods. In the case of advanced system strength studies, entirely new detailed computer models of parts of the SWIS and customer generator facilities have been developed. Other studies such as estimating the amount of DPV that disconnects during system disturbance conditions have required novel methods of assessment and calculation.

Minimum demand is falling and power system controls need to keep pace

AEMO's 2022 WEM ESOO forecasts minimum operational demand levels to reach progressively lower levels across the next 5-years as a result of continued DPV installations on the SWIS.[1] At the time of writing this report, the most recent minimum operational demand on the SWIS is 765 MW recorded on 14 November 2021. At the time of publishing AEMO's 2021 WEM ESOO, the historical observed minimum demand was 954 MW. This highlights the extent to which the minimum operational demand on the SWIS is falling with recent observations confirming AEMO's near-term forecasts.

SWIS minimum operational demand is continuously falling in parallel with an increase in the participation of inverter-based generation technologies on the SWIS. Synchronous machines have

[1] The term 'operational demand' refers to the demand that is supplied from market generators in the WEM and can be measured at any time of the day, on any day, month or year. The term 'minimum operational demand' refers to the lowest level of operational demand observed on the SWIS.

historically provided characteristics to the SWIS such as inertia (which improves ability to maintain frequency stability), system strength (to help maintain voltage stability) and ramping capability (to meet supply demand ramps) by virtue of being on for the purpose of providing energy. As operational demand falls, these characteristics, or other services that synchronous generators provide are declining.

In the absence of specifically procuring these services from alternatives that provide a similar level of response, the power system will be characterised by:

- **Lower levels of inertia,** resulting in an increased risk of frequency stability issues associated with a post-contingent frequency response that exhibits very high rate of change of frequency and a lower frequency nadir.[2]
- **Less operational flexibility,** increasing reliability issues associated with generation supply balance and generation supply adequacy during the ramp from minimum demand to the peak demand interval.
- **Lower system strength,** manifesting itself as a complex array of issues associated with generator inverter stability, voltage stability and issues associated with protection of power system plant.

Other emerging aspects on the power system have also been identified which are contributing to increasing risks during very low demand periods. These add to the complexity of managing system security during low demand periods and include:

- **The potential for DPV to disconnect during system disturbances**, resulting in increased magnitude of credible contingency sizes, increasing the risk of frequency instability.
- **Two-way power flow on the distribution network,** reducing the efficacy of the SWIS UFLS designed as a last resort measure to help protect the SWIS against widespread outages arising from non-credible contingencies.

Key findings

Maintaining adequate frequency control

Operability of the power system is reliant on the ability to maintain the frequency within a narrow control band. Should the frequency fall below 48.75 Hz, automatic protection systems will disconnect customers from the grid as a last line of defence against widespread outages.

► *There are many variables that determine the ability to maintain the frequency within the standard. The most significant variables are the prevailing level of inertia, availability of spinning reserve and the expected magnitude of a system disturbance, or contingency event.*

► *The prevailing level of inertia is primarily a function of the specific synchronous generation machines that are on-line and their rotating mass. When the level of inertia is low there is an increased risk that the frequency will vary outside the frequency operating standard for a single contingency.*

► *The prevailing magnitude of a contingency event is typically a function of size of the largest single generation unit output or loss of a single network element which may disconnect multiple generation facilities. However, this has been exacerbated by concurrent or sympathetic disconnection of DPV which is making the actual magnitude of contingency size/risk greater.*

[2] Frequency nadir is the minimum frequency observed on the power system following a system disturbance.

In order to establish a secure operating environment considering the collective effects of system inertia and contingency risk (amongst other factors) a minimum demand threshold has been defined. This measure is called the minimum demand threshold (MDT). The limiting factor that currently sets the demand threshold on the SWIS in low demand periods is frequency stability.[3]

- *The MDT is the minimum operational demand*[4] *level below which the SWIS is no longer secure and emergency actions are required. It is expressed as a MW range and depends on the specific collection of generators that are online at any point in time.*
- *Taking action to ensure the operational demand is maintained above the MDT ensures that the power system can return to a satisfactory operating state without the need to disconnect a large portion of customers in the event a credible contingency occurs.*
- *From 14 February 2022 Emergency Solar Management (ESM) capability must be available on any new and upgraded DPV systems installed. This functionality provides another option for the power system operator to maintain system security by ensuring that demand stays above the MDT.*

At the time of preparing this report, the currently established MDT on an operational demand basis varies between approximately 550 MW and 650 MW depending on the generators that are online at the time. This is based on expectations around the availability of the current generation fleet during times of minimum operational demand. Based on forecasts of minimum demand in AEMO's WEM 2022 ESOO Expected Scenario, the MDT is expected to materialise within the next year.

Determining the magnitude of a credible contingency

It has been identified that a portion of DPV disconnects due to an inability to ride through voltage and frequency disturbances caused by faults on generator circuits and/or the transmission network. This effectively increases the magnitude of the contingency event on the system, adversely impacting frequency stability and system security. In most scenarios, it is the impact of DPV disconnecting that potentially places the SWIS outside system security boundaries. Operating the power system at or above the MDT whilst taking into consideration the potential loss of DPV when scheduling generators for provision of ESS ensures the system remains secure.

- *To ensure that new and upgraded DPV systems do not further exacerbate this issue, new inverter standards were introduced in December 2021. Enhanced ride through capability was mandated in the SWIS in May 2021. Whilst new and upgraded systems are expected to have this capability, it will take time for a sufficient scale of implementation to materially improve system security.*
- *The largest contingency on the SWIS has increased as a result of DPV disconnecting and any studies or operational practices that use the largest contingency size as an input should account for this.*

Frequency stability studies completed throughout this project have identified that contingency sizes at certain times will be considerably larger when taking DPV disconnections into account. Possible activation of automatic UFLS was identified due to frequency falling below 48.75 Hz. In all cases studied, dispatching generation out-of-merit as a pre-contingent response, within the MDT, was sufficient to ensure UFLS was not initiated after the outage occurred. However, as power system inertia continues to decline, dispatching generation out-of-merit will no longer be sufficient.

[3] The limiting factor that sets the SWIS MDT may change over time.

[4] The MDT has been determined based on system load which has been translated to an operational demand equivalent for the purpose of this report. Section 3.1 provides a summary of the different demand definitions.

Further work will assess the risk associated with the different fault scenarios that lead to a material quantity of generation and DPV disconnecting from the system. This involves consideration for the likelihood of the different fault types against the severity of the consequence to the SWIS to determine an appropriate operational response. This includes assessing the impact of DPV disconnection and UFLS.

Maintaining adequate flexibility to respond to large rapid changes

The prevailing level of dispatch from on-line generators plus available voluntary or contracted demand side response determines the operational flexibility of the system to respond to contingency events. Ensuring that the SWIS is carrying sufficient spinning reserve to rapidly replace supply that is lost from a credible contingency event is currently the binding limitation that sets the MDT range. There should be sufficient flexibility available to replace lost supply and to maintain frequency above the threshold for operation of the UFLS system. The MDT is set by the minimum sum of the active power output of all generators that are online, whilst also considering the requirements to provide sufficient ESS to maintain a secure power system.

- *The power system operator has enhanced operating protocols within the daily planning routine to specifically consider this issue and factor necessary actions into market operations.*
- *In the short-term, there are occasions where additional generators are required to be scheduled online to operate with sufficient headroom to increase the amount of spinning reserve available to maintain frequency stability and avoid UFLS. This also means that other generators may be dispatched to a lower output.*

Reviewing UFLS requirements and implementation

The primary purpose of the UFLS system is to provide a last line of defence against uncontrolled widespread outages resulting from several non-credible contingencies. Prior to the advent of significant quantities of DPV, the UFLS system implementation has been based on customers connected to the distribution system predominantly being loads. Various segments of the power system are configured to automatically disconnect from the power system when the frequency falls below 48.75 Hz (stage 1) and subsequent lower frequency levels. The target level of automatic disconnection is 15% of system demand in stage 1 and a cumulative 75% across 5 stages.

As DPV installations have increased, the underlying load connected to the distribution system is increasingly being supplied from DPV generation, resulting in a material reduction in net demand on the distribution system, eroding the efficacy of UFLS in the process. Operational experience and observations of distribution network feeder loading has indicated a continual reduction in availability of distribution connected load for UFLS and reverse power flow on distribution feeders.

- *The ongoing relevance of the current UFLS requirements has been tested through detailed frequency stability studies. The study assessed whether achieving the target UFLS requirement of 15% per stage was enough to ensure adequate SWIS frequency response. The studies showed that if the current requirement was met, the performance of the UFLS system would be adequate. However, further increases in DPV connections and future synchronous generation retirements are anticipated to trigger the need to modify the UFLS design standard to maintain adequate levels of performance and risk.*
- *Although achieving the UFLS requirement of 15% per stage is enough to ensure adequate SWIS frequency response after a system disturbance, the SWIS does not currently achieve the requirement due to the degradation of load available for disconnection.*

- *An assessment across a range of scenarios including DPV disconnection and cascading generator tripping was conducted using the historically available load shedding levels and projected UFLS system settings. Based on using the historical average UFLS load shedding levels (from April 2020 to April 2021), the results highlighted contingency sizes that trigger UFLS stages and frequency collapse reduced on average by up to 20%.*
- *A review of national and international best practice in maintaining an effective UFLS system was performed, with a particular focus on identifying the power systems that are experiencing challenges in decreasing minimum demand levels because of increasing DPV penetration. Although it was found that power systems similar to the SWIS are experiencing the same issues and exploring similar solutions, the SWIS does operate with higher risk due to increased DPV penetration and the lack of interconnection to other networks. This places more emphasis on the need to assess UFLS solutions on an ongoing basis.*
- *Due to the rapid erosion of available UFLS demand on the distribution networks, Western Power have recently implemented an emergency solution that facilitated the inclusion of a number of existing transmission connected customers onto the UFLS system to ensure increased demand is available for disconnection. Further work is still needed to add increased functionality that will provide more flexibility in managing the available UFLS reserves*
- *Due to the high growth in DPV connections forecast over the next 5 years, future stages of UFLS investment beyond the current committed works are anticipated to improve and achieve the current and future UFLS design requirements.*

Work already completed has resulted in recommendations for improvements to both the modelling and performance of the SWIS UFLS system, including limiting export on commercial PV disconnections, connection of transmission connected customers into UFLS, functionality for dynamic arming of reverse power blocking, extending implementation of remote UFLS system control and dynamic UFLS management system.

Maintaining sufficient system strength

System strength is a collective term encapsulating a range of technical factors not specifically linked with frequency stability. The common factor coinciding with the low demand issue is that various characteristics of synchronous generators have historically provided for high system strength conditions. As synchronous generators are displaced, the characteristics that they have long provided are removed from the system. Declining system strength presents a complex array of power system control and quality issues associated with generator inverter stability, voltage stability and issues associated with the protection of power system plant. The effects of low system strength are localised rather than system wide and therefore the nature of issues and solutions are location specific.

- *An initial SCR screening tool was built to identify high-risk areas by calculating SCRs for different generation and network conditions. The screening studies identified the North Country region as a high-risk area and a detailed EMT model was built for the generation facilities and the transmission network in that region of the grid. EMT models are being constructed for the other high-risk areas identified.*
- *Assessment for existing generators in that region using a detailed EMT model indicates that existing generators remain stable for the normal and contingency conditions studied, though additional operational scenarios continue to be investigated.*
- *Assessments for new generator connections have identified several issues that are currently being investigated, including the need to retune the controllers that oversee the operational aspects of the facility, investigations into additional customer equipment that may be needed and constrained operation under specific scenarios. This is a part of the standard connection process.*

The system strength work is ongoing and an integrated network and generator EMT model is being built for other high risks areas of the SWIS including Eastern Goldfields, East Country and the South-West. Further studies are also being undertaken for the North Country region for both existing and new entrant facilities for more contingency conditions.

Ensuring sufficient system ramping capability and reactive power control

On very low demand days electricity usage is the lowest in the middle of the day, peaks during the evening and there can be a significant difference between the two. This difference requires a generation fleet that is capable of increasing output to meet the increase in demand across the afternoon period. The scheduling decisions around the dispatch of generators during low demand periods requires consideration for what is needed in the afternoon period. Having insufficient ramping capability can result in adverse impacts to system reliability. Additionally, managing system voltages within planning and operational limits during low demand days can be challenging for lightly loaded power systems. Ensuring there is sufficient capability from generators online to absorb excessive reactive power is important to consider when scheduling to ensure that network voltages are operating within allowable ranges.

- *A ramping study was performed that examined the worst-case system load ramp that may eventuate for the study period between 2021 to 2023. It was determined that sufficient ramping capacity is available to accommodate the worst-case projected 2-hour ramp. To manage the worst-case 4-hour ramp, some non-flexible units may need to be committed in advance of the ramp, which may result in some out of merit dispatch.*
- *Power flow studies were undertaken at progressively lower operational demand for different network operating conditions and switching actions. These studies were performed to assess whether enough reactive capability was available from generators online to ensure voltage limits adhere to planning limits. The studies showed that voltages were able to remain within planning limits for normal operating conditions for the transmission and distribution networks.*

The need for further work in this area will be assessed based on how much minimum demand is falling across 2022.

Using ESM to manage MDT

The MDT is the minimum operational demand level below which the SWIS is no longer secure and emergency actions such as ESM may be required. ESM is one mechanism available to the power system operator to maintain system security by ensuring operational demand stays above the MDT. An MDT of 650 MW is more onerous than an MDT of 550 MW as it binds at a higher operational demand.

The number of customers that may be impacted by an ESM event depends on the quantity of DPV output needed to be curtailed such that operational demand stays above the MDT. How long customers are impacted for depends on the duration of time that operational demand is below the MDT. It may be possible to implement ESM on a rotational basis to spread events across a wide customer base and minimise the potential for customers to be subject to multiple ESM events times within a short period of time.

- *An assessment of demand forecasts and demand profiles were undertaken to assess how often ESM may be required to keep operational demand above the current MDT range. If the forecasts of minimum operational demand in AEMO's 2022 WEM ESOO are reached the MDT is expected to materialise within the next year.*
- *Applying an MDT of 650 MW resulted in first activation of ESM in 2022-23.*
- *Applying an MDT of 550 MW resulted in first activation of ESM in 2022-23 the same year.*

- *The average duration of an ESM event lasted for between 2 and 3 hours. However, in the worst case, the longest ESM event lasted for up to 7 hours, occurring in 2024-25 using an MDT of 650 MW. It is expected that actions would take place to lower the MDT to mitigate against long duration ESM events such as these from occurring.*
- *The average ESM quantity needed to maintain operational demand above the MDT increased throughout the study period. The average quantity of ESM required in the first year varied between 3 MW and 70 MW depending on the MDT used. This increased throughout the study period to between 110 MW and 140 MW. This highlights that ESM events will impact more of the SWIS customer base with declining operational demand.*
- *Based on current DPV installation rates on the SWIS, there should be sufficient ESM capability installed by the time first activation may be required. Compliance of new DPV installations should be confirmed for ESM capability.*

Following this Stage 1 report completion, Stage 2 of the Low Load Project is already in progress to follow through the recommendations for further work.

Consideration for low load events is now being considered in other parts of the planning and forecasting activities embedded in the WEM. These include:

- AEMO's 2022 WEM ESOO, published on 17 June 2022 which refines minimum demand forecasts.
- Western Power's Transmission System Plan, which may report on reliability and security issues, ongoing modelling of UFLS and system strength modelling.
- Energy Policy WA's Whole of System Plan 2023, which will monitor system operability and system security conditions for a range of future energy scenarios.
- Action undertaken as part of the Energy Transformation Strategy Stage 2, which may also examine different incentives to increase demand in the middle of the day.

2. Introduction

The energy transformation is presenting new challenges to power system security on the SWIS. One of these significant challenges is managing power system security during times where electricity demand on the grid is very low.[5]

The continued installation of DPV is resulting in periods of low demand occurring with greater frequency and at increasingly lower levels. This trend is forecast to continue over time and is occurring in parallel to an increase in the participation of inverter-based generation technologies on the SWIS. This is driving a fundamental change to the SWIS with operating conditions emerging that historically have not been observed.

Maintaining power system security during low demand conditions is one key aspect of operating a power system with higher penetrations of renewable energy and DER. The procurement, scheduling and dispatch of energy and ESS requires consideration of these new operating conditions now and into the future.

These new operating conditions also require new methods for modelling and analysing risk. Traditional measures that have historically been used to manage security on the SWIS need to be reviewed in response to the changing power system.

Energy Policy WA, with industry partners Western Power and AEMO have formed the Low Load Project. The project brings together different studies undertaken by Western Power and AEMO to examine the issues associated with low demand and to present outcomes and findings in a co-ordinated manner.

2.1 The Low Load Project

The purpose of the project is to assess, understand and quantify emerging risks to power system security on the SWIS during periods of low demand and to ensure appropriate responses, frameworks and mechanisms are in place and available to maintain power system security when called upon

The project team includes government and industry expert representatives from:

- Energy Policy WA, acting as the project coordinator and lead.
- Western Power, providing expert network analysis, network modelling development, demand forecasting, and delivery of activities to assess network risks and solutions.
- AEMO, providing expert power system analysis, operational experience, forecasting and delivery of activities to assess power system, market risks and solutions.

[5] In the context of this report, the term “low demand” refers to low operational demand.

Q2 2022
Stage 1 Report

Q4 2022
Stage 2 Report

Stage 1

Stage 1 involves detailed power system and network modelling to explore the different technical challenges that could arise during low demand conditions.

This stage involves detailed modelling of the power system and the transmission network to:

- Understand what the issues impacting power system security during low demand conditions are.

- Project when these issues may occur.

- Quantify how often these issues may occur.

- Evaluate the risks to the power system as a result of the identified issues.

Stage 2

Stage 2 presents a recommended course of action to mitigate the identified risks. It involves:

- Evaluating options available to manage issues.

- Recommend a course of action that may involve short-term, medium term and longer-term responses.

- Establish the role of government in the solution.

The purpose of this report is to present a summary of the work undertaken in Stage 1. The structure of the report is as follows:

- Section 1 presents the executive summary of key findings
- Section 2 provides the background of the Project, a summary of this Report and the work that this Project is related to
- Section 3 provides the technical overview of the low demand issues on the SWIS and the mechanisms that are in place currently to manage the risk
- Section 4 outlines the technical areas of focus that the Project has examined, and the approaches taken to examine them
- Section 5 presents a summary of each issue identified through each focus area and the key findings
- Section 6 discusses the next stages of the Project and next steps
- The Appendices provide a summary of the techno-regulatory framework used to guide the analysis undertaken in the Project, a high-level summary of the key data, inputs, assumptions and methodologies used.

2.2 Work related to the low demand issue

The DER Roadmap

The DER Roadmap was published in April 2020 and outlines a five-year plan to guide the integration of DER, including rooftop solar PV, battery storage, electric vehicles and demand response into the SWIS, and ensure that the benefits are shared across all members of the community.[6] A progress report was published in April 2021.[7] Work to implement the roadmap is

[6] https://www.wa.gov.au/government/distributed-energy-resources-roadmap

[7] https://www.wa.gov.au/government/publications/distributed-energy-resources-roadmap-progress-report. For example, the progress report provides information on the development of Project Symphony.

ongoing, with the support of project partners including Western Power and AEMO. Some of the work delivered through the DER Roadmap related to power system risk during low demand include:

- Bringing forward improved disturbance ride through capability for new inverters
- Launch of the WA DER Register which gives AEMO greater visibility of new rooftop solar PV and battery capacity, assisting planning and forecasting
- A review of UFLS to validate the ongoing suitability of the current design particularly in a high DER environment
- The introduction of DEBS, reducing the incentive to oversize DPV systems relative to load, encouraging west facing systems, and improving the value of self-consumption and battery use.
- Project Symphony, a trial that lays the groundwork for enabling virtual power plant participation in various markets in the WEM.

Integrating Utility-scale Renewables and DER

In 2019, AEMO released its *Integrating Utility-scale Renewables and Distributed Energy Resources in the SWIS* report (2019 Renewable Energy Integration Report), identifying an urgent need to manage power system risks presented by growing levels of inverter based renewable generation and DER. The report identified that, without mitigation, the SWIS faced significant issues affecting market efficiency and system stability resulting from unmanaged growth in DPV.

In 2021, AEMO released the *Renewable Energy Integration – SWIS Update,* an update to the 2019 Renewable Energy Integration Report (the 2021 Renewable Energy Integration Report)[8] noting the progress made in improving power system security on the SWIS between 2019 and 2021. These improvements have been delivered as a result of collaboration and co-ordination between key industry bodies, government reforms through the ETS, investment in the technical capability of the SWIS and actions to build upon operational tools and capabilities to manage system security.[9]

Although DPV has been installed at record levels between 2019 and 2021 (with installations exceeding all forecast expectations) the improvements to SWIS power system security realised through work completed to date has resulted in a potential net improvement in power system resilience. Despite the significant progress made, the 2021 Renewable Energy Integration Report does continue to highlight the potential risks associated with further reduced low demand periods.

The report notes that based on the current generation fleet on the SWIS, there will be a minimum operational demand level at which there will be limited combinations of generators that could be scheduled and dispatched to provide both energy and ESS whilst also adhering to technical capabilities such as minimum stable operating limits. Should key generator units be unavailable through a planned or unplanned outage there are potentially fewer combinations that could be made available. This presents operational challenges to power system security as operational demand continues to fall and introduces market inefficiencies due to the need to schedule generation facilities out of merit.

One of the key outcomes of the Low Load Project is to assess appropriate MDT levels to apply to the current generation fleet on the SWIS. Due to the complex nature of power system operations, there is likely to be multiple minimum operational demand values for different operating conditions. These types of thresholds could be set to ensure that demand does not fall below a level where there are not appropriate generation dispatch combinations that can provide a secure outcome.

[8] https://aemo.com.au/-/media/files/electricity/wem/security_and_reliability/2021/renewable-energy-integration--swis-update.pdf?la=en

[9] For example, AEMO has developed and deployed a real-time frequency stability monitoring tool in the control room

The AEMO 2021 Renewable Energy Integration Report makes 13 recommendations for action. The recommendations that are directly related to low demand and examined specifically in this Project include:

- a review of the UFLS scheme
- active management of DPV on instruction from AEMO to avoid power system security issues (also known as emergency solar management).
- the assessment of ramping capability on the SWIS.

Emergency solar management

Following AEMO's recommendation for the introduction of active management of DPV on the SWIS, the functionality for ESM has been introduced from 14 February 2022.[10]

These requirements apply to new and upgraded rooftop solar PV and battery systems with inverter capacities of 5 kW or less. Systems that were installed before 14 February 2022 are not impacted by these new rules unless they are upgraded.

Active management of DPV requires the above systems to have the capability for their output to be remotely turned down or switched off (and back on again) as a last resort in emergency situations to manage power system security, avoiding larger more wide-spread customer outages.

The introduction of ESM provides an additional mechanism for AEMO to manage power system security on the SWIS which will grow over time with continued DPV uptake.

Whilst this functionality will be introduced to new and upgraded systems, the vast majority of existing systems on the SWIS (i.e. nearly 2 GW) will not have this capability unless they are upgraded. As such, there is still an impetus to evaluate the risk to power system security and the operational responses needed to manage the technical issues arising during periods of low demand.

Power system security and reliability standards framework

EPWA released the *Power System Security and Reliability Standards Framework* information paper in 2021 (PSSR 2021 Information Paper) outlining deficiencies with the existing regulation and governance of PSSR standards in the WEM. The paper builds upon the work completed under the Foundation Regulatory Frameworks workstream within the Energy Transformation Strategy in streamlining a number of security and reliability issues including:

- Moving the frequency operating standards from Western Power's Technical Rules to the WEM Rules
- Revising the definition of operating states and the credible contingency framework in the WEM Rules and aligning its operation with the Technical Rules
- Moving the generation performance standards from the Technical Rules to the WEM Rules
- Changes to the rules around UFLS and the requirement for development of an UFLS Requirement and Specification document
- Allowing AEMO membership in the Technical Rules Committee and to provide advice and support on Technical Rules amendments including discussion on PSSR standards.

10 Emergency Solar Management (www.wa.gov.au)

The PSSR 2021 Information Paper notes outstanding issues under the current framework which are related to low demand conditions. In particular, limitations in the existing reliability standards to consider generation and network adequacy for peak demand conditions only, rather than under a broader set of system conditions which may include low operational demand periods. The paper recommended increased co-ordination between AEMO and Western Power to maintain power system security and reliability to cater for the increasing prevalence of low demand intervals amongst interim improvements to PSSR standards.

Project Symphony

Project Symphony is an important test of the long-term vision for active DER participation in the SWIS. Project Symphony lays the groundwork for enabling household solar, batteries and appliances (like pool pumps and air-conditioners) to opt-in to be aggregated as VPPs for participation in various energy markets. To manage power system security during low demand periods, a VPP could be used to increase operational demand on the power system by either turning down output from DER or turning on appliances. Market mechanisms would be in place to compensate the VPP, allowing aggregators to provide a service to manage power system security using DER. The project has received ARENA funding for the development of the necessary hardware and systems to enable VPP aggregation and participation.[11]

[11] https://arena.gov.au/news/composing-a-distributed-energy-symphony-in-western-australias-largest-energy-grid/

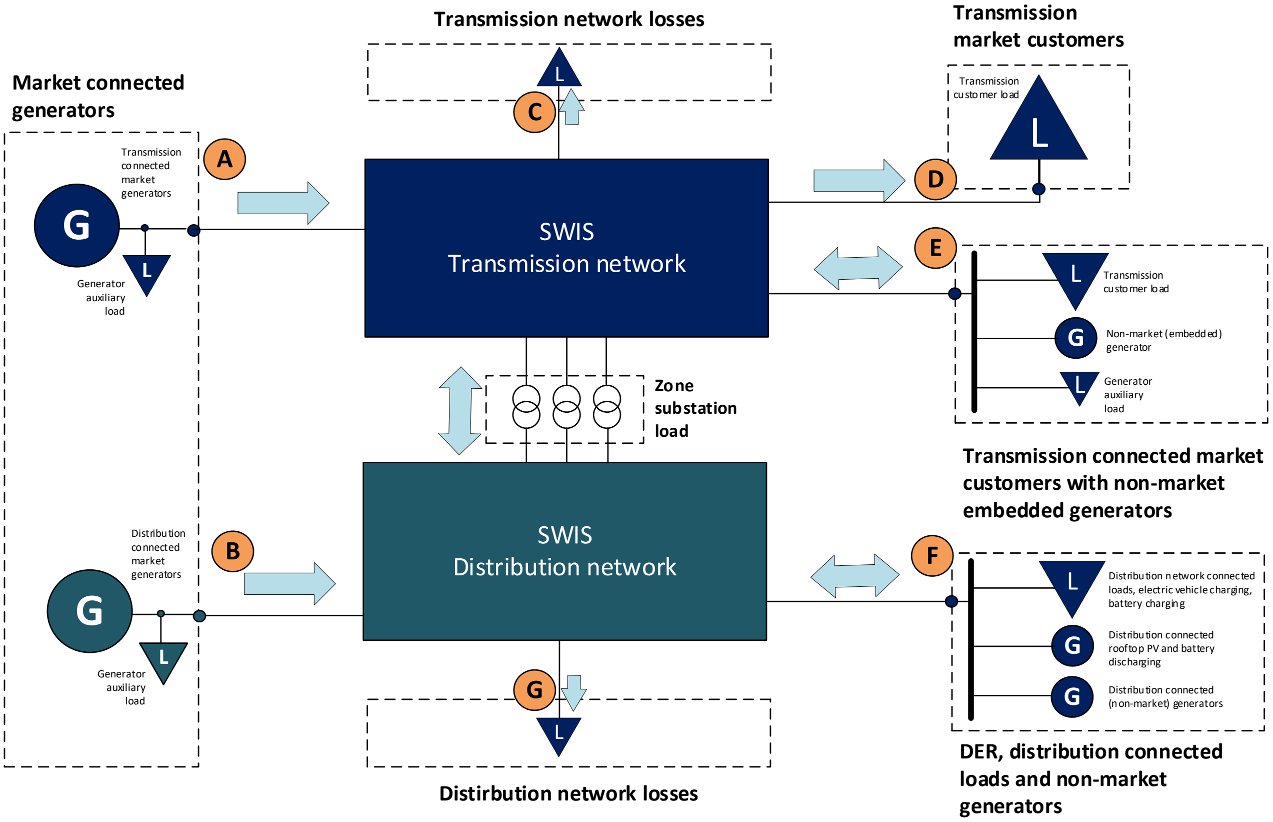
3. The low demand issue

3.1 Demand definitions

Table 1 provides the definitions of demand used in the context of this report. Demand values are typically based on interval metered data which is the basis for AEMO's ESOO reporting.

