AEMC

REVIEW

Australian Energy Market Commission

FINAL REPORT

MECHANISMS TO ENHANCE RESILIENCE IN THE POWER SYSTEM - REVIEW OF THE SOUTH AUSTRALIAN BLACK SYSTEM EVENT

12 DECEMBER 2019

INQUIRIES

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ABOUT THE AEMC

The AEMC reports to the Council of Australian Governments (COAG) through the COAG Energy Council. We have two functions. We make and amend the national electricity, gas and energy retail rules and conduct independent reviews for the COAG Energy Council.

SUMMARY

1 The South Australian black system event of 28 September 2016 highlighted the fact that the NEM power system faces a new and pressing set of system security challenges. Addressing these challenges is critical to making sure that the NEM continues to deliver a secure and reliable supply of energy for customers.

2 This report presents recommendations from the Australian Energy Market Commission's (AEMC or Commission) South Australian black system event review (BSE review). This review was commissioned by the COAG Energy Council, which required the Commission to identify and report on any systemic issues that contributed to the black system event in South Australia, or affected the response.

3 The South Australian black system event illustrates how the risk and resilience profile of the power system is changing. The event demonstrates the need to evolve existing power system security and resilience frameworks, to better reflect the full range of emerging risks present as the power system changes.[1]

4 Since the South Australian black system event in September 2016, there have been a number of reforms made to enhance the resilience of the power system, and reduce the risk of another black system event. The AEMC has made a number of rules to deliver improved system strength, inertia and emergency frequency control; and AEMO has updated and revised operational actions. Together with the ESB and other market bodies, we will continue to progress work assessing the delivery of critical system services.

5 Having considered these reforms, and other existing NER arrangements for power system resilience, the Commission has identified operational approaches to enhancing power system resilience as an area where opportunities exist for further system security framework development.

6 In particular, the review has identified a clear opportunity to develop new measures to manage system security risks from 'indistinct' events.

7 Existing frameworks are designed to manage the risks from contingency events, which involve the failure or removal from service of specific generating units or network elements. Such events are distinct and definable. The changing power system risk and resilience profile is seeing an increase in risk from 'indistinct' events. These risks are associated with distributed events, which act on multiple generation and network assets in an affected area over time. Put another way, an indistinct event is one where the system security risk does not arise from failure of a single specific asset, or where the specific asset(s) involved are not reasonably identifiable ex-ante.

8 The review identifies a need for existing frameworks to be expanded to effectively manage risks from indistinct events. To achieve this, the review presents detailed recommendations for changes to NER frameworks for power system security in three areas, being:

1 The review has assessed power system security resilience in terms of the power system's ability to ***avoid***, ***survive***, ***recover*** and ***learn*** from severe non-credible or high impact low probability (HILP) events. Measures to increase the resilience of the power system can include measures to make the system ***stronger***, more ***interconnected***, or ***smarter.***

- implementation of a general power system risk review
- implementing protected operation as a means of enhancing power system resilience to indistinct events associated with abnormal conditions, and
- clarifying the applicability of rules during market suspension.

9 **General power system risk review:** the review proposes changes to existing NER frameworks to implement a holistic General Power System Risk review (GPSR) process, to effectively identify emerging risks to power system from all sources. The GPSR will act as a front-end risk identification process to inform risk management actions through other mechanisms, including protected events and operation, applications of the RIT-T/D, and the ISP.

10 The GPSR will be an annual review, integrated with existing planning frameworks that will involve AEMO, TNSPs, and DNSPs transparently assessing risks to power system security associated with six key risk areas. These will increase the transparency of emerging system security risks that may need to be managed.

11 **Protected operation:** the review recommends introducing protected operation as a new operational tool for AEMO to enhance the resilience of the power system to indistinct events that are associated with abnormal conditions. Protected operation will allow AEMO to adjust the settings of the power system during abnormal conditions, such as extreme weather, to account for the increased risk that the system will be severely impacted by the abnormal conditions. Protected operation will allow AEMO to take additional actions such as constraining the dispatch of generation, limiting inter-connector flows, or directing on certain generators. Allowing AEMO to better manage the nature of risks from operating a system that is different to how it used to be.

12 Protected operation will support more efficient operation of the power system by allowing AEMO to take action necessary to protect the system from indistinct risks. This will reduce the risk of load shedding and maintain a secure supply of energy for customers.

13 While it is important for AEMO to have flexibility to take these actions, doing so can change market outcomes, at significant cost to customers. It's therefore important that market participants, customers and governments understand the costs of AEMO protecting the power system.

14 For this reason, AEMO will consult publicly on the nature of the indistinct events it will protect the system against, what actions it will take to do so, and the "triggers" for when it will take those actions. When defining these periods of protected operation, AEMO will seek to minimise overall costs, by firstly defining the nature and likelihood of the indistinct risk, and assessing this against the lowest cost way to manage the risk.

15 The Commission recognises the difficulty of accurately defining and assessing the costs and benefits of actions to address indistinct risks, given the high degree of uncertainty associated with these events. We consider that AEMO will draw on its expertise as system operator to exercise its discretion when assessing these indistinct events, and when identifying the lowest cost solutions to address them.

16 The review proposes two types of protected operation: pre-defined and ad-hoc protected

operation.

17 Pre-defined protected operation involves AEMO identifying, through the GPSR, an indistinct event the risk of which increases during abnormal conditions, specifying and publishing criteria setting out its approach to assessing the level of risk arising from the indistinct event, and the actions it would take to prevent a cascading failure, or maintain the system in a secure state.

18 The Commission considers that pre-defined protected operation will provide clarity in the NER as to what actions can be taken in relation to indistinct events, and under what conditions such actions should be taken. This clarity supports AEMO in meeting its system security responsibilities, as there will be more transparency for market participants, policy makers and market bodies in relation to these events.

19 Equally however, AEMO should not be prevented, or consider themselves to be prevented, from taking necessary action to maintain the security of the system. Flexibility is required so that AEMO can adjust and take necessary actions as the needs arise.

20 The Commission has therefore also proposed the concept of "ad-hoc" protected operation, to complement the pre-determined protected operation mechanism. Ad-hoc protected operation will allow AEMO to take operational action to prevent a cascading failure and will apply to indistinct risks that are either unanticipated, or where AEMO has identified a new and severe risk from an indistinct event but there has been insufficient time to complete the process for pre-defined protected operation. Ad-hoc protected operation is intended to be an emergency measure. On each occasion AEMO declares a period of ad-hoc operation, AEMO would be required to report publicly, and to the Panel, as soon as practicable following the occasion. This will create flexible, transparent, arrangements for managing indistinct events.

21 **Market suspension:** the review recommends clarifying that AEMO and Registered Participants must continue to comply with the NER during a period of market suspension except in accordance with specific provisions for flexibility. A new general provision that provides AEMO with flexibility to determine that compliance with a rule would place a material risk on their ability to maintain power system security during a period of spot market suspension is proposed. This general flexibility provision will be accompanied by arrangements for transparency.

22 **Future work program**: The review also maps out a future work program. This future work program will include consideration of:

- how to better account for non-credible contingencies in network planning processes
- whether existing system standards warrant further examination, or whether new standards need to be developed, to enhance power system resilience, and
- whether enhancements to the frameworks for load shedding and system restoration may be needed to enhance power system resilience

23 The Commission will continue working with the ESB, AEMO, and the AER on future rule changes as well as other work looking at making the system security framework fit for purpose given a changing generation mix. To facilitate the submission of rule change requests on the recommendations made in this review, Appendices A, B, and C present

indicative rule change requests.

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Table 1: Summary recommendation table

RECOMMENDATION	PROPOSAL	NEXT STEPS
Expand existing frameworks to enhance prompt identification of risks to system security from all sources.	Implement a general power system risk review (GPSR)	Suggested rule change request is provided in Appendix A
Expand existing frameworks to make clear how indistinct events can be a type of protected event and implement protected operation for indistinct events that are related to abnormal conditions.	Implement mechanisms for enhancing operational resilience	Suggested rule change request is provided in Appendix B
Expand existing frameworks to make clear that the arrangements apply during market suspension and provide AEMO with enhanced flexibility to prioritise system security obligations during this period.	Clarify applicability of NER arrangements during market suspension	Suggested rule change request is provided in Appendix C
Address need for future resilience framework development.	Conduct a future work program on resilience in system security frameworks.	The AEMC with continue to work with the AER, AEMO, ESB, and other stakeholders on these matters and will update stakeholders in early 2020.

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1 SUMMARY REPORT

South Australia experienced a 'black system' event at 16:18 Australian Eastern Standard Time (AEST) on Wednesday 28 September 2016. Approximately 850,000 South Australian customers lost electricity supply. Most electricity supply was restored in eight hours; however a number of customers suffered a prolonged loss of supply. The economic cost of the black system event was estimated at 367 million dollars.[2]

The South Australian black system event highlighted the fact that the NEM power system faces a new and pressing set of system security challenges. Addressing these challenges is critical to ensuring that the NEM continues to deliver a secure supply of energy for customers.

More specifically, the South Australian black system event highlighted a number of issues with the NER system security frameworks. It therefore represents an opportunity to consider whether existing NER arrangements for system security and resilience remain fit for purpose.

This report presents recommendations from the Australian Energy Market Commission's (AEMC or Commission) South Australian black system event review (BSE review). This review was commissioned by the COAG Energy Council, which required the Commission to identify and report on any systemic issues that contributed to the black system event in South Australia, or affected the response. This review has therefore considered and recommended changes to existing regulatory and market frameworks necessary to address the systemic issues identified in respect of the South Australia black system event.

This summary report provides an overview of the main report. It includes the following:

- An introduction to the review's scope and Commission's approach to conducting the review (report chapters 2 and 3)
- A discussion of 'indistinct' events arising as a result of a changing power system risk and resilience profile (report chapter 3)
- An introduction to the concept of power system resilience and economic considerations relating to resilience (report chapters 3 and 5)
- Results from a gap analysis of existing arrangements, areas for specific review recommendations, and future work (report chapter 6)
- A description of the specific recommendations made by the Commission in the review, including:
  - implementing a General Power System Risk review (GPSR) (review chapter 7)
  - mechanisms for enhancing operational resilience through protected operation (review chapter 8)
  - managing indistinct risks in normal operating conditions (review chapter 9), and
  - market suspension (review chapter 10).

2 Business SA, Blackout survey results, https://www.business-sa.com/Commercial-Content/Media-Centre/Latest-Media-Releases/September-Blackout-Cost-State-$367-Million

1.1 This report and review scope

The Commission's South Australian black system event review was initiated at the request of COAG Energy Council.

The terms of reference issued by COAG Energy Council (in Appendix F) require the AEMC to build on the AER compliance report and AEMO incident report in identifying systemic issues arising from the South Australian black system event.

While the review is motivated by the circumstances of the South Australian black system event, the Commission has adopted a forward-looking approach. As such, we have sought not to comment on the AER's compliance findings in respect of the pre-and post event periods. Instead, we have focussed on forward-looking policy development to address systemic issues identified in the NER frameworks, with the goal of enhancing the overall resilience of the NEM.

The Commission has identified the following set of systemic issues which are addressed in the review's recommendations:

- a changing and more uncertain power system risk profile arising from a transitioning generation mix
- reduced power system resilience to non-credible events accompanied by a less certain power system response to disturbance conditions, and
- a lack of overarching processes for identifying and managing emerging 'indistinct' risks to power system security.

This review holistically considered arrangements for the management of risk and resilience in the NEM to address these systemic issues. In line with the COAG Energy Council's terms of reference, the review either makes:

- recommendations for specific changes to NER arrangements, or
- identifies current or future Commission, AEMO, or ESB work streams which will address the issues identified.

Detailed recommendations for change are made in areas where there are clear gaps in existing NER arrangements that are not being currently addressed through other processes. In addition, future work is proposed in areas where existing arrangements may be strengthened.

1.2 Indistinct events and a changing power system risk and resilience profile

The South Australian black system event illustrates how the system security risk and resilience profile of the power system is changing. The learnings that have come out of the various reviews of the event have demonstrated the need to evolve the existing system security and resilience frameworks, to better reflect the full range of emerging risks present as the power system changes.

During the pre-black system event period in South Australia on 28 September 2016, the AER identified unexpected reductions in wind farm generation in South Australia as risking the security of the South Australian power system.[3] While these events were not material in causing the black system that later occurred, the AER's compliance investigation exposed a lack of clarity on whether these events could be considered 'contingency events', and how their risks should be managed through existing security frameworks. As explored in further detail below, these unexpected reductions in wind generation can be considered an *indistinct event.*[4] Increasing risks due to indistinct events, and uncertainty as to how they are best managed, motivates the need to re-consider existing security frameworks.

A changing power system risk and resilience profile

Existing arrangements reflect the risk profile of the power system at the time they were developed. In particular, these arrangements were implemented at a time when the NEM's generating mix was dominated by a limited number of large, scheduled, thermal generation units. Given this generation mix, the dominant events causing risk to power system security involved the sudden, and unexpected loss of network elements or large blocks of generation or load.[5] These events were classified as contingency events and existing frameworks developed for managing the associated risk.

The NEM's generation mix has changed markedly in recent years, with the reduced operation, mothballing or retirement of a number of large synchronous thermal generating units, coupled with the rapid deployment of distributed inverter connected / asynchronous renewable generation resources, at both transmission and distribution levels.

This changing generation mix has changed the power system risk and resilience profile in the following ways:[6]

- *increasing generation and load risk and uncertainty:* the events which lead to changes in intermittent generation output are often not related to internal failure of the unit, but rather involve weather conditions, such as changes in sunlight intensity or wind speeds. These changes are generally distributed, and can affect a significant number of units and systems in a surrounding area rather than a single specific generating unit. While these changes can to some extent be forecast and assessed probabilistically, there is also some associated uncertainty, particularly under abnormal conditions such as high wind speeds and storm conditions.
- *increasing system response risk and uncertainty:* the power system's response to disturbances is becoming more uncertain. This change reflects a number of factors,

3 AER, Black system compliance report, p. 59.

4 As will be discussed in Chapter 3, indistinct events are not contingency events as they do not involve the failure or removal from service of a specific identifiable power system element. Indistinct events are distributed, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. Risk and uncertainty arise from the difficulty predicting the aggregate size of these events, and the specific power system assets affected. Indistinct events may still involve rapid unexpected changes in aggregate generation or damage to power system assets.

5 The loss of large thermal generating units were generally due to internal plant failure which made their loss independent of the loss of any other thermal generating unit.

6 The Commission here distinguishes between risk and uncertainty, defining risk as those random events with ascertainable probabilities, while uncertainty are those random events whose probabilities cannot be determined. Where necessary to distinguish between risk and uncertainty, this has been clearly identified.

including lower levels of fault current and inertia as synchronous units have retired, as well as a more complex demand side, due to an increased prevalence of distributed energy resources (DER). Other factors, such as an increasing prevalence of network protection schemes, also increase the complexity and therefore the uncertainty, of power system response to a disturbance. System response is difficult to quantify and describe probabilistically, and is therefore highly uncertain.

Indistinct events and the need to reconsider existing frameworks for system security

Existing frameworks are designed to manage the risks from contingency events. These events involve the independent failure or removal from service of specific generating units or network elements - they are therefore 'distinct' in nature. The changing power system risk and resilience profile however is seeing an increase in risk and uncertainty from 'indistinct' events.

Indistinct risks are associated with distributed events, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. An indistinct event is one where the system security risk does not arise from a single specific asset, or the specific asset(s) involved are not reasonably identifiable ex-ante.[7] Unlike distinct contingency events, the risk associated with indistinct events is not associated with when the event might occur, but instead with the nature of the event itself.

