Power System Frequency Risk Review – Stage 2 Final Report

December 2020

A report for the National Electricity Market

Important notice

PURPOSE

AEMO has prepared the 2020 Power System Frequency Risk Review – Stage 2 Report under clause 5.20A.3 of the National Electricity Rules.

This publication has been prepared by AEMO using information available to 22 October 2020. Information made available after this date may have been included in this publication where practical.

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Executive summary

AEMO, in consultation with transmission network service providers (TNSPs), undertakes a Power System Frequency Risk Review (PSFRR) and prepares a PSFRR report for the National Electricity Market (NEM) at least every two years, in accordance with rule 5.20A of the National Electricity Rules (NER). AEMO published the last PSFRR report in 2018.

The purpose of the PSFRR is to review the potential for "non-credible" power system contingency events to cause frequency changes large enough to initiate generator disconnections and result in widespread transmission outages or a black system.

AEMO has undertaken the PSFRR for 2020 in two stages. The Stage 1 report was published in July 2020[1], and addressed:

- The status of actions recommended in the 2018 review.
- Changes to the power system that occurred since the 2018 review, including levels of inertia, maximum/minimum demand, interconnector flow patterns and changes to the generation mix.
- Non-credible contingency events and associated management arrangements to be prioritised for detailed assessment in Stage 2 of the 2020 review.
- High priority recommendations for non-credible contingency events that could result in the separation of South Australia from the rest of the NEM power system.

The Stage 2 PSFRR assessment and report (this report) builds on the reviews undertaken in Stage 1. The PSFRR does not address all possible risks associated with non-credible contingency events in the NEM. Rather, it specifically considers frequency risks for a number of critical non-credible contingency events, and assesses select boundary conditions to identify current or emerging frequency stability risks.

Through consultation with TNSPs and stakeholders, the following five priority non-credible contingency events were identified for consideration in Stage 2:

- Loss of double-circuit Queensland – New South Wales Interconnector (QNI), leading to New South Wales and Queensland separation.
- Loss of multiple single-circuit interconnectors between New South Wales and Victoria, leading to New South Wales and Victoria separation.
- Loss of double-circuit Heywood interconnector, leading to Victoria and South Australia separation.
- Loss of the double-circuit corridor between Heywood and Moorabool, leading to Victoria and South Australia separation.
- Loss of double-circuit Calvale – Halys transmission line between Central Queensland (CQ) and South Queensland (SQ), leading to tripping of parallel circuits and a complete separation of CQ from SQ.

AEMO has also conducted a preliminary assessment of the performance of existing emergency frequency control schemes (EFCSs) for management of potential frequency risks in the next two years (until the 2022 PSFRR). While further work is underway, particularly on assessment of the impacts of distributed photovoltaics (PV) on under-frequency load shedding (UFLS), and as part of a NEM-wide review of UFLS schemes, this report provides some preliminary insights, and makes a range of recommendations, outlined below.

[1] At https://aemo.com.au/consultations/current-and-closed-consultations/2020-psfrr-consultation.

Modifications to existing emergency frequency control schemes

Under the Frequency Control Workplan[2], AEMO is presently working with NSPs to review the mainland NEM-wide UFLS frequency trip settings. This review is expected to be completed by mid-2021. AEMO is also progressing with additional analysis to assess the impacts of distributed PV on the effectiveness of UFLS schemes across the mainland NEM. Further to this review, the 2020 PSFRR recommends the following modifications to existing EFCSs:

- Continued growth in distributed energy resources (DER) is likely to see a net load reduction in distribution feeders and more distribution feeders feeding power back to the transmission network during the middle of the day. To ensure the effectiveness of UFLS, it is recommended that all transmission and distribution NSPs review the design of existing UFLS schemes with the aim of:
  - Ensuring that the amount and distribution of available load in the UFLS scheme is adequate to ensure its effectiveness. This may require adjustments in existing relay settings, re-assigning feeders, addition of further load to the UFLS scheme, and other changes to optimise performance of the scheme.
  - Avoiding UFLS trip of back-feeding distribution feeders. That is, minimising the risk that UFLS exacerbates an under-frequency event by tripping generation rather than load, particularly during periods of high DER generation. This may require dynamic arming schemes designed to disarm UFLS relays when circuits are in reverse flow.
- ElectraNet, in collaboration with AEMO, to continue work on enhancements to the reliability of South Australia's System Integrity Protection Scheme (SIPS) by implementing a Wide Area Protection Scheme (WAPS). The scheme design should consider the impact of UFLS effectiveness on scheme operation. The final scheme is expected to be commissioned by mid-2022. As described in the Frequency Control Workplan[2], AEMO is presently working with NSPs to review the mainland NEM-wide UFLS frequency trip settings. This review is expected to be completed by mid-2021. Further analysis is also progressing to assess the impacts of distributed PV on the effectiveness of UFLS schemes across the mainland NEM.

Protected event recommendation for South Australia

The growth in DER in South Australia has the potential to significantly reduce the effectiveness of UFLS in periods with low load or high distributed PV generation to control frequency following the non-credible loss of interconnection between South Australia and Victoria, when South Australia is importing power from Victoria. In some cases, UFLS action could even exacerbate the disturbance by disconnecting circuits operating with reverse power flow. Distributed PV also exhibits under-frequency disconnection behaviour, which further compromises effectiveness of UFLS in arresting a frequency decline.

Currently AEMO, ElectraNet and SA Power Networks (SAPN) are working on various measures to address the diminishing UFLS effectiveness and also making efforts to add further loads into UFLS schemes. In October 2020, a set of updated and expanded constraints was implemented to limit imports into South Australia on the Heywood interconnector when insufficient UFLS is available to manage the non-credible loss of the interconnector. This action was taken under limits advice required by South Australian electricity regulations.

AEMO considers it preferable to manage the identified risks of Heywood separation under the NER protected event framework. This would allow AEMO to implement the same constraints, and possibly take additional pre-defined actions (to be determined based on analysis proceeding at present) whenever the non-credible separation could lead to an under-frequency event that has a material risk of cascading failure. AEMO is currently investigating the specific actions to be proposed, and the estimated costs and benefits of those actions. AEMO is targeting a submission to the Reliability Panel in early 2021, seeking the non-credible synchronous separation of South Australia from the rest of the NEM be considered a protected event under certain conditions.

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[2] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

CQ-SQ SPS upgrade

The CQ-SQ SPS is designed to prevent separation of the Central and South Queensland networks following a non-credible contingency on the Calvale to Halys double-circuit line. The inadequacy of the CQ-SQ special protection scheme (SPS) was identified in the 2018 PSFRR. The 2020 PSFRR studies also confirm that the existing CQ-SQ SPS is not adequate to manage the impact of double-circuit loss of Calvale – Halys 275 kilovolts (kV) lines during high power flow between Central and South Queensland coincident with high power flows across QNI. These findings are consistent with advice provided by Powerlink that the existing CQ-SQ SPS may not be effective for CQ-SQ power flows exceeding 1,700 megawatts (MW)[3] and up to the N-1 secure limit of 2,100 MW.

AEMO has analysed whether incorporating additional generation in central and north Queensland into a revised CQ-SQ SPS along with Callide units would improve system stability. The studies have identified that:

- During high CQ-SQ transfers and QNI exporting to New South Wales – tripping additional generators in central and north Queensland, in addition to Callide units, will help to avoid instability in the eastern 275 kV corridors of CQ-SQ lines after the loss of Calvale – Halys lines.
- During high CQ-SQ transfers and QNI importing from New South Wales – tripping additional generators in central and north Queensland, in addition to Callide units, was seen to further destabilise QNI. For QNI import cases Powerlink may additionally need to consider measures to reduce load or increase generation in SQ.

Further to the above observations, the 2020 PSFRR studies confirms observations made in 2018 PSFRR regarding following risks associated with the existing CQ-SQ SPS:

- If the CQ-SQ SPS operates during high export conditions from Queensland over QNI, the remaining CQ-SQ circuits in Queensland experience large power swings leading to loss of synchronism. Line protection systems in eastern corridor lines are expected to disconnect the circuits during the loss of synchronism. This would result in reversal of QNI power flow and a large increase in import over QNI interconnector, with the potential to lead to instability across QNI and cascading failure in the rest of the NEM. Instability was detected in studies with the CQ-SQ flow exceeding 1,800 MW and QNI operating at the secure export limit.
- If the CQ-SQ SPS operates during high import conditions into Queensland over QNI, the resulting large increase in QNI flows has the potential to lead to instability across QNI, islanding of Queensland with possible widespread supply interruptions and cascading outages, and possible flow on effects to other NEM regions. During non-credible loss of Calvale – Halys lines, instability was detected across QNI for CQ-SQ flows exceeding 1,500 MW and QNI operating at the secure import limit.

AEMO's studies indicate that managing the CQ-SQ flow and the amount of generation tripped under the SPS are the key variables for successful management of the non-credible loss of the Calvale – Halys double-circuit transmission line. Revisions to the existing SPS are required and underway. This confirms the urgent need for work already being progressed by Powerlink in consultation with AEMO, to develop an enhanced CQ-SQ SPS. The development of the enhanced scheme should consider the following matters:

- Control actions that minimise the potential loss of synchronism across the remaining CQ-SQ circuits and loss of synchronism across QNI.
- Need to both reduce load (or increase generation) in southern Queensland and trip generation in central and north Queensland to achieve the required risk mitigation under all secure power transfers.
- System strength impacts of tripping any generator under the SPS (refer to AEMO's 2020 System Strength and Inertia report, to be published December 2020, for more details).
- Impact of increased transfers across QNI that may result once the committed QNI upgrade is completed.

[3] As reported in Section 6.3 of the 2019 Powerlink TAPR, at https://www.powerlink.com.au/reports/transmission-annual-planning-report-2019.

AEMO will continue to work closely with Powerlink to implement an upgraded CQ-SQ scheme, currently planned for completion by mid-2021. Depending on the final scheme design and any residual risks, AEMO will consider the merits of declaring a protected event to enable ex-ante measures to be taken.

Review of South Australian minimum inertia level to manage rate of change of frequency (RoCoF)

Future case studies indicate that, in the event of loss of the Heywood interconnection between Victoria and South Australia while importing, the RoCoF in the South Australian island may exceed levels considered acceptable to minimise the risk of cascading failures. These case studies included the synchronous inertia available from the four synchronous condensers fitted with flywheels that ElectraNet is currently installing at Davenport and Robertstown, as well as the inertia provided by two synchronous generators assumed to be online at all times, in line with the current planning assumptions around minimum unit commitment in South Australia[4].

Work is presently being undertaken by ElectraNet and AEMO to reassess power system operational limits post commissioning of the four synchronous condensers, with a view to replace current planning assumptions with necessary arrangements after the synchronous condensers are commissioned. That analysis is expected to be completed in early 2021.

Management of over-frequency events in South Australia

An automatic over-frequency generation shedding (OFGS) scheme is installed on a number of generators in South Australia and south-western Victoria, which is designed to trip when the system frequency exceeds 51 hertz (Hz) to prevent uncontrolled increases in frequency. Selected case studies undertaken as part of the PSFRR indicate that the effectiveness of South Australia's OFGS scheme depends on the network location and conditions of any South Australian separation. For the non-credible loss of the Heywood interconnector when South Australia is exporting, the OFGS scheme can contain the maximum frequency rise within frequency operating standard (FOS) limits. However, when South Australia separates from Moorabool Terminal Station (MLTS) during export or import with high generation between MLTS and Heywood Terminal Station (HYTS), the present OFGS scheme may not be adequate to maintain the islanded South Australia frequency within limits.

At present only wind farms that were operational in 2018, when the South Australia's OFGS scheme was developed, participate in the scheme. Since then, 245 MW of wind and 315 MW of solar generation has been connected in South Australia.

In light of this analysis, AEMO, in consultation with ElectraNet, will review the effectiveness of the OFGS and modify it if required, to include additional generation in the scheme.

Impact of Primary Frequency Response (PFR)

AEMO is working with NEM generators to progressively implement the PFR Rule change that came into effect in June 2020 with a three year sunset period. Given the regulatory uncertainty associated with the future of PFR beyond 2023, the 2020 PSFRR has considered in detail the impact of PFR from capable generators for future case scenarios in the 2022-23 period. AEMO's studies assessed the implications of non-credible islanding of South Australia and Queensland similar to the separation event that occurred in August 2018. Key observations from those studies include:

- Without the provision of PFR consistent with NER requirements, and in the absence of regionally procured frequency control ancillary services (FCAS), significantly more UFLS load and OFGS generation would be required to manage frequency and security. Sourcing adequate UFLS load will become increasingly difficult with continuing growth in DER installations including distributed PV.

[4] See https://www.aer.gov.au/system/files/AEMO%20-%20Assumptions%20for%20South%20Australian%20GPG%20in%20the%202018%20ISP%20-%20August%202019.pdf.

- Without PFR, higher frequency peaks and lower nadirs were observed, at levels with potential to cause failure of online plants and tripping of frequency based protection devices.
- After islanding, restoration of frequency within the FOS recovery bands may not be possible in some scenarios without PFR response.

These studies indicate that effective PFR is critical in managing the frequency and system security going forward due to reduced system inertia, high inverter-based resources (IBR), distributed PV integration, and reduced UFLS net load availability.

Note: Throughout this report, references to PFR relate to mandatory PFR as required by clause 4.4.2(c1) of the NER.

Recommendations to modify Emergency Alcoa Portland (APD) Tripping Scheme

At present AusNet and AEMO (in its capacity as the Jurisdictional Planning Body for Victoria) are working towards upgrading the Emergency APD Tripping (EAPT) scheme to make it more reliable. The following observations from the 2020 PFSRR studies should be considered during the EAPT upgrade design:

- The high level of recent IBR generation between MLTS and HYTS can significantly impact the South Australia frequency profile for separation events both during South Australia export and import. Further studies are recommended to confirm the conditions under which EAPT is required to operate.
- Power swings may occur following contingency events which have the potential to trigger EAPT scheme operation unexpectedly. This should be considered in the ongoing EAPT review. A topology-based scheme is likely to be required to avoid the unexpected EAPT operations[5]. This review should also consider potential interactions with the Interconnector Emergency Control Scheme (IECS), as discussed below.
- During South Australian separation from Moorabool, APD load could be tripped either by EAPT action or by UFLS. In the latter case there is a lower frequency nadir. It is recommended that this be considered as part of the EAPT scheme review to ensure appropriate EAPT action and minimise frequency disturbances.

Interconnector Emergency Control Scheme (IECS)

IECS is implemented in the Victorian network to address risks associated with the trip of multiple 330 kV and 220 kV transmission lines on the Victoria to New South Wales interconnection between Murray Switching Station (MSS) and Thomastown Terminal Station (TTS). The scheme is armed when fire is observed within 10 km of the common corridor of the monitored lines included in the scheme and a fire warning is declared by Country Fire Authority (CFA) in the North Central or North Eastern Victorian region.

This IECS scheme was designed to shed preselected load blocks and generation, to reduce the risk of Victorian network separation due to instability and reduce operation of automatic UFLS that would occur if Victoria separates from New South Wales. The PSFRR has considered the IECS scheme operation and identified that the scheme could be ineffective during (low probability) periods of high import to Victoria on the MSS-DDTS-SMTS 330 kV corridor[6]. The scheme remains armed until the loss of monitored lines included in the scheme are declared as credible when the CFA advises that the fire is within 5 km of the monitored lines.

Based on the study results, the 2020 PSFRR recommends the following:

- The performance of the IECS should be reviewed by AEMO Victorian Planning, including assessment of any necessary modifications to the scheme. This recommended review should be focused on the low probability operating conditions under which IECS operation may not be sufficient to prevent separation

[5] AEMO has recently completed a review on the EAPT, and recommended changing this scheme to a topology-based scheme.

[6] This finding is consistent with the original design of IECS, as it was expected that IECS itself may be insufficient to prevent instability and system separate if the non-credible contingencies covered by the scheme occurs during low probability high Victorian import periods. In this case, the frequency in the Victorian island would be managed by operation of NEM UFLS schemes.

between Victoria and New South Wales following non-credible contingency events. In these cases, the interaction and coordination between IECS and UFLS is critically important.

- The power flow changes and network disturbances during the non-credible separation of DDTS – SMTS or DDTS – MSS lines has the potential to trigger EAPT scheme operation. This should be considered by AEMO as part of the EAPT review.
- Following the commissioning of the 300 MW battery energy storage system (BESS) at Moorabool[7], imports into Victoria from New South Wales are expected to increase during some periods. It is recommended that operation of the IECS, including opportunities to utilise the BESS to mitigate the impact of non-credible contingency events, be considered through the IECS review.

Consultation process for Stage 2

AEMO sought submissions from interested parties on a draft of the PSFRR stage 2 report in late November 2020, and also held an industry forum to facilitate feedback.

Appendix A3 of this report outlines the feedback provided and how it has been addressed.

Summary of 2020 PSFRR recommendations

- All NSPs to review the design of existing UFLS schemes to ensure effectiveness and avoid UFLS trip of back-feeding distribution feeders.
- Powerlink, in consultation with AEMO, to continue work on enhancing the CQ-SQ SPS to successfully manage the non-credible loss of the Calvale – Halys double-circuit transmission line, taking into consideration the analysis presented in this PSFRR.
- AEMO to incorporate insights from this study in the EAPT upgrade design, to improve effectiveness, particularly around topology and during South Australia separation from Moorabool, and considering IECS operation.
- AEMO and ElectraNet to review and expand the South Australia OFGS scheme.
- AEMO to seek Reliability Panel declaration of a protected event for non-credible separation of South Australia under some conditions, including stakeholder suggestions for additional options that should be considered for management of the proposed protected event.
- Continuence of PFR after 2022-23, provided the cost benefit analysis identifies that this is in the best interest of consumers.

[7] See https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery.

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Acronyms

Acronym	Term
AC	Alternating Current
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AEST	Australian Eastern Standard Time
AGC	Automatic Generation Control
APD	Alcoa Portland
BESS	Battery Energy Storage System
COAG	Council of Australian Governments
CQ-SQ	Central QLD-South QLD
DC	Direct Current
DER	Distributed Energy Resources (including distributed PV and embedded synchronous generators)
DDTS-MSS	Dederang – Murray
DDTS-SMTS	Dederang – South Morang
EAPT	Emergency Alcoa-Portland Potline Tripping scheme
EFCS	Emergency Frequency Control Scheme
EMS	Energy Management System
EMT	Electromagnetic Transient
ESOO	Electricity Statement of Opportunities
EST	Eastern Standard Time
FAPR	Fast Active Power Response
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
FOS	Frequency Operating Standard
MLTS-HGTS	Moorabool – Haunted Gully

Acronym	Term
HIC	Heywood Interconnector
HSM	High Speed Measurement
HYTS	Heywood Terminal Station
Hz	Hertz
IBR	Inverter Based Resources
ISP	Integrated System Plan
kV	Kilovolts
MD	Maximum Demand
MLTS-MOPS	Moorabool – Mortlake
MVA	Megavolt Amperes
MW	Megawatts
NEM	National Electricity Market
NER	National Electricity Rules
NSP	Network Service Provider
AS/NZS	Australian/New Zealand Standard
OFGS	Over-frequency Generation Shedding
OPDMS	Operations and Planning Data Management System
OTR	Office of the Technical Regulator
PEC	Project EnergyConnect
PFR	Primary Frequency Response
PMU	Phasor Measurement Unit
POE	Probability of Exceedance
PSFRR	Power System Frequency Risk Review
PSSE	Power System Simulator for Engineering (also PSS®E or PSS/E)
PV	Photovoltaic
QNI	Queensland – New South Wales Interconnector
RIS	Renewable Integration Study
ROCOF	Rate of Change of Frequency
SAPN	SA Power Networks
SCADA	Supervisory Control and Data Acquisition
SESS	South East Sub-Station

Acronym	Term
SETS	South East Terminal Station
SF	Solar Farm
SIPS	System Integrity Protection Scheme
SPS	Special Protection Scheme
TNSP	Transmission Network Service Provider
UFLS	Under-frequency Load Shedding
VNI	Victoria- New South Wales Interconnector
WAMPAC	Wide Area Monitoring Protection and Control
WAPS	Wide Area Protection Scheme
WF	Wind Farm

1. Introduction

This report addresses AEMO's obligations under clause 5.20A of the National Electricity Rules (NER). Under this clause, AEMO, in consultation with Transmission Network Service Providers (TNSPs), must undertake a Power System Frequency Risk Review (PSFRR) for the National Electricity Market (NEM) at least once every two years, considering:

- Non-credible contingency events which AEMO expects would likely involve uncontrolled frequency changes leading to cascading outages or major supply disruption.
- Current arrangements for managing such non-credible contingency events.
- Options for future management of such events.
- Likelihood of such events occurring.
- The performance of existing special protection schemes (SPSs), including emergency frequency control schemes (EFCSs)[8] which impact system frequency performance.

The purpose of the PSFRR is to review the potential for "non-credible" power system contingency events to cause frequency changes large enough to initiate generator disconnections and result in widespread transmission outages or a black system. As discussed above, the PSFRR involves assessment of key non-credible contingency events based on review of historic events, and known risks, in consultation with TNSPs. It is not a comprehensive review of all non-credible events which could occur on the power system.

The first stage of the 2020 PSFRR, completed in July 2020, identified four priority non-credible contingency events which are the focus of studies completed in Stage 2 of the PSFRR. This was subsequently expanded to five, to include contingency events between Heywood and Moorabool in Victoria leading to separation between Victoria and South Australia. These non-credible contingency events were selected based on the likelihood of them resulting in uncontrolled increases or decreases in frequency, presenting a risk of cascading outages or major supply disruptions.

Through the studies, AEMO has:

- Assessed the performance and adequacy of existing SPSs for management of potential frequency risks in the next two years (until the 2022 PSFRR).
- Reviewed options (and plans in place) for future management of such events, which may include considering the need for new or modified SPSs or EFCSs, declaration of protected events, network augmentation, and non-network alternatives to augmentation.
- Made recommendations for further analysis necessary as part of the detailed design of new or modified schemes.
- Developed recommendations, consistent with the scope of the PSFRR to deliver system security outcomes and consumer benefits.

[8] The Stage 1 PSFRR report identified a number of SPSs in each region which contribute to the management of the frequency risk posed by non-credible contingencies. Those schemes were collectively referred to as ECFSs in the Stage 1 PSFRR report, however not every scheme listed is currently treated as an EFCS. Other than under-frequency load shedding (UFLS), there are only two schemes in the NEM defined as EFCSs under the NER, which are the South Australia System Integrity Protection Scheme (SIPS) and the South Australia over-frequency generation shedding (OFGS) scheme.

1.1 Priority non-credible contingencies

The first stage of the 2020 PSFRR reviewed:

- The status of actions recommended in the 2018 review.
- Changes to the power system occurring since the 2018 review, including levels of inertia, maximum/minimum demand, interconnector flow patterns and changes to the generation mix.
- Non-credible contingency events and associated management arrangements to be prioritized for detailed assessment in Stage 2 of the 2020 review.
- High priority recommendations to manage non-credible contingency events that could result in the separation of South Australia from the rest of the NEM power system.

The Stage 1 review of non-credible contingency events and associated management arrangements identified a number of non-credible contingency events that occurred since the 2018 PSFRR. Of these events, 11 resulted in "major" frequency excursions, whereby the system frequency exceeded the applicable operational frequency tolerance band, required the operation of an SPS, and/or resulted in the power system no longer being in a secure operating state. Of the one non-credible events resulting in "major" frequency excursions, six occurred in South Australia, with three events in Victoria, two in New South Wales, and a single event in Queensland.

Through consultation with TNSPs and other stakeholders, the following five priority non-credible contingency events were identified for consideration in Stage 2:

- Loss of double-circuit Queensland – New South Wales Interconnector (QNI), leading to New South Wales and Queensland separation.
- Loss of multiple single-circuit interconnectors between New South Wales and Victoria, leading to New South Wales and Victoria separation.
- Loss of double-circuit Heywood interconnector (HIC), leading to Victoria and South Australia separation.
- Loss of the double-circuit corridor between Heywood and Moorabool, leading to Victoria and South Australia separation.
- Loss of double-circuit Calvale – Halys transmission line between Central Queensland (CQ) and South Queensland (SQ).

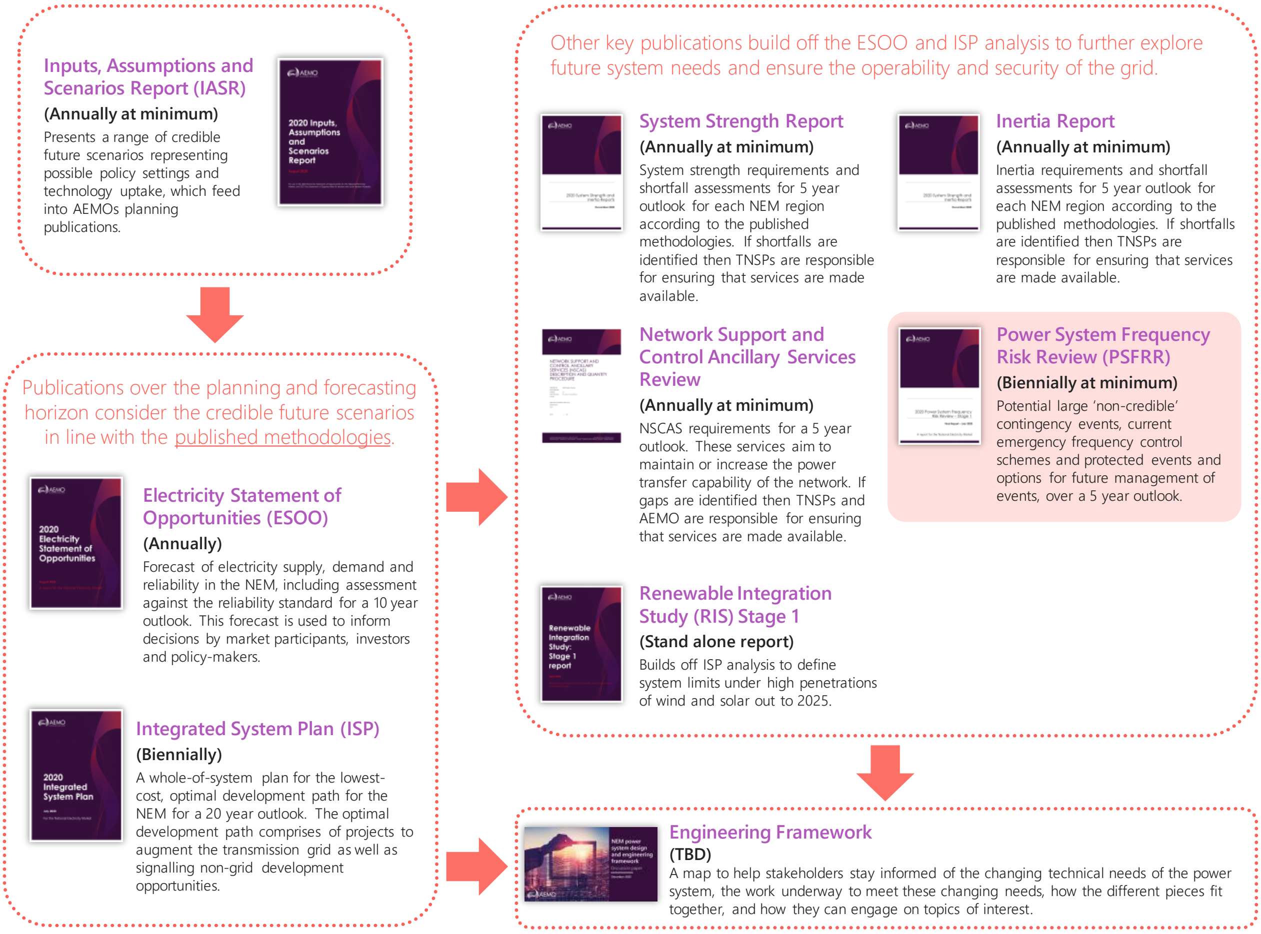
The outcomes of the consultation process and rationale for selecting those non-credible events are documented in the final Stage 1 report published in July 2020[9].

1.2 PSFRR relationship with other reports

The PSFRR draws inputs from a number of related reports and processes, and informs and underpins several reports and processes owned by AEMO and TNSPs. Figure 1 shows the PSFRR in relation to other key AEMO documents and processes.

[9] At https://aemo.com.au/consultations/current-and-closed-consultations/2020-psfrr-consultation.

Figure 1 Relationship of PSFRR with other AEMO documents and processes



1.3 Stage 2 consultation

In the 2020 PSFRR Stage 2 draft report published on 27 November 2020, AEMO invited stakeholder feedback on the PSFRR and its recommendations. AEMO received written submissions from Energy Queensland, Delta Electricity and the Australian Energy Regulator (AER), which are published on the AEMO website[10].

As part of the consultation process, AEMO also conducted a Q&A session on 7 December 2020 to provide a further opportunity for stakeholder input and feedback.

AEMO has considered feedback provided through the written submissions and Q&A session in finalising the PSFRR Stage 2 report. The key matters raised, and AEMO's responses, are summarised in Appendix A3.

1.4 Acknowledgments

AEMO would like to acknowledge and thank Powerlink, TransGrid, ElectraNet, TasNetworks, and AusNet Services for their input to the development of the 2020 PSFRR Stage 2 report, as well as SA Power Networks (SAPN) in relation to emerging issues with UFLS in South Australia.

AEMO would also like to thank engineering consultants GHD who assisted with the review, as well as stakeholders who inputted and contributed to the consultation process.

[10] See https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-psfrr-consultation.

2. Factors influencing the system frequency

The PSFRR studies were conducted in PSSE, a simulation tool for assessing power system dynamics. PSCAD or single mass models were not used in the study. The PSSE simulations include models of the following key power system element characteristics and control systems, each of which can have a significant impact on the system frequency following a non-credible contingency event:

- Generator frequency response.
- Performance of distributed energy resources (DER) including distributed photovoltaics (PV).
- Over-frequency generator shedding (OFGS) schemes.
- UFLS schemes.
- Special Protection Schemes (SPSs) that impact system frequency.
- Pre-contingent power transfers and network augmentations.
- FCAS.

As discussed in the Renewable Integration Study (RIS) Stage 1 report[11], the PSFRR Stage 1 report, and the recently published frequency control work plan[12], there are known gaps in the capability to model power system frequency performance. In the NEM PSSE dynamic simulation models available to AEMO, many legacy generators in mainland states do not have their governors modelled, and distributed PV performance and SPSs are not represented.

The following sections describe the PSFRR activities carried out to adequately model each of the above frequency impacting elements. Further detail is provided in Section 7.2 regarding current and emerging frequency modelling requirements.

2.1 Governors and generator primary frequency response

The following approach was taken to represent generator governor control systems in the NEM PSSE model:

- Where an adequate model was available, that model was adopted.
- If there were missing governor models for some units at a power station, but others had governor models, then those governor models were applied to all similar generating units at the power station.
- For large semi-scheduled and scheduled synchronous generators without governor models, generic governor models were developed that provide a PFR consistent with the minimum interim PFR requirements published by AEMO. Generic models were developed for hydro, steam and gas turbines. The generic governor models used for the 2020 PSFRR studies have limited features and as a result may over-estimate the actual PFR response that would be provided. AEMO will continue to develop generic governor models through progressive improvement and validation against actual performance and

[11] AEMO, April 2020, at https://aemo.com.au/energy-systems/major-publications/renewable-integration-study-ris.

[12] AEMO, September 2020, at https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

through specific modelling information from generators. As a result of the limitations, frequency dynamics cannot be fully investigated at this stage.

- For semi-scheduled wind farms and solar farms without dynamic models, a generic model was adopted that provided a primary frequency lower response consistent with the minimum interim PFR requirements.
- No change was made for smaller generators with low capacity factors, as the PFR contribution from these generators is expected to be negligible.
- No change was made for non-scheduled generators, as they are not expected to provide PFR.

AEMO's interim PFR requirements came into effect from 4 June 2020[13], and are being progressively implemented in stages by all capable scheduled and semi-scheduled generators. The requirements apply to both new and existing connected generators, subject to exemptions and variations based on capability and other specific criteria. Relevant generating systems must provide PFR when dispatched at a level above 0 megawatts (MW).

Considering the implementation of PFR by the generators, the governor model development approach involved implementation of models which meet the interim primary frequency response requirements:

- Droop at the connection point must be set to less than or equal to 5%. When operating at maximum power no further frequency raise response is expected from the generator.
- The PFR deadband must be no wider than +/- 0.015 Hz.

To implement the PFR requirements, generic models were developed for three different types of generators: hydro, steam turbine and gas turbine. The generic models were customised for each generator by adjusting the maximum and minimum power output limits. In total, generic governor models were developed for 16 gas turbines, 12 steam turbines, and 12 hydro generating units. The following PSSE library models were adopted:

- Steam turbines: IEEEG1SDU.
- Gas turbines: GGOVDU.
- Hydro turbines: HYGOVDU.

2.2 DER modelling

Growing DER, particularly distributed PV generation, have a significant impact on power system frequency performance. Current Australian Standard AS/NZS:4777 requires distributed PV resources to provide an active power response to over-frequency events by reducing output linearly as frequency exceeds 50.25 Hz. However, distributed PV is not able to provide a response to under-frequency events if energy constrained, and has no inertia, therefore does not contribute to arresting under-frequency contingency events. Some distributed PV is known to disconnect in response to under-frequency events below 49 Hz, which exacerbates under-frequency disturbances[14].

The distributed PV active power response requirements in the current standards were implemented from 2015, but most of the distributed PV installed prior to 2015 has no active power response capability. Field evidence from past disturbances also indicates that at least 30% of sampled inverters installed under the 2015 standard do not deliver the required over-frequency response[15,16].

[13] Interim PFR Requirements, at https://aemo.com.au/-/media/files/initiatives/primary-frequency-response/2020/interim-pfrr.pdf?la=en.

[14] AEMO, Response of existing PV inverters to frequency disturbances, April 2016, at https://aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

[15] AEMO, Final Report – Queensland and South Australia system separation on 25 August 2018, published January 2019, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2018/qld---sa-separation-25-august-2018-incident-report.pdf?la=en&hash=49B5296CF683E6748DD8D05E012E901C.

[16] AEMO, Final Report – New South Wales and Victoria Separation Event on 4 January 2020, published September 2020, at https://aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-nsw-and-victoria-separation-event-4-jan-2020.pdf?la=en&hash=A35535D1D6AD14F9967B13C822A37A07.

Further specific requirements for distributed PV and other inverter -based generation to be capable of riding through under- and over-frequency events between 47 Hz and 52 Hz were implemented in late 2016. Prior to 2016, the relevant Australian standard allowed higher under-frequency trip settings. AEMO has identified that a significant proportion of older distributed PV has under-frequency trip settings between 47 and 49 Hz[17]. The under-frequency tripping of pre-2016 distributed PV is therefore unpredictable.

With significant generation from distributed PV during the middle of the day, some of the distribution feeders can experience reverse power flow towards the transmission system. If such a distribution feeder is enlisted for UFLS and trips during an under-frequency event, it will act in opposite sense to the intent of the UFLS (effectively tripping generation rather than load), further exacerbating the frequency fall.

To predict the impact of distributed PV during frequency contingencies, it is important to include it in the study model. AEMO has mapped the installed capacity of distributed PV in the NEM according to feeder and substation. This information was used in modelling the distributed PV. In the PSSE load flow, distributed PV was represented as an equivalent lumped generator at substation level with a counteracting (equivalent) load so that the transmission flow is not altered. The PSSE dynamic model 'DERAEMO1' was attached to the distributed PV 'generator' to simulate the distributed PV dynamic response. An AEMO in-house developed DER script accounts for the date and time information for a particular study case and determines the appropriate amount of distributed PV generation to be included at a particular bus along with counteracting load. The script also includes the dynamic model for the distributed PV at relevant busbars. The DER dynamic model has been calibrated to represent an aggregate of both legacy and modern distributed PV generation. Modern distributed PV generation has characteristics compliant with current AS/NZS: 4777 settings. The relative proportion of installed distributed PV for each type is varied depending on the date of the study. This approach allowed the original operational load flow snapshot conditions to be preserved.

2.3 Load relief assumption

Load relief refers to the phenomenon where, under a decline in frequency, motors connected to the power system (such as induction or synchronous motors) reduce the amount of power they consume, thereby reducing the severity of the under-frequency event. The impact of load relief has reduced in recent years due to increasing level of loads being connected to the power system via a power electronic interface, as well as technologies such as variable speed drives, which do not reduce their power consumption under a frequency decline.

While load relief in the region of 1-1.5% was historically assumed to mitigate the severity of under-frequency events, the adoption of these new technologies required AEMO to reassess this assumption. Studies of major frequency disturbances undertaken by AEMO in 2019 assessed that load relief was approximately 0.5% in mainland regions of the NEM[18]. AEMO currently assumes 0.5% load relief (0.5% change in demand for a 1% [0.5 Hz] change in frequency) in all mainland regions of the NEM when determining the requirement for contingency FCAS services. AEMO is reviewing the current load relief assumption in Tasmania of 1%, and will progressively reduce load relief from December 2020[19].

Given the significantly reduced load relief in the NEM mainland regions, load relief has not been considered as a mitigating factor for under-frequency events in the dynamic studies completed for the Stage 2 PSFRR.

2.4 OFGS and UFLS modelling

UFLS and OFGS schemes are employed in power systems to respond during extreme under- or over-frequency events, restoring the balance of power in a system by reducing load or generation power

[17] For further information on pre-2016 distributed PV frequency trip settings , see https://aemo.com.au/-/media/Files/PDF/Response-of-Existing-PV-Inverters-to-Frequency-Disturbances-V20.pdf.

[18] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/ancillary_services/2019/update-on-contingency-fcas-nov-2019.pdf.

[19] See https://aemo.com.au/Market-Notices?marketNoticeQuery=80127&marketNoticeFacets=.

output through disconnection. Each region of the NEM has an automatic UFLS scheme to prevent frequency collapse following a multiple contingency event. Under normal operation, the mainland NEM regions form a single alternating current (AC) interconnected network, and their UFLS schemes are co-ordinated and operated collectively when frequency declines in the range of 49-47 Hz. When a region is islanded, the UFLS scheme in the region should operate independently to arrest frequency decline in that region.

UFLS schemes are implemented throughout the NEM, however at present OFGS schemes are only implemented in South Australia, south Western Victoria and Tasmania. In an OFGS scheme, generator protection settings are coordinated to progressively trip generation for over-frequency events at 51-52 Hz in South Australia and 52-55 Hz in Tasmania. Over-frequency generator tripping in other regions of the NEM currently takes place above 52 Hz through the over-frequency protection settings of registered generating systems.

For the 2020 PSFRR, UFLS was implemented in the PSSE library model using frequency trip settings and desired UFLS capacities based on inputs from NSPs, which detailed load shedding settings and the average load available for shedding at each substation. For PSFRR studies, to implement the UFLS settings in load flow and dynamics a separate UFLS script was developed. For every operational snapshot used for the study, the developed script identifies and separates the UFLS load from the net load connected to a substation and attaches under-frequency trip relays to the UFLS loads in the dynamic model. Where the load at a substation in the snapshot is less than that of the desired load shedding capacity, the script limits the load available for shedding to that present in the snapshot. Also, the script assigns under-frequency trip relays to negative loads indicating reverse power flow, to capture disconnection of distributed PV along with a distribution feeder trip.

An automatic OFGS scheme is installed on a number of generators in South Australia and south-western Victoria which is designed to trip when the system frequency exceeds 51 Hz to prevent uncontrolled increases in frequency. The scheme was implemented using OFGS trip settings for the participating wind farms, and dynamically linked to the wind farms in the PSSE model, therefore the amount of generation disconnected by the scheme was consistent with the output of the wind farms in each study.

For the purposes of the PSFRR and assessment of mainland non-credible contingency events, the Tasmanian OFGS was not explicitly represented. For cases where Tasmanian frequency falls below 48 Hz, this indicates Tasmanian UFLS activation, and for cases where Tasmanian frequency increases above 52 Hz, this indicates Tasmanian OFGS activation.

2.5 Special Protection Scheme modelling

A number of SPSs are in place in the NEM to manage credible and non-credible contingency events. Three relevant schemes were included in the modelling to assess their adequacy and the impact on power system performance:

- South Australia System Integrity Protection Scheme (SIPS) – this scheme operates to detect and attempts to control conditions that could lead to a loss of synchronisation between South Australia and Victoria.
- Emergency Alcoa Portland (APD) Tripping scheme (EAPT) – the scheme is designed to detect loss of 500 kilovolt (kV) connection between Heywood and Moorabool and trip the Heywood to South East lines at Heywood, effectively separating the South Australian region at Heywood. Also, when the PSSE model detects the loss of 500 kV connection between Heywood and Moorabool, it trips the Heywood to Moorabool/APD lines at Heywood to prevent the Victorian generators between Moorabool and Heywood feeding the APD smelter load in islanded mode.
- CQ-SQ SPS – this protection scheme operates to trip generation in Central Queensland following the non-credible loss of the double-circuit Halys – Calvale 275 kV lines. This aims to limit the increase in power flow in the parallel eastern 275 kV lines between Calliope River – Gin Gin and Wurdong – Gin Gin and avoid transient instability across these lines. If the eastern corridors lose synchronism along with the loss of Halys – Calvale lines, North and Central Queensland will be separated from South Queensland.

These SPSs play an important role in the management of system separation events, and the frequency response of the NEM. Hence it is important to verify their performance and integrity under a range of system conditions, and to determine their adequacy for future scenarios.

2.5.1 System Integrity Protection Scheme

The non-credible loss of multiple generating units in South Australia at times of high import into the region can lead to the tripping of the Heywood interconnector due to high power transfers. This non-credible event would result in rapid frequency decline, and poses a risk of cascading failures leading to a state-wide blackout.