Table 1: Demand definitions

Term	Definition
Demand (or load)	'Demand' (or load) refers to the electrical power that is being consumed. In the context of this report, demand refers to operational demand unless otherwise stated.
Operational demand	The term 'operational demand' refers to the demand that is supplied from market generators. In the diagram below operational demand is represented by: (A) + (B), where (A) + (B) = (C) + (D) + (E) + (F) + (G)
Low demand	The term 'low demand' refers to low operational demand, referring to where demand supplied from market generators is low.
Minimum operational demand	The term 'minimum operational demand' refers to the lowest level of operational demand observed on the grid and can be measured at any time of the day, on any day/month/year.



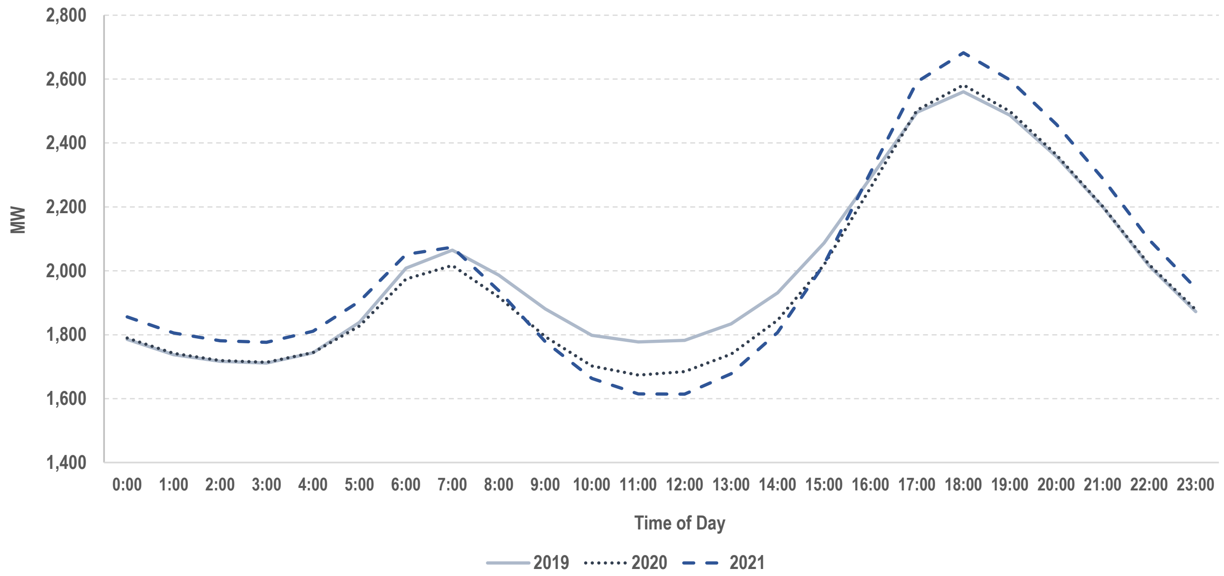
3.2 Low operational demand on the SWIS

A key characteristic of the energy transition occurring in Western Australia is the speed and scale at which customers are installing DPV on their premises. This technology has accelerated in recent years with an estimated 27.5 MW of DPV installed per month.[12] The estimated total DPV in the SWIS as of March 2022 is 2042 MW with the majority of DPV systems installed being in the metropolitan and greater urban areas.

AEMO's 2022 WEM ESOO projects this technology to grow at an average annual rate of 7.0% or 238 MW annually over a 10-year period.[13] The SWIS is forecast to have an estimated 4716 MW of DPV installed by October 2032.

The impact of additional DPV installations on the SWIS can be seen in the average time of day demand profile in Figure 1. SWIS demand during the period between 8am and 3pm has fallen further in recent years with the lowest observed demands on the SWIS now occurring during the middle of the day.

Figure 1: SWIS average time of day demand profile



Recent challenges with the global economy have also resulted in new commercial and industrial operations that were expected to come online being deferred. Additionally, large energy users are now considering how best to manage emissions reductions throughout their operations. Whether these users self-supply through behind-the-meter low emissions technologies or electrify operations and seek additional demand from the grid will impact operational demand on the SWIS.

The combined effect of these factors is that the minimum daytime demand being supplied from the SWIS has fallen in recent years. As a result, the SWIS is more frequently operating at lower operational demand levels. Conversely, the average peak demand on the SWIS has increased during the evening period in 2021 highlighting system reliability still remains an important consideration.

[12] Based on the WEM DER Register accessed at the time of AEMO's 2022 WEM ESOO publication. Based on installed panel capacity.

[13] This number includes degradation of DPV capacity. The ESOO forecasts continued growth in DPV uptake however this is moderated over time owing to declining financial incentives..

Figure 2 shows a load duration curve for the SWIS for the bottom 10% of all operational demand levels for that year.[14] The load duration curve shows how often the SWIS operated below a certain demand level. It can be observed that in each year from 2019 to 2021, the SWIS has operated with consistently lower levels of operational demand and for a greater proportion of the year.

Figure 2: SWIS load duration curve (lowest 10% of all periods)

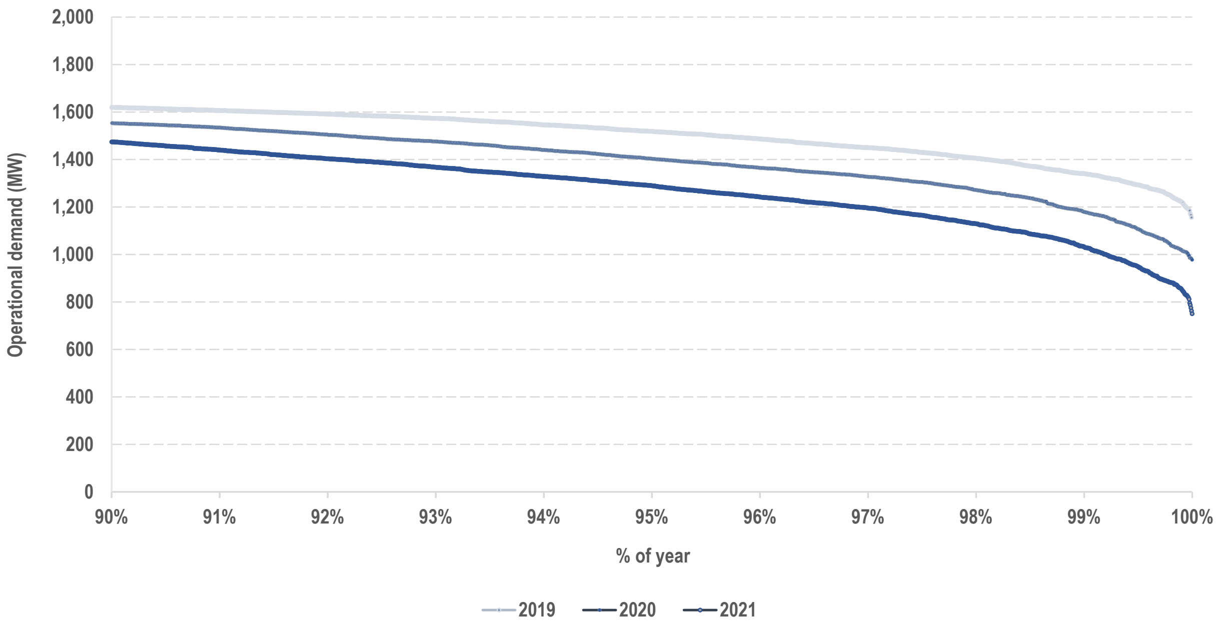


Table 2 presents the percentage of the year the SWIS has operated below 1000 MW and the equivalent hours that presents. In 2021, the SWIS operated with operational demand below 1000 MW for around 0.8% for that year (equivalent to 70 hours). In 2019, this value was zero.

Table 2: Duration of the SWIS operating below 1000MW

Year	Percentage of the year the SWIS operated below 1000 MW	Equivalent hours of the year the SWIS operated below 1000 MW
2019	0.00%	0.0
2020	0.04%	3.5
2021	0.80%	70.0

3.3 Minimum operational demand levels

Table 3 shows the five lowest minimum operational demand levels recorded up to mid November 2021. All instances occurred in the middle of the day and on the weekend.

Table 3: Five lowest minimum operational demand levels

Date	Trading Interval (Beginning)	Day of week	Minimum operational demand (MW)
5 September 2021	12:30	Sunday	871

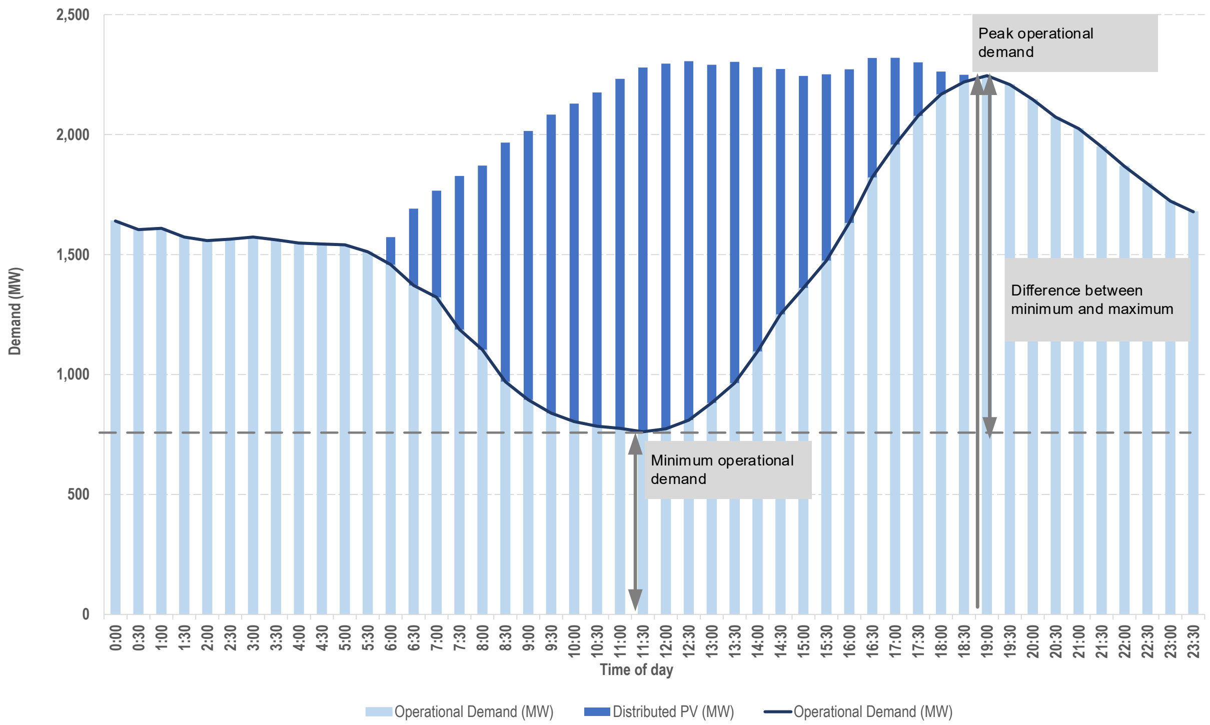
[14] Published WEM Market Data for 2021, 2020 and 2021.
https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/data-wem/market-data-wa

Date	Trading Interval (Beginning)	Day of week	Minimum operational demand (MW)
23 October 2021	12:30	Sunday	862
7 November 2021	12:30	Sunday	834
13 November 2021	12:00	Saturday	821
14 November 2021	11:30	Sunday	765

At the time of writing this report the minimum operational demand record observed on the SWIS is 765 MW on 14 November 2021.[15] Figure 3 shows the operational demand recorded on that day and shows operational demand starts to materially decrease around 6:00 as DPV starts generating, reaching a low in the middle of the day coinciding with peak DPV output.

Operational demand begins ramping up from the middle of the day and peaks between 18:00-19:00. The difference between the minimum demand level and the peak demand level is 1452 MW highlighting the ramping requirement across the 6-hour period from the minimum demand period to the peak demand period. This ramping profile is now a common occurrence of the SWIS.

Figure 3: Operational demand on the 14 November 2021



3.4 Minimum operational demand forecasts

As a result of the continued increase in DPV installations on the SWIS, AEMO's 2022 WEM ESOO forecasts minimum operational demand levels to reach progressively lower levels across the next 5 years. Table 4 provides a summary of the minimum operational demand forecasts in AEMO's 2022 WEM ESOO based on the current forecast DPV installation rates in the absence of ESM.

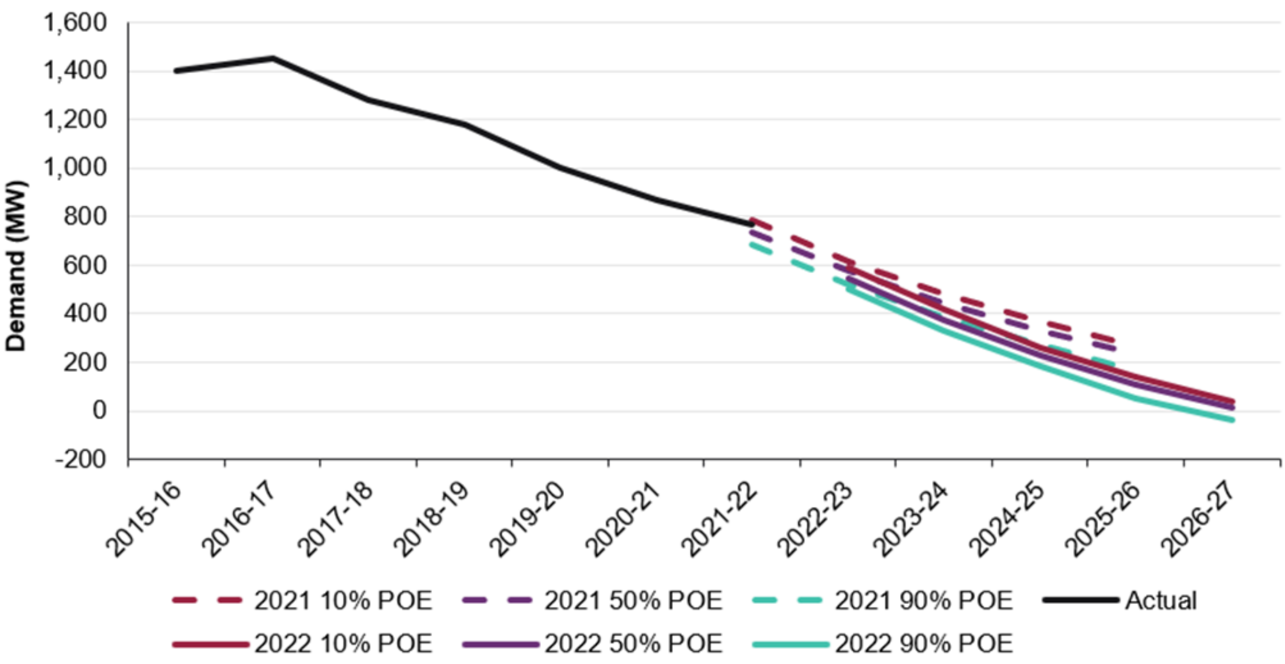
[15] The largest individual SWIS load (Boddington Goldmine) had a shutdown during this period.

Table 4: Minimum operational demand forecasts expected demand growth

Capacity Year	Minimum operational demand forecast		
	10% POE	50% POE	90% POE
2022-23	587	546	502
2023-24	416	375	333
2024-25	262	231	184
2025-26	140	108	54
2026-27	40	11	-37

Figure 4 shows the forecast annual minimum operational demand to 2026-27 and historical observations. AEMO's 2022 WEM ESOO forecasts a minimum demand level of 546 MW in 2022-23 under the expected scenario with the current minimum operational demand recorded at 765 MW. These recent observations confirm AEMO's historical near-term forecasts, highlighting the extent at which minimum operational demand is falling.

Figure 4: Minimum operational demand forecasts (AEMO 2022 WEM ESOO)



3.5 Changing generation mix and inertia

In parallel with the lower demand levels being observed on the SWIS, the generation mix dispatched during low demand periods is also changing.

Figure 5 shows a comparison of the average output of scheduled generation against the average output of non-scheduled generation across the year on a time-of-day basis. The figure shows that output from scheduled generation has decreased in each of the previous three years whilst output from non-scheduled generation has increased.[16]

Notably, the reduction in scheduled generation is observed to be more pronounced during the middle of the day, caused by the significant reductions in operational demand. During times where operational demand is low, large amounts of DPV generation reduces the demand for electricity supplied by generation facilities in the WEM whether scheduled or non-scheduled. It can be observed that the average generation dispatched from both scheduled and non-scheduled generation in the middle of the day is less. The reduction in operational demand which is occurring in parallel to the recent connections of large non-scheduled generators has displaced scheduled generation.

Figure 5: Average time of day generation from scheduled and non-scheduled generation

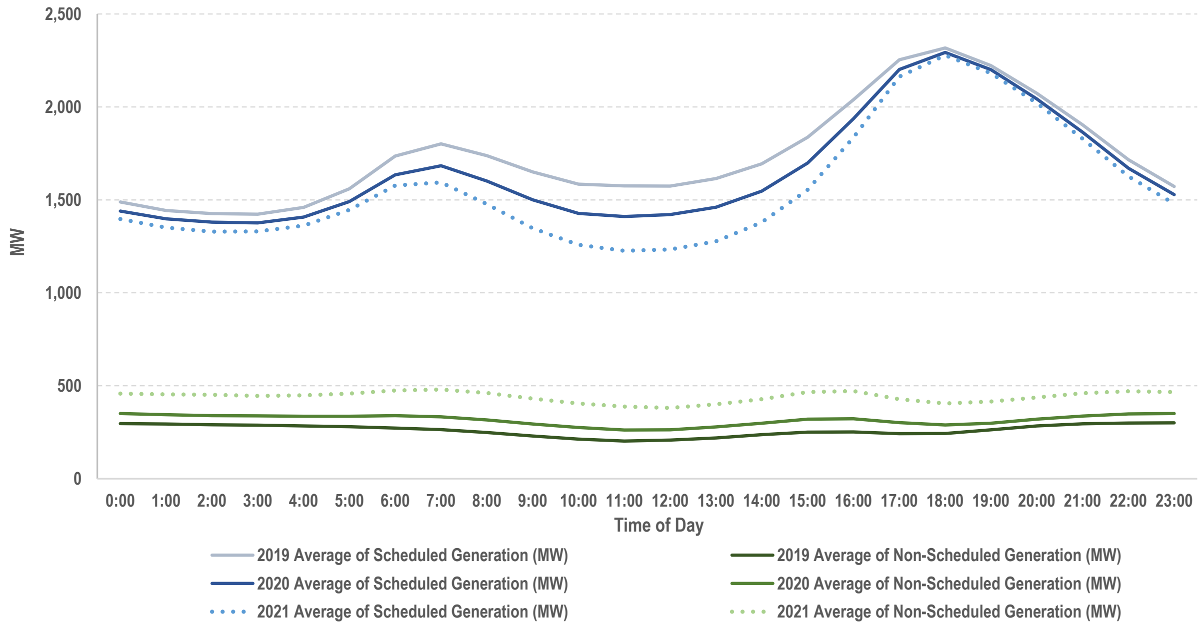
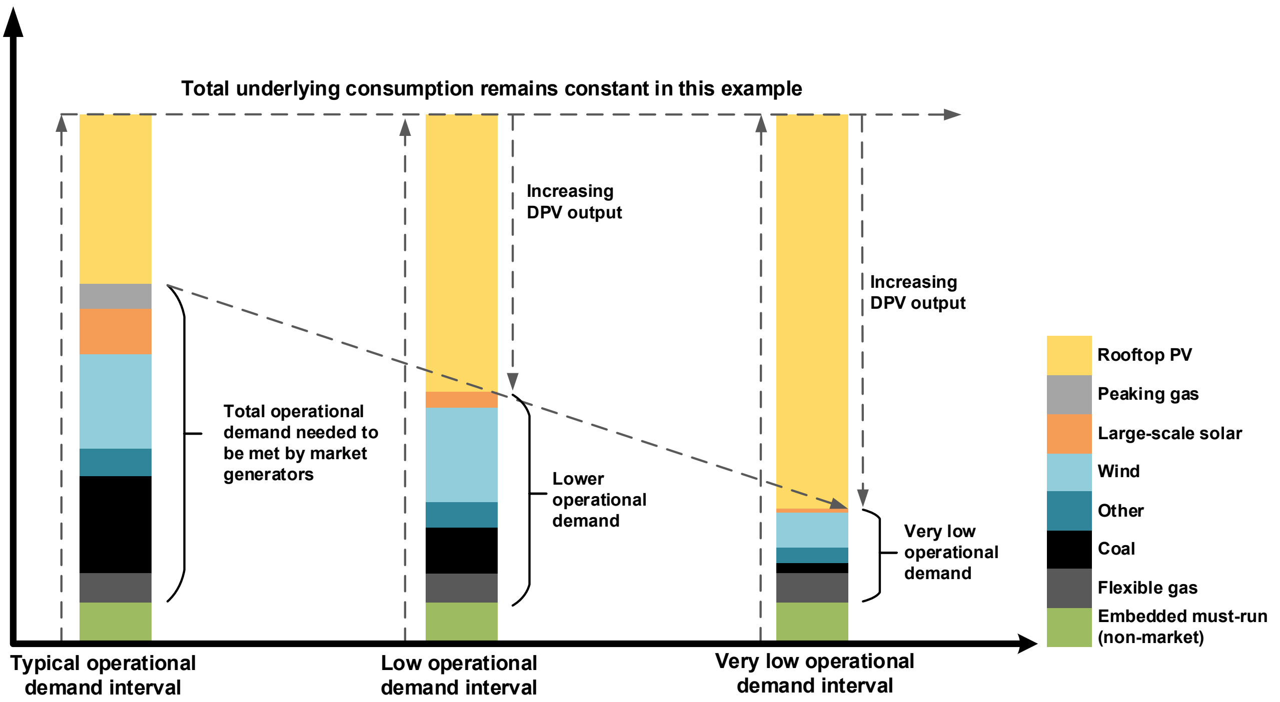


Figure 6 shows a diagram illustrating the conceptual impact of increasing DPV output on lowering operational demand in the SWIS and the impact on the mix of generation that is dispatched during these periods based on the generation technologies connected and available in the SWIS currently. The chart conceptually illustrates that during times where operational demand is very low, less energy is required to be supplied by all types of generation facilities participating in the WEM.

[16] In the context of this report, non-scheduled generation refers to generation from intermittent non-scheduled generators (IINSG) and does not include photovoltaic non-scheduled generators

Figure 6: Conceptual impact of DPV on reducing operational demand



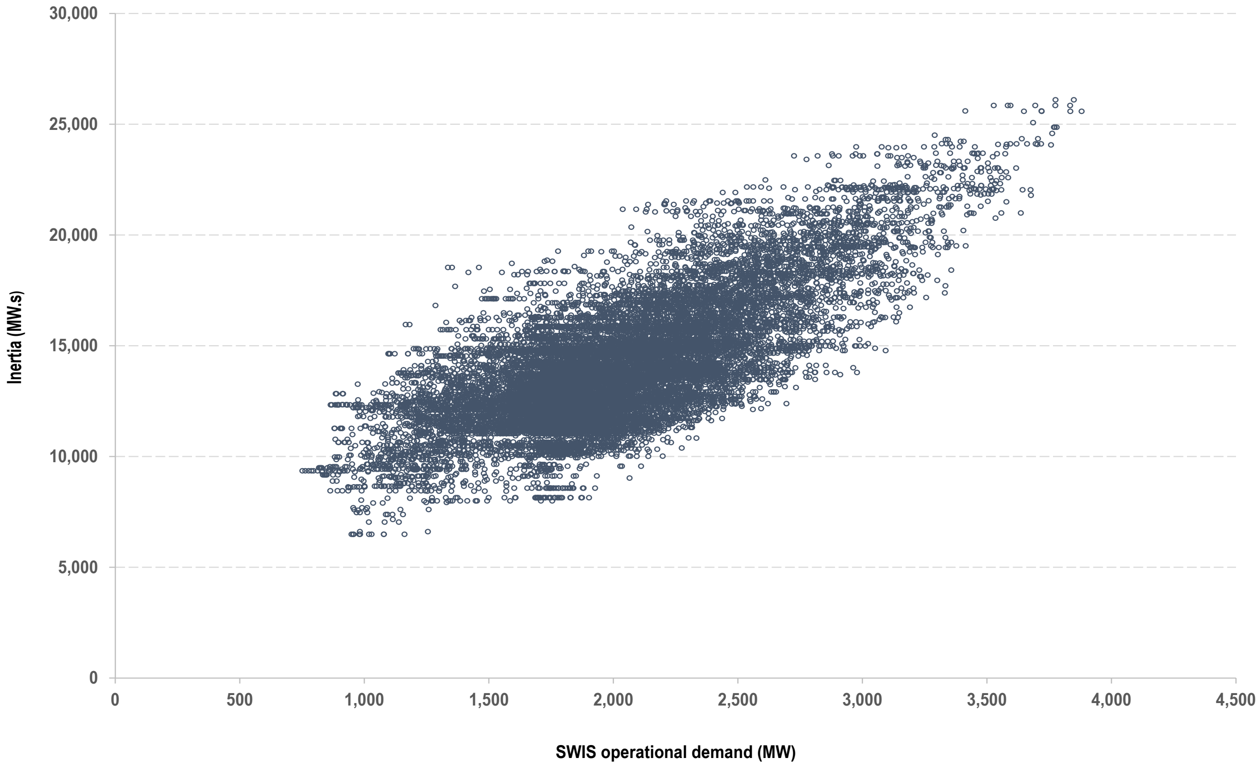
From a strictly energy perspective the synchronous machines that have historically been dispatched for energy during these low demand periods are more likely to be out-of-merit, operating flexibly or increasingly likely to be taken off-line altogether, decreasing the physical property of inertia available from market generation facilities.[17]

Inertia can be defined as the amount of kinetic energy stored in the rotating masses of generators and motors that are synchronised to the power system. This stored kinetic energy is supplied to the power system when there is a sudden change in demand and generation. This is often referred to as the inertial response of the power system.

[17] There may be several generation facilities that will bid a portion of their available energy at the floor price to be dispatched for commercial or technical reasons. These units are considering a complex combination of technical and commercial considerations involving operating above minimum stable limits, the impact of operating at a lower part of their efficiency curve requiring more fuel per unit of energy produced, minimum run times, the cost impact of additional starts and shut-downs and also regulatory obligations. There are also embedded generation units that are typically operating within a load facility providing support to industrial processes such as for producing steam. Additionally, units that are cleared for ESS may also be scheduled to be on in the energy market.

Figure 7 shows a scatter plot of the calculated inertia from market generators against operational demand in 2021.[18]

Figure 7: Scatter plot of operational demand versus inertia from market generation



The primary source of inertia and inertial response on the power system is from generators that are synchronous machines. The inverter-based resources that are currently connected to the power system through power electronic devices do not provide inertial response.[19]

Figure 8 and Figure 9 shows the generation (MW) from inverter-based resources and non-inverter-based resources alongside system inertia from market generators on the lowest operational demand day of 14 November 2021 and the lowest calculated inertia day of 14 March 2021.[20]

In Figure 8 the step change in inertia occurring at 8:00 and at 13:30 illustrates the impact of synchronous generation decommitting and committing back to the power system. The inertial response is provided by market generation sources available in the SWIS regardless of generation output. This means that whilst the level of inertia provided from a machine dispatched at very low generation output is the same as that of the generator dispatched at maximum output, when a machine synchronises or de-synchronises, inertia increases and decreases in a stepped response.

In Figure 9, the step change in inertia occurring at 4:00 is the impact of one of the coal fired units de-committing. Similarly, the larger step change observed at 9:00 is the impact of another synchronous unit de-committing from the power system. Inertia begins to increase in stepped

[18] Inertia on the power system is not a directly measurable quantity. SWIS inertia is calculated for each trading interval based on reported market generation dispatch data and inertia constants for each facility in the SWIS. These system inertia values do not include demand side inertia, distribution connected generators or embedded generators that may be behind the connection point. In the SWIS, the presence of demand side inertia can be large.

[19] It is noted that facilities that are equipped with special control loops in the future may be able to emulate an inertial response.