The increasingly indistinct nature of risks to power system security illustrate the need to evolve existing system security frameworks to appropriately manage the full range of risks to power system security in a changing power system.

1.3 Resilience to non-credible contingencies and HILP events

The COAG Energy Council's terms of reference require the Commission to consider the suitability of existing NER system security frameworks for managing High Impact Low Probability Events (HILP) events. The tornadoes which bought down the transmission lines in South Australia's mid-north on 28 September 2016, leading to the black system, are an example of a non-credible, HILP event. In this review, the Commission considered HILP events in the more general context of arrangements for maintaining a resilient power system to account for non-credible contingencies.

The review has assessed power system security resilience in terms of the power system's ability to ***avoid***, ***survive***, ***recover*** and ***learn*** from severe non-credible / HILP events:[8]

- **avoidance:** The avoidance phase involves preparing the power system for the occurrence of a non-credible event.
- **survival:** The ability of the power system to survive a non-credible event will depend on the technical performance of generating systems and networks being maintained at a

7 Therefore, unlike distinct contingency events, indistinct events cannot be characterised in terms of a specific outcome for the power system arising from the failure or removal from a service of a finite set of easily identifiable power system elements.

8 Framework adopted from - M. Panteli, P. Mancarella, *The Grid: Bigger, Stronger, Smarter?*, IEEE Power and Energy Magazine, June 2015.

sufficiently high standard to be able to support the operation of the system and remain operating during disturbances.

- **recovery:** The restoration of the power system's functionality to the pre-contingency level following a major disturbance will occur over a period of time following the disturbance, where the status of the power system is assessed and an action plan developed to return the power system to its pre-disturbance level.
- **learning:** The ability of stakeholders, particularly AEMO as the system operator, to learn from major power system incidents.

Measures to increase the resilience of the power system can include measures to make the system **stronger**, more **interconnected**, or **smarter:**

- **Stronger** - A stronger grid can be achieved by increasing the level of certain power system services (such as inertia and fault level) and increasing the ability of generating systems to withstand voltage and frequency disturbances.
- **Interconnected** - A more interconnected grid involves physical enhancements to network configuration. These changes may act to make the network less vulnerable to severe events.
- **Smarter** - A smarter grid can involve a broad set of actions that improve the observability, controllability, and operational flexibility of the power system in responding to HILP events.

This description of resilience, and the general set of tools that can be used to enhance resilience, is relevant to our consideration of the economics of resilience, the assessment of gaps in the existing NER system security resilience frameworks, and the development of our work program in this review and in future. Each of these is discussed below.

Economics of resilience

The review considered issues associated with effectively assessing the costs and benefits of measures to deliver enhanced resilience and system security.

Procuring additional system security resilience enhances the ability of the system to ***avoid***, ***survive*** and ***recover*** from a severe disturbance, such as a HILP event. The benefit of these measures is therefore the avoided cost of these events. However, traditional probabilistic cost/benefit processes can't always accurately describe these benefits, as the events are highly uncertain with difficult to determine probabilities. This means it may become more difficult to accurately assess the benefits of resilience measures, as the degree of uncertainty in the system increases over time.

Increasing the accuracy of probabilistic analysis is therefore critical to undertaking more effective cost benefit assessments of system security resilience measures. This can be complemented by carefully designed system security regulatory frameworks, which can be used to identify the nature of these events, and explore the range of solutions that might be used to manage them.

These system security frameworks may also utilise deterministic methods, to complement and guide the use of probabilistic measures. These frameworks should also seek to procure the optimal amount of resilience utilising a range of possible sources, that reflect a portfolio of measures across smarter, stronger, and more interconnected.

Finally, effective cost / benefit system security assessment frameworks must consider the full extent of the benefits that flow from resilience. This includes the initial benefit of reducing the risk of blackouts and load shedding as well as potential longer term benefits of improved market outcomes. These should be actively examined and incorporated into decisions.

Resilience gap analysis

The review assessed existing NER system security arrangements relevant to a resilient power system. This assessment was used to identify gaps in existing arrangements relevant to the resilience of the power system in order to set priorities for the review.

In order to focus our work in this review, the Commission undertook a high level gap analysis. The purpose of this gap analysis was to determine where opportunities existed for further work to enhance power system security resilience which was not being addressed in other AEMC, AEMO, AER or ESB processes. This gap analysis was informed by the mapping of ***avoid***, ***survive***, ***recover***, ***learn***, against the sets of tools of ***stronger***, ***interconnected*** and smarter shown in Figure 1.1 below.

Figure 1.1: Resilience gap analysis

	Avoid	Survive	Recover	Learn
Stronger	• Interconnector limits • Updated power system models • New power system standards • AEMO reforms to FCAS procurement	• Special protection schemes • Frequency control ancillary services • Network support & control ancillary services • Generator performance standards • Minimum fault/inertia levels • Primary frequency control • Reforms to system strength processes • New system services • DER standards • New special protection schemes	• GTPS update • New SRAS and restoration services	• AEMO incident reports
Interconnected	• Annual performance reviews • RIT-T • ISP-interconnections	• Annual performance reviews • RIT-T • ISP-interconnections	• More SRAS options • Inter-regional support during recovery	• ISP Group projects
Smarter	• Improvements to forecasting processes • Better modelling processes • Protected events framework • Enhanced protected operation framework • Reference events	• Underfrequency load shedding functionality • Refinements to SPS/SIPS • Coordination of protection schemes • Post cascade islanding services • Control software upgrade co-ordination and management of automation • Further enhancements to underfrequency control schemes	• Updated models aid SRAS procurement • More effective SRAS testing and restart processes	• AEMO incident reports • Frequency risk review • Generalised power system risk review

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Priorities for review recommendations

The Commission, together with the other market bodies, have already progressed a large number of reforms to enhance the resilience of the power system - many of these are described in the table above. Since the black system event, some notable completed and ongoing reforms to enhance power system security resilience include:

- the Managing rate of change of frequency and fault level rules, which are designed to maintain these critical system characteristics
- the Generator technical performance standards rule, which strengthened and introduced new requirements for generators, which will make the system more stable and better able to manage various risks
- the Emergency frequency control schemes rule, which enhanced the ability of the system to manage major disturbances, and introduced a regular frequency risk review process, and
- the Mandatory primary frequency response rule change requests, which are considering measures to better control frequency in the NEM.

Noting this extensive work program, the Commission identified that operational system security measures to make the system smarter, and enhance its ability to avoid, survive and learn from HILP events, represented a clear gap in existing arrangements, which were not being addressed through other workstreams.

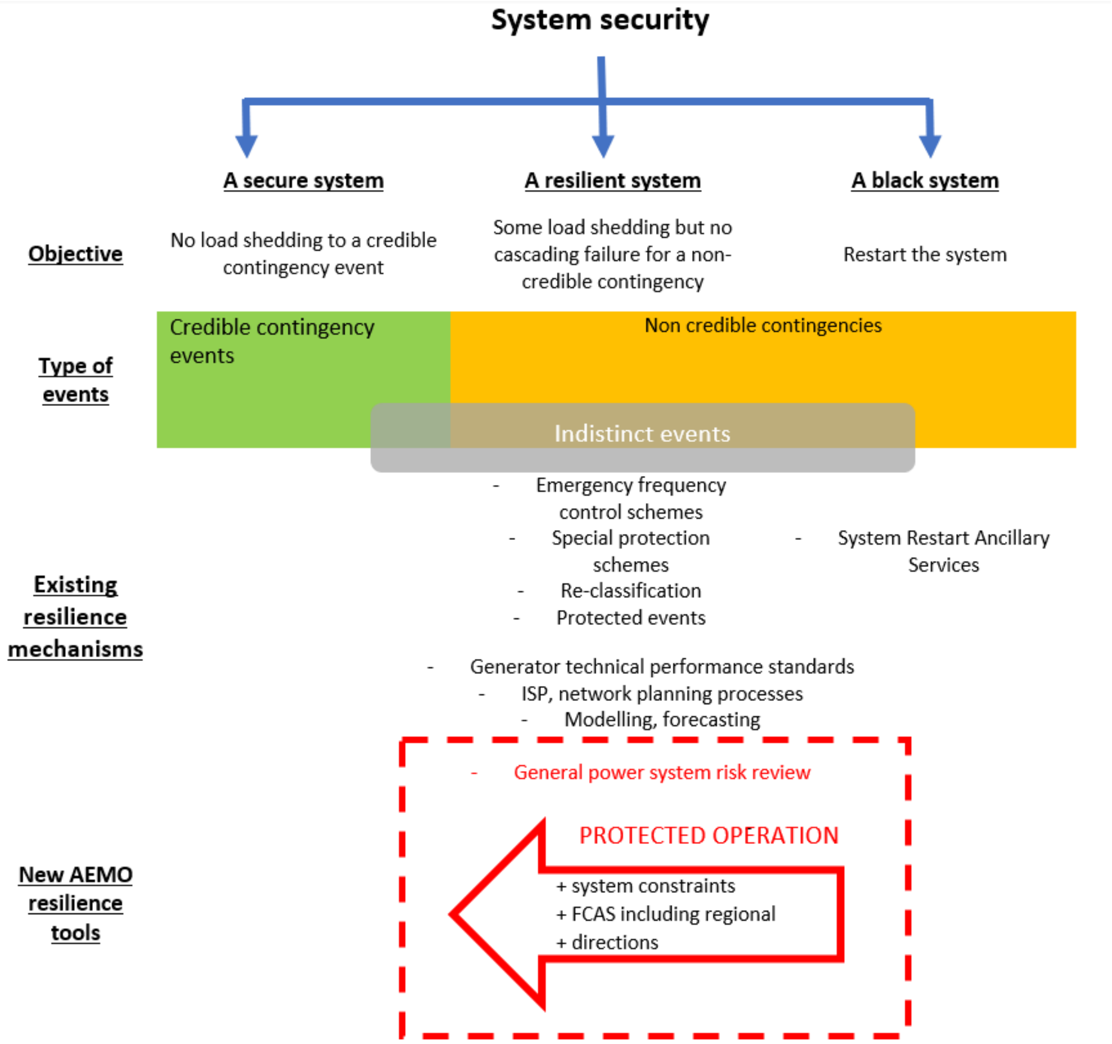
On this basis, this review has prioritised developing specific recommendations for smart, operational measures to enhance power system resilience, specifically for risks arising from non-credible indistinct events, including HILP events.

These represent low cost measures involving relatively incremental changes to existing system security frameworks that should deliver material resilience benefits. These measures include the introduction of:

- a generalised power system risk review, and
- a protected operations framework.

These changes fit within and complement the existing frameworks for management of system security as indicated in Figure 1.2

Figure 1.2: Recommendations in context of existing arrangements



Source: AEMC

In addition, we have included discussion on ways to manage risk from indistinct events in system operation outside of abnormal conditions. Finally, we have proposed a number of changes to the framework for market suspension.

In addition to these recommendations, the Commission also considers that further reforms may be necessary to effectively and efficiently enhance system resilience into the future. Future work investigating further mechanisms to enhance system security resilience may include the following elements:

- Enhancing network planning and investment processes for resilience, through amending the protected events framework, to more transparently identify and develop network solutions to address non-credible contingencies.

- Considering the development of additional, or changes to existing, system security standards made by the Reliability Panel or system standards specified in the schedule to Chapter 5 of the NER.
- Enhancement to NER arrangements for emergency under frequency load shedding
- Considering the potential for new system security services to be defined covering anti-cascade protection.

1.4 General power system risk review

The resilience gap analysis identified a need for a holistic, transparent process for identifying emerging risks to power system security from all sources.

Emerging risks to power system security need to be promptly identified to then be effectively and efficiently managed. Existing arrangements for identifying emerging risks to power system security include a Power System Frequency Risk review (PSFR) for identifying risks to frequency from non-credible contingency events.

Given the changing power system risk and resilience profile, the review recommends changes to broaden the existing PSFR beyond frequency to become a more frequent and holistic General Power System Risk review (GPSR) process for effectively identifying emerging risks to power system from all sources.

Summary of the review's recommendation

The GPSR would act as a front end risk identification process to inform risk management actions through other processes including protected events and operation, RIT-T/D, and ISP. The GPSR would:

- enhance the breadth of the sources of risk considered to include a wider range of sources of risk beyond frequency. The GPSR would specify six key risk areas which AEMO should investigate in a GPSR. These include:
  - increases or decreases in frequency
  - increases or decreases in voltage
  - levels of inertia
  - the availability of system strength services
  - the prevalence of distributed energy resources, and
  - the installation of special protection schemes.
- deepen the review to formally include DNSPs. The GPSR would formally include DNSPs and TNSPs in the review to fully capture systemic risks and opportunities at the distribution network level, including those arising from increasing penetrations of DER.
- increase the speed and frequency of the review process to allow for more effective early identification of emerging risks to the power system. The GPSR would be an annual review conducted via an expedited process.
- Integrate the review with other AEMO and NSP planning processes to enhance outcomes from the review.

1.4.1 Benefits of our recommendation

The GPSR will promote the efficient operation and use of electricity services in the long term interests of consumers of electricity, particularly with respect to the safety and security of the national electricity system.

A key benefit provided by this recommendation is a significant increase in the degree of transparency available to the market generally, in terms of a clear identification of the emerging risks that will need to be addressed. This benefits AEMO, in terms of enhancing its ability to operate the system. However, it also benefits other parties, including the other market bodies, market participants and jurisdictions, given increased transparency helps support effective decision-making both in investment and operational timescales.

It is in the long term interests of consumers that emerging risks due to a changing power system are identified promptly, risks to power system security are effectively assessed from all sources, and key parties are effectively co-ordinated in the process of identifying and assessing emerging risks. Although AEMO and NSPs may incur some costs in conducting an annual GPSR, these should be outweighed by the benefits that flow from earlier identification, and action taken, to address material risks. This is likely to result in parties being better able to manage the risks of major supply disruptions, or black system events.

1.5 Mechanisms for enhancing operational resilience

The resilience gap analysis identified operational system security measures as a clear gap in existing arrangements for maintaining power system resilience to indistinct events. The review therefore recommends extending existing frameworks to provide AEMO with additional operational mechanisms to manage risk and maintain power system resilience to the occurrence of indistinct events.

The review recommends introducing protected operation as a new operational tool for AEMO to enhance the resilience of the power system to indistinct events that are associated with abnormal conditions. Existing system security frameworks that provide for AEMO to enhance the resilience of the power system, being re-classification and protected events, are designed to manage contingency events and are therefore not readily applicable to indistinct events that are not related to the failure or removal from service of specifically identifiable power system assets.

To address this issue, the review recommends:

- clarifying that the protected event framework may be used for the management of risks from 'standing' indistinct events, and
- introducing protected operation as a new tool for AEMO to manage risks from indistinct events which are associated with abnormal conditions.

Summary of the review's recommendation

The review recommends clarifying and expanding the existing protected event framework to more effectively enhance the resilience of the power system to indistinct events.

Introduction of a new operational tool, protected operation, is recommended for this purpose. Two types of protected operation are proposed and described below:

- pre-defined protected operation, and
- ad-hoc protected operation.

Pre-defined protected operation

Pre-defined protected operation involves AEMO identifying, through the GPSR, an indistinct event the risk of which increases during abnormal conditions, specifying and publishing criteria setting out its approach to assessing the level of risk arising from the indistinct event, and the actions it would take to prevent a cascading failure, or maintain the system in a secure state.