The SIPS was designed to rapidly identify conditions that could lead to a loss of synchronisation between South Australia and Victoria, and is designed to correct these conditions in three stages:

- Stage 1 – fast response trigger to inject power from battery energy storage systems (BESS).
- Stage 2 – load shedding trigger to shed approximately 200 MW of South Australian load.
- Stage 3 – out-of-step trip scheme (islanding South Australia).

It should be noted that the increasing distributed PV connections in South Australia will reduce the amount of load available to shed in Stage 2 SIPS action. However, this impact was not specifically considered in the PSFRR studies. Based on the recommendations of 2018 PSFRR, ElectraNet, in collaboration with AEMO, is enhancing the reliability of SIPS by implementing a Wide Area Protection Scheme (WAPS). The WAPS scheme uses Phasor Measurement Unit (PMU) technology to develop the enhanced scheme. ElectraNet expects the scheme to be commissioned by mid-2022. The development of the scheme will need to consider the impact of distributed PV on scheme requirements.

2.5.2 Emergency Alcoa Portland Tripping scheme

The EAPT scheme is designed to prevent the APD smelter load remaining connected to an islanded South Australian system in the event of separation from (or west of) Moorabool where this would result in an unacceptable reduction in voltage or frequency in South Australia.

The scheme measures active power flow on the Heywood interconnector and frequency measured at Heywood to detect a likely separation. On detecting likely separation conditions, the scheme opens two 500 kV circuit breakers at Heywood Terminal Station (HYTS) which effectively separates South Australia from Victoria and creates an island of APD, Tarrone Terminal Station (TRTS), Haunted Gully Terminal Station (HGTS) and Mortlake Power Station (MOPS). This prevents a severe frequency decline in the resulting South Australia island by disconnecting the APD load.

The EAPT scheme operates on simultaneous detection of the following three conditions at HYTS:

- A sudden decrease in active power flow towards HYTS on the Moorabool Terminal Station (MLTS) lines of more than 280 MW.
- A sudden increase in active power flow from South Australia through the HYTS transformers of more than 200 MW.
- Frequency on either South East Sub-Station (SESS) 275 kV line below 49.7 Hz measured at HYTS.

The scheme will also operate on simultaneous detection of the following two conditions:

- A sudden decrease in active power flow towards HYTS on the MLTS lines of more than 280 MW.
- Voltage on both HYTS 500 kV busbars below 80% of nominal voltage for a period greater than 400 milliseconds, indicating a severe voltage depression.

AEMO, in its capacity as the Jurisdictional Planning Body for Victoria, is presently undertaking a review of the EAPT scheme to account for recent changes to the power system, including connected generation. The EAPT review will consider potential scheme changes which take into account network topology based on circuit breaker status.

A model for the existing EAPT scheme has been developed as part of the 2020 PSFRR. The EAPT model has been integrated into the power system model and considered for PSFRR studies involving South Australia separation from (or west of) MLTS.

2.5.3 CQ-SQ special protection scheme

In the event of non-credible loss of Halys – Calvale 275 kV lines, the CQ-SQ SPS is designed to prevent excessive power flows on circuits parallel to the Calvale to Halys double-circuit line by tripping up to two Callide generating units depending on pre-contingent CQ-SQ cut-set flow. Tripping of Callide units is intended to avoid an increase in power flow in the parallel eastern 275 kV lines between Calliope River – Gin Gin and Wurdong – Gin Gin and avoid transient instability across these lines. If the instability is not prevented, the loss of eastern corridors following the Calvale – Halys line loss could potentially push QNI into instability, and such an event could result in NEM-wide supply disruptions and cascading failures.

To study the frequency risks associated with the non-credible loss of CQ-SQ, the CQ-SQ SPS was modelled in PSSE studies simulating the non-credible loss of the Halys – Calvale transmission lines.

Studies by Powerlink and AEMO have already identified a need to upgrade the CQ-SQ SPS to manage higher power flows expected from Central to South Queensland in the future, and work is underway to develop Stage 1 of a revised scheme that will work in parallel with the existing scheme.

Powerlink has identified a likely requirement to trip inverter-based generation ahead of synchronous generation to maintain system strength. However, given the variable nature of such generation (including different cloud cover patterns and transitions from afternoon to evening), implementation is challenging. Powerlink has initiated a project to implement a new wide area monitoring protection and control (WAMPAC) architecture into the CQ–SQ SPS by mid-2021. As per the plan, WAMPAC will include approximately 600 MW of renewable generators. The existing CQ–SQ SPS will continue to trip up to two Callide units.

2.6 Pre-contingent loading and network augmentations

The power flow across the transmission lines that trip on a non-credible contingency event is a key consideration when assessing the potential frequency risk. A greater pre-contingency power flow will present a more severe frequency disturbance. For the 2020 PFSRR studies, the frequency risk assessments consider realistic worst case pre-contingent loading levels. The studies undertaken modelled transfer levels consistent with the maximum secure transfer levels observed across each of the circuits tripped by the priority non-credible contingency events.

The following network augmentations have the potential to impact the frequency risks posed by the five non-credible contingency events:

- QNI upgrade – TransGrid has secured the Australian Energy Regulator's (AER's) approval of its contingent project application for the QNI upgrade[20]. This project delivers upgrades of the QNI interconnector which add over 150 MW of line capacity in both directions of transfer, with the works expected to be completed in 2021-22[21]. The upgrade has the potential to increase the severity of the non-credible loss of the QNI interconnector. As the project should be commissioned before the next PSFRR, sensitivity studies have been performed to assess the additional frequency risks posed by the upgrade.
- Project EnergyConnect (PEC) – TransGrid and ElectraNet are partnering to deliver a new high voltage AC interconnector between South Australia and New South Wales. The project has progressed to submission of a contingent project application to the AER on 30 September 2020. Subject to satisfactory regulatory and other approvals, ElectraNet and TransGrid are working towards completing construction by 31 December 2023. By establishing a new AC interconnection between South Australia and the rest of the

[20] See https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/contingent-projects/transgrid-qni-minor-upgrade-contingent-project.

[21] Committed project list on page 14 of the 2020 ISP https://aemo.com.au/-/media/files/major-publications/isp/2020/final-2020-integrated-system-plan.pdf?la=en.

NEM, PEC would substantially reduce the frequency risk posed by the non-credible loss of the Heywood interconnector or the trip of the 500 kV lines between Moorabool and Heywood. The expected timing of the interconnector development allows those benefits to be assessed in the next PSFRR.

- Victoria – New South Wales Interconnector (VNI) Minor – this project will deliver minor upgrades to the existing VNI. The regulatory approval process for the project is close to completion, with project completion expected in 2022-23. The project is expected to improve the ability to transfer power from Victoria to New South Wales by 40 MW initially and 170 MW once other enabling projects are completed[22]. Some of the enabling projects have longer lead times as they require construction of new transmission lines, with achievement of the full transfer limit increase expected in 2025. As the project does not install new transmission corridors, it has the potential to increase frequency risks associated with the non-credible loss of the VNI when transferring power from Victoria to New South Wales. Given the bulk of the increase in transfer capability is likely to occur after 2022-23, the impact of the augmentation to the VNI on frequency risk can be deferred to a subsequent PSFRR.

[22] Page 89 2020 ISP, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

3. Simulation of priority non-credible contingency events

3.1 Validation of model

To validate the additional frequency control models, AEMO applied them to PSSE study cases and benchmarked the simulation results against three actual events. This was done by comparing the simulated power system responses in PSSE with those captured on high speed monitor (HSM) recorded data during the relevant event. The following events were assessed:

- 25 August 2018 – series of events separating the mainland regions of the NEM into three islands, isolating Queensland from New South Wales and South Australia from Victoria. Both circuits of QNI tripped due to lightning activity, islanding Queensland from the rest of the NEM. Following this event, Basslink increased export from Tasmania to Victoria, leading to 81 MW of load shedding through the Adaptive Under-Frequency Load Shedding scheme (AUFLS2) which is part of switching FCAS to rebalance the Tasmanian power system. The loss of QNI also caused a sudden change in power flow across Heywood interconnector, leading to EAPT protection operation and causing islanding of South Australia and the trip of APD loads.
- 16 November 2019 – separation of South Australia from Victoria. Two 500 kV transmission lines between Heywood and Mortlake terminal stations tripped due to protection mal-operation, including both circuits connecting to APD. The NEM was considered to be in a secure operating state before this contingency and the Heywood interconnector was exporting around 307 MW to Victoria immediately prior to the event. The resulting frequency impact from this event was a significant over-frequency in South Australia, with rate of change of frequency (RoCoF) measured at 1.15 Hz/s and a peak South Australia frequency of 50.85 Hz. There was a minor frequency rise of 0.15 Hz in the rest of the NEM due to APD load loss.
- 23 August 2020 – large generator trip. The Kogan Creek generator in Queensland tripped from 740 MW. This resulted in a significant reduction in frequency across the NEM. All mainland regions remained synchronised following the event and the mainland frequency fell to 49.68 Hz remaining below 49.85 Hz for 310 seconds.

Appendix A1 presents the results of these benchmarking studies, demonstrating that the models developed for the PSFRR are adequate for analysis of future system frequency performance.

3.2 Boundary case selection

To assess power system frequency related risks, it is important to consider operating conditions where the power system is under stress, to determine whether schemes and measures in place are adequate to maintain and restore power system frequency. In selecting boundary cases key system characteristics were considered.

System inertia

System conditions with low system inertia coupled with high interconnector transfers will pose onerous conditions with respect to frequency contingencies. Low inertia conditions generally coincide with higher generation from inverter-based resources (IBR) and lower synchronous generation, and lead to reduced system strength, which can result in more volatile response to disturbances. Hence, historical system snapshots with low inertia, high IBR generation with high power flows in the respective non-credible contingency lines were considered for the study.

UFLS availability

The changes in load composition driven by growing levels of DER can significantly reduce the effectiveness of UFLS schemes. As discussed in the Stage 1 PSFRR report, the proliferation of DER including distributed PV is continuing to erode the net load available to existing UFLS schemes and cause reversal of power flows in some cases. During an under-frequency event, disconnection of feeders operating with reverse power flows will exacerbate the frequency disturbance.

The selected boundary conditions included time periods during the middle of the day which should correspond to lower available UFLS due to the amount of distributed PV generation. Boundary conditions also considered some overnight cases to capture the effect of lower underlying demands present at these times.

Power system transfers

Higher interconnector power transfers can lead to greater supply-demand imbalances following non-credible contingency events involving the loss of interconnectors. Boundary conditions were therefore selected which had power flows in the relevant interconnectors at maximum secure transfer limits.

Primary frequency response

The presence of primary frequency response (PFR) will help reduce changes in frequency and also help with frequency recovery following contingency events, therefore the amount of PFR available will influence the post-contingent power system frequency. The capability and operating point of dispatched generation can significantly influence the amount of PFR available to the power system. For instance, synchronous generators operating at a lower active power output will generally have a greater ability to respond to an under-frequency event than if they are operating at close to their rated capacity. In practice, other limitations can apply depending upon the operating level and mode, which are not practical to capture in the PSSE models. IBR generators operating at their maximum output according to energy source availability will not respond to under-frequency events but should be able to reduce their output for over-frequency events according to their frequency droop.

Selecting boundary conditions with lower amounts of synchronous generation and higher levels of IBR tends to reduce the amount of primary frequency response available to respond to under-frequency events. This PSFRR therefore focuses on these more arduous conditions.

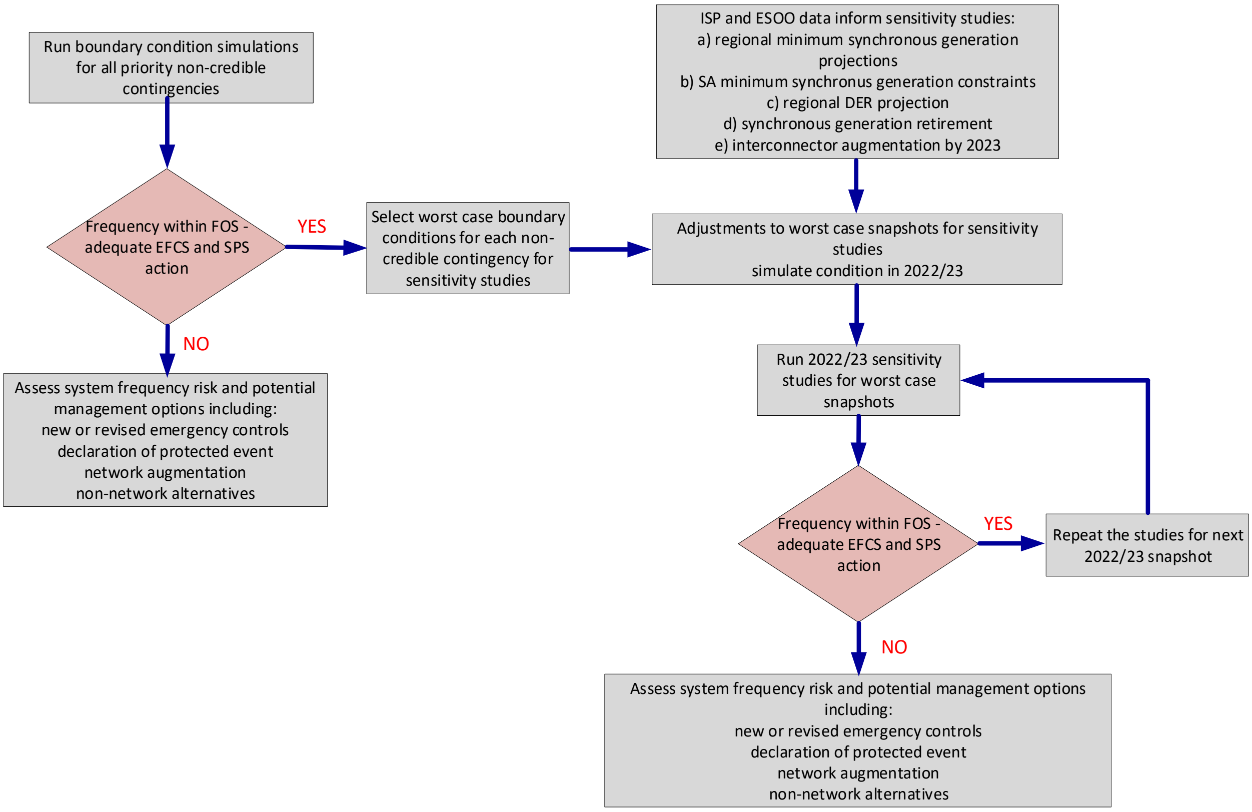
Note: Throughout this report, references to PFR relate to mandatory PFR to be provided in accordance with clause 4.4.2(c1) of the NER.

3.3 Simulation of non-credible contingencies

AEMO identified boundary cases for investigating the frequency performance following the five priority non-credible contingency events based on historic snapshots of the power system. A subset of those cases was then used as the basis for assessing future frequency performance by accounting for power system augmentations, new connections and changes in power system operation anticipated to occur over the next five years.

Figure 2 illustrates the approach.

Figure 2 Non-credible contingency simulation process



3.3.1 Acceptance criteria

The frequency response following the considered non-credible contingencies was assessed as acceptable if the following conditions were met:

- The UFLS schemes prevent the frequency falling below 47.5 Hz (a buffer of 0.5 Hz[23] over the requirements of the FOS).
- The frequency after operation of the UFLS should not rise above 50.5 to provide a 0.5 Hz buffer against OFGS operation at 51.0 Hz.
- The RoCoF did not exceed ±2 Hz/s following the non-credible contingency. This limit was selected after considering advice from GE Energy Consulting regarding the potential risk of gas turbine generators failing to ride through higher RoCoF events (for both positive and negative RoCoF)[24]. Generator tripping is more problematic for under-frequency events, but uncontrolled and unanticipated tripping behaviour at high positive RoCoF may also introduce risks, which are reflected in these acceptance criteria.

Longer-term frequency performance is not modelled, due to the practicality of modelling AGC control, however steady-state settling frequency has been observed. RoCoF has been calculated using frequency traces for the period following the application of the contingency for a linear segment (for a period of at least 500 ms) of the frequency trace where the slope is at a maximum. Portions of the frequency traces with sharp transients are excluded in the RoCoF calculation.

[23] A 0.5 Hz buffer provides a safety margin to account for limitations in modelling accuracy and the possibility of more-onerous system conditions not covered by the modelled scenarios. 0.5 Hz is a reasonable buffer as it is sufficiently large in proportion to the acceptable frequency deviations bounded by the FOS (+2 Hz and -3 Hz for mainland regions of the NEM).

[24] GE Energy Consulting report available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

3.3.2 Sensitivity studies examining future conditions

AEMO undertook studies to assess the power system frequency risks over a five-year horizon. Future system models were developed considering demand and generation forecasts aligned with the 2020 ESOO and ISP projections.

DER

The 2020 ESOO projects continued DER growth in all NEM regions. Table 1 shows estimated levels of DER in each region for spring 2022 and spring 2025, derived from the 2020 ESOO High DER scenario forecast and used to develop future study cases.

For this PSFRR, DER was modelled as a specific distributed PV component connected in parallel with an equivalent load so as not to distort the load flow condition in the original boundary condition snapshot. This distributed PV model allows the dynamic frequency response provided by the connection of additional DER to be explicitly modelled in the sensitivity studies, and also to take into account the effect of UFLS action on net load. Based on the projections, it could be anticipated that other regions, particularly Victoria, will start to see issues with UFLS effectiveness similar to South Australia in the near future.

Table 1 Regional DER penetration

Region	DER by 2022-23		DER by 2024-25	
	(MW)	% of MD*	(MW)	% of MD
Queensland	4,082	42%	5,332	54%
New South Wales	4,017	28%	5,461	38%
Victoria	3,764	39%	5,745	60%
South Australia	1,842	57%	2,290	69%
Tasmania	214	15%	283	20%
Total	13,919		1,9113	

* % of 10% POE sent out operational maximum demand forecast in that year in the 2020 ESOO.

Projected available inertia

The 2020[25] ISP includes projections for inertia levels in each region of the NEM. Table 2 lists the amount of inertia projected to be available for 100% of the time in 2024/25 for each region under the Step Change scenario. The PSFRR sensitivity studies modelled the reduction in inertia by replacing selected synchronous generators in each region in the historical boundary condition snapshot with a generic IBR model. The IBR was modelled as providing the same generation output as the original synchronous generator to ensure no change to the load flow conditions. The frequency response of each generic IBR was tuned to provide a primary frequency response consistent with PFR requirements. This provides a 5% droop response for over--frequency events that move frequency beyond a 0.015 Hz deadband with no under-frequency response. The future case studies therefore represent the frequency response expected from new IBR that replaces synchronous generation in this scenario.

[25] See https://aemo.com.au/-/media/files/major-publications/isp/2020/appendix--7.pdf?la=en.

Table 2 Projected minimum amount of available synchronous inertia in 2024-25[A]

Region	Inertia (MWs)
Queensland	16,761
New South Wales	14,892
Victoria	8,248
South Australia	4,400
Tasmania	3,200[B]

A. As provided in the 2020 Integrated System Plan Appendix 7. Power System Security. 2020 updated inertia values are available in AEMO's 2020 System Strength and Inertia Report, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/operability/2020/2020-system-strength-and-inertia-report.pdf?la=en.
B. The value shown for Tasmania is the level required to maintain Tasmania in a satisfactory state when islanded, reflecting the completion of a procurement of inertia services by TasNetworks in order to make the minimum threshold level of inertia available[26].

The projected minimum amount of available inertia for South Australia is equivalent to only relying on synchronous inertia from the four synchronous condensers fitted with flywheels that ElectraNet is currently delivering at Davenport and Robertstown.

Work is presently being undertaken by ElectraNet and AEMO to reassess power system operational limits post commissioning of the four synchronous condensers, superseding the current planning assumptions[27]. That analysis work is expected to be completed by mid-2021.

Unless otherwise stated, for any 2022-23 sensitivity study the synchronous inertia level was set to be half way between the inertia in the boundary condition snapshot and that shown in Table 2.

Growth in IBR

The sensitivity studies model growth in IBR in each region, with the amount of additional IBR reflecting what is required to meet minimum inertia targets as synchronous generation withdraws from the system.

New or augmented interconnectors

The 2020 PSFRR studies have not explicitly considered any interconnector upgrade projects that will be commissioned after 2022. As the QNI upgrade project is expected to be commissioned prior to the next PSFRR, its impact has been considered by repeating worst case studies for the non-credible loss of QNI with the pre-contingent power transfer increased to match the increase in capability delivered by the upgrade. For other planned interconnector augmentations, the need for changes to existing SPSs are being considered by the TNSPs as part of the scope of those projects and will also be examined during the next PSFRR.

Sources of Fast Frequency Response

Any new IBR seeking development approval in South Australia is expected to deliver a response equivalent to providing an inertia of 2.55 MWs for each megavolt amperes (MVA) of IBR generation capacity. The Central scenario in the 2020 ISP report shows no increase in solar and wind generation in South Australia to 2025, hence no additional equivalent inertia was included in the sensitivity studies.

[26] See https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2019/Notice-of-Inertia-Fault-Level-Shortfalls-Tasmania-Nov-2019.pdf.

[27] AEMO, https://www.aer.gov.au/system/files/AEMO%20-%20Assumptions%20for%20South%20Australian%20GPG%20in%20the%202018%20ISP%20-%20August%202019.pdf.

4. Simulation results

The following sections present a summary of the key results and insights gained through simulation of each of the five priority non-credible contingency events. Each section provides:

- A description of the non-credible contingency event, including details of any relevant SPS.
- A summary of key results and insights gained through simulations performed using historical boundary-condition snapshots.
- A summary of future 2022-23 case study results and insights gained through the future case studies.
- An assessment of risks relating to the assessed non-credible contingency event.

It may be noted that scenarios in simulation studies indicate a particular type of operating situation or a group of situations and cases refer to a particular operating snapshot considered for the study.

4.1 Loss of double-circuit QNI leading to New South Wales and Queensland separation

4.1.1 Background of event

The 330 kV double-circuit transmission line from Bulli Creek to Dumaresq, known as QNI, is an AC interconnector between Queensland and New South Wales. QNI has a nominal flow capacity of 300-600 MW from New South Wales to Queensland, and 1,078 MW from Queensland to New South Wales.

The simultaneous trip of both transmission circuits is possible, and has occurred historically, but for power system operational purposes it is considered as a non-credible event. The 2018 PSFRR discussed the risk of non-credible separation of QNI during high New South Wales exports leading to Queensland over-frequency, and potential for cascading outages. In the 2018 PSFRR, AEMO identified that an OFGS scheme could be considered to mitigate the risk of QNI separation leading to over-frequency in Queensland. While a coordinated OFGS is not in place in Queensland, generating systems do have over-frequency trip settings implemented consistent with their generator performance standards.

4.1.2 Historical case studies – Queensland export

A set of six boundary condition snapshots was selected to assess non-credible loss of QNI when exporting around 1200 MW from Queensland to New South Wales. The double-circuit trip of QNI was simulated using each boundary condition snapshot and the frequency response in each region of the NEM assessed.

Table 3 presents the maximum frequency deviation from 50 Hz (nadir) observed in each case for different NEM regions. It should be noted that the simulation studies do not include the UFLS models of Tasmania and hence any frequency drop below 48 Hz in Tasmania indicates UFLS action. The level of UFLS triggered in the simulation model is also included in the last column.

Table 3 Frequency simulated following the trip of the QNI for each boundary condition snapshot

Case ID	QLD inertia (GWs)	NSW inertia (GWs)	QNI flow (MW)	Regional frequency peak/nadir (Hz)			UFLS remarks
				QLD	NSW/VIC/SA	TAS	
1	32	31	1186	50.85	49.15	47.55	No mainland UFLS
2	29	29	1167	50.70	49.35	47.55	No mainland UFLS
4	26	27	1193	51.05	49.05	47.45	No mainland UFLS
5	39	42	1217	50.70	49.05	47.55	No mainland UFLS
6	43	42	1229	50.75	49.15	48.25	No mainland UFLS
7	36	30	1215	50.90	49.15	48.30	No mainland UFLS

The following observations are made based on the studies:

- For all historical cases considered for the QNI non-credible contingency, frequency peak and nadir were within the FOS limits (that is, frequency between 47 Hz and 52 Hz).
- In Queensland the over-frequency settles below the 51 Hz stabilisation limit specified in the FOS. In some of the simulations the settling frequency was above the 50.5 Hz recovery limit. The simulation results may present a conservative or optimistic result depending upon the actual unit response at the time of an event.
- Case 7 was run with the EAPT model active as it was assessed as the case most likely to trigger the scheme. The simulation confirmed that the EAPT scheme did not operate.
- Most of the cases produced a similar level of maximum frequency rise in Queensland and a similar level of frequency fall in other regions of the NEM. Although Case 6 had the highest QNI transfer, it had higher inertia which led to a lower frequency rise in Queensland and less severe frequency reductions elsewhere.

The boundary condition simulations for QNI export conditions indicate that existing frequency controls are able to minimise risks associated with power system frequency performance caused by the non-credible loss of QNI.

4.1.3 Future 2022-23 case studies – Queensland export

Case studies representing different possible power system conditions in 2022-23 were developed from the Case 2 historical condition included in Table 3. To capture the increase in QNI export capacity through the planned QNI upgrade, the increase of 200 MW in QNI export was equivalently simulated using Case 2 by tripping 200 MW of load in Queensland and 200 MW of generation in New South Wales while tripping both QNI lines representing an equivalent flow of 1,367 MW (1,167 + 200 MW). Table 4 presents the maximum frequency deviation from 50 Hz (nadir or peak) observed in future case studies for different NEM regions for the non-credible loss of QNI.

Table 4 Frequency simulated following the trip of the QNI in future export cases

Case ID	Inertia QLD (GWs)	Inertia NSW (GWs)	QNI (equ. flow) (MW)	Regional frequency peak/nadir (Hz)			UFLS utilised
				QLD	NSW, VIC & SA	TAS	Region (MW)
2c	17	15	1,367	50.79	48.95	47.40	NSW 312 MW
2d	17	15	1,367	51.55	48.95	47.40	NSW 312 MW

The future case studies were undertaken with conservative assumptions regarding possible power system conditions looking forward to 2022-23. The following key changes were modelled as described in Section 3.3.1:

- Reduction in synchronous inertia in all regions based on 2020 ISP Step Change scenario.
- Increase in DER in each region based on the 2020 ESOO High DER scenario.
- Increased contingency size with the QNI upgrade commissioned.
- Reduction in available UFLS as a result of continued DER growth.

The following two cases were simulated:

- Case 2c, representing a potential 2022-23 future case with PFR provided by Queensland generators. In this case generators with existing bespoke governor models provide PFR in accordance with those models and all other large generators provide a PFR consistent with the published PFR requirement. It modelled growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertial levels projected in the Step Change scenario in the 2020 ISP. The amount of UFLS available in this case was reduced from that modelled in Case 2, as described in Table 5. The reduction assumed that all additional DER projected to connect by 2022-23 will reduce available UFLS. The DER in this case reflects that forecast for 2024-25 in the High DER scenario in the 2020 ESOO. Sufficient additional IBR were modelled to achieve the minimum inertia in 2024-25 in the Step Change scenario in the 2020 ISP. In this case all large generating systems in Queensland (>30 MW) were modelled as operating with a PFR enabled in line with the published requirements. This future case also modelled a 200 MW increase in the contingency size to reflect the likely increase in QNI flow once the QNI upgrade is completed.
- Case 2d, representing a 2022-23 future case without PFR provided by Queensland generators (>30 MW) In this scenario, response to the over-frequency in Queensland is provided by the response of DER and smaller (<30 MW) IBR. All else remains the same as Case 2c.

The difference in available UFLS modelled in Cases 2c and 2d from historical case 2 reflects a conservative view of the UFLS expected in 2022-23. It effectively assumes that every additional unit of DER generation projected by 2022-23 in the ESOO High DER scenario will reduce the available UFLS by the same amount. In practice, if some of the growth in DER is on feeders that are not part of the UFLS scheme, it will have less impact on the available UFLS. However, additional growth in DER beyond 2022-23 has the potential to further reduce the available UFLS from that modelled in these cases. By 2024-25 the projected DER growth could fully offset existing UFLS.

Table 5 Available UFLS in Case 2 and Case 2c and the additional DER projected by 2022-23

Region	Available UFLS (MW)		Additional DER by 2022-23 (MW)	Net UFLS tripped (MW)	Percentage UFLS tripped %
	Case 2	Case 2c			
NSW	3,264	1,337	1,927	312	23
VIC	2,624	577	2,047	0	0
SA	549	0	777	0	0

The simulated results indicate that:

- The simulated frequency in future cases also remained within the limits specified in the FOS. The maximum over-frequency observed in the Case 2c, with IBR in Queensland providing PFR consistent with the published requirement, was similar to that simulated for the original boundary condition snapshot, however the settling frequency was significantly reduced. The reduction in over-frequency settling frequency in these future cases is due to the additional PFR to over-frequency provided by the additional

DER and IBR replacing synchronous generators to achieve the required minimum synchronous generation levels.

- The over-frequency simulated in Case 2d, which modelled no PFR from generating systems in Queensland, was significantly higher reaching 51.55 Hz. In this scenario, the frequency response provided by smaller IBR and DER assisted with maintaining the over-frequency within the limits specified in the FOS, however the frequency settled to 51 Hz which exceeds the stabilisation and recovery thresholds specified in the FOS.
- While the RoCoF observed in future case simulations in Queensland was higher than that simulated using the historical snapshot, the maximum RoCoF remained well within the required 2 Hz/s upper limit, as described in Section 3.3.1. The RoCoF observed in New South Wales, Victoria and South Australia for this non-credible contingency was also well within 2 Hz/s. This suggests there is low risk of RoCoF-related cascading failures following QNI separation.
- In the future cases, the forecast reduced inertia and PFR available from synchronous generating systems in New South Wales, South Australia and Victoria, coupled with the increased contingency size, produced a lower frequency nadir in NEM regions other than Queensland with a significant increase in the amount of UFLS used. This highlights the increased dependency on UFLS to control the frequency within limits. Appendix A2 provides additional information comparing the frequency performance in each region in the boundary condition simulation and the future cases.
- The studies including PFR suggest that the frequency risks associated with the non-credible loss of QNI while exporting are likely to remain manageable to 2022-23. Beyond that time, it is important that additional measures are taken to avoid UFLS becoming ineffective during periods with high distributed PV generation. Continued growth in DER is likely to see more distribution feeders operating with reverse power flow (towards the transmission network) during periods of low load coincident with high solar irradiance. To maximise the effectiveness of UFLS AEMO has commenced work with NSPs to review the design of existing UFLS schemes. Section 6.2.1 discusses multiple options being considered in South Australia, which is at the forefront of integrating distributed PV and managing UFLS effectiveness issues.
- The studies of the non-credible loss of QNI while exporting did not identify an immediate need to implement an OFGS scheme in Queensland to cater for QNI contingencies, if the semi-scheduled IBR generators provide PFR consistent with the published NER requirement. The studies suggest that the additional PFR delivered by IBR and increased levels of DER should help manage over-frequency events, particularly those that occur during periods of the day with high solar generation. In the longer term, developing an OFGS may offer benefits through better coordination of any tripping of generation in the event that the frequency in Queensland remains outside the limits in the FOS for greater than the times specified in the FOS. An OFGS may also assist to manage over-frequency events in the future particularly if inertia continues to decline and Queensland experiences a higher RoCoF following contingency events. This should be further considered as part of the 2022 PSFRR.

4.1.4 Historical case studies – Queensland import

A set of three boundary condition snapshots was selected to assess non-credible loss of QNI when importing around 500-600 MW from New South Wales to Queensland. The double-circuit trip of QNI was simulated using each boundary condition snapshot and the frequency response in each region of the NEM assessed. Table 6 presents the maximum frequency deviation from 50 Hz (nadir or peak) observed in each case for different NEM regions. If UFLS was triggered in the simulations, the amount of load shed is noted in the last column.

Table 6 Frequency simulated following the trip of the QNI for each boundary condition snapshot

Case ID	Inertia QLD (GWs)	Inertia NSW (GWs)	QNI (MW)	Regional frequency peak/nadir (Hz)			UFLS utilised Region (MW)
				QLD	NSW, VIC & SA	TAS	
8	34	33	592	48.99	50.33	50.14	QLD 193
9	31	37	515	49.00	50.27	50.30	QLD 216
10	36	37	489	49.05	50.27	50.30	QLD 13.5

For the historical cases simulated the frequency in each region remains within the limits specified in the FOS:

- All historical boundary conditions simulated resulted in UFLS operation in Queensland to arrest the reduction in frequency following non-credible loss of QNI.
- In all cases the UFLS coupled with the primary frequency response from synchronous generators was adequate to maintain frequency within the limits defined in the FOS.
- Case 8 was the most severe boundary condition. With QNI importing 592 MW from New South Wales to Queensland, this resulted in a minimum Queensland frequency of 48.99 Hz. This required 193 MW of UFLS to arrest the frequency decline. Among the cases in Table 6, Case 8 was therefore selected as a worst-case boundary condition for use for a future study case based on the QNI import level and UFLS operation.

While the boundary condition simulations indicate that existing frequency controls were able to manage the frequency disturbance caused by the non-credible loss of QNI when importing at the secure transfer limit, this requires significant levels of UFLS. The reliability of significant levels of UFLS is a key consideration as the level of DER continues to increase. This issue was further explored through sensitivity studies modelling future system conditions, discussed below.

4.1.5 Future 2022-23 case studies – Queensland import

Case studies representing different possible power system conditions in 2022-23 were developed from the Case 8 boundary condition snapshot described in Table 6. To capture the increase in QNI import capacity through the planned QNI upgrade, the increase of 200 MW in QNI export was equivalently simulated using Case 8 by tripping 200 MW of generation in Queensland and 200 MW of load in New South Wales while tripping both QNI lines representing an equivalent flow of 792 MW (592 + 200 MW). Table 7 presents the maximum frequency deviation from 50 Hz (nadir or peak) observed in future case for different NEM regions.

Table 7 Frequency simulated following the trip of the QNI in future import cases

Case ID	Inertia QLD (GWs)	Inertia NSW (GWs)	QNI (MW)	Regional frequency peak/nadir (Hz)			QLD UFLS shed (MW)
				QLD	NSW/VIC/SA	TAS	
8d	24	14	592	48.00	50.19	50.12	536
8e	24	14	592	Freq. collapse	50.19	50.12	654 (100 %)

The future case studies were undertaken with conservative assumptions regarding possible power system conditions looking forward to 2022-23. The following key changes were modelled as described in Section 3.3.1:

- Reduction in synchronous inertia in all regions based on 2020 ISP Step Change scenario.
- Increase in DER in each region based on the 2020 ESOO High DER scenario.
- Increased contingency size with the QNI upgrade commissioned.

- For conservative results, in Cases 8e and 8d the available UFLS in original Case 8 is reduced by the projected increase in DER to account for UFLS load reduction due to increase in DER.

The following two cases were simulated:

- Case 8d, representing a potential 2022-23 future case with PFR provided by Queensland generators. In this case generators with existing bespoke governor models provide a PFR dictated by those models and all other large generators provide a PFR consistent with the published PFR requirement. It modelled growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertia levels projected for a 2022-23 case, using the Step Change inertia projections in the 2020 ISP. The DER growth also represents a 2022-23 case modelled on the 2020 High DER ESOO scenario. In this case the amount of net UFLS available was reduced by the projected growth in DER as described in Table 8. The case modelled a 200 MW increase in the contingency size to reflect the increase in QNI flow likely once the QNI upgrade is completed. In this case all large generating systems in Queensland (>30 MW) were modelled as producing a PFR in accordance with the published requirement.
- Case 8e, representing a potential 2022-23 future case without PFR provided by Queensland generators (>30 MW).

Table 8 shows the amount of UFLS tripped in the two future cases studies and demonstrates that in Case 8d, which models a minimum amount of PFR in Queensland, all of the available UFLS is utilised.

Table 8 Available UFLS in boundary case and 2022-23 future case

Region	Available UFLS (MW)		Additional DER by 2022-23 (MW)
	Case 8	Case 8d and 8e	
QLD	1,685	654	1,038

Table 9 UFLS utilised in future cases compared with available UFLS

Region	Available UFLS (MW)	Net UFLS tripped (MW)	Percentage UFLS tripped %	Net UFLS tripped (MW)	Percentage UFLS tripped %
	Case 8d and 8e	Case 8d	Case 8d	Case 8e	Case 8e
QLD	654	536	82%	654	100%

In practice, if some of the growth in DER is on feeders that are not part of the UFLS scheme, it will have less impact on the available UFLS. However, additional growth in DER beyond 2022-23 has the potential to further reduce the net available UFLS from that modelled in Case 8d and 8e. By 2024-25 the projected DER growth could fully offset existing UFLS.

The simulated results indicate that:

- The simulated frequency nadir in Case 8d, with large generating systems in Queensland assumed to provide PFR, remained within the limits specified in the FOS. The reduced inertia and reduced frequency raise response available from synchronous generators in Queensland produced a lower frequency nadir with significant amounts of UFLS being required. In case 8d, some of the generators with bespoke governor models were not able to provide a sustained response to correct the under-frequency event. Sensitivity studies reveal that if all large synchronous generators in Queensland were able to deliver a sustained PFR consistent with the published requirements, the frequency nadir in this future case could be increased by approximately 0.5Hz and the amount of UFLS reduced by approximately 100 MW.

- In Case 8e, which modelled no PFR from large generating systems in Queensland, the frequency collapsed following the non-credible loss of QNI. In this case the assumed growth in DER to 2022-23 significantly reduced the net available UFLS and, in the absence of any appreciable PFR from Queensland generators, there was insufficient UFLS to prevent frequency collapse. This case highlights that it is important to ensure there is PFR available within Queensland.
- The additional DER and IBR installed in the southern mainland regions delivered significant PFR, achieving a lower frequency peak in the future cases than the original historical snapshot even though the QNI transfers were increased further due to increased transfers associated with QNI upgrades in the future cases.
- While the RoCoF simulated in Queensland for the future cases was higher than that simulated using the boundary condition snapshot, it remained within 2 Hz/s. The RoCoF observed in the remainder of the NEM for this non-credible contingency was also within 2 Hz/s. This suggests that, on current projections, specific measures are unlikely to be required prior to the next PSFRR to manage RoCoF for the non-credible loss of QNI while importing.
- The future cases suggest that the frequency risks associated with the non-credible loss of QNI while importing are likely to remain manageable to 2022-23, if large generators in Queensland provide PFR. Beyond that time, it is important that measures are taken to avoid growth in DER reducing the availability of UFLS during midday periods with high distributed PV generation. Continued growth in DER is likely to see more distribution feeders feeding back to the transmission network during the middle of the day. To maximise the effectiveness of UFLS it is recommended that NSPs review the design of existing UFLS schemes. Section 6.2.1 discusses multiple options being considered in this regard in South Australia, which is at the forefront of integrating distributed PV and managing UFLS effectiveness issues.
- The upgrade of QNI has the potential to increase the contingency size. This stresses the need for Queensland generators to provide PFR particularly during daylight hours when the amount of available UFLS may be reduced by the growth of DER.
- To maximise the effectiveness of UFLS with increasing levels of DER, it is recommended that the design of existing schemes be reviewed to provide a more sophisticated approach that allows feeders to be excluded from UFLS when they are supplying power to the transmission system. This change should improve the effectiveness of UFLS by minimising the risk that UFLS exacerbates an under-frequency event by tripping generation rather than load particularly during periods of high DER generation. Without these revisions, continued growth in DER has the potential to render the existing Queensland UFLS insufficient by 2024-25 for managing the non-credible loss of QNI while importing. To address this, it is recommended that NSPs in Queensland consider changes to existing UFLS schemes to adopt more sophisticated approaches for selecting appropriate feeders for load shedding at any time.

Continued growth in DER and large scale IBR connections beyond 2022-23 has the potential to further erode the effectiveness of the present frequency control capabilities in Queensland following QNI separation events. Three primary areas of concern are:

- Reduction in the frequency raise response available within Queensland. As fewer synchronous generators are dispatched this tends to reduce the PFR available within Queensland which would otherwise support frequency recovery following QNI separation events. As frequency raise response in the NEM is normally sourced as a global requirement there is no specific Queensland regional requirement unless the loss of the QNI has been reclassified as a credible contingency. This will increasingly expose Queensland to risk of frequency collapse following non-credible contingency events. The risk is unlikely to arise across the next few years once changes to generator controls are implemented to meet PFR requirements, but may increase into the future with lower levels of synchronous generation or if generators cease to deliver PFR requirements. It is recommended that the risk be reviewed further in the 2022 PSFRR.
- Lack of alternative technologies providing frequency raise response. Technologies such as BESS have been shown to be effective in contributing frequency raise response in South Australia. Development of BESS in

Queensland with primary frequency response enabled would help mitigate the loss of frequency raise response (or dispatch of frequency raise outside Queensland).

- Erosion of the effectiveness of UFLS by continued growth in DER.

In addition to working with NSPs to revise the design of UFLS in Queensland, it is recommended that further analysis be undertaken by AEMO and Powerlink to assess the effectiveness of BESS or other developments on local primary frequency raise response. The ongoing effectiveness of UFLS in Queensland will be reassessed as part of the next PSFRR, with specific consideration given to whether declaration of a protected event is warranted to manage the risk associated with the non-credible loss of QNI while importing. Declaration of a protected event could enable management of the risk by specifying a local requirement for frequency raise FCAS in Queensland under dispatch conditions where the UFLS would otherwise be ineffective in managing the non-credible loss of QNI while importing.

4.2 Loss of multiple single-circuit interconnectors between New South Wales and Victoria leading to New South Wales and Victoria separation

4.2.1 Background of event

New South Wales is interconnected with Victoria via three 330 kV AC transmission lines routed between Murray – Upper Tumut, Murray – Lower Tumut, and Jindera – Wodonga substations, and another 220 kV AC transmission line between Buronga and Red Cliffs. The nominal capacity of the New South Wales – Victoria interconnection (termed as VIC1-NSW1) is 400-1,350 MW from New South Wales to Victoria and 700-1,600 MW from Victoria to New South Wales.