[20] Inertia is also provided by other elements such as demand side inertia (synchronous motor loads), non-market synchronous machines that may be an embedded generator behind a connection point and other power system elements such as synchronous condensers.

responses as overall demand increases in the afternoon period and more generation is synchronised. The de-committed unit and other gas units come online in the afternoon demand ramp.

Figure 8: Inertia from market generation sources 14 November 2021 (lowest demand day)

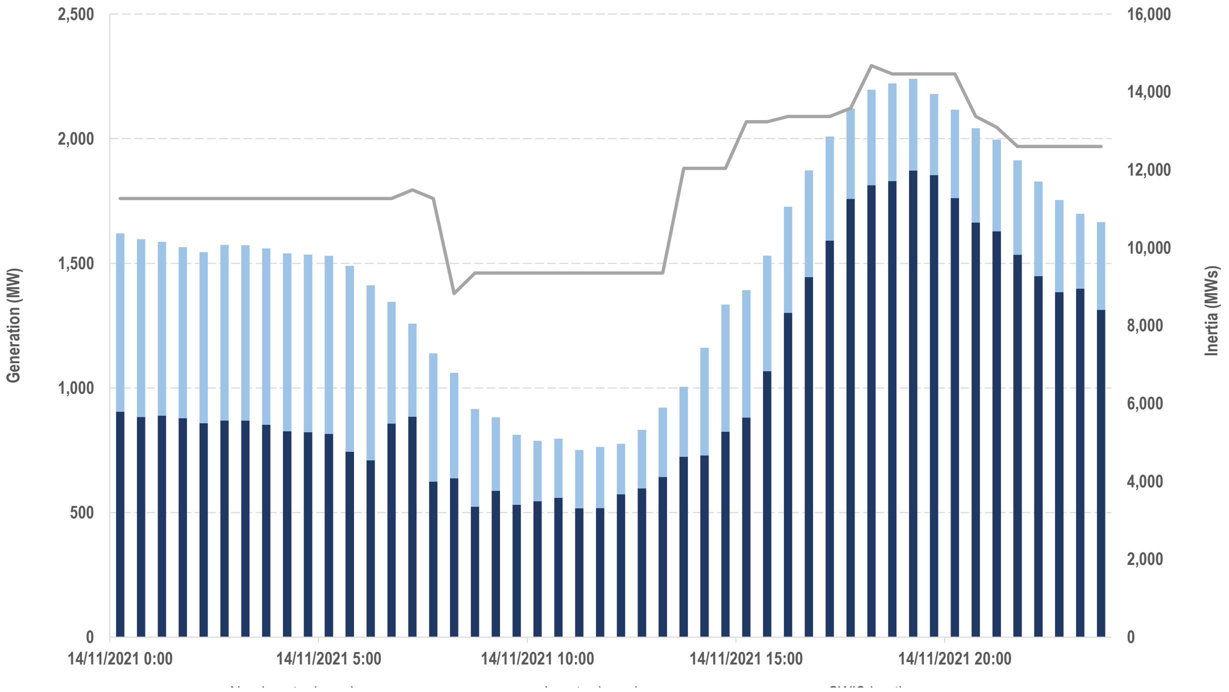
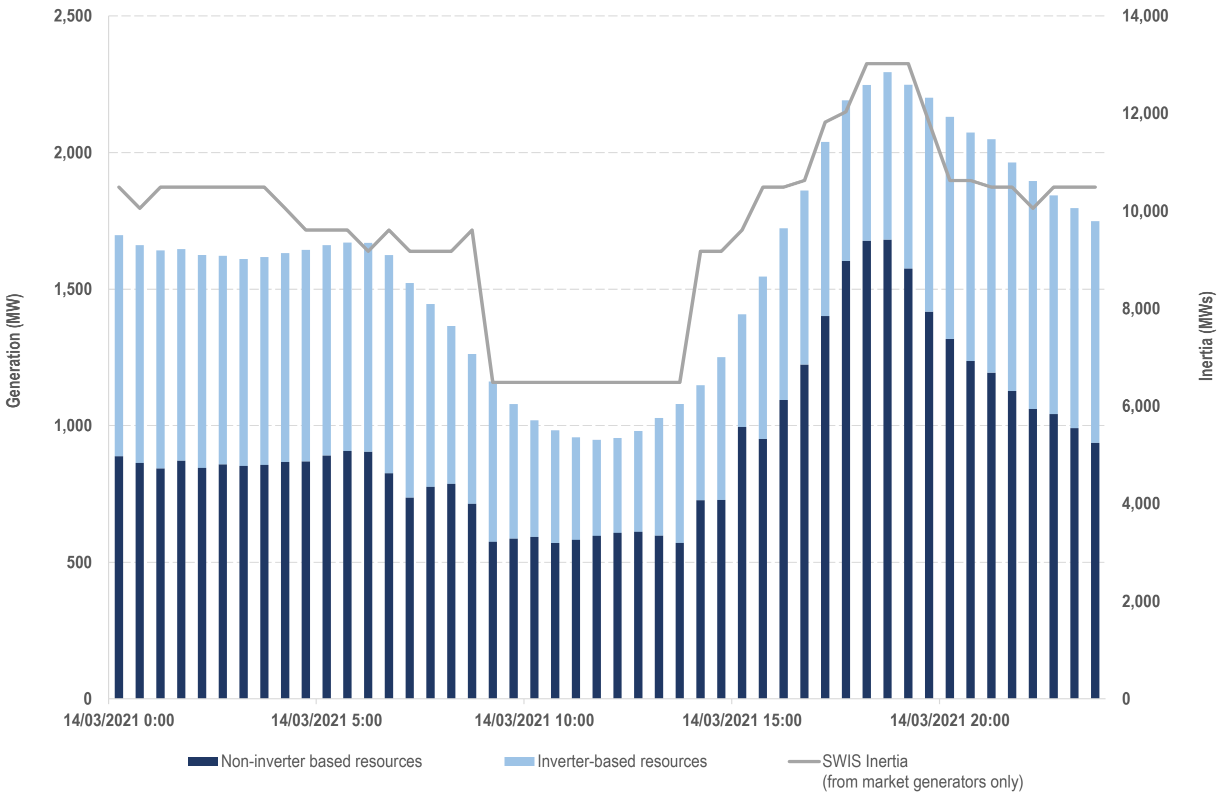


Figure 9: Inertia from market generation sources 14 March 2021 (lowest inertia day)



3.6 The impact of decreasing synchronous generation

Synchronous machines have historically provided services to the SWIS such as inertia (which improves ability to maintain frequency stability), system strength (to help maintain voltage stability) and ramping capability (to meet rapid changes in supply-demand balance) by virtue of being on for the purpose of providing energy. These services have been provided as a by-product of the synchronous generation capacity mix on the power system.

In the absence of specifically procuring these services from alternative sources that provide a similar level of response, the power system during low demand periods will be characterised by:

- **Lower levels of inertia,** resulting in an increased risk of frequency stability issues associated with a post-contingent frequency response that exhibits very high rates of change of frequency and a lower frequency nadir.
- **Lower system strength,** manifesting itself as a complex array of issues associated with generator inverter stability, voltage stability, power quality and issues associated with protection of power system plant.
- **Less operational flexibility,** increasing reliability issues associated with generation supply balance and generation supply adequacy during the ramp from minimum demand to the peak demand interval.

A number of other emerging aspects on the power system have also been identified which are contributing to increasing risks during very low demand periods. These emerging aspects add to the complexity of managing system security during low demand periods and include:

- **The potential for DPV to disconnect during system disturbances**, resulting in increased magnitude of credible contingency sizes, increasing the risk of frequency instability
- **Two-way power flow on the distribution network,** challenging the efficacy of the SWIS under-frequency load shedding (UFLS) system designed as a last resort measure to help protect the SWIS against a widespread system outage following non-credible contingencies.

As more synchronous machines reach the end of their physical and economically efficient life, the total inertia that is installed on the SWIS will decrease over time (all other things being equal). This means that whilst there may be operational responses now that enable necessary generation to be dispatched to meet energy and essential system service requirements, the exit of these machines will require new technologies to replace these services over time. These technical considerations are discussed in greater detailed in section 3.7 and further in appendices.

3.7 Technical considerations during low demand periods

Managing power system security during low demand periods requires consideration of several complex interactions between the physical power system and the commercial markets in the WEM. Table 5 provides a summary of some of these technical considerations with a specific focus on low demand periods.

Table 5: Technical considerations during low demand periods

Technical consideration	Comments
Maintaining frequency stability for system disturbance conditions	Maintaining frequency stability during low demand periods is made more difficult as the power system may exhibit a higher rate of change of frequency and a lower frequency nadir in the event of a large supply outage coinciding with low inertia conditions.

Technical consideration	Comments
	This means that the SWIS frequency is at greater risk of falling outside frequency operating standards and in the worst-case may result in a large number of customers being disconnected. The above is also made more challenging due to the potential for undesirable DPV disconnection during system disturbances thereby increasing the largest supply contingency.
Speed of primary frequency response	Arresting falls in system frequency in a timeframe quick enough to start bringing the power system back to steady state operating conditions relies on very fast frequency responses provided through a system inertial response (available from synchronised generation facilities or technology such as synchronous condensers) or other technology types able to provide a very fast demand reduction or supply response. In a power system with very high rates of change of frequency, the timeframe required for the response to be enacted will mean certain technology types cannot respond fast enough to meet that requirement.
Managing system strength	Managing system strength is a key aspect of maintaining system security during low demand periods in power systems with very high penetrations of inverter-based resources and low levels of inertia. There is extensive analysis focusing on this aspect of the power system nationally and internationally. The study of system strength is a field of investigation centred on analysing the inter-related aspects of stability, power quality and protection. System strength is a measure of how resilient the voltage waveform on the power system is to disturbances, such as those caused by a sudden change in load or an energy producing system, the switching of a network element, tap changing of transformers and other types of faults.[21] A network location is said to be "strong" in terms of system strength when the voltage at that location is relatively unaffected by a nearby disturbance. Conversely, a location is said to be "weak" in system strength if the voltage at that location will be relatively sensitive to a disturbance, resulting in a voltage dip (or increase) that is deeper and more widespread.[22] As highlighted in section 3.5, at times of very low demand and with energy being supplied via a predominantly inverter-based generation fleet, there are fewer synchronous machines connected to the power system. The impact of low system strength needs to be examined across many different lenses as the issue may manifest in different ways. For example, a manifestation of low system strength is related to complexities associated with inverter control systems that allow inverter-based resources to connect to the grid. Inverter manufacturers will specify a minimum short-circuit ratio as a proxy for system strength at

[21] WEM Rules Feb 2022, Technical Rules (30 June 2021 Amended)

[22] Based on the definition of system strength used in the proposed amendments to the Technical Rules

Technical consideration	Comments
	which stable operation of the inverter is guaranteed. Operating below the minimum levels often presents challenges related to the synchronisation of the facility to the network and maintaining stable operation. Operating far below the minimum guaranteed SCR will mean different approaches will be required, such as the use of grid forming inverters or supplementing system strength with additional connection assets. Other consequences of operating a power system with lower system strength include: o A more complicated connection process for new entrant connections resulting in longer timeframes for connections, driven by investigations into alternative options such as control system tuning, additional connection assets and operational constraints. o Complexities associated with outage management and outage approvals. Historical outage planning has largely involved assessing whether enough generation is available to be dispatched to meet the forecast demand. However, outage approvals will become more complicated with lower system strength as reducing fault levels/short-circuit ratios may impact inverter-based resources that are subject to those constraints. o Adverse impacts on power quality, manifesting in reliability issues.
Managing system strength (from a modelling and simulation perspective)	SCR is used as an indicator of the strength of a connection point on a power system. This approach is useful as the SCR provides a simple metric that can be calculated and assessed relatively quickly in power flow analysis software. However, SCR does not provide the full story of whether a system strength issue is present and/or what type of issue is likely to manifest. The modelling that has historically been used to simulate generator response is considered no longer sufficiently accurate to assess areas of a power system with very high penetrations of inverter-based resources or single facilities that may be connected to a weak part of the network. The response of these resources is highly dependent upon the programming of the software that controls the electronics that act as the interface between the grid and the energy source. These parts of the network will need detailed computer representations that model the response of these power electronics and the operation of the software control systems at a very fast timescale. This is especially important in grid locations where large amounts of inverter-based resources are connected in proximity.
Disconnection of DPV[23]	From a system planning and operations perspective, a key input into modelling frequency response is the size of the largest supply outage.

[23] Changes to connection requirements seek to mitigate this issue, by requiring voltage disturbance ride though capabilities for new or upgraded installations after 1 July 2021. Whilst this action will go some ways to mitigating the impact of future DPV installations on increasing the largest supply outage it will take several years before inverters with updated capability make up the majority of DPV on the system. Disconnection of DPV is therefore likely to be an issue to be managed.

Technical consideration	Comments
	The connection of specific generation facilities in recent years has meant that the largest supply outage could be set by the potential for a network outage to disconnect multiple generation facilities. The possibility of DPV disconnecting further exacerbates the issue. DPV can disconnect because of a fault on either a network element or a generator circuit. These are described below. (1) Network outage ○ A fault occurs on an electrically close transmission network element causing a substantial voltage depression at nearby metropolitan zone substations. ○ A portion of DPV and customer load disconnects due to an inability to ride through a voltage disturbance. This has the impact of reducing system frequency if the amount of DPV disconnected is greater than the load that is disconnected. ○ If the frequency falls below an operational threshold another portion of inverter connected DPV trips due to instability of the inverter to be able to ride through a frequency disturbance thereby reducing frequency further. (2) Generator outage ○ A fault occurs on a generator circuit causing frequency to fall due to the generator being lost. ○ A portion of inverter connected DPV disconnects due to an inability to ride through a frequency disturbance reducing system frequency further ○ The same fault that occurred on the generator circuit simultaneously causes a voltage depression at nearby metropolitan zone substations. ○ A portion of inverter connected DPV and customer load disconnects due to an inability to ride through a voltage disturbance reducing system frequency further if the amount of DPV disconnected is greater than the quantum of load disconnected. In both situations described above, the largest supply outage on the SWIS has increased due to a portion of DPV not being able to ride through frequency and/or voltage disturbance. This increases the contingency size in both instances. Whilst the issue of DPV disconnecting is a risk during all daylight periods, it is more onerous during low demand conditions as this is where the ratio of DPV output to demand is the highest. Shoulder periods may also exhibit increased risk as this is where generation is increasing on the system to meet increasing demand thereby increasing the single contingency size during this period. The impact of losing generation supply during low demand periods is greater due to the likelihood that system inertia is lower and the rate of change of frequency following a system disturbance is greater contributing to a lower frequency nadir during the disturbance.

Technical consideration	Comments
Maintaining under frequency load shedding levels (UFLS)	UFLS refers to the automatic protection scheme that is designed with the aim of arresting the frequency decline and preventing a system wide collapse. The UFLS system trips blocks of load in five discrete stages following the non-credible loss of multiple generators and/or network elements. Western Power has traditionally implemented UFLS through the automatic disconnection of medium voltage distribution network feeders (operating at 11, 22 and 33 kV).[24] Activation of UFLS results in demand being removed from the power system. The design of UFLS in the SWIS is predicated on distribution feeders being a net importer of energy (i.e. acting as a net load) such that when this UFLS is activated, the net impact is a fall in demand. If a distribution feeder was acting as a net exporter of energy (for example, due to DPV generation exceeding the demand on the feeder), disconnecting such distribution feeders would exacerbate the frequency decline as it would result in a further reduction in supply to the power system. The significant uptake of DPV in the SWIS is resulting in reduced levels of demand on distribution network feeders and increasing number of feeders becoming net exporters. This means that the net demand available to be disconnected from distribution feeders during low demand periods. Not maintaining adequate levels of UFLS on a power system means it is at greater risk of triggering deeper UFLS stages (more customer disconnection) and widespread outages.
Maintaining enough ramping capability on the power system to meet future peak demand requirements.	On very low operational demand days, demand is the lowest in the middle of the day and peaks during the evening and there can be a significant difference between the two. The difference requires a generation fleet that is capable of ramping up to meet the increase in demand. During very low demand periods, the decisions around dispatch of generation during that period may also need to take into consideration what is needed for that afternoon ramp.
Maintaining minimum stable operating limits	Consideration of a generator's minimum stable operating limit becomes an important consideration particularly during low load periods. For synchronous generators, scheduling of raise services requires these units to be synchronised to the power system, operating at or above their minimum stable limits and with sufficient headroom to be able to raise their output in the event of a system disturbance.
Having sufficient reactive power management at minimum demnad	Reactive power management is important to maintain voltage profiles within planning and operational limits. Lightly loaded power systems (for e.g. in the middle of the day) generate excess reactive power causing higher voltages. Generator performance standards require facilities to provide the capability to help with reactive power management by either absorbing or providing reactive power when needed.

[24] Proposed amendments to the Technical Rules governing the UFLS system include Western Power developing and maintaining an UFLS Specification Document. The WEM Rules also has requirements for the co-ordination of load shedding schemes between AEMO and Western Power.

3.8 Managing risks associated with low demand

Managing the technical risks specifically associated with low demand issues requires a holistic solution that is implemented and co-ordinated over several different timeframes including in the long-term planning and market design stage, the connections phase and on an operational timescale. These are described in Figure 10.

Figure 10: Mitigating low demand risks on different timescales

Planning	Connections	Operations
Embedding the assessment of low operational demand events into the system planning and network planning frameworks to assess the impact of different demand, generation and outage impacts through the Electricity Statement of Opportunities, the Whole of System Plan, Transmission System Plan and other planning and forecasting publications. Ensure the design of the market incentivises the type of services that are needed and when they are needed in a timely and efficient manner and ensure that regulatory mechanisms exist to procure alternatives.	Connecting new facilities under guidelines and standards that take into account technical issues that may impact the power system and the new facility during periods of low demand. Examples of recent improvements include new DPV installations requiring enhanced ride-through and ESM capability, requirements for new facilities to provide EMT models for system strength studies, consideration of system strength mitigation.	Ensure low operational demand events are catered for in system adequacy assessments, including consideration of low demand events in outage planning, constraint equation development, operation protocols for triggering of emergency solar management and ensure AEMO has sufficient access to last-resorts measures to manage system security.

- **Planning frameworks and jurisdictional codes.** Western Power and AEMO are required to plan the power system to meet the network performance standards described in the Technical Rules, the WEM Rules and other jurisdictional codes such as the Network Quality and Reliability of Supply Code. System risks during low load conditions are evaluated through periodic planning and operational planning activities undertaken by Western Power and AEMO. These activities are supported through the design of the electricity market and the Energy Transformation Strategy. Whilst historically, these planning activities have tended to be focused on peak and shoulder demand periods, assessing risks associated with low demand periods is now becoming increasingly embedded into the standard planning and forecasting processes. Examples of this include:
  - Issues such as system strength that have not been historically contemplated in the regulatory framework are now being introduced into the Technical Rules and in the WEM Rules as explicit requirements to consider during network planning.[25]
  - AEMO's WEM ESOO now explicitly provides forecasts of minimum operational demand in addition to the peak demands. Different statistical forecasts account for high, medium, and low forecasts using probabilities of exceedance at 10%, 50% and 90%.[26]
  - The future design of the WEM includes new ESS markets such as the ROCOF Control Service and co-optimisation of credible contingency sizes to ensure

[25] Western Power's current approved Technical Rules (December 2016 version) does not explicitly mention system strength. Proposed amendments made to the Technical Rules on 30 June 2021 include the explicit treatment of system strength as a planning and monitoring obligation. WEM Rules 3.11A.2.(a) discusses system strength in the context of triggering procurement of NCESS.

[26] AEMO's WEM ESOO publishes forecasts for minimum operational demand levels for 10% POE, 50% POE and 90% POE levels.

sufficient procurement of very fast frequency response and potential reductions in largest supply contingencies (if least-cost) to maintain frequency stability during low inertia conditions. The future WEM Dispatch Engine also allows for the co-optimisation of negative energy bids.

  - Appropriate functionality for AEMO or Western Power to procure non-co-optimised ESS to provide a regulatory mechanism for procurement of additional services to mitigate risks during low demand periods should the timing and scale of market responses not be sufficient.[27]
  - Introduction of rules that allow the registration and participation of technologies such as utility scale batteries to enter the market.
  - Transmission System Planning and Whole of System Planning reviews that include consideration for minimum operational demand, system security thresholds and operability assessments.

- **Connections:** The connections framework plays an important role in ensuring that issues that may present at low demand are assessed and communicated to intending market participants and new entrant generation and load facilities. This is facilitated by:
  - The development of a SWIS EMT model necessary to undertake detailed system strength studies in specific areas with very low system strength for the purpose of assessing generator connections and negotiation of performance standards and access agreements. The connections framework now includes obligations on market participants to provide detailed models of control systems suitable for EMT modelling during the connections process.
  - Undertaking the detailed EMT modelling to inform the negotiation of generator performance standards and the consideration for the impact that system strength may have on the facility. This type of analysis can help to inform actions during the connection process and negotiation of generation performance standards such as the tuning of inverter control systems, modifications to the internal network reticulation of a generation site before connection. These can help to mitigate against system strength issues for the benefit of that facility, thereby avoiding runback or curtailment after connection. These assessments can also help to identify additional connection assets that may be required to mitigate system strength (such as synchronous condensers or battery energy storage systems).
  - The traditional UFLS system that has been implemented through distribution networks feeder tripping may be insufficient during low demand conditions, requiring transmission load customers to also provide UFLS.
  - Ensuring that DER are being connected with appropriate functionality to improve grid stability when needed. The introduction of enhanced inverter standards is an important step to mitigate the risk of DPV disconnecting during system disturbance events occurring during low demand periods. These enhanced inverter standards mean that new inverter connections require ride-through capability.[28]

- **Operations:** Whilst solutions that are introduced during the long-term planning phase and the connections process may mitigate some of the responses required in operational

[27] https://www.wa.gov.au/system/files/2022-04/AEMO-NCESS-Trigger-Submission.PDF. As an example, the Coordinator of Energy received a submission from AEMO seeking to trigger the NCESS procurement process for a fast frequency response service to help account for unplanned DPV disconnection.

[28] Changes to solar inverter system standards - https://www.westernpower.com.au/industry/industry-news/changes-to-solar-inverter-systems-standards-online-information-session/

timescales, they are unlikely to remove them entirely. In these events, short-term operational measures will be required to manage very low demand periods. Some of these include:

- The use of constraint equations in security-constrained economic dispatch to ensure dispatch of generation results in a secure and reliable power system that considers frequency stability and system strength during low demand periods.
- Curtailment of generation output to manage the maximum contingency size.
- Outage planning that takes into consideration the availability of certain generation facilities during seasons where low operational demands may eventuate and the impact that outages may have on reducing inertia and therefore frequency stability response and other issues such as voltage stability.
- Out of merit generation dispatch to ensure certain facilities are on to provide the required balance between ESS and energy dispatch whilst operating within technical limits.
- The utilisation of appropriate real-time monitoring devices and the introduction of algorithms that quantify security indices that assess system inertia and stability margins on an operational timescale.
- The triggering of ESM as a last resort measure to manage DPV output during extremely low demand periods that would otherwise place the system at risk of widespread outages.

4. High level modelling methodology

4.1 Key objectives and outputs

The Project aims to understand the technical considerations that are involved in operating the SWIS during low demand conditions and to ensure appropriate mechanisms are in place and available to maintain power system security when called upon.

Stage 1 involves power system and network modelling to explore the different technical challenges that could arise during low demand conditions. This stage involves detailed modelling of the power system and the network to:

- Understand what the issues related to power system security during low demand conditions are.
- Project when these issues may occur.
- Evaluate the risks to the power system because of the identified issues.

Table 6 summarises the key outcomes of the Project.

Table 6: Key outcomes of the Project

Issue	Key outcome	Outputs
Minimum demand threshold	Calculate the range of MDT's which the SWIS must operate above to maintain system security.	An operational demand threshold range in the unit of MW.[29]
Potential for DPV disconnection	Estimate the magnitude of DPV that could be disconnected in key locations on the SWIS and the fault conditions which could trigger these.	An estimate on the % of DPV and % of load that could be disconnected during different system disturbance conditions under different fault types at different network locations.
Credible contingency size	Understand the nature of the largest credible contingency size on the SWIS and how that could be impacted by disconnection of DPV.	Indications of the largest credible contingency size which sets the spinning reserve requirement in the SWIS.
Frequency stability studies	Identify what generation dispatch combinations are necessary to provide sufficient contingency reserve to prevent triggering UFLS.	An evaluation of the key drivers that lead to scenarios where frequency stability cannot be maintained during low demand periods and outage conditions that could cause this to occur.
Reactive power management	Ensure voltages are adeqauately managed through reactive power management.	Confirmation that generation dispatch adequately provides reactive power management capability to manage system voltages for specific scenarios.
UFLS	Determine the ongoing suitability of the current UFLS design	A recommendation on the efficacy of the UFLS standard, the operational implementation of the current design requirement and a review of its

[29] The MDT is not related to the efficacy or availability of UFLS.

Issue	Key outcome	Outputs
	requirements and whether they need to be updated or amended.	appropriateness to prevent a system collapse following a non-credible event. In combination with the work from the DER Roadmap, the outputs from this work willl be used to shape the inaugural and future revisions of the UFLS Requirements and Specification documents, as per the new WEM Rules obligations. It will also inform operational guidelines and the development of a long-term UFLS strategy that includes recommendations to support future network investments to improve the performance and associated risks of UFLS.
System strength studies	Identify areas on the Western Power network where very low system strength may result in inverter instability and voltage stability issues using short-circuit ratios and detailed EMT models.	An evaluation of short-circuit ratios on key connection points in the SWIS as a first stage screening of network areas that may be susceptible to low system strength. Detailed EMT studies of these areas to identify the operating conditions that could result in system strength issues. The identification of which generators may be susceptible to system strength issues and may be subject to changes to operational modes as a result.
System strength model	Develop detailed power system models suitable for undertaking detailed system studies in areas of the network where system strength is very low.	An EMT model of key areas of the SWIS that is suitable for detailed system strength studies. Due to the need to prioritise the work, the North Country region of the SWIS has been developed first.
System ramping	Identify the system ramping capability required to achieve supply demand balance between minimum demand periods and peak demand periods on the SWIS for future years.	Determine whether actions need to be taken to specifically manage the system ramping constraint.

4.2 Approaches to each issue

Given the breadth of the focus areas covered in the Project, several different approaches were used to undertake the review, assessment, modelling, simulation and analysis required to derive the Stage 1 findings. In a majority of the focus areas explored, the methodology used to derive the findings has been built specifically for this purpose and has been without precedent owing to the unique characteristics of the SWIS.

Table 7 provides a high-level summary of the approaches used in this Project.