The protected operation framework will allow AEMO to take all necessary actions to manage risks arising from pre-identified indistinct events. This would provide AEMO with the flexibility it needs to manage the increasing uncertainties described above.

These actions could include constraining the dispatch of generation, or procuring additional system services. In doing so, AEMO would have the discretion to maintain the power system in a secure state for these identified indistinct events - this means that AEMO could take those actions necessary so that no load shedding occurs following the event.

The Commission considers that this new framework would benefit consumers by allowing AEMO to take all actions necessary to reduce the risks of major supply disruptions. However, these actions come at a cost; for example, limiting power flows between regions can increase wholesale prices, while constraining dispatch can mean more expensive generators need to come online. It is therefore important these costs are examined, to highlight when and where they are necessary.

So that these costs are clearly examined and weighed against the consequences of indistinct events, we have recommended that AEMO follow a general cost minimisation principle when it assesses these events and decides what actions to take. In applying this principle, we consider that AEMO would seek to identify those options for managing the indistinct event that can be delivered at the lowest cost, on the basis that the benefits of those actions are likely to exceed those costs.

The Commission recognises the difficulty of undertaking these kinds of assessments for events that are inherently uncertain. We consider that in following a general cost minimisation principle, AEMO would acknowledge the uncertainty of these events, and exercise its expert judgement as system operator in determining what is a reasonable set of actions to take.

Further to this, the Commission recognises that the complexity of these assessments means that some further guidance for AEMO may be needed. We have therefore proposed that the Reliability Panel would have the scope to issue guidelines applying to the assessment of the costs and benefits of indistinct events to assist AEMO in this process, if deemed necessary.

We have also proposed a set of consultation requirements for AEMO, to consult on how it would assess the risk arising from indistinct events identified in the GPSR, the costs and benefits of the operational actions proposed to manage risks from the indistinct event, and how AEMO's selected management options would satisfy the principle of cost minimisation. AEMO would be required to consult publicly in accordance with the rules consultation procedures and publicly report on the ex-ante application of the pre-defined protected framework every 6 months.

The review also recommends requiring consultation in accordance with the rules consultation procedures be applied to consultation on AEMO's criteria for the reclassification of distinct contingency events.

Ad-hoc protected operation

The Commission considers that pre-defined protected operation would provide AEMO with clarity as to what actions will be taken, and under what conditions these actions should be taken. This clarity supports the operation of the power system, in that there is reduced uncertainty for AEMO as to what actions should be undertaken.

Equally however, AEMO should not be prevented, or consider themselves to be prevented, from taking necessary action to maintain the security of the system. Flexibility is required so that AEMO can adjust and take necessary actions as the needs arise.

The Commission has therefore also proposed the concept of "ad-hoc" protected operation, to complement the pre-determined protected operation mechanism.

Ad-hoc protected operation would allow AEMO to take any additional operational action necessary to prevent a cascading failure. It would apply to indistinct risks that are either un-anticipated, or where AEMO has identified a new and severe risk from an indistinct event, but has not yet had time to complete the process to declare a pre-determined protected operation period. Ad-hoc actions may also be used to provide AEMO's with additional operational flexibility to take actions beyond those specified in any pre-defined criteria.

Ad-hoc protected operation is intended to be something of a last resort emergency measure; ideally, AEMO would have been able to identify emergent risks that warrant action through the GPSR process. On each occasion AEMO declares a period of ad-hoc operation, AEMO would therefore be required to report publicly, and to the Panel, as soon as practicable following the occasion.

As mentioned above, if the Reliability Panel considers it necessary or desirable, it may elect to determine guidelines for pre-defined and ad-hoc protected operation. The Reliability Panel would also act in a general oversight role by considering AEMO's performance as part of its Annual Market Performance Review (AMPR).

Protected events

The review recommends existing arrangements be retained for protected events with the following changes to clarify the applicability of indistinct events and enhance the efficiency of the Reliability Panel approval process.

The review recommends protected events are to apply only to the management of 'standing' risks (both distinct and indistinct) the occurrence of which are not a strong function of abnormal conditions. Management of risks from indistinct events that are a function of abnormal conditions would be through protected operation. Indistinct events are to clarified as being able to be classified as a type of protected event.

The review does not recommend changes to governance arrangements for protected events other than to enhance the efficiency of the approval process through an expedited Reliability Panel approval process. This expedited approval process would be available for an application which is straight forward and not considered controversial.

1.5.1 Benefits of our recommendations

The recommended framework would promote the long term interests of consumers because it includes arrangements that: are flexible to respond as circumstances change; apply responsibility for managing identified risks to AEMO; include a cost minimisation objective that will require consideration, to the extent possible given the uncertainties involved, of the costs of the actions to manage identified risks and benefits of managing those risks; and is transparent with appropriate levels of organisational accountability.

The recommended framework also balances transparency provided by pre-defined criteria with operational flexibility for AEMO to respond to emergency circumstances as they arise. Excessively rigid requirements that do not provide such flexibility for AEMO are unlikely to be in the long term interests of consumers, given the high levels of uncertainty that apply to indistinct events and the need for AEMO to apply its expertise in managing these events.

The protected operation framework therefore provides AEMO with the authority to take ad-hoc protected operation actions in emergency circumstances. This will be complemented with reporting and transparency requirements. Authority to take ad-hoc actions, combined with additional report and transparency obligations, balances the need for AEMO to take operational actions necessary to maintain security, with transparency and confidence for the market more generally.

The proposal for protected operation would be for the management of risks from indistinct events during abnormal conditions. Overall cost impacts are limited by the duration during which the actions taken by AEMO will apply. Short term actions to constrain the power system to either avoid, or minimise the amount of load shedding from an indistinct event will therefore involve limited costs to market efficiency. These costs are likely to be outweighed by the significant security and resilience benefits of implementing the protected operation framework.

1.6 Managing indistinct risks under normal operating conditions

The current criteria for maintaining the power system in a secure state can be described as an N - 1 security criterion. Under this approach, the power system is maintained in a secure state for the finite set of credible contingency events.

The review considered providing additional flexibility to mange the power system in a secure state for indistinct events that are probabilistically assessed as being reasonably possible and therefore credible. Additional constraints to maintain the system in a secure state for these events were described as implementing an "N - 1 (plus)" security criterion and provided for a dynamically adjustable technical envelope to address credible indistinct risks.

The review's final recommendation is for protected operation to be used to maintain the power system in a secure state, for risks from indistinct events associated with abnormal conditions, where efficient to do so. This limits the rationale for an N - 1 (plus) security criterion to managing system security risks from indistinct events under normal operating conditions.

A number of risks arising from indistinct events may exist during normal operating conditions. The review identified credible levels of sympathetic DER tripping in response to credible contingency events as an indistinct risk not associated with abnormal conditions given its presence to differing degrees every day. Risks such as (but not limited to) credible levels of sympathetic DER tripping may be suitable for management within an N - 1 (plus) framework.

Summary of the review's recommendation

The review does not recommend specific NER arrangements for managing credible indistinct events under normal operating conditions. The review recommends that AEMO and the AEMC perform additional investigation on these risks prior to recommending detailed changes to NER frameworks. The review recommends AEMO and the AEMC work together in this area, along with other interested stakeholders, in early 2020 to consider specific arrangements for managing such risks.

1.7 Market suspension

The market suspension period following the South Australian black system event was an unprecedented 13 days long. The AER’s compliance investigation into the market suspension period exposed uncertainty as to:

- the applicability of rules arrangements which are not explicitly specified as applying during a period of market suspension, and
- the level of flexibility available to AMEO to prioritise core system security obligations over rules requirements of a more administrative nature.

When the market is suspended, the NER sets out specific arrangements related to how spot prices will be set and AEMO's powers to issue directions to Registered Participants. The rules are however silent on the extent to which other NER requirements apply during a period of market suspension. This silence has the potential to create uncertainty for market participants and AEMO in co-ordinating efforts to address the issues which led to the market suspension.

A period of market suspension is likely to involve adverse circumstances potentially including serious system security issues. Rules arrangements that are unclear may complicate management of these circumstances. There is therefore likely to be a need for clear flexibility for AEMO to prioritise core system security obligations in cases where compliance with a less important rules requirement materially impacts AEMO's ability to maintain power system security during a period of market suspension.

Summary of the review's recommendation

The review recommends clarifying that AEMO and Registered Participants must continue to comply with the Rules during a period of market suspension except in accordance with specific provisions for flexibility. Flexibility provisions include:

- Existing provisions in the rules relating to the operation of the spot market during a period of market suspension, and
- A new general provision that provides AEMO with flexibility to determine that compliance with a rule would place a material risk on their ability to maintain power system security during a period of spot market suspension.

If AEMO determines that compliance with a certain rule provision would place a material risk on its ability to maintain power system security during a period of market suspension, AEMO would be subject to a requirement to, as soon as practicable, take all reasonable steps to inform the AER and Registered Participants likely to be affected.

1.7.1 Benefits of our recommendations

Clarifying the applicability of rules arrangements during a period of market suspension, providing AEMO with flexibility to reasonably prioritise system security arrangements, and enhancing transparency as to AEMO's actions during a period of market suspension will enhance AEMO's ability to resolve the matters leading to the market suspension and therefore advance the NEO by enhancing the safety and security of the national electricity system. It will also help market participants and policy-makers make more efficient decisions during a period of market suspension since arrangements applying to all parties will be clearer.

1.8 Next steps

The Commission recommends further engagement with AEMO and other stakeholders. This would include a range of activities including further engagement with:

1. stakeholders on the approach to implementing protected operation within the rules
2. AEMO on additional investigations into the management of indistinct risks to power system security which may apply under normal operating conditions, and
3. with AER, AEMO, Panel and industry, to explore the further work programs set out in the gap analysis chapter 5.

To facilitate the submission of rule change requests on the recommendations made in this review, Appendices A, B, and C present suggested rule change requests.

2 INTRODUCTION

South Australia experienced a 'black system' event at 16:18 Australian Eastern Standard Time (AEST) on Wednesday 28 September 2016. Approximately 850,000 South Australian customers lost electricity supply including households, businesses, transport, community services, and major industries. Most electricity supply was restored in eight hours; however the wholesale market in South Australia was suspended for a total period of 13 days.[9] The total cost of the black system event to South Australian businesses has been estimated at 367 million.[10]

The NEM's system security and resilience frameworks are designed to avoid a black system occurring:

- The current regulatory framework has arrangements in place to manage the consequences of events that AEMO considers to be reasonably possible to occur ("credible contingencies") without load shedding. The NER deems the certain contingencies, such as the loss of a single network element or generator, to always be credible.
- Emergency control schemes are also in place to automatically reduce load given a serious non-credible contingency,[11] in order to prevent cascading failures potentially leading to a major supply disruption or black system.
- Should a black system event ultimately occur, System Restart Ancillary Services (SRAS) are procured from generators that have specialised equipment allowing them to restart without external support, in order to re-energise the system.

On 28 September 2016 these arrangements were unable to prevent a black system event occurring in South Australia. The circumstances leading up to, and process of recovering from, the South Australian black system event therefore represent an opportunity to consider whether system security and resilience arrangements in the NER remain fit for purpose, particularly in the context of a power system which is undergoing a rapid transition and a changing generation mix.

Following the black system event, COAG Energy Council tasked the Australian Energy Market Commission (AEMC or the Commission) to review the factors which contributed to the black system event. That is the subject of this report.

9 AEMO, Integrated final black system incident report, March 2017, p. 5.

10 Business SA, Blackout survey results – key findings. https://business-sa.com/getmedia/1b28b42b-0fc3-4ce4-ac24-de71d825c51a/J009159_blackout-Survey-results_v8

11 non-credible contingencies are those that are not considered to be reasonably possible in the circumstances. these are usually considered to be rare in occurrence, such as the combination of a number of credible contingency events occurring at the same time)

2.1 Terms of reference

The terms of reference issued by COAG Energy Council require the review to build on work conducted by the Australian Energy Regulator (AER) in its compliance report and the Australian Energy Market Operator (AEMO), in its technical incident report.[12] In respect of findings from the AER compliance and AEMO incident reports, the terms of reference require the Commission to consider:

- the causes of the black system event, including the role of the transmission sector and the role of the generation sector in contributing to the event or the response
- why a state-wide black system event occurred, rather than being contained within limited parts of the network
- any conclusions whether the power system security frameworks and procedures specified in the National Electricity Rules (NER) operated effectively leading up to, during and following the event, in particular, the effectiveness of power system restart processes following the event, and
- any implications of vulnerabilities identified with respect to the South Australian electricity system for the stability and security of the grid as a whole.

In providing its report to the COAG Energy Council, the terms of reference also require the Commission to consider and report on:[13]

- the nature of the economic costs of disruption to the power system, similar to the black system event that occurred in South Australia on 28 September 2016, and the needs of high energy users to maintain secure and reliable energy supplies so that they maintain international competitiveness, and how these needs may be met
- the effectiveness of the power system security framework established under the NER, and other relevant regulatory frameworks to manage high impact, non-credible events
- any improvements in existing processes, tools available to the system operator or to components of the electricity system in South Australia (for example, the availability of additional ancillary/system balancing services, additional interconnection with eastern states) that would assist in preventing a recurrence of the events experienced, and
- whether additional synchronous generation (or any viable alternative technology with equivalent functionality) in the South Australian region would have helped in preventing the black system event on 28 September 2016.

The full terms of reference for the review are presented in Appendix F.

2.2 Scope of the review

This section sets out the scope of the review including the Commission's approach to interpreting COAG Energy Councils terms of reference and utilising AER compliance findings.

12 COAG Energy Council, terms of reference - review of the system black event in South Australia on 28 September 2016, p. 3

13 Ibid, p. 4

2.2.1 Approach to determining the scope

The COAG Energy Council's terms of reference requires the review to identify and report on any systemic issues that contributed to the black system event in South Australia, or affected the response. This review has therefore considered changes to existing regulatory and market frameworks necessary to address the systemic issues identified in respect of the South Australian black system event.

The Commission considers that a systemic issue is one that relates to the function of the NEM as a whole, including the effective function of both the physical and regulatory elements necessary for the secure supply of energy, in line with the National Electricity Objective.

In this review, issues arising from the South Australian black system event are taken to be systemic to the extent that they relate to the broader set of frameworks for system security in the NEM, and are not solely limited to the circumstances that applied in South Australia on 28 September 2016. Therefore, systemic issues are those that arose from the South Australian black system event and that have material implications for either other regions of the NEM, or the continued secure supply of energy services in line with the NEO.

The systemic issues identified and addressed are also not solely relevant to the specific events that occurred in South Australia on 28 September 2016. In addition to the South Australian black system event, the Commission has also considered issues arising from other recent system security events. Specifically, the review was informed by the Queensland, South Australia separation event on 25 August 2018 and the UK load shedding event on 9 August 2019 in identifying issues and making recommendations. Relevant details of these events are presented in Appendix D.

2.2.2 Interaction with AER and AEMO work

The COAG Energy Council's terms of reference require the Commission to build on findings from the AER compliance and AEMO incident reports.

AEMO published its final integrated incident report into the South Australian black system event in March 2017.[14] In December 2018 the AER published a detailed compliance report into the pre and post event stages of the black system event.[15] The AER did not publish a detailed compliance report considering the event itself, with the AER limiting its reporting to events prior to the loss of transmission lines in South Australia's mid north and events following the commencement of system restoration. On 7 August 2019 it elected to commence action in the Federal Court in relation to these specific issues relating to generator compliance leading to the black system event.[16]

The AEMC's review has therefore considered the details of the pre-and post event periods, as published by the AER in its compliance report. Due to ongoing court action, the terms of reference requirement for the AEMC to consider the causes of the black system event,

14 AEMO, Black system incident investigation, March 2017.

15 AER, Black system compliance report, December 2018.

16 AER, https://www.aer.gov.au/news-release/south-australian-wind-farms-in-court-over-compliance-issues-during-2016-black-out

including the role of the transmission sector and the role of the generation sector in contributing to the event, has not been considered in detail in this review.