The separation of New South Wales and Victoria is considered a non-credible contingency event. While a large storm or bushfire event could trip one or more of the existing transmission lines, the simultaneous loss of all circuits is very unlikely. Bushfires burning in close proximity to the transmission lines comprising the New South Wales to Victoria interconnection can present an elevated risk of separation. However, in this scenario AEMO will introduce operational constraints to reduce power flows and reduce the impact of line outages.

As bushfire situations can evolve rapidly there is a risk that line outages may occur prior to power flows being reduced to secure limits. This unlikely, but plausible scenario could result in the tripping of all circuits forming the interconnection. This non-credible event has been analysed for this review.

4.2.2 Historical case studies – Victoria import

One boundary condition snapshot was selected to assess the potential frequency risk associated with the non-credible loss of the interconnection between New South Wales and Victoria during high import into Victoria. Simulations modelled the simultaneous trip of the four circuits between New South Wales and Victoria, the Murray – Upper/Lower Tumut circuits, Jindera – Wodonga and Buronga – Red Cliffs. While this event is unlikely due to the geographic separation of the circuits it provides worst-case contingency conditions for assessing the frequency risk following separation of New South Wales and Victoria.

Table 10 presents the maximum frequency deviation from 50 Hz (nadir or peak) observed in each NEM region. It should be noted that the simulation studies do not include the UFLS models of Tasmania and hence any frequency drop below 48 Hz in Tasmania indicates UFLS action. Table 11 shows the amount of UFLS utilised in Victoria and South Australia after the contingency expressed as a proportion of the amount of UFLS available in the boundary condition snapshot.

For this boundary condition snapshot, the simulated frequency in each region remains within the limits specified in the FOS and the RoCoF remained well below the 2 Hz/s upper limit noted in Section 3.3. The APD load was tripped by the UFLS scheme in this simulation.

Table 10 Simulated frequencies following the trip of the New South Wales – Victoria interconnectors for import case

Case ID	VNI	NSW+QLD inertia	SA+VIC inertia	Regional frequency peak/nadir (Hz)				EAPT operation
	(MW)	(GWs)	(GWs)	QLD & NSW	VIC	SA	TAS	
1	955	57.66	21.54	50.3	48.85	48.85	49.9	No

Table 11 Under-frequency load shedding and distributed energy resource data for import case

Region	Net UFLS load (MW)	Net UFLS tripped (MW)	Percentage UFLS tripped
VIC	2,662	578	21.71
SA	727	136	18.71

4.2.3 Future case study for import conditions

The historical boundary condition snapshot in Section 4.2.2 was modified to reflect expected minimum synchronous inertia in 2022-23. This was achieved by making the adjustments to the synchronous inertia, amount of IBR and DER modelled as described in Section 3.3.2, with the exception that the growth in distributed PV was not modelled as reducing the amount of UFLS available. Table 12 presents the frequency nadir or peak observed by simulating the non-credible contingencies resulting in the separation of New South Wales from Victoria.

Table 12 Simulated frequencies following the trip of the New South Wales – Victoria interconnectors for future import case 1,137 MW

Case ID	VNI (MW)	NSW+QLD inertia (GWs)	SA+VIC inertia (GWs)	Regional frequency peak/nadir (Hz)				EAPT operation
				QLD & NSW	VIC	SA	TAS	
1	955	45.84	17.20	50.30	48.89	48.89	49.87	No

The simulated frequency in each region remains within the limits specified in the FOS, with a similar frequency nadir to the historical boundary condition snapshot. The reduction in inertia in the future case was not significant, hence the future case results are similar to the historical case. In the future case also the UFLS scheme in Victoria disconnected APD load. Table 13 shows the amount of UFLS that operated in this future case.

Table 13 Under-frequency load shedding and distributed energy resource data for future import case

Region	Net UFLS load (MW)	Net UFLS tripped (MW)	Percentage UFLS tripped
VIC	2,662	454	17.05
SA	727	118	16.23

4.2.4 Historical case studies – New South Wales import

Two boundary condition snapshots were selected corresponding to conditions with high exports from Victoria to New South Wales. Simulations modelled the simultaneous trip of the four circuits between New South Wales and Victoria, the Murray – Upper/Lower Tumut circuits, Jindera – Wodonga, and Buronga – Red Cliffs. While this event is unlikely due to the geographic separation of the circuits, it provides worst-case contingency conditions for assessing the frequency risk following separation of New South Wales and Victoria.

Table 14 presents the maximum frequency deviation from 50 Hz (nadir or peak) observed in each NEM region.

Table 14 Simulated frequencies following the trip of the New South Wales – Victoria interconnectors for export case

Case ID	VNI (MW)	NSW+QLD inertia (GWs)	SA+VIC inertia (GWs)	Regional frequency peak/nadir (Hz)				Oscillatory instability
				QLD & NSW	VIC	SA	TAS	
1	971	53.54	18.03	N/A	N/A	N/A	N/A	Yes
2	1,137	70.12	22.18	49.28	50.64	50.64	50.22	No

Case 1 resulted in oscillatory instability in QNI following the contingency. It was found that in this scenario, Queensland was exporting 1,134 MW to New South Wales pre contingency. Following the contingency, the QNI flow increased to more than 1,300 MW, and this increase in flow led to QNI instability. This case study result highlights the importance of considering QNI transfer and Queensland/New South Wales FCAS dispatch while determining secure Victoria – New South Wales transfer limits, especially at times of extreme weather conditions or bushfires where this non-credible separation is plausible.

In Case 2 studies, the simulated frequency in each region remained within FOS limits and the RoCoF remained below the 2 Hz/s upper limit noted in Section 3.3. In this case the over-frequency in Victoria and South Australia did not result in the activation of South Australia's OFGS scheme, however the Tailem Bend Solar Farm in South Australia tripped on over-voltage protection. There was no UFLS observed in any of the NEM regions and the EAPT scheme did not operate.

Case 2 simulations indicate that under- or over-frequency is unlikely to be a significant risk during a New South Wales – Victoria separation event. Both the north and south islands retain sufficient PFR and UFLS to arrest and recover-frequency following a separation event. Furthermore, both islands retain sufficient inertia to control RoCoF following separation.

4.2.5 Future case studies for export conditions

To study future case studies, the historical boundary condition snapshot Case 2 in Table 14 was modified to reflect expected minimum synchronous inertia in 2022-23. This was achieved by making the adjustments to the synchronous inertia, amount of IBR and amount of DER modelled as described in Section 3.3.2, with the exception that for VNI studies IBR growth did not offset UFLS availability. Table 15 presents the frequency nadir or peak observed for the non-credible separation of New South Wales from Victoria.

Table 15 Simulated frequencies following the trip of the New South Wales – Victoria interconnectors for export case

Case ID	VNI (MW)	NSW+QLD inertia (GWs)	SA+VIC inertia (GWs)	Regional frequency peak/nadir (Hz)				Oscillatory instability
				QLD & NSW	VIC	SA	TAS	
2	1,137	51.14	15.92	49.10	50.55	50.55	50.15	No

The simulated frequency in each region remains within the limits specified in the FOS, with the frequency nadir or peak similar to that obtained using the historical boundary condition snapshot. The reduction in inertia in the future case in Queensland and New South Wales lead to a slightly lower nadir triggering a small amount of UFLS. Table 16 shows the amount UFLS tripped in this future case. In the future case study, the EAPT scheme did not operate.

Table 16 Under-frequency load shedding and distributed energy resources data for future stable export case

Region	Net UFLS load (MW)	Net UFLS tripped (MW)	Percentage UFLS tripped
NSW	3,559	N/A	N/A
QLD	1,804	13	0.7

The over-frequency in Victoria and South Australia did not result in the activation of the South Australia OFGS scheme, due to the relatively low over-frequency during the separation event.

Appendix A2.2 provides additional information and simulation graphs for the VNI separation event.

4.2.6 Non-credible loss of DDTS-SMTS and MSS-DDTS 330 kV lines

The 2020 PSFRR studies assessed the impact of non-credible loss of DDTS-SMTS and MSS-DDTS 330 kV lines during Victoria high import conditions. The non-credible separation of DDTS-SMTS and MSS-DDTS 330 kV lines could be possible during bushfires. The IECS is intended to address risks associated with tripping of multiple 330 kV and 220 kV transmission lines on the Victoria to New South Wales interconnection between Murray Switching Station and Thomastown Terminal Station.

The scheme is armed when fire is observed within 10 km of the common corridor of the monitored lines included in the scheme and a fire warning is declared by Country Fire Authority (CFA) in the North Central or North Eastern Victorian region.

This IECS scheme was designed to shed preselected load blocks and generation, to reduce the risk of Victorian network separation due to instability and reduce operation of automatic UFLS that would occur if Victoria separates from New South Wales.

The PSFRR has considered the IECS scheme operation and identified that the scheme could be ineffective during (low probability) periods of high import to Victoria on the MSS-DDTS-SMTS 330 kV corridor[28]. The scheme remains armed until the loss of monitored lines included in the scheme are declared as credible when the CFA advises that the fire is within 5 km of the monitored lines.

The PSFRR considered the IECS as part of these non-credible studies.

The non-credible loss of DDTS-SMTS and MSS-DDTS 330 kV lines during high Victorian import levels can cause:

- Overloading of the parallel 220 kV networks between DDTS and TTS and also the 220 kV lines between DDTS and BETS. The overloading could result in transient instability of the lines and thermal overloads.
- IBR plant to be disconnected due to over/under voltages.
- Voltage collapse in the Victorian network.
- Victorian generators to lose synchronism with New South Wales and Queensland generators

[28] This finding is consistent with the original design of IECS, as it was expected that IECS itself may be insufficient to prevent instability and system separate if the non-credible contingencies covered by the scheme occurs during low probability high Victorian import periods. In this case, the frequency in the Victorian island would be managed by operation of NEM UFLS schemes.

- Multiple transmission lines and generating units to be tripped leading to a complete Victoria – New South Wales separation.
- Due to the operation of EAPT, South Australia to be islanded.

The 2020 PSFRR has considered a historical high summer Victoria import case, with flows of 1,200 MW in DDTS-SMTS 1 and 2 and 1,500 MW in DDTS-MSS 1 and 2. Simulation studies included various modes of operation of the IECS.

The following observations were made based on the study results:

- For the considered flow conditions, multiple transmission lines were found to lose transient stability following the trip of DDTS-SMTS 1 and 2 or DDTS-MSS 1 and 2 along with generation and load shedding by IECS.
- IBR plant may disconnect due to operation of over/under voltage protection.
- The EAPT scheme was found to operate, due to active power swings and low frequency in Victoria.
- Victorian generators were found to lose synchronism with New South Wales and Queensland generators.
- For the simulation studies undertaken, IECS was found to be ineffective in preventing multiple transmission line losses.

Based on the study results, the following actions are recommended:

- The performance of the IECS should be reviewed by AEMO Victorian Planning, including assessment of any necessary modifications to the scheme. This recommended review should be focused on the low probability operating conditions under which IECS operation may not be sufficient to prevent separation between Victoria and New South Wales following non-credible contingency events. In these cases, the interaction and coordination between IECS and UFLS is critically important.
- The power flow changes and network disturbances during the non-credible separation of DDTS-SMTS or DDTS-MSS lines has the potential to trigger EAPT scheme operation. This should be considered by AEMO as part of the earlier mentioned EAPT review
- Following the commissioning of the 300 MW BESS at Moorabool[29], imports into Victoria from New South Wales are expected to increase during some periods. It is recommended that operation of the IECS, including opportunities to utilise the BESS to mitigate the impact of non-credible contingency events be considered through the IECS review.

4.3 Loss of double-circuit Heywood interconnector leading to Victoria and South Australia separation

4.3.1 Background of event

South Australia is synchronously connected to the rest of the NEM via a double-circuit 275 kV AC interconnector between Heywood substation in Victoria and South East Sub Station in South Australia. The nominal operational transfer capability of the Heywood interconnector is 550 MW from South Australia to Victoria, and 600 MW from Victoria to South Australia.

The Murraylink high voltage direct current (HVDC) link also connects between Red Cliffs in Victoria and Monash in South Australia. The HVDC link including underground cable was commissioned in 2002 with a nominal capacity of 220 MW from Victoria to South Australia, and 200 MW from South Australia to Victoria

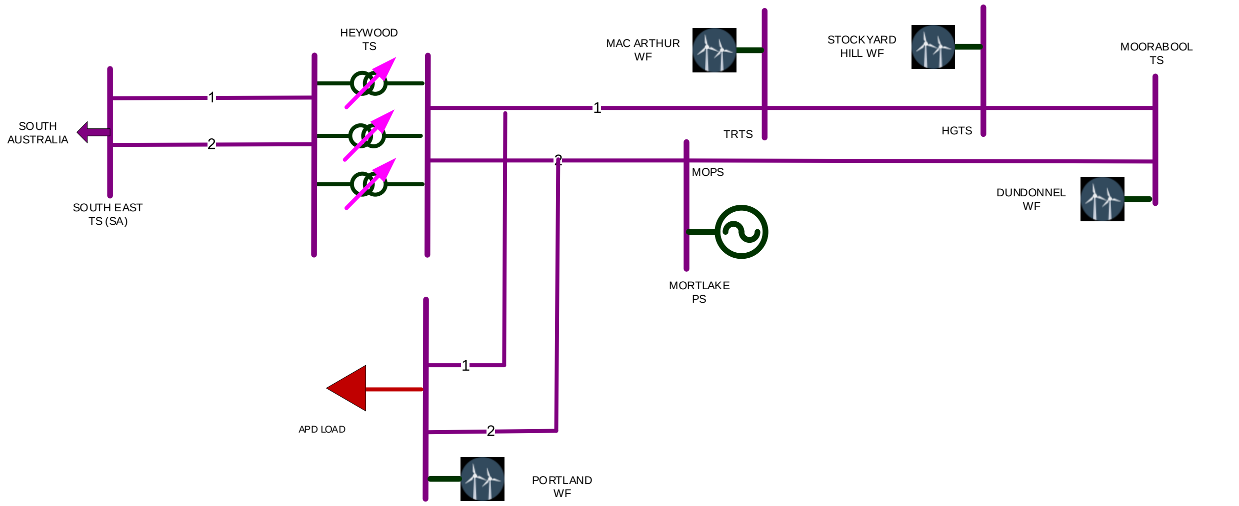
The simultaneous loss of both Heywood interconnector circuits is considered a non-credible contingency event. Figure 3 gives an overview of the transmission network around the Heywood interconnector. There are

[29] See https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery.

multiple mechanisms which may result in synchronous separation of South Australia from the rest of the NEM:

- Loss of the Heywood interconnector double-circuit 275 kV lines from Heywood to South East.
- Loss of circuits between Heywood and Moorabool such as Moorabool – Mortlake (MLTS-MOPS) and Moorabool – Haunted Gully (MLTS-HGTS) 500 kV lines in Victoria (Further discussed in Section 4.4).
- Operation of protection schemes designed to manage flows on Heywood interconnector (SIPS and EAPT schemes, described in Section 2.5).

Figure 3 Transmission network around Heywood interconnector (approximate representation)



Loss of the Heywood interconnector can lead to a high RoCoF in South Australia, due to its relatively low levels of synchronous inertia. South Australia currently has UFLS and OFGS schemes in place. However, there is concern that following a non-credible separation, in periods with low load or high distributed PV generation, the UFLS may not be adequate to arrest frequency decline or prevent cascading failure. This risk is increasing with the ongoing growth in distributed PV, which reduces the net load available to be disconnected by existing UFLS schemes. In some cases, UFLS action could even exacerbate the disturbance by disconnecting circuits operating with reverse power flows. Distributed PV also exhibits under-frequency disconnection behaviour, which further compromises effectiveness of UFLS in arresting a frequency decline.

AEMO has recently implemented an updated and expanded set of constraints on imports into South Australia across the Heywood interconnector designed to keep the RoCoF on non-credible loss of the Heywood interconnector within limits advised under regulation 88A of South Australia's *Electricity (General) Regulations 2012*. However, AEMO considers it preferable, and more transparent, to manage the identified risks under the NER protected event framework. AEMO is preparing a submission to the Reliability Panel to this effect (see Section 6.2.4 for more details)

The loss of the interconnector during high power transfers can also impact frequency performance in the remaining NEM regions.

4.3.2 Future case study model for South Australia islanded studies

The South Australian power system includes significant distributed PV, impacting the operation of UFLS at times of high distributed PV generation. To accurately predict South Australia's frequency performance in response to a separation event, it is important to capture the distributed PV frequency based trips and the impact of distributed PV embedded in UFLS distribution feeders. Hence, to appropriately represent the distributed PV and UFLS feeders, a simplified modelling approach was applied to study the 2022-23 future case studies. This section outlines the simplified PSSE model used to study the South Australia separation from HYTS and MLTS (see Section 4.4 for the latter).

The Operations and Planning Data Management System (OPDMS) NEM model includes the network at the transmission level, and the distribution network is captured as lumped load at the respective transmission substations. In contrast, the simplified modelling approach for future case studies involved the following:

- A simplified representation of the South Australia transmission network consisting of a single bus.
- All the synchronous generators included in the study are modelled as per OPDMS in load flow and dynamics.
- At present in South Australia only wind farms are participating in OFGS. All the OFGS participating wind farms are modelled as per OPDMS.
- All solar farms, and all wind farms not participating in OFGS, are represented as lumped (aggregated) units.
- The UFLS loads and underlying distributed PVs in the feeders are represented in 20 different groups according to their UFLS frequency trip settings. Under high RoCoF conditions (> 1.5 Hz/s), approximately 15% of the UFLS load in South Australia is set to trip in RoCoF when frequency falls below 49.4 Hz. All remaining distributed PVs and non-UFLS loads are modelled as a single generator and a single load, respectively.
- All distributed PV generation within the study is represented in a dynamic model with appropriate frequency trip settings to represent distributed PV under-frequency and over-frequency disconnection behaviour as well as PFR lower capability[30]. It should be noted that in results tables the distributed PV tripped quantity refers to total distributed PV disconnection due to its frequency protection or UFLS, and this does not include changes due to distributed PV dynamic frequency reduction.
- The network from South East Terminal Station (SETS) to MLTS, including the Victorian load and generation between SETS and MLTS, is included as per OPDMS.
- All synchronous and semi-scheduled generating systems are modelled to provide PFR consistent with the minimum requirements. For semi-scheduled systems, only lower PFR was assumed to be available. If PFR implementation progresses more slowly than anticipated, or shows that less response is feasible, the results presented in this report will be optimistic. The amount of PFR provided by generators can only be confirmed after the completion of PFR implementation.
- Unless mentioned for all study cases, the Hornsdale BESS was dispatched to provide ±70 MW of FFR, in alignment with the present guaranteed level of FCAS response. Other BESS were assumed to provide no response.
- The EAPT model was included, however the SIPS model was not included in the study.
- Distributed PV, system inertia and load derived from ESOO forecasts were considered in setting up study cases.
- The four synchronous condensers with flywheels planned for South Australia were included in the study.

The system performance is identified to be inadequate to meet the FOS requirement of maintaining frequency between 47 Hz and 52 Hz, and considered a fail scenario (highlighted in red in results tables) if any of the following is observed:

- The RoCoF exceeds ±3 Hz/s.
- Minimum frequency is below 47.5 Hz (allowing a buffer of 0.5 Hz over the FOS requirement).
- Maximum frequency is above 52 Hz.

AEMO also identified potential 'risk' periods, (highlighted orange in result tables), where either of the following is observed:

- The RoCoF exceeds -2 Hz/s (under importing conditions).

[30] AEMO, Response of existing PV inverters to frequency disturbances, April 2016, at https://aemo.com.au/-/media/Files/PDF/Response-of-Existing-PVInverters-to-Frequency-Disturbances-V20.pdf.

- Minimum frequency is below 48 Hz.

These risk criteria were introduced in addition to the 'fail' criteria to represent escalating risks associated with progressively more severe events. If frequency falls below 48 Hz, there are increasing risks of complications and adverse outcomes, with many power system elements operating far outside of their normal ranges.

To study the non-credible loss of MLTS-MOPS and MLTS-HGTS 500 kV lines resulting in islanding of South Australia from MLTS, the following additional modelling assumptions were applied:

- Generation from Stockyard Hill and Dundonnell wind farms is assumed to trip 150 ms after the loss of the MLTS-MOPS and MLTS-HGTS circuits due to SPS operation.
- Under import conditions into South Australia, no OFGS wind generation is assumed to be available. However, the over-frequency protection for Mortlake Power Station and the RoCoF sensitive protection for Macarthur Wind Farm have been modelled.

4.3.3 Historical case studies – South Australia export

A set of six boundary condition snapshots was selected by exploring system conditions associated with high power transfer from South Australia to Victoria (South Australia export).

The double-circuit trip of the Heywood interconnector (HIC) was simulated using each boundary condition snapshot, and the frequency response in each region of the NEM reviewed. Table 17 presents the peak or frequency nadir simulated in each region and the inertia provided by synchronous generators in South Australia and Victoria for each boundary condition for South Australia export. If South Australia's OFGS was triggered, the combined wind farm output that was tripped is noted in the last column. In addition, Waterloo Wind Farm would also trip if the frequency goes above 51 Hz for more than 200 ms. Due to modelling issues, Waterloo Wind Farm was modelled as a negative load for the purposes of simulation, therefore its OFGS response was not represented in these studies.

Table 17 Simulated frequencies following the trip of the Heywood interconnector on South Australia export for boundary condition snapshots

Case ID	Inertia (GWs)		HIC (MW)	Regional frequency peak/nadir (Hz)					OFGS utilised (MW)
	SA	VIC		QLD	NSW	VIC	SA	TAS	
1	7.4	14.7	636	49.58	49.58	49.58	51.30	48.70	SA - 225
3	5.3	11.2	556	49.70	49.70	49.70	51.43	49.60	SA - 51
4	4.3	12.9	588	49.63	49.63	49.63	51.35	49.90	SA - 138
5	7.4	14.7	596	49.64	49.64	49.64	51.35	49.05	SA - 235
6	5.3	15.8	588	49.60	49.60	49.60	51.30	48.85	SA - 86
1A	6.2	13.7	586	49.66	49.66	49.66	51.05	49.10	SA - 109

For each of the boundary condition snapshots, the simulated frequency in each region remains within the limits specified in the FOS:

- Many of the cases produce a similar maximum frequency rise in South Australia and a similar frequency fall in other regions of the NEM; as such there is no clear worst-case boundary condition:
  - The South Australia OFGS scheme operated for all Heywood interconnector trip contingency studies, although some differences in the participating wind farms are visible across cases. This is due to the specific conditions in each snapshot in terms of wind farm status and their pre-contingency dispatch levels.

- Complete utilisation of OFGS generators was not observed in any of the historic case simulations.
- UFLS did not operate in the remainder of NEM regions in any of the cases studied.

4.3.4 Future 2022-23 case studies – South Australia export

Future South Australia export study cases were set up based on historical snapshot Case 4 conditions described in Section 4.3.2 for the Heywood interconnector contingency. The Heywood interconnector export level was adjusted to its maximum level and the ESOO 2022 projected demand and distributed PV forecasts for periods of export from South Australia to Victoria were modelled. The double-circuit loss of the Heywood interconnector has been applied to the simplified model resulting in South Australia being islanded from the rest of the NEM.

The proportion of OFGS to non-OFGS wind generation was varied in alignment with historical trends of wind generation during high South Australia export conditions to test onerous conditions for over-frequency management. Two cases were developed based on historical Case 4: one with a low level of online OFGS wind generation, and another with a medium level. The study case data for the future power system conditions with South Australia export is summarised in Table 18.

Table 18 Future scenario South Australia study case data for South Australia islanding from HYTS when South Australia is exporting

Case ID	SA inertia (GWs)	HIC export (MW)	SA load (MW)	Net UFLS load (MW)	Net distributed PV (MW)	OFGS wind generation (MW)	OFGS wind farm/non-OFGS wind farm
4_a	6.266	640	1,748	1,460	1,340	219	0.3
4_b	6.266	640	1,748	1,460	1,340	317	0.5

Table 19 shows the study results with PFR when South Australia is exporting.

Table 19 Future scenario South Australia study cases results for South Australia islanding from HYTS with primary frequency response when South Australia is exporting

Case ID	Freq nadir (Hz)	Freq peak (Hz)	Freq ROCOF (Hz/s)	UFLS load tripped (MW)	UFLS load tripped (%)	Distributed PV trip (MW)	SA OFGS wind farms tripped (%)	OFGS wind generation (MW)
4_a	-	51.23	1.91	-	-	322.91	48.34	219
4_b	-	51.21	1.91	-	-	322.91	48.34	317

Observations from the study results are:

- For all cases, the system frequency is observed to remain within the limits of the FOS.
- Following OFGS action, South Australia over-frequency is arrested and no subsequent under-frequency is observed (that is, the reduction in distributed PV is due to its dynamic characteristics only, and is not associated with UFLS operation).
- Even with low South Australia OFGS availability, the total OFGS generation was not found to be entirely exhausted. However, future reductions in OFGS generation, due to the displacement of existing OFGS generators by new generators, would reduce the margin available.

Table 20 shows the study results with no PFR from large synchronous and semi-scheduled generating systems for South Australia export at the time of loss of the Heywood interconnector.

Table 20 Future scenario South Australia study cases results for South Australia islanding from HYTS without primary frequency response when South Australia is exporting

Case ID	Freq nadir (Hz)	Freq peak (Hz)	Freq ROCOF (Hz/s)	UFLS load tripped (MW)	UFLS load tripped (%)	Distributed PV reduction (MW)	SA OFGS wind farms tripped (%)	OFGS wind generation (MW)
4_a	-	51.64	1.97	-	-	284.29	57.67	219
4_b	-	51.35	1.97	-	-	271.42	55.88	317

Observations from the study results are:

- Comparing Table 19 and Table 20, the cases with no PFR show a higher frequency peak and more generation shed as part of OFGS, as well as a much slower frequency recovery.

4.3.5 Historical case studies – South Australia import

A set of six boundary condition snapshots was selected exploring system conditions associated with high power transfer from Victoria to South Australia (South Australia import).

The double-circuit trip of the Heywood interconnector was simulated using each boundary condition snapshot and the frequency response in each region of the NEM reviewed. Table 21 presents the frequency peak or nadir simulated in each region and notes the Heywood interconnector transfer conditions and the inertia provided by synchronous generators in South Australia and Victoria for each boundary condition. If UFLS operated in South Australia, the amount of load shed (excluding DPV) is noted in the last column. The table also includes the results obtained for a future case study which projected the conditions in case 10A to 2022-23.

Table 21 Simulated frequencies following the trip of the Heywood interconnector on South Australia import for boundary condition snapshots

Case ID	Inertia (GWs)		HIC (MW)	Regional frequency peak/nadir (Hz)					UFLS utilised region (MW)
	SA	VIC		QLD	NSW	VIC	SA	TAS	
7	5.3	18.0	616	50.28	50.28	50.28	48.20	50.34	SA 474
8	5.3	15.5	638	50.29	50.29	50.29	48.40	50.36	SA 373
9	5.3	16.4	648	50.29	50.29	50.29	48.20	50.38	SA 410
10	5.3	16.0	640	50.19	50.19	50.19	47.91	50.15	SA 472
10A	5.3	17.7	618	50.25	50.25	50.25	47.90	50.25	SA 465
11	5.3	16.0	616	50.28	50.28	50.28	48.0	50.40	SA 400

For each of the boundary condition snapshots, the frequency in each region remains within the limits specified in the FOS:

- All of the boundary conditions simulated resulted in UFLS in South Australia operating to arrest the reduction in frequency following the non-credible contingency event.
- In all cases the UFLS coupled with assumed PFR from synchronous generators and FFR from Hornsdale BESS was sufficient to maintain South Australia frequency within the limits specified in the FOS.

4.3.6 Future 2022-23 case studies – South Australia import

Table 22 provides the study cases considered for future 2022-23 involving the loss of the Heywood interconnector at HYTS, and the study results. Two case studies were considered: cases 1 to 3 refer to dispatch scenarios that could eventuate if the Heywood interconnector import constraints were not applied, and cases 4 to 8 refer to cases where the Heywood interconnector import is limited by the constraints associated with South Australian electricity regulations, described in Section 6.2.

Table 22 Future scenario South Australia study cases for South Australia islanding from HYTS when South Australia importing with primary frequency response

Case ID	SA inertia (GWs)	HIC import (MW)	SA load (MW)	Underlying UFLS load (MW)	Net distributed PV (MW)	SA freq nadir (Hz)	SA RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	Net DER tripped (MW)	Percentage UFLS tripped	Heywood import constraints binding
1	6.266	485	1,702	1,282	841	47.56	-1.87	1,113	738	87%	No
2	6.266	522	1,902	1,458	1,003	47.49	-2.03	1,265	885	87%	
3	6.266	485	1,943	1,500	1,110	47.47	-1.86	1,480	1,021	99%	
4	8.9045	317	1,702	1,282	841	48.35	-0.74	557	442	43%	Yes
5	8.9045	314	1,902	1,458	1,003	48.31	-0.73	627	527	43%	
6	8.9045	268	1,943	1,500	1,110	48.37	-0.59	640	583	43%	
7	6.266	544	1,926	1,437	517	48.39	-2.13	772	280	54%	No
8	6.266	533	2,209	1,682	701	48.47	-2.08	786	334	47%	

Observations from the study results are:

- Cases 1 to 3 are considered as having failed since the frequency nadir is either below the 'fail' limit of 47.5 Hz or close to the limit. Further, the cases required almost complete usage of UFLS loads.
- Cases 4 to 8 are found to be able to manage the frequency within limits, with sufficient UFLS load to arrest frequency decline, and an additional margin of UFLS load available for further tripping if required. High RoCoF values marginally exceeding the defined risk threshold are, however, observed for cases 7 and 8.

To estimate the impact of PFR governor response and the absence of regional FCAS, Cases 4 to 8 in Table 22 were repeated with no governor response from synchronous or semi-scheduled generating systems. The Hornsdale BESS continues to provide FFR in this case. The study results are shown in Table 23.

Table 23 Future scenario South Australia study cases for South Australia islanding from HYTS when South Australia on import without primary frequency response

Case ID	SA inertia (GWs)	HIC import (MW)	SA load (MW)	Underlying UFLS load (MW)	Net distributed PV (MW)	SA freq nadir (Hz)	SA RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	Net DER tripped (MW)	Percentage UFLS tripped
4	8.9045	317	1,702	1,282	841	47.80	-0.75	928	656	72%
5	8.9045	314	1,902	1,458	1,003	47.80	-0.74	1,040	782	71%
6	8.9045	268	1,943	1,500	1,110	47.79	-0.60	1,070	866	71%
7	6.266	544	1,926	1,437	517	48.32	-2.14	772	282	54%
8	6.266	533	2,209	1,682	701	48.38	-2.09	920	379	55%

Observations from the study results are:

- Comparing the study results in Table 22 and Table 23, the amount of additional UFLS load required to arrest frequency above 47.5 Hz is significantly larger in the cases without PFR. Therefore the amount of UFLS load shed in the event of separation at Heywood (for a given Heywood interconnector import and South Australia inertia) will be higher if PFR is not provided by generators.
- The studies without PFR have a lower frequency nadir than those with PFR (Table 22 and Table 23). As shown in Table 23, cases 4 through 6 have a frequency nadir of ~47.8 Hz, placing them in the 'risk' category with increased operational risks. With PFR, the frequency nadir remains above 48.3 Hz for the same set of cases, representing a much safer operating zone.
- Under conditions of higher post-disturbance RoCoF, such as in cases 7 and 8, the effect of PFR on the frequency nadir and total load shed is reduced due to the short time for sufficient governor action to occur, highlighting the need for further studies into South Australia separation. These studies will be undertaken as the part of the proposed protected event submission.
- The results in Table 22 assumes that all large generating systems provide PFR in accordance with current NER requirements.

4.4 Double-circuit trip of MLTS-MOPS and MLTS-HGTS, leading to Victoria and South Australia separation

4.4.1 Background of event

As described in Section 4.3.1, another possible separation of South Australia from the rest of the NEM is through loss of Moorabool – Mortlake (MLTS-MOPS) and Moorabool – Haunted Gully (MLTS-HGTS) 500 kV lines in Victoria, such as on 31 January 2020. The frequency risks in South Australia for this contingency are similar to those discussed in section 4.3.1.

4.4.2 Historical case studies – South Australia export

The same set of six boundary condition snapshots with high power transfer from South Australia to Victoria (South Australia export) mentioned in Section 4.3.2 was used to carry out simulations for this non-credible contingency event.

The double-circuit trip of MLTS-MOPS and MLTS-HGTS was simulated using each boundary condition snapshot and the frequency response in each region of the NEM reviewed. All simulations modelled the EAPT scheme and any generator inter-trips triggered by loss of the MLTS-MOPS and MLTS-HGTS circuits.

Table 24 presents the peak or frequency nadir simulated in each region and notes the Heywood interconnector transfer conditions and the inertia provided by synchronous generators in South Australia and Victoria for each boundary condition. If South Australia's OFGS was triggered, the OFGS wind farms' megawatts tripped are noted in the last column. It should be noted that the simulation studies do not include the UFLS models of Tasmania, hence any frequency drop below 48 Hz in Tasmania indicates UFLS action.

Table 24 Simulated frequencies following the trip of the MLTS-MOPS and MLTS-HGTS on South Australia export for boundary condition snapshots

Case ID	Inertia (GWs)		HIC (MW)	Regional frequency peak/nadir (Hz)					OFGS utilised (MW)
	SA	VIC		QLD	NSW	VIC	SA	TAS	
1	7.4	14.7	636	49.78	49.78	49.78	51.00	49.81	SA - 47
3	5.3	11.2	556	49.69	49.69	49.69	51.10	49.50	SA - 39
4	4.3	12.9	588	49.65	49.65	49.65	51.10	49.93	SA – None, VIC – MacArthur WF (404 MW)
5	7.4	14.7	596	49.82	49.82	49.82	51.00	49.83	SA - None
6	5.3	15.8	588	49.52	49.52	49.52	51.10	48.30	SA - 66
1A	6.2	13.7	586	49.68	49.68	49.68	51.10	49.33	SA – 43

For each of the boundary condition snapshots, the simulated frequency in each region remains within the limits specified in the FOS:

- Many of the cases produce a similar maximum frequency rise in South Australia and a similar frequency fall in other regions of the NEM; as such there is no clear worst-case boundary condition identified from these cases.
- The South Australia OFGS scheme operates only in some of the cases. By comparison, the over-frequency in South Australia and the amount of OFGS wind generation tripped for the MLTS-MOPS and MLTS-HGTS trip contingency was less than for the Heywood interconnector trip contingency. This is due to APD load remaining connected to the South Australia system. Should APD load also trip (as it did on 31 January 2020), this would exacerbate the frequency rise and is likely to lead to further OFGS action.
- Complete utilisation of OFGS generation was not observed in any of the simulations.
- UFLS did not operate in the remainder of NEM regions in any of the cases studied.
- Case 4 was the worst case in terms of over-frequency in South Australia for MLTS-MOPS and MLTS-HGTS trip contingency, reaching a maximum of 51.1 Hz.

4.4.3 Future 2022-23 case studies – South Australia export

The studies for the loss of the double-circuit MLTS-MOPS and MLTS-HGTS under South Australia export conditions for future scenarios adopted the same cases and assumptions as for the double-circuit loss of the Heywood interconnector in Table 18. This included creating a low OFGS and a medium OFGS scenario by varying the proportion of OFGS to non-OFGS wind generation in alignment with historical trends during high South Australia export conditions.

In the cases in Table 25, a total of 123 MW of solar farms were dispatched out of the maximum solar farm capacity of 315 MW in South Australia; hence, when the solar farms are dispatched to full capacity there is a potential to displace the wind farms and thereby reduce the amount of net OFGS dispatch. AEMO has undertaken sensitivity studies relating to output of generation between MLTS and HYTS as well as any potential closure of the APD smelter. While no retirement decisions have been announced, it is important to understand the impacts such a future decision may have on network operations and planning.

The study case data for the future power system conditions with South Australia export is summarised in Table 25 and Table 26.

Table 25 Future scenario South Australia study case data for South Australia islanding from MLTS when South Australia is exporting, South Australia conditions

Case ID	SA inertia (GWs)	HIC export (MW)	SA load (MW)	Underlying UFLS load (MW)	Net distributed PV (MW)	OFGS wind generation (MW)	OFGS WF/non OFGS WF
4_a	6.266	640	1,748	1,460	1,340	219	0.3
4_b	6.266	640	1,748	1,460	1,340	317	0.5

Table 26 Future scenario South Australia study case data for South Australia islanding South Australia is exporting, conditions between HYTS and MLTS

Scenario	Case ID	Net generation between MLTS and HYTS (MW)	Power flow to MLTS (MW)	APD load (MW)	Generation inertia between MLTS and HYTS (GWs)
1 – High generation between MLTS and HYTS	4_a	2,096	2,164	450	3.976
	4_b	2,096	2,164	450	3.976
2 – High generation between MLTS and HYTS, no APD	4_a	2,096	2,658	0	3.976
	4_b	2,096	2,658	0	3.976
3 – Low generation between MLTS and HYTS, no APD	4_a	1,512	2,092	0	0
	4_b	1,512	2,092	0	0

Table 27 shows the study results including PFR during the double-circuit loss of trip of MLTS-MOPS and MLTS-HGTS for South Australia export. Observations from the study results are:

- Scenario 1 – high generation between MLTS and HYTS.
  - The frequency is maintained within limits, however the available OFGS is almost exhausted, indicating a very small margin. This highlights the importance of increasing the amount of generation participating in the OFGS, potentially including solar farms.
  - In future, if more generators are added to OFGS then the availability of more OFGS generation will help reduce the frequency peak during over-frequency events; however, proper trip setting coordination is required to avoid over-tripping. Excessive OFGS trips could lead to a frequency reversal, and potentially result in UFLS operation if the frequency were to fall below 49 Hz.
- Scenario 2 – high generation between MLTS and HYTS without APD.
  - With APD load offline, a more severe over-frequency is observed compared to Scenario 1. The frequency peak is observed to breach the 52 Hz limit and all available OFGS is utilised. This indicates that existing OFGS generation would be inadequate to manage the frequency in this scenario. If frequency exceeded 52 Hz, this is treated as fail case.
- Scenario 3 – high generation between MLTS and HYTS, no APD and Mortlake Power Station offline.

- The frequency is marginally maintained within the 52 Hz limit and all available OFGS is practically exhausted. This is more severe than Scenario 1 but less than Scenario 2.
- Due to the absence of Mortlake Power Station, it is possible that system strength between HYTS and MLTS is reduced after separation to lower levels which may are not adequate for wind farms in the region to operate satisfactorily. This has not been assessed in detail in this report, but is recommended for further analysis using Electromagnetic Transient (EMT) modelling tools.

- For all scenarios, the value of RoCoF is not captured due to the presence of large transients in the frequency trace immediately after the contingency.
- Due to the presence of high generation between HYTS and MLTS, following the separation of South Australia, frequency in South Australia rises to high values. Following this peak, wind farms between MLTS and HYTS trip due to protection operation, leading to a drop in frequency and change in Heywood interconnector power flow. This results in EAPT operation in all cases.
- Similar to the South Australia import scenario (see Section 4.4.5) it is possible for the SIPS Stage 2 scheme to trigger due to high transient active power swings into South Australia immediately after the contingency, resulting in load shedding through SIPS action.
- The presence of a high level of generation between MLTS and HYTS makes South Australia separation from MLTS more onerous than from HYTS and results in severe South Australia over-frequency. Hence adaptation of the EAPT should be considered to immediately disconnect South Australia following separation from MLTS to avoid high frequency in South Australia.

Table 27 Future scenario South Australia study cases results for South Australia islanding from MLTS with primary frequency response when South Australia is exporting

Scenario	Case ID	Freq nadir (Hz)	Freq peak (Hz)	Underlying UFLS load tripped (MW)	Underlying UFLS load tripped (%)	Distributed PV trip (MW)	SA OFGS WF tripped (%)	OFGS wind generation (MW)	VIC Macarthur **Wind Farm** trip (%)	EAPT SPS operation
1 – High generation between MLTS and HYTS	4_a	48.91	51.81	128	9%	538	92%	219	100%	Yes
	4_b	48.83	51.71	275	19%	637	77%	317	100%	Yes
2 – High generation between MLTS and HYTS, no APD	4_a	-	52.23	-	-	-	100%	219	100%	-
	4_b	-	52.21	-	-	-	100%	317	100%	-
3 – High generation between MLTS and HYTS, no APD and Mortlake PS offline	4_a	49.02	51.98	0	0%	378	100%	219	100%	Yes
	4_b	48.80	51.92	273	19%	647	92%	317	100%	Yes

Table 28 Shows the study results with no PFR from synchronous and semi-scheduled generating systems during the MLTS-MOPS and MLTS-HGTS contingency for South Australia export.

Table 28 Future scenario South Australia study cases results for South Australia islanding from MLTS without primary frequency response when South Australia is exporting

Scenario	Case ID	Freq nadir (Hz)	Freq peak (Hz)	Underlying UFLS load tripped (MW)	Underlying UFLS load tripped (%)	Distributed PV trip (MW)	SA OFGS WF tripped (%)	OFGS wind generation (MW)	VIC Macarthur WF trip (%)	EAPT SPS operation
1 – High generation between MLTS and HYTS	4_a	-	52.07	-	-	-	100	219	100	-
	4_b	48.80	51.97	301	21%	652.38	100	317	100	YES
2 – High generation between MLTS and HYTS, no APD	4_a	-	52.26	-	-	-	100	219	100	-
	4_b	-	52.24	-	-	-	100	317	100	-
3 – High generation between MLTS and HYTS, no APD and Mortlake PS offline	4_a	-	52.07	-	-	-	100	219	100	-
	4_b	-	52.02	-	-	-	100	317	100	-

Observations from the study results are:

- Comparing Table 27 and Table 28, the cases with the PFR response show a lower amount of OFGS generation tripping and a lower frequency peak compared to the cases without the PFR response.
- The study results show that the absence of PFR results in the inability to manage frequency within limits for all cases except Scenario 1 Case 4_b. In all cases even with a medium level of OFGS wind generation available, all OFGS is observed to be exhausted.