Table 7: High level summary of modelling methodologies

Focus area	High level summary of methodology
Disconnection of DPV during system disturbance events	In contrast to a single large contingency where the loss of generation supply can be directly measured and quantified, the lack of customer level monitoring, the various manufacturers and versions of inverter models (each with inconsistent performance levels), coupled with the distributed nature of DPV requires a different modelling technique. The methodology developed by Western Power involves a combination of analysing high-temporal resolution information recorded during disturbance events occurring during the day and the evening. This method is used to derive a correlation between the underlying load response and voltage/frequency variations for night-time events where DPV is not a consideration. The underlying load response was then applied to day-time events where DPV is generating with the difference in the response providing an estimation of DPV disconnecting. To estimate how much DPV and load could be disconnected for different faults across the system, the mathematical equations developed through the statistical analysis were then applied to the results of simulations undertaken in power system analysis software. This work identified the fault scenario that resulted in the most onerous frequency stability issue, assessing different types of faults at different locations to derive changes in the voltage vector shift (capturing the shift in both voltage magnitude and angle) that could then be used as inputs into the equations. An estimation of how much DPV could trip was then calculated for key faults on the transmission network. The methodology was applied to recent events on the SWIS to confirm the accuracy of this model. An alternative method was concurrently developed to assist in the verification of the DPV estimates. The second method involved looking at successful auto-reclose day-time events on medium voltage feeders with high PV installed and deriving an average ramp rate for PV reconnection after a successful reclosure. The ramp up rate was then applied to the day-time system disturbances to then deduce how much PV had disconnected and compared to the results from the statistical analysis.
Maximum supply contingency	The power system is planned to maintain stable operation following credible contingency events. Depending on the combination of the type of fault, what element of the power system the fault occurs on and when it occurs, the impact on the power system can be more or less severe. For example, a three-phase fault on a transmission busbar could have a very severe consequence but is very rare in occurrence. A single-phase to ground fault is the more common fault but typically has less of an impact on the power system. Where the fault occurs can also have an impact on the severity of the system response. It may be impractical and very costly to procure spinning reserve to always cater for the most severe consequence arising from a maximum supply contingency assumed to occur during the worst part of the day. The methodology undertaken to define the maximum supply contingency which considers DPV disconnection relies on historical analysis of generator dispatch during low demand conditions and an assessment of risk to determine whether DPV disconnecting plus a generator outage is credible.
Frequency stability	Frequency stability studies centre on calculating the frequency nadir under

Focus area	High level summary of methodology
	different operating conditions and an assessment of the rate of change of frequency following a system disturbance. AEMO has developed a SWIS frequency model that estimates the post-contingency frequency response based on pre-fault operating conditions and different contingency conditions. The frequency response of the system is compared against frequency operating standards and UFLS settings to assess the risk of consequential generator tripping and/or customer disconnections. The factors that impact on the post-contingent frequency response after a fault are: o System inertia. o System load / load relief and inertia. o Size of the contingency. o The quantity of primary frequency response available. o The speed of primary frequency response provided. The methodology undertaken to assess the above impacts centres on different generator dispatch profiles, different fault types and different contingency sizes using AEMO's frequency response model.
UFLS	The methodology undertaken to review UFLS involves the following key streams: (1) Development of models, assessment method and performance criteria to evaluate UFLS (2) Review of UFLS industry best practice (3) Performance review of existing UFLS system according to performance criteria (4) Proposed improvements to the existing UFLS system A number of key performance criteria have been defined (in accordance with the Technical Rules) to assess the SWIS UFLS system. This includes defining a range of thresholds for several key frequency parameters to assess simulation outputs from a single mass frequency model. This continues the work under Action 10 of the DER Roadmap.
System strength	System strength studies have been undertaken in a staged approach. Screening studies focused on calculating SCR for multiple generation dispatch and network contingency conditions at the connection point and the inverter terminals for specific generators. An output of the screening studies is an 'SCR trace' that shows the range of SCR values that could eventuate on that connection point or inverter terminals for different generation dispatch and network contingency conditions. An initial scan of the SCR trace is performed and compared against SCR thresholds based on industry standards. The second stage of modelling involves the development of EMT models (using in-house developed EMT models for existing facilities and customer provided EMT models for future facilities). This is split up into two phases: • The first phase of this study involves assessing individual facilities with

Focus area	High level summary of methodology
	several Thevenin equivalent representations of the power system to cover various system operating conditions, with the objective being to assess system strength within the generation facility only. Any critical scenarios that are found can be used to help within the second phase of EMT modelling. • The second phase of EMT modelling involves a study of a group of generation facilities in an area with detailed network representations between the generation facilities.[30] This phase of modelling assesses system strength with consideration for the interactions that one generation facility may have on another facility that is close by. Different demand, dispatch and network contingency scenarios are used to simulate the response of the generation facilities to investigate performance under different scenarios.
Reactive power management	The study of reactive power management centres on assessing the voltages on the power system using load flow simulations for different demand and generator conditions and comparing prevailing voltages against planning limits for steady state operating conditions, steady state post-contingent conditions and under step changes. Future dynamic studies may be needed to refine the analysis.

Key findings from the focus area studies that have been completed to date are presented in the following section.

[30] To mitigate against lengthy simulation times whilst preserving sufficient accuracy, the network has been split into different simulation areas to cover discrete sets of generation facility interactions.

5. Findings

5.1 DPV disconnections

Key findings

It has been identified that a portion of DPV disconnects during system disturbances.

DPV can disconnect due to an inability to ride through voltage and frequency disturbances caused by electrically close faults on generator circuits and/or the transmission network. The impact of this is to increase the single largest contingency on the system which could impact adversely on system security.

To ensure that new and upgraded DPV systems do not further exacerbate this issue, new inverter standards were introduced in December 2021. Enhanced ride through capability was mandated in the SWIS in May 2021. Whilst new and upgraded systems are expected to have this capability, it will take time for a sufficient scale of implementation to materially improve system security.

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- *To ensure that new and upgraded DPV systems do not further exacerbate this issue, new inverter standards were introduced in December 2021. Enhanced ride through capability was mandated in the SWIS in May 2021. Whilst new and upgraded systems are expected to have this capability, it will take time for a sufficient scale of implementation to materially improve system security.*

It has been identified that DPV undesirably trips as a result of voltage and frequency disturbances caused by faults on generator circuits and / or the transmission network.

Network contingencies that have previously resulted in a reduction in SWIS demand can now result in a net increase in demand due to the widespread disconnection of DPV throughout the network. The combined effect is an increase to the prevailing magnitude of the largest supply contingency which potentially compromises frequency stability.

Table 8 provides a summary of the estimated DPV disconnection for historical system disturbance events. The modelling shows that more than 100 MW of DPV has been disconnected in recent system events which adds a significant amount to the typical contingency size in the SWIS. It is important to note that this DPV tripping is somewhat offset by load reductions (as a result of the same fault), though the general net impact in the middle of the day is that the DPV tripping exceeds the load disconnection.

Table 8: Recent day-time system disturbances and estimated disconnection of DPV

Day	Faulted circuit	Frequency nadir (Hz)	Estimated DPV disconnection [31] (MW)
11 January 2018	GLT-ST 91	50	98
7 February 2019	NT-MU 91	50	18

[31] Based on the data points used for the statistical analysis undertaken.

Day	Faulted circuit	Frequency nadir (Hz)	Estimated DPV disconnection [31] (MW)
9 January 2020	KW-KEM/OLY 91	49.66	171
18 September 2020	ST-SNR/BYF 81	49.74	104
17 October 2020	NBT-YDT 91	49.17	62
2 January 2021	NBT-YDT 91	48.89	114
4 February 2021	KW-CC/MED 81	49.82	119
29 March 2021	BLUEWATERS G1	49.17	9

To estimate the portion of DPV that could disconnect and the load response for different faults across the system, mathematical equations were developed based on measurements from disturbance events over the past few years.

These equations were then applied to the results of simulations undertaken in power system analysis software, using generation and loads from a low load day as the basis for the operating conditions in the simulations. Different modelling methodologies were used to independently verify DPV disconnection estimates across different load types and at the system and substation level. A summary of estimated DPV disconnection for critical locations on the 330 kV system under different fault types using both methods is provided in Table 9.

Table 9: Estimated DPV disconnection due to voltage disturbances for different faults

Approximate fault location	Severity[32]	% DPV disconnection due to voltage disturbance		% underlying load effect due to voltage	
		Method 1 (System)	Method 2 (Substation)	Method 1 (System)	Method 2 (Substation)
Neerabup Terminal	Low	15	17	3	3
	Moderate	20	23	4	5
	Severe	44	50	21	23
Kwinana[33]	Low	15	17	3	3
	Moderate	20	23	4	5
	Severe	44	50	22	23
South West	Low	12	13	2	1
	Moderate	15	16	3	2
	Severe	36	38	14	14
Southern Terminal	Low	16	18	3	3
	Moderate	21	24	5	5
	Severe	47	53	24	26

[32] The fault severity categories of low, moderate and severe correspond to 1-ph (with 5ohm fault resistance), 2-ph (bolted) and 3-ph (bolted) faults.

[33] The results for the Kwinana and the Neerabup faults show similar results as the same voltage vector shift was observed for both faults.

The results of the simulations and analysis showed that the amount of DPV that could disconnect depends on the type of fault and whether the fault has occurred electrically close to regions with high levels of DPV installation. It was identified that a 3-phase fault on key 330 kV infrastructure could disconnect a significant portion of the DPV fleet in the local area. The amount of energy lost from the disconnected DPV would also depend on whether the fault occurred in a period of high DPV output.

Further assessments were undertaken to examine the likelihood of different fault types occurring, the duration of time where a fault could impact DPV disconnection and the potential impact on the maximum contingency size. This is discussed further in section 5.2.

In the absence of any mitigation, the amount of DPV that could be disconnected on the SWIS will increase with new customer installations and upgrades to inverter and panel capacity. Updated inverter standards have been introduced to improve the ride through capability of DPV during system disturbances to help reduce the amount of DPV that could be lost.

5.2 Largest contingency size

Key findings

The prevailing magnitude of a contingency event is typically a function of size of the largest single generation unit output or loss of a single network element which may disconnect a number of generation facilities. However, this has been exacerbated by concurrent or sympathetic disconnection of DPV which is making the actual magnitude of contingency size/risk greater.

- *It has been identified that contingency sizes at certain times will be considerably larger when taking DPV disconnections into account.*
- *Whilst different types of faults (1-ph, 2-ph, 3-ph) have been observed to result in different levels of DPV and load disconnecting, 3-ph faults that occur on the 330 kV network electrically close to key load centres result in large amounts of DPV and load disconnecting.*
- *3-phase faults are rare in occurrence with network outage statistics showing that 3-phase faults on the 330 kV network accounted for less than 1% of all faults recorded in the past 42 years. Whilst more work is being undertaken to assess the relative risks of catering for DPV disconnections associated with a 3-phase fault, a 2-phase fault is more likely. Mitigation measures are currently being progressed based on estimates of DPV disconnection based on 2-phase faults.*
- *The largest contingency on the SWIS has increased as a result of DPV disconnecting and any studies or operational practices that use the largest contingency size as an input should account for this.*

It has been identified that a 3-phase fault on key 330 kV infrastructure disconnects a significant portion of the DPV fleet in the local area. The analysis also shows that there is a risk of DPV disconnection for 2-phase and 1-phase faults.

Whilst it is prudent to model the impact that a 3-phase fault may have on system security, carrying enough reserve to cater for frequency stability issues that could arise because of a 3-phase fault disconnecting both generation and a portion of DPV would be a large cost to market participants.

In practice, 3-phase faults are rare in occurrence having accounted for less than 1% of all faults recorded in the past 42 years. Table 10 shows network outage statistics for different voltage levels for different fault types.[34]

Table 10: Summary of 330 kV network outage statistics

Network voltage	Fault type	% of all faults	Total
330 kV	3-phase	1	542
	2-phase	16	
	1-phase	83	

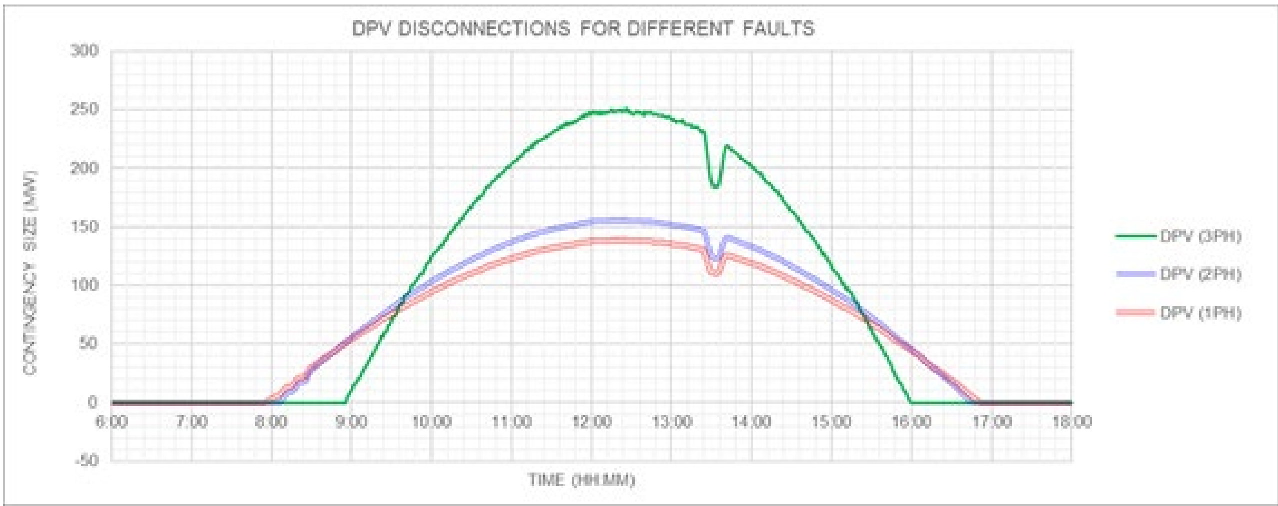
More work is being undertaken to assess the relative risks of catering for DPV disconnections associated with a 3-phase fault. A 2-phase fault is historically more likely to occur and its use in frequency stability studies is considered an appropriate balance between ensuring the SWIS is secure and reliable and increased costs to consumers.

The work undertaken to identify the amount of DPV that could disconnect has been used as an input consideration when defining the largest contingency size that could eventuate on the SWIS.

When including the impact of DPV disconnecting in the calculation of contingency sizes, the net impact on the power system is considered, which is the difference between load disconnecting and DPV disconnecting following the system disturbance.

This is a key input into frequency stability studies (discussed further in section 5.3). Figure 11 shows the potential for DPV to be disconnected for different fault types on one particular low demand day using estimated DPV output. Cloud cover between 13:00 and 14:00 results in a reduction in DPV output.

Figure 11: DPV disconnections for different fault types on 5 September 2021



The largest contingency size is dynamic and changes between dispatch intervals. Table 11 summarises the scenarios that could set the largest supply contingency on the SWIS. The largest contingency size is calculated as the maximum of these scenarios.

[34] Fault records extracted from Western Power database from late 1978. The "% of all faults" column has been calculated for those events where the faulted phase is known, though the "Total" column includes all recorded events regardless of whether the faulted phase was recorded or not.

The largest theoretical supply contingency on the SWIS is set by the potential for a 330 kV outage in the North Country region. Although this situation is unlikely and has not historically occurred in the middle of the day, 390 MW of generation could theoretically be lost for maximum coincident generation output and in the absence of any other constraints limiting output. Accounting for the impact of DPV disconnecting would further increase the theoretical maximum.

Table 11: Setting the largest contingency size

Scenario	Description	Comment
DPV	(1) Disconnection of DPV sets the largest supply contingency	When DPV output is highest in the middle of the day, a fault occurs in an area with very high DPV penetration resulting in DPV disconnecting due to the inability to ride through voltage and frequency disturbances. The net impact on the power system in terms of lost supply is the difference between the amount of DPV tripped and the amount of load disconnecting.
GEN	Disconection of generation sets the largest supply contingency, which could result from either: (2) Disconnection of a single generator unit (3) Disconnection of generation connected to the 330 kV network in the North Country	When a generator or network outage results in a generator (operating as the largest single source) or a group of generators (operating as the largest single source) disconnecting from a single outage
GEN + DPV	(4) Disconnection of generation and DPV collectively sets the largest supply contingency	Combination of (1) coinciding with either (2) or (3). Note, when considering DPV disconnection in the context of determining credible contingency sizes, it is the net impact that is calculated.

Figure 12 shows how the largest contingency size changes throughout the day by comparing how much DPV could disconnect for different fault types against the largest generator contingency. On this particular day, between 12:00 and 13:00, the amount of generation that could be lost from DPV disconnecting is as high as the largest generator contingency.[35] This highlights the central role that DPV is playing in supplying the SWIS during the middle of the day and the need to cater for its potential loss. The amount of DPV that could disconnect in the rare case a 3-phase fault were to occur is around 100 MW higher.

[35] Based on 2-phase faults

Figure 12: Contingency size comparison: DPV vs. GEN

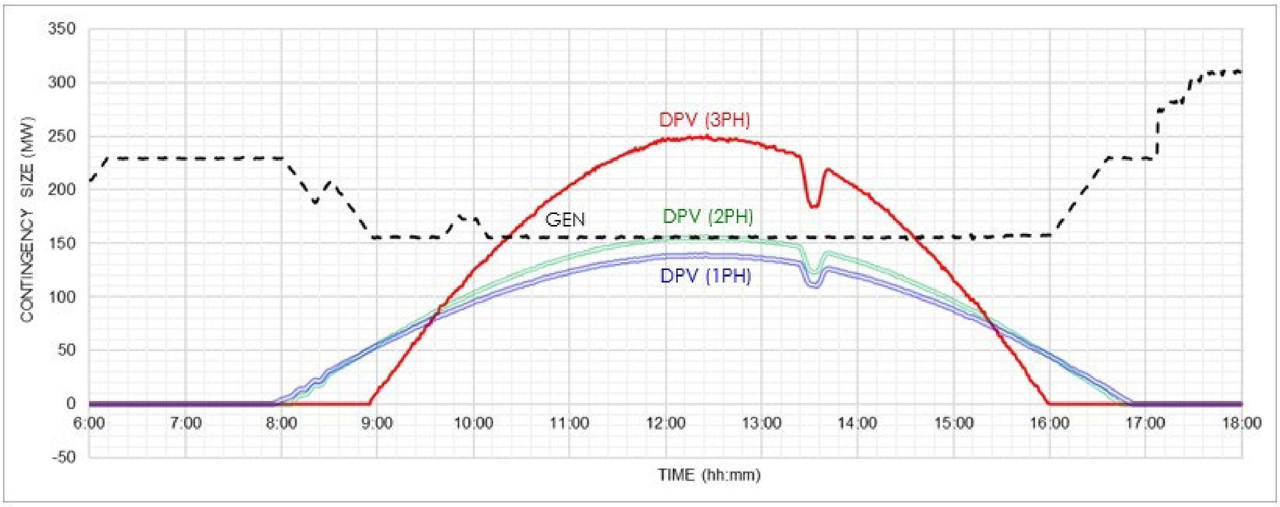
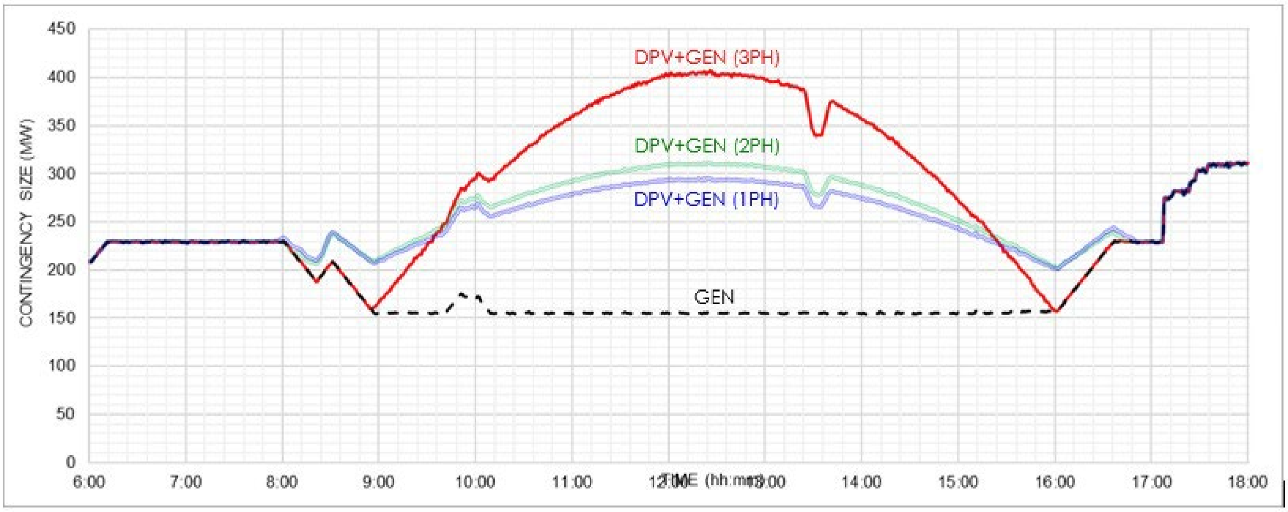


Figure 13 also shows how the largest contingency size changes when catering for DPV disconnection. The charts shows that on this day, contingency sizes could increase by approximately 100 - 150 MW when catering for DPV disconnection. This value increases by approximately 100 MW if 3-phase faults are considered.

Figure 13: Contingency size comparison: DPV+GEN vs. GEN



5.3 Frequency stability

Key findings

Operability of the power system is reliant on the ability to maintain system frequency within a narrow control band. Should the frequency fall below 48.75 Hz, automatic protection systems (i.e. UFLS) will disconnect customers from the grid as a last line of defence against uncontrolled widespread outages.

- ► *There are a large number of variables that determine the ability to maintain the frequency within the standard. The most significant variables are the prevailing level of inertia, availability of the spinning reserve and the expected magnitude of a system disturbance, or contingency event and the potential for DPV to disconnect.*

- *Activation of automatic UFLS was identified due to frequency falling below 48.75 Hz. In most cases, it is the potential impact of DPV disconnecting that takes the system outside system security boundaries.*
- *In all cases studied, dispatching generation out-of-merit as a pre-contingent response was sufficient to ensure UFLS was not initiated after the outage occurred. Scheduling additional spinning reserve and reducing the largest contingency size is only required for a few hours in the middle of the lowest demand days, depending on the actual DPV contribution to meeting the underlying load.*
- *There are likely to be operating conditions that will require additional generators to be online to increase the amount of spinning reserve which AEMO carries to maintain frequency stability and avoid activation of UFLS.*
- *As power system inertia continues to decline over time, due to asset unavailability or retirements, dispatching generation out-of-merit will no longer be sufficient to maintain adequate system security. Other responses will be required.*

Frequency stability studies were performed considering the multiple characteristics that simultaneously impact SWIS frequency response including contingency size, system inertia, system load and the availability of the spinning reserve service. Several sensitivity scenarios were also studied to consider the various compositions of generator units that typically provide the spinning reserve service.

AEMO has updated its in-house frequency stability tool to undertake the studies. The frequency stability tool is a single mass frequency model that simulates the frequency response on the SWIS using different operating conditions.

Three types of outcomes were identified:

1) **Initial consideration of mitigation required for different types of faults.** For comparative purposes, a specific low demand day was considered to estimate the different responses necessary to mitigate against a possible UFLS event and the duration for which this response is required. The modelling involves simulating the frequency response of the SWIS for multiple generation dispatch profiles under 3-phase, 2-phase and 1-phase faults. Several sensitivity cases were also introduced involving the use of different gas turbines for provision of spinning reserve and also changes to the generator dispatch (see Appendix C for a summary). Variables that were modelled include:
    a. Changing the size of the largest generator contingency (at either 155 MW or 120 MW)
    b. Different types of faults (3-ph, 2-ph, 1-ph) which impacts the amount of DPV and load which will disconnect following the disturbance
    c. The number of additional gas turbines required above the typical dispatch to ensure adequate primary frequency response.
2) **Operational mitigation required for different dispatch outcomes.** Having identified the impact of relative mitigation actions, this analysis then considered the operational actions needed to maintain stability with current levels of DPV disconnection and expected load.
3) **Impact of reduced load on UFLS system[36].** With a reduced amount of load available to be disconnected through the UFLS system compared to design requirements, a smaller non--credible contingency event may result in a frequency collapse. A number of scenarios

[36] The text here relates to observations made during the time transmission connected loads were not assigned to the UFLS system. While this aspect is related to the availability of UFLS, the analysis and actions required here were considered together with those to maintain frequency stability.

were modelled, to determine key factors impacting this outcome. While there is no current defined requirement as to how this is managed, the methodology examined a scenario involving the loss of the 4 largest generators with a 5 second time delay between each outage where the first initiating contingency could be a generator and a subsequent DPV trip. Analysis was undertaken to ensure this scenario did not result in a system collapse.

Mitigation required for different types of faults

Table 12 provides a set of results that summarise the average reduction in contingency size needed for the specific low demand day. It also summarises the impact of scheduling additional spinning reserve and/or committing additional gas turbines on the contingency size reduction needed.

Table 12: Quantity of average contingency size reduction

Assumed largest unit dispatch	Fault type	Quantity of average contingency size reduction		
		Actual dispatch	1 x Extra GT	2 x Extra GTs
155 MW	3-ph	36 MW	11 MW	0 MW
	2-ph	33 MW	10 MW	0 MW
	1-ph	29 MW	7 MW	0 MW
120 MW	3-ph	15 MW	0 MW	0 MW
	2-ph	13 MW	0 MW	0 MW
	1-ph	10 MW	0 MW	0 MW

Table 12 shows that based on the actual historical dispatch for that day, a reduction in the contingency size would have been needed. The findings show that a combination of providing additional spinning reserve through committing additional generators and reducing the largest contingency were able to mitigate against a possible UFLS event for all the scenarios studied. While the impact of a three-phase fault has the most severe impact on the SWIS frequency response, it is also the least likely fault (as shown in section 5.1).

Table 13 indicates the period of time between 9:00 and 16:00 that a reduction in contingency size may be required.

Table 13: Period of average contingency size reduction

Assumed largest unit dispatch	Fault type	Period of average contingency size reduction		
		Actual dispatch	1 x Extra GT	2 x Extra GTs
155 MW	3-ph	45%	23%	0%
	2-ph	64%	28%	0%
	1-ph	63%	20%	0%
120 MW	3-ph	27%	0%	0%
	2-ph	39%	0%	0%
	1-ph	34%	0%	0%

The table shows that to avoid an UFLS event under the specific operating conditions, providing additional spinning reserve and/or reducing the largest contingency size is required for a few hours in the middle of the day depending on the actual DPV contribution to meeting the underlying load.

With additional gas turbine units scheduled online, the period of contingency reduction or additional spinning reserve required decreases. The impact of reducing coal unit dispatch is also shown, identifying the potential benefit of operating coal units below minimum stable operating points.

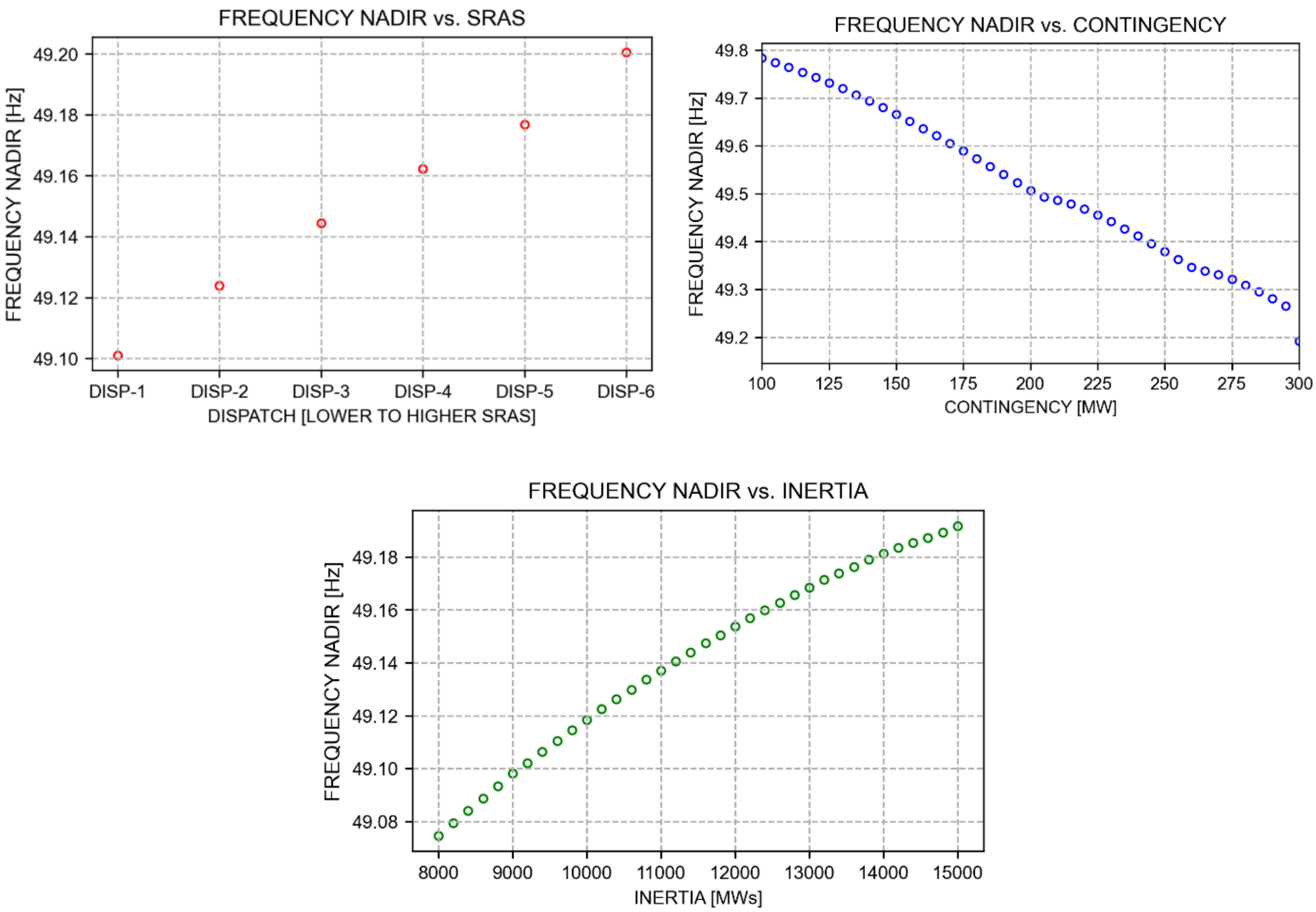
This level of mitigation will not be adequate for all future cases if additional actions such as ESM or implementing a fast frequency response (FFR) solution are not implemented.