The Commission has also not elected to make detailed recommendations on the effectiveness of power system restart processes and SRAS following the black system event. The issues that arose following the black system event in respect of SRAS are currently the subject of two rule change requests being considered by the Commission, one from the AER and the other from AEMO.[17] As these issues are being addressed via other processes, the Commission has elected not to provide detailed consideration of system restart processes and SRAS in this review. Details of the AER and AEMO rule change requests can be found on our webpage.[18]

While the review is motivated by the circumstances of the South Australian black system event, the Commission has adopted a forward-looking approach. As such, we have sought not to comment on the AER's compliance findings in respect of the pre-and post event periods. Instead, the review will focus on forward-looking policy development to enhance the resilience of the NEM.

The review has therefore focussed its consideration on the following of COAG's terms of reference:

- whether power system security frameworks and procedures specified in the NER operated effectively leading up to, during and following the event, and
- any implications of vulnerabilities identified with respect to the South Australian electricity system for the stability and security of the grid as a whole.

2.2.3 Evolution of NER frameworks for resilience

In addition to considering the effectiveness of existing frameworks, the Commission has also considered the following in accordance with the terms of reference:

- the nature of economic costs of disruption to the power system similar to the black system event that occurred in South Australia, and the needs of high energy users to maintain secure and reliable energy supplies to maintain international competitiveness,
- the effectiveness of the power system security framework established under the NER, and other relevant regulatory frameworks to manage high impact, non-credible events, and
- any improvements in existing processes, tools available to the system operator or to components of the electricity system in South Australia (for example, the availability of additional ancillary/system balancing services, additional interconnection with eastern states) that would assist in preventing a recurrence of the events experienced, and whether additional synchronous generation (or any viable alternative technology with equivalent functionality) in the South Australian region would have helped in preventing the black system event on 28 September 2016 in South Australia.

17 The System restart services, standards, and testing rule change.

18 System restart services, standards, and testing rule change: https://www.aemc.gov.au/rule-changes/system-restart-services-standards-and-testing

The Commission has interpreted these terms of reference as requiring the review to consider the evolution of NER frameworks beyond the current arrangements for managing system security in the NEM.

In particular, these terms speak to the concept of power system resilience, which may involve a set of arrangements or systems or obligations, over and above those currently included in the NEM to manage system security, for managing events including, but not limited to, High Impact Low Probability (HILP) events such as the tornadoes which bought down the transmission lines in South Australia leading to the black system. The review considers historic, current, and potential future NER arrangements for power system resilience and identifies operational frameworks as an area for detailed recommendations in this review.

2.3 Purpose of this report

This report presents the final findings from the AEMC's South Australian black system event review (BSE review).

As required by the COAG Energy Council, the Commission has identified the following set of systemic issues arising from the South Australian black system event:

- a changing and more uncertain power system risk profile arising from a transitioning generation mix
- reduced power system resilience to non-credible events and a less certain power system response to disturbance conditions
- deterministic system security frameworks which are no longer fit for purpose given high levels of risk and uncertainty in system conditions, and
- a lack of overarching processes for identifying and managing emerging risks and uncertainties in power system security.[19]

This review holistically considered arrangements for the management of risk and resilience in the NEM to address these systemic issues. In line with the COAG Energy Council's terms of reference, the review either makes:

- recommendations for specific NER rule changes to address identified issues, or
- identifies current or future Commission, AEMO, or ESB work programs which are intending to address the issues identified.

This review focusses on making detailed recommendations in areas not being addressed in these other work streams. These areas include:

- improving processes for holistic identification and management of emerging risks and uncertainties in power system security
- evolving power system security frameworks to provide for 'indistinct' risks and uncertainties that cannot be effectively managed under existing frameworks, and

19 As will be discussed in Chapter 5, references to risk in the chapter incorporate both risks which can have a probability distribution defined and uncertainties that cannot.

- enhancing operational tools available to AEMO to improve power system resilience under abnormal operating conditions.

The Commission has also set out a number of areas where future work could be progressed to further enhance the resilience of the NEM.

2.4 Review process and consultation

In line with COAG's terms of reference, the review commenced following the AER's publication of a compliance report into the pre-and post event periods of the South Australian black system event on 14 December 2018.

On 18 April 2019, the Commission published an issues and approach paper identifying a range of issues for consideration for the review arising from the AER's compliance investigation.[20] Two submissions were received to this paper: one from the AER and the other from AEMO. The Commission also undertook bi-lateral consultation with the set of key stakeholders specified in COAG's terms of reference being AEMO, ElectraNet, SA Power Networks, the AER and the South Australian Government following publication of this paper.

On 15 August 2019, the Commission published a discussion paper of proposed mechanisms to enhance resilience of the power system and convened a technical reference group to consider these proposals.[21] The Commission received 12 stakeholder submissions to this discussion paper and held a technical reference group meeting on 16 August 2019 to consider issues further. Feedback from stakeholder submissions and the technical reference group meeting were utilised to develop the final recommendations in this report.

All reports and submissions are publicly available via the review's web page, which can be found at: https://www.aemc.gov.au/markets-reviews-advice/review-of-the-system-black-event-in-south-australi

In order to fully consider the matters raised in the stakeholder submissions received to the discussion paper, the Commission elected to proceed directly to publishing a final report, without publishing a draft as had been initially intended. As public consultation on the review's discussion paper had only recently concluded, the Commission considered a draft report, followed by an additional public consultation round, was no longer required. To enhance consultation in respect of rule change requests arising from the review, the Commission has included suggested rule change requests in appendices A - C of this final report.

2.5 Structure of the final report

The report is structured into the following chapters:

- **Chapter 3** discusses background and context by setting out current frameworks for power system security, introduces a framework for understanding power system resilience, and describes the challenge of a changing power system risk and resilience

20 AEMC, Issues and approach paper, 18 April 2019.

21 AEMC, Staff discussion paper, 15 August 2019.

profile. This chapter introduces the concept of indistinct events and identifies a need for power system security frameworks to provide for their management.

- **Chapter 4** sets out the assessment framework including the principles applied by the Commission in making recommendations for change that are consistent with, and advance, the National Electricity Objective.
- **Chapter 5** discusses the economics of power system resilience and considers how to achieve an economically efficient level of power system resilience given a changing power system.
- **Chapter 6** presents a power system resilience gap analysis which assesses existing and potential future NER arrangements for a resilient power system. This analysis identifies opportunities for detailed recommendations for change to be provided in this report. This Chapter also identifies the related Commission, AEMO, and ESB work streams which are addressing key elements of the power system resilience challenge.
- **Chapter 7** recommends changes to the NER to implement a General Power System Risk Review (GPSR) to holistically assess and address the full scope of emerging risks and uncertainties in the power system.
- **Chapter 8** recommends changes to the NER to implement an operational mechanism for 'protected operation' as a means of providing AEMO with enhanced scope to flexibly and efficiently take operational action to enhance the resilience of the power system to risks and uncertainties due to indistinct events associated with abnormal conditions.
- **Chapter 9** considers issues involving the management of risks and uncertainties from indistinct events under normal operating conditions.
- **Chapter 10** recommends changes to enhance the flexibility available to AEMO during a period of market suspension. This chapter recommends a new framework to provide AEMO with flexibility to prioritise actions necessary to support system security during a period of market suspension.

3 BACKGROUND AND CONTEXT

3.1 Introduction

This chapter provides background and context to the issues considered, and recommendations made by this review.

Existing system security arrangements are initially introduced including the concept of credible and non-credible contingencies, processes for managing system security, and contingency re-classification for managing heightened risks due to abnormal conditions.

A framework for understanding power system resilience is then presented. This framework is used by the review to assess existing and potential future arrangements for resilience in the NEM.

Finally, this chapter considers the power system's changing risk, uncertainty, and resilience profile given an evolving generation mix.[22] The changing power system risk and resilience profile is identified as leading to increasing risk from 'indistinct' events. The difficulty of addressing these risks within existing NER system security frameworks is then discussed.

The South Australian black system event is referenced throughout as an example justifying the evolution of existing arrangements for system security beyond the management of distinct contingency events to incorporate risks associated with indistinct events.

3.2 Existing arrangements for system security

The NER defines power system security as the safe scheduling, operation and control of the power system on a continuous basis in accordance with the power system security principles set out in clause 4.2.6 of the NER.[23]

Existing arrangements for power system security, have a number of components. These include:

- That the power system should, to the extent practicable, be maintained in a secure state with the technical envelope set and contingency capacity reserves procured to avoid load shedding for the occurrence of any credible contingency event.[24]
- Requirements for AEMO to take all reasonable actions following a contingency event (either credible or non-credible) to return the power system to a secure state as soon as practicable (or at least within 30 minutes).[25]
- Implement emergency frequency control schemes to significantly reduce the risk of cascading outages following significant multiple contingency events.[26]

22 The Commission here distinguishes between risk and uncertainty, defining risk as those random events with ascertainable probabilities, while uncertainty are those random events whose probabilities cannot be determined. Where necessary to distinguish between risk and uncertainty, this has been clearly d footnote content here

23 Chapter 10 of the NER.

24 Clauses 4.2.6(a), 4.2.4(a), 4.2.4(b)(2), 4.2.5(c)(2) of the NER.

25 Clause 4.2.6(b) of the NER.

26 Clause 4.2.6(c) of the NER.

- Procure system restart ancillary services (SRAS) to allow the restoration of the power system following a major supply disruption or black system event.[27]

Existing NER frameworks for system security are built around managing the consequences associated with contingency events. This section introduces the following as foundational ideas relevant to the systemic issues considered by the review:

- the concept of credible and non-credible contingencies
- processes for managing the power system in a secure state, and
- contingency re-classification for managing abnormal conditions.

3.2.1 Credible and non-credible contingencies

Existing frameworks for system security are built around managing the consequences of a 'contingency event'. Contingency events are disturbances that pose a risk to, and uncertainty in, the stable and secure operation of the power system. Contingency events are defined in the NER as events affecting the power system which AEMO expects would likely involve the failure or removal from operational service of one or more generating units and/or transmission elements.[28]

Power system security arrangements are set out in Chapter 4 of the NER and divide the set of all possible contingencies into two categories:[29]

- those that AEMO considers are reasonably possible, such as the loss of a single element or generator. Contingencies that AEMO considers reasonably possible are termed 'credible' contingencies, and
- those that AEMO considers are not reasonably possible, given prevailing conditions. These are termed non-credible contingencies and are generally considered to be events that are rare in occurrence, such as the combination of a number of credible contingency events occurring at the same time.

Examples of credible contingency events include (but are not limited to) the loss of a single generating unit or major item of transmission plant, other than as a result of a three-phase fault.[30]

The current system security arrangements in the NER impose an obligation on AEMO to operate the power system, to the extent practicable, to prevent the loss of any load following the occurrence of a credible contingency event. This obligation is referred to as being in a secure operating state.[31]

27 Clause 4.2.6(e) of the NER.
28 Clause 4.2.3(a) of the NER.
29 Clauses 4.2.3 (a) and (b) of the NER.
30 Clause 4.2.3(b) of the NER.
31 Clause 4.2.4(b) of the NER, with a clause 4.2.2(a) requiring a satisfactory operating state to exclude under frequency load shedding.

Non-credible contingency events are events which are not credible contingency events. These can include (without limitation) three-phase network faults or the simultaneous failure of multiple generating units or double circuit transmission lines.[32]

Non-credible contingencies still occur, but the probability of their occurrence is sufficiently low to make them not reasonably possible. AEMO is not required to operate the system in a secure state preventing the loss of load, for a non-credible contingency. However, the power system security frameworks require the implementation of emergency frequency control schemes, as a last line of defence preventing a black system or major supply disruption due to the occurrence of a non-credible contingency.[33]

3.2.2 Managing power system security and maintaining a secure operating state

AEMO is required by the NER, to the extent practicable, to maintain the power system in a secure state.[34] This section discusses arrangements for maintaining the power system in a secure state within the context of the broader set of arrangements for maintaining power system security which also include:

- following a contingency event (whether a credible or non-credible contingency) AEMO should take all reasonable steps to return the power system to a secure operating state as soon as practicable and in any case within 30 mins
- provision for emergency under frequency load shedding should a non-credible contingency occur, and
- sufficient system restart ancillary services should be available to re-energise the system following a major supply disruption such as a system black event.

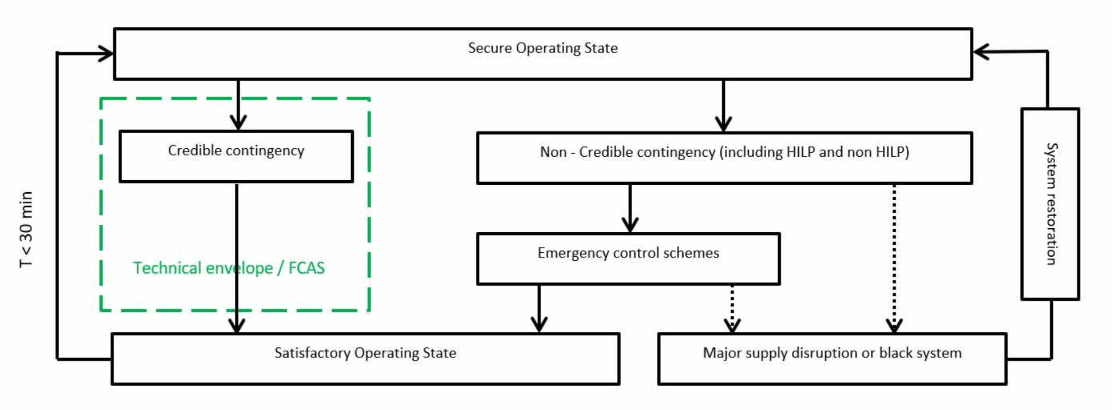
The block diagram in Figure 3.1 illustrates how arrangements for maintaining a secure power system fit into overall power system security processes.

32 Clause 4.2.3(e) of the NER.

33 As discussed later in this paper, the NER set out a number of other frameworks that are also designed to assist the system's survival following a non-credible contingency, such as the requirements placed on generators under the generator access standards.

34 Clause 4.2.6(a) of the NER.

Figure 3.1: Existing system security arrangements



Source: AEMC

A secure power system has the following meaning in the NER:[35]

- A power system that is in a secure operating state is able to maintain a satisfactory operating state following the occurrence of a credible contingency event.[36]
- A satisfactory operating state is achieved when power system frequency, voltage, current, and plant operation all remain within appropriate limits as specified by the power system security standards.[37]

Practically, a power system is in a secure state if there is no load shedding following a credible contingency event. As credible contingency events include the failure or removal from service of a single generating unit or network element, the requirement to avoid load shedding following a credible contingency is sometimes referred to as an N - 1 security criterion.

To maintain the power system in a secure state, AEMO defines a "technical envelope", within which the power system is to be operated.[38] The technical envelope represents the operating limits applied to each element of the power system such that a satisfactory state, without load shedding, is achieved following the occurrence of any credible contingency event.