4.4.4 Historical case studies – South Australia import

The same set of six boundary condition snapshots with high power transfer from Victoria to South Australia (South Australia import) discussed in Section 4.3.5 was used for carrying out simulations for non-credible separation of South Australia from MLTS.

The double-circuit trip of MLTS-MOPS and MLTS-HGTS was simulated using each boundary condition snapshot and the frequency response in each region of the NEM reviewed. All simulations modelled the EAPT scheme and any inter-trips of generators triggered by loss of MLTS-MOPS and MLTS-HGTS circuits. Table 29 presents the frequency peak or nadir observed in each region and notes the Heywood interconnector transfer conditions and the inertia provided by synchronous generators in South Australia and Victoria for each boundary condition. If UFLS operated in South Australia, the amount of load shed is noted in the last column.

Table 29 Simulated frequencies following the trip of the MLTS-MOPS and MLTS-HGTS on South Australia import for boundary condition snapshots

Case ID	Inertia (GWs)		HIC (MW)	Regional Frequency Peak/Nadir (Hz)					UFLS utilised region (MW)
	SA	VIC		QLD	NSW	VIC	SA	TAS	
7	5.3	18.0	616	50.44	50.44	50.44	48.30	51.50	SA 417
8	5.3	15.5	638	50.35	50.35	50.35	48.30	50.85	SA 373
9	5.3	16.4	648	50.42	50.42	50.42	48.20	51.10	SA 430
10	5.3	16.0	640	50.35	50.35	50.35	47.80	50.90	SA 472
10A	5.3	17.7	618	50.34	50.34	50.34	47.80	50.25	SA 465
11	5.3	16.0	616	50.42	50.42	50.42	47.80	51.10	SA 400

For each of the boundary condition snapshots, the frequency in each region remains within the limits specified in the FOS:

- All of the boundary conditions simulated resulted in UFLS in South Australia to arrest the reduction in frequency following the non-credible contingency event.
- In all cases the UFLS coupled with the PFR from synchronous generators was sufficient to maintain South Australia frequency within the limits specified in the FOS.
- The EAPT scheme operated as designed for MLTS-MOPS and MLTS-HGTS contingencies in all cases.
- Case 10A was the most severe boundary condition for both non-credible contingencies in terms of frequency excursion in South Australia, with a nadir of 47.90 Hz for a Heywood interconnector separation event and 47.80 Hz for separation at MLTS-MOPS and MLTS-HGTS 500 kV lines. Controlling frequency to this level required shedding 465 MW of load in South Australia.

4.4.5 Future scenario 2022-23 studies – South Australia import

HIC contingency cases 4 to 8 have been considered to assess future scenario studies involving the loss of the double-circuit MLTS-MOPS and MLTS-HGTS (see Section 4.3.6). These cases result in synchronous separation of South Australia from the rest of the NEM. The case setup accounts for limits associated with South Australian electricity regulations, described in Section 6.2. To assess the impact of generation between MLTS and HYTS and the possible future shutdown of the APD load, three additional scenarios were developed from the cases in Section 4.3.6, as summarised in Table 30.

Table 30 Future scenario South Australia study case data for South Australia islanding from MLTS with South Australia import

Scenario	Case ID	SA inertia (GWs)	HIC import (MW)	SA load (MW)	Underlying UFLS load (MW)	Net distributed PV (MW)	Generation inertia between MLTS and HYTS (GWs)	Net generation between MLTS and HYTS (MW)	Power flow to MLTS (MW)	APD load (MW)
1 – High generation between MLTS and HYTS	4	8.9045	317	1,702	1,282	841	3.976	1,980	1,203	450
	5	8.9045	314	1,902	1,458	1,003	3.976	1,980	1,206	450
	6	8.9045	268	1,943	1,500	1,110	3.976	1,980	1,252	450
	7	6.266	544	1,926	1,437	517	3.976	1,980	963	450
	8	6.266	533	2,209	1,682	701	3.976	1,980	974	450
2 – High generation between MLTS and HYTS, no APD	4	8.9045	317	1,702	1,282	841	3.976	1,980	1,649	0
	5	8.9045	314	1,902	1,458	1,003	3.976	1,980	1,652	0
	6	8.9045	268	1,943	1,500	1,110	3.976	1,980	1,698	0
	7	6.266	544	1,926	1,437	517	3.976	1,980	1,411	0
	8	6.266	533	2,209	1,682	701	3.976	1,980	1,422	0
3 – Low generation	4	8.9045	317	1,702	1,282	841	0	0	-772	450
	5	8.9045	314	1,902	1,458	1,003	0	0	-769	450
	6	8.9045	268	1,943	1,500	1,110	0	0	-722	450
	7	6.266	544	1,926	1,437	517	0	0	-1,018	450
	8	6.266	533	2,209	1,682	701	0	0	-1,007	450

Table 31 shows the study results for the scenarios with PFR.
Observations from the study results are:

- For all scenarios the system frequency is observed to be managed to within limits. However, in some cases the RoCoF was above the limit threshold of 3 Hz/s and in others above the risk threshold of 2 Hz/s (highlighted in red and orange respectively). For the high generation scenarios, there were high magnitude frequency transients present immediately following the line separation at MLTS due to several generation trips. RoCoF during these frequency transient periods was therefore not calculated.
- Scenario 1 – high generation between MLTS and HYTS.
  - Following the separation, due to the presence of high generation between MLTS and HYTS, frequency rose sharply and excess generation between MLTS and HYTS caused Heywood interconnector import to sharply increase before it reduced due to the trip of wind farms approximately 200 ms after separation. Large voltage angle swings occurred during the initial increase in import level. Although the SIPS model was not explicitly represented in this study, based on review of the study outcomes this response has the potential to initiate Stage 2 of the scheme resulting in load shedding.
  - After the trip of the wind farms, the frequency reversed below 49 Hz, initiating South Australia UFLS and APD tripping.
  - Due to the loss of APD load, the Heywood interconnector import increases significantly, potentially leading to SIPS Stage 1 action.

- South Australia frequency and Heywood interconnector flows are included in Figure 34 in the Appendix section corresponding to Scenario 1 Case 7.
- For all the Scenario 1 cases, EAPT did not operate.
- A separate simulation was undertaken to assess the impact if the EAPT scheme had operated for cases 7 and 8 (see Figure 35 in the Appendix). The results for these simulations were similar to the loss of the Heywood interconnector under import conditions (see Section 4.3.6) with the outcome being a much lower frequency nadir for South Australia (approximately 48.2 Hz) and significantly more South Australia UFLS load shed. This indicates that the operation of EAPT in this case will reduce the risk to levels equivalent to South Australia islanding from HYTS.

- Scenario 2 – high generation between MLTS and HYTS, no APD.
  - The results were similar to Scenario 1 above with potential to activate SIPS action.
  - EAPT did not operate in any of the cases.
  - The studies indicate that following separation there is potential for the Heywood interconnector to lose stability. Further studies by AEMO and ElectraNet are recommended to confirm whether upgraded SIPS (WAPS) would operate to avoid this condition.
- Scenario 3 – low generation between MLTS and HYTS.
  - The frequency was managed within limits with sufficient UFLS load to arrest the frequency decline, similar to what was observed with the Heywood interconnector contingency for South Australia import conditions (see Section 4.3.6).
  - Post-disturbance, a very high initial RoCoF was observed which significantly reduces upon the operation of the EAPT scheme to separate the APD load from South Australia. The RoCoF values for cases 7 and 8 are observed to exceed the 3 Hz/s acceptance level, while for cases 4, 5 and 6, the risk level of 2 Hz/s is exceeded. The risk due to high RoCoF could be reduced if the EAPT schemes were to operate faster.

Table 31 Future scenario South Australia study cases results for South Australia islanding from HYTS with South Australia import and primary frequency response

Scenario	Case ID	Freq nadir (Hz)	Freq peak (Hz)	Freq RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	Underlying UFLS load tripped (%)	Generation tripped (MW)	EAPT SPS operation
1 – High generation between MLTS and HYTS	4	49.57	50.41	-	-	-	1,171	No
	5	49.57	50.42	-	-	-	1,171	No
	6	49.60	50.44	-	-	-	1,171	No
	7	48.92	50.58	-	540	29%	1,171	No
	8	48.93	50.36	-	360	17%	1,171	No
2 – High generation between MLTS and HYTS, no APD	4	-	51.03	-	-	-	1,171	No
	5	-	51.02	-	-	-	1,171	No
	6	-	51.02	-	-	-	1,171	No
	7	-	50.73	-	-	-	1,171	No
	8	-	50.74	-	-	-	1,171	No
	4	48.39	-	-2.422	1,010	58%	-	Yes

Scenario	Case ID	Freq nadir (Hz)	Freq peak (Hz)	Freq RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	Underlying UFLS load tripped (%)	Generation tripped (MW)	EAPT SPS operation
3 – Low generation	5	48.38	-	-2.413	1,079	56%	-	Yes
	6	48.46	-	-2.278	996	51%	-	Yes
	7	48.28	-	-5.139	1,224	65%	-	Yes
	8	48.32	-	-5.112	1,372	64%	-	Yes

To estimate the impact of PFR governor response and the absence of regional FCAS, the study cases in Table 30 were repeated with no governor response from synchronous and semi-scheduled generating systems. The study results are included in Table 32.

Table 32 Future scenario South Australia study cases results for South Australia islanding from HYTS with South Australia import without primary frequency response

Scenario	Case ID	Freq nadir (Hz)	Freq peak (Hz)	Freq RoCoF (Hz/s)	Underlying UFLS load tripped (MW)	Underlying UFLS load tripped (%)	Generation tripped (MW)	EAPT SPS operation
1 – High generation between MLTS and HYTS	4	49.56	50.42	-	-	-	1,171	No
	5	49.56	50.42	-	-	-	1,171	No
	6	49.60	50.45	-	-	-	1,171	No
	7	48.92	51.01	-	542	29%	1,171	No
	8	48.92	51.00	-	546	26%	1,171	No
2 – High generation between MLTS and HYTS, no APD	4	-	51.30	-	-	-	1,463	No
	5	-	51.23	-	-	-	1,171	No
	6	-	51.26	-	-	-	1,463	No
	7	-	51.00	-	-	-	1,171	No
	8	-	51.01	-	-	-	1,171	No
3 – Low generation	4	47.89	-	-2.422	1,297	75%	-	Yes
	5	47.90	-	-2.413	1,410	74%	-	Yes
	6	47.89	-	-2.278	1,439	74%	-	Yes
	7	48.27	-	-5.140	1,260	67%	-	Yes
	8	48.31	-	-5.113	1,372	64%	-	Yes

Observations from the study results are:

- Comparing Table 31 and Table 32, for cases where UFLS activates, the amount of additional UFLS load required to manage the frequency within 47.5 Hz is generally larger in the cases without PFR. Therefore, the amount of UFLS which occurs in the event of separation at Moorabool (for a given operating point) will be higher if PFR is not provided by generators. For some cases (Scenario 2 Cases 4 to 6) the amount of generation tripped is also reduced where PFR is enabled.

- The studies without PFR generally have a lower frequency nadir and higher frequency peak than those with PFR. As shown in Table 32, Scenario 3 cases 4 through 6 have a frequency nadir of ~47.9 Hz, placing them in the 'risk' category with increased power system operational risks. With PFR, the frequency nadir remains above 48.2 Hz for the same set of cases, representing a lower risk of uncontrolled frequency response.

4.5 Loss of double-circuit Calvale – Halys transmission line between Central and South Queensland

4.5.1 Background of event

The double-circuit Calvale – Halys 275 kV transmission corridor transfers power from generation in Central and North Queensland to load centres and interconnectors further south. Outages on the Calvale – Halys double-circuit have the potential to overload parallel circuits, resulting in instability, protection operation and subsequent islanding of central and north Queensland. Depending upon CQ-SQ active power transfers, this could result in over-frequency in CQ and under-frequency in the remainder of the NEM and possible QNI instability.

The CQ-SQ SPS implemented by Powerlink is designed to trip up to two Callide generating units depending on the CQ-SQ flow, following a double-circuit trip of the Calvale – Halys line. The SPS is intended to minimise the risk of a complete separation of CQ-SQ, but is expected to be effective only for CQ-SQ transfers up to 1,700 MW[31].

AEMO has assessed power system frequency risks associated with a Calvale – Halys 275 kV double-circuit contingency. Given QNI transfers impact the likelihood of overloading on circuits parallel to Calvale – Halys, the assessment considers both QNI import and export conditions.

4.5.2 Historical case studies – QNI export

A set of six boundary condition snapshots were selected exploring system conditions associated with high transfers from CQ to SQ and export of power across QNI from Queensland. The double-circuit trip of the Calvale – Halys transmission lines was simulated using each boundary condition snapshot and the frequency response in each region of the NEM reviewed.

Table 33 presents the frequency nadir simulated in each region, as well as CQ-SQ and QNI transfer conditions for each boundary condition. It should be noted that the simulation studies do not include the UFLS models of Tasmania and hence any frequency drop below 48 Hz in Tasmania indicates UFLS action.

If CQ-SQ SPS is ineffective, power transfers on the remaining CQ-SQ circuits could exceed transient stability limits. Any instability detected on those remaining CQ-SQ circuits or across QNI is noted in the last column of the table. Loss of synchronism across the remaining CQ-SQ circuits is likely to produce a large change in power flow across QNI and may result in loss of synchronism between Queensland and New South Wales. Cases where instability occurred did not run to completion and hence there is no frequency nadir provided. The table also includes the results obtained for a future case study which projected the conditions in Case 3 to 2022-23.

Powerlink has identified that during periods of high renewable generation in the north of the state, disconnection of synchronous generation can reduce system strength, leading to stability issues. Powerlink has commenced an investigation of an enhanced SPS that provides effective control actions to mitigate the CQ-SQ stability risks following the double-circuit loss of the Calvale to Halys transmission lines. To this end,

[31] Further details of the CQ-SQ scheme are provided in section 6.3 of the 2019 Powerlink Transmission Annual Planning Report (TAPR), at https://www.powerlink.com.au/reports/transmission-annual-planning-report-2019.

Powerlink is investigating the implementation of WAMPAC architecture into the CQ-SQ SPS to allow approximately 600 MW of renewable generators in North Queensland to be tripped by the SPS.

Sensitivity studies were carried out to examine whether the tripping of IBR is effective in avoiding instability on the remaining CQ-SQ circuits following the non-credible contingency event. The results in Table 33 model the existing SPS which trips up to two Callide generating units.

Table 33 Frequency simulated following the trip of Calvale to Halys line with QNI exporting for each boundary condition snapshot

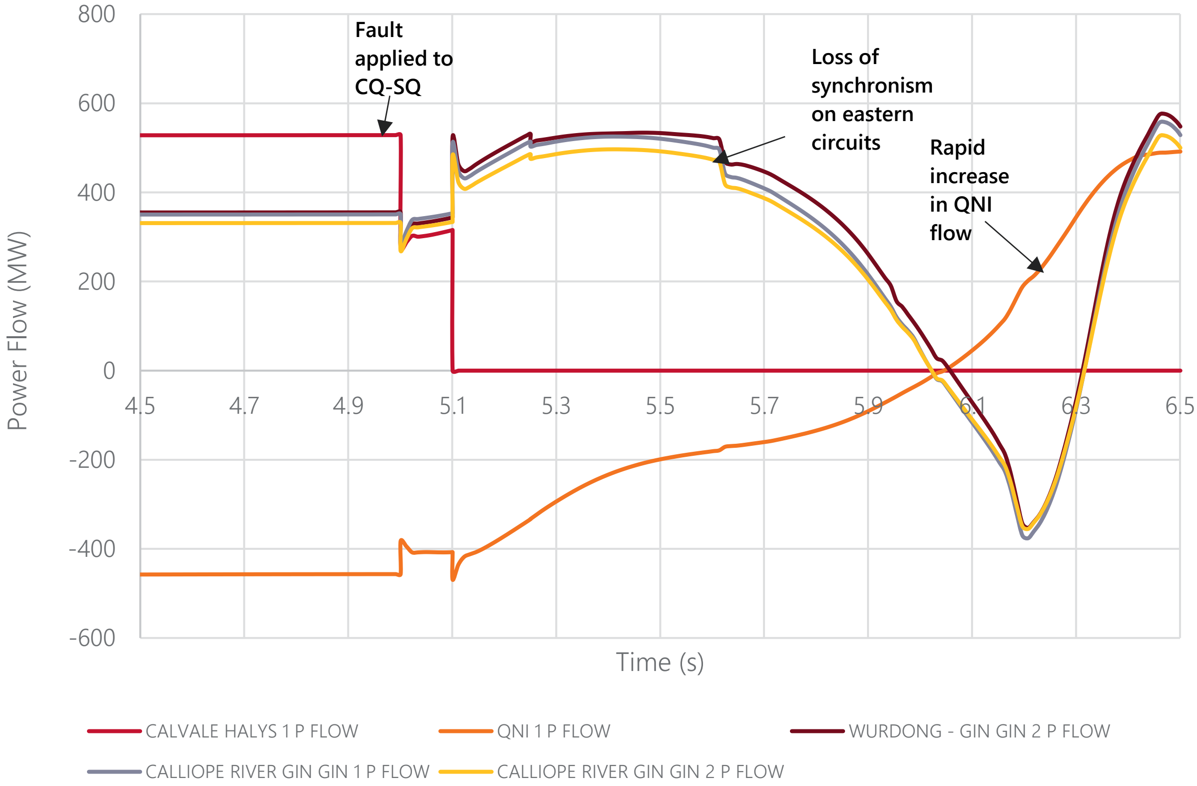
Case ID	Inertia Qld (GWs)	Inertia NSW (GWs)	QNI (MW)	CQ-SQ (MW)	Regional frequency peak/nadir (Hz)					UFLS utilised region (MW)	Instability timing
					QLD	NSW	VIC	SA	TAS		
2	35	39	354	2,136						No UFLS	3.2 s after line trip
3	30	30	628	2,012	49.57	49.57	49.57	49.57	48.70	No UFLS	No instability
4	30	30	851	1,562	49.60	49.60	49.60	49.60	48.80	No UFLS	No instability
5	27	37	746	1,875	49.55	49.45	49.55	49.80	48.50	No UFLS	No instability
6	33	35	883	2,079						No UFLS	1.6 s after line trip
7	28	30	1,116	1,813						No UFLS	0.8 s after line trip

The non-credible contingencies simulated for the boundary conditions listed in Table 33 indicate that the existing CQ-SQ SPS may not be effective in managing the double-circuit trip of the Calvale-Halys transmission lines when exporting power from Queensland to New South Wales. Three of the boundary conditions with CQ-SQ flows exceeding 1800 MW showed instability on the remaining CQ-SQ circuits following double-circuit trip of the Calvale to Halys transmission line. This result supports the advice provided by Powerlink that the existing SPS is only effective for CQ-SQ transfers up to 1700 MW.

Figure 4 shows power flows across key transmission corridors following the simulated non-credible contingency using CQ-SQ case 6.

In this instance the high CQ-SQ flow triggers the CQ-SQ SPS to trip two Callide generators, a total reduction in generation of 800 MW. The resulting reduction in transfers from CQ to SQ is not sufficient to prevent loss of synchronism across the eastern CQ-SQ circuits. Once that occurs QNI imports increase rapidly. The rapid increase in power flow across QNI has the potential to result in loss of synchronism between Queensland and New South Wales. If this occurs, it has the potential to lead to widespread supply interruptions or a black system across Queensland with flow on impacts to other NEM regions. During periods of high power transfer across CQ-SQ and high exports across QNI, the separation across the CQ-SQ cut-set followed by separation across QNI has more serious potential consequences than the non-credible loss of QNI under maximum import conditions.

Figure 4 CQ-SQ Case 6 – instability following Calvale-Halys line trip



The boundary condition simulations showing instability illustrate that effective management of the risk posed by the non-credible loss of the Calvale – Halys line requires consideration of both the amount of generation available to be tripped by the SPS scheme and the pre-contingent CQ-SQ flow.

The three boundary conditions exhibiting a loss of synchronism across the remaining CQ-SQ circuits cover a range of pre-contingent power flows and loading levels on the Callide generators tripped by the SPS. Two have power transfers between CQ and SQ that exceed 2,000 MW. Case 7 had a lower CQ-SQ transfer of 1,813 MW. In this case the Callide C generators are operating at lower output, making the CQ-SQ SPS less effective. The total generation available to trip in this case was 605 MW. In case 3, the total generation at Callide C was 800 MW and the instability was avoided even with CQ-SQ flows which were higher than in case 7.

The key conclusion that can be drawn from the boundary condition simulations is that the existing CQ-SQ SPS is not able to manage the risk posed by the double-circuit loss of Calvale to Halys when flows between CQ and SQ exceed 2,000 MW with Callide C generating 800 MW. With lower levels of generation at Callide C, the CQ-SQ SPS may not be effective in managing the risk unless CQ-SQ flows are below 1,700 MW.

To understand how the risk associated with this non-credible contingency may change with expected power system developments, CQ-SQ case 3 was used to undertake a future case study modelling the 2022-23 power system. This future case study only considered this two-year outlook as a number of existing boundary conditions had already highlighted issues with the ability to manage this non-credible contingency event. The future case (case 3s) models growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertial levels projected for 2022-23 in the Step Change scenario in the 2020 ISP. This case modelled the same level of UFLS being available as in the original boundary condition snapshot. The DER in this case reflects the forecast for 2022-23 in the High DER scenario in the 2020 ESOO.

In the future case study, the frequency in all regions is controlled to within the limits specified in the FOS and the RoCoF remains within 2 Hz/s. For this case the CQ-SQ SPS was able to maintain synchronism and stability following non-credible loss of Calvale – Halys 275 kV circuits. This result suggests that the effectiveness of the CQ-SQ SPS was insensitive to the modelled changes in the amount of IBR, DER and synchronous inertia. The lower inertia in the future case study and lower raise capability both contribute to the frequency nadir being lower. The frequency nadir fell to 49.47 Hz which triggered a small amount (7.7 MW) of UFLS in Queensland in the study.

Powerlink has advised that it is investigating a revised CQ-SQ SPS that includes tripping of up to 600 MW of renewable generation in North Queensland. An additional sensitivity study was performed repeating case 6 with any of the renewable generators nominated by Powerlink for potential inclusion in the scheme also tripped. This resulted in an additional 257 MW of renewable generation being tripped for this case. The tripping of the additional renewable generation was sufficient to avoid loss of synchronism across the remaining CQ-SQ circuits following the non-credible loss of the Calvale – Halys transmission line.

4.5.3 Future scenario 2022-23 studies – QNI export

To understand how the risk associated with this non-credible contingency may change with expected power system developments, CQ-SQ case 3 was used to undertake a future case study modelling the 2022-23 power system. Table 34 presents the frequency nadir simulated in each region, the CQ-SQ and QNI transfer conditions for the future case. It should be noted that the simulation studies do not include the UFLS models of Tasmania and hence any frequency drop below 48 Hz in Tasmania indicates UFLS action.

Table 34 Frequency simulated in future case following the trip of Calvale- Halys line with QNI exporting

Case ID	Inertia QLD (GWs)	Inertia NSW (GWs)	QNI (MW)	CQ-SQ (MW)	Regional frequency peak/nadir (Hz)					UFLS utilised region (MW)	Instability timing
					QLD	NSW	VIC	SA	TAS		
3s	23	22	628	2,012	49.47	49.47	49.47	49.47	48.2	QLD 7.7	No instability

This future case study only considered a two-year outlook, as a number of existing boundary conditions had already highlighted issues with the ability to manage this non-credible contingency event. The future case (Case 3s) models growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertial levels projected for 2022-23 in the Step Change scenario in the 2020 ISP. This case modelled the same level of available UFLS as in the original boundary condition snapshot. The DER in this case reflects that forecast for 2022-23 in the High DER scenario in the 2020 ESOO.

In the future case study, the frequency in all regions is controlled to within the limits specified in the FOS and the RoCoF remains within 2 Hz/s. For this case the CQ-SQ SPS was able to ensure no loss of synchronism or instability following non-credible loss of Calvale – Halys 275 kV circuits. This result suggests that the effectiveness of the CQ-SQ SPS was insensitive to the modelled changes to the amount of IBR, DER and synchronous inertia. The lower inertia in the future case study and lower raise capability both contribute to the frequency nadir being lower. The frequency nadir fell to 49.47 Hz which triggered a small amount (7.7 MW) of UFLS in Queensland in the study.

The future case study results do not suggest that the changes to the level of DER or synchronous inertia expected by 2022-23 are likely to have a material impact on the effectiveness of the existing CQ-SQ SPS. The key factors dictating its effectiveness remain the magnitude of the pre-contingency transfer between CQ and SQ and the amount of generation able to be shed by the scheme.

4.5.4 Historical case studies – QNI import

A set of three boundary condition snapshots was selected, exploring systems conditions associated with high transfers from CQ to SQ and import of power into Queensland across QNI. The double-circuit trip of the Calvale – Halys transmission line was simulated using each boundary condition snapshot and the frequency response in each region of the NEM reviewed.

Table 35 presents the frequency nadir simulated in each region, the CQ-SQ and QNI transfer conditions, and the inertia provided by synchronous generators in New South Wales and Queensland for each boundary condition. Any instability detected on the eastern CQ-SQ corridor and QNI is noted in the last column. In case 9, trip of the Callide units by CQ-SQ SPS and large power swings across the eastern CQ-SQ corridors produced a large change in power flow across QNI and loss of synchronism between Queensland and New South Wales. Case 9 where instability occurred did not run to completion and hence there is no frequency nadir provided in the results table.

A sensitivity study was also undertaken to examine whether the tripping of additional renewable generation is effective in avoiding instability on the remaining CQ-SQ circuits following the non-credible contingency event. The results shown in Table 35 model the existing SPS which trips up to two Callide generating units.

Table 35 Frequency simulated following the trip of the Calvale to Halys line with QNI importing for each historical boundary snapshot

Case ID	Inertia (GWs)		QNI (MW)	CQ-SQ (MW)	Regional frequency peak/nadir (Hz)					UFLS utilised region (MW)	Instability timing
	QLD	NSW			QLD	NSW	VIC	SA	TAS		
9	29	32	615	1,533						No UFLS	1.4 s after line trip
10	38	37	460	1,520	49.57	49.70	49.70	49.70	48.25	No UFLS	No instability
11	45	38	406	1,446	49.60	49.60	49.60	49.60	48.55	No UFLS	No instability

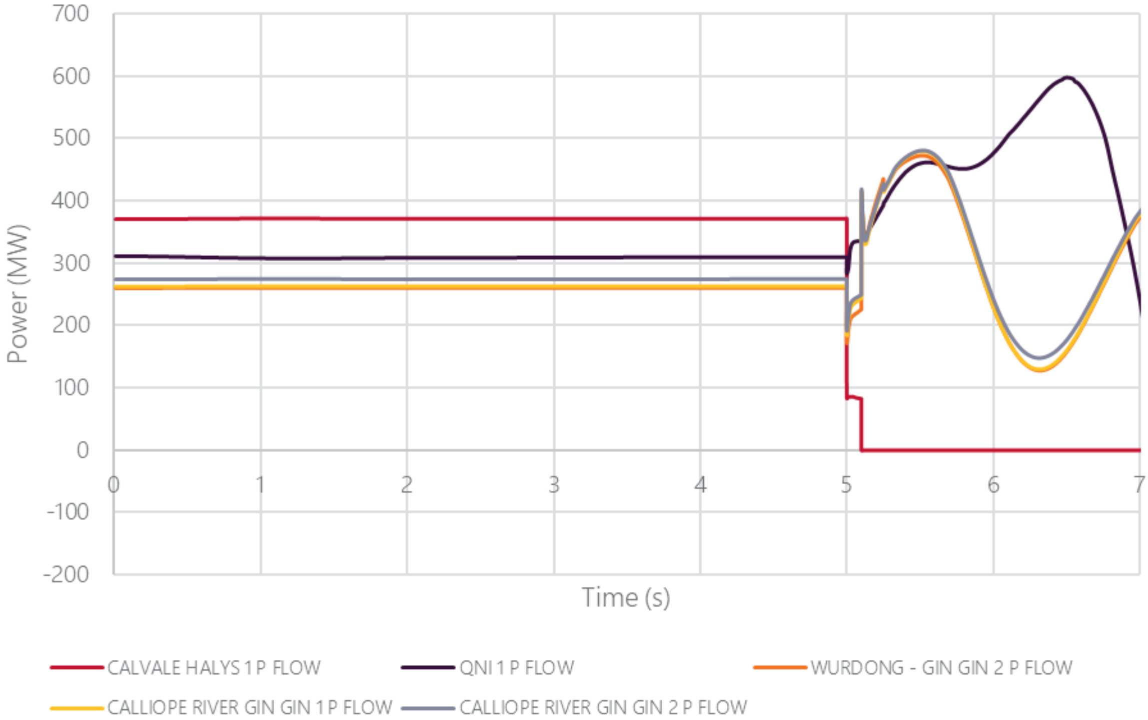
The non-credible contingencies simulated for the boundary conditions listed in Table 35 support previous analysis showing that the existing CQ-SQ SPS may not be effective in managing the double-circuit trip of the Calvale – Halys transmission line when importing power into Queensland across QNI. However, the result obtained for case 9 suggests that the CQ-SQ SPS may not be effective even at flows below 1,700 MW. In this case the pre-contingent CQ-SQ flow was 1,533 MW and the Callide C units were loaded to 731 MW.

Figure 5 illustrates the power flows across the key transmission corridors following the non-credible contingency using CQ-SQ case 9.

In this instance the high CQ-SQ flow triggers the CQ-SQ SPS to trip two Callide C generators. The resulting reduction in transfers from CQ to SQ is not sufficient to prevent loss of synchronism across QNI. The tripping of the generation at Callide C increases imports into Queensland across QNI. Further increases occur in response to the power swings on the remaining CQ-SQ circuits. The increased flow across QNI results in a loss of synchronism across QNI, with the potential for widespread supply interruptions or a black system across parts of Queensland, and possible flow on effects to other NEM regions. The severity of the event will be influenced by which protection operates in response to the loss of synchronism across QNI.

Variations of case 9 were simulated to investigate the sensitivity of the results to factors including the level of import across QNI, the amount of primary frequency response available both in Queensland and across the NEM and the type of fault that led to tripping of the Calvale to Halys line (e.g. two phase to ground or three phase fault). These studies identified that relatively small changes to the distribution of PFR, the pre-contingency flow on QNI and changes to the type of fault could alter the result from being unstable to stable.

Figure 5 CQ-SQ Case 9 – instability following Calvale – Halys line trip



The boundary conditions simulated identify instabilities occurred for case 9 while case 10 was stable. A comparison of these cases reveals that:

- CQ and SQ flow is very similar in each case, being 13 MW higher in case 9.
- QNI import is 55 MW higher in case 9.
- The amount of generation at Callide C is lower in Case 9, making the CQ-SQ SPS less effective. The total generation available to trip is 731 MW in case 9 and 810 MW in case 10.

These results suggest that the pre-contingent CQ-SQ flow is not the sole factor determining whether instability will occur following double-circuit trip of Calvale – Halys line; the amount of generation able to be tripped by the CQ-SQ SPS, QNI import levels and the amount of PFR available are also important factors that determine whether the existing CQ-SQ SPS will be effective in managing risks associated with this non-credible contingency.

A key conclusion that can be drawn from the historical boundary condition case 9 simulations is that during the double-circuit loss of Calvale to Halys when flows between CQ and SQ exceed 1,533 MW with two Callide generating units tripped by CQ-SQ SPS (net 731 MW) and QNI importing at 615 MW QNI import limit, CQ-SQ SPS was not effective. The PSFRR recommends the impact of QNI transfers be considered when finalising the design of the upgraded CQ-SQ SPS.

4.5.5 Future scenario

To understand how the risk associated with this non-credible contingency may change with expected power system developments, CQ-SQ case 10 was used to undertake a future case study modelling power system conditions anticipated in 2022-23. This sensitivity study only considered this two-year outlook as a number of existing boundary conditions had already highlighted issues with the ability to manage the non-credible contingency.

The future case (case 10s) models growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertial levels projected for 2022-23 in the Step Change scenario in the

2020 ISP. This case modelled the same level of available UFLS as in the original boundary condition snapshot. The DER in this case reflects that forecast for 2022-23 in the High DER scenario in the 2020 ESOO.

In the future case studied, the frequency in all regions remains within the limits specified in the FOS and RoCoF remains within 2 Hz/s. In addition, the CQ-SQ SPS is effective in ensuring there is no loss of synchronism or instability following this non-credible contingency event. The lower inertia in the future case study and lower raise capability both contribute to the frequency nadir being lower. The frequency nadir fell to 49.33 Hz which triggered a small amount (7.8 MW) of UFLS in Queensland.

The sensitivity study results do not suggest that the changes to the level of DER or synchronous inertia expected over the next few years are likely to have a material impact on the effectiveness of the existing CQ-SQ SPS. The key factors dictating its effectiveness remain the magnitude of the pre-contingency transfer between CQ and SQ, the amount of generation able to be shed by the scheme and the pre-contingency import across QNI.

As Powerlink is investigating a revised CQ-SQ SPS that includes up to 600 MW of renewable generation in North Queensland, AEMO performed an additional sensitivity study repeating case 9 by tripping one the renewable generators nominated by Powerlink operating at 81 MW in case 9. However, this additional trip failed to avoid the loss of synchronism across QNI following the non-credible loss of the Calvale – Halys transmission line. Tripping additional generators in addition to Callide units was seen to further destabilise QNI. For QNI import cases, Powerlink could consider other measures to reduce load or increase generation in SQ.

A further sensitivity was undertaken for case 9 which modelled the QNI upgrade, to assess whether the enhanced voltage control provided as part of the upgrade avoids or reduces the risk of instability following the loss of both circuits between Calvale and Halys. This sensitivity study also modelled an increase in QNI flow of 200 MW consistent with the increased transfer capability delivered by the upgrade. The sensitivity study showed that QNI instability occurred following the trip of both Calvale – Halys lines following a three-phase fault. A graph of the resultant power flows is shown in Appendix A2.

It is recommended that appropriate measures be developed to manage the risk of instability following a double-circuit trip of the Calvale to Halys line. Measures may include:

- Powerlink continuing to develop an enhanced CQ-SQ SPS utilising WAMPAC technology that better manages the risk posed by the non-credible double-circuit loss of the Calvale – Halys transmission line. The development of the enhanced system should consider the following matters:
  - Effectiveness of the scheme under both QNI import and export conditions.
  - Control actions that will prevent loss of synchronism across the remaining CQ-SQ circuits and loss of synchronism across QNI.
  - Need to trip both load in southern Queensland and generation in central and north Queensland to achieve the required risk mitigation under all secure power transfers.
  - System strength impacts of tripping any generator under the SPS.
  - Impact of increased transfers across QNI that may result once the committed QNI upgrade is completed.

Powerlink is currently upgrading the existing CQ-SQ SPS to manage the CQ-SQ separation risks and to achieve higher power transfer across CQ-SQ corridors in stages. The first stage of the upgrade is expected to be completed by mid-2021. During the interim period until Stage 1 is completed, a protected event declaration would be impractical, given the further studies necessary to define the range of conditions to be managed by the protected event and the time needed to complete the protected event declaration process with the Reliability Panel. It is recommended instead that AEMO and Powerlink work closely on the CQ-SQ SPS upgrade and ensure the timely implementation of a design to mitigate the above identified risks as much as practicable.

4.5.6 Future scenario 2022-23 studies – QNI import

To understand how the risk associated with this non-credible contingency may change with expected power system developments, CQ-SQ case 10 was used to undertake a future case study modelling the 2022-23 power system. Table 36 presents the frequency nadir simulated in each region, the CQ-SQ and QNI transfer conditions for the future case. It should be noted that the simulation studies do not include the UFLS models for Tasmania, hence any frequency drop below 48 Hz in Tasmania indicates UFLS action.

Table 36 Frequency simulated in future case following the trip of Calvale – Halys line with QNI exporting

Case ID	Inertia QLD (GWs)	Inertia NSW (GWs)	QNI (MW)	CQ-SQ (MW)	Regional frequency peak/nadir (Hz)					UFLS utilised region (MW)	Instability timing
					QLD	NSW	VIC	SA	TAS		
10s	27	25	460	1,520	49.30	49.30	49.30	49.30	47.80	QLD 7.9	No instability

This sensitivity study only considered this two-year outlook as a number of existing boundary conditions had already highlighted issues with the ability to manage the non-credible contingency.

The future case (case 10s) models growth in DER and additional IBR generation replacing synchronous generation to achieve the minimum inertial levels projected for 2022-23 in the Step Change scenario in the 2020 ISP. This case modelled the same level of UFLS being available as in the original boundary condition snapshot. The DER in this case reflects that forecast for 2022-23 in the High DER scenario in the 2020 ESOO.

In the future case studied, the frequency in all regions remains within the limits specified in the FOS and RoCoF remains within 2 Hz/s. In addition, the CQ-SQ SPS is effective in ensuring there is no loss of synchronism or instability following this non-credible contingency event. The lower inertia in the future case study and lower raise capability both contribute to the frequency nadir being lower. The frequency nadir fell to 49.30 Hz which triggered a small amount (7.9 MW) of UFLS in Queensland.

The sensitivity study results do not suggest that the changes to the level of DER or synchronous inertia expected over the next few years are likely to have a material impact on the effectiveness of the existing CQ-SQ SPS. The key factors dictating its effectiveness remain the magnitude of the pre-contingency transfer between CQ and SQ, the amount of generation able to be shed by the scheme and the pre-contingency import across QNI.

5. Review of frequency risk management measures

The following elements make significant contributions to the management of the frequency risks posed by the five priority non-credible contingencies considered in the 2020 PSFRR:

- Generator primary frequency response.
- Effectiveness of UFLS.
- OFGS (in South Australia and Tasmania).
- Operation of SPSs (for example, CQ-SQ, SIPS, IECS and EAPT).
- Measures associated with management of protected events (Heywood interconnector).

5.1 Primary frequency response

The simulation studies assume that all future IBR are capable of providing PFR consistent with the requirements published by AEMO. The studies completed for the 2020 PSFRR demonstrate that providing a PFR consistent with the published requirements is an effective means of ensuring IBR contribute significantly to control of over-frequency events. All the future cases studied produced a similar or improved response to over-frequency events, which indicates that the response to over-frequency events is likely to improve into the future with growing levels of IBR.

As all capable scheduled and semi-scheduled generating systems will be required to deliver PFR aligned with AEMO's interim PFR requirements[32], this should similarly improve response to under-frequency events. With continued growth in distributed PV and large-scale IBR connections, there will be an increasing number of periods with high IBR generation and lower levels of synchronous generation. This will reduce availability of primary frequency raise response from synchronous generators.

To the extent that large-scale BESS operate as scheduled generators, they will also be required to provide primary frequency raise response. AEMO's studies of priority non-credible contingency events only modelled the frequency response available from existing BESS and did not model growth in BESS (or other technologies) that may provide additional frequency raise capabilities in future. The Hornsdale BESS was modelled with 70 MW headroom according to arrangements in place to provide system reliability services.

The simulation studies show that the FFR provided by the Hornsdale BESS contributes to management of frequency nadirs and peaks during frequency events. The development of similar BESS in other regions of the NEM could be an effective means of providing frequency control when there are fewer synchronous

[32] PFR implementation is ongoing, prioritising larger generating units, and is subject to limited exemptions and variations. Mandatory provision of PFR under the NER is currently scheduled to end in June 2023; a regulatory replacement has not yet been formulated. The interim PFR requirements and related information are available at: https://aemo.com.au/initiatives/major-programs/primary-frequency-response.

generators online (or synchronous generators are operating at a level or in a mode at which a frequency response is not provided).

5.2 Under-frequency load shedding

The simulation of non-credible contingency events demonstrates that DER growth will continue to reduce the effectiveness of UFLS schemes. There are three main ways in which DER growth undermines the effectiveness of UFLS:

- Distributed PV reduces the net load on UFLS feeders, reducing the amount of load that is shed when the UFLS activates.
- With more distributed PV connected, more feeders will experience reverse power flows during the middle of the day. UFLS activation at these times risks disconnecting feeders with reverse power flows which will exacerbate an under-frequency event, rather than helping to correct the disturbance.
- Legacy distributed PV systems demonstrate under-frequency disconnection behaviour, meaning that severe under-frequency events are further exacerbated by the disconnection of legacy distributed PV.

The projected growth in DER in the High DER scenario in the 2020 ESOO has the potential to significantly erode the available UFLS in each mainland region, threatening the effectiveness of the UFLS schemes.

South Australia has already reached the point where its UFLS scheme may not be effective under some conditions. Various measures are underway in South Australia to improve the load available for UFLS. Similar measures to those noted in Section 6.2.1 may be investigated in other regions, pending mainland NEM UFLS review.