Implementing ESM will allow additional generators to be online to meet demand and operating above their minimum stable limit, thus increasing the amount of PFR which can be made available. Similarly, increasing the speed of response through an FFR service (prior to the new market start) will enable larger contingency sizes to be managed[37].

Operational mitigation required for different dispatch outcomes

The studies undertaken above focused on identifying the impact of mitigation actions on actual dispatch conditions observed on a historical low demand day. Further assessment was undertaken to consider the operational actions needed to maintain stability with current levels of DPV tripping and expected load.

Figure 14: SWIS frequency nadir vs different input assumptions

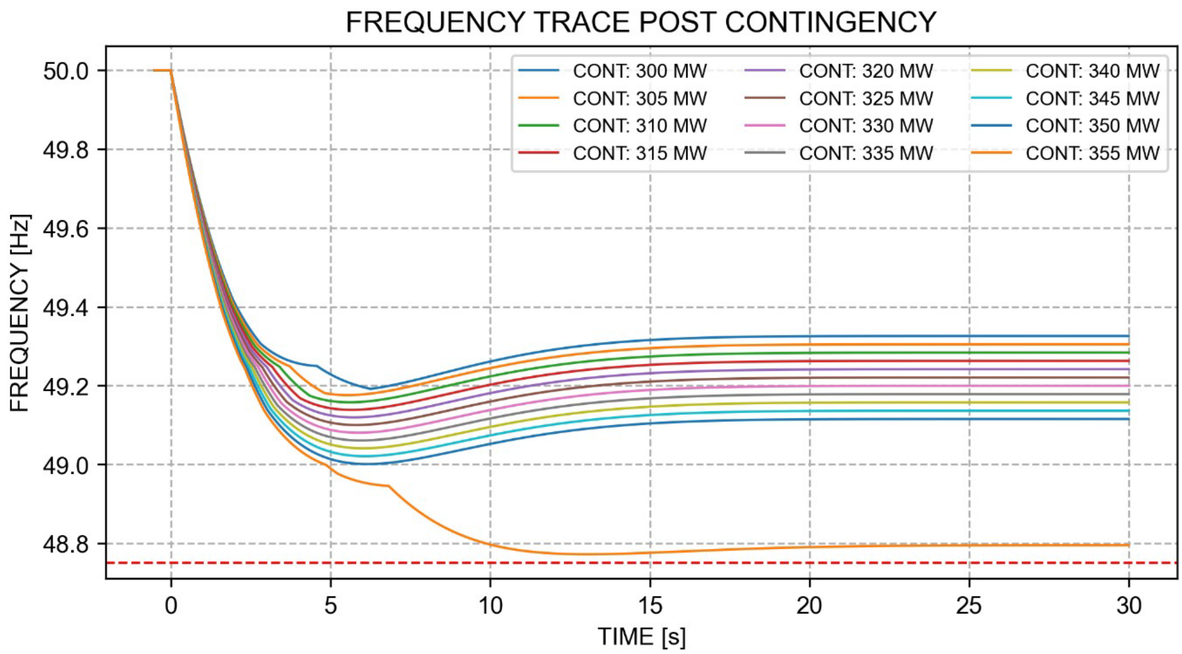


[37] AEMO has sought expressions of interest for provision of up to 100MW of FFR prior to new market start, see https://aemo.com.au/consultations/tenders/ffr.

Figure 14 provides a set of results showing the impact of varying different pre-fault operating conditions on the SWIS frequency response after a disturbance. The trend lines observed through these simulations were developed into detailed operational limits for inclusion into real-time operations. The actions currently available to be taken to manage frequency stability include increasing the amount of spinning reserve available from units, increasing the amount of inertia synchronized to the SWIS and reducing the largest contingency size.

An example of the SWIS frequency response for various contingency sizes is shown in Figure 16 for a specific set of operating conditions. For this operating condition, a 355 MW contingency resulted in the SWIS frequency falling close to the stage 1 activating threshold for UFLS (48.75 Hz). In the worst case a slightly larger contingency can push the system towards activation of UFLS due to the additional DPV that trips off due to reduced frequency.

Figure 15: Post contingency SWIS frequency response for different contingency sizes



Frequency stability is impacted by the availability of load to be disconnected on the UFLS system

It should be noted that frequency stability is impacted by increasing DPV installations reducing the amount of net load available to be disconnected on the UFLS system. Reduced amounts of load available to be disconnected on UFLS compared to design requirements means that the power system is more susceptible to frequency collapse at lower contingency levels. Section 5.6 discusses UFLS availability and the impact that reducing UFLS load has on frequency stability in the SWIS.

5.4 Determining the MDT

Key findings

In order to establish a secure operating environment considering the collective effects of system inertia and contingency risk (amongst other factors) a minimum demand threshold has been defined. This measure is called the minimum demand threshold (MDT). The limiting factor that currently sets the demand threshold on the SWIS in low demand periods is frequency stability.

The MDT is the minimum demand level where the SWIS is no longer able to be operated securely and emergency conditions are required. The MDT is set based on consideration of credible contingencies only. Taking action to ensure the operational demand is maintained above the MDT for the combination of generators online ensures that the power system can return to a satisfactory operating state without the need to disconnect a large portion of customers following a credible contingency event.

- *The currently established MDT for the SWIS on an operational demand basis varies between approximately 550 MW and 650 MW depending on the generators that are online at the time.*
- *Ensuring the SWIS is able to carry sufficient spinning reserve and primary frequency response is currently the binding limitation that sets the MDT range. The MDT is set by the sum of the active power output of the generators that are online whilst providing sufficient ESS to maintain a secure power system. The value considers thermal generators that are likely to be committed during low load periods and which are currently utilised to provide reactive power support and the ability to meet the peak demand.*
- *Based on forecasts of minimum demand in AEMO's WEM 2022 ESOO Expected Scenario, the MDT is expected to materialise within the next year.*
- *From 14 February 2022 ESM capability must be available on any new and upgraded DPV systems installed. This functionality provides another option for the power system operator to maintain system security by ensuring that demand stays above the MDT.*
- *The MDT will change as the SWIS generation technology mix changes. As an example, the connection of utility-scale storage may allow the MDT to be at lower levels under certain operating conditions.*
- *The MDT is influenced by various generators' minimum stable operating point. The MDT could be lowered if synchronous generators (particularly coal units) are able to operate at a lower minimum stable loading.*
- *UFLS does not impact the setting of the MDT as it is triggered by non-credible contingencies.*

There must be a minimum level of system demand on the power system that allows generation to be online and operating above their minimum stable operating point to provide all services including energy whilst keeping the power system secure. This minimum demand level is referred to as the MDT.

The MDT is the minimum demand level below which the SWIS is no longer secure and emergency actions are required to ensure demand does not fall below it. In the short-term, this may take the form of ESM in the WEM and in the long-term, market incentives that encourage electricity demand in the middle of the day such as 2-way markets and changes to tariffs.

The MDT for any given period is dependent on the specific generation facilities that are operating in the SWIS and the ones that are online at the time. It is impacted by the minimum stable operating point for each generator unit that is required to be online to provide energy and ESS.

The power system studies to determine SWIS MDT focus on assessing the combination of generators that are required to be online during minimum demand periods, taking into consideration the potential impact of expected inertia, contingency size and DPV disconnection for that minimum demand period.

Analysis undertaken by AEMO has identified that an operational demand range of approximately 550 MW to 650 MW is the MDT for the SWIS based on the current generation technology mix and expectations around the availability of the fleet during minimum operational demand periods.

The factors that may influence MDT going forward include new generation technologies that are able to provide the above services, changes to minimum stable operating points, uplifts in ESS capability and changes to the ESS requirements on the power system.

Based on AEMO's 2022 WEM ESOO forecasts, the MDT is expected to materialise within the next 2 years.

5.5 Other technical considerations (reactive power, ramping)

Key findings

On very low demand days electricity usage is the lowest in the middle of the day and subsequently peaks during the early evening and there can be a significant difference between the two. This difference requires a generation fleet that is capable of increasing output to meet the increase in demand across the afternoon period. Additionally, managing system voltages within planning and operational limits during low demand days can be challenging for lightly loaded power systems. Ensuring there is sufficient capability from generators online to absorb excessive reactive power is important to consider when scheduling. Having insufficient reactive power control and operating voltages outside of planning limits risks damaging customer equipment.

- *The generators that are likely to be dispatched at the minimum demand level are sufficient to maintain reactive power control. There is sufficient flexibility in the existing generation fleet that if a planned outage were to occur, other combinations of generator dispatch could facilitate sufficient reactive power management. Additional dynamic studies are needed to continue to refine the analysis and assessment.*
- *It was determined that there is sufficient ramping capacity to accommodate projected 2-hour ramps up to 2023, based on the current expectation of DPV uptake. To manage worst case 4-hour ramps, some non-flexible units may need to be committed in advance. Out of merit dispatch may be required to allow generators with sufficient ramping capability to be online.*

Reactive power and voltage management

Power flow studies were undertaken at progressively lower SWIS operational demand for different network operating conditions and switching actions. These studies were performed to assess whether enough reactive capability was available from generators online to ensure voltage limits adhere to planning limits described in Table 14. The studies showed that voltages were able to remain within planning limits for normal operating conditions for the transmission and distribution networks.

Table 14: Planning limits

Study	Planning Limits
Steady state voltage	Except as a consequence of a non-credible contingency event, the minimum steady state voltage on the transmission system and those parts of the distribution system operating at voltages of 6 kV and above must be 90% of nominal voltage and the maximum steady state voltage must be 110% of nominal voltage. For those parts of the distribution system operating below voltages of 6 kV, the steady state voltage must be within: (1) ± 6% of the nominal voltage during normal operating state, (2) ± 8% of the nominal voltage during maintenance conditions, (3) ±10% of the nominal voltage during emergency conditions.

Ramping

A ramping study was also performed that examined the worst-case system load ramp that may eventuate for the study period between 2021 to 2023. Historically observed load ramps from 2020 were used as the basis for the study, with assumptions around future DPV uptake implemented to produce a forecast of the ramping profile in future years. An assessment was completed looking at the collective ramping capacity of the generation units that are expected to be online.

It was determined that sufficient ramping capacity is available to accommodate the worst-case projected 2-hour ramp. To manage the worst-case 4-hour ramp, some non-flexible units may need to be committed in advance of the ramp, which may result in some out of merit dispatch.

5.6 UFLS

Key findings

As DPV installations have rapidly increased, the underlying load connected to the distribution system is increasingly being supplied from DPV generation, resulting in a material reduction in net demand on the distribution system. This is eroding efficacy of UFLS to keep the power system secure for multiple contingency events. Operational experience and observations of distribution network feeder loading has indicated a continual reduction in availability of distribution connected load for UFLS and reverse power flow on distribution feeders. Key findings are summarised below:

- *The ongoing relevance of the current UFLS requirements has been tested through detailed frequency stability studies. The study assessed whether achieving the target UFLS requirement of 15% per stage was enough to ensure adequate SWIS frequency response. The studies showed that if the current requirement was met, the performance of the UFLS system would be adequate. However, further increases in DPV connections and future synchronous generation retirements are anticipated to trigger the need to modify the UFLS design standard to maintain adequate levels of performance and risk.*
- *Although achieving the UFLS requirement of 15% per stage is enough to ensure adequate SWIS frequency response after a system disturbance, the SWIS does not currently achieve the requirement due to the degradation of load available for disconnection.*
- *An assessment across a range of scenarios including DPV disconnection and cascading generator tripping was conducted using the historically available load shedding levels and projected UFLS system settings. Based on using the historical average UFLS load shedding levels (from April 2020 to April 2021), the results highlighted contingency sizes that trigger UFLS stages and frequency collapse reduced on average by up to 20%.*
- *A review of national and international best practice in maintaining an effective UFLS system was performed, with a particular focus on identifying the power systems that are experiencing challenges in decreasing minimum demand levels because of increasing DPV penetration. Although it was found that power systems similar to the SWIS are experiencing the same issues and exploring similar solutions, the SWIS does operate with higher risk due to increased DPV penetration and the lack of interconnection to other networks. This places more emphasis on the need to assess UFLS solutions on an ongoing basis.*
- *Western Power have recently facilitated the move of a number of existing transmission connected customers onto the UFLS system to ensure increased demand is available to be disconnected. Further work is also needed to include more transmission connected customers into the UFLS system.*
- *Due to new DPV connections forecast over the next 5 years, there is a need to invest in the UFLS system beyond the current committed works. These investments are anticipated to improve and achieve the current and future UFLS design requirements.*

- *The MDT is not impacted by the UFLS system as it is there to arrest a fall in system frequency caused by multiple non-credible contingencies. The MDT is set based on credible contingencies.*
- *A significant uplift in UFLS modelling capability across AEMO and Western Power has enabled substantially improved assessment of frequency and voltage stability with respect to UFLS requirements and performance. This includes updates to existing frequency stability models that simulate frequency response to determine frequency performance. These have also been embedded into real-time operations.*
- *Work already completed has resulted in recommendations for improvements to both the modelling and performance of the SWIS UFLS system, including limiting export on commercial PV connections, connection of existing transmission connected customers into UFLS, functionality for dynamic arming of reverse power blocking, implementing remote UFLS system control and dynamic UFLS management system.*

UFLS refers to the automatic protection scheme that is designed to arrest and recover a fall in frequency following the loss of multiple generators and/or network elements that result in the loss of generation. UFLS disconnects discrete blocks of load across five stages at set frequency levels. Its primary purpose is to provide a last line of defence against uncontrolled widespread outages resulting from non-credible contingencies.

Prior to the advent of significant quantities of DPV, the implementation of the UFLS system have been based on customers connected to the distribution system predominantly being loads. Various segments of the power system are configured to automatically disconnect from the power system when the frequency falls below 48.75 Hz (stage 1) and subsequent lower frequency levels. The target level of automatic disconnection is 15% of system demand in stage 1 and a cumulative 75% across all 5 stages (i.e. an additional 15% in each stage).

Western Power has traditionally planned the power system to have sufficient UFLS load shedding reserves through the automatic disconnection of distribution network feeders in the medium voltage network (11/22/33 kV) which sheds distribution connected customers connected to that feeder. This is implemented through protection systems at Western Power zone substation assets.

Evaluating the SWIS UFLS standard

In collaboration with Western Power, AEMO implemented a number of enhancements to their existing real-time stability tool to simulate frequency response against an established performance criteria designed to assess adequacy of UFLS including consideration for system inertia, demand (load relief), contingency size and DPV output. Sensitivity analysis was also carried out and examined future DPV output levels, generator retirements, the presence of BESS and cascading generator contingencies.

Table 15 summarises the scenarios that have been modelled for the analysis assuming the current UFLS design requirements are achieved. This assessment has been done to assess the ongoing suitability of the current UFLS design requirements. Where a scenario includes DPV disconnection, it refers to consequential DPV disconnection in response to frequency triggers. Additional studies are now being undertaken with the latest information on DPV disconnection due to system faults and voltage issues.

Table 15: Scenarios modelled to evaluate UFLS (if achieving current design requirement)

Scenario	Type	Name	Demand range (MW)[38]	# of generation dispatch scenarios
#1	Base	Historical Pi Data	1100 – 4200	Day = 250 Night = 250
#2		Base (no DPV)	1100 – 4200 900 – 4500 600 – 5000	Day = 250 Night = 250
#3	Sensitivity cases	Base + DPV	1100 – 4200 900 – 4500 600 – 5000	Day = 100 Night = 100
#4		Base + DPV + BESS	1100 – 4200 900 – 4500 600 – 5000	Day = 100 Night = 100
#5		Base + DPV – Muja C	1100 – 4200 900 – 4500 600 – 5000	Day = 100 Night = 100
#6		Base + DPV (Cascading)	1100 – 4200 900 – 4500 600 – 5000	Day = 100 Night = 100

The work undertaken in this review evaluates the SWIS UFLS standard, assuming that the amount of load able to be disconnected on UFLS is always maintained at 15%. The results of studies showed:

- Overall, a high portion of simulations met the defined performance criteria across a range of scenarios and operating conditions (i.e. ~90-98%).
- The assessment of the SWIS UFLS stages with the existing settings met (i.e. 15% of the system load available to shed for each stage at all times) shows a high level of compliant performance. This suggests that the current SWIS UFLS requirement of 15% for each stage remains adequate. However, continual increases in DPV connections and future synchronous generation retirements are eventually expected to trigger modifications to the current design requirements to maintain performance and risk levels associated with UFLS.
- The trigger for non-compliant performance were typically related to frequency overshoot. This highlights the need for a modelling improvement as over-frequency droop control (for non-scheduled generation) and over-frequency protection settings were not modelled in the tool. Improvements around modelling droop control and over-frequency settings will be implemented in future work.
- Most of the non-compliant UFLS performance was observed to occur at UFLS Stage 5 which has a lower probability of occurring than higher UFLS stages.
- The inclusion of a large-scale BESS showed benefits to the performance of the UFLS, by providing fast frequency responses to reduce frequency over-shoot issues and the impacts

[38] Scenarios were formulated such that the SWIS frequency response was assessed across a range of demand levels. This project has focused on the studies performed for lower demand levels.

of DPV disconnection with higher nadir frequencies being observed. Scenario 4 achieved the best compliance, highlighting the impact that a BESS has on improving frequency performance on the SWIS if operated specifically to improve system security. The BESS displaces an equivalent size of spinning reserve with faster frequency response and a significant reduction in frequency overshoot issues.

- Scenario 6 investigated the impacts of cascading generator tripping (with a 15 sec time delay) which produced the lowest levels of compliant performance, driven by prolonged periods of lower system frequency that manifest into frequency undershoot issues. The performance across the study period did not materially change due to the assumptions around new capacity DPV having ride-through capability and no ROCOF issues.
- There were no rate of change of frequency issues identified for the scenarios modelled.

As noted above, the work undertaken in this review assumed that the amount of load able to be disconnected on UFLS is always maintained at 15% One key recommendation from this work was regarding the need to test this assumption and evaluate the SWIS against the actual achieved UFLS levels especially considering declining SWIS load due to DPV output. Further information is provided below.

Declining UFLS availability

The significant uptake of DPV in the SWIS is resulting in reduced levels of demand on distribution network feeders and an increasing number of feeders becoming net exporters. This means that the net demand available to be disconnected from distribution feeders, particularly during low demand periods is decreasing to the point where the efficacy of UFLS on the SWIS needs to be assessed.

Table 16 summarises the assessment into the historical UFLS reserves based on data from 1 April 2020 to 1 April 2021. The assessment examined how much UFLS is available during daytime, night-time and as a total.

Table 16: Declining levels of UFLS, historical data 1 April 2020 to 1 April 2021[39]

Type	All stages (%)	Stage 1 (%)	Stage 2 (%)	Stage 3 (%)	Stage 4 (%)	Stage 5 (%)
Technical Rules requirement	75	15	15	15	15	15
Combined Day and Night						
Average	58.4	13.9	14.2	10.8	10.1	9.5
Maximum	75.5	19.1	18.1	13.6	13.0	15.3
Minimum	41.7	10.4	10.9	7.1	6.5	5.5
Average plus Std Deviation	63.1	15.1	15.1	11.8	11.1	10.9
Average minus Std Deviation	53.7	12.8	13.2	9.9	9.1	8.2
Day						
Average	57.5	14.5	13.8	10.6	9.8	8.9
Maximum	73.6	18.9	17.3	13.4	12.6	13.8
Minimum	41.9	10.2	10.8	7.0	6.5	5.5
Average plus Std Deviation	62.2	15.7	14.6	11.6	10.8	10.1
Average minus Std Deviation	52.8	13.2	12.9	9.7	8.8	7.6
Night						
Average	58.7	13.6	14.2	10.9	10.2	9.8
Maximum	75.7	17.0	18.1	13.6	13.0	15.3
Minimum	43.8	10.4	11.6	7.6	7.3	6.1
Average plus Std Deviation	63.3	14.4	15.3	11.8	11.1	11.1
Average minus Std Deviation	54.1	12.7	13.2	10.0	9.3	8.5

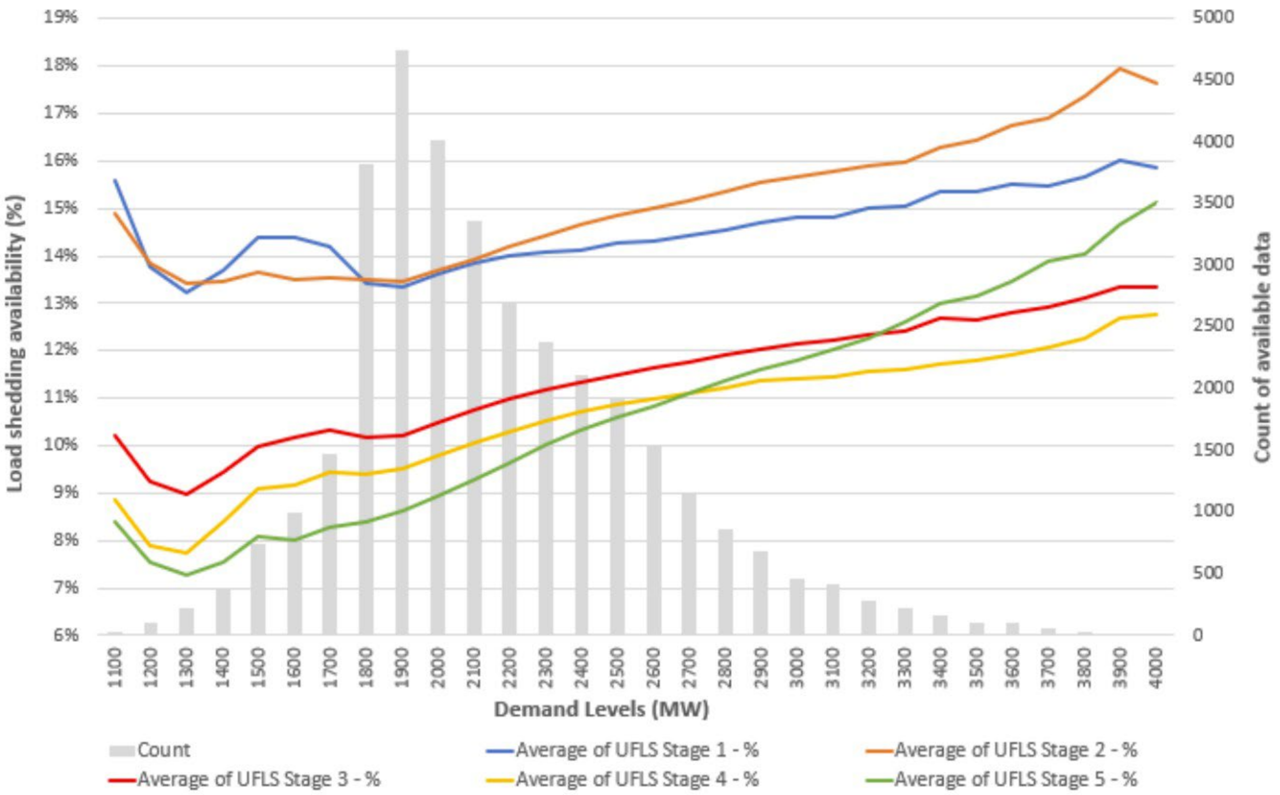
The assessment shows that:

- On average, the total daytime UFLS levels is round 57% against a target of 75% and these rapidly declined throughout the year.
- The minimum observed daytime UFLS levels were 42% against a target level of 75%, showing the extent at which UFLS does not meet the standard at times.

- All five UFLS stages failed to achieve the 15% per stage requirement discussed in the Technical Rules for either daytime or night-time events.[39]

Figure 16 illustrates the UFLS load shedding availability levels per UFLS stage across the range of historical demand (i.e. 1100 MW to 4200 MW). It shows a clear positive relationship between UFLS load shedding availability levels and demand.

Figure 16: UFLS Stage load shedding availability – average (combined) values



Assessing the impact of declining UFLS availability on the SWIS

Three different scenarios have been considered in order to evaluate the performance of the existing UFLS system using the historical and forecast lower levels of UFLS load shedding availability. Table 17 provides a summary of scenarios. A description is provided below:

- Scenario 1 is considered a reference case scenario as it excludes the impact of unintentional DPV disconnections.
- Scenario 2 aims to investigate the impact of unintentional DPV disconnections during under frequency events on the performance of the UFLS system.
- Scenario 3 is used to determine the impact to the performance of the UFLS system as a result of cascading generator tripping (with a 15 second time delay between each successive contingency) that leads to prolonged periods of operation below the acceptable operating band from the remaining intact generating units.

[39] The daytime period for this assessment is defined to be 08:00 to 16:00 inclusive and the night-time period all other times. Network utilisation between 16:00 and 18:00 is still impacted by DPV output although to a lesser extent. As more DER is connected on the SWIS, the minimum values are expected to continue to fall, while the divergence between the average daytime and night-time periods is also expected to grow.

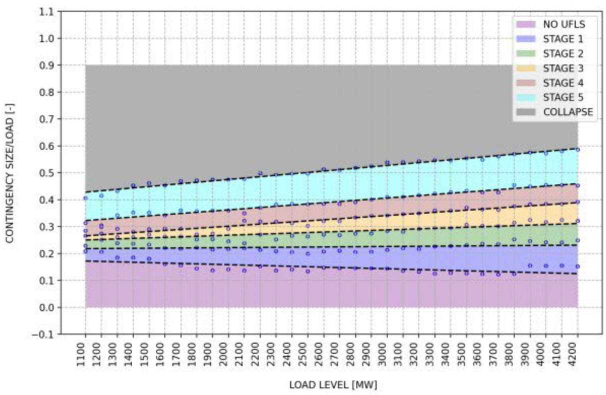
Table 17: Summary of study scenarios

No.	Scenario ID	Demand range (MW)	Year	UFLS load shedding levels	Remarks
S1	Base Case	1100 - 4200	2021	Each scenario applied: • Average • Average – 1 Std Dev • Average – 3 Std Dev	Instantaneous contingencies without DPV disconnection
S1	Base Case	600 – 4300	2023		
S2	Base Case + DPV	1100 - 4200	2021		Instantaneous contingencies with DPV disconnection
S2	Base Case + DPV	600 – 4300	2023		
S3	Base Case + DPV and cascade contingencies	1100 - 4200	2021		Cascade contingencies with DPV disconnection
S3	Base Case + DPV and cascade contingencies	600 – 4300	2023		

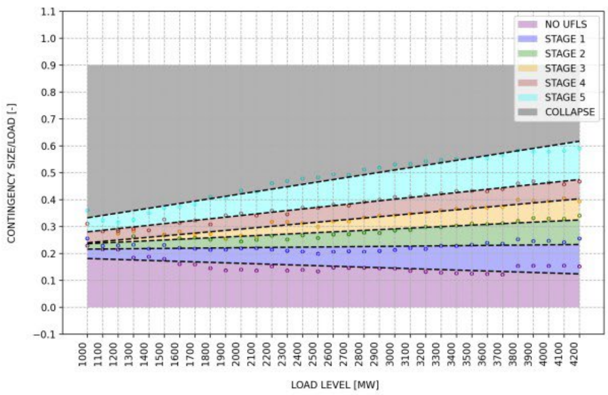
Findings from assessment of declining UFLS availability on the SWIS

Figure 17 shows the ratio of the contingency size to demand that would trigger each UFLS stage and a SWIS frequency collapse for scenario 'S2 – Base Case + DPV'. This scenario investigates the impact of unintentional DPV disconnections during under-frequency events on the performance of the UFLS system. Graphs (a) to (d) show the impact that declining UFLS availability has on decreasing the size of the contingency that would lead to activation of UFLS and a frequency collapse.