The technical envelope is implemented through constraints applied to the operation of the power system. These constraints include inter-regional interconnector flows, intra-regional transmission flows, and generator dispatch which reflects thermal, voltage, and transient stability limits in the power system. In addition to the constraints making up the technical envelope, AEMO also makes sure that there is sufficient contingency capacity reserves of both reactive power and active power (frequency response) to maintain voltage and

35 Clause 4.3.1 of the NER.

36 Clause 4.2.4 of the NER.

37 Clause 4.2.2 of the NER.

38 Clause 4.2.5 of the NER.

frequency with the limits defined by power system security standards for any credible contingency that may arise.

These arrangements are illustrated by the left most path in Figure 3.1, which shows a credible contingency event surrounded by a dashed green box. This dashed green box represents the security arrangements, including the technical envelope and contingency capacity reserves, which maintain the power system in a satisfactory operating state, without load shedding, following any credible contingency event.

Importantly, existing frameworks do not require AEMO to consider the consequences of a disturbance. The current framework is an entirely deterministic, binary approach to managing power system risks and uncertainties, from the failure of removal from service of specific assets. The approach to managing the consequences of a contingency event is based solely on AEMO's view as to the probability of the event (i.e. whether it is reasonably possible, or not). This observation is relevant to coming discussion on the management of risks arising from 'indistinct' events.

AEMO is not required to maintain the system in a secure operating state for any non-credible contingency. Instead, AEMO is obliged to co-ordinate with Network Service Providers to implement emergency frequency control schemes which shed load or generation to reduce the risk of cascading outages and major supply disruption (such as a system black) should a non-credible contingency occur.[39] This situation is depicted by the middle path in Figure 3.1 which represents a severe non-credible contingency, such as the loss of multiple generating or network elements, followed by the action of emergency control schemes and load shedding being used in order for the power system to transition back to a satisfactory operating state.

While non-credible contingency events often do not threaten power system security,[40] a severe non-credible contingency which overwhelms the emergency control schemes may lead to a major supply disruption or black system event. A black system is defined in the NER as the absence of voltage on all or a significant part of the transmission system within a region during a major supply disruption affecting a significant number of customers.[41] For a black system to occur, all system security arrangements must have been used and so overwhelmed, including the use of emergency control schemes as the last line of defence. This was what occurred in South Australia on 28 September 2016.

While the NEM and its regulatory frameworks are designed to avoid the occurrence of a black system, AEMO is still required to procure system restart ancillary services (SRAS) from generators. In the event of a major supply disruption or black system, contracted SRAS providers as well as any other available resources may be called on by AEMO to supply energy to restart power stations, and assist the process of restoring the power system. The path on the far right of Figure 3.1 illustrates the circumstances which applied in South

39 Clauses 4.3.1(pa) and S5.1.10.1 of the NER.

40 Non-credible events are non credible due to their probability of occurrence and are not automatically severe enough to threaten power system security.

41 Chapter 10 of the NER, Glossary.

Australia on 28 September 2016 by describing a severe non-credible contingency which leads to a black system event requiring system restoration.

3.2.3 Contingency reclassification for managing abnormal conditions

As noted above, AEMO is required to form a view on whether a contingency is "reasonably possible" given the prevailing circumstances.[42]

Events which are not reasonably possible, and therefore non-credible, under normal conditions may under abnormal conditions become reasonably possible, and therefore credible.[43] The NER defines abnormal conditions as conditions posing added risks to the power system including, without limitation, severe weather conditions, lightning, storms, and bushfires.[44] AEMO is required to develop and publish criteria for deciding whether any non-credible contingency has become ‘reasonably possible’ given such conditions.[45]

On identifying the existence of abnormal conditions, AEMO is required to seek information to identify any non-credible contingency event which has become ‘more likely’ and notify the market.[46] Should the identified event then proceed to becoming ‘reasonably possible’, AEMO is then required to re-classify the normally non-credible contingency as credible and notify the market.[47]

A decision to reclassify allows AEMO to take ex-ante action to maintain the system in a secure state for the event, including by:

- adjusting the technical envelope (such as by limiting interconnector flows) and/or
- procuring appropriate levels of ancillary services to maintain voltage and frequency within appropriate bands following occurrence of the event.

Circumstances in South Australia on 28 September 2016 involved abnormal conditions. During the days preceding the 28 September, weather services were forecasting a severe storm heading towards South Australia with severe weather warnings and forecasts of high wind speeds.[48] AEMO identified the storm and high-wind conditions as abnormal conditions and considered re-classifying non-credible contingencies to manage the risks to power system security. AEMO however did not consider it was able to manage the identified risks associated with high wind speeds through the reclassification process, as it was unable to identify specific power system assets for which the failure or removal from service was reasonably possible in the conditions.[49]

The challenge identified by AEMO in this regard reflects the limitations of existing system security frameworks for managing what this review refers to as 'indistinct' risks and

42 Clause 4.2.3(b) of the NER.

43 Clause 4.2.3A(e) of the NER. Assessment of what is and is not reasonably possible given the presence of abnormal a decision for AEMO to make having regard to all relevant facts and circumstances.

44 Clause 4.2.3A(a) of the NER.

45 Clause 4.2.3B of the NER.

46 Clause 4.2.3A(b)(2) and (c) of the NER.

47 Clause 4.2.3A(g) of the NER.

48 AEMO, Black system event incident report, p. 119.

49 AER, Black system event compliance report, p. 52.

uncertainties. Indistinct risks and uncertainties are those system security issues arising from events which are not associated with the failure or removal from service of a single identifiable power system asset.

3.3 An introduction to power system resilience

The events in South Australia which led to the black system itself involved tornadoes and storm super cells which brought down a number of transmission lines in South Australia's mid north.[50] The storm in South Australia and the resulting tornadoes are an example of a High Impact, Low Probability event (HILP), which tests the resilience of the power system (i.e. something that has a low likelihood of occurring, but has large consequences if it does). The review's terms of reference require the Commission to consider power system resilience specifically in relation to HILP events.

Large, distributed power systems like the NEM are routinely subject to a number of disturbances, of varying severity and frequency. The power system is planned and operated on the basis of the frequency and severity of these disturbances, in terms of the impact that the disturbance has on the operation of the power system.

As noted above, the majority of the disturbances that affect the operation of a power system can and are classed as credible events. These are disturbances that occur reasonably frequently, with small to moderate impacts, which can easily be modelled. As described above, the NER requires AEMO to operate the power system in a secure operating state for the occurrence of any credible contingency event.

However, power systems can also experience more severe disturbances, such as those that occurred in South Australia on 28 September. These events are non-credible in that they occur relatively infrequently, and are generally more difficult to model. This means their impact is much less predictable and potential consequences much less known.[51]

These more severe non-credible events can expose the power system to potential cascading failures. A cascading failure is an uncontrolled failure of parts of the power system, which can lead to a major supply disruption, or ultimately a black system event. As an example, a cascading failure may occur where the loss of a generator disturbs the system to such an extent that a subsequent generator trips, in turn further destabilising the system and causing further units to trip.[52] These events can result in the widespread loss of supply to a large number of customers, or even a black system event as occurred in South Australia on 28 September 2016.

In a general sense, the ability of the power system to avoid, survive and recover from non-credible events can be described as the "resilience" of the power system. This section

50 AEMO, Black system incident report, p. 117 - A storm super cell is a storm characterised by the presence of a deep, persistently rotating up draft. Super cells are often responsible for the development of tornadoes.

51 The causes of HILP events are varied and may include natural events such as floods, cyclones, tornadoes, earthquakes, tsunamis or space weather events. In addition, cyber-attacks or physical attacks on power system infrastructure may also severely impact the operation of the power system.

52 A cascading failure is still possible following a credible contingency if the system's behaviour does not match models. This can occur if generators or network plant do not meet required performance requirements or the models are deficient.

presents the Commission's framework for understanding power system resilience from a system security perspective, as an introduction to the assessment of NER arrangements for resilience presented in Chapter 6, and mechanisms for enhancing operational resilience in Chapter 8.

3.3.1 A framework for describing power system resilience

In a general sense, the ability of the power system to ***avoid***, ***survive, recover,*** and ***learn*** from severe non-credible disturbances, including HILPs, can be described as the “resilience” of the power system. Power system resilience is a relatively new concept and there is not currently a commonly accepted understanding of what it denotes and how it can be modelled.[53]

As described further below, the Commission generally considers power system resilience in the NEM in the context of the ability of the system to ***avoid***, ***survive***, ***recover*** and ***learn*** from severe non-credible events:

- **avoidance:** The avoidance phase involves preparing the power system for the occurrence of a non-credible event. This can include:[54]
  - developing new special protection and emergency frequency control schemes that would limit the severity of the event's consequences (an example of an emergency frequency control schemes would be an automatic under-frequency load shedding scheme that would operate when a disturbance occurs),
  - changing generator technical performance standards to better enhance the ability and capability of connected generators to withstand disturbance conditions, and
  - reclassification of a non-credible contingency as credible, where there is sufficient cause to do this.
- **survival:** The ability of the power system to survive a non-credible event will depend on the technical performance of generating systems and networks being maintained at a sufficiently high standard to be able to support the operation of the system and remain operating during disturbances. For example, having sufficient inertia, system strength and other services within the power system will support the operation and survival of the system. Other survival mechanisms include the actual effective operation of special protection schemes and emergency frequency management schemes designed to shed load, generation or trip network elements in order to arrest the progress of a cascading outage (all of which are planned, developed and implemented as part of the "avoid" stage).
- **recovery:** The restoration of functionality of the power system to the pre-event level will occur over a period of time following the disturbance, where the status of the power system is assessed and an action plan developed to return the power system to its pre-

53 However, a number of papers have been published which propose ways of conceptualising resilience. In particular, we have utilised the conceptual framework described in the following paper, as a way to think about resilience in the NEM. See: *Power systems resilience assessment: hardening and smart operational enhancement strategies*, M. Panteli, D. Trakas, P. Mancarella and N. Hatziargyriou, Proceedings of the IEEE, Vol. 105, No. 7, July 2017. In addition, AEMO has discussed concepts of resilience in the following AEMO insights paper: AEMO, *Building power system resilience with pumped hydro energy storage*, July 2019.

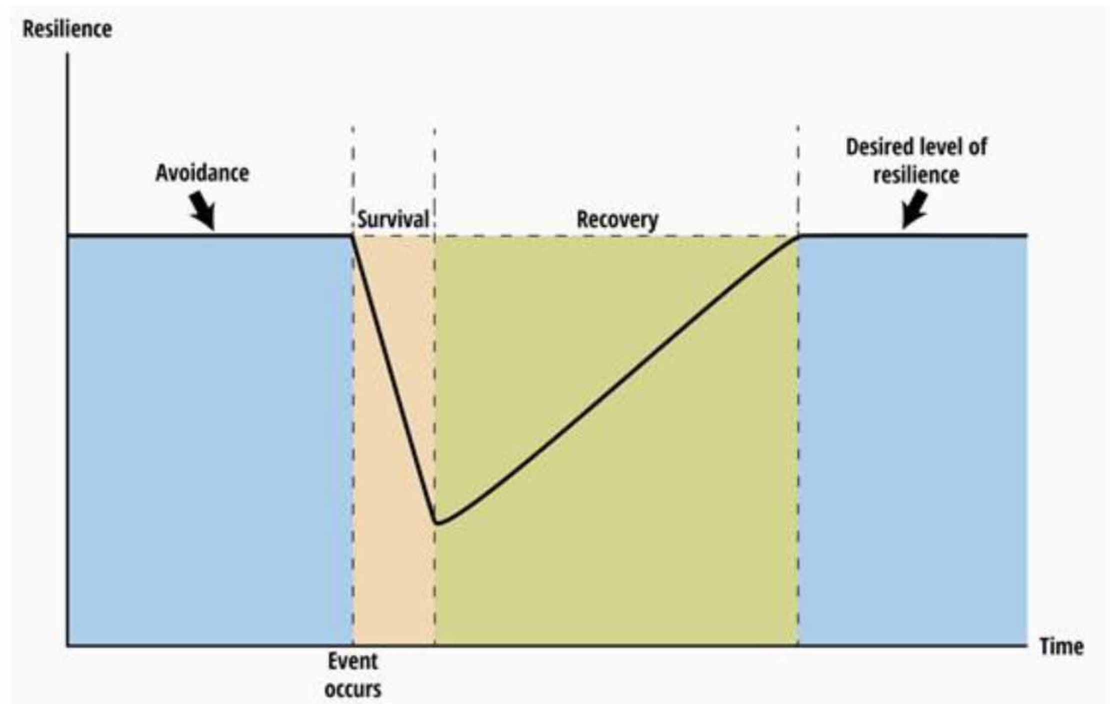
54 Several of the measures listed are applicable across avoid, survive and recover.

disturbance level. This relies on the operation of system restart services, where there has been a major supply disruption or black system event, restarting of any additional generation necessary to meet demand, reconnection of supply to affected customers, and the repair of damaged equipment, which may take several weeks and be necessary to restore supply to some customers.

- **learning:** The ability of stakeholders, particularly AEMO as the system operator, to learn from major power system incidents will depend on the quality and quantity of measurement data, post event analysis and reporting following a major power system incident, the level of compliance analysis by the relevant regulators and the flexibility of the governance arrangements for the NEM.

Figure 3.2 illustrates each of these stages (avoidance, survival, and recovery) in response to a high impact - low probability event affecting the power system.

Figure 3.2: Power system resilience and avoidance, survival and recovery



Source: Adapted from Mathaios Panteli, Pierluigi Mancarella, The Grid: Stronger, Bigger, Smarter?: Presenting a Conceptual Framework of Power System Resilience, IEEE Power and Energy Magazine, June 2015

The resilience of a power system may be enhanced through a range of measures. These measures fall within one of the following categories of actions.[55] Figure 3.2 provides a visual

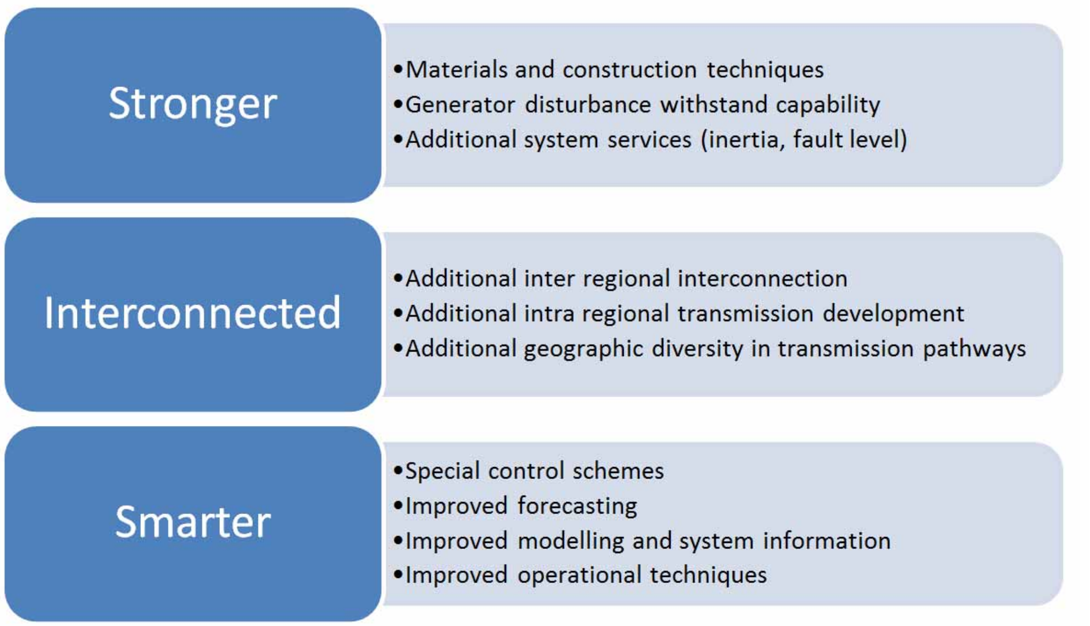
55 See: *The Grid: Stronger, Bigger, Smarter?: Presenting a Conceptual Framework of Power System Resilience*, M. Panteli, P. Mancarella, IEEE Power and Energy Magazine, June 2015.

summary of some the classes of options that can be used to provide and enhance power system resilience.