TasNetworks has recently reviewed all distribution network feeders utilised as part of the Tasmanian UFLS scheme, and communicated the following observations to AEMO:

- Around three feeders were identified as having sufficient DER connected to them to cause 'reverse power flows' for significant periods of time. In Tasmania, the connection of mini-hydro and methane recovery generating units to the distribution network has contributed to such outcomes, in addition to an increasing amount of distributed DPV. Two of the feeders have been swapped to alternatives in the same substation. The third has been removed from the UFLS until sufficient load is restored at the affected connection point, but is not significant in context of the scheme's overall performance. TasNetworks will continue to monitor the installation of DER and the resulting impacts on the UFLS scheme.
- TasNetworks is undertaking further review of UFLS in light of increasing IBR penetration and more regular operation of the Tasmanian network at low inertia. This work stream forms part of ongoing integration studies associated with the connection of future wind and solar generation, as well as consideration of issues associated with better modelling of DER. There is an increasing recognition that unintended tripping of DER during large network disturbances is a potential risk, noting that EFCSs need to be robust to such outcomes. TasNetworks has been engaged in a modelling improvement program being coordinated by AEMO and is looking to apply the improved modelling techniques as part of its forward-looking review of UFLS adequacy. TasNetworks will share the outcomes of study results with AEMO once they are available.

In addition to the identified issues relating to DER growth, increasing IBR and low inertia impacting the effectiveness of UFLS schemes, the future potential for major industrial customers to leave the network must also be considered in UFLS design. AEMO has commenced working with NSPs to review and ensure the functionality of UFLS to manage the impact of these issues.

5.3 Over-frequency generator shedding

South Australia and Tasmania are the only regions in the NEM to have implemented OFGS schemes, where generator protection is coordinated to trip for over-frequency events at 51-52 Hz in South Australia and

52-55 Hz in Tasmania. The South Australian OFGS scheme was implemented to counter reduced system inertia and FCAS lower availability.

Over-frequency generator tripping in other parts of the NEM currently takes place above 52 Hz through individual over-frequency protection settings, consistent with generator performance standards. As noted in the system incident report for the 25 August 2018 trip of QNI, some generators also have over-frequency protection that can operate after prolonged periods (>10 minutes) at lower frequencies (50.5 Hz).

At present only those wind farms that were operational in 2018 when South Australia's OFGS scheme was developed participate in the scheme. Selected case studies undertaken for the PSFRR indicate that for the non-credible loss of the Heywood interconnector when South Australia is exporting, the maximum frequency rise was managed within FOS limits and RoCoF was within 2 Hz/s. However, there is an increased risk of over-frequency events during periods of high large-scale solar generation in South Australia. Since the OFGS was designed in 2018, 245 MW of wind and 315 MW of solar generation has been connected in South Australia. It is recommended that AEMO and ElectraNet undertake a review of the effectiveness of the OFGS and modify if required, including the addition of additional generation to the scheme.

TasNetworks has communicated its observations on the Tasmanian OFGS scheme to AEMO. TasNetworks has integrated two additional wind farms into the OFGS scheme. It noted that the OFGS generator trip settings between 52.0 Hz and 53.0 Hz are becoming increasingly congested. Integration of future IBR connections into the Tasmanian OFGS is likely to become more challenging unless over-frequency operating capabilities in excess of 53.0 Hz can be offered, even if only for a limited period of time. TasNetworks notes that it is a requirement of the negotiated access standard (refer NER S5.2.5.3 (d)) that the risk of over-tripping which leads to a frequency rebound substantially below 50 Hz be properly considered. As it will become increasingly difficult to allocate over-frequency trip settings which provide adequate discrimination under high RoCoF scenarios, TasNetworks may not be able to accept proposed negotiated access standards within this range at some point in the future. A possible alternative is to consider the use of additional frequency supervised RoCoF tripping elements, however this will certainly increase the complexity of the OFGS scheme design.

AEMO plans to further assess the over-frequency response derived from IBR as part of the 2022 PSFRR.

5.4 Special protection schemes

This section focuses on the following SPSs which are crucial to management of the non-credible contingency events studied in the 2020 PSFRR:

- South Australia SIPS.
- CQ-SQ SPS

5.4.1 South Australia SIPS

The non-credible loss of multiple generating units in South Australia at times of high import into South Australia can lead to the tripping of the Heywood interconnector due to extreme power flows. This non-credible event would result in rapid frequency decline, and poses a high risk of cascading failures potentially leading to a state-wide blackout. The SIPS scheme is designed to proactively manage and avoid separation.

Following the 2018 PSFRR, ElectraNet has been working with AEMO to develop an advanced PMU based Wide Area Protection Scheme (WAPS). The WAPS is expected to be commissioned in mid-2021, and will improve the reliability of the scheme. The scheme performance and functionality will continue to be monitored and assessed by ElectraNet and AEMO, including through subsequent PSFRRs, as the South Australian system continues to evolve, and the scheme may be further enhanced and developed in future.

Any new schemes proposed as part of the anticipated Project EnergyConnect development will need to consider and coordinate with the WAPS, and may necessitate changes to the WAPS.

5.4.2 CQ-SQ SPS

The CQ-SQ SPS is designed to operate following loss of the Calvale – Halys double-circuit 275 kV lines. The scheme disconnects up to two of the most highly loaded Callide generating units based on the CQ-SQ cut-set flow to avoid a loss of synchronism across the eastern 275 kV circuits connecting CQ and SQ.

Studies undertaken as part of the 2020 PSFRR showed that following the loss of the Calvale – Halys double-circuit 275 kV lines there is increased potential for:

- The eastern 275 kV corridor to lose synchronism for transfer levels above 1,800 MW when QNI is exporting to New South Wales.
- QNI to lose synchronism for CQ-SQ transfers above 1,500 MW when QNI is importing.

Under these conditions there is an increased risk of QNI separation, with potential flow on impacts to other NEM regions.

AEMO will continue to work with Powerlink to advance the upgraded CQ-SQ scheme to mitigate risks associated with ineffective operation of the scheme.

In advance of those changes, it would be impractical to seek declaration of a protected event relating to this contingency.

5.5 Review of UFLS and OFGS schemes by AEMO

AEMO periodically conducts a review of UFLS and OFGS schemes. The current NEM mainland UFLS review will be completed by mid-2021. The adequacy of the UFLS and OFGS settings based on this review will be considered in the next PSFRR.

The UFLS and OFGS review will include the following considerations:

- AEMO and NSPs must work collaboratively to review the impact of growing DER connections in each region and ensure sufficient UFLS load availability to manage frequency during large non-credible under-frequency events for both system intact and islanding conditions.
- Selected case studies undertaken for the PSFRR indicate that for the non-credible loss of the Heywood interconnector when South Australia is exporting, the maximum frequency rise was managed within FOS limits and RoCoF was within 2 Hz/s. However, there is an increased risk of over-frequency events during periods of high large-scale solar generation in South Australia. Since the OFGS scheme was designed in 2018, 245 MW of wind and 315 MW of solar generation has been connected in South Australia. It is recommended that AEMO and ElectraNet undertake a review of the effectiveness of the OFGS scheme and modify it as necessary, including by the addition of additional generation.

6. Adequacy of protected events

6.1 Existing protected events

In the 2018 PSFRR, it was identified that a number of scenarios could result in the tripping of transmission lines and the loss of multiple generators in South Australia, which could lead to a sudden and rapid increase in the power imported over the Heywood interconnector, and subsequent separation of South Australia from the rest of the NEM.

This finding led to the declaration of a protected event to assist in managing the risk. The protected event is specified as; 'the loss of multiple transmission elements causing generation disconnection in the South Australia region during periods where destructive wind conditions are forecast by the Bureau of Meteorology.'

As discussed in Section 2.5.1 the SIPS scheme is planned to be replaced by an enhanced WAPS scheme. In addition to the existing SIPS scheme, AEMO is currently managing the risks associated with the protected event by limiting the maximum flow into South Australia on the Heywood interconnector to 250 MW during destructive wind conditions. AEMO considers a 250 MW import limit imposed by the existing protected event continues to be necessary.

The potential for destructive winds to impact transmission circuits in South Australia leading to disconnection of multiple generators still exists, and as such there is a clear need to retain the existing protected event. While no changes are recommended to the protected event, as noted in Section 5.4.1, there is a need for regular ongoing review of the design of the SIPS and WAPS to maintain and improve its effectiveness as the power system develops.

Since the protected event declaration by the Reliability Panel, there have been two instances where AEMO has invoked the 250 MW import constraint to manage the protected event. This occurred on August 2019 and 22 January 2020. As imports to South Australia were below 250 MW during these periods, management of the protected event did not result in any additional costs to the market.

The 2020 PSFRR recommends the continuance of the 2018 PSFRR declared South Australia protected event for the following reasons:

- The existing protected event has been declared to cover the risks due to the loss of multiple transmission lines in South Australia during destructive wind conditions. The risk of losing transmission circuits due to destructive winds remains.
- The Heywood interconnector's capability has not changed since the protected event declaration was made by the Reliability Panel, and as this remains the only HVAC interconnection into South Australia, the potential consequence of the disconnection of multiple generators when importing above 250 MW remains unchanged from when the protected event was declared.
- Changes in operating requirements for system strength (post commissioning of synchronous condensers) are likely to result in increased likelihood of South Australian import conditions coincident with destructive wind conditions.

- The protected event is expected to continue to provide benefit to consumers in mitigating the risk of supply interruptions.
- Work to implement the WAPS is progressing but yet to be complete, therefore the uncovered risk remains the same.

AEMO will review the continuance of the protected event again in the 2022 PSFRR, with consideration to the commitment status and timing of Project EnergyConnect.

6.2 New protected event to manage risk of insufficient UFLS in South Australia to respond to non-credible separation

As outlined in Stage 1 of the 2020 PSFRR[33], AEMO's studies have found that distributed PV generation has reduced the effectiveness of South Australia's UFLS in arresting a frequency decline in multiple ways. Distributed PV generation reduces the net load on UFLS circuits, reducing the amount of load that is shed when the UFLS activates, thereby reducing the effectiveness of the scheme. As PV generation grows further, circuits move into reverse flows, and the action of UFLS relays to trip load circuits will exacerbate an under-frequency event, rather than helping to correct the disturbance. Distributed PV also demonstrates under-frequency disconnection behaviour, meaning that severe under-frequency events are further exacerbated by the disconnection of distributed PV that trips earlier than the UFLS stages.

South Australia relies on UFLS as an important 'safety net' to arrest a severe frequency decline caused by a significant non-credible event, like the simultaneous trip of multiple generating units anywhere in the NEM, or the loss of both Heywood interconnector circuits when it is importing into South Australia.

This section provides an update on progress towards addressing the issues identified with the South Australia UFLS scheme. An overview of the plan is provided in Section 6.2.1, followed by updates on a subset of the initiatives which have been the focus of activity for the past six months.

AEMO's analysis of UFLS adequacy in other NEM regions is underway. It is anticipated that similar challenges will emerge as distributed PV levels grow in other regions. AEMO will communicate findings as they become available, and work with stakeholders on management approaches.

6.2.1 Plan for addressing South Australia UFLS issues

The plan and implementation timeline for the various measures to slow the decline in UFLS effectiveness and restore emergency frequency response in South Australia are summarised in Table 37.

Table 37 Summary of plan for addressing SA UFLS issues

	Action	Purpose	Timeline
1 Immediate stop gap measures to minimise risk in Spring 2020			
1.1	Add more load to SA UFLS	Increasing the amount of load in the UFLS will increase UFLS effectiveness.	In progress, targeting completion by Dec 2020 if possible.
1.2	Update and expand constraint set that limits Heywood imports into SA	Dynamically reducing interconnector imports in periods when UFLS is known to be inadequate will minimise the risk that a non-credible double-circuit loss of the Heywood interconnector will lead to cascading failure. This has been implemented under existing SA regulations and associated limits advice.	Implemented 9 October 2020

[33] AEMO (July 2020), 2020 Power System Frequency Risk Review – Stage 1, Appendix A1. Available at https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-psfrr-consultation.

	Action	Purpose	Timeline
2 Intermediate measures to maximise UFLS performance and minimise risk during 2021 to 2023			
2.1	NEM Review of UFLS settings	AEMO is required to conduct periodic reviews of UFLS schemes. This is underway at present, and will include a review of the SA UFLS scheme. This may result in adjustments to relay settings and other changes to optimise performance of the scheme. If any changes are required, this will be done in consultation with the Office of the Technical Regulator (OTR), network businesses, and the loads involved.	Underway Target completion: Mid 2021 Possible changes to settings: Mid to late 2021
2.2	Protected event submission to the Reliability Panel	AEMO intends to make a recommendation to the Reliability Panel that non-credible separation of SA be declared as a protected event in periods where the SA UFLS is inadequate to prevent cascading failure upon separation. This formalises the expanded and updated constraints that have been implemented initially under SA regulations, and allows AEMO to implement a wider range of management actions to better mitigate risks. The possible need for additional measures to enhance frequency recovery capabilities in the minutes following a disturbance is under analysis at present.	Submission: Early 2021 AEMC consultation: Mid 2021 Possible implementation of updated measures: Late 2021/early 2022
2.3	Dynamic arming of UFLS relays	AEMO and SA Power Networks (SAPN) are co-designing a dynamic arming scheme that will disarm UFLS relays when circuits are in reverse flows, which should materially slow the decline in the amount of UFLS load available. It will also allow real-time optimisation of settings which will improve UFLS performance. Implementation of the scheme will require installation of new relays at some substations. Locations experiencing reverse flows (with very high distributed PV generation) will be targeted first.	Underway Development of AER contingent project proposal: Early 2021 Implementation: Immediately following AER approval. Targeting commencement late 2021/early 2022, with progressive rollout to circuits in reverse flows as required.
2.4	Improving DER standards and compliance	AEMO is collaborating with stakeholders on updates to AS/NZS4777.2 to improve disturbance ride through characteristics of distributed resources, and improve the response of distributed batteries to provide increased assistance in responding to severe frequency disturbances. These changes should reduce the detrimental impacts of distributed PV disconnections during severe frequency events. AEMO is also working with stakeholders on a program of work to improve compliance of distributed resources with the relevant standards. AEMO is also increasing the reporting on distributed PV behaviour in the incident reporting process, and is working with stakeholders to improve distributed PV behaviour where necessary[34].	Draft AS/NZS4777.2 is under review. Final published: Targeting Dec 2020 Mandatory application: 1 year after final published
3 Long-term frameworks			
3.1	Project EnergyConnect	Project EnergyConnect (PEC) will reduce the likelihood of South Australia separating from the rest of the NEM, which reduces the likelihood of an extreme frequency disturbance related to separation events. It will remain important that South Australia has effective emergency frequency response capabilities, but PEC will reduce reliance on these mechanisms and reduce the incidence of UFLS triggering. For South Australian system security, an SPS will be implemented with PEC to manage the loss of either both Heywood interconnector circuits, or both PEC interconnector circuits. For the SPS to be effective, a wide range of plant such as generators, grid-scale batteries and large loads will need to participate in the scheme.	Subject to AER approvals, PEC is proposed to be commissioned in 2023-24..

[34] For example, AEMO incident report for disturbance on 31 January 2020.

Enduring regulatory frameworks

Technical options to replace the necessary emergency frequency response capabilities in the long term in a power system with high levels of DER are likely to include:

- Increased fast active power response (FAPR) from utility-scale batteries, switched loads, and other types of inverter connected generation and storage, and
- More granular load shedding options implemented at the individual customer level (with relays separating load from distributed generation), including at large customer sites.

AEMO is exploring these options with NSPs, and collaboratively investigating possible regulatory frameworks for emergency frequency response with high levels of DER which would appropriately support efficient investment.

6.2.2 Addition of more load to South Australia UFLS

As reported in Stage 1 of the 2020 PSFRR[35], AEMO's analysis on the South Australia UFLS showed periods with as little as 100 MW of net load in the UFLS scheme in 2019, and projected periods with less than 0 MW of net UFLS load from spring 2020 (with more than half the UFLS load blocks in reverse flows at certain times).

AEMO informed SAPN and ElectraNet that the amount of load in the South Australia UFLS is no longer sufficient in some periods, and they have proceeded to increase the amount of load in the scheme as much as possible:

- SAPN and the OTR identified around 100 MW (average) of distribution connected load (40-50 MW at times of minimum load) which could be added to the UFLS. This has now been added to the UFLS at the lowest frequency stages.
- ElectraNet and the OTR identified around 150-230 MW (average) of transmission connected load to be added to the UFLS at the lowest frequency stages. Transmission connected UFLS load exhibits variance of several hundred MW, and can reach a total as low as 30 MW in some periods, when outages occur. The majority of these customers will be added to the scheme by December 2020, with negotiations underway with the remaining customers.

There is minimal further net load available to boost UFLS effectiveness via this approach. SAPN has advised that even if all additional distribution connected load were added, in light load periods this would add only around 25 MW to the UFLS. These final loads will be considered by SAPN and the OTR for feasibility and cost effectiveness in early 2021.

In 2020, AEMO has now measured historical periods with:

- 62 MW of total South Australia UFLS load, recorded on Sunday 13 September 2020 (13:50 AEST).
- 41 MW of total South Australia UFLS load, recorded on Sunday 11 October 2020 (12:30 AEST).

These values include the new customer load added to the scheme, as noted above. For context, the total net load in the South Australia UFLS scheme should be in the realm of at least 600 – 1,000 MW, to be adequate to manage severe non-credible contingency events of the type observed historically. As noted above, it is no longer possible to source this much load in periods with high distributed PV generation via conventional automatic load shedding techniques.

This highlights the importance of the other complementary measures outlined in the plan above.

Real-time data feed of total South Australia UFLS load

In the past, SAPN and ElectraNet have supplied AEMO with data on UFLS load in annual batches on request, to support planning and design studies. Given the low levels of load now occurring in some periods, and the dynamic nature of this load, more frequent monitoring and management is now required. To facilitate this,

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[35] AEMO (July 2020), 2020 Power System Frequency Risk Review – Stage 1, Appendix A1, at https://aemo.com.au/en/consultations/current-and-closed-consultations/2020-psfrr-consultation.

SAPN and ElectraNet have established a real-time data feed to AEMO of the total quantity of UFLS load in South Australia. This allows AEMO to monitor South Australia UFLS load in real time, and use this to inform operational decisions.

6.2.3 Updated and expanded Heywood import constraints

South Australia relies on UFLS to arrest frequency declines caused by significant non-credible events, such as the simultaneous trip of both Heywood interconnector circuits when it is importing into South Australia. Based on future dispatch projections, AEMO's analysis indicates that if there were a double-circuit loss of the Heywood interconnector, South Australia would be at risk of cascading failure around 2-4% of the time[36].

By reducing flows into South Australia on the Heywood interconnector to levels that can be effectively managed by the expected capability of the UFLS scheme, the risk of cascading failure is minimised if a separation event occurs. An updated and expanded constraint set which reduces these risks was implemented on 9 October 2020 (see below for constraint formulation).

South Australian Regulations

AEMO has worked with ElectraNet to update and expand the constraint set originally introduced to meet the requirements of the limits advice provided to AEMO by ElectraNet under regulation 88A of the *Electricity (General) Regulations 2012* (SA). This advice requires that AEMO keep the RoCoF in South Australia below 3 Hz/s for the non-credible trip of both Heywood interconnector circuits.

The previous constraint set limited Heywood interconnector flows to maintain instantaneous RoCoF upon separation to 3Hz/s or less. The increased likelihood of cascading failure due to ineffective UFLS operation means the current formulation may no longer meet ElectraNet's limits advice under the regulation in all periods, because RoCoF will exceed 3 Hz/s once cascading failure starts to occur.

AEMO is preparing a request to the Reliability Panel to declare the separation of South Australia as a protected event when the South Australia UFLS is inadequate to prevent cascading failure. This will formalise mitigation actions under the NER, and account for a wider range of possible separation pathways.

Development of the constraint

AEMO assessed UFLS performance in South Australia using a single mass model representation of the South Australian network. The model used half-hourly UFLS load data from SAPN and ElectraNet, and the contingency event modelled was the double-circuit loss of the Heywood interconnector. A large number of simulations were performed across a wide range of future dispatch projections, including the 2020 ESOO[37] Central scenario and other possible dispatch scenarios that could eventuate.

UFLS was defined to be inadequate (a 'fail' condition) if RoCoF exceeded 3Hz/s, or the minimum frequency was below 47.6 Hz. These criteria identify periods where cascading failure to a black system is very likely. AEMO also identified 'high risk' periods where RoCoF exceeded 2Hz/s, or the minimum frequency was below 48 Hz. These 'risk' periods show an increasing risk of complications and adverse outcomes and should be avoided if possible.

Regression analysis was applied to the simulation results to develop a constraint which defines an import limit for the Heywood interconnector based on UFLS load, distributed PV generation, power system inertia and the availability of FAPR[38]. The constraint will adjust dynamically in real time based on these factors, constraining flows into South Australia only when required.

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[36] Analysis based on the forecast period prior to the installation of the synchronous condensers with flywheels at Davenport and Robertstown.

[37] AEMO, NEM Electricity Statement of Opportunities, September 2020, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en.

[38] FAPR, a sub-second active power response, was found to provide significant assistance in arresting a frequency decline. For example, with 150 MW of FAPR in South Australia, all cases with Heywood imports below 150 MW met the acceptance criteria. FAPR can be delivered by inverter connected resources such as utility-scale battery energy storage and solar farms, and some load resources. The constraint will adjust in real time based upon the availability of FAPR. AEMO is exploring adjustments to the NER to provide improved mechanisms for procuring these responses to assist with emergency frequency response.

As the Heywood UFLS constraint requires real-time estimates of UFLS load and distributed PV generation, AEMO's Energy Management System (EMS) feed has been updated to receive this information, including a new SCADA feed established from SAPN and ElectraNet.

Constraint formulation

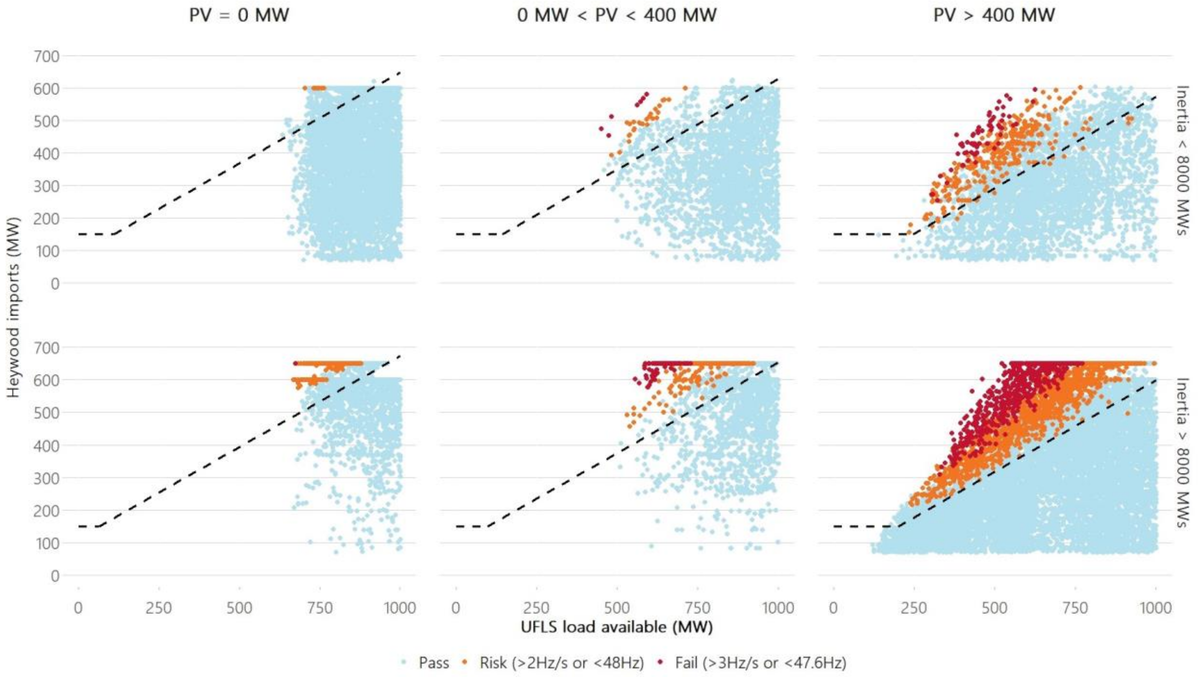
When the total UFLS load in South Australia is less than 1,000 MW, the following constraint is applied on flows into South Australia[39]:

VIC to SA flows on the Heywood interconnector are limited to the maximum of:

- Available FAPR
- -50.7 + 1.3*Inertia - 0.1*Distributed PV generation + 0.6*(UFLS load – 30) + 0.3*FAPR – 25
- 0.

A visual representation of the constraint is provided in Figure 6. Each dot represents a simulation of a dispatch interval with various levels of Heywood interconnector imports and UFLS load, with each of the six panels showing different levels of distributed PV generation and power system inertia. Blue dots represent simulations that met all acceptance criteria, red dots represent simulations that are very likely to lead to cascading failure, and orange dots represent 'risk' conditions. A representation of the constraint is illustrated by the dashed black line. Heywood interconnector imports will be limited to this level, adjusting based on real time conditions. A fact sheet on the constraint is available on AEMO's website[40].

Figure 6 Visual representation of the Heywood UFLS constraint



The constraint illustrated by the black dashed lines is indicative, and shown for conditions of 150 MW FAPR, with 7,000 MWs of inertia (top panels), 9,000 MWs inertia (bottom panels), and 0 MW PV (left panels), 200 MW PV (central panels) and 800 MW PV (right panels).

[39] The unit of inertia used for the constraint is MWs/100MVA base, in alignment with AEMO's real time systems. All other constraint terms have units of MW. The constraint formulation contains two values which act as safety margins: an estimated 30 MW measurement uncertainty on the UFLS load value, and a 25 MW operating margin (consistent with Heywood operating margins used for other constraints) to allow for operational movements in Heywood flows within the dispatch interval.

[40] AEMO, Heywood UFLS constraints, October 2020, at https://aemo.com.au/-/media/files/initiatives/der/2020/heywood-ufls-constraints-fact-sheet.pdf?la=en&hash=066F80AE0EE3CF9701A0509818A239BB.

Update to the instantaneous RoCoF constraint

AEMO's analysis, alongside investigation by consultants[41] and discussions with international system operators, indicates that risks of power system complications and the potential for synchronous units tripping increase for RoCoF exceeding 1 Hz/s, and escalate considerably at RoCoF levels exceeding 2Hz/s. Because of the rarity of such system conditions, there is large uncertainty regarding power system behaviour in this range.

The previous constraint set limited the instantaneous RoCoF to 3Hz/s immediately following a separation event. If further unit tripping occurs, a cascading failure could result and RoCoF will accelerate beyond 3Hz/s as the power system fails.

Due to the risks identified at RoCoF levels in the 2-3 Hz/s range, the existing constraint has therefore been updated (as of 9 October 2020) to reduce the **instantaneous** RoCoF limit for imports into South Australia from 3 Hz/s to 2 Hz/s. This provides reasonable confidence that cascading failure will be avoided in the event of a non-credible separation, and RoCoF can ultimately be kept below 3 Hz/s to meet the existing limits advice under South Australian regulations.

The amendment to the instantaneous RoCoF limit only applies to periods where the Heywood interconnector is importing into South Australia. The limit for exports across Heywood from South Australia into Victoria has remained unchanged at 3 Hz/s. AEMO is undertaking further analysis at present to examine risks associated with export conditions.

The RoCoF limit constraint will be reviewed ahead of the commissioning of the synchronous condensers at Davenport and Robertstown, and as part of the protected event.

Constraint impacts

Historical analysis shows that the updated and expanded constraint set would have bound 1.7% of the time in calendar year 2019. Based on the 2020 ESOO Central scenario forecast, the constraints are projected to bind 6-7% of the time in 2020-21[42], due to a projected increase in the number of periods of energy import into South Australia. It is intended that these constraints will be replaced in 2021 with a new formulation (or another mitigation option) under the proposed protected event.

These constraints primarily bind in periods with low to moderate load, when price, reliability and market impacts will be moderate or low. Market studies indicate that the regression-based constraint never binds at operational demand levels exceeding 1,400 MW, and the updated RoCoF limit binds in only a handful of periods when operational demand is greater than 2,000 MW. For context, the forecast peak demand in South Australia in 2020-21 is 2,900 to 3,200 MW[43].

6.2.4 Protected event submission

AEMO is preparing a request to the Reliability Panel to declare the separation of South Australia under certain conditions as a protected event. This will formalise mitigation actions under the NER, and account for a wider range of possible separation pathways (outlined below). The proposed scope of the submission, and some preliminary findings, are outlined below.

Definition of the protected event

AEMO will propose to the Reliability Panel that separation of South Australia from the rest of the NEM be considered a protected event at certain times, allowing action to be taken whenever the non-credible separation could lead to an under-frequency event that has a material risk of resulting in cascading failure.

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[41] GE Energy Consulting, Final report: Advisory on Equipment Limits associated with High RoCoF, 9 April 2017, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Reports/2017/20170904-GE-RoCoF-Advisory.

[42] Analysis based on the forecast period prior to the installation of the synchronous condensers with flywheels at Davenport and Robertstown.

[43] AEMO, 2020 ESOO Central scenario, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.

Preliminary analysis suggests that the over-frequency response from distributed PV provides a helpful and material reduction in generation when a severe over-frequency occurs, which assists in managing over-frequency events when large quantities of distributed PV are operating.

There are a range of ways in which South Australia can separate from the rest of the NEM. This includes:

- Double-circuit loss at the Heywood interconnector.
- Double-circuit loss in the Victorian 500 kV network at various locations.
- Double-circuit loss in the South Australian network between South East and Tailem Bend.
- Operation (or maloperation) of the EAPT scheme.
- Operation (or maloperation) of the SIPS, caused by a large loss of generation in South Australia.
- Operation (or maloperation) of other protection schemes which isolate the circuits listed above.

AEMO is exploring these various separation mechanisms, and will develop a specific list of separation types to be covered by the protected event. This will draw on the analysis completed for this review.

Scope of the submission

AEMO's submission to the Reliability Panel will outline[44]:

- The nature and likelihood of the non-credible event.
- The consequences for the power system if the event occurs, including an estimate of the unserved energy.
- Options for management of the non-credible event.
- AEMO's recommended options, and rationale for this recommendation.
- An estimate of the additional costs to operate the power system, for each recommended option.

The primary focus of AEMO's submission will be to address the identified issues related to the South Australia UFLS, and implement measures to improve frequency response following a non-credible separation event. The NER frameworks also indicate that any protected event should be treated similarly to a credible contingency for the purposes of system strength assessment, management of voltage control, and system stability assessment. AEMO will apply a pragmatic approach to these aspects, aiming to address any identified issues where this is assessed to be sensible and in the long term interests of consumers, and providing transparency about the proposed arrangements.

Interventions considered

The options under consideration for implementation under the proposed protected event include:

- Adaption of the updated and expanded constraint set that limits imports on the Heywood interconnector when UFLS is inadequate to prevent cascading failure upon separation. This will include considering a range of possible separation types, as listed above.
- Changes to the response of FAPR providers, to improve frequency recovery outcomes (discussed further below).
- Enablement of local FCAS in South Australia, to assist with frequency recovery (or alternative sources of frequency response).
- Adaptation or addition of control schemes.

Stakeholder suggestions for additional options that should be considered for management of the proposed protected event are welcome as part of the feedback on this report.

The addition of new loads to the South Australia UFLS, and the implementation of dynamic arming of UFLS relays will not be considered within the scope of the proposed protected event, because these interventions

[44] NER 5.20A.4

are required under the NER to provide sufficient load under the control of under-frequency relays[45], and will therefore be pursued regardless of a protected event declaration. As these measures are implemented, they will alleviate constraints implemented under the protected event, and will therefore reduce the costs of managing the proposed protected event.

The protected event submission will not explore the minimum generating unit requirements in South Australia, following commissioning of the ElectraNet synchronous condensers with flywheels. A minimum of two synchronous generating units will be assumed to be operating in all periods, prior to commissioning of Project EnergyConnect, as a requirement for system normal operation, consistent with AEMO's other planning publications. Any interventions proposed under the protected event will be assumed to be additional to this baseline.

The intention is for the protected event to focus on implementation of cost effective actions to manage the identified under-frequency risks in South Australia. In the NER, the protected events framework requires AEMO to treat a protected event identically to a credible contingency event with regard to system strength and voltage stability. This means that declaring a protected event could have additional implications for the assessment of these requirements. As for the declaration of previous protected events, AEMO's submission to the Reliability Panel will be transparent about the specific actions proposed and their limitations (with costs and benefits assessed).

Timing

AEMO is targeting a submission to the Reliability Panel in early 2021.

Preliminary findings

If the separation of South Australia under certain conditions is declared a protected event, AEMO must, to the extent practicable, operate the power system in a manner that will meet the FOS for the protected event. This requires that frequency in South Australia is restored to 49-51 Hz within two minutes, and 49.5-50.5 within 10 minutes following separation. This is reflected in the generator performance requirements in the NER[46], which require that generators can sustain operation for up to two minutes for frequency in the range 49-51 Hz, and up to 10 minutes with frequency in the range 49.5-50.5 Hz. Some synchronous generators in South Australia have legacy performance capabilities, and will disconnect if frequency is below 49.5 Hz for more than 8 minutes. If frequency is not recovered to these levels within the required timeframe, and unit tripping results, this could lead to cascading failure in the minutes following a separation event.

AEMO's preliminary analysis indicates that following a non-credible separation of South Australia from the rest of the NEM, it may no longer be possible in some periods to achieve these frequency recovery timelines. With the installation of the ElectraNet synchronous condensers with flywheels, there may be a fewer number of synchronous units operating in some periods, particularly when demand is low. This means that there may be limited frequency raise capability available immediately following separation. It may take 10-30 minutes or longer to adjust constraints, enable sufficient FCAS services, implement the necessary changes through Automatic Generation Control (AGC) and NEM dispatch, and ramp up fast-start units if necessary, to move generation dispatch and recover power system frequency. This means that sufficient local autonomous response is necessary to meet the recovery timelines outlined above. Projected dispatch outcomes from market modelling in the ESOO Central scenario[47] indicate that sufficient flexible headroom may not be available in the quantities required in some periods, following commissioning of the synchronous condensers with flywheels.

In addition, the growing BESS capacity in South Australia has a complex interaction with power system frequency dynamics. BESS and other inverter connected resources are extremely capable providers of FAPR, which is an important contributor to the arrest of the initial frequency decline in a severe disturbance.

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[45] NER S5.1.10.1

[46] NER S5.2.5.3 Generating system response to frequency disturbances

[47] AEMO (August 2020) 2020 Electricity Statement of Opportunities, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/2020-electricity-statement-of-opportunities.pdf?la=en&hash=85DC43733822F2B03B23518229C6F1B2.

However, AEMO's preliminary studies indicate that a growing quantity of BESS delivering FAPR via a typical droop response may increase the difficulty of frequency recovery in the minutes following separation. A droop response provides important primary frequency control, but doesn't deliver the secondary type control that is necessary to "reset" the power system. Given the likely 10-30 minute time frames for re-adjusting AGC and NEM dispatch after a separation event, and the likelihood that there will not be sufficient delayed and regulation FCAS available to cover a non-credible loss of Heywood, some local and autonomous mechanism is required to also manage this frequency restoration function, which a pure droop control does not deliver.

FAPR provides a similar functionality to shedding of UFLS load blocks in the initial arrest of the frequency decline, but FAPR on a droop is fundamentally different to UFLS in the following minutes of frequency recovery. UFLS load blocks will remain disconnected until AEMO's control room gives permission to restore load (typically within around 40 minutes[48], when frequency has stabilised and restored to the necessary levels). This means that a relatively small amount of power injection can be sufficient to restore power system frequency, and load blocks can then be restored when power system dispatch starts to adapt. However, when FAPR pre-empts (and therefore prevents) triggering of UFLS blocks, a much larger amount of power injection is necessary in the initial minutes following separation, to simultaneously restore power system frequency, and also compensate for FAPR providers reducing their injection as they move down their droop curve. The net result is that a growing contribution from FAPR providers (such as BESS) on a droop provides increasing assistance in the initial arrest of the frequency decline, but also increases the challenge in frequency recovery following separation.

Preliminary analysis indicates it may be feasible to introduce some adjustments to the form of the frequency response delivered by FAPR providers, so that this secondary type response to assist with frequency recovery in the minutes following separation is delivered. This response would only be required in rare circumstances following extreme frequency disturbances, where frequency has not recovered to within generator performance requirements (49-51 Hz within 2 minutes, and 49.5-50.5 Hz within 8 minutes). Preliminary indications suggest that these changes could be a cost effective way to minimise the need for scheduling potentially large quantities of local frequency reserves in system normal periods, to manage frequency recovery following non-credible separation events. Inclusion of delayed and regulated FCAS supported by Automatic Gain Control (AGC) scheme also can be considered.

AEMO is investigating the possible specification of this response at present, and exploring whether this could be implemented as part of the protected event.

[48] For UFLS trigger events on 1 November 2015 and 1 December 2016 in South Australia, AEMO gave permission to restore load 39 and 38 minutes after the event, respectively.

7. Framework and resilience

7.1 Scope of future power system risk review (PSFRR)

The power system is transforming at a rapid rate, leading to additional complexities in planning and operating the power system. The fundamental requirements of safe, reliable and economical power supply to consumers remain unchanged. In order to provide a reliable supply, it is important to continuously assess power system risks, as well as the costs of mitigating those risks.

AEMO notes that the COAG Energy Council has submitted a rule change proposal addressing power system risks[49] and welcomes the opportunity to work with stakeholders to develop appropriate revisions to the NER to address these opportunities for improvement. AEMO is committed to working with the AEMC and other stakeholders in relation to the proposed rule change.

In progressing this rule change AEMO recommends reviewing AEMO and NSP roles in relation to the power system risk review, including data, modelling and analysis requirements. An expanded review should complement and build on existing planning processes to avoid duplication, and ensure adequate consideration of other risks such as voltage and system strength related risks which can lead to cascading outages resulting in frequency issues.

7.2 Modelling and data requirement for PSFRR

The success of the PSFRR depends on the quality of models and data used for the risk assessments. In order to deliver the 2020 PSFRR several inadequacies in the power system models were identified and addressed. As the industry continues to transition, a concerted effort from all stakeholders is required to ensure models and modelling tools are adequate for planning and operations as well as integration of new generator connections. Table 38 summarises the criticality of accurate modelling information required to support review of non-credible contingency risks, but is also relevant to other areas of analysis.

Table 38 Modelling requirements

Category	Historical treatment	Current/ future requirement
Synchronous generator governor models	• Significant effort to develop and validate models for Tasmania. • Mixed quality for remainder of NEM. Many governors are not represented or do not represent actual performance. Partly this is because frequency control had not historically been a significant issue, and modelling focused on assessment of other phenomena (e.g. damping of voltage oscillations).	• Increasingly critical to explicitly model and validate governor frequency models across the entire NEM to assess frequency stability. • With implementation of changes for PFR, new/ updated models are required. • If not already available, frequency control models should be developed during control system upgrades. • With increasingly low levels of inertia, generator frequency performance of existing generators is critical.

[49] See https://www.aemc.gov.au/rule-changes/implementing-general-power-system-risk-review.

Category	Historical treatment	Current/ future requirement
IBR	• The level of detail of IBR models has increased over time and there are many legacy model issues. • In many cases, there are limited options to obtain necessary updates.	• Essential that models are robustly tested both when they are initially received by the TNSP and AEMO, and also after each update. AEMO is observing that issues are having a compounding effect, and with an increasing need to assess power system performance under boundary operating conditions, the veracity of these models is ever more crucial. • IBR model frequency control mode and settings are required to be updated based on actual plant mode and settings.
System snapshots	• AEMO developed the OPDMS platform to generate system snapshots. AEMO is increasingly requiring additional operational parameters to enable these cases to be appropriately setup and 'tuned' for system studies.	• Good quality and well dynamically initialising snapshots are required for efficient and robust studies.
UFLS and OFGS	• UFLS and OFGS modelling has not typically been integrated into detailed wide-area models.	• As UFLS schemes become more sophisticated and DER growth continues appropriate scripts and models must be developed that can adequately represent UFLS and DER. The models need to be suitable for both historical snapshots and future snapshots. • Appropriate OPDMS models have to be developed for South Australia and other NEM regions that suitably represent the distributed PV and UFLS feeders. • As OFGS schemes become more crucial to system frequency performance, explicit models will be increasingly required.
SPSs	• SPSs have not historically been included in wide-area power system models in most regions, rather they have been assessed in isolation as part of the design phase, and often no specific models are developed.	• With the increasing prevalence of SPSs, including potential for dependencies or unintended operation, it is important that SPSs are explicitly modelled.
Modelling tools	• A combination of time-domain modelling and simplified modelling using Single Mass Models has been adequate to assess system frequency performance	• Increasingly it is necessary to use multi-mass models and wide-area time-domain models to assess system frequency performance accounting for generator controls, protection schemes and UFLS/DPV behaviour • Increasingly verification using EMT modelling tools will be required to assess system strength stability, which has the potential to impact frequency risks

7.3 Protected events

The current framework for protected events was introduced in 2017 in response to the lessons learned from the 2016 South Australian black system event. Various insights have come from the application of the protected event framework and through that experience we make the following observations and recommendations:

- There is potential for duplication in the process for declaring protected events, which could delay declaration of the protected event and therefore the measures necessary to address security risks. Given the rate of change of the energy system, there is a greater potential for issues to be identified as they materialise. To address this AEMO has proactively engaged with the Reliability Panel to seek input and to ensure required analysis and justification is included in submissions, thereby minimising duplication of effort in the process.

- Recommendation of a protected event EFCS by the PSFRR may provide greater certainty regarding funding for new NSP infrastructure compared to other planning and funding processes. This could lead to definition of special protection schemes (SPSs) as emergency frequency control schemes (EFCSs) which could otherwise be developed by NSPs under S5.1.8. This is assumed to be an unintended outcome of the framework, and should be considered in its review.
- The NER require that any protected event is treated identically to a credible contingency with regards to voltage control and voltage unbalance requirements, system stability assessment, and system strength assessment. Multiple NER clauses reference credible contingency events and protected events identically, requiring that AEMO, NSPs and market participants take actions to manage protected events in an identical manner to credible contingency events. This can create highly undesirable outcomes:
  - The need to assess these additional aspects of managing a protected event makes an already long process for assessing possible new protected events even slower, and highly onerous.
  - The lack of flexibility in the framework may mean that prudent ex-ante action to address known frequency risks cannot be taken at all, if the costs of additionally managing system strength and voltage stability to the same standard as a credible event are not justified on a cost/benefit assessment. In these circumstances the protected events framework is rendered useless and critical risks may remain unmitigated.