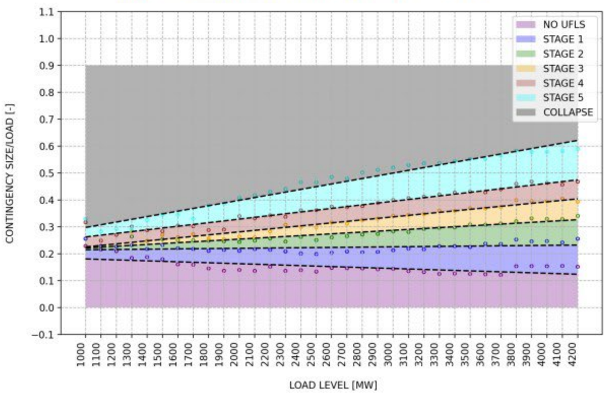
Figure 17: Contingency size and UFLS stage boundaries



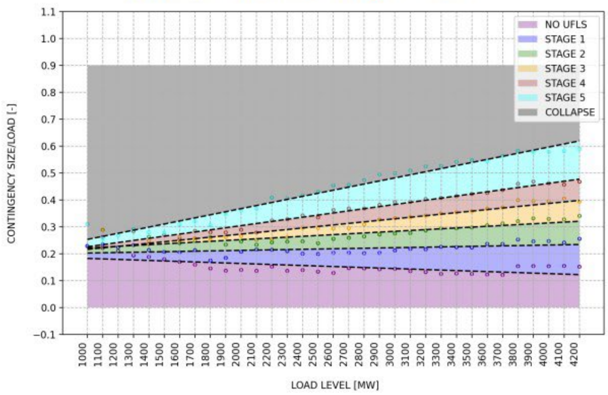
(a) Design Requirement Loads



(b) Historical Average Loads



(c) Historical Average Loads -1σ



(d) Historical Average Loads -3σ

Table 18 summarises the impact that a reduction in UFLS availability has on reducing the maximum contingency threshold the SWIS could withstand before each stage of UFLS is activated for a sample study where the operational demand is 1100 MW. Other operational demand levels were assessed as noted in Table 17.

Table 18: Maximum contingency thresholds at different UFLS levels (study at 1100 MW)

Scenario	UFLS availability (%)	Stage 1 (MW)	Stage 2 (MW)	Stage 3 (MW)	Stage 4 (MW)	Stage 5 (MW)	Collapse (MW)
S1 Day (no DPV)	15%	254	340	403	437	498	632
	Average	257	340	406	428	460	551
	Average minus 1 Std Dev.	257	335	400	410	447	521
	Average minus 3 Std Dev.	257	322	372	374	416	462
S2 Day (with DPV)	15%	189	239	275	292	354	470
	Average	197	238	263	269	315	375
	Average minus 1 Std Dev.	196	236	247	254	295	338
	Average minus 3 Std Dev.	198	223	246	244	257	291

The results of studies showed:

- Decreased load availability across all UFLS stages has a negative impact on the effectiveness of the UFLS system. This decreases the maximum contingency size that the system could withstand for each UFLS stage and before a system collapse could occur.
- The contingency size required to trigger system collapse during low system load conditions when using historical average load shedding levels is reduced by up to 20% when considering DPV disconnection. In practice, this may trigger operational actions to reduce the contingency risk size to ensure the SWIS frequency response is maintained within performance criteria. For example, in one operating condition under Scenario 2 (with DPV), the instantaneous contingency size required to trigger system collapse falls to greater than 375 MW for the historical observed levels of UFLS availability. This represents a 95 MW decrease in comparison to a scenario where the current UFLS design requirements were achieved. The maximum contingency size falls even further to greater than 338 MW and greater than 291 MW when further reductions in load shedding levels are applied (specifically at one standard deviation and three standard deviations lower).[40]
- Although studies show that overall contingency sizes are reduced, some contingency levels are not credible. For example, a 354 MW contingency is not considered credible at low system loads, since current system limitations would constrain the network contingency to less than or equal to 200 MW and there are no scheduled generators larger than 340 MW (nor are they likely to be dispatched at full output).[41] Despite this, prudent actions are

[40] These values represent the actual simulation values, rather that the values calculated from the linear regression equations.

[41] North Country wind farms less Karara load

necessary to consider pre-emptive operational actions during times where rare severe risks may present such as bushfires around key 330 kV corridors.

- The assessment undertook base case analysis using the historical average UFLS levels. There were no inclusions of forecast load shedding availabilities. Instead, studies were undertaken using sensitivity studies to reduce load availability by one average standard deviation and three average standard deviations. These were performed to simulate declining levels of UFLS. It is expected that without additional action taken to secure more load during low-load periods, contingency size thresholds would continue to decrease and further reduce the effectiveness of the UFLS.

Review of UFLS best practice

Western Power undertook a comprehensive national and international review of best industry practice relating to UFLS to identify latest developments in managing frequency stability and the use of UFLS in high power systems with very high DPV and other DER penetration. A number of utilities were surveyed (see appendices). Recommended solutions for the SWIS UFLS system are provided in Table 19.

Table 19: Recommended investigations to improve UFLS

<table>
<tr><th>Timeframe</th><th>Solution</th><th>Description</th></tr>
<tr><td rowspan="3">Short-term
(0-2 year)</td><td>Enhanced capability</td><td>UFLS remote control, reverse block capability</td></tr>
<tr><td>Additional load reserves</td><td>Connection of Transmission customer loads to UFLS</td></tr>
<tr><td>Dynamic UFLS management</td><td>Real-time management of load shedding reserves to optimise the effectiveness of UFLS</td></tr>
<tr><td rowspan="7">Long-term
(2+ years)</td><td>ROCOF triggers</td><td>Improved functionality to trigger UFLS based on ROCOF rather than a fixed activation threshold.</td></tr>
<tr><td>Adaptive UFLS</td><td>Ability to change UFLS settings according to system conditions</td></tr>
<tr><td>Enhanced frequency control</td><td>For example, community batteries provide UF support</td></tr>
<tr><td>Increased UFLS selectivity</td><td>Increased load shedding reserves by tripping only the load component of a customer supply (e.g. customers with BESS, AMI for residential customers)</td></tr>
<tr><td>Accelerate Protection relay replacement</td><td>Improve the relay functionality for UFLS on feeders (i.e. remote control, dynamic UFLS stage allocation, reverse block)</td></tr>
<tr><td>UFLS settings optimisation</td><td>Optimisation of settings such as the number of UFLS stages, time delays between stages.</td></tr>
<tr><td>Application of export limits</td><td>The retrospective application of export limits to commercial customers may result in more load available to be disconnected on UFLS.</td></tr>
</table>

5.7 System strength

Key findings

System strength is a collective term encapsulating a range of technical factors. The common factor coinciding with the low demand issue is that various characteristics of synchronous generators have historically provided for high system strength conditions. As synchronous generators are displaced, the characteristics that they have long provided are removed from the system.

Declining system strength presents a complex array of power system control and quality issues associated with the stability of inverter-based generators, voltage stability and issues associated with protection of power system plant. The effects of low system strength are localised rather than system wide and therefore the nature of issues and solutions are location specific.

- ► *An initial SCR screening tool was built to identify high risk areas by calculating SCRs for different generation and network conditions. A detailed EMT model was built for the generation facilities and the transmission network in the North Country region.*
- ► *EMT models of existing generators have been developed from existing unencrypted PowerFactory models. Generators seeking connection have provided EMT models as part of obligations in the connection process.*
- ► *Assessments for new generator connections have identified several issues that are currently being investigated, including the need to retune the controllers that oversee the operational aspects of the facility, investigations into additional customer equipment that may be needed and constrained operation under specific scenarios.*
- ► *The system strength work is ongoing and an integrated network and generator EMT model is being built for other high risks areas of the SWIS. Further work is also being undertaken for the North Country region.*

SCR screening

The system strength studies performed here have focused on assessing the stability of the inverter-based generation facilities including the existing facilities and the future facilities intending to connect to the SWIS.

Stage 1 of these system strength studies focuses on calculating SCR for thousands of generation dispatch conditions during system normal and network contingency conditions. These calculations are performed at the following points:

- At the connection point of the facility (the interface between the facility and the SWIS).
- At the inverter terminals with an assumed 1.0 pu contribution from all inverters.
- At the inverter terminals with an assumption of zero current contribution from adjacent inverters.
- Sensitivity studies were also undertaken within the SCR stage 1 studies to test the sensitivity to system impedance.

Table 20 provides a summary of the SCR screening results. The results show that:

- The East Country region of the SWIS (along the 220 kV towards the Eastern Goldfields) can exhibit an SCR of less than 3 following an outage of the 220 kV line. However, due to the potential for thermal overloads on the 220 kV lines, an inter-trip scheme is imposed to the generators in the region which disconnects the generators following a 220 kV outage.
- The region north of Three Springs can experience an SCR of less than 3 due to the distance of the region from large synchronous units. These SCRs can be experienced for a variety of outages, including an outage of either 330 kV or 132 kV lines.
- The south-east region of the SWIS also can experience an SCR of less than 3, also owing to these units being at the fringe of the grid.
- The available fault level in the East Country and the Eastern Goldfields is generally low highlighting the potential challenge that new generators may have in connecting to the region.

Table 20: Summary of findings for SCR screening stage 1[42]

Facility	Minimum SCR at connection point	Minimum SCR at inverter terminals with 1 pu current contribution from all inverters	Minimum SCR at inverter terminals with no current contribution from adjacent inverters
North Country Wind Farm 1	5.0	17.8	3.3
North Country Wind Farm 2	3.8	17.0	2.0
North Country Wind Farm 3	6.0	11.6	2.8
North Country Wind Farm 4	6.2	12.8	3.1
North Country Solar Farm 1	13.2	18.6	11.2
North Country Solar Farm 2	12.2	24.7	6.2
East Country Solar Farm 1	3.6	38.0	2.0
East Country Solar Farm 2	5.2	23.5	4.1
South East Wind Farm 1	4.3	5.9	1.7
South East Wind Farm 2	3.2	17.5	2.0

An output of stage 1 is an 'SCR trace' that shows the range of SCR values that could eventuate on that busbar for different generation dispatch and network contingency conditions. Each generator's response is assessed to identify the onerous SCR at their point of connection. Any suspicious oscillatory behaviour is then investigated further and a solution for the related contingency condition is proposed.

Detailed EMT modelling (stage 1)

Detailed stage 1 system strength studies were performed with in-house developed models for existing facilities as well as vendor developed models for future facilities using a Thevenin equivalent (voltage behind impedance) model. Sensitivities were considered which varied the reactive power control modes for facilities, including consideration for voltage droop control, constant Q control and power factor control modes.

To validate the model, the EMT and RMS models for different disturbances were created to ensure the overall response of the facility was consistent.

Table 21 provides a summary of the detailed EMT studies completed to date. Note, not all facilities have completed studies due to the ongoing development of computer models.

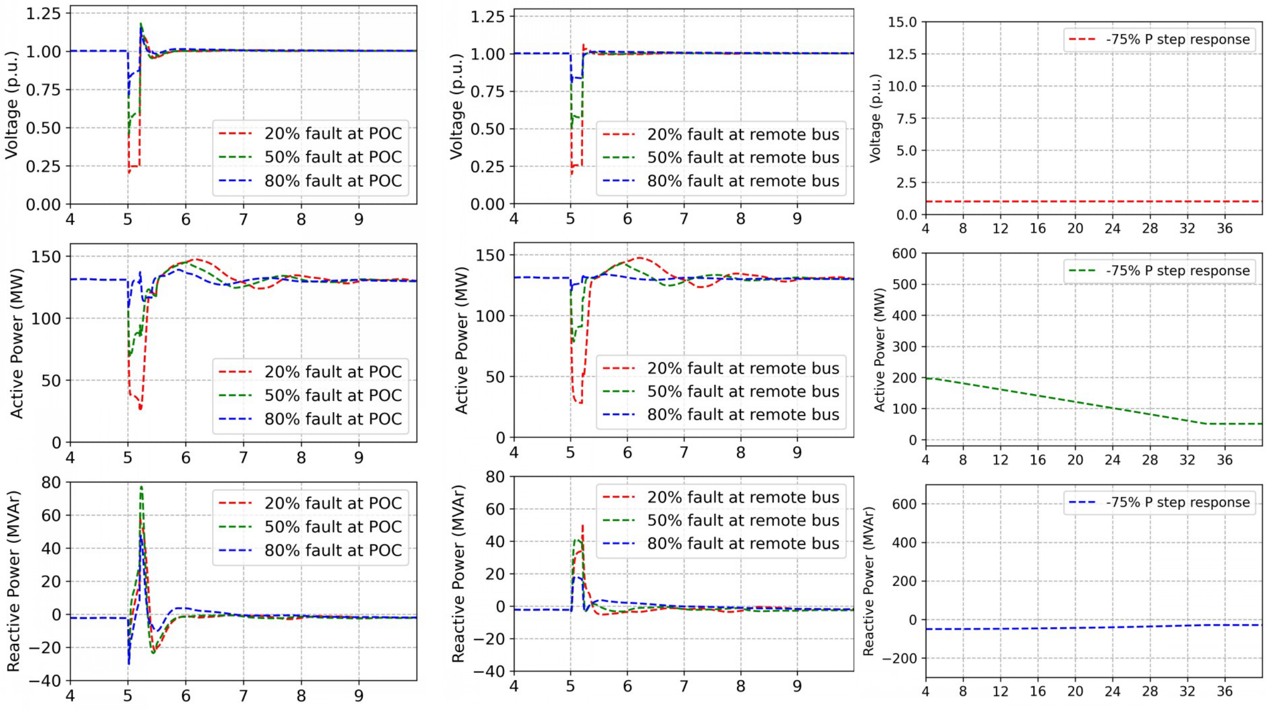
[42] Not all facilities were available due to computer models still being developed

Table 21: Key findings from detailed EMT studies completed

Facility	Lowest SCR System Normal	Lowest SCR N-1/N-1-1	Comments
North Country Wind Farm 1	10.7	5.0	No system strength issues envisaged
North Country Wind Farm 2	6.4	3.7	No system strength issues envisaged
North Country Wind Farm 3	8.2	5.7	No system strength issues envisaged
North Country Wind Farm 4	9.8	6.2	Oscillatory active power step response for contingency
North Country Wind Farm 5	6.6	2.8	Minor issues in the customer model. Oscillatory behaviour observed for one system contingency.
North Country Solar Farm	18.7	13.1	No system strength issues envisaged.
East Country Wind Farm 1	8.2	3.6	Facility instructed to operate in constant Q
East Country Wind Farm 2	6.0	4.3	Several issues in the customer model. Oscillatory behaviour observed for several system conditions.
East Country Wind Farm 3	4.2	2.0	In progress
South East Wind Farm 1	6.5	2.0	Minor issues in the customer model. Oscillatory behaviour observed for one system contingency
South East Wind Farm 2	7.9	5.1	No system strength issues envisaged
South East Wind Farm 3	9.4	6.0	No system strength issues envisaged

Figure 18 shows a single sample set of the EMT simulations performed for a North Country generation facility, examining voltage, active power and reactive power response to different fault conditions under different active power output and system contingency conditions at the point of connection (POC). No oscillatory behavior was observed under the most onerous of cases.

Figure 18: Example simulation results for a North Country generation facility



Detailed EMT modelling (stage 2)

Due to the identification of low SCR values and the large number of inverter-based generation facilities located in the North Country region, this area was prioritized for detailed EMT modelling.

The objective of this detailed EMT Modelling is to understand the performance limits of inverter-based generation facilities in low system strength conditions and to understand the potential controller interactions between the facilities.

The EMT simulations were computationally intensive and to reduce simulation times, the network in the North Country has been split into five simulation regions. Each region covers a distinct portion of the network.

The cases that have been defined for modelling are summarized in Table 22. Further information on the assumptions can be found in Appendix E.4.

Table 22: Cases for modelling

Ref	Name	Dispatch	Network	Fault event
D1	Peak load	Peak load	N-0 N-1	All fault types (Listed in Appendix E.4.)
D2	Minimum load_NCGroup1	Minimum load dispatch (for NC Group 1)	N-0 N-1	
D3	Minimum load_NCGroup2	Minimum load dispatch_2 (for NC Group 2)	N-0 N-1	
D4	Minimum load_NCGroup3	Minimum load dispatch_3 (for NC Group 3)	N-0 N-1	

System strength findings to date

For the studies conducted thus far, all of the existing facilities in the North Country are expected to retain control loop stability. Simulations of new entrant generation facilities did show a number of modelling issues that warrant attention. These discussions are being progressed as part of the standard connections process.

Further work is ongoing to refine the EMT models and to undertake system studies for more contingency conditions in the North country. EMT models of the Eastern Goldfields, the East Country and the South-East region of the SWIS have been implemented and validated and studies are in-progress for these load areas.

5.8 Activation of ESM

Key findings

The MDT is the minimum operational demand level below which the SWIS is no longer secure and emergency actions such as Emergency Solar Management (ESM) may be required. ESM is one mechanism available to the power system operator to maintain system security by ensuring operational demand stays above the MDT. An MDT of 650 MW is more onerous than an MDT of 550 MW as it binds at a higher operational demand.

The number of customers that are impacted by an ESM event depends on the quantity of DPV output needed to be curtailed such that operational demand stays above the MDT. How long customers are impacted for depends on the duration of time that operational demand would otherwise fall below the MDT. It may be possible to implement ESM on a rotational basis to spread events across a wide customer base and minimise the potential for customers to be subject to multiple ESM events times within a short period of time.

- *An assessment of demand forecasts and demand profiles were undertaken to assess how often ESM may be required between to keep operational demand above the current MDT range. If the forecasts of minimum operational demand in AEMO's 2022 WEM ESOO are reached the MDT is expected to materialise within the next year.*
- *Based on an MDT range of between 650 MW and 550 MW, the operational demand in the WEM is forecast to breach the MDT within the next year according to AEMO's 2022 WEM ESOO.*
- *The average duration of an ESM event lasted for between 2 and 3 hours. However, in the worst case, the longest ESM event lasted for up to 7 hours, occurring in 2024-25 using an MDT of 650 MW. It is expected that actions would take place to lower the MDT to mitigate against long duration ESM events such as these from occurring.*
- *The average ESM quantity needed to maintain operational demand above the MDT increased throughout the study period. The average quantity of ESM required in the first year varied between 3 MW and 70 MW depending on the MDT used. This increased throughout the study period to between 110 MW and 140 MW. This highlights that ESM events will impact more of the SWIS customer base with declining operational demand.*
- *Based on current DPV installation rates on the SWIS, there should be sufficient ESM capability installed by the time first activation may be required.*

An assessment of demand forecasts and demand profiles was undertaken to assess how often ESM may be required to keep operational demand above the current MDT range. The study period covered 2021-22 to 2024-25.

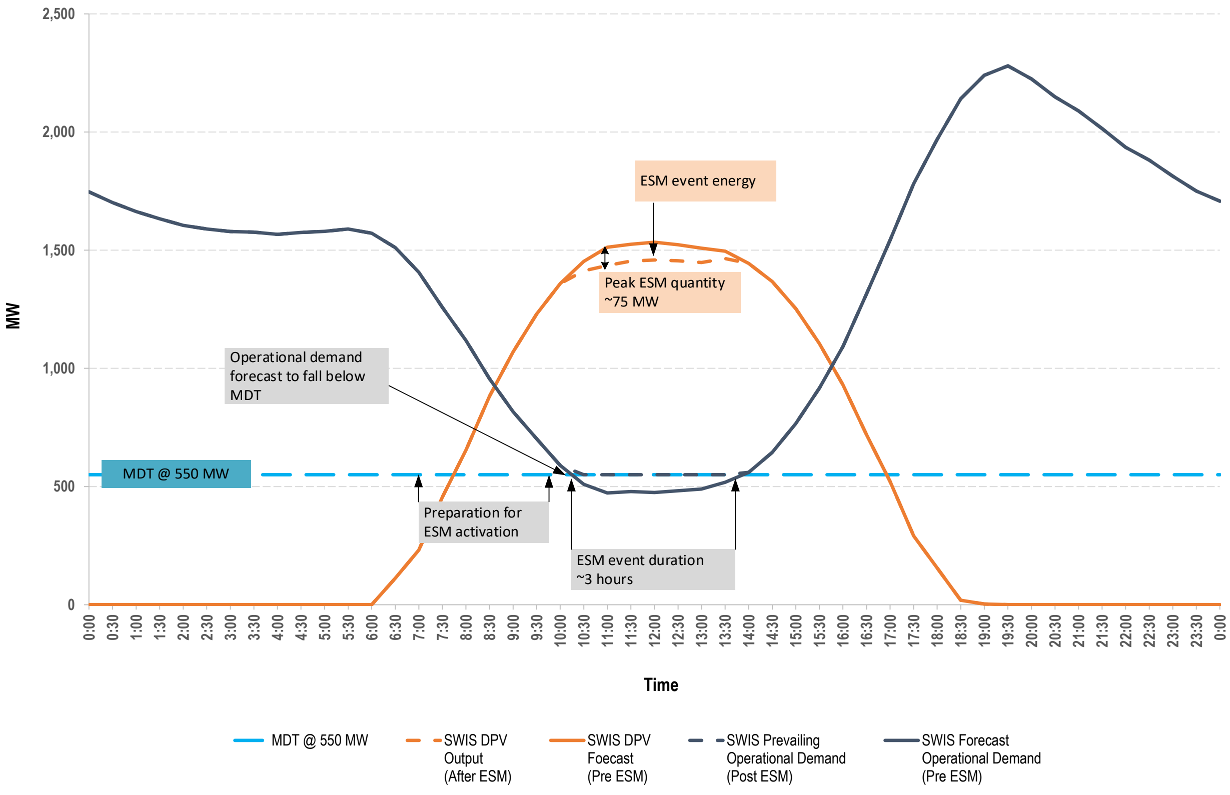
AEMO's 2022 WEM ESOO Expected scenario was used as the basis for the annual minimum operational demand forecasts.[43] A half-hourly, time-sequential demand profile was produced for each year of the study period. The demand profile has the minimum operational demand in each year achieving AEMO's minimum operational demand forecast. These profiles build upon the historically observed SWIS demand profile and account for forecasts of annual operational energy, annual peak demand values, annual minimum demand values and also the impact of DPV and other DER on demand.

Different weather reference years are used to assess the natural volatility present in half hourly operational demand shapes from year to year. Applying multiple weather reference years introduces variability to the solar resource which impacts DPV dispatch therefore impacting the shape of operational demand in the SWIS from period to period. This captures aspects such as historical cloud cover and the historical correlation between weather and demand, projecting the impact of these characteristics forward to future load shapes.

An MDT of either 650 MW or 550 MW has been applied throughout the study period. In reality the MDT changes between this range depending on the generators that are online at the time. Modelling the upper and lower limit of the MDT presents a reasonable range of outcomes that might eventuate. The MDT will change as the SWIS generation technology mix changes. As an example, the connection of utility-scale storage may allow the MDT to be operated at lower levels under certain operating conditions. Further work is needed to quantify the extent of any reduction in the MDT and potential benefits have not been included here.

Figure 19 presents a modelled potential future ESM event occurring on the 22 October 2023.

Figure 19: Modelled ESM event occurring on 22 October 2023



[43] The 50% POE values have been used.

ESM activation findings

Table 23 summarises the estimated annual usage of ESM with an MDT of 550 MW and 650 MW. An equal weighting has been applied to each weather reference year studied.

Table 23: Estimated ESM usage with equally weighted weather reference years

Case	Case Description	FYE	Hours ESM was used (hrs)	Percentage of the year where ESM was used (%)	Annual ESM Energy (MWh)	Percentage of total available DPV energy spilled (%)
Case 1	550 MW Limit	2023	0.8	0.010	3	0.000
		2024	14.0	0.160	1,112	0.034
		2025	97.5	1.113	9,759	0.277
Case 2	650 MW Limit	2023	10.3	0.118	604	0.020
		2024	43.8	0.500	3,555	0.108
		2025	195.5	2.232	24,109	0.686

Further assessment was undertaken on each ESM event observed. Table 24 provides a summary of the average ESM event with equal weighting applied to each weather reference year.

The full set of results is provided at Appendix F.

Table 24: Analysis of ESM events with equally weighted weather reference years

Case	Case Description	FYE	Events (number)	Average ESM quantity per event (MW)	Average ESM duration per event (Hr)	Average ESM energy per event (MWh)
Case 1	550 MW Limit	2023	1.7	3.4	0.5	1.7
		2024	6.0	111.3	2.7	245.0
		2025	39.3	110.4	2.5	246.8
Case 2	650 MW Limit	2023	4.3	68.5	2.3	138.7
		2024	20.0	78.3	2.1	169.6
		2025	71.0	136.2	2.8	338.3

Should annual minimum demand forecasts be reached the MDT is expected to materialise within the next year. It's noted an MDT of 650 MW is more onerous than an MDT of 550 MW. Applying an MDT of 650 MW resulted in first activation of ESM in 2022-23. Applying an MDT of 550 MW resulted in first activation of ESM in 2022-23, the same year.

An MDT of 650 MW results in more events per year relative to an MDT of 550 MW. Applying an MDT of 650 MW resulted in an average of four ESM events first occurring in 2022-23. This increased to 71 events by 2024-25 as forecast operational demand falls to a low of 231 MW. There are more periods of time where forecast operational demand is below the MDT.

Applying an MDT of 550 MW resulted in materially fewer events, with under two ESM events first occurring in 2023-24 (the same year). This increased to 39 events by 2024-25. This highlights that should the SWIS be able to operate with a 550 MW MDT compared to a 650 MW MDT, the number of ESM events is expected to be substantially lower.

The number of customers that are impacted by an ESM event depends on the quantity of DPV output needed to be spilled such that operational demand stays above the MDT. How long customers are impacted for depends on the duration of time that forecast operational demand is below the MDT (see Figure 19 above). It may be possible to implement ESM on a rotational basis to spread events across a wide customer base and minimise the potential for customers to be subject to multiple ESM events within a short period of time.

The average duration of a typical ESM event lasted for between 2 and 3 hours. However, in the worst case, the longest ESM event observed lasted for up to 7 hours. This occurred in 2024-25 with an MDT of 650 MW. This event was particularly long due to very high sustained DPV output during a weekend day in spring. It is expected that actions would take place to lower the MDT to mitigate against long duration ESM events such as these from occurring.

The average ESM quantity needed to maintain operational demand above the MDT increased throughout the study period. The average quantity of ESM required was upwards of 136 MW equating to around 34,000 systems that could be impacted.[44] This highlights that ESM events will impact more of the SWIS customer base and for longer periods of time with declining operational demand.

6. Next steps

The purpose of this report is to present a summary of the work undertaken in Stage 1. A number of modelling artefacts are being refined including:

- further development of EMT models for other high-risk areas
- other EMT studies covering more contingency scenarios
- refinement of the risk assessment associated with disconnection of DPV and its inclusion in credible contingency scenarios.

Following this Stage 1 report completion, Stage 2 of the Low Load Project is already in progress to follow through the recommendations for further work. Consideration for low load events is now being captured in other parts of the planning and forecasting activities embedded in the WEM. These include:

- AEMO’s 2022 WEM ESOO, which will be published in Q2 2022 and looks to refine minimum demand forecasts.
- Western Power’s Transmission System Plan, which may report on reliability and security issues, ongoing modelling of UFLS and system strength modelling.
- Energy Policy WA’s Whole of System Plan 2023, which will monitor system operability and system security conditions for a range of future energy scenarios.
- Action undertaken as part of the Energy Transformation Strategy Stage 2, which may also examine different incentives to increase demand in the middle of the day.

[44] Based on an assumed coincident output of 4 kW from a single system during low operational demand period.

Appendices

Appendix A. Recent actions to address low demand

Whilst the risks associated with system security issues during low demand are being investigated in detail through this project, there has also been a significant amount of action to mitigate low demand issues either directly or indirectly through parallel work.

Actions have been made through improving the planning and regulatory framework, improved connection standards and guidelines used in the access framework. Responses have also been made on an operational time scale to manage the issue in real-time. Furthermore, network investment has also assisted in managing the issue in recent years.

Table 25 provides a summary of actions that have been undertaken in the SWIS in recent years and the responses that are being investigated now. For actions where the benefit will be realised on a future timeframe, an indicative timeframe is provided.