- **Stronger** - A stronger grid can be achieved by increasing the level of certain power system services (such as inertia and fault level) and increasing the ability of generating systems to withstand voltage and frequency disturbances. The erosion of these system services in recent years has been a key contributing factor to the general reduction in NEM power system resilience.[56]
- **Interconnected** - A more interconnected grid involves physical enhancements to network configuration. These changes may act to make the network less vulnerable to severe events. This can include additional geographic diversity in transmission line siting, re-routing transmission lines to areas less affected by extreme weather, and introducing additional interconnection between regions.
- **Smarter** - A smarter grid can involve a broad set of actions that improve the observability, controllability, and operational flexibility of the power system in responding to non-credible events. In addition, the re-classification mechanism, the implementation of special protection schemes which pre-emptively shed load on observation of a severe event, and improvements in modelling and forecasting of such events, are also examples of smart measures to improve the resilience of the power system. Smart measures may be thought of as additional 'tools' for the system operator as specified by the review's terms of reference.

56 For example, in South Australia, the retirement of the Northern Power Station in March 2016 reduced the amount of synchronous generation in the SA region and contributed to the loss of physical attributes that have traditionally been provided as an inherent characteristic of energy generated by synchronous generators. The loss of synchronous inertia was particularly important in the events leading to the South Australian black system event.

Figure 3.3: Options for enhancing power system resilience



Adapted from - *The Grid: Stronger, Bigger, Smarter?: Presenting a Conceptual Framework of Power System Resilience*, M. Panteli, P. Mancarella, IEEE Power and Energy Magazine, June 2015

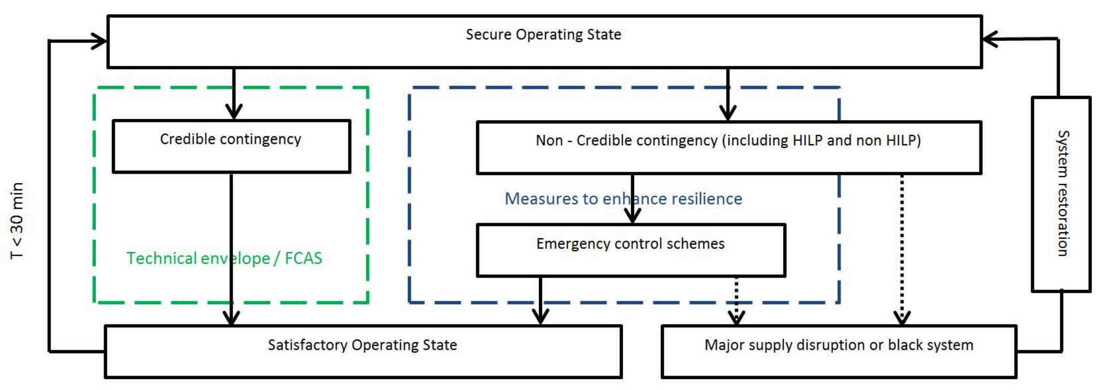
The NEM's system security frameworks already include a number of measures that provide a degree of resilience to non-credible events, including HILPs. Chapter 6 will present a gap analysis identifying our current focus areas for enhancing resilience, and areas for future framework development.

3.3.2 Arrangements for a secure and resilient power system

This review considers system resilience mainly through the lens of ***avoiding***, ***surviving***, ***recovering*** and ***learning*** from non-credible events, by enhancing the ***strength***, ***intelligence*** and ***interconnectedness*** of the power system. Figure 3.4 illustrates how arrangements for enhancing resilience relate to existing NER frameworks for system security and maintaining a secure power system. Measures to enhance power system resilience increase the probability of the power system ultimately returning to a satisfactory operating state following a non-credible event, rather than ending in a major supply disruption or black system event. Measures to enhance power system resilience are represented in this figure by the dashed blue box which complements arrangements for a secure power system represented by the dashed green box.

Importantly, Figure 3.4 demonstrates that a system may be resilient while also allowing some load shedding to occur following a non-credible event. Controlled automatic load shedding may be a key component of the ***survive*** stage of resilience, provided it prevents an uncontrolled, cascading failure. The allowance for load shedding represents a key distinction between arrangements for power system resilience to non-credible events, and the requirement for maintaining the system in a secure state for credible contingencies.

Figure 3.4: **Enhancing system security through a more resilient power system**



AEMC

The concept of power system resilience focusses on how a ***stronger***, more ***interconnected*** and ***smarter*** grid may enhance the ability to ***avoid, survive***, and ***recover***.

In addition, enhancing power system resilience may also assist in keeping the power system stable and secure in the presence of credible contingency events. For example, requiring additional inertia or fault level to provide greater resilience for non-credible events may also improve the performance of the power system to credible contingencies, potentially relaxing the technical envelope or requiring less ancillary services to maintain the system in a secure operating state. That is, a more interconnected, stronger, and smarter grid may also reduce the operational measures required to maintain the power system in a secure state under existing frameworks.

The benefits of actions to enhance power system resilience will therefore not only include a reduction in the consequences of non-credible and HILP events, but may also reduce the ongoing costs associated with the actions AEMO takes to maintain the system in a secure state to the set of credible contingency events. Measures to enhance the resilience of the power system may provide a number of beneficial outcomes. These are explored in more detail in Chapter 5, which discusses the economics of resilience.

3.3.3 Emerging risks, uncertainties, and indistinct events

This review draws a fundamental distinction between two types of system security events, described here as distinct and indistinct.

Distinct risks are taken to be those involving events causing the sudden unexpected loss of a discrete/specific generating system or network element. These events are considered contingency events and managed under existing frameworks for system security.

Emerging risks and uncertainties due to the changing power system are significantly 'indistinct' in nature. Indistinct events are not contingency events as they do not involve the failure or removal from service of a specific identifiable power system element. Indistinct events are distributed, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. Risk and uncertainty arise from the difficulty predicting the aggregate size of these events, and the specific power system assets affected. Indistinct events may still involve rapid unexpected changes in aggregate generation or damage to power system assets.

Risks and uncertainties from indistinct events differ from those arising due to 'distinct' events as:

- indistinct events are distributed and act on multiple generation and network assets in an affected area, over time,
- the specific power system elements associated with the event cannot be clearly defined and may involve the generating systems in a geographic area, rather a specific unit, and
- system security risks and uncertainties arise from the aggregate response of generation and other power system assets may be uncertain and difficult to establish ex-ante.

Therefore, unlike distinct contingency events, indistinct events cannot be characterised in terms of a specific outcome for the power system arising from the failure or removal from a service of a finite set of easily identifiable power system elements.

Indistinct event and existing frameworks for contingency classification

Existing frameworks for managing system security are largely deterministic in their approach. They are built around the concept of contingency events which involve the sudden unexpected loss of a specific, identifiable, generating unit or network element. The approach to operationally managing the consequences arising from a contingency event is binary; they are either fully accounted for in the technical envelope if credible, and not accounted for if non-credible. The approach to management is therefore solely determined by the probability of the event and whether it is reasonably possible or not.

Risk and uncertainty in managing indistinct events

Unlike a distinct contingency event, the nature of an indistinct system security event contains a number of elements. Indistinct events include both the assets that will be affected, the response of the system, and the consequences arising from the event.

Instead of existing system security arrangements, that only consider the chance of and event happening (whether it is reasonably possible or not), indistinct events require an assessment which recognises the uncertainty in the nature of the event, the consequences arising from the event, as well as the power system's likely resulting response. As the probability of the event, along with its consequences need to be considered, existing frameworks that only consider the chance of the event happening are likely to be inappropriate for managing risk and uncertainty from indistinct events.

While the Commission is aware of a range of potential approaches to probabilistically assessing the system security risks arising from indistinct events, no specific recommendations for particular approaches will be made in this review. AEMO is the party best positioned to consider the best approach to characterising indistinct event risk for system security with further consideration to be given in the future AEMO-AEMC work program recommended in Chapter 9.

3.4 Declining general levels of power system resilience

System security resilience in the NEM is considered to be declining from historic levels. Using the framework presented in this chapter, the ability of the power system to **avoid**, **survive**, and **recover** from severe non-credible contingencies and HILP events is declining. This reduction is attributable to a range of factors.

Resilience is particularly important in the current environment of rapidly changing technical characteristics of the NEM power system as the generation mix changes, bringing with it new and, sometimes, unpredictable and undesirable responses to system disturbances.

Historically, the power system's response to a disturbance event was determined by the physical dynamics of rotating, electro-magnetically coupled synchronous generators and loads. The retirement of existing synchronous generating units, combined with increasing penetrations of inverter connected asynchronous generation and inverter driven load have changed the physical response of the system to a disturbance. This change is due to reduced levels of critical system services such as the provision of fault current and inertia, which in turn reduces the resilience of the power system by making it more vulnerable to instability and cascading failures, following a disturbance.

A range of other factors have also impacted on levels of power system resilience. These include:

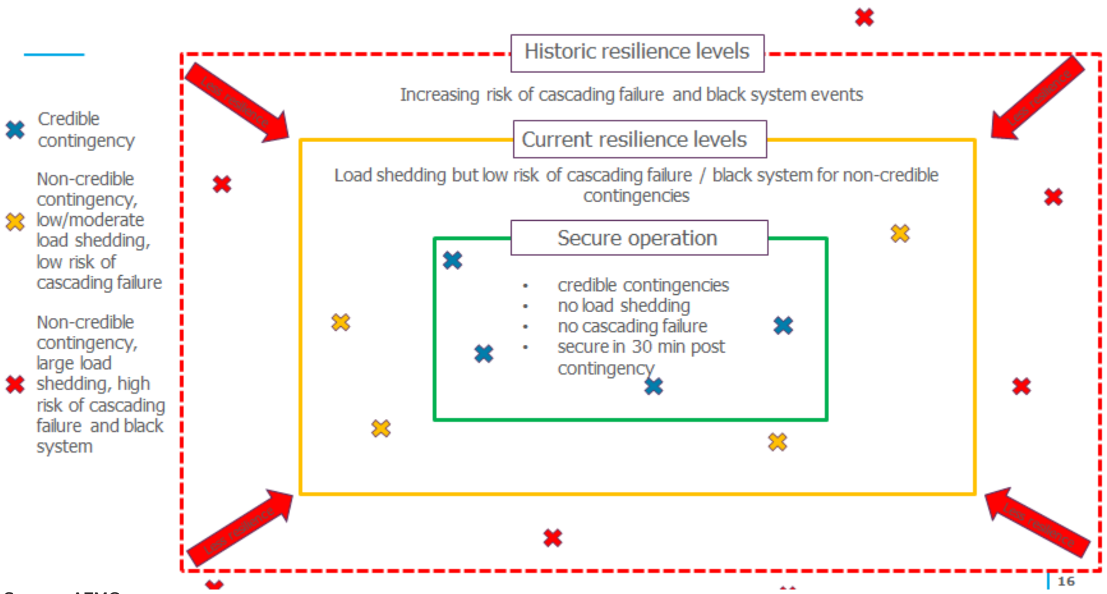
- reduction in primary frequency control
- increasing potential for adverse network and generator control and protection system interactions
- increasing uncertainty in the behaviour of load given implementation of intelligent load control systems and behaviour of DER

Further discussion on the implications of each of these points is provided in the following section 3.5.

The implications of declining levels of power system resilience are more load shedding and an increased risk of system collapse, following non credible contingencies and HILP events. Historically, such events may have been survived with limited, or no load shedding.

This decrease in resilience is conceptually illustrated in the following figure, which demonstrates how the reduction in system security resilience from historic levels has increased the chance of significant load shedding and cascading failure, in response to a non-credible contingency.

Figure 3.5: Decreasing levels of system resilience



Source: AEMC

The Queensland NSW separation event on 25 August 2018 is an example of how decreasing resilience has reduced the power system's ability to survive a non-credible contingency.

On 25 August 2018 a lightning strike on a transmission tower structure supporting the two 330 kV QLD–NSW interconnector lines caused simultaneous faults on single phases of both circuits of the interconnector. The Queensland and NSW power systems ultimately lost synchronism as a result of these faults, islanding the Queensland region.[57]

The last time Queensland separated from the rest of the NEM was on 28 February 2008. A comparison of key outcomes between the 2008 and 2018 events is provided in Figure 3.6. Figure 3.6 shows that a much larger deviation in frequency was experienced in 2018 relative to 2008, for a total event size that was 221 MW smaller in size. In addition, while 1078 MW of load shedding occurred in 2018, none occurred in 2008. This contrast suggests a reduction in the power system's ability to survive a non-credible contingency event and could be considered to show a reduction in the resilience of the power system since 2008.

57 AEMO, Primary frequency control rule change request, p. 11 - Further detail on the on events of this disturbance is provided in Appendix D - The Queensland NSW separation ultimately cascaded into a separation of Victoria and South Australia when the Heywood interconnector tripped due to operation of the EPAT protection scheme. The Victorian-SA separation is discussed later in the following section.

Figure 3.6: Comparison between 2008 and 2018 NSW-QLD separation events

	2008	2018
Net loss of supply QLD to NSW	1,091 MW	870 MW
Other regions separated	NIL	South Australia
Maximum frequency QLD	50.62 Hz	50.9 Hz
Minimum frequency NSW	49.55 Hz	48.85 Hz
Load interrupted	NIL	997.3 MW (UFLS) 81 MW (contracted)

AEMO, Primary frequency control rule change, p. 11

Addressing declining levels of power system resilience requires NER frameworks to be implemented that procure efficient levels of power system resilience. Without efficient levels of power system resilience the consequences of events, such as the Queensland NSW separation event on 25 August 2018, will continue to increase with future black system events becoming more frequent. Chapter 5 on the economics of power system resilience discusses this point further.

3.5 A changing power system risk and resilience profile

Events such as the South Australian black system, and the 25 August 2018 separation event, illustrate how the risk and resilience profile of the power system is changing. This in turn demonstrates the need to evolve existing security and resilience frameworks, to better reflect the full range of emerging risks and uncertainties present as the power system changes. This section provides background and context on the changing nature of risk and uncertainty in the power system.

The power system has always faced risk from a range of sources. These risks and uncertainties reflect both the characteristics of the generation and network elements making up the power system and the types of disturbances which may occur.

Existing frameworks were implemented at a time when the NEM was made up of a limited number of generally controllable, scheduled, thermal generation units. The major risks and uncertainties to system security at that time involved the sudden, unplanned trip of one or more of these units, or the transmission lines linking these units to load centres. Such events were codified in the NER as contingency events, and the arrangements described in this chapter were implemented for managing their consequences.

The NEM's generation mix has changed markedly in recent years, with the reduced operation, mothballing or retirement of a number of large synchronous thermal generating units, coupled with the rapid deployment of inverter connected / asynchronous renewable generation resources, at both transmission and distribution levels. This change in the generation mix is also occurring alongside a demand side which is changing to include an increase in demand side participation and more variable loads. This is resulting in a changing power system risk and resilience profile which includes:

- an increase in risk and uncertainty from generation and load, and
- increasing risk and uncertainty from system response to disturbances.