A more agile and flexible protected events framework would allow bespoke solutions to be designed and implemented more rapidly to efficiently target key system failure risks as they are identified. It is hoped that some of these issues can be considered as part of the COAG Energy Council rule change mentioned in Section 7.1.

8. Recommendations and conclusions

It is recommended that the following actions are taken to manage risks associated with the five priority non-credible contingencies considered in the 2020 PSFRR. The recommendations are presented below grouped under each non-credible contingency event and include immediate and longer term actions.

8.1 Managing risks associated with the non-credible loss of QNI

Based upon 2020 ESOO DER growth projections to 2022-23, the existing UFLS schemes should remain effective in responding to QNI separation under export conditions. However, by 2024-25, based on projected growth in DER, and assuming no alternate measures to provide fast active power response, UFLS may be insufficient across the southern mainland regions of the NEM to avoid cascading failures following non-credible contingencies, possibly leading to black system events. The risk is highlighted by the observation that the projected growth in DER by 2024-25 is greater than the existing amount of load available of UFLS in these regions.

Similar concerns exist due to the growth of DER in Queensland eroding the effectiveness of the UFLS scheme in managing the under-frequency following the non-credible loss of QNI while importing power into Queensland.

To address these concerns, it is recommended that AEMO work with NSPs in each region to:

- Review the settings and load availability for UFLS.
- Maximise the amount of transmission and distribution connected load under the control of the UFLS scheme.
- Implement real-time monitoring of UFLS feeders and use the data used to block feeders exhibiting reverse power flow from tripping in response to under-frequency events.
- Encourage consumer level switching control of loads in response to under-frequency events.
- Encourage the deployment of plants providing FFR/FAPR in all mainland regions of the NEM.

In addition, AEMO will:

- Continue the process of implementing the mandatory PFR rule[50] for all capable generators to deliver PFR whenever synchronised. Future case studies have confirmed that without PFR from Queensland generators, loss of QNI under high import conditions could potentially result in frequency collapse in Queensland.
- Progress the actions outlined in AEMO's recently published frequency workplan, for ongoing improvement of system frequency performance[51].

[50] See https://www.aemc.gov.au/rule-changes/mandatory-primary-frequency-response.

[51] See https://aemo.com.au/-/media/files/electricity/nem/system-operations/ancillary-services/frequency-control-work-plan/external-frequency-control-work-plan.pdf?la=en.

Over time the level of synchronous generation in Queensland is likely to continue to reduce, resulting in a reduction in the PFR available in Queensland to respond to higher frequencies by increasing output (most large scale IBR plant can also provide PFR but rarely maintain headroom). The studies undertaken for the 2020 Stage 2 PSFRR suggest this might become a material concern by 2024-25. It is recommended that the 2022 PSFRR specifically consider the projected availability of sufficient raise PFR in Queensland, with consideration of any interdependencies with system strength requirements. Encouraging the development of plants providing FFR/FAPR will help address the potential decline in the available raise PFR. By the 2022 review, there may also be increased certainty on the future of PFR under the regulatory framework from June 2023.

The ongoing effectiveness of UFLS in Queensland should be reassessed as part of the next PSFRR with specific consideration given to whether declaration of a protected event is warranted to manage the risk associated with the non-credible loss of QNI while importing. This may be necessary if planned measures to address the declining UFLS effectiveness are unsuccessful. Declaration of a protected event under conditions with low levels of UFLS available in Queensland and high imports into Queensland across QNI would enable a number of options to manage the risk posed by the non-credible loss of QNI, including specifying a local requirement for frequency raise FCAS in Queensland or constraining imports across QNI.

8.2 Managing risks associated with the non-credible loss of the interconnection between New South Wales and Victoria

The historical and future scenario simulations undertaken for Victoria export conditions indicate that under or over-frequency or RoCoF is unlikely to be a significant risk given a New South Wales – Victoria separation event. On current projections, the existing UFLS schemes should remain effective in responding to a loss of VNI until 2022-23. The study results also indicate that it is important to consider the QNI flows during reclassification of VNI corridors for a possible separation during extreme weather events like bushfire, as there is a possibility of QNI becoming unstable.

Historical and future scenario simulations undertaken for Victoria import conditions also indicate that under or over-frequency or RoCoF is unlikely to be a significant risk for a New South Wales – Victoria separation event. However, frequency management in the southern region under this scenario largely depends on the effectiveness of UFLS scheme in Victoria and South Australia. The growth in DER in South Australia and Victoria has the potential to significantly reduce the available UFLS in periods with low load or high distributed PV generation. In the light of this, it is recommended that NSPs in Victoria and South Australia review the design of existing UFLS schemes to ensure that adequate loads are available for UFLS and to avoid tripping of back-feeding distribution feeders.

The 2020 PSFRR has considered the non-credible loss of DDTS-SMTS 1 and 2 and DDTS-MSS 1 and 2 during high Victoria import conditions. Simulation studies included various modes of operation of the IECS. The following observations were made based on the study results:

- For the considered flow conditions, multiple transmission lines were found to lose transient stability following the trip of DDTS-SMTS 1 and 2 or DDTS-MSS 1 and 2 along with generation and load shedding by IECS.
- IBR plants may disconnect due to operation of over/under voltage protection.
- EAPT scheme was found to operate, due to active power swings and low frequency in Victoria.
- Victorian generators were found to lose synchronism with New South Wales and Queensland generators.
- For the simulation studies undertaken, IECS was found to be ineffective in preventing multiple transmission line losses.

Based on the study results, the following actions are recommended:

- The performance of the IECS should be reviewed by AEMO Victorian Planning, including assessment of any necessary modifications to the scheme. This recommended review should be focused on the low probability operating conditions under which IECS operation may not be sufficient to prevent separation between Victoria and New South Wales following non-credible contingency events. In these cases, the interaction and coordination between IECS and UFLS is critically important.
- The power flow changes and network disturbances during the non-credible separation of DDTS-SMTS or DDTS-MSS lines has the potential to trigger EAPT scheme operation. This should be considered by AEMO as part of the earlier mentioned EAPT review.
- Following the commissioning of the 300 MW BESS at Moorabool[52], imports into Victoria from New South Wales are expected to increase during some periods. It is recommended that operation of the IECS, including opportunities to utilise the BESS to mitigate the impact of non-credible contingency events be considered through the IECS review.

8.3 Managing the risks associated with the non-credible loss of the interconnection between South Australia and Victoria

The future scenario studies on non-credible Heywood interconnector separation from HYTS show that:

- When South Australia is importing at the time of separation:
  - Without the current UFLS constraint applied, as updated and extended in October 2020, South Australia frequency cannot be managed under certain high import conditions. With this constraint applied, South Australia frequency is observed to be managed to within limits, however there is still some risk associated with high RoCoF under some conditions.
  - If large generating systems in South Australia are not providing PFR, significantly more UFLS load will be required to contain frequency and the frequency nadir will be lower, and a greater proportion of power system events may result in UFLS operation.
- When South Australia is exporting at the time of separation:
  - Under high South Australia export conditions, the South Australia frequency is observed to be managed within limits with adequate margins in OFGS tripping. Since at present only wind farms participate in the OFGS scheme, it is recommended that additional solar farms be considered for inclusion in the scheme to cover the risk of low wind and high solar generation situations.
  - With generators providing PFR, the frequency peak is lower, less generation is shed as part of OFGS and the frequency recovery is much faster when compared with a scenario without PFR.

The future scenario studies on non-credible Heywood interconnector separation from MLTS show that:

- When South Australia is importing at the time of separation:
  - Under high South Australia import conditions, system frequency is observed to be managed within limits. However, with minimum generation online between HYTS and MLTS, an unacceptably high RoCoF is observed post event prior to the EAPT scheme operating. Speeding up the EAPT scheme operation would reduce the duration for which this high RoCoF (exceeding 3 Hz/s) persists. Implementation of a topology-based scheme is expected to address this issue.
  - With high generation between HYTS and MLTS, the initial power swings and the magnitude of the Heywood interconnector import flow increase can trigger the SIPS Stage 1 (BESS response) and Stage 2 (load shedding), which may lead to SIPS load shedding. In these situations, the EAPT scheme does not operate. It is recommended this situation is considered during the proposed EAPT scheme upgrade.

[52] See https://www.energy.vic.gov.au/renewable-energy/the-victorian-big-battery.

- With generators not providing PFR, the frequency nadir is lower and more load is shed as part of UFLS and the frequency recovery is much slower.
- Going forward, in scenario analysis without APD, South Australia frequency risk increases during South Australia import for a separation from MLTS. High RoCoF and high frequency were encountered and also under certain conditions the Heywood interconnector can lose stability. However, it should be noted the impact of SIPS is not included in the study.

- When South Australia is exporting at the time of separation:
  - Under coincident conditions of high South Australia export and a high level of generation between HYTS and MLTS, nearly all projected OFGS generation is seen to be exhausted and system frequency comes very close to the FOS limit of 52 Hz. Without the APD load, the frequency is observed to exceed 52 Hz, leading to possible severe failure. Making more generation available for OFGS will assist in reducing the frequency peak, however following the OFGS action there is potential for the frequency to reverse and fall below 49 Hz leading to UFLS. This risk could be sufficiently managed if the EAPT scheme is designed to separate South Australia from HYTS following MLTS separation under high export and high generation conditions. Hence the PSFRR recommends further analysis and possible modification to separate South Australia from HYTS following MLTS separation.
  - The present EAPT scheme is not expected to operate during South Australia exporting. However, in future if APD were to close, higher levels of RoCoF and frequency changes may be experienced in South Australia following separation events. This would necessitate further review of existing South Australia EFCSs, as well as EAPT to effectively separate South Australia from HYTS to avoid high South Australia frequency.
  - It is possible for the SIPS Stage 2 scheme to trigger due to high transient active power swings into South Australia immediately after the contingency.
  - The existing EAPT scheme is observed to operate following reversal of system frequency and under-frequency tripping of APD due to UFLS action. In this circumstance, EAPT is ineffective at arresting the initial over-frequency in South Australia.
  - From the 2022-23 future scenario studies, and assuming no additional OFGS, it was observed that the absence of PFR resulted in cases where the FOS limit of 52 Hz was exceeded, whereas with PFR the frequency was marginally managed within limits.
  - With generators providing PFR, the frequency peak is lower, less generation is shed as part of OFGS and the frequency recovery is much faster.

The above discussion refers to the EAPT scheme, which is an existing scheme for managing frequency risks relating to non-credible contingencies between Victoria and South Australia. AEMO will further consider alternate solutions, including implementation of a revised scheme as an NSP planned Special Protection Scheme under clause S5.1.8 of the NER or an EFCS.

8.4 Managing the risk associated with the double-circuit trip of the Calvale – Halys transmission line

The boundary condition simulations undertaken for both QNI import and export conditions demonstrate that the existing CQ-SQ SPS is not able to manage the impact of the double-circuit loss of Calvale to Halys transmission line for high transfers between CQ and SQ and high transfers across QNI. The study results reinforce previous findings from the 2018 PSFRR.

The key factors dictating the effectiveness of CQ-SQ SPS remain the magnitude of the pre-contingency transfer between CQ and SQ, the amount of generation able to be shed by the scheme, and the pre-contingency flows across QNI.

Additional studies modelling the functional design of the upgraded CQ-SQ scheme showed that extending the SPS scheme to include tripping of North Queensland renewable generation may not be effective in managing the risk posed by the loss of the double-circuit transmission line between Calvale and Halys.

The studies showed that following the loss of the Calvale-Halys double-circuit 275 kV lines there is increased potential for:

- The eastern 275 kV corridor to lose synchronism for transfer levels above 1,800 MW when Queensland is exporting to New South Wales, or
- QNI to lose synchronism for CQ-SQ transfers above 1,500 MW when Queensland is importing.

Under these conditions there is an increased risk of QNI separation, with potential flow on impacts to other NEM regions.

AEMO will continue to work with Powerlink to advance the upgraded CQ-SQ SPS scheme to mitigate risks associated with ineffective operation of the scheme.

Powerlink is currently upgrading the existing CQ-SQ SPS to manage the CQ-SQ separation risks and to achieve higher power transfer across CQ-SQ corridors in stages. The first stage of the upgrade is expected to be completed by mid-2021.

During the interim period until Stage 1 is completed, a protected event declaration would be impractical, given the further studies necessary to define the range of conditions to be managed by the protected event and the time needed to complete the protected event declaration process with the Reliability Panel. It is recommended instead that AEMO and Powerlink work closely on the CQ-SQ upgrade and ensure the timely implementation of a design to mitigate the above identified risks as much as practicable.

A1. Benchmarking of historical events

A1.1 25 August 2018

On Saturday 25 August 2018, there was a single lightning strike on a transmission tower structure supporting the two circuits of the 330 kV QNI lines. The lightning strike triggered a series of reactions creating faults on each of the two circuits of QNI at 13:11:39. The Queensland and New South Wales power systems then lost synchronism, islanding the Queensland region two seconds later, at 13:11:41.

At the time, 870 MW of power was flowing from Queensland to New South Wales. Queensland experienced an immediate supply surplus, resulting in a rise in frequency to 50.9 Hz. The remainder of the NEM experienced a supply deficit, resulting in a reduction in frequency.

In response to the reduction in frequency in the remaining interconnected regions:

- The frequency controller on the Basslink interconnector immediately increased flow from Tasmania to Victoria from 500 MW up to 630 MW. This created a supply deficit in Tasmania, causing the disconnection of 81 MW of contracted interruptible load under the automatic under-frequency load shedding scheme (AUFLS2) to rebalance the Tasmania power system at 13:11:46.
- The South Australia – Victoria interconnector at Heywood (HIC) experienced rapid changes in power system conditions that triggered the EAPT scheme. The scheme responded to those conditions, as designed, to separate the South Australia region at Heywood. This occurred some 6 seconds after the QNI separation at 13:11:47.
- The frequency decline in New South Wales was captured by high speed recordings on synchronous generators. This data was used to benchmark the simulations, to determine the accuracy of the proposed modelling. Figure 7 shows that relative accuracy was able to be achieved in the benchmarking of this event with a frequency decline to close to 49 Hz in New South Wales measured and simulated before load shedding began the recovery of frequency.

The frequency in Queensland experienced an immediate over-frequency following separation with an increase to approximately 50.9 Hz measured following the event. Figure 8 shows that the separation event was able to achieve a relatively accurate frequency increase in Queensland, with an increase in frequency to 50.7 Hz simulated. The eventual settling frequency followed a similar curve to the recorded frequency in the simulation.

Figure 7 Benchmarking of simulated and measured frequency in New South Wales following 25 August event

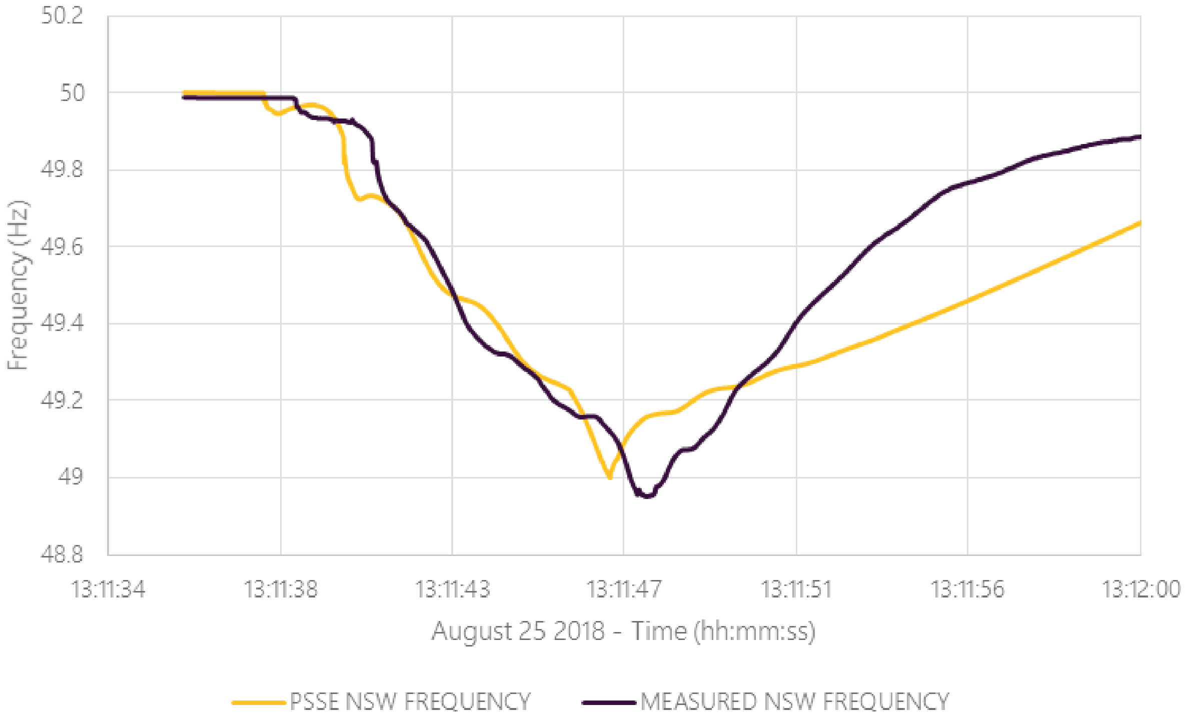
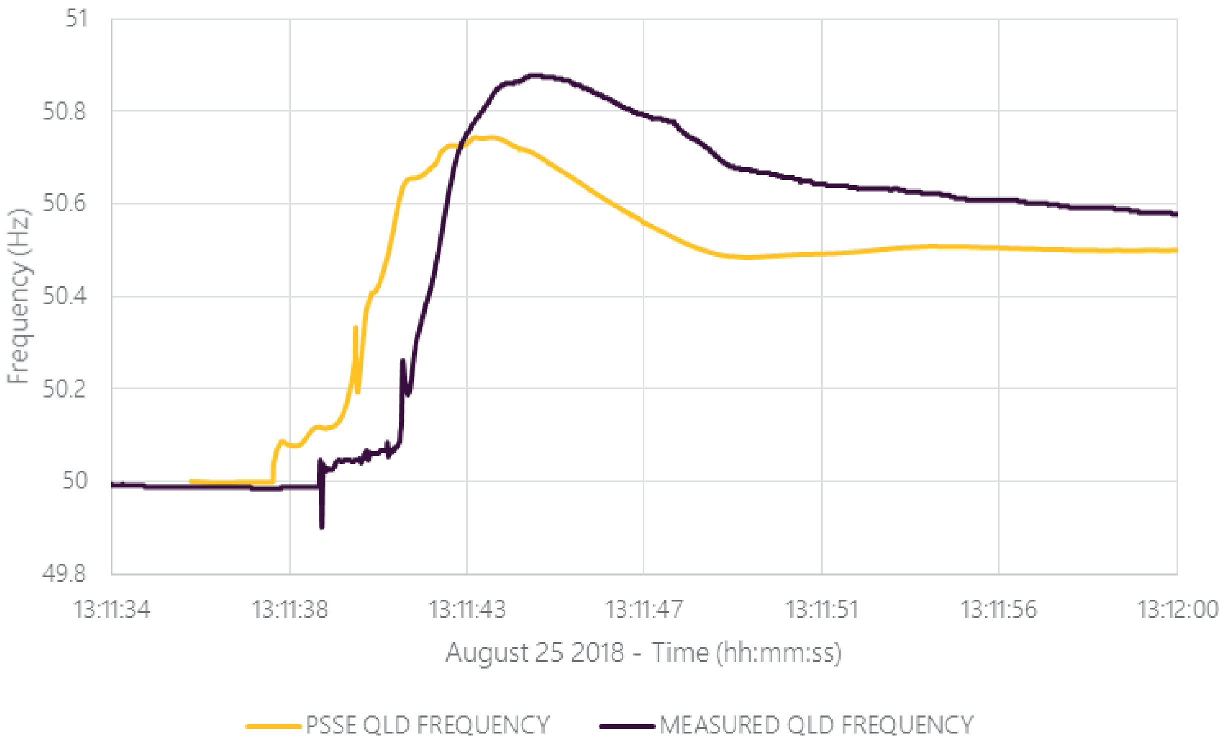
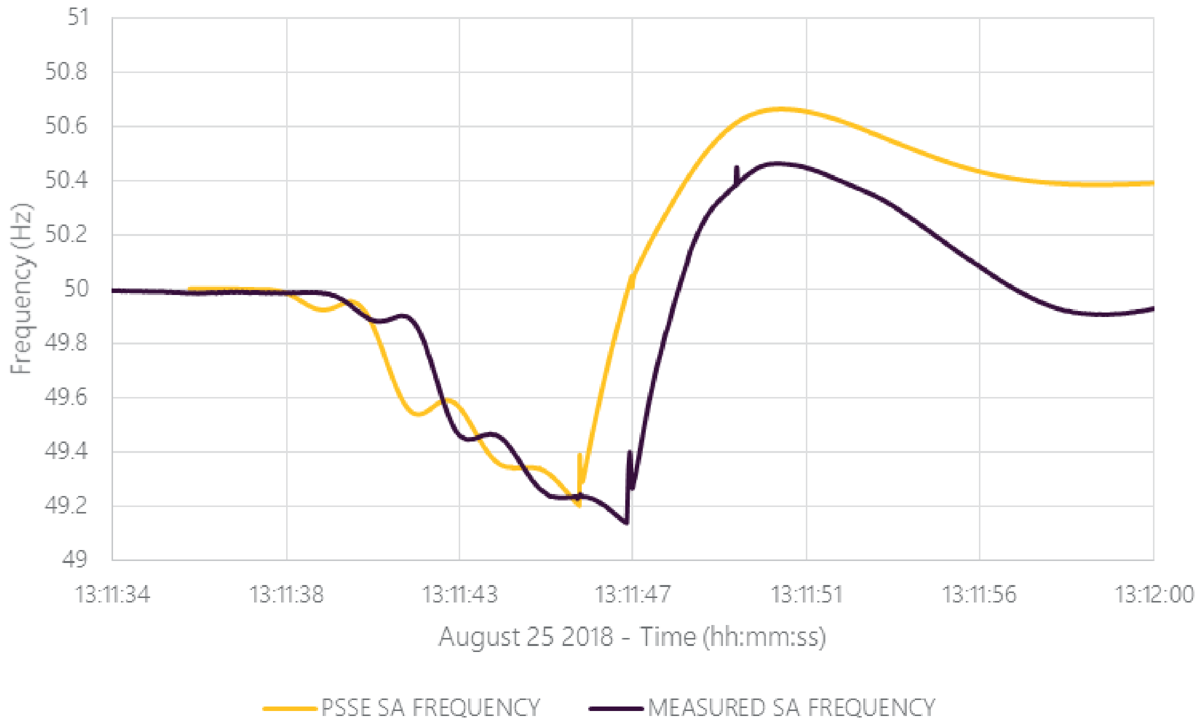


Figure 8 Benchmarking of simulated and measured frequency in Queensland following 25 August event



South Australia also experienced an over-frequency event following separation from Victoria. Figure 9 shows that the benchmarking for frequency in South Australia was relatively successful, with an over-frequency to 50.65 Hz simulated, slightly above the measured frequency peak of 50.45 Hz.

Figure 9 **Benchmarking of simulated and measured frequency in South Australia following 25 August event**



A1.2 16 November 2019

At 18:06:47 (EST) on 16 November 2019, two 500 kV transmission lines in Victoria were disconnected simultaneously due to spurious signals from telecommunications equipment that caused the maloperation of protection equipment on both circuits. This non-credible contingency event resulted in the disconnection of the South Australian region from the rest of the NEM power system for nearly five hours, and disconnection of electrical supply to the APD aluminium smelter in Victoria for nearly three hours.

This event was used for benchmarking of the models used in the frequency risk review. Figure 10 shows that relatively good alignment was achieved with regards to South Australian recorded and simulated frequencies, with a similar maximum frequency of close to 50.8 Hz achieved, and a similar settling frequency achieved. However, the rate of change of frequency in South Australia was greater in the recorded event than in the simulated OPDMS snapshot.

The separation of South Australia caused a marginal over-frequency event in the remainder of the NEM. Frequency regulation prior to the event in the NEM was inconsistent with the studied snapshot, which had initial conditions set to 50 Hz. Nonetheless, the modelled increase in frequency in New South Wales shown in Figure 11 was relatively consistent with the overall shape of the frequency increase recorded in New South Wales.

Figure 10 Benchmarking of simulated and measured frequency in South Australia following 16 November event

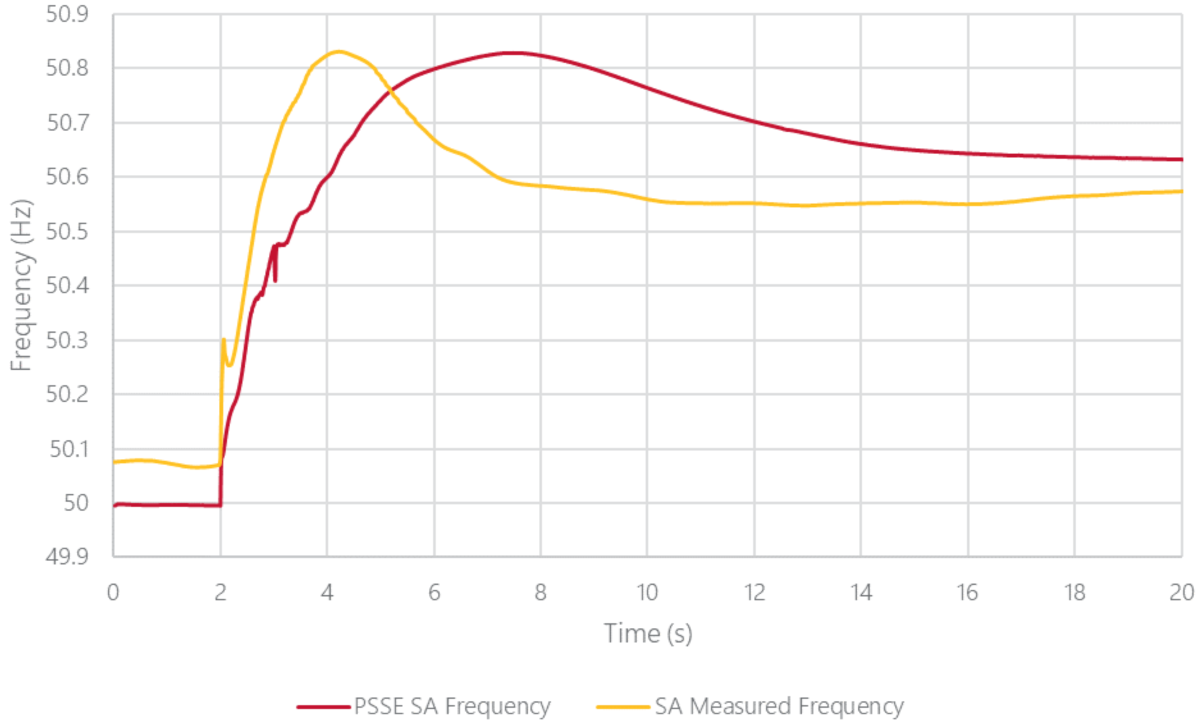
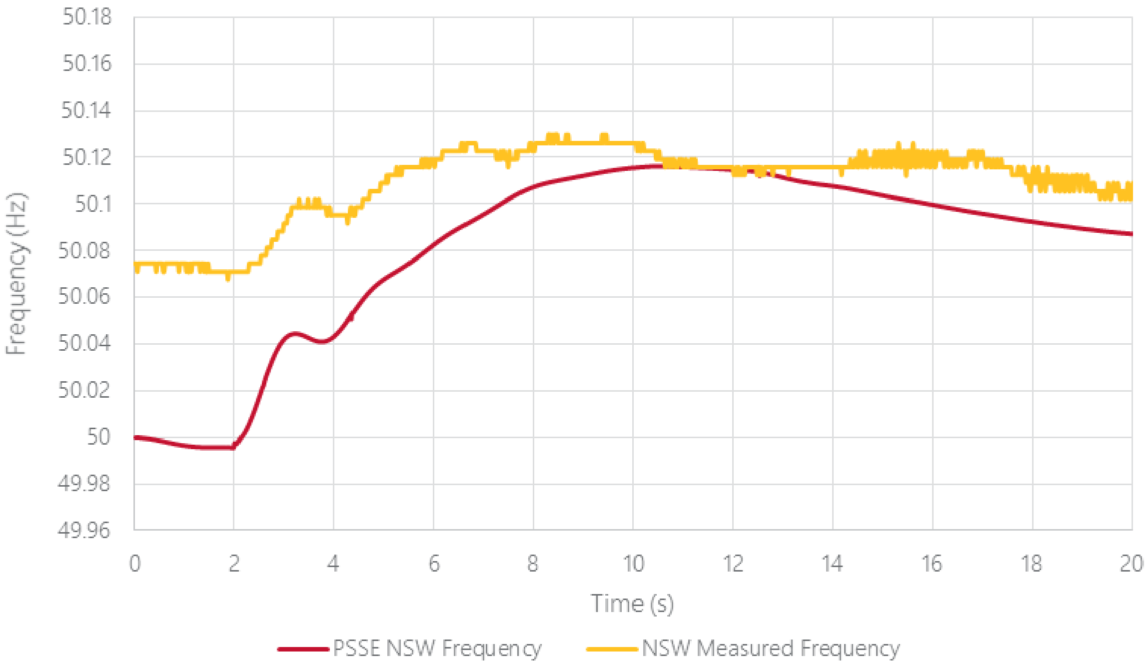


Figure 11 Benchmarking of simulated and measured frequency in New South Wales following 16 November event

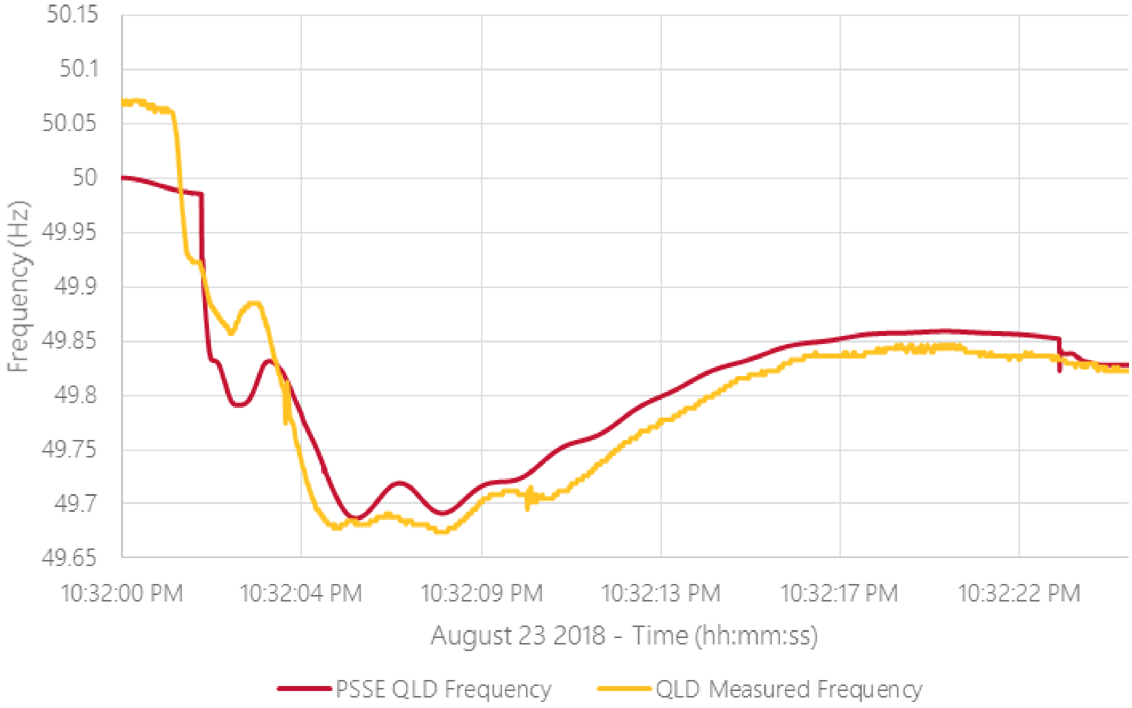


A1.3 23 August 2020

On 23 August 2020, the Kogan Creek generator in Queensland tripped when operating at 740 MW. The resulting frequency disturbance in the NEM resulted in a nadir of 49.68 Hz, with frequency remaining below

49.85 Hz for 310 seconds. There was no islanding that resulted from this frequency disturbance, therefore the frequency in the mainland NEM remained synchronised throughout the event. Figure 12 shows a good alignment was established between frequency response in the simulated OPDMS snapshot and measured from the high speed recordings in Queensland.

Figure 12 Benchmarking of simulated and measured frequency in Queensland following 23 August event



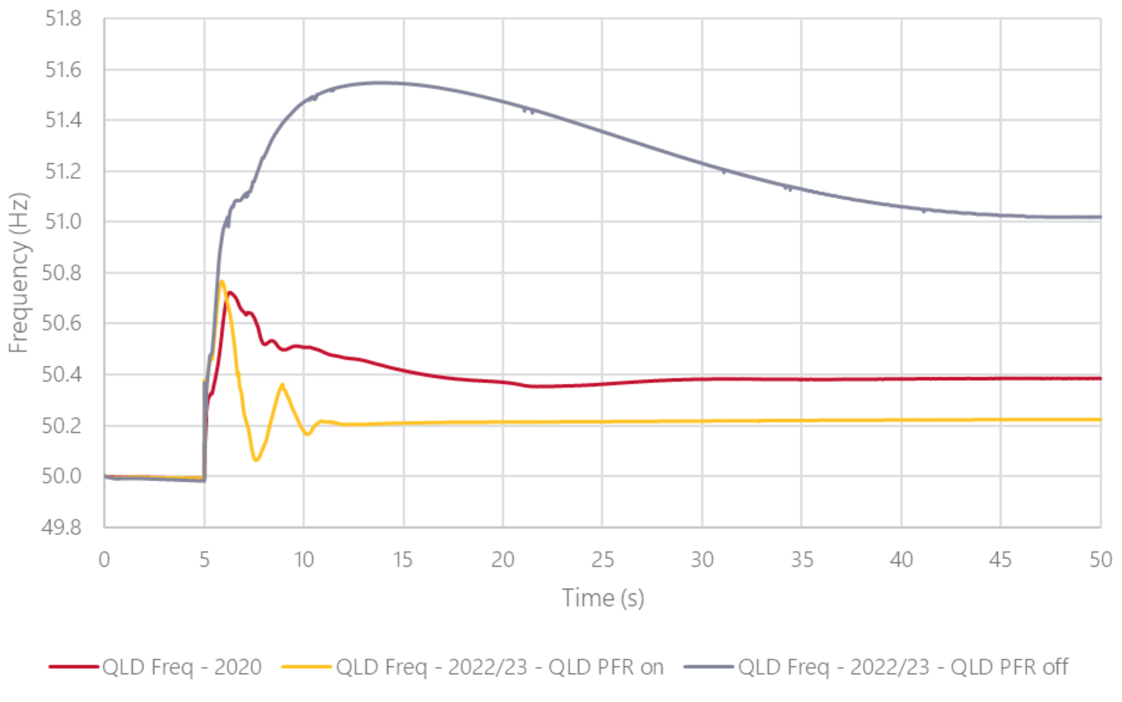
A2. Simulation of priority non-credible events

A2.1 Loss of QNI leading to New South Wales and Queensland separation

A2.1.1 Sensitivity studies exploring future conditions when exporting from Queensland

Figure 13 shows the Queensland frequency simulated following the non-credible trip of QNI for the historical case 2 (refer to Table 3 for case description) and two future cases (case 2c and case 2d in Table 4).

Figure 13 Overlay of Queensland frequency response for boundary condition and future cases for loss of QNI when exporting



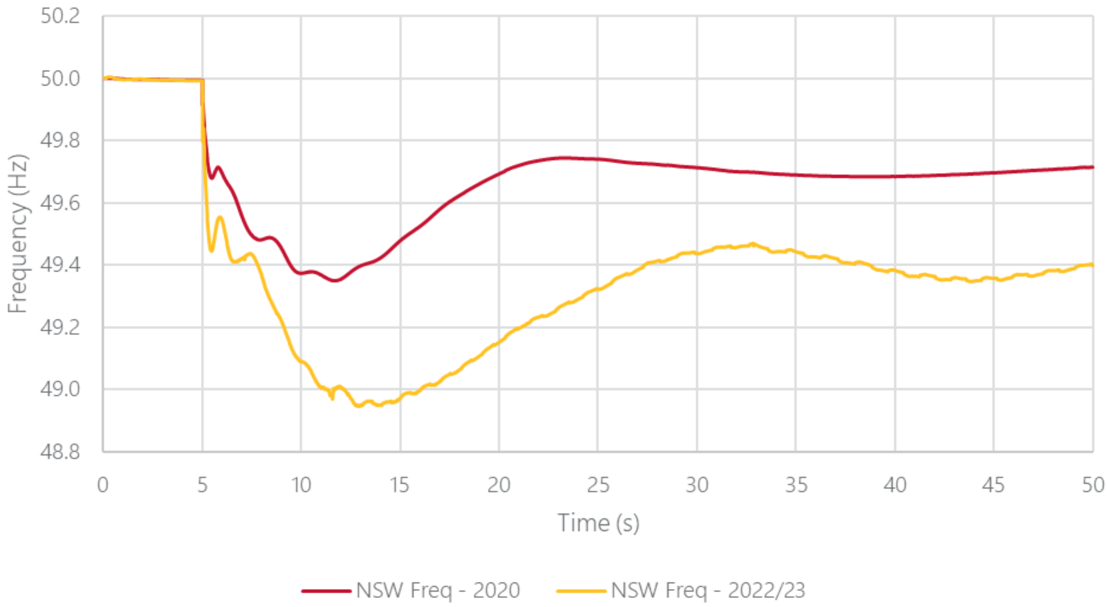
The two future cases made different assumptions regarding the available PFR in Queensland. One case modelled all larger generators providing PFR, while the other modelled larger generators contributing no PFR. In the case with PFR modelled, large generators in Queensland with bespoke governor models were assumed to provide a PFR defined by those models while all other generators were assumed to provide a PFR consistent with the published requirement.

The overlay indicates that the over-frequency occurring due to the trip of QNI becomes less onerous over time, if scheduled and semi-scheduled Queensland generating systems provide PFR in line with current requirements. This is primarily due to an increased response to the over-frequency provided from inverter based generation. Increasing the export limit on QNI by 200 MW (simulated by tripping a 200 MW load in Queensland coincident with the trip of QNI), results in an over-frequency no more severe than initially observed in 2020, however the settling frequency is significantly lower due to the additional PFR from DER and additional IBR assumed to replace synchronous generation.

If large IBR generators in Queensland do not contribute PFR in the future case, a significant over-frequency can occur due to non-credible loss of QNI.

Figure 14 shows the New South Wales frequency simulated following the non-credible trip of QNI for the historical case 2 as described in Table 3 and the corresponding future cases in Table 4. The overlay indicates that the under-frequency resulting from this event becomes significantly worse over time, particularly with the planned upgrade of QNI. Simulating a 200 MW increased transfer from Queensland, consistent with the increase expected following the QNI upgrade, results in a significantly higher RoCoF requiring some load shedding in the rest of the NEM.

Figure 14 Overlay of New South Wales frequency response for boundary condition and future cases for loss of QNI when exporting



A2.1.2 Sensitivity studies exploring future conditions when importing into Queensland

Figure 15 and Figure 16 show the Queensland frequency simulated following the non-credible trip of QNI for the historical Case 8 and future cases (Cases 8d and 8e) as described in Table 6 and Table 7.

The future cases model different assumptions regarding the amount of PFR provided by large generators in Queensland in 2022-23. The overlay indicates that the future reduction in inertia in Queensland, along with a potential for reduced load shedding availability and a potential increase of QNI flows leads to a significantly worse frequency outcome, with a higher RoCoF and a lower frequency nadir. Turning off PFR at all large generators in Queensland in 2022-23 results in the remaining UFLS capability in Queensland being unable to balance the system, and therefore causes a collapse in frequency. Provided Queensland generators deliver PFR, the decline in frequency is arrested and with the aid of UFLS the frequency remains within the limits specified in the FOS. In the case with PFR modelled, large generators in Queensland with bespoke governor models were assumed to provide a PFR defined by those models while all other generators were assumed to provide a PFR consistent with the published requirement. Some of the generators with bespoke governor models were not able to provide a sustained response to correct the under-frequency event.