Table 25: Recent implementations to help manage low demand risks

Action	Description	Timeframe
Additional network investment	Western Power has installed reactors to manage voltages during low demand periods.	A network investment that is in-service now
Out of merit generator dispatch	AEMO has occasionally dispatched certain generators out of merit during low demand periods.	An operational response that is being used now
Provision of additional spinning reserve	For certain operating conditions, AEMO has recently increased the provision of spinning reserve from generators to cater for potential disconnection of DPV.	An operational response that is being used now
Connecting existing transmission connected load customers to UFLS	Western Power have recently facilitated the move of a number of transmission connected customers onto the UFLS system to ensure increased demand is available to be disconnected, although still below the 75% requirement.	Initial phase of implementation (temporary solution) has been completed. Final implementation to add enhanced funnctionality within 1-2 years.An operational response that is being used now
Increased levels of reserve blocking functionality and remote UFLS telemetry on distribution feeders	Western Power is currently upgrading protection relay equipment on MV feeders to add reverse blocking capability and remote UFLS telemetry. This increased functionality will prevent the disconnection of distribution feeders that are net exporters of energy exacerbating an UFLS event. Increased remote telemetry provides greater flexibility to manage available UFLS load shedding reserves.	An investment that is being constructed. In-service within this year.
Active management of DPV	Functionality for emergency solar management has been introduced from 14 February 2022 on all new and upgraded installations. At the historical average installation rate of 25 MW per month of DPV being connected, 300 MW of emergency solar management could be available in a year's time.	A connection standard that is in effect now. An operational response that is available now, but requires new installations and upgrading of existing systems to achieve scale of response. Potential to achieve sufficient scale in 6-12 months.

Action	Description	Timeframe
Improving ride-through capabilities of DPV to withstand system disturbances	New inverter based systems are now subject to revised inverter standards that require defined ride-through capabilities to improve grid stability. This is expected to mitigate DPV disconnecting during system disturbances.	A connection standard that is in effect now. An inherent operational response that is being improved now, but requires new installations and is dependent on when DPV systems are updated/upgraded to achieve scale of response. The majority of legacy inverters will still be susceptable until replaced or upgraded at end of life.
Installation of large-scale batteries	Synergy are currently in the construction phase of their 100 MW / 200 MWh battery storage system. Other market participants are investigating similar projects. These assets will be able to provide additional services to the SWIS through contract or new market mechanisms.[45]	An investment that is being constructed and will be in-service in ~1 year. Other storage projects may be in-service in 2-3 years.
Interruptable load demand response	Use of a future NCESS to contract with loads to reduce embedded generation and increase system load.	An operational response that could be investigated. Potential to take effect in ~1 year.
Managing ROCOF	Introduction of the future ROCOF Control Service and co-optimisation of credible contingency sizes in the SWIS will assist in mitigating frequency stability issues as part of future market reforms.	Fundamental change in WEM design and a new market starting in October 2023. Scale of response uncertain at market start.
Increase residential and commercial load during day-time periods through tariffs	Commencement of a time-of-use tariff pilot to encourage greater energy consumption in the middle of the day when solar energy is plentiful is being trialled as part of the DER Roadmap.	In effect now However benefit from uptake across the SWIS likely to be 3-5 years away.
DER participation projects (including Project Symphony)	Developing capability for opt-in VPP services that can be called on to reduce PV output or increase load as a commercial transaction with DER owners is a part of the vision for DER in WA. This includes work on Dynamic Operating Envelopes which facilitates flexible export arrangements at different times of the day (within the confines of network constraints at these times). These take time to implement and achieve sufficient scale.	Potential to achieve sufficient scale to assist in 5 years.

[45] Synergy - About us - News and announcements - Media releases - New archives article page

Appendix B. Disconnection of PV on the SWIS

B.1 Methodology overview

Identifying how much DPV has disconnected during system disturbances is not something that can be measured directly. These values were then inferred and estimated through analysis of historical system events.

The methodology developed to estimate and forecast the amount of DPV that could be disconnected in the future involves a combination of analysing high-temporal resolution information recorded during disturbance events, statistical analysis to estimate the relationship between power system characteristics and the amount of DPV that could disconnect and forecasting where DPV is prevalent in the network.

B.2 Voltage impact

Historical system events were identified to undertake analysis of the power system where the focus was on:

- 330kV and 132kV faults.
- getting different fault types where possible.
- for day events - selecting faults that occurred in the last 4 years
- night events - selecting faults from 2014 onwards.

A total of 20 events were included in the analysis (8-day events and 12-night events).

See Table 26.

Table 26: System disturbance events assessed

Fault	Day/ Night event	Date	Time	Faulted Circuit	Faulted Phases	Frequency Nadir
1	Day	11-Jan-18	12:34:19	GLT-ST91	B-R	50
2	Day	7-Feb-19	13:52:00	NT-MU91	B-E	50
3	Day	9-Jan-20	13:56:56	KW-KEM/OLY91	B-R	49.66
4	Day	18-Sep-20	12:22:56	ST-SNR/BYF81	W-B	49.74
5*	Day	17-Oct-20	14:51:04	NBT-YDT91	B-E	49.17
6*	Day	2-Jan-21	11:26:40	NBT-YDT91	B-E	48.89
7	Day	4-Feb-21	14:46:37	KW-CC/MED81	W-B	49.82
8*	Day	29-Mar-21	10:04:42	Blue Waters G1	No Fault	49.17
9	Night	17-Mar-14	3:29:00	LN2 KW ST 330kV	W-E	50.2
10	Night	22-May-14	3:49:00	LN2 KW ST 330kV	W-E	50.18
11	Night	7-Jan-15	3:41:00	SUT6 MU 0 330kV	B-E	49.83
12	Night	2-Feb-15	22:07:00	LN1 GLT ST 330kV	W-E	49.96
13	Night	3-Feb-15	19:31:00	LN1 SHO WLT 330kV	B-R	50.09
14	Night	6-Jan-16	20:22:00	LN1 NT MU 330kV	R-E	49.64
15	Night	7-Jan-16	3:03:00	LN31 SHO ST OLY 330kV	R-E	50.04
16	Night	7-Jan-16	21:29:59	LN31 SHO ST OLY 330kV	W-E	50
17	Night	14-Dec-19	20:05:00	LN1 SHO WLT 330kV	R-E	49.99
18*	Night	10-Feb-20	0:46:00	LN1 KW NGK 330kV	W-E	49.54
19	Night	20-Jan-21	1:48:00	LN31 PIC PNJ BSN 132kV	3-phase	49.945
20	Night	3-Mar-21	18:43:00	LN31 CC KW MED 132kV	3-phase	50.028

Different sources of information were considered to use in the analysis. These included:

- Fault recorders (high-voltage and medium-voltage network)
- Protection relay oscillography (high-voltage and medium-voltage network)
- SCADA data (high-voltage and medium-voltage network)
- Power quality loggers (low-voltage network)
- Western Power employee DPV data (low-voltage network)
- Inverter OEM / third party data (low-voltage network)

From the above list, the fault recorder data was the main source given the high resolution information it provided for each fault event. This was supplemented with information from SCADA data, PQ loggers and Western Power data.

From the fault recorder at various sites, the following power system characteristics were derived and analysed for the pre-fault condition, during the fault and post fault:

- voltage magnitude
- voltage angle
- power (MW)
- fault duration
- frequency

The above data was taken at each zone substation transformer MV incomer circuit. This data was then used as input into a multi factor statistical model.

The Western Power network has fault recorders installed at many zone substations with the exception of a few older metro zone substations. This included several zone substations which would service areas with high installed DPV capacity. Not having the data from these sites would result in a 'gap' in the analysis as there wouldn't be coverage of the DPV behaviour at those sites.

Hence an estimate of the change in power during the fault disturbances was derived for these sites using the outgoing line readings from nearest (electrically) adjacent sites with fault recorders.

During a system disturbance which results in a voltage dip, the impact results in both load and PV reducing. To distinguish how much PV and how much load reduced by at the system or feeder level is not straight forward. Therefore, to try and identify the load response for a transmission fault, night-time events were investigated and analysed to isolate the load behaviour following a fault (i.e. when DPV is not on).

The results would then be used to estimate the load behaviour during the daytime event, and the remaining difference in the change in power would be considered as the PV behaviour.

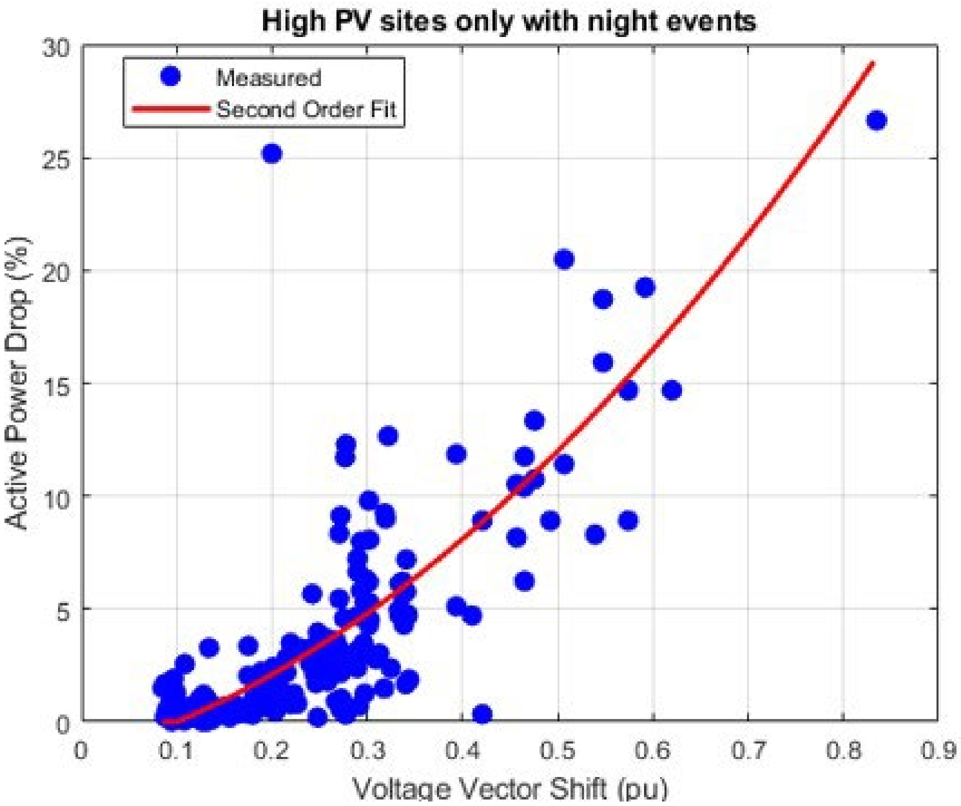
A multi-variate statistical model was created to see what correlations existed between the load response (% change in power) and the following factors:

a. change voltage magnitude
b. change in voltage angle
c. fault duration

The data extracted from the fault recorders for all the night events were used to calculate the above factors and used as inputs to the statistical model. The strongest factors that impacted the load response were change in voltage magnitude and angle. Combining the effects of this, the voltage vector shift was calculated for all the events and used to derive a general load response correlation equation.

The equation represents an underlying load response characteristic (non DPV impacted) that estimates the relationship between the change in percentage active power (percentage of the underlying load) at a connection point verses the shift in the voltage vector.

Figure 20: Correlation between change in active power and voltage vector shift for night events



Furthermore, load response equations were derived for each site (where a strong correlation was noted) to see if it would impact the results and provide further accuracy.

The load response correlation equations were then used for the day time events across all the sites to estimate how much load has tripped based on the voltage vector shift seen at each site for the day events and the estimated underlying load.

The estimated load trip amount is added to the measured net power change measured by the fault recorder for each site, and the resultant change is the estimated amount of DPV (in MW) disconnected. A percentage DPV trip is then derived based on the DPV generation at the time of the fault.

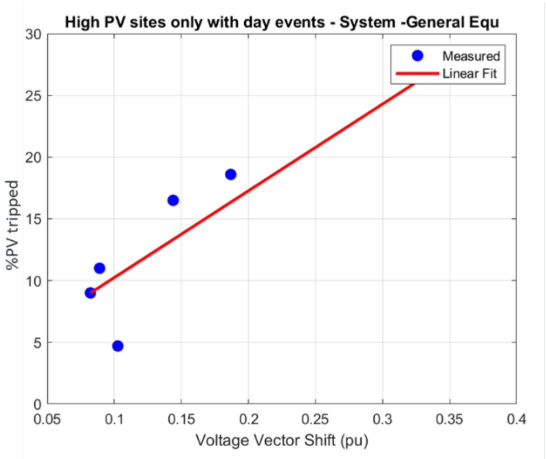
Similar to the load response using the night events – the multi-variate statistical model was created to now see what correlations existed between the DPV disconnection and the same factors used for the load response analysis.

The result was the same where the strongest factors influencing the DPV disconnection were voltage magnitude and angle. Hence the voltage vector shift was used again to derive a DPV disconnection correlation equation based on the general load response equation and another based on the site-specific load response equations.

The equations represent DPV disconnection characteristic that estimates the relationship between the percentage PV tripping (percentage of the PV generation) at a connection point verses the shift in the voltage vector.

Consideration was also given to plotting the data looking at the fault events on a system level instead of a substation (per site) level. This resulted in a similar characteristic as seen in figure 26.

Figure 21: Correlation between %PV tripped and voltage vector shift for day events (system level)



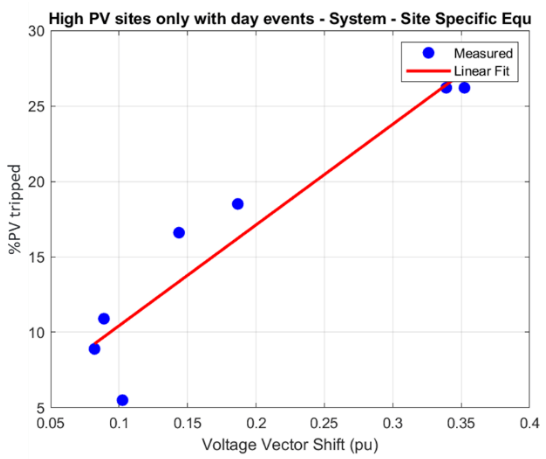
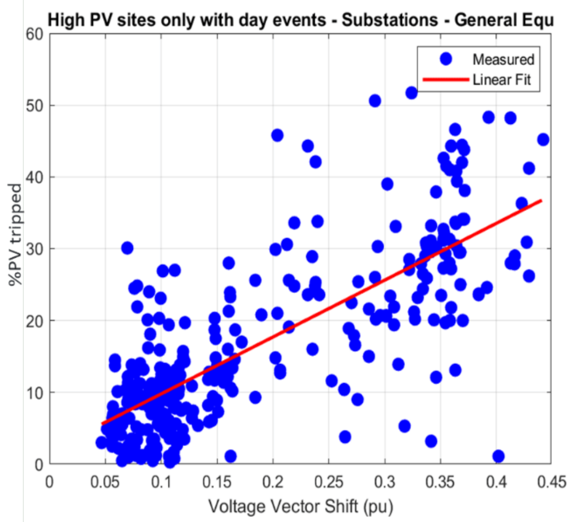
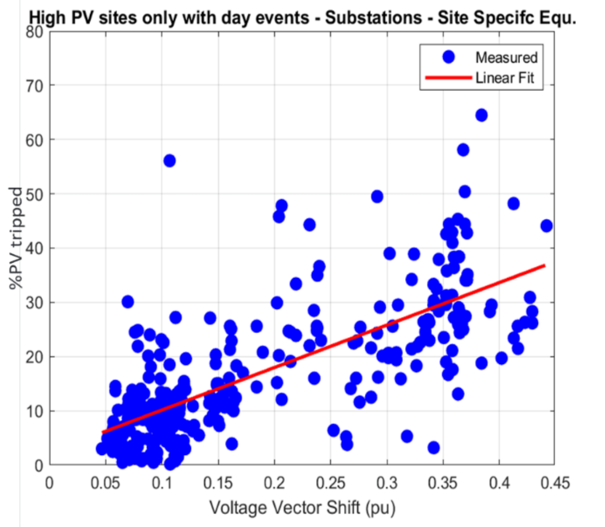


Figure 22: Correlation between %PV tripped and voltage vector shift for day events (substation level)



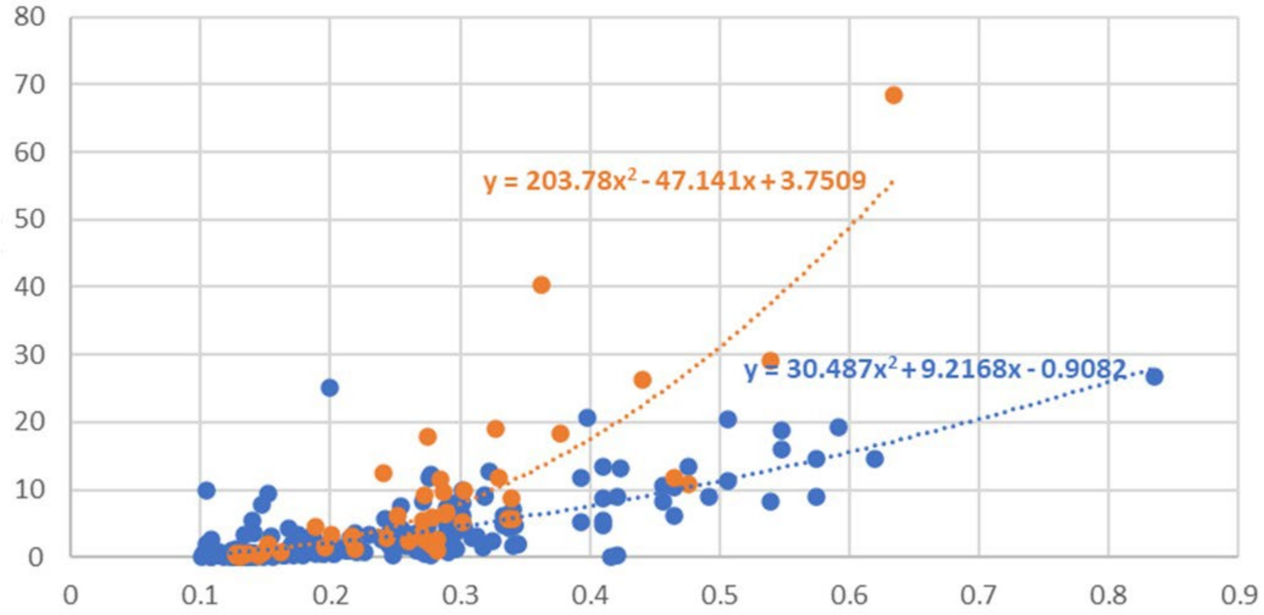


Further refinement of the process was applied where the sites were categorised into two load types:

a. Residential load
b. Commercial/Light industrial

Using the data set for the night-time events, two load response correlation equations were derived for the different load types. See the Figure 23.

Figure 23: Load response correlation equations during night-time events



Using the two load type categories, load response equations were derived on a per site basis. These equations and load types were then reapplied to the day events. Resulting in the following DPV disconnection correlation equations on a substation level and a system level.

Figure 24: DPV disconnection correlation equations substation level

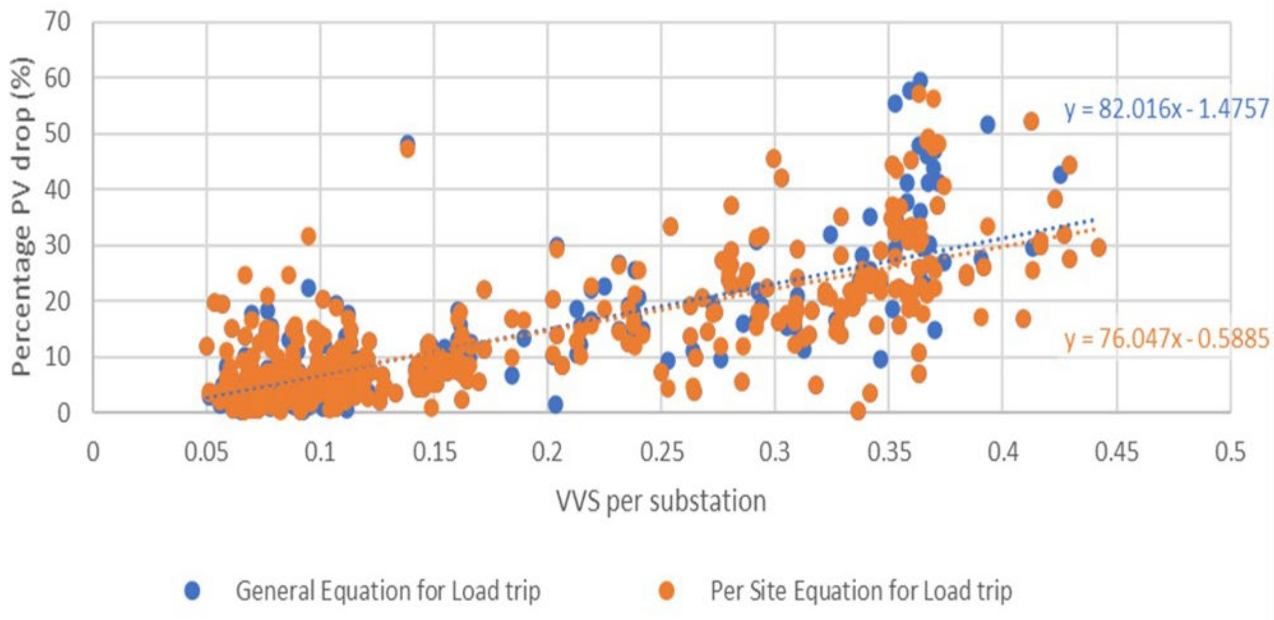
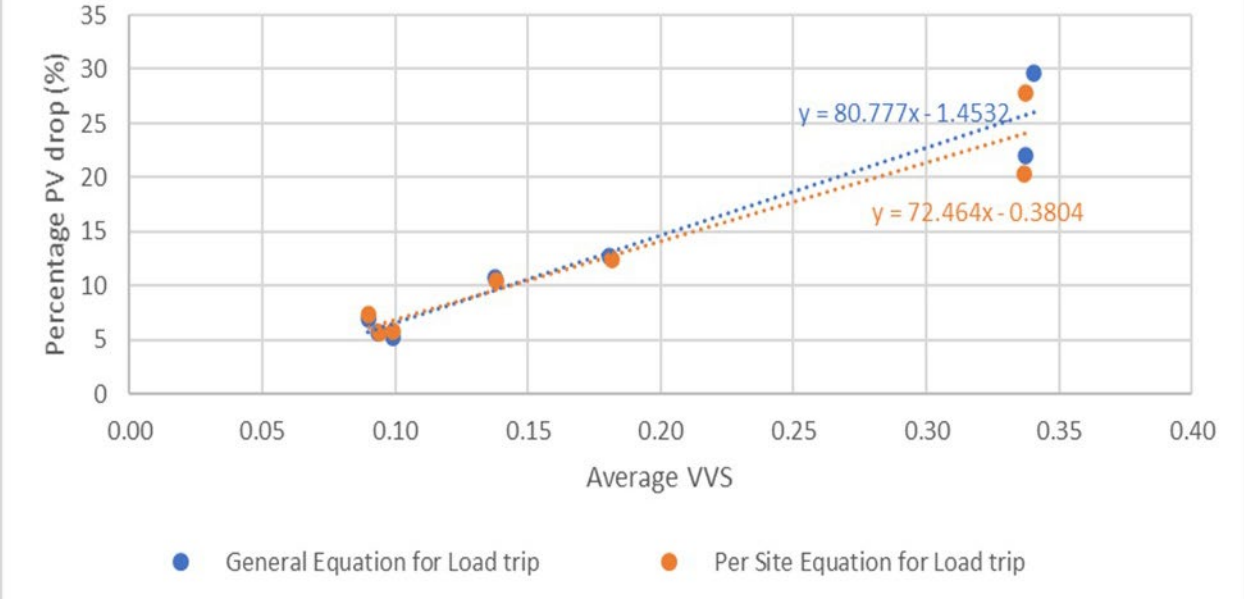


Figure 25: DPV disconnection correlation equations system level



B.3 Frequency impact

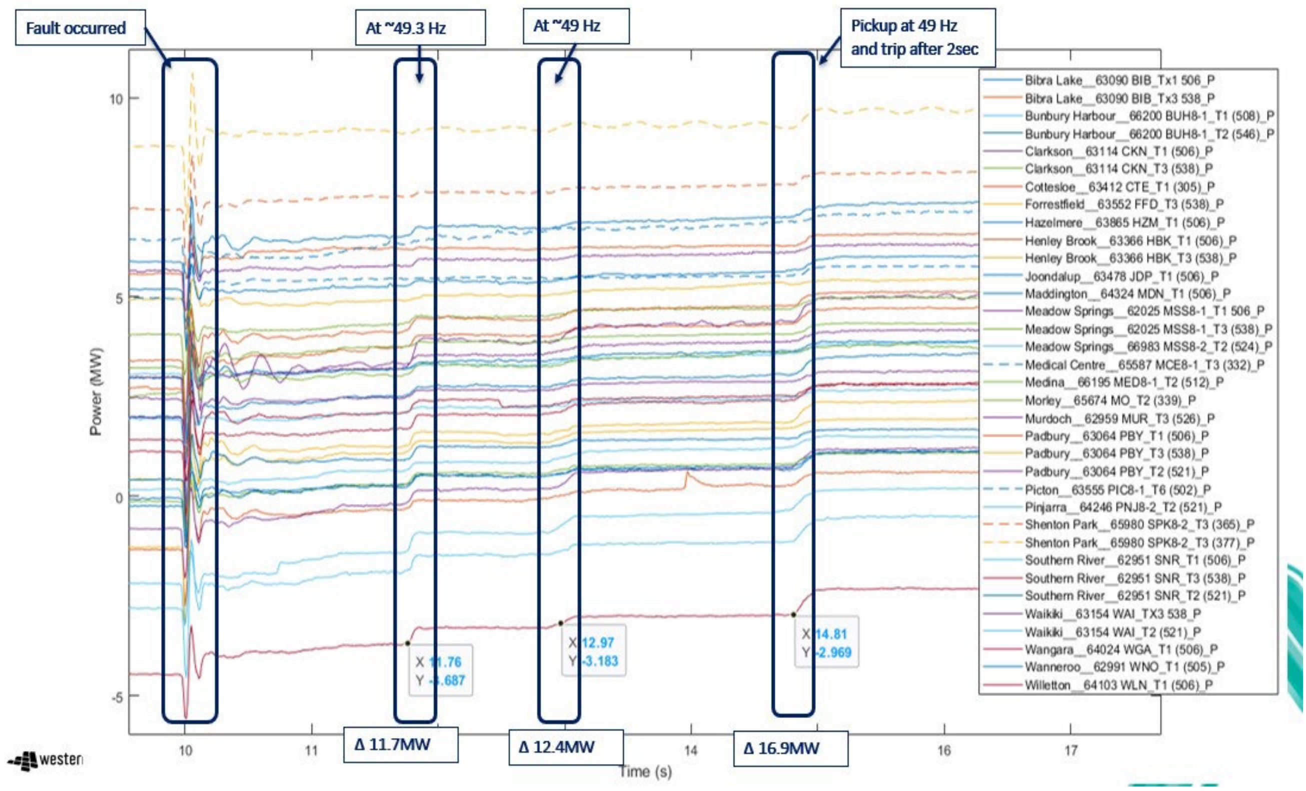
Out of the 8-day events identified, only 3 of them had a frequency impact where the frequency nadir dropped below 49.25 Hz.

Day	Time	Faulted circuit	Frequency phases	Frequency nadir (Hz)
11 January 2018	12:34:19	GLT-ST 91	B-R	50
7 February 2019	13:52:00	NT-MU 91	B-E	50
9 January 2020	13:56:56	KW-KEM/OLY 91	B-R	49.66
18 September 2020	12:22:56	ST-SNR/BYF 81	W-B	49.74
17 October 2020	14:51:04	NBT-YDT 91	B-E	49.17
2 January 2021	11:26:40	NBT-YDT 91	B-E	48.89
4 February 2021	14:46:37	KW-CC/MED 81	W-B	49.82
29 March 2021	10:04:42	BLW G1	No fault	49.17

The following methodology centres on understanding the impact of frequency on DPV disconnecting:

(1) Assess the change in active power during the system disturbance and identify where the greatest change in active power occurred and the frequency at which they occurred. Looking at the 2 Jan 2021 event, where the lowest frequency nadir was observed, the net power MW plot shown below displays across several zone substations distinct step changes that lines up with certain frequency points.

Figure 26: Net power at several zone substations (2nd of January 2021 event)



(2) Similar trends were identified across other events that had a frequency impact which led to identifying the frequency trigger at which PV tripped and the corresponding MW impact. Table 27 provides a summary.