3.5.1 Changing risks from generation and load

The sudden, unplanned, loss of a single thermal generating unit was, and remains, a significant event. The large size of these units, coupled with the fact that there is a relatively small number of them in total, historically meant that managing system security risk in the power system involved protecting against the loss of a few large units.

The loss of large thermal generating units could be anticipated to the extent that they may or may not reasonably occur, but not when they would occur. This is because the modes of failure which lead to their sudden unexpected removal from service generally involved internal plant sub-system failure, which was not correlated with the failure of any other single generating unit. Expressed another way, there was no meaningful way of forecasting when these units might fail - this was a risk that could occur at any time, and therefore needed to be protected against on an ongoing basis.

Power systems with high penetrations of variable generation, such as solar and wind, are, in contrast, made up of a much larger number of smaller generating units - each wind turbine could be considered a generating unit in its own right. These variable generating units are generally dispersed over a wide geographical area and are also dependent on the availability of their underlying energy resource, either wind speed or solar radiation.

With this very different generation mix, emerging risks and uncertainties in power system security are often not related to internal failure of a unit, but rather involve weather conditions, such as significant and rapid changes in sunlight intensity or wind speeds. These changes are distributed, and can affect a significant number of units and systems in a surrounding area. This means that system security risks may arise from an external event, such as a storm front passing across a region, requiring the aggregate impact across all the generating units in the affected area to be considered, rather than the loss of a specific unit.[58]

The risk to system security from variable renewable generation is related to forecasting error, or other sources of unexpected changes in generation levels, such as the operation of over speed protection on wind turbines. Therefore, unlike the unexpected loss of a thermal generator, any risks to power system security due to this intermittent renewable generation can be characterised in terms of the forecast conditions.

These risks may be generally small under normal operating conditions, but are likely to significantly increase, and become highly uncertain, during abnormal conditions such as severe weather. In aggregate, these changes could be sufficient to represent a risk to power

58 It should be noted that as synchronous thermal generators retire and are replaced by a larger number of smaller variable generating systems, the size of the largest single contingency in a region from the failure or removal from service of a generating unit may decrease thereby increasing the significance of indistinct risks in the overall power system risk profile.

system security. Such circumstances arose during the pre-black system event in South Australia where rapid and unexpected changes in wind farm generation resulted in Heywood Interconnector flows exceeding their secure limits.[59]

The behaviour of load is also becoming more risky and uncertain. High penetrations of distributed energy resources such as solar PV, increasing levels of battery storage and smart load management systems are also increasing uncertainty in the overall behaviour of load relative to historic levels.

The changing nature of generation and load is challenging existing system security frameworks. This is because those frameworks were designed around contingency events involving the failure or removal from service of large generating units. In order to be fit for the future, NER frameworks must be able to deal with the full set of system security risks and uncertainties present in a changing power system including those arising in a system with high penetrations of renewable generation.

Pre South Australian black system event period - An example of the changing NEM power system security risk profile

The changing power system risk profile is illustrated by circumstances during the pre-South Australian black system event period.

During the pre- black system event period, the AER's analysis found that there were several extended periods during which the Heywood interconnector experienced flows significantly exceeding its secure limits.[60] These interconnector flows occurred due to rapid and unexpected reductions in output that occurred across a number of wind farms in South Australia.[61] This reduction in output is understood to be at least partly due to the feathering of multiple distributed wind turbines across the South Australian region, with wind speeds at the time significantly exceeding the 90 km/h feathering threshold.[62]

In its compliance report, the AER considered that this situation represented a risk to power system security, as the actual metered flows on the Heywood interconnector were sufficiently high to raise the possibility of separation between South Australia and Victoria had the 260 MW largest credible contingency been experienced. That is, the unexpected reduction in wind farm generation during the pre black system event period pushed Heywood flows to a point where, had the identified distinct credible contingency (loss of Lake Bonney WF) occurred, there was the potential for flows sufficient to trip the Heywood interconnector. While wind farm feathering did not contribute to the black system event itself, the AER considered that power system security was compromised during the pre-event period due to these events.[63]

59 AER, *Black system event compliance report,* p. 52.

60 AER, Black system event compliance report, p. 80.

61 AER, Black system event compliance report, p. 42.

62 Ibid. Feathering is an event which involves a wind turbine's control system detecting excessively high wind speed conditions and adjusting the angle at which the wind turbine blades meet the wind, to reduce the aerodynamic load on the machine. This is a known turbine safety mechanism that affects each turbine according to its local meteorological conditions. It is generally understood that feathering begins to occur for wind speeds of 90 km/hr which was significantly below the forecast maximum wind speed on 28 September 2016. When a wind farm undergoes feathering its active power output can drop significantly, and may remain low for as long as the high wind speed conditions remain.

63 AER, Black system event compliance report, p. 14.

The AER's compliance investigation identified different interpretations as to the kind of events that may be considered to be contingency events and therefore managed under existing power system security frameworks.[64] In particular, AEMO questioned whether the existing contingency classification framework can be effectively applied to managing risks associated with unexpected generation variability, such as that which occurred during the pre black system event period.[65] These risks illustrate the need to reassess whether existing NER frameworks remain fit for purpose in effectively managing the full set of risks present in a changing power system.

3.5.2 System response

The power system's response to disturbances is also becoming more uncertain. This increase in response uncertainty reflects a number of factors, including the general erosion in system services as synchronous units have retired, generators have turned off their narrow band governor response, as well as a more complex demand side, due to an increased prevalence of distributed energy resources. Other factors, such as increasing prevalence of network protection schemes, also increase the complexity and therefore the uncertainty, of power system response to a disturbance.

System response uncertainty is more complex (and complicated) to model and quantify than risks from generation and load. The power system therefore needs to be appropriately resilient to the occurrence of unexpected non-credible outcomes, given the more opaque and potentially material uncertainty associated with system response.

This section introduces two sources of risk and uncertainty in the system response to a disturbance event:

- potential for unexpected control and protection system behaviour, and
- risks in the response of distributed generation to a disturbance event and the effect of distributed generation on the operability of Under Frequency Load Shedding (UFLS) systems.

This is not an exhaustive list, but instead are some key examples that illustrate the challenge of a more uncertain system response to disturbances. In addition to the South Australia black system event, challenges in each of these areas have arisen in recent system security events in Australia, such as the 25 August 2018 Queensland-NSW separation event,[66] and the recent UK generation trip and load shedding event.[67] Examples from these events are briefly described below, with further details provided in Appendix D.

64 AER, Black system event compliance report, p. 52.

65 Ibid.

66 AEMO, Final report - Queensland and South Australia system separation on 25 August 2018 Note that the Queensland-NSW separation event was one part of a larger event that included the separation of Victoria and South Australia.

67 NationalGridESO, Interim technical report and the 9 August event, https://www.nationalgrideso.com/information-about-great-britains-energy-system-and-electricity-system-operator-eso

Potential for unexpected control and protection system behaviour

System response may have also become riskier and more uncertain given the increasingly complex network and generator protection and control systems. These mechanisms are themselves typically introduced to enhance the system's capability to survive a non-credible contingency, by shedding specific loads or triggering a response from a generator or battery, in order to prevent frequency or voltage instability caused by a disturbance.

However, unless they are correctly designed and configured, these systems can inadvertently introduce new modes of failure and system security risks and uncertainties. These risks and uncertainties may flow from unforseen adverse interactions between multiple schemes that were not fully understood when the schemes were implemented. The potential interaction between control and protection systems further compound the risk and uncertainty faced in power system operation, as control and protection system interactions are complex and difficult to fully predict.

In addition, a changing power system can lead to unexpected outcomes where protection system settings are no longer fit for purpose. The Queensland and South Australia system separation on 25 August 2018 involved the unexpected action of a network protection scheme, the Emergency APD Portland Tripping (EAPT) scheme. The EAPT scheme tripped the Heywood interconnector, resulting in separation between Victoria and South Australia. While the EAPT scheme operated as designed, the power system has changed since its implementation such that AEMO has identified that the scheme is no longer consistently suitable for the range of power system conditions that now apply.[68]

AEMO, in its final incident report, also noted the role of fast battery response in South Australia as a further reason justifying a review of the EAPT scheme design.[69]

> The fast response of the Hornsdale battery during the event contributed to operation of the EAPT scheme. The [Hornsdale battery's] active power response to the initial under-frequency condition seen in SA was a component of the overall rapid increase in power transfer from SA towards VIC following the initial loss of QNI. A larger and faster active power response from installed battery systems for the same frequency change would further increase the likelihood of triggering the EAPT scheme, and islanding of SA in any future system events. As a result of these recent and continuing developments in the SA power system, the design settings of the EAPT scheme now require review.

The need to adjust the parameters of the EAPT scheme given the introduction of new technologies, such as batteries, is one example that illustrates the importance of making sure that protection system settings are fit for purpose.

Risk in the response of distributed generation to a disturbance event and effect on the

68 AEMO, Final report - *Queensland and South Australia system separation on 25 August 2018, p.7.*

69 Ibid., p. 67.

operability of Under Frequency Load Shedding (UFLS) systems.

The behaviour of load in response to a disturbance event is also becoming riskier due to the response of distributed energy resources. Risk arising from the performance of distributed energy resources in response to disturbances is compounded by the low levels of AEMO and NSP visibility and control of these generating systems.

Real world examples include the large scale tripping of residential solar PV output during both the Queensland and South Australia system separation on 25 August and UK generation trip and load shedding event on 9 August 2019. It is worth noting that the large scale trip of DER following the separation of the Queensland region in August 2018 actually helped in the control of frequency, and therefore delivered a resilience benefit. However, it is also the case the in other parts of the NEM, solar PV did not behave as expected as per the applicable Australian Standard.[70] This demonstrates how a lack of transparency as to the characteristics of DER can create some uncertainty in system response.

This highlights that while DER can provide some support during a disturbance, an uncoordinated response could equally exacerbate a disturbance; for example, by "shaking off" a volume of DER generation and exacerbating a low frequency event, as occurred during a major power system disturbance that occurred on 9 August 2019 in the UK.

High levels of distributed generation also increase the risk as to the effectiveness of emergency frequency control schemes, which are critical to the NEM's ability to survive severe power system disturbances. Emergency under frequency load shedding schemes shed load in response to frequency falling below specified limits. These schemes act as a last line of defence to a major supply disruption and rapidly rebalance load and generation in response to a low frequency event. High levels of DER can reduce the effectiveness of these schemes and potentially compromise their functionality, by reducing the amount of stable load behind network feeders that is actually available to be shed during a disturbance.

Characterising risk and uncertainty in the power system's response to a disturbance event is highly challenging. Such response is non-linear and hard to model. In order to maintain the resilience and security of a power system with high levels of response uncertainty, existing frameworks need to provide appropriate levels of flexibility for AEMO to adjust power system operation to account for different levels of risk and uncertainty arising under certain conditions.

70 Ibid., p.5.

4 ASSESSMENT FRAMEWORK

This chapter sets out the assessment framework utilised by the Commission in conducting this review, specifically:

- the Commission's approach to the NEO, and
- the principles we have considered in identifying options and making recommendations.

4.1 National Electricity Objective

The overarching objective guiding the Commission's approach to this review is the National Electricity Objective (NEO). The Commission's assessment of any recommendations must consider whether the proposed recommendations promote the NEO. Similarly, with any related rule changes, the Commission must consider whether the proposed rules promote the NEO.[71] The NEO is set out in section 7 of the National Electricity Law (NEL), and states:

> To promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -
>
> (a) price, quality, safety, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

The Commission considers that the relevant aspects of the NEO for consideration in this review are the efficient operation of the electricity system, with respect to the price and security of supply of electricity, as well as the safety and security of the national electricity system.

4.2 Robustness to climate change risks

As discussed above, the Commission makes its decisions on rule changes with reference to the NEO. The NEO does not specifically require the Commission to have regard to the long-term interests of consumers with respect to climate change or the environment.

However, in order to make decisions that meet the NEO, the Commission considers whether its decisions are robust to any impacts on price, quality, safety, reliability and security of supply of energy or energy services, if these matters are impacted by ***mitigation*** or ***adaptation*** [72] risk, that manifests due to the issue of climate change.

For the black system event review, the Commission has considered climate change adaptation and mitigation risks in the following ways.

Adaptation

71 Section 88 of the NEL.

72 ***Mitigation*** refers to measures associated with actively reducing the extent of the impacts of climate change. ***Adaptation*** refers to measures taken to manage and adapt to the consequences of climate change.

We consider that the recommendations made in this review are robust to climate change adaptation risks, in that the regulatory frameworks we have introduced are scalable, and can be adapted to account for more extreme impacts of anthropogenic climate change in future, particularly more extreme weather. More generally, the regulatory frameworks we have introduced are themselves designed to make the power system more adaptable to the likely future impacts of climate change.

One of the key modelled impacts of anthropogenic climate change is an increase in the frequency and severity of extreme weather events.[73]

In Australia, climate change may exacerbate incidence of high temperatures and may contribute to the severity of drought conditions, both of which in turn increase the risk of extreme bushfires. Climate change will also drive an increased risk of "compound events", where extremes of variables like windspeed and rainfall occur at the same time.[74]

As discussed throughout this review, extreme weather is likely to impact the power system by increasing the extent to which generation and network assets may be damaged or removed from service, and by driving uncertainty around generation availability from an increasingly weather dependent generation fleet. It may also impact on demand patterns, such as through more extreme heat events driving increases in peak demand, while simultaneously placing additional stress on the system.

The Commission considers that the recommendations made in this review are robust to the adaptation risks of climate change. Firstly, the regulatory frameworks we have introduced are scalable and can account for increasingly severe and frequent extreme weather events. Secondly, these new regulatory frameworks themselves directly support adaptation to climate change risks, by enabling the earlier identification of these risks by AEMO, and allowing AEMO greater flexibility to take actions necessary to protect the power system as these risks arise.

These recommendations will therefore support the ongoing efficiency of the operation of the power system and maintenance of security and efficient prices for consumers, as they are robust to the adaptation risks associated with anthropogenic climate change.

Mitigation

We consider that the recommendations made in this review are robust to climate change mitigation risks, in that they are specifically designed to account for the consequences of the main mitigation measure being utilised in the NEM, specifically the shift in the generation mix to being predominantly variable and asynchronous.

73 See: Seneviratne, S.I., N. Nicholls, D. Easterling, C.M. Goodess, S. Kanae, J. Kossin, Y. Luo, J. Marengo, K. McInnes, M. Rahimi,M. Reichstein, A. Sorteberg, C. Vera, and X. Zhang, 2012: Changes in climate extremes and their impacts on the naturalphysical environment. In: *Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation*[Field, C.B., V. Barros, T.F. Stocker, D. Qin, D.J. Dokken, K.L. Ebi, M.D. Mastrandrea, K.J. Mach, G.-K. Plattner, S.K. Allen,M. Tignor, and P.M. Midgley (eds.)]. *A Special Report of Working Groups I and II of the Intergovernmental Panel on ClimateChange (IPCC)*. Cambridge University Press, Cambridge, UK, and New York, NY, USA, pp. 109-230. Available at: https://www.ipcc.ch/site/assets/uploads/2018/03/SREX-Chap3_FINAL-1.pdf

74 Australian Bureau of meteorology, *State of the Climate*, 2018

Amongst the various economy wide measures being used to mitigate the impacts of climate change, the rollout of asynchronous, variable renewable generation is the primary measure adopted in the NEM power system.

The specific characteristics of this generation means that, historically, it has not automatically provided the same kinds of synchronous system stabilising services that were provided by thermal, synchronous generators.[75]

As noted in this review, this removal of system services is directly impacting the risk profile of the power system, and making it more vulnerable to the impacts of HILP events.

The Commission therefore considers that the recommendations made in this review are robust to specific mitigation impacts, being the rollout of asynchronous generation, the shift in the NEM generation mix and reduction in availability of system stabilising services. By allowing for the earlier recognition of risks associated with this change in the generation mix, and allowing AEMO to take whatever actions are needed to manage these risks, our recommendations will support the continued security of the power system, at the lowest cost to consumers, in the presence of the mitigation risks posed by climate change.

4.3 Assessment principles

In addition to the NEO, the Commission has set out a number of principles to guide the assessment of options on potential changes to market and regulatory frameworks relevant to the scope of the review. These principles are:

- **Efficient framework design -** When considering potential changes or additions to the regulatory framework we need to consider whether these modifications are undertaken in an efficient way, balancing the benefits against costs in such a way that promotes the long-term interests of consumers.
- **Proportionality -** When considering potential changes or additions to the regulatory framework, the materiality of the current and potential issues must be assessed, in order to consider whether or not the costs associated with the proposed changes are proportional to the benefits that would be expected. This also involves considering the potential changes underway in the NEM, and so the ability of current frameworks to adapt and address the implications of those changes.
- **Technology neutrality -** Regulatory arrangements should be designed to take into account the full range of potential solutions. They should not be targeted at a particular technology, or be designed with a particular set of technologies in mind. Technologies are changing rapidly and, to the extent possible, a change in technology should not require a change in regulatory arrangements. Equally, however, regulatory frameworks should not form a barrier to new technologies, to the extent that the use of those technologies is consistent with the physical safety and security requirements of the NEM.

75 This is not to say that all variable, asynchronous generation cannot provide some system services; historically however, not many of these types of generators have elected to do so. The Commission notes recent trials by various wind farms to offer some system services, and the capability of asynchronously connected battery storage to do so.

- **Flexibility -** Regulatory arrangements must be flexible to changing conditions. They must be able to remain effective in achieving system security over the long term in a changing market and power system environment. Regulatory or policy changes should not be implemented to address issues that arise at a specific point in time. Further, NEM-wide solutions should not be put in place to address issues that have arisen in a specific jurisdiction only. Solutions should be flexible enough to accommodate different circumstances in different jurisdictions.
- **Risk allocation -** Regulatory arrangements should be designed to explicitly take into consideration the trade-off between risks and the costs of managing those risks through system security requirements. Risk allocation and the accountability for decisions related to the management of risk should rest with those parties best placed to manage them.
- **Effective governance:** When assessing new regulatory frameworks we will consider whether these new frameworks adhere to good governance principles, including:
  - Stability and transparency: Efficient investment and operational decisions are supported by confidence in the maintenance of a secure and safe power system. This confidence will be maintained where the regulatory frameworks for power system security change in a transparent way over time.
  - Appropriate allocation of responsibilities: Roles and responsibilities should be allocated on the basis of experience of organisations. Allocation of responsibilities should also reflect the primary function of the organisation.
  - Clear and transparent objectives: Organisations should have clearly defined objectives and adequate operational scope to meet those objectives within the overarching governance framework.
  - Accountability: Organisations should be accountable for how they have met their objectives. This should be enabled through obligations to consult and regular reporting obligations.

5 ECONOMICS OF POWER SYSTEM RESILIENCE

In its terms of reference, the COAG Energy Council requested the Commission consider the economic costs associated with HILP events.[76]

This chapter considers how regulatory frameworks can be used to assess the economics of power system resilience. These frameworks are facing challenges, as the nature of the risks and uncertainties faced by the power system continue to change.[77]

Despite these challenges, it is critical that policy-makers undertake transparent assessments of the costs and benefits of power system resilience, to meet the long term interests of consumers. This can be achieved through purposeful regulatory framework design that recognises and accounts for these challenges.

This chapter begins with an exploration of the kinds of trade-offs that policy makers must consider, when defining appropriate levels of power system resilience and describes some existing NER frameworks that attempt to do this for power system resilience, often utilising a probabilistic approach. It then describes how increasing uncertainty in the system may challenge the effectiveness of largely probabilistic frameworks.

The chapter concludes with a description of a potential way forward, in terms of the development of a coordinated approach to assessing the costs and benefits of resilience. This way forward includes two main components:

- effective coordination of multiple measures to enhance resilience will be increasingly important. A coordinated approach provides the best chance of delivering effective resilience enhancements, at the lowest overall cost to consumers.
- effective assessment of the benefits of power system resilience requires a mix of both probabilistic and deterministic methods. The inherent uncertainty of the kinds of system security events that can cause major supply disruptions limits the extent to which a probabilistic-based approach can be solely relied upon. Policy makers may therefore need to exercise some judgement, or apply deterministic "rules of thumb", when deciding how much power system resilience is needed in the system. However, this judgement can, and should be, informed by the use of probabilistic methods, provided the limitations of these methods are acknowledged upfront. It must also be as transparent as possible, so that all affected parties understand, and can provide input into, the deterministic assumptions and decisions made.

Further to this, this chapter also considers how to characterise the full range of benefits associated with enhanced power system resilience. While the initial benefit of power system resilience is a reduction in the extent of consumer supply interruption caused by a major disturbance, some resilience measures may also enhance the efficiency of short and longer

76 Specifically, the COAG Energy Council asked us to consider: 1) the nature of the economic costs of disruption to the power system, similar to the system black event that occurred in South Australia on 28 September 2016 and 2): The needs of high energy users to maintain secure and reliable energy supplies so that they maintain international competitiveness, and how these needs can be met. The first of these considerations is addressed in this chapter, the second in Appendix E.

77 The Commission here distinguishes between risk and uncertainty, defining risk as those random events with ascertainable probabilities, while uncertainty are those random events whose probabilities cannot be determined.

term market outcomes. When assessing measures to enhance power system resilience, it is critical that all of these benefits are recognised and captured through a cost benefit assessment processes.

The concepts described in this chapter are directly relevant to the policy solutions discussed in Chapter 6. These are designed around the principle that power system resilience can be delivered at lowest cost through the coordinated use of multiple resilience measures. Furthermore, the regulatory frameworks used to deliver these measures may utilise both probabilistic and deterministic methods.

5.1 A theoretical approach to assessing the costs and benefits of resilience

Resilience, as explained in Chapter 3, is characterised by this review as the ability of the power system to ***avoid***, ***survive***, ***recover*** and ***learn*** from high-impact, low probability events, by enhancing the power system's ***strength***, ***smartness*** and ***interconnectedness***.

The resilience of the power system has eroded in recent years, largely due to the changes in the generation mix, as well as changes in consumer preferences and behaviour. The system faces increased levels of uncertainty; new approaches to manage and limit the impacts of this uncertainty are therefore necessary, in order to maintain the security of supply expected by customers.

Purposeful regulatory intervention is necessary to restore power system resilience to levels that are efficient and more importantly, that meet consumer expectations of a secure and reliable supply of electricity. These regulatory frameworks must be able to:

- quickly and effectively identify, and differentiate between, risks and uncertainties as they emerge
- quantify the magnitude of these emergent risks, as well as describing and assessing the nature of uncertainties (to the greatest extent possible)
- identify and assess solutions, and
- determine whether the costs of implementing these solutions outweigh the avoided costs of the risks and the uncertainties they are designed to address.

5.1.1 Complexity of assessing the costs and benefits of resilience measures

In a purely theoretical sense, it would be possible to discern an optimal level of power system resilience, where the costs of achieving that level are commensurate with the benefits provided.

With respect to increasing power system resilience, the following considerations are relevant:

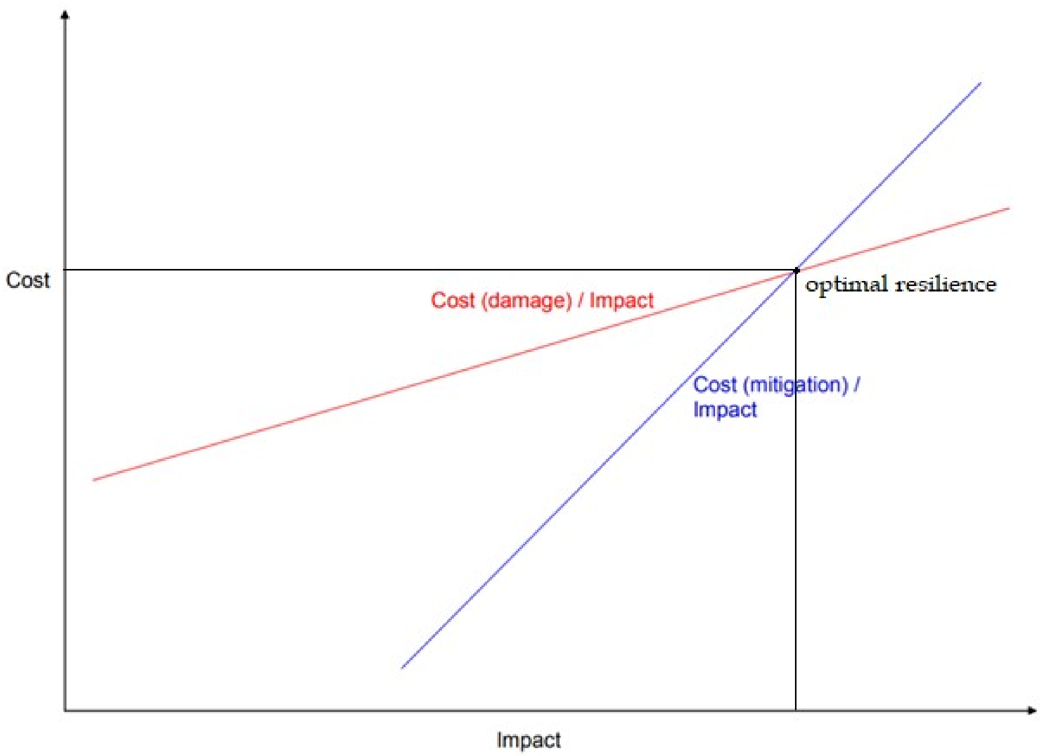
1. The cost of resilience relate to the costs of the measures used to increase the level of resilience, with respect to ***avoiding***, ***surviving***, and/or ***recovering*** from a severe disturbance HILP-type event, which may result in a cascading failure leading to a major supply disruption. This includes the investment costs of additional assets to make the

power system more resilient, as well as the costs of operational measures that may change market outcomes.

2. The benefits of resilience relate to the costs *avoided,* by reducing the probability of a major supply disruption or black system event occurring due to a HILP event. Determining this component is particularly challenging, given the potential uncertainty associated with the likelihood and costs of these HILP events

The theory behind the evaluation of the costs and benefits of resilience is illustrated in a highly stylised way in Figure 5.1.

Figure 5.1: Optimal level of resilience



Source: Blackett Review of High Impact Low Probability Risks, Government Office of Science, 2011, p. 21.

The red line represents the costs of repairing damage, or any costs associated with a loss of supply, as the impact of the event increases. The blue line represents the cost of installing mitigation measures, or power system resilience mechanisms, as described in Chapter 3.

The 'optimal' level of resilience is the point on the graph where the (avoided) costs of damage equal the cost of achieving that level of resilience. To the left of that point, there is a net benefit in increasing the level of power system resilience: the increased benefit (in avoided costs of damage) exceeds the cost of procuring resilience mechanisms. To the right of that point, the marginal benefit is outweighed by the marginal cost and it is not cost-effective to increase the level of resilience.[78]

The benefits of resilience mechanisms and mitigation strategies typically manifest as:

- being better prepared to avoid severe consequences of a high impact-low probability event
- having a greater ability to survive such an event (i.e. the event does not trigger cascading outages), and
- having greater resources being available to recover faster following the event.

While relatively straightforward in concept, there are challenges associated with the practical application of an approach to valuing resilience.

The primary challenge relates to the difficulty of identifying the benefits of increased resilience, which are the avoided costs of reducing the probability, and/or magnitude of a severe HILP-type event. This difficulty reflects the fact that these kinds of events are often inherently uncertain, with unknown underlying probability distributions.

This uncertainty means that relying solely on probabilistic cost benefit assessments may not always provide an effective tool for assessing the avoided costs of these events. This can result in errors being made by policy makers, through incorrectly assessing the probability of an event. If probabilities are overestimated, this may result in an over-procurement of resilience measures, imposing inefficient costs on participants. Alternatively, an underestimation could result in under-procurement, potentially increasing the severity and therefore costs associated with the event.

Another challenge is related to the fact that the benefits of increased resilience will tend to accrue and be realised over time, in contrast to the costs of resilience measures which are immediate and so much easier to quantify.[79]

In contrast, while complexities may exist in determining the optimal combination of resilience measures (see below), the costs of these measures themselves are more concrete and easier to quantify. It follows that while informational limits may arise in estimating both the costs and benefits of resilience, these limits may be greater for the latter. This adds to the difficulty of developing regulatory frameworks that can effectively capture and account for the full value of enhanced power system resilience measures.

Another challenge relates to the difficulty of accurately quantifying the nature of the economic benefits of increased power system resilience. In particular:

1. increased resilience may result in benefits for the wider electricity sector. For example, resilience mechanisms to make the system ***stronger*** may result in the increased provision of system services, which may in turn relax constraints on the dispatch of lower cost variable renewable generation. This may in turn help to lower wholesale prices for

78 Reflecting its highly stylised nature, Figure 1 assumes the costs (mitigation) and benefits (i.e. cost damage) are linear in terms of the amount of resilience (the variable on the horizontal axis). In reality, the relationship between the level of resilience and the associated costs and benefits may include step-changes and other non-linearities.

79 Again, this reflects the fact that these benefits are based on the expected avoided costs of future, uncertain, non-credible contingencies.

customers in the short term and may also support improved reliability outcomes over the longer term.

2. enhanced resilience may also provide benefits outside of the immediate electricity sector, for example, the avoided costs to the broader economy and reduced societal disruption from a lower chance of load shedding. These benefits may be harder to quantify in existing metrics, such as the value of customer reliability.

While these challenges are significant, carefully designed regulatory frameworks can be used to assess the costs and benefits of power system resilience measures. The Commission considers there are several characteristics of these frameworks that can help to address these challenges for power system security.

Firstly, frameworks should be as transparent as possible. This will allow market bodies, governments, regulators, market participants, consumer groups and all other interested stakeholders to understand, provide input and if necessary critique, the costs and benefits that underpin a decision to increase or decrease system resilience.

Furthermore, these frameworks should acknowledge the uncertainty inherent in the cost-benefit assessment, and utilise a mix of probabilistic and deterministic methods to inform decision making. Deterministic methods can provide "rules of thumb" to guide decision making, to account for limitations with solely relying on probabilistic methods to assess uncertain events.

In terms of developing solutions to enhance power system resilience, there may be merit in developing and coordinating multiple frameworks, to obtain resilience measures from various sources. This is on the basis that utilising a mix of measures to enhance resilience is likely to increase effectiveness and reduce overall costs for system security.

These ideas are explored in more detail in this chapter. The next section describes some of the current regulatory frameworks that go some way to quantifying the costs and benefits of power system resilience in the NEM. Some of these measures provide working examples of ways to utilise both probabilistic and deterministic methods to manage the uncertainty associated with these events. It then describes how the growth of uncertainty in power system operations will create new challenges for these frameworks. It then sets out a conceptual approach for the use of regulatory frameworks that utilise both probabilistic and deterministic methods to assess the costs and benefits of resilience, and deliver an efficient resilience "portfolio", to manage risks at the lowest cost to consumers.

5.2 Existing frameworks for assessing the costs and benefits of