Figure 15 Overlay of Queensland frequency response for boundary condition and 2022-23 sensitivity cases for loss of QNI when importing

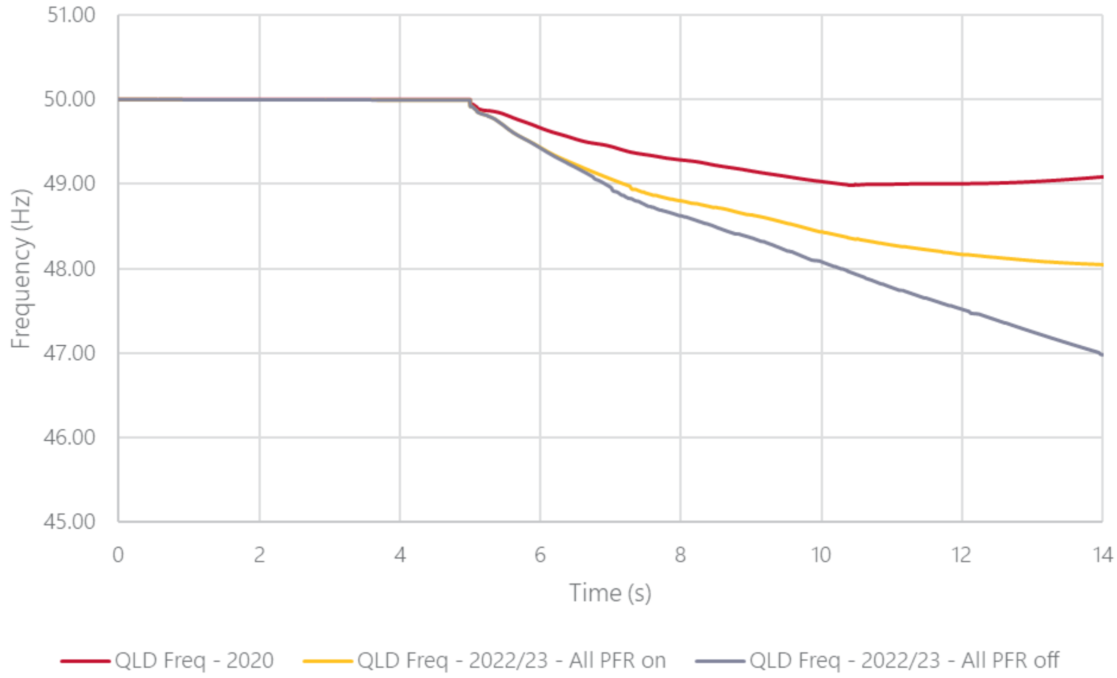


Figure 16 Overlay of Queensland frequency response for boundary condition and 2022-23 sensitivity case with all Queensland PFR enabled for loss of QNI when importing

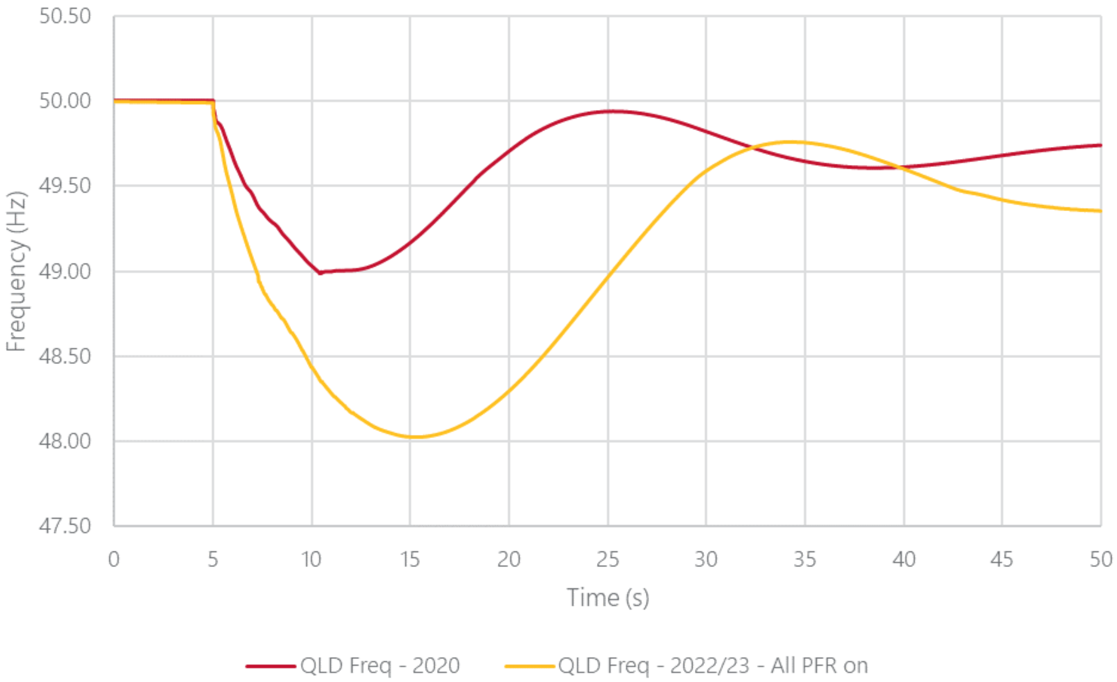
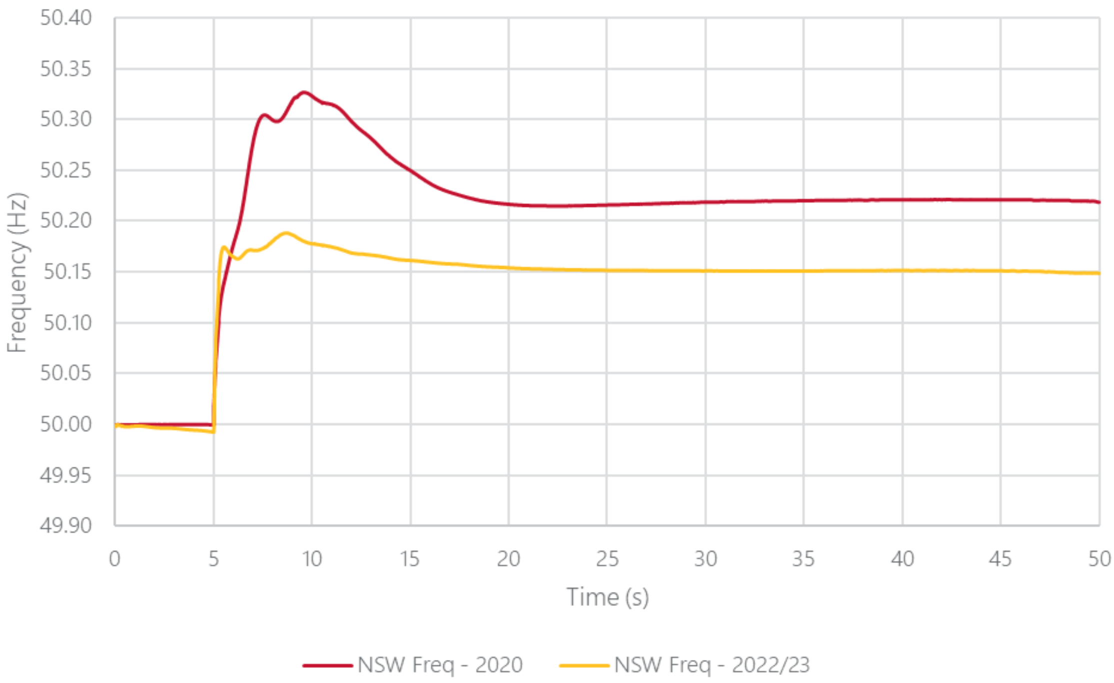


Figure 17 shows the New South Wales frequency simulated following the non-credible trip of QNI for the case 8 boundary condition and corresponding future cases (cases 8d and 8e) described in Table 6 and Table 7. The overlay indicates that the over-frequency occurring due to the trip of QNI becomes less onerous over time, primarily due to an increased response to the over-frequency from inverter connected generation. The presence of PFR in Queensland does not affect the frequency in the remainder of the NEM, and therefore the frequency traces for the future cases are identical. Despite a modelled increase in contingency size resulting from increased QNI flows, and a lower level of inertia resulting in a higher RoCoF, this over-frequency remains less onerous due to the response from inverter based generation including DER.

Figure 17 Overlay of New South Wales frequency response for boundary condition and 2022-23 sensitivity for loss of QNI when importing



A2.2 Loss of VNI leading to New South Wales and Victoria separation

A2.2.1 Future scenario 2022-23 studies – Victoria importing

Figure 18 shows the New South Wales frequency simulated following the non-credible separation of VNI for the case 1 boundary condition and a future case as described in Table 6 and Table 7.

The future case models a variation of the conditions expected in 2022-23. The overlay indicates that the future reduction in inertia on the NEM in New South Wales and Queensland, along with an increase in levels of connected IBR and DER results in a similar frequency response within the northern island in the present and future case. Frequency remains within the acceptable operating standard, and over-frequency is slightly improved due to a faster droop response from IBR and DER than currently provided by synchronous generators.

Figure 18 Overlay of New South Wales frequency response for boundary condition and future case for non-credible loss of VNI circuits when importing to Victoria

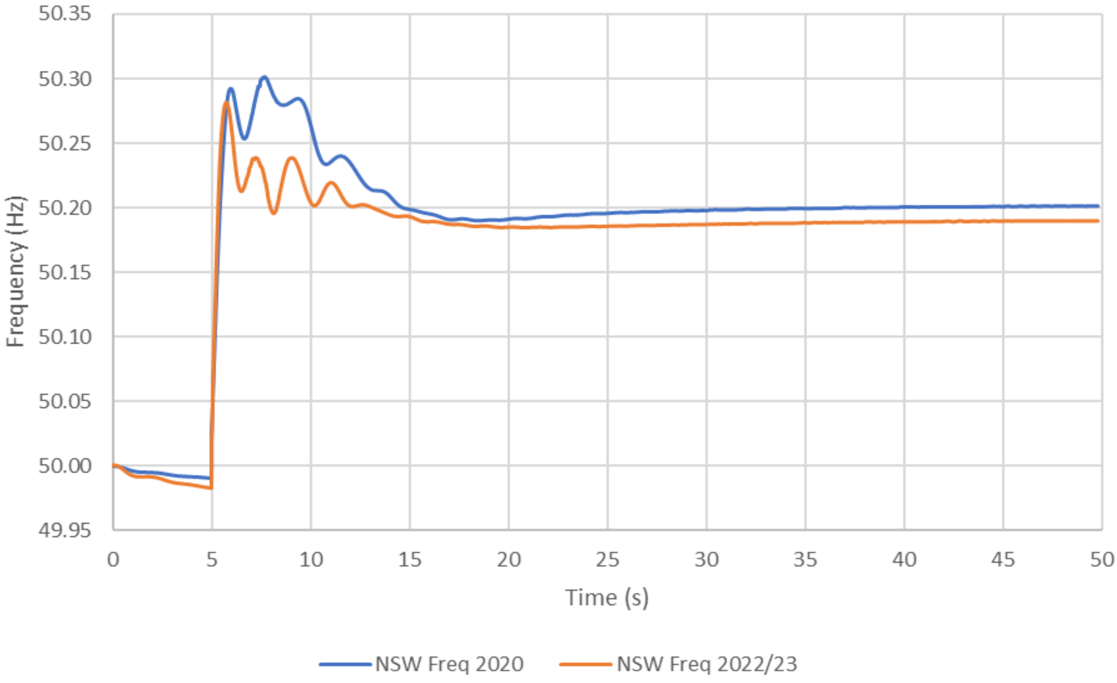
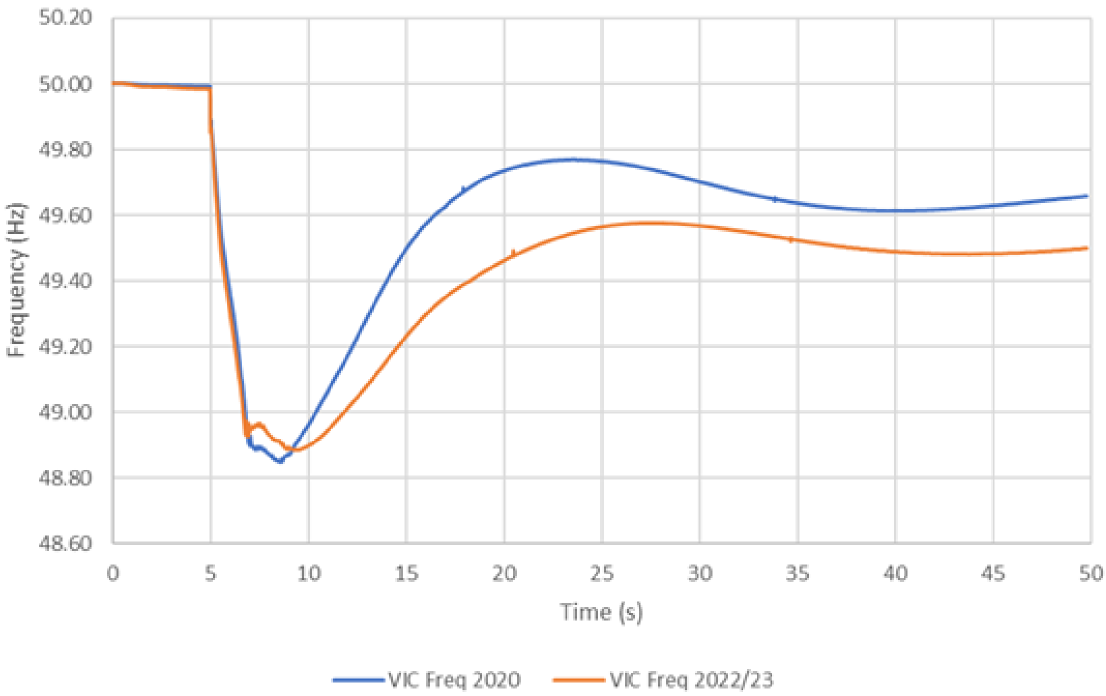


Figure 19 shows the Victoria frequency simulated following the non-credible separation of VNI for the case 1 boundary condition and a future case as described in Table 6 and Table 7.

Figure 19 Overlay of Victoria frequency response for boundary condition and future case for non-credible loss of VNI circuits when importing to Victoria



The future case models a variation of the conditions expected in 2022-23. The overlay indicates that the future reduction in inertia on the NEM in Victoria, along with an increase in levels of connected IBR and DER results in a similar frequency response in Victoria in the present and future case. Frequency remains within the acceptable operating standard, although significant load shedding is required in both cases. A marginally higher RoCoF and lower amount of load shedding is observed in the future case, resulting in a marginally worse frequency recovery.

A2.2.2 Future scenario 2022-23 studies – New South Wales importing

Figure 20 shows the New South Wales frequency simulated following the non-credible separation of VNI for the case 2 boundary condition and a future case as described in Table 14 and Table 15. The future case models a variation of the conditions expected in 2022-23. The overlay indicates that the future reduction in inertia on the NEM in New South Wales and Queensland, along with an increase in levels of connected IBR and DER results in a marginally worse frequency response within the northern island in the present and future case, with a lower settling frequency and frequency nadir and a higher RoCoF. However, frequency remains within the acceptable operating standard.

Figure 20 Overlay of New South Wales frequency response for boundary condition and future case for non-credible loss of VNI circuits when exporting to New South Wales

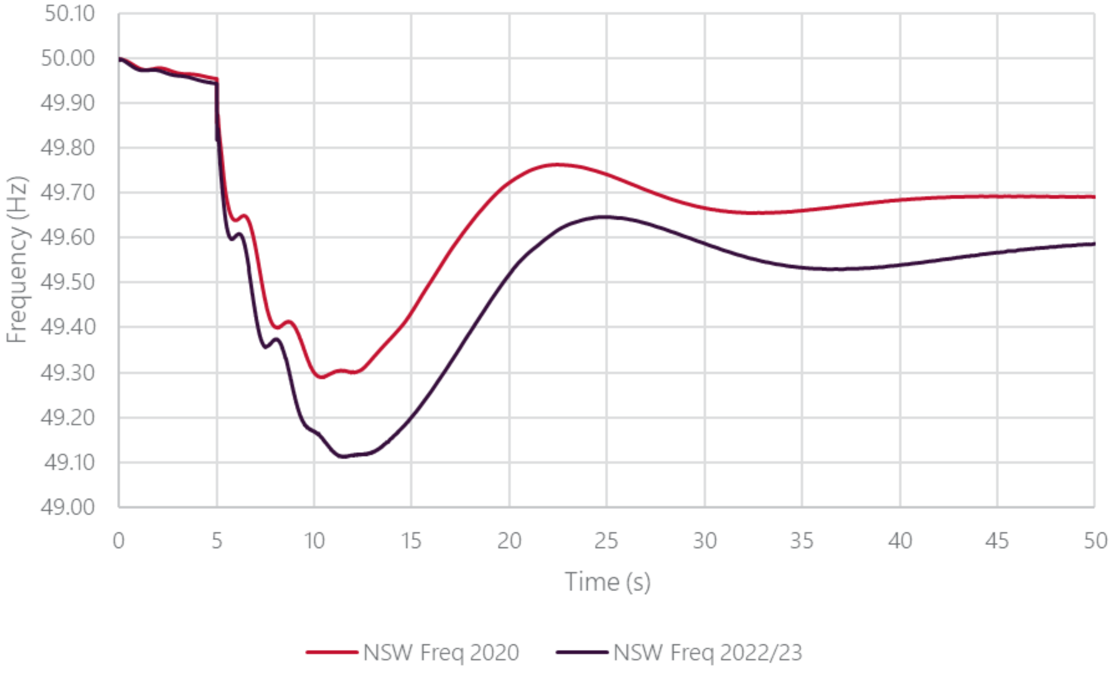
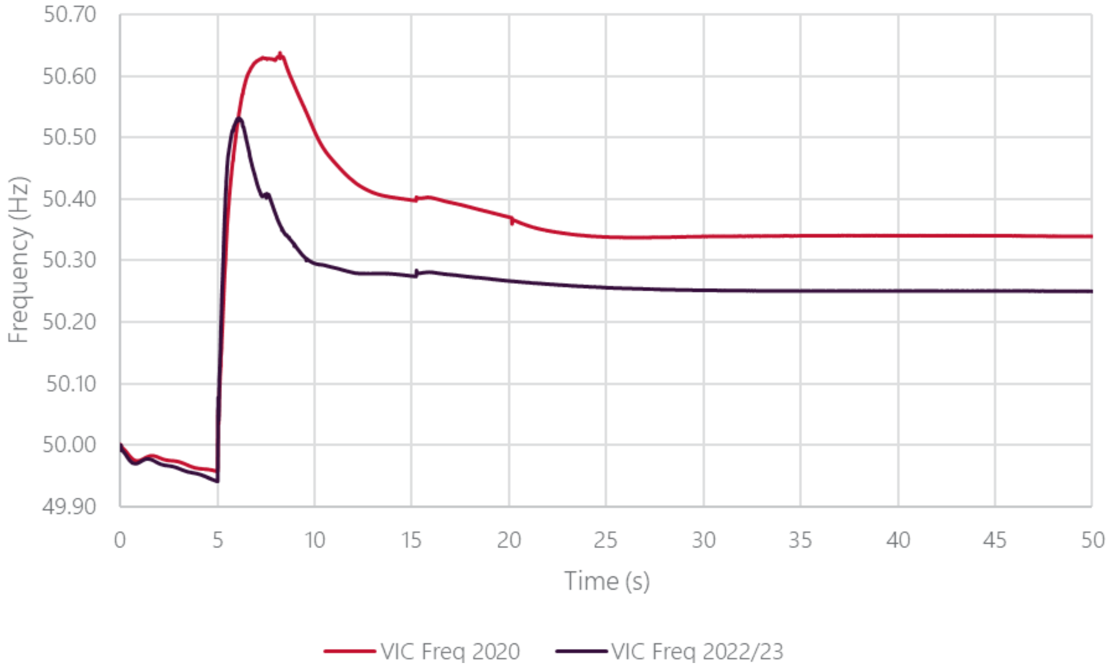


Figure 21 shows the Victoria frequency simulated following the non-credible separation of VNI for the Case 2 boundary condition and a future case as described in Table 14 and Table 15. The future case models a variation of the conditions expected in 2022-23. The overlay indicates that the future reduction in inertia on the NEM in Victoria, along with an increase in levels of connected IBR and DER results in a marginally improved frequency response in Victoria in the present and future case. Frequency remains within the acceptable operating standard, and over-frequency is slightly improved due to a faster droop response from IBR and DER than currently provided by synchronous generators.

Figure 21 Overlay of Victoria frequency response for boundary condition and future case for non-credible loss of VNI circuits when importing to New South Wales



A2.3 Loss of the Heywood interconnector leading to Victoria and South Australia separation

A2.3.1 Historical case studies – South Australia import

Figure 22 shows the South Australia frequency simulated following the non-credible trip of Heywood interconnector for the Case 10 historical boundary condition described in Table 17.

Figure 22 South Australia frequency response for Moorabool non-credible contingency for historical case 10

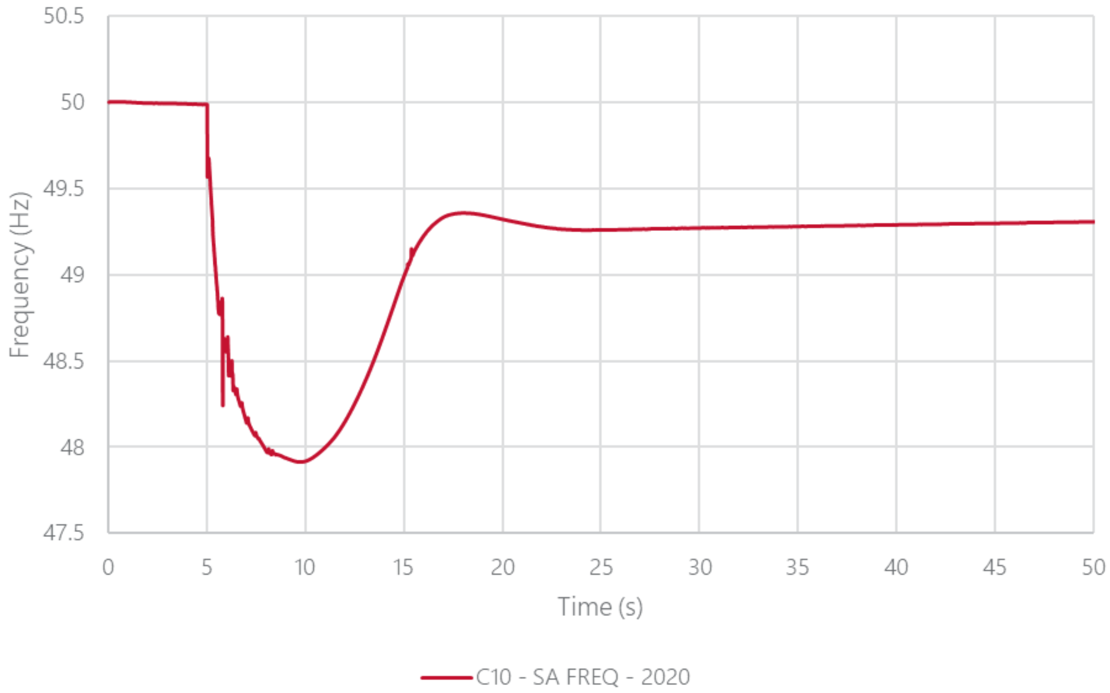
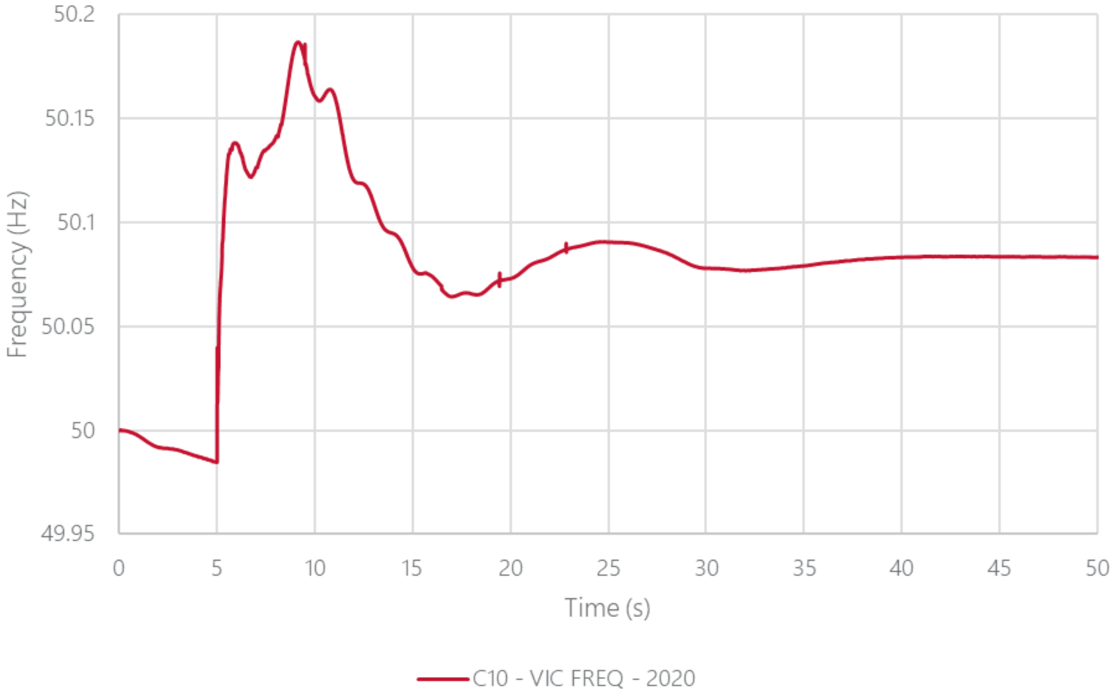


Figure 23 shows the Victorian frequency for the same event. The South Australia frequency was regulated through UFLS action and the Victorian frequency was managed well for the event.

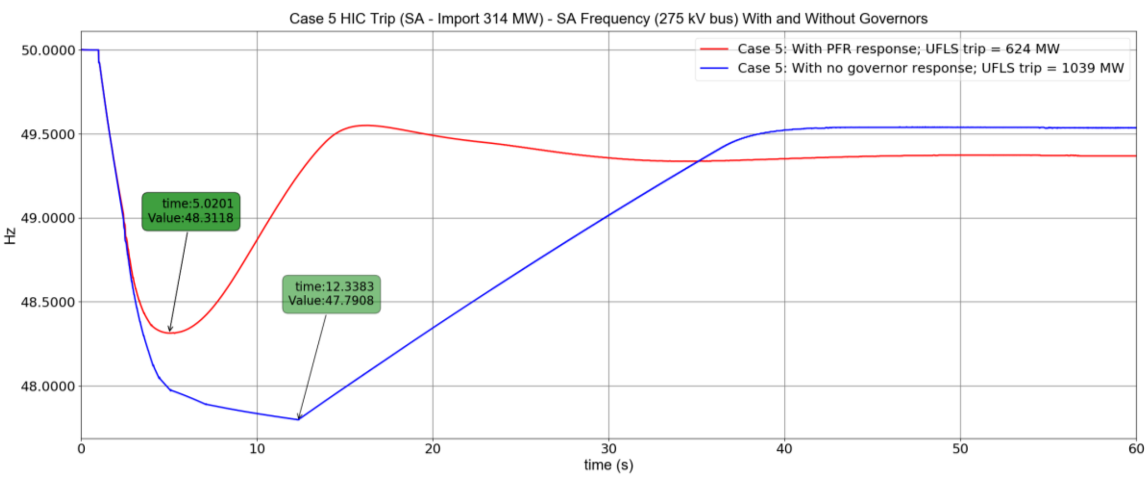
Figure 23 Victoria frequency response for Moorabool non-credible contingency for historical Case 10



A2.3.2 Future scenario 2022-23 studies – South Australia import

The frequency comparison with and without PFR for case 5 mentioned in Table 22 and Table 23 for South Australia separation from HYTS when importing is given in Figure 24. The figure shows that without generator PFR support the frequency nadir will be lower and the frequency recovery will be slower.

Figure 24 South Australia import frequency comparison with and without PFR for Case 5



A2.3.3 Historical case studies – South Australia export

Figure 25 shows the simulated South Australian frequency following the non-credible trip of the Heywood interconnector for the Case 3 historical boundary condition study detailed in Section 4.3.3.

Figure 25 **South Australia frequency response for Heywood interconnector non-credible contingency for historical Case 3**

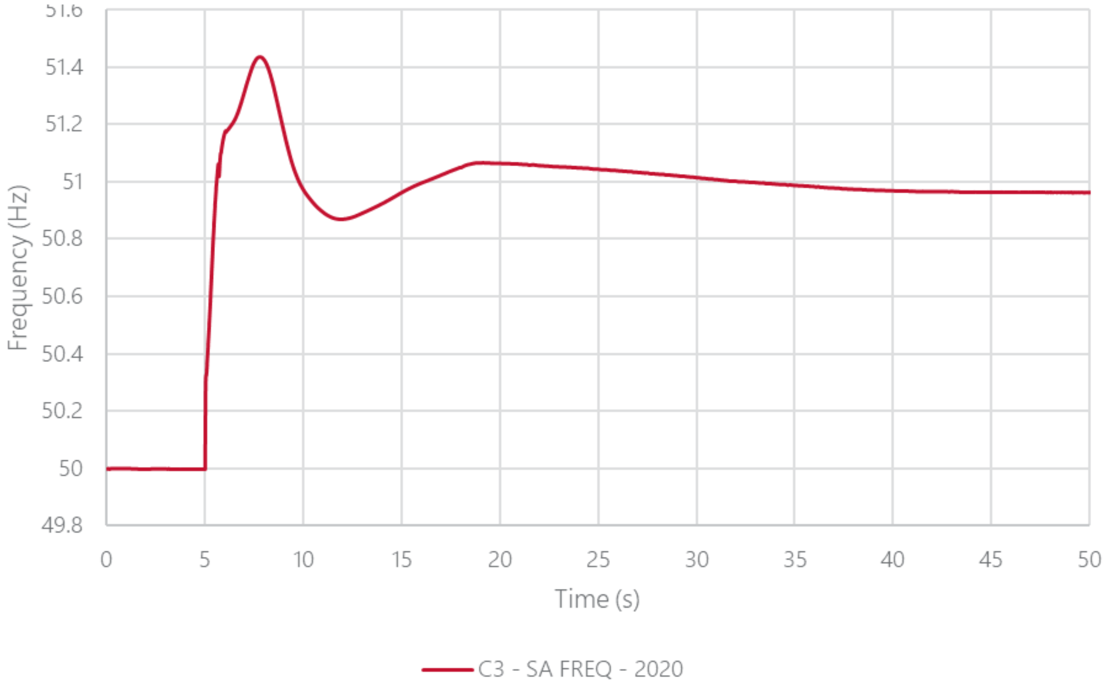
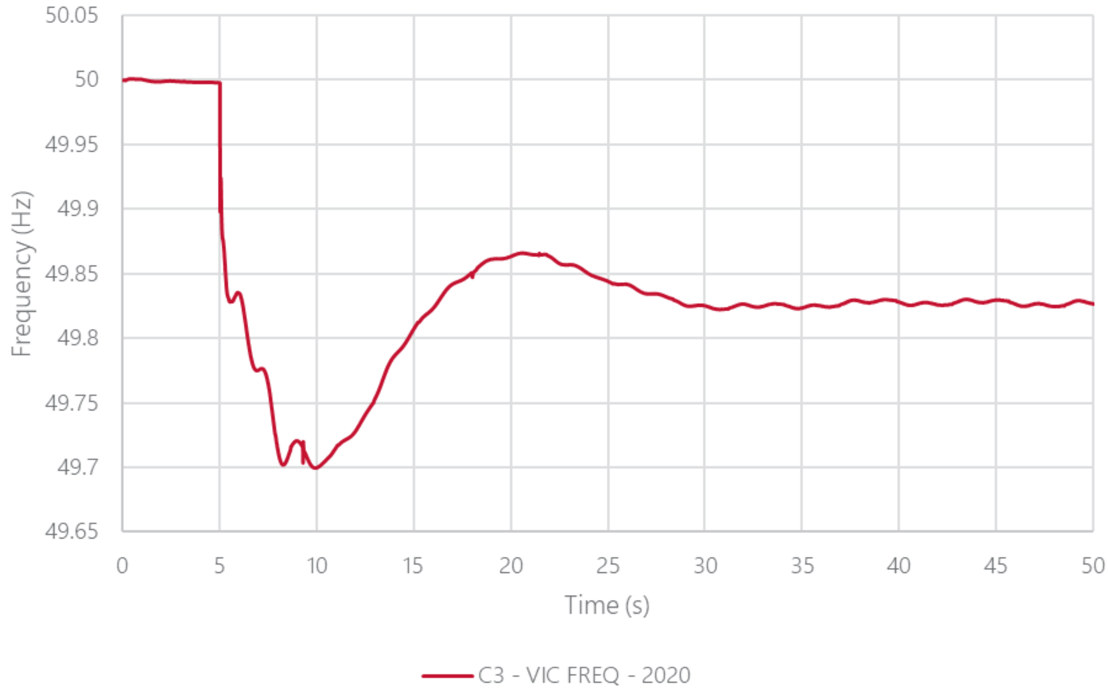


Figure 26 shows the simulated Victorian frequency for the event, showing that South Australia frequency was managed well with OFGS action and the remaining NEM frequency could be regulated without UFLS actions.

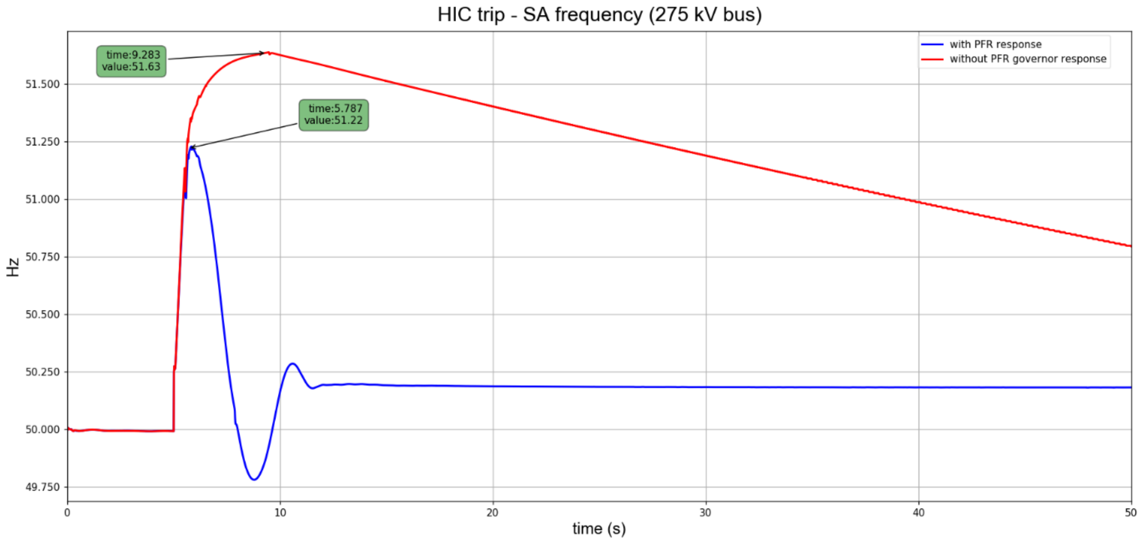
Figure 26 **Victoria frequency response for Heywood interconnector non-credible contingency for historical Case 3**



A2.3.4 Future scenario 2022-23 studies – South Australia export

The frequency comparison with and without PFR for Scenario 1 case 4_a mentioned in Table 19 and Table 20 is shown in Figure 27. The figure shows that without PFR support the frequency peak will be higher and the frequency recovery will be slower.

Figure 27 Frequency with and without PFR for South Australia export during the double-circuit loss of the Heywood interconnector for Scenario 1 Case 4_a



A2.4 Double-circuit trip of MLTS-MOPS and MLTS-HGTS, leading to Victoria and South Australia separation

A2.4.1 Historical case studies – South Australia import

Figure 28 shows the islanded South Australian frequency simulated following the non-credible trip of the Heywood interconnector for the case 10A boundary condition (described in Table 29). The frequency trace indicates that the under-frequency occurring in the islanded South Australia network due to the trip of the Moorabool circuits when South Australia is importing is onerous for the system, resulting in a high RoCoF and significant under-frequency load shedding. However, frequency remains within the limits specified in the FOS.

Figure 29 shows the Victoria frequency simulated following the non-credible trip of the Moorabool circuits for the Case 10A boundary condition (described in Table 29) The frequency trace indicates that the over-frequency occurring on the remainder of the NEM due to the trip of the Moorabool circuits when South Australia is importing is not particularly onerous for the system, frequency remaining well within the limits specified in the FOS.

Figure 28 South Australia frequency response for Moorabool non-credible contingency for Case 10A

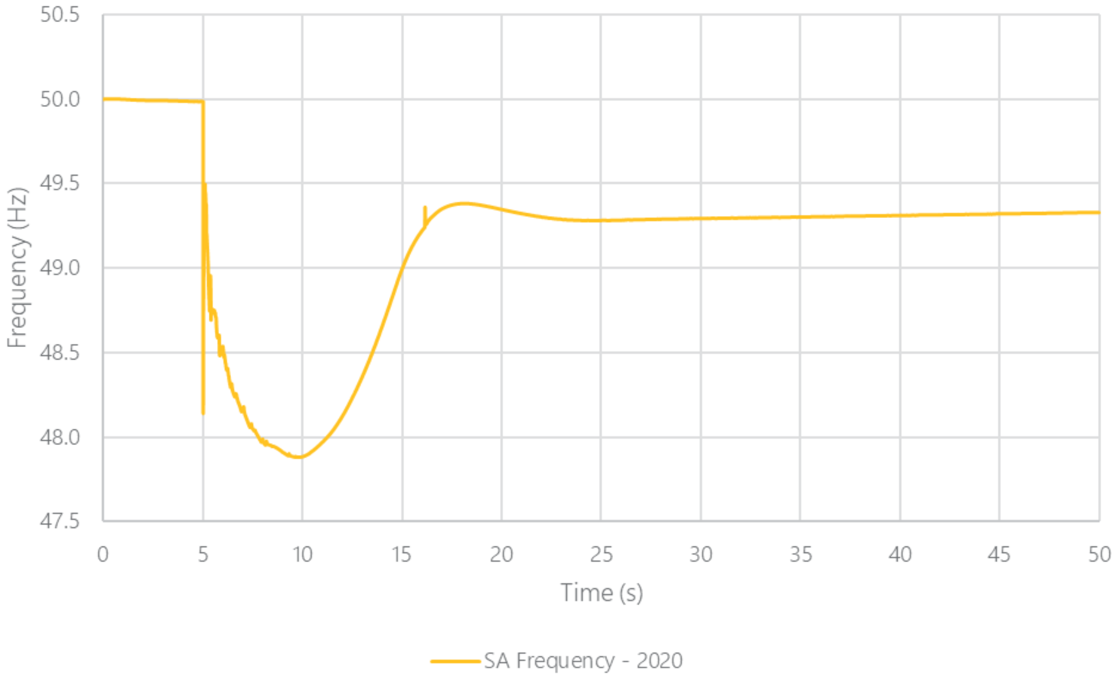
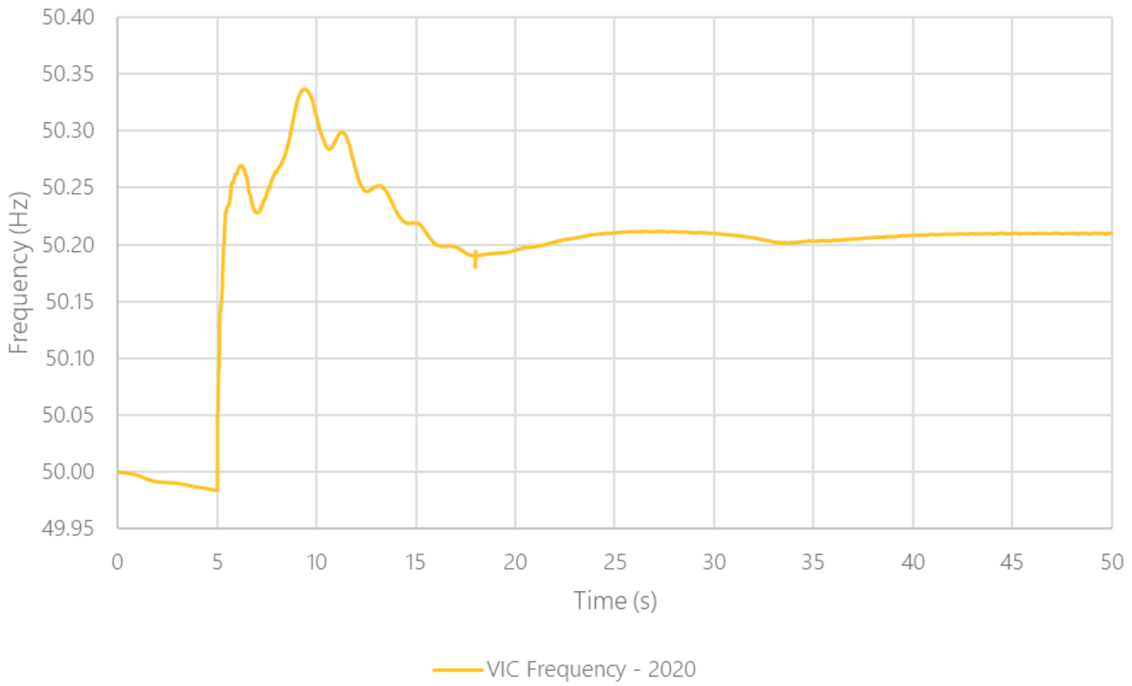


Figure 29 Victoria frequency response for Moorabool non-credible contingency for Case 10A



A2.4.2 Future scenario 2022-23 studies SA export – the double-circuit loss of MLTS-MOPS and MLTS-HGTS

The frequency trends for Scenario 1 case 4_a and case 4_b (as described in Table 27 and Table 28 with and without PFR during the double-circuit loss of MLTS-MOPS and MLTS-HGTS are shown in Figure 30 and Figure 31, respectively.

Figure 30 demonstrates that with a low amount of OFGS wind generation available and no PFR, the frequency might exceed the FOS limits and the system will likely collapse. The results highlight the importance of sufficient available OFGS generation in South Australia during high export conditions.

To investigate the effectiveness of the presence of more OFGS generation in comparison with Scenario 1 Case 4_a, a higher OFGS dispatch case in Scenario 1 Case 4b was used. The increased OFGS generation helped to limit the frequency peak below 52 Hz as shown in Figure 31. The Case 4b simulations were repeated without the governor response and the results included in Figure 31. The results indicate that without governor response the frequency is not recovering to within FOS limits. This result emphasises the importance of PFR for frequency recovery.

Figure 30 Frequency with and without PFR for South Australia export during the double-circuit loss of MLTS-MOPS and MLTS-HGTS for Scenario 1 Case 4_a

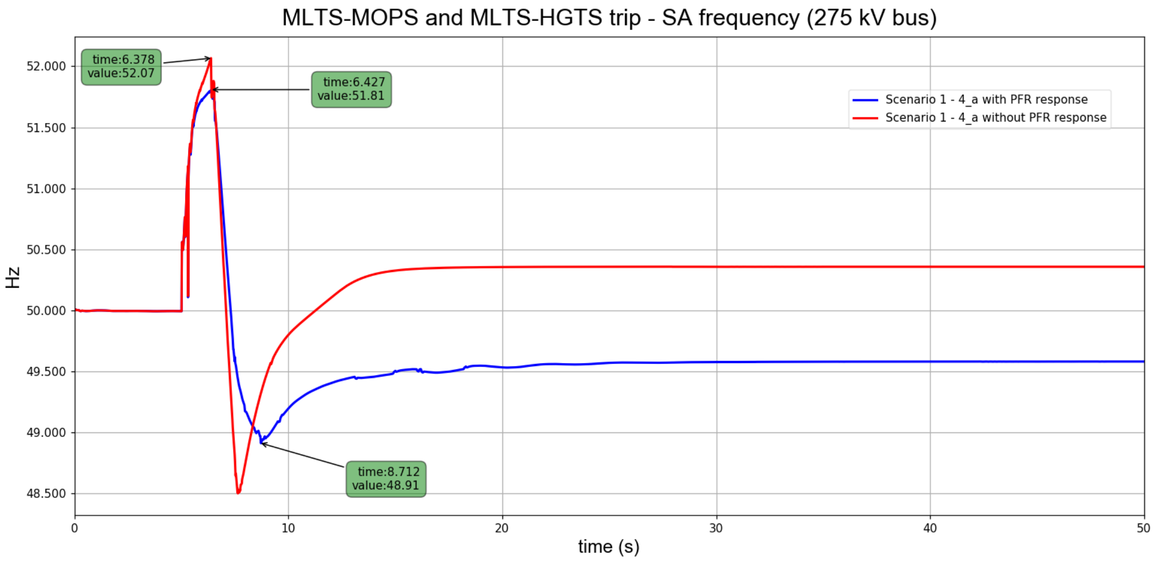
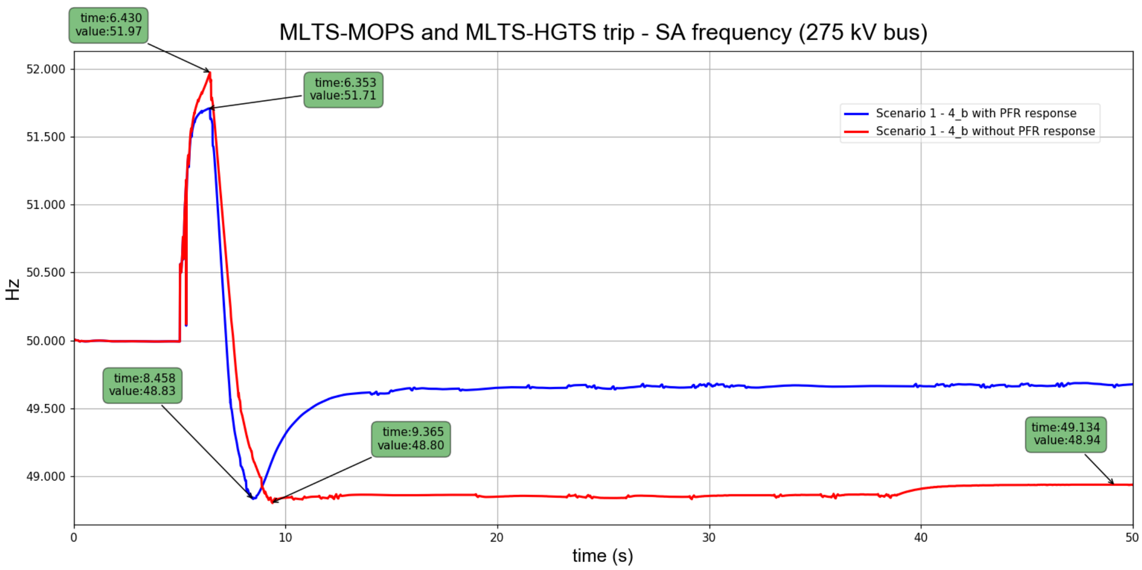


Figure 31 Frequency with and without PFR for South Australia export during the double-circuit loss of MLTS-MOPS and MLTS-HGTS for Scenario 1 Case 4_b



A2.4.3 Historical case studies – South Australia export

Figure 32 shows the islanded South Australian frequency simulated following the non-credible trip of the Moorabool circuits for the case 4 boundary condition (described in Table 24). The frequency trace indicates that the over-frequency occurring in South Australia is onerous when South Australia is exporting. However, South Australia frequency remains within the limits specified in the FOS.

Figure 32 South Australia frequency response for Moorabool non-credible contingency for Case 4

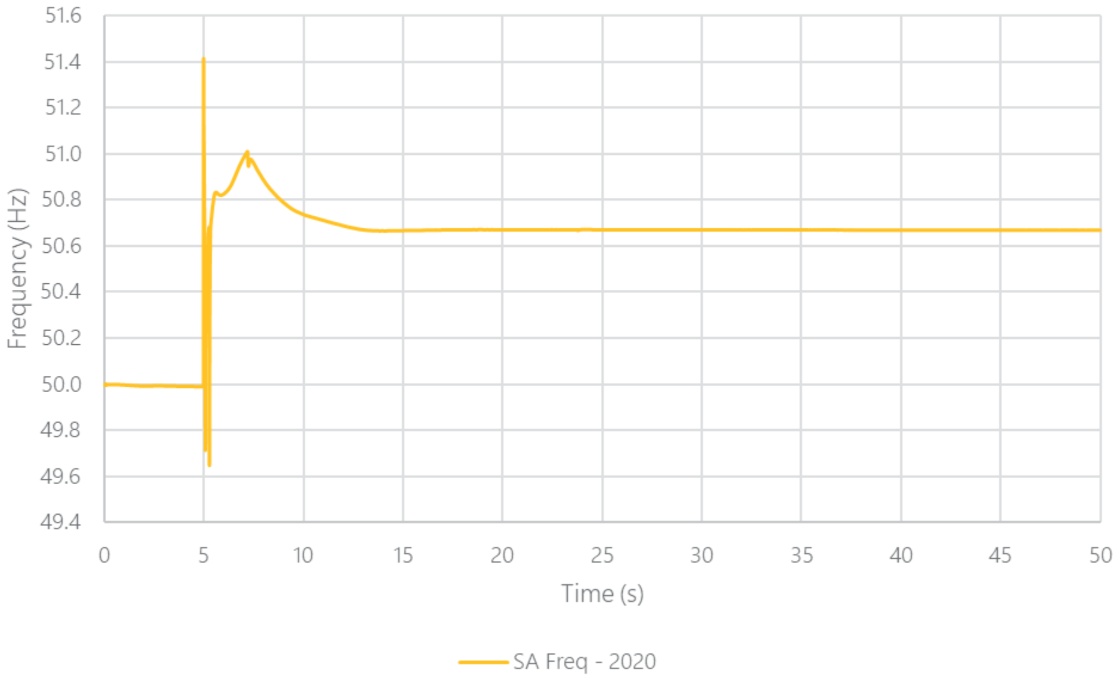
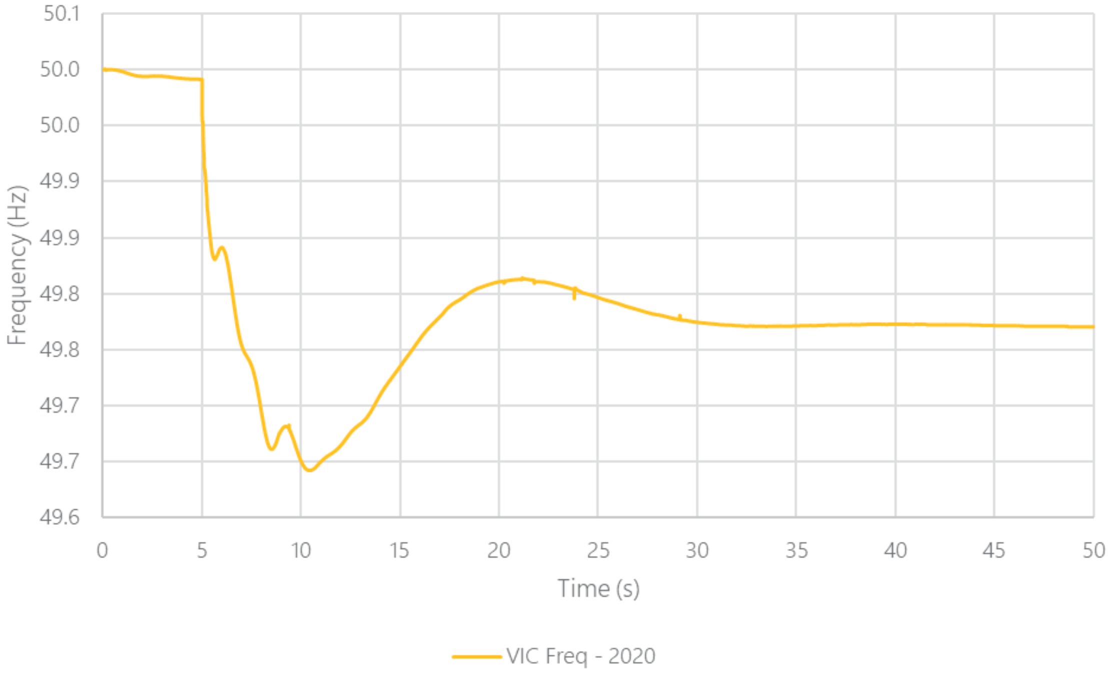


Figure 33 shows the Victoria frequency simulated following the non-credible trip of the Moorabool circuits for the Case 4 boundary condition (described in Table 24). The frequency trace indicates that the under-frequency occurring on the remainder of the NEM due to the trip of the Moorabool circuits when exporting is not particularly onerous for the system, remaining well within the limits specified in the FOS.

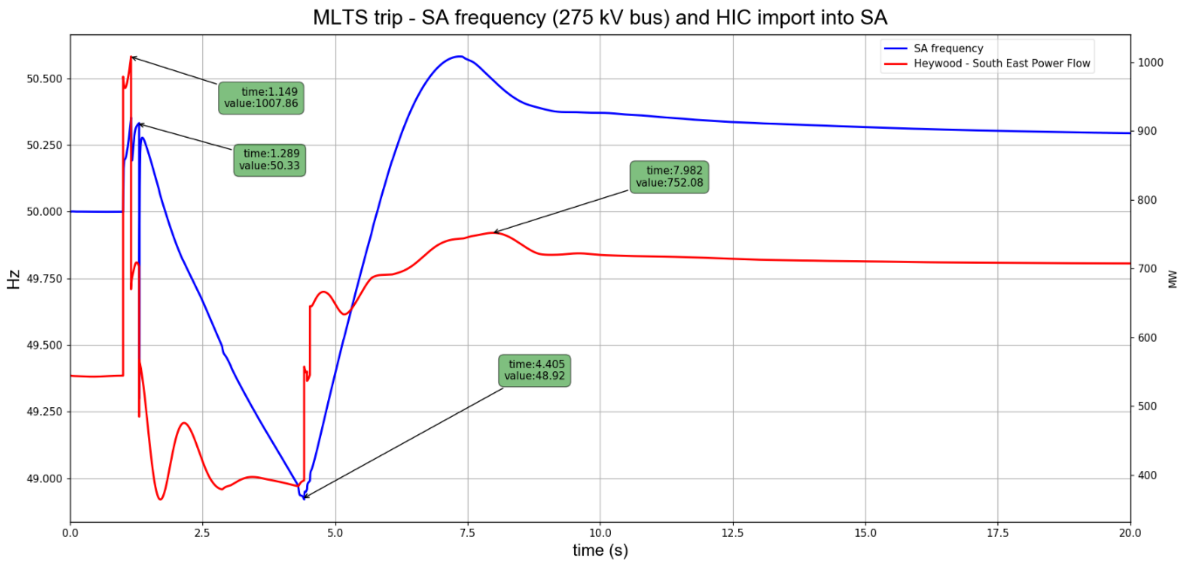
Figure 33 Victoria frequency response for Moorabool non-credible contingency for Case 4



A2.4.4 Future scenario 2022-23 studies South Australia import – the double-circuit loss of MLTS-MOPS and MLTS-HGTS

The South Australia frequency and Heywood interconnector power flow responses for Scenario 1 Case 7 described in Section 4.4.4 are shown in Figure 34.

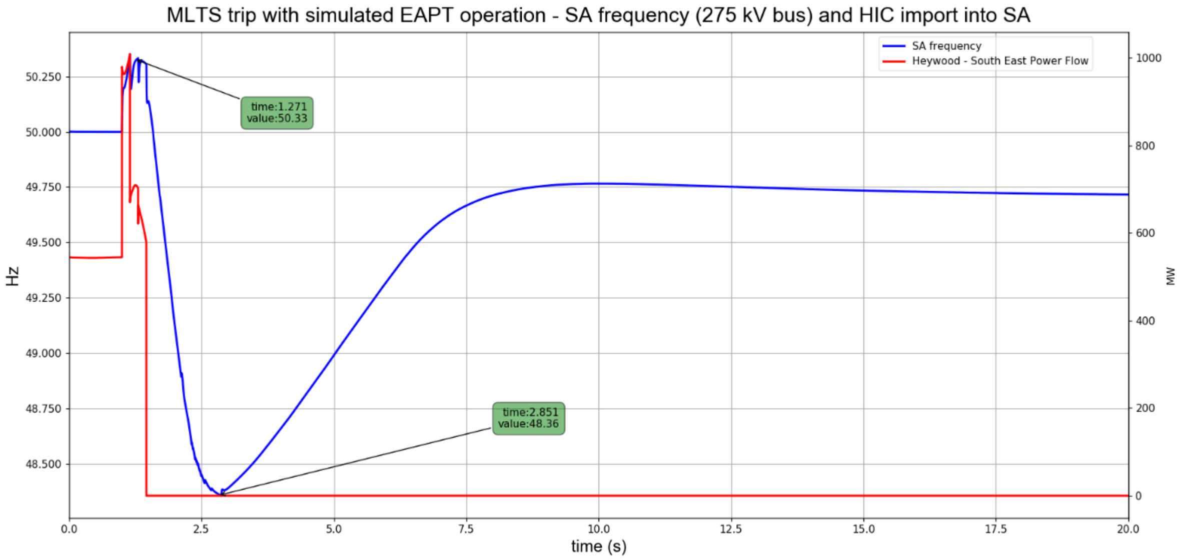
Figure 34 Frequency and Heywood interconnector import into South Australia with PFR for Scenario 1 Case 7



In this simulation, the separation initially causes a rise in system frequency before generation between MLTS and HYTS are tripped due to protection operation and the frequency falls. The EAPT scheme is observed not to operate and as a result APD load and some South Australia load are shed in UFLS. The Heywood interconnector import into South Australia is observed to exceed the SIPS Stage 1 threshold following APD trip, meaning it is possible for a BESS response to result from such an event which could exacerbate the over-frequency. There is also a possibility that the very high level of import observed immediately after the separation at MLTS could cause the out of step component of the SIPS Stage 2 to operate and shed load within South Australia. This eventuality as not been simulated.

A sensitivity study considering the outcome in the event that the EAPT scheme does operate immediately after the initial separation event is presented in Figure 35. The main different in this case is that the South Australia frequency nadir reaches a much lower value (~48.3 Hz compared to ~48.9 Hz) and a much larger quantity of load within South Australia is shed. In both cases the entire APD load is lost, to UFLS operation in the case where EAPT does not operate and due to collapse of the small island between HYTS and MLTS in the instance where it does operate.

Figure 35 Frequency and Heywood interconnector import into South Australia with PFR for Scenario 1 Case 7 for a simulated operation of EAPT



A2.5 Loss of double-circuit Calvale – Halys transmission line between Central and South Queensland

A2.5.1 Future case 2022-23 studies – QNI exporting

Figure 36 shows the power flows across key circuits following the non-credible trip of the Calvale – Halys transmission lines for case 3 boundary condition and the future case reflecting inertia, IBR and DER projected by 2022-23. Conditions for these cases are described in Section 4.5.2 and 4.5.3.

The figure indicates that the loss of the Calvale – Halys circuit and Callide units lead to a rapid reduction in power flows on the QNI. The future case was established to have an identical load flow to the present case, with an identical Calvale-Halys line transfer. The future case result is very similar to the original boundary condition result indicating a low sensitivity to the modelled changes in synchronous generation, IBR and DER.

Figure 37 shows the simulated Queensland frequency following the non-credible trip of the Calvale-Halys circuit for the Case 3 (described in Section 4.5.2 and 4.5.3) boundary condition and the 2022-23 sensitivity study. For both the boundary condition and the 2022-23 future case, Central Queensland does not separate from the wider NEM following the trip of both Calvale – Halys lines. The figure shows that the under-frequency performance is marginally worse in the future case.

Figure 36 Power flows across key circuits for CQ-SQ non-credible contingency for case 3 and 2022-23 sensitivity

Figure 37 Queensland frequency response for CQ-SQ non-credible contingency for case 3 and 2022-23 sensitivity

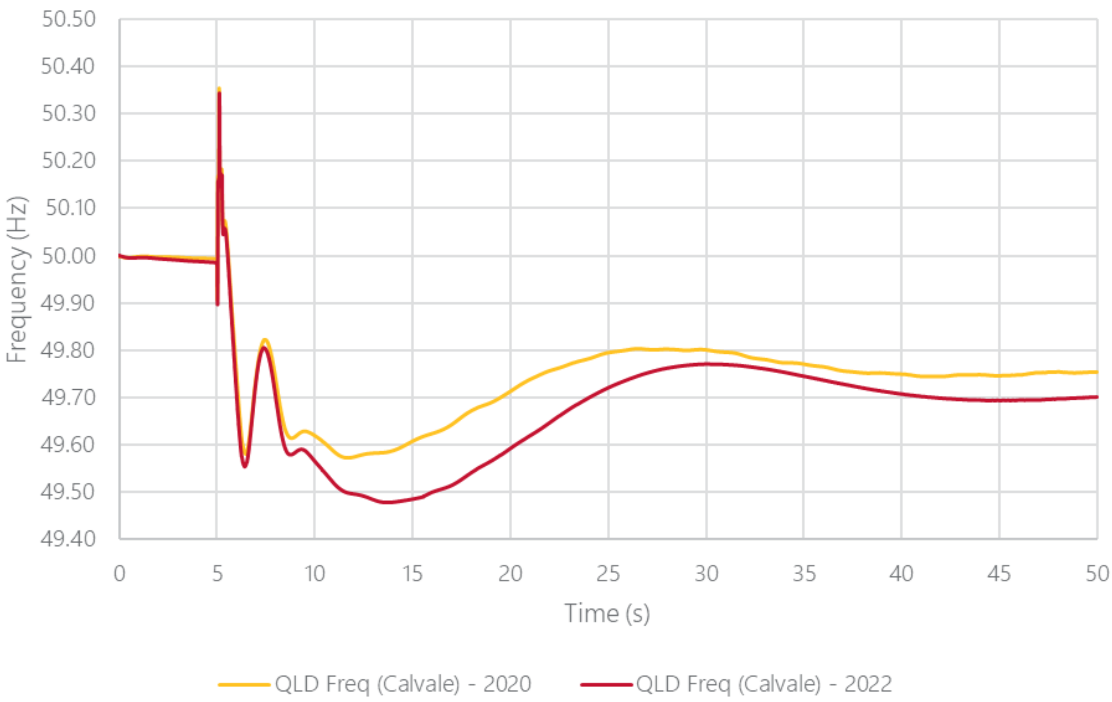
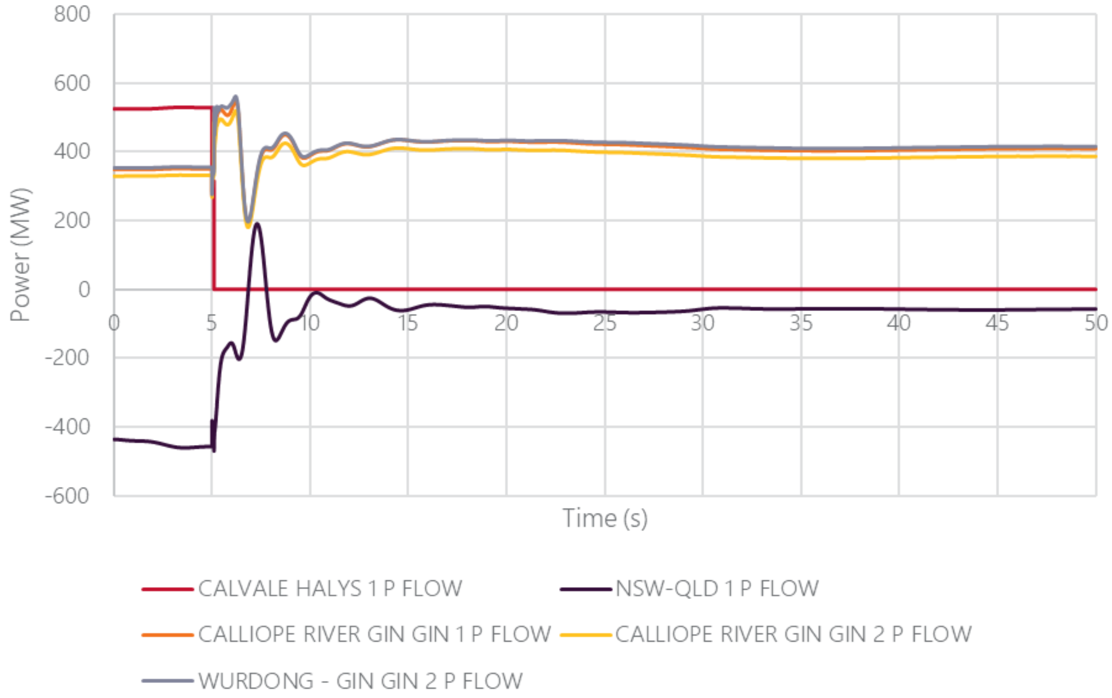


Figure 38 shows the results of a further sensitivity study undertaken on Case 6, (described in Section 4.5.2) which augmented the CQ-SQ special protection scheme by tripping additional renewable generation in Central and North Queensland in addition to the Callide generating units. The tripping of the additional renewable generation was sufficient to avoid loss of synchronism across the remaining CQ-SQ circuits following the non-credible loss of the Calvale – Halys transmission line.

Figure 38 Power flows across key circuits for CQ-SQ non-credible contingency for Case 6 sensitivity



A2.5.2 Future case 2022-23 studies – QNI importing

Figure 39 shows the power flows across key circuits following the non-credible trip of the Calvale – Halys transmission line for the Case 10 (described in Section 4.5.5 and 4.5.6) boundary condition and the 2022-23 sensitivity study. The figure indicates that the loss of the Calvale – Halys circuits lead to a rapid increase in power flows on the QNI, but does not result in instability in this case. Calvale – Halys flows are identical in both studies.

Figure 40 shows the Queensland frequency simulated following the trip of both Calvale – Halys lines for the Case 10 (described in Section 4.5.5 and Section 4.5.6) boundary condition and the 2022-23 sensitivity study. The figure indicates that Central Queensland does not become separated from the wider NEM under this non-credible trip, and that under-frequency performance is marginally worse in the future case.

Figure 41 shows the results of a further sensitivity study undertaken on Case 9 (described in Section 4.5.4), which augmented the CQ-SQ SPS by tripping renewable generation in Central and North Queensland in addition to the Callide generating units. This further sensitivity study also modelled in detail the upgrade of QNI, to determine whether the additional reactive compensation equipment installed would result in stable operation under the CQ-SQ contingency. However, the risk of instability remained in this sensitivity study despite this upgrade, with the trip of both Calvale-Halys lines following a three phase fault resulting in a loss of synchronism across QNI.

Figure 39 Power flows across key circuits for CQ-SQ non-credible contingency for Case 10 and 2022-23 sensitivity

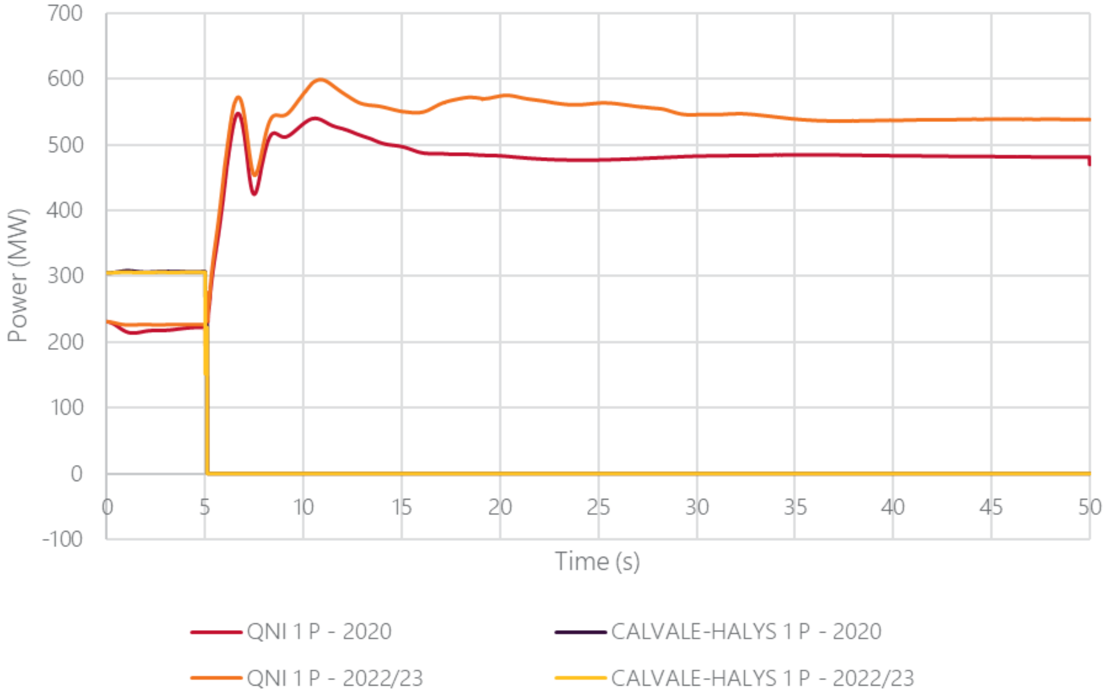


Figure 40 Queensland frequency response for CQ-SQ non-credible contingency for Case 10 and 2022-23 sensitivity

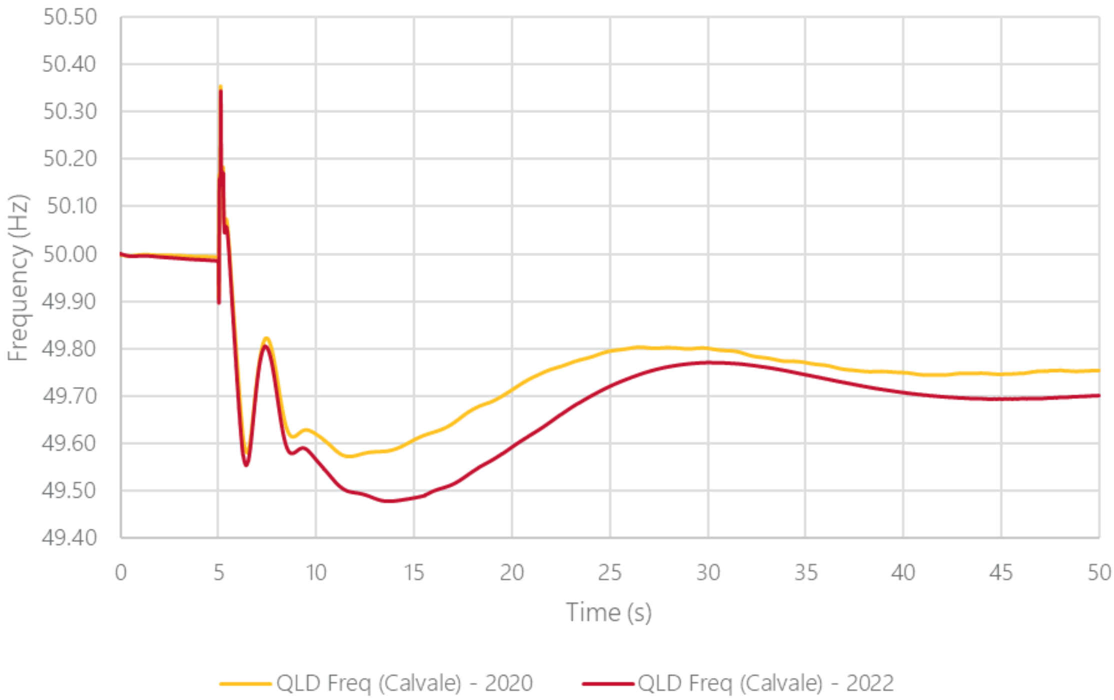
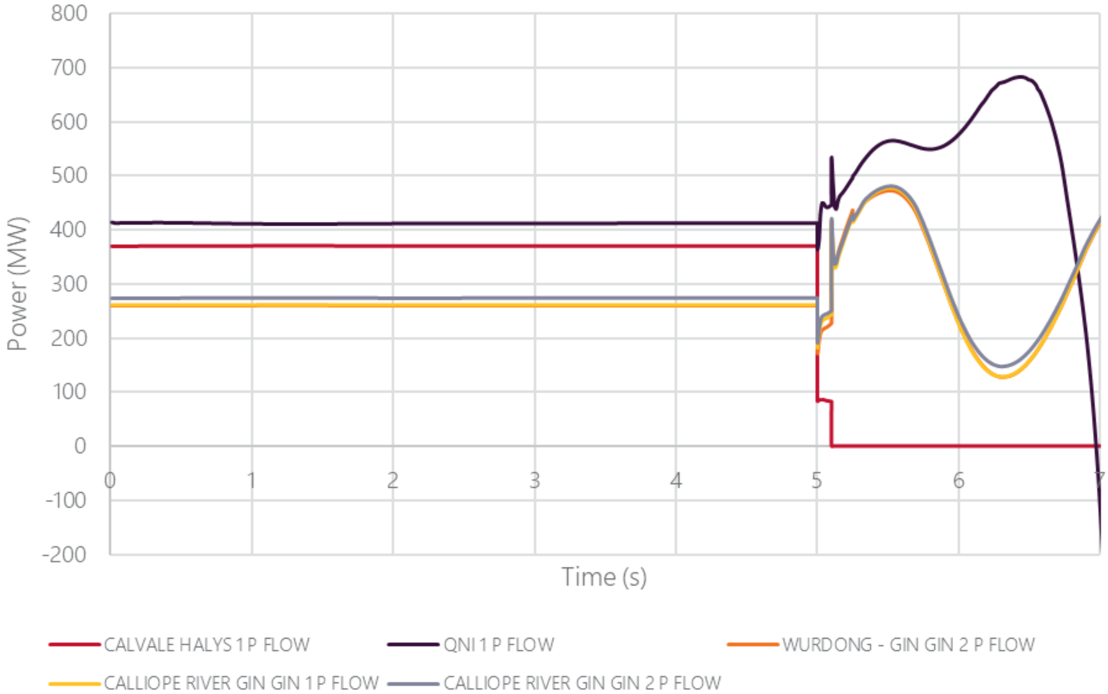


Figure 41 Power flows across key circuits for CQ-SQ non-credible contingency for case 9 sensitivity incorporating QNI upgrade



A3. Stage 2 consultation – summary of key feedback and responses

1. Comment: In the Q&A session, AEMO was asked to clarify current planning assumptions relating to ongoing operation of synchronous generators in South Australia and associated synchronous condenser regulatory approval assumptions.
   - Response: At present, at least four synchronous generators are required to remain online to manage power system security in South Australia[53]. Further to the discussion in the Executive Summary and Section 3.3.2 of this report, AEMO's present planning assumption is that two synchronous generators will be required to remain online at all times following the commissioning of two synchronous condensers at Davenport and two synchronous condensers at Robertstown[54]. This requirement is expected to further reduce if a new interconnector between South Australia and the other NEM regions is constructed. AEMO refers interested parties to ElectraNet's economic valuation report[55] and the AER's contingent project approval report[56] for further information.
2. Comment: Through the consultation feedback, the AER expressed a view that the NER require AEMO to review the planning assumption that two synchronous generating units be on at all times to manage the loss of the Heywood interconnector as part of its 2020 PSFRR.
   - Response: AEMO agrees that consideration of non-credible loss of the Heywood interconnector is within the scope of the PSFRR. However, the broader suite of planning assumptions underlying PSFRR analysis is used across a range of AEMO's planning and forecasting activities and cannot reasonably be revised or reviewed specifically for the PSFRR process. Planning assumptions do require regular review, a process that requires extensive analysis and relies on input and information from participants, NSPs in particular. Further to item 1 above, AEMO is presently assessing ongoing requirements to manage security in South Australia following the commissioning of two synchronous condensers at Davenport and two synchronous condensers at Robertstown. That analysis is expected to be completed in Q1 2021, and will define operating requirements for secure operation of South Australia. These requirements will define a baseline for assessment of whether additional measures may be necessary and economically justified to manage non-credible contingency events. Following completion of this work, AEMO will consider the merits of undertaking an interim 2021 PSFRR to investigate and report on

[53] See https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf?la=en.

[54] See https://www.aer.gov.au/system/files/AEMO%20-%20Assumptions%20for%20South%20Australian%20GPG%20in%20the%202018%20ISP%20-%20August%202019.pdf.

[55] See https://www.electranet.com.au/wp-content/uploads/2019/02/2019-02-18-System-Strength-Economic-Evaluation-Report-FINAL.pdf.

[56] See https://www.aer.gov.au/system/files/AER%20-%20Final%20Decision%20-%20ElectraNet%20-%20SA%20system%20strength%20contingent%20project%20-%2016%20August%202019.pdf

this particular issue, including any associated recommendations to pursue a further protected event for loss of the Heywood interconnector under certain conditions[57].

  - It should be further noted that similar considerations apply to other regions of the NEM. For example, if system strength requirements in Queensland were to vary the required number of units online, this may require review of limits associated with normal operations as well as potential changes to the impact of non-credible contingencies on frequency stability in the Queensland region. As the power system transforms, it will be increasingly important for AEMO to consider the interdependency between various workstreams that define system operability requirements. AEMO's recent 2020 System Strength and Inertia report includes an infographic illustrating these various dependencies and considerations[58].

3. Comment: In the Q&A session and through the submission from Delta Electricity it was raised that there are a variety of possible (mandatory) Primary Frequency Response (PFR) characteristics, and it was requested that additional studies be undertaken to demonstrate the impact of wider deadband settings, either through the PSFRR or other exercise.
   - Response: Generator governor models used in PSFRR studies are intended to provide an indication of actual frequency performance, however it should be noted that there are a number of uncertainties in the modelling. For example, assumptions regarding the rate of response and the duration that a response is sustained are dependent upon the characteristics of the plant and accuracy of models (or generic models used to represent plant performance where no specific model is available). Furthermore, any exemption or variation to certain mandatory PFR requirements will impact the actual response.
   - To adequately assess other governor response characteristics, detailed modelling information is needed from Registered Participants representing actual plant performance, as AEMO understands that plant performance for a wide deadband response could vary widely across the fleet and be significantly different to PFR capability. This is challenging given legacy model issues (discussed in Section 7.2) and the inherent complexity of (synchronous) generator governor control systems.
   - The initial operating point is also important when assessing the impact of wide deadband settings. For example, for a deadband of +/-500 millihertz (mHz), the initial power system frequency is more likely to be anywhere in the range of 49.85 Hertz (Hz) to 50.15 Hz at the time of a non-credible contingency event. Due to limitations in the PSS/E simulation program used to undertake the PSFRR studies, it is not possible to assess the impact of the initial operating frequency. It is understood that the industry proposal for wide-band frequency response also involves narrow band response, with lower droop and limiters on the maximum active power response. Such a characteristic would be inherently more complex to model through power system simulations, requiring updates or provision of new governor control system models.
   - AEMO acknowledges the benefit of wide deadband response to assist with extreme frequency events, as well as the need to explore how it interacts with the mandatory PFR requirements. AEMO plans to further investigate the frequency control requirements (including wide deadband response) needed following sunset of the current mandatory PFR rules in 2023, as part of the Technical Input on PFR Incentivisation Rule Change[59]. AEMO is committed to working with the Australian Energy Market Commission (AEMC) and industry stakeholders through this review.
4. Comment: In the Q&A session, a comment was made about the potential benefit of regional frequency control ancillary services (FCAS) to address issues such as those experienced on 25 August 2018 where

[57] Noting that the current Heywood protected event recommendation in this 2020 PSFRR is specifically focused on addressing risks during periods of inadequate under-frequency load shedding.

[58] See infographic, AEMO 2020 System Strength and Inertia report, at www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/planning-for-operability.

[59] See https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

there was no contingency lower FCAS dispatched in Queensland, which would have assisted with limiting the resulting over-frequency experienced in Queensland.

  - Response: AEMO acknowledges this issue, and notes similar issues relating to non-credible contingency events on 16 November 2019 and 31 January 2020. Both events resulted in synchronous separation between Victoria and South Australia.
    - On 16 November 2019[60], the South Australian frequency peak reached 50.7 Hz. Additional dispatch of FCAS lower services would have assisted with better management of South Australian over-frequency.
    - On 31 January 2020[61], the South Australian frequency peak reached 51.1 Hz, and the frequency nadir in the Queensland/New South Wales/Victoria island reached 49.66 Hz. A disproportionate amount of enabled FCAS raise was located in South Australia, which therefore did not assist in limiting the under-frequency in the remainder of NEM mainland regions. Additional dispatch of FCAS raise services would have assisted with limiting the Queensland/New South Wales/Victoria under-frequency.
  - While AEMO can and does implement regional FCAS to address credible separation risks, further work would be required to justify regional FCAS dispatch requirements for non-credible events. Any assessment to declare protected events in these circumstances (and thereby enable regional dispatch of FCAS or other measures) is dependent on both over-frequency and under-frequency performance, including the under-frequency load shedding scheme (UFLS). AEMO will continue to assess this through the PSFRR and implementation of the frequency workplan[62].

5. Comment: EnergyQueensland noted in its submission that it is hesitant to finalise any review of UFLS schemes, pending AEMO's review of UFLS requirements.
   - Response: AEMO is working collaboratively with NSPs including EnergyQueensland and Powerlink in the review of UFLS schemes. AEMO acknowledges the dependency between UFLS settings schedules (developed by AEMO) and investments required by NSPs to augment or implement new UFLS schemes. AEMO plans to work collaboratively with NSPs in 2021 to address security requirements in an effective and cost-efficient manner.
6. Comment: Delta Electricity suggested in its submission that more detailed description and qualification of what is meant by PFR could be included in the report.
   - Response: Relevant sections of this report have been updated to clarify that references to PFR relate to provision of mandatory PFR consistent with the minimum interim PFR requirements published by AEMO.
7. Comment: Delta Electricity suggested it is unnecessary to consider scenarios with no PFR.
   - Response: AEMO considers that scenarios with no PFR after June 2023 provide a meaningful reference point to assess risks related to an absence of generator frequency control. AEMO consider this a possible, but unlikely, outcome of the AEMC's PFR incentive arrangements review[63].
8. Comment: Delta Electricity raised an issue regarding divergence in the frequency histogram after implementation of mandatory PFR, and suggested the PSFRR discuss coordinated collective controls of governors, unit controllers, AEMO's Automatic Generation Control (AGC), and market systems.

[60] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2019/final-report-sa-and-victoria-separation-event-16-november-2019.pdf?la=en&hash=231CA53842A89C65036F1F288D0DCF73.

[61] See https://www.aemo.com.au/-/media/files/electricity/nem/market_notices_and_events/power_system_incident_reports/2020/final-report-vic-sa-separation-31-jan--2020.pdf?la=en.

[62] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-control-work-plan.

[63] See https://www.aemc.gov.au/rule-changes/primary-frequency-response-incentive-arrangements.

– Response: AEMO shares Delta's views regarding the importance of frequency co-ordination. The frequency performance improvements following the commencement of Tranche 1 PFR implementation, have allowed AEMO to commence work to improve AGC performance.

– In early December AEMO undertook some adjustments to AGC area tuning in the mainland regions to better cater for changes to frequency conditions that have occurred over the last few months. Specifically, AEMO reduced AGC's internal deadbands to better optimise the use of Regulation FCAS resources. Initial indications suggest these changes have improved time error management and regulation utilisation. AEMO has also commenced a program of reviewing the AGC tuning for units across the NEM particularly those that revised active power control for PFR implementation.

– AEMO considers this work to be outside the scope of the PSFRR, but is undertaking further review in this area. Progress will be reported in the weekly and quarterly frequency reviews[64].

9. Comment: Delta Electricity suggested negative load relief be considered in the PSFRR to take into account performance of distributed PV.

   – Response: AEMO has explicitly modelled distributed PV in the PSFRR studies, thereby taking into account voltage and frequency trip settings. The models take into account the aggregate performance of distributed PV, including pre- and post-2015 installations, and have been calibrated and validated against observations of numerous past disturbances, and from bench testing of inverters. AEMO will continue to review load relief factors on an ongoing basis and apply changes as determined to be necessary, such as current changes being implemented for Tasmanian load relief values[65].

[64] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/frequency-and-time-deviation-monitoring.

[65] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/ancillary-services/load-relief.