Table 27: Total amount of DPV disconnected due to voltage and frequency

Event	Faulted circuit	Frequency trigger	PV tripped MW	Sum PV tripped due to frequency	% PV trip (due to frequency)
11 Jan 2018	GLT-ST 91	Not observed			
7 Feb 2019	NT-MU 91				
9 Jan 2020	KW-KEM/OLY 91				
18 Sep 2020	ST-SNR/BYF 81				
17 Oct 2020	NBT-YDT 91	49.27 Hz, 0s	16	16	4.3
2 Jan 2021	NBT-YDT 91	49.26 Hz, 0s	20	65	4.3
		49.00 Hz, 0s	15		3.2
		49.00 Hz, 2s	30		6.5
4 Feb 2021	KW-CC/MED 81				
29 Mar 2021	BLW G1	49.25 Hz, 0s	8.5	8.5	3.3

B.4 Overall Impact

The corresponding total amount of DPV disconnected is the sum of DPV disconnected due to voltage and the DPV disconnected due to frequency.

The summary of the equations to be used to estimate DPV disconnection due to voltage and frequency as well as load response to derive the net power change is shown in Table 28, Table 29 and Table 30.

Table 28: Equations used to estimate DPV disconnection due to voltage effect

Voltage effect			
PV% trip (% of PV generation) = A * Vs (pu) + B			
	A	B	Cut off Vs
Substations – generation equation	82.02	-1.48	0.05
Substations – site specific equation	76.05	-0.59	0.05
Substations – average	79.03	-1.03	0.05
System – general equation	80.78	-1.45	0.05
System – site specific equation	72.46	-0.38	0.05
System - average	76.62	-0.92	0.05

Table 29: Equations used to estimate DPV disconnection due to frequency effect

Frequency effect			
PV% trip (% of PV generation post voltage effect)			
	49.25 Hz	49.0 Hz	49 Hz and 2 s delay
System	2.55	1.89	3.86

Table 30: Equations used to estimate load disconnection

Load				
Load% trip (% of underlying load) = A * Vs^2 + B * Vs + C				
	A	B	C	Cut off Vs
Residential	30.49	9.22	-0.91	0.1
Commercial / Light industrial	203.78	-47.14	3.75	0.1

B.5 Alternative methodology

An alternative approach was concurrently developed to help verify the results from the methodology described above. The methodology involves looking at successful auto-reclose day-time events on medium voltage feeders with high PV installed downstream of the feeder to confirm the average ramp rate after reconnection of PV one minute after a successful auto-reclose. The ramp up rate was then used on a system level to deduce how much PV had disconnected for the system events and hence used to compare the modelled DPV response. The process involves:

(1) Identifying system disturbance events (3 years of SCADA data was used) on MV feeders with high DPV installed and with auto-reclose functionality. Selected 15 auto-reclose events on those feeders that occurred during the day to include in the analysis.

(2) For each event, the % PV ramp up rate (per minute) was calculated taking the feeder MW readings between 1 and 2 minutes after a successful auto-reclose (assuming no load response occurred in that time). See Table 31 for the table of results. Note: Ramp rates were calculated based on the PV capacity for that feeder obtained as at January 2021.

(3) An average ramp rate was derived from the 15 events and used on the system events analysed in the statistical analysis.

(4) Using data from fault recorders for day-time system disturbances assess the MW trend for DPV ramp up (i.e. the DPV disconnected now reconnecting) from the time between 1 and 2 minutes after the fault occurred (assuming load response occurs in first minute and no-load response occurs between 1 and 2 minutes). See figure 32 below for an example trend observed for the 4th February 2021 event.

(5) Taking the average % ramp rate calculated from the MV feeders auto-reclose data as an estimate of the ramp rate that DPV would reconnect at after the system fault, and the MW trend observed between 1 and 2 minutes after the fault, it is used to calculate the DPV that has disconnected. The results can be seen in Table 31 where it is comparable with the results of the statistical analysis.

Table 31: PV Ramp Rate calculated for MV feeder auto-reclose events.

	Auto-Reclose Event Date	Time	MV Feeder	Ramp Rate (per min)
1	14-Oct-20	12:20:41	PBY 526.0	44.3%
2	11-Sep-20	12:15:34	MH 520.0	44.1%
3	8-May-20	14:27:40	MED 511.0	38.4%
4	1-May-20	15:07:01	CKN 505.0	34.1%
5	23-Jan-20	13:08:22	HZM 507.0	53.4%
6	11-Dec-19	10:30:47	MH 520.0	43.5%
7	14-Nov-19	10:51:52	LDE 526.0	37.4%
8	6-Nov-19	13:32:30	MH 502.0	41.7%
9	30-Sep-19	14:17:21	HZM 507.0	37.0%
10	19-Aug-19	15:39:34	BIB 507.0	19.4%
11	9-Jul-19	12:06:20	LDE 525.0	34.9%
12	26-Jan-19	15:43:28	MH 509.0	24.6%
13	9-Nov-18	13:43:55	MDN 508.0	11.8%
14	14-Aug-18	15:20:58	CKN 540.0	19.0%
15	16-Jul-18	11:38:47	HBK 504.0	24.8%
			Average (Total)	33.9%

Figure 27: Power (MW) trend of Zone substations with High PV - 4 February 2021 event

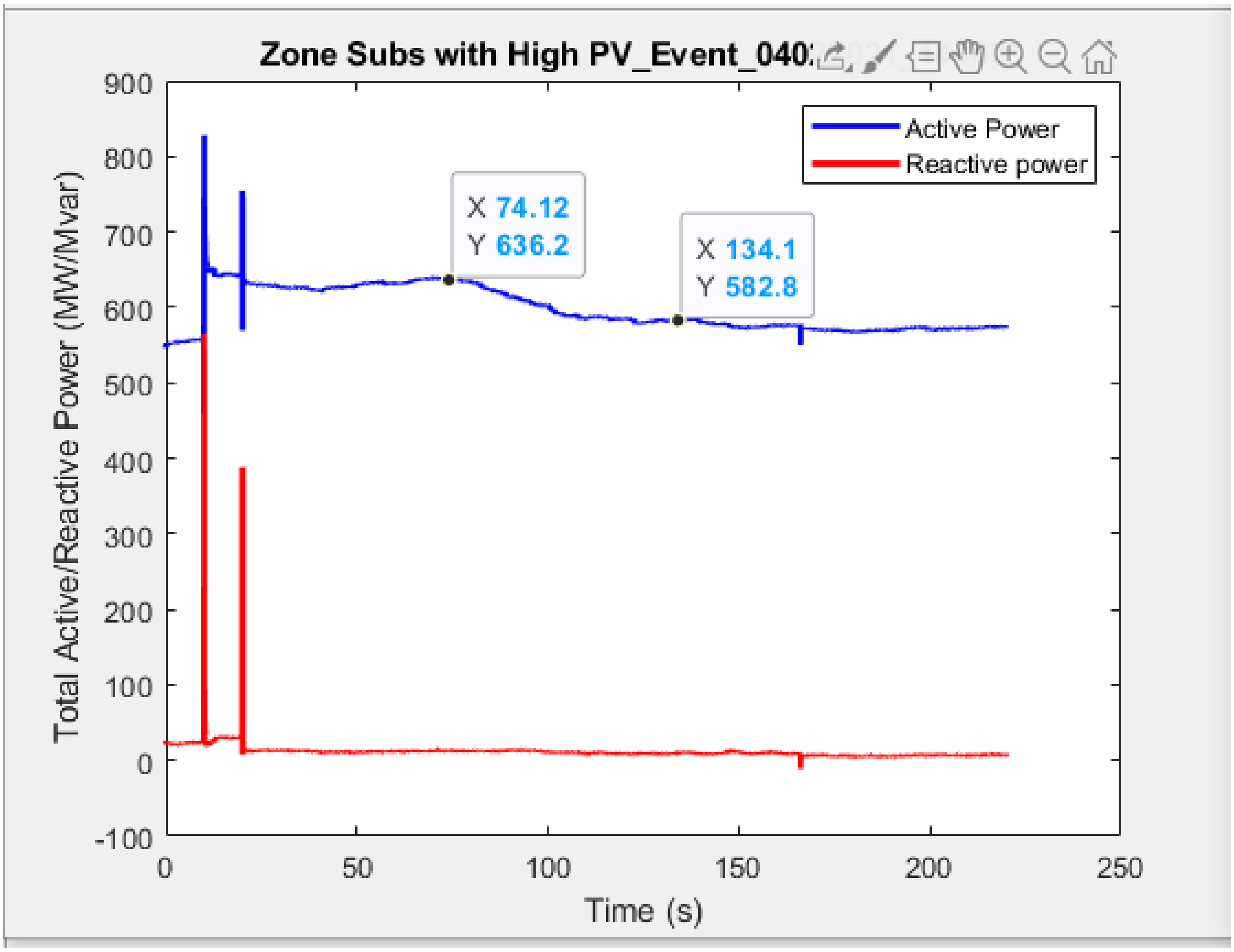


Table 32: Comparison of Estimated DPV loss between Alternate and Statistical method.

Day	Faulted circuit	Freq nadir (Hz)	Estimated DPV loss (MW)	Alt Method Est DPV loss (MW)	Comment
11 January 2018	GLT-ST 91	50	98	115.29	% Ramp rate based on 2021 installs, thereby overstating PV tripped via alt method.
7 February 2019	NT-MU 91	50	18	n/a	No PV Ramp seen.
9 January 2020	KW-KEM/OLY 91	49.66	171	n/a	Several faults on the day can't get a clear ramp rate
18 September 2020	ST-SNR/BYF 81	49.74	104	93.27	
17 October 2020	NBT-YDT 91	49.17	62	47.32	Difference in MW calculated due to some PVs that tripped due to Freq haven't come back yet.
2 January 2021	NBT-YDT 91	48.89	114	82.58	
4 February 2021	KW-CC/MED 81	49.82	119	98.97	
29 March 2021	BLUEWATERS G1	49.17	9	n/a	No PV Ramp seen– Reconnection due to Frequency recovery

Appendix C. Managing frequency stability

C.1 Main factors affecting system frequency response

The table below provides a summary of the main factors that affect system frequency and how to achieve a better system frequency response (in the absence of any other change).

Table 33: Factors that impact system frequency

Factor	Frequency nadir	Rate of change of frequency	Settling frequency
System inertia	Higher system inertia results in a higher (better) frequency nadir post contingency.	Higher system inertia results in a lower (better) rate of change of frequency post contingency.	System inertia has negligable impact on the steady state settling frequency.
System load / load relief	Higher system loads and load relief results in a higher (better) frequency nadir post contingency.	Higher system inertia results in a lower (better) rate of change of frequency post contingency.	Higher load will result in a higher (better) steady state settling frequency.
Size of the contingency	Smaller contingency size results in a higher (better) frequency nadir post contingency.	Smaller contingency size results in a lower (better) rate of change of frequency post contingency.	Smaller contingency size results in a higher (better) steady state settling frequency.
The quantity of primary frequency response	Higher primary frequency response quantity results in a higher (better) frequency nadir post contingency.	Higher primary frequency response quantity results in a lower (better) rate of change of frequency post contingency.	Higher primary frequency response quantity results in a higher settling frequency.
The speed of primary frequency response	A very fast primary frequency response will result in a higher (better) frequency nadir post contingency.	A very fast primary frequency response will result in a lower (better) rate of change of frequency post contingecy	The speed of primary frequency response has negligable impact on the steady state settling frequency.

C.2 Assessment methodology

AEMO has used its in-house frequency stability tool to undertake a number of studies related to frequency stability. The frequency stability tool is a single mass frequency model that simulates the frequency response on the SWIS under different operating conditions.

The following types of studies were conducted:

1. Comparison of magnitude of mitigation required for different types of faults.
2. Determination of largest contingency and required operational actions.
3. Operational response required to mitigate reduced levels of load on the UFLS system.

The methodology to define the inputs and assumptions involves the following:

(1) Define the generation dispatch profiles

   a. Four hundred (420) generation dispatch profiles were extracted for a low demand day on the 5 September 2021, between 9am and 4pm at a one-minute resolution.

   b. Each of the 420 dispatch profiles is simulated to determine the impact of the largest contingency MW which includes the impact of DPV, the underlying demand response and any consequential generator unit trips

   c. The step above is simulated for all 3-phase, 2-phase and 1-phase-ground faults.

   d. To assess the impact of higher spinning reserve provision, sensitivity cases were introduced involving:

      i. Actual dispatch plus one extra gas turbine needed

      ii. Actual dispatch plus two extra gas turbines needed

   The committed GTs for the sensitivity scenarios are selected from the Synergy portfolio and in line with the principles described in Synergy's dispatch guidelines

   e. The largest generation unit outputs considered were 155 MW and 120 MW.

C.3 Operational actions to mitigate largest contingency

The study was conducted with the following methodology:

1. A credible generation dispatch scenario is developed for specific system loads based on known or likely bidding and commitment behaviour of Market Participants during Spring Shoulder period (i.e., low load days). The base case scenario is designed such that all ancillary service requirements[2] are met.

2. The net DPV shake-off caused by voltage vector shift (VVS) and frequency drop is calculated as per the latest data provided by WP.

3. For each dispatch profile, the system kinetic energy or inertia (KE_SYS) is calculated as:

$$KE\_SYS = KE\_GEN + KE\_LOAD - KE\_CONT$$

   where KE_GEN is the total generation inertia calculated by summing the inertia of all the units committed in MWs, KE_LOAD is the load inertia in MWs, and KE_CONT is the contingency of the tripped unit in MW.s.

4. To consider the most onerous scenario, it is assumed that the largest generation contingency is formed by the loss of DPV and relevant generator, termed as *"DPV+GEN"* contingency type in this report.

5. A load relief factor (LRF) of $k_p = 2$ is used in the model based on a series of estimates made with high-resolution fault recorder data from previous contingency events in the SWIS (calibrated against system events to confirm its accuracy/validity). This factor has proven to be a robust estimate across all the SWIS events analysed. it should be noted that the LRF is continuously being re-estimated to capture trends in load composition and behaviour (e.g., the replacement of directly coupled induction machines with inverter-fed machines, deindustrialisation, etc).

6. Additional 17 sensitivity scenarios are developed by adjusting the base dispatch profile case to consider different compositions of Synergy's SRAS-provider units.

7. The base case and sensitivity scenarios are simulated to determine the largest contingency size that can be borne by the system for a single credible generator contingency (and with potential DPV disconnection) without triggering under-frequency load shedding (UFLS), i.e., frequency nadir > 48.75 Hz.

8. The simulations are performed using the AEMO System Frequency Response model (SFM) developed in MATLAB and recently validated by the AEMO / Western Power join project team for the SWIS UFLS study (DER Roadmap Action 10). Note that the SFM includes validated responses from non-SRAS units, that provide a droop response under the Western Power Technical Rules.

9. To assess whether there is still adequate UFLS available when a large customer on the ULFS scheme is on outage (forced/planned), it is assumed that three additional non-credible generator contingencies occur in a cascading manner with a short time delay of 5 seconds between consecutive generator trips post the largest *"DPV+GEN"* contingency. The SFM considers contingencies by size, with the largest generator being tripped first, followed by the next largest generator 5 seconds later. Cascading trips of generators that are not subject to a single contingency risk (or failure mode) are significantly more likely than simultaneous instantaneous trips. Cascading collapses have precedent in historical events where generators sympathetically trip sequentially after a major system disturbance, e.g., 2016 South Australia blackout.

10. It is assumed that the system can accommodate four (4) concurrent generator contingencies before system collapse, making up almost 50% of the system load. This means that the system remains stable after the first 4 largest generator trips and may collapse on the 5th contingency. The rationale for this assumption is as follows:
    - A trip of the largest generator should be covered by SRAS and not trigger UFLS,
    - A cascading trip of the two largest generators (e.g., one generator trip followed by a sympathetic trip) may lead to early stage UFLS activation (e.g., Stages 1 or 2),
    - A cascading trip of the three largest generators may lead to mid-stage UFLS activation (e.g., Stage 2 to 4),
    - A cascading trip of the four largest generators may lead to late-stage UFLS activation (e.g., Stage 4 to 5),
    - A cascading trip of five or more largest generators may lead to system collapse It is worth noting that after 4 or more generator trips during periods of low system load, there is likely to be severe voltage regulation / reactive power control problems and the network may not necessarily be intact (e.g., regions may need to be disconnected).

11. It is assumed that the maximum total generation contingency size manageable before frequency collapse is 50% of the system load. This is broadly in line with the results from the UFLS studies report with an intact 75% UFLS availability across all five stages, which showed that multiple non-credible contingencies making up 55%-60% of the system load potentially cause frequency collapse.

12. The SFM has an allowance for DPV shake-off at pre-specified under-frequency thresholds. While this creates an instantaneous generation shortfall at the time of tripping, there is a high likelihood that the load exposed by the DPV disconnection is now available for UFLS.

Appendix D. Availability of UFLS

D.1 Review of UFLS best practice

Western Power undertook a comprehensive national and international review of best industry practice relating to UFLS to identify latest developments in managing frequency stability and the use of UFLS in high power systems with very high DPV and other DER penetration.

Table 34: Review of UFLS

Type	Geography
System operator	Australia (East Coast)
System operator	United States of America - multiple
Research	Ireland
DNSP	Australia (East Coast) - multiple
TNSP	Australia (East Coast) - multiple
Transmission operator	Ireland
TNSP	New Zealand
TNSP / DNSP	United States of America - multiple

The assessment concluded that overall, Western Power is already at the forefront of implementation of a number of UFLS features including remote UFLS telemetry, and reverse blocking compared with most survey participants.

The key points of the findings are highlighted below:

1. Common issues are being experienced worldwide however the risks for the SWIS are higher due to the low load shedding availability, reverse power flow, higher ROCOF/less inertia.
2. Strategies being considered or implemented by other utilities in this space include:
    1. Regular review periods to assessed UFLS effectiveness
    2. Greater discrimination for UFLS system – tripping loads below feeder level
    3. Reverse blocking capability
    4. Implementation ROCOF triggers
    5. PMU high speed data to review UFLS performance/real-time UFLS load availability
    6. Dynamic arming of UFLS feeders to manage load shed availability when DPV output is high

Appendix E. Managing System Strength

E.1 Background

System strength is a measure of the resilience of the network in maintaining voltage waveforms after a disturbance. Examples of disturbances are those caused by a sudden change in load or an energy producing system, the switching of a network element, tap changing of transformers and different types of faults.

A network location is said to be “strong” in terms of system strength when the change in voltage at that location will be relatively unaffected by a nearby disturbance. Conversely, a location is said to be “weak” in system strength if the voltage at that location will be relatively sensitive to a disturbance, resulting exacerbating the system voltage which might become widespread in the system.[46] Lack of system strength might also result into instability of non-synchronous generators.

The impact of progressively lower system strength during periods of very low demand is complex due to the inter-related nature of the power quality, stability, control, and protection in the system. The impact of low system strength can span many different lenses as the issue may manifest in different ways.

As an example, a manifestation of low system strength is related to complexities associated with maintaining stability of phased locked loop (PLL) controllers. Inverter manufacturers will specify a minimum SCR as a proxy for system strength at which stable operation of the inverter is guaranteed. Operating below the provided minimum levels of SCR often presents challenges related to the synchronisation of the facility to the network and maintaining stable operation. Operating far below the minimum guaranteed short-circuit ratio might not be possible without providing additional voltage support through installation of BESS, synchronous condensers, network reinforcements or moving toward a grid former inverter.

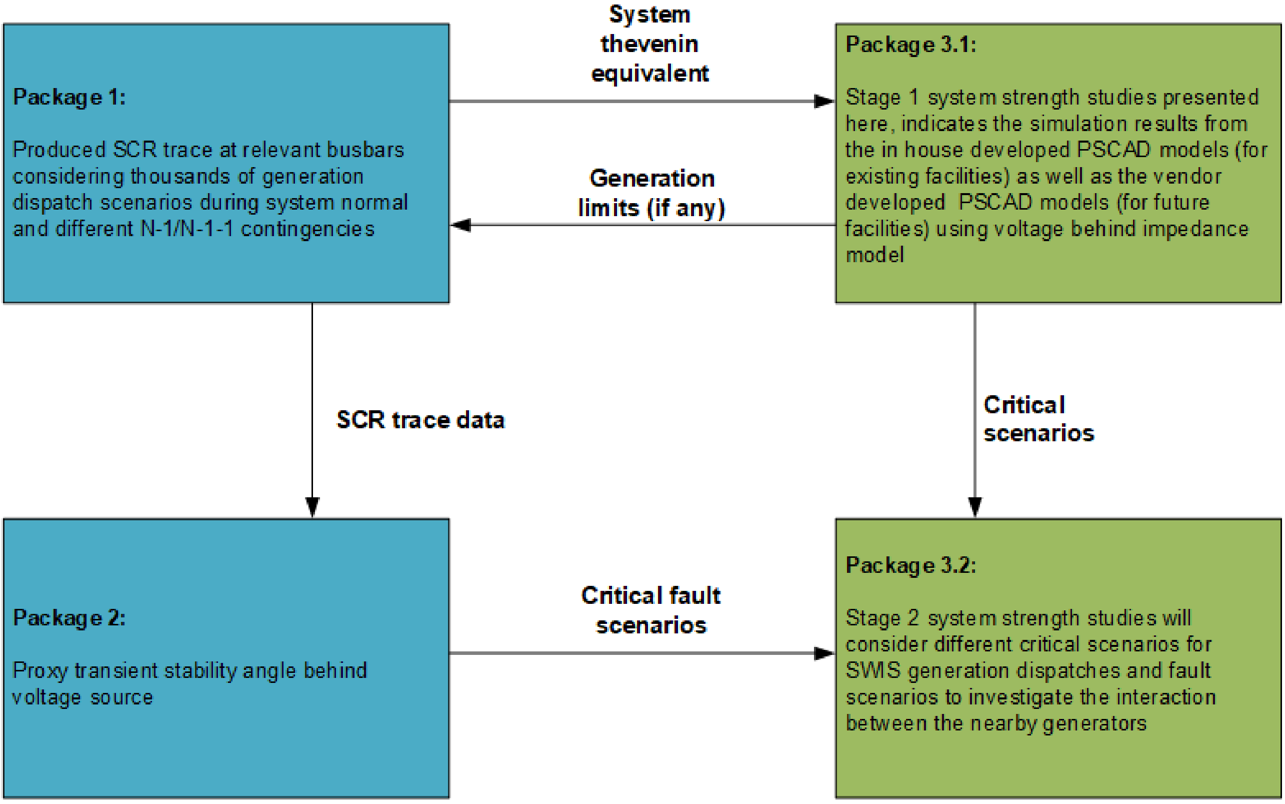
Another impact of low system strength on the power system is poor quality and instability of the voltage waveform resulting in an inability to return to an adequately damped shape following a system disturbance. Furthermore, this issue may also result in harmonic resonance and waveform oscillations which might potentially cause damage to the existing assets.

For the Low Load Project, system strength has been assessed primarily by investigating the stability of grid following inverters’ controller.

[46] Based on the definition of system strength used in the proposed amendments to the Technical Rules,

E.2 Methodology

The high-level methodology of each package of work and their correlation is shown below.



E.3 Stage 2 EMT Modelling

The objective of Stage 2 EMT Modelling is to understand the performance limits of inverter-based generation facilities in low system strength conditions and to understand the potential controller interactions between the facilities.

The second stage of modelling required the development of EMT models which was split up into two phases:

- Package 3.1 uses in-house EMT models for existing facilities as well as vendor developed EMT models for future facilities. The first phase of this study involves assessing individual facilities in a single machine infinite bus (SMIB) environment with a Thevenin equivalent representation of the power system. This phase investigates the facility's response to different conditions of the system that in turn results to different short-circuit ratio at POC. Any identified generation limits are fed back into the SCR trace study (Package 1). Any critical scenarios that are found are further investigated in the second phase of EMT modelling.
- The second phase of EMT modelling involves a study of a group of generation facilities in an area considering detailed EMT representation of the network in that area.[47] The purpose of the second phase of system strength studies is to investigate any possible interactions between the controllers of nearby generators. Different demand, dispatch and network contingency scenarios are used to simulate the response of the generation facility to investigate the performance of the facility in different system strength conditions.

[47] To mitigate against lengthy simulation times whilst preserving sufficient accuracy, the network may be split into different simulation areas to cover discrete sets of generation facilities.

Appendix F. Estimating the usage of ESM

F.1 Results

Table 35 summarises the estimated ESM usage across each reference year.

Table 35: Estimated ESM usage at 550 MW MDT and 650 MW MDT

Case	Description	FYE	Hours ESM was used (hrs)	Percentage of the year ESM was used (%)	Annual ESM Energy (MWh)	Percentage of total available DPV energy spilled (%)
Case 1	550 MW MDT 2016-17 RY	2023	1.0	0.011	4	0.000
		2024	20.0	0.228	1,750	0.053
		2025	101.0	1.153	9,924	0.282
	550 MW MDT 2017-18 RY	2023	0.5	0.006	2	0.000
		2024	3.5	0.040	391	0.012
		2025	116.0	1.324	12,019	0.342
	550 MW MDT 2018-19 RY	2023	1.0	0.011	2	0.000
		2024	18.5	0.211	1,196	0.036
		2025	75.5	0.862	7,334	0.209
Case 2	650 MW MDT 2016-17 RY	2023	13.5	0.154	808	0.026
		2024	63.0	0.719	5,326	0.162
		2025	193.0	2.203	24,218	0.689
	650 MW MDT 2017-18 RY	2023	6.0	0.068	403	0.013
		2024	13.5	0.154	1,003	0.031
		2025	225.0	2.568	28,895	0.822
	650 MW MDT 2018-19 RY	2023	11.5	0.131	601	0.020
		2024	55.0	0.628	4,337	0.132
		2025	168.5	1.924	19,214	0.546

Table 36 summarises the estimated ESM usage with equal weighting against each reference year.

Table 36: Estimated usage at 550 MW MDT and 650 MDT (equally weighted reference years)

Case	Case Description	FYE	Hours ESM was used (hrs)	Percentage of the year where ESM was used (%)	Annual ESM Energy (MWh)	Percentage of total available DPV energy spilled (%)
Case 1	550 MW Limit Average across RY	2023	0.8	0.010	3	0.000
		2024	14.0	0.160	1,112	0.034
		2025	97.5	1.113	9,759	0.277
Case 2	650 MW Limit Average across RY	2023	10.3	0.118	604	0.020
		2024	43.8	0.500	3,555	0.108
		2025	195.5	2.232	24,109	0.686

Table 37 summarises the average ESM usage across each reference year for each unique event.

Table 37: Estimated ESM usage at 550 MW MDT and 650 MW MDT for each event

Case	Case Description	FYE	Events (number)	Average ESM quantity per event (MW)	Average ESM energy per event (MWh)	Average ESM duration per event (Hr)
Case 1	550 MW Limit 2016-17 RY Base	2023	2.0	3.8	1.9	0.5
		2024	9.0	78.4	194.4	2.2
		2025	40.0	108.5	248.1	2.5
	550 MW Limit 2017-18 RY Base	2023	1.0	4.0	2.0	0.5
		2024	1.0	175.0	391.0	3.5
		2025	47.0	115.6	255.7	2.5
	550 MW Limit 2018-19 RY Base	2023	2.0	2.3	1.1	0.5
		2024	8.0	80.5	149.5	2.3
		2025	31.0	107.1	236.6	2.4
Case 2	650 MW Limit 2016-17 RY Base	2023	5.0	65.7	161.5	2.7
		2024	26.0	88.6	204.8	2.4
		2025	66.0	143.1	366.9	2.9
	650 MW Limit 2017-18 RY Base	2023	3.0	69.4	134.5	2.0
		2024	7.0	69.2	143.3	1.9
		2025	80.0	146.3	361.2	2.8
	650 MW Limit 2018-19 RY Base	2023	5.0	70.4	120.1	2.3
		2024	27.0	77.0	160.6	2.0
		2025	67.0	119.4	286.8	2.5

Table 38: Estimated ESM usage at 550 MW MDT and 650 MW MDT for each event

Case	Case Description	FYE	Events (number)	Average ESM quantity per event (MW)	Average ESM energy per event (MWh)	Average ESM duration per event (Hr)
Case 1	550 MW Limit Average across RY	2023	1.7	3.4	1.7	0.5
		2024	6.0	111.3	245.0	2.7
		2025	39.3	110.4	246.8	2.5
Case 2	650 MW Limit Average across RY	2023	4.3	68.5	138.7	2.3
		2024	20.0	78.3	169.6	2.1
		2025	71.0	136.2	338.3	2.8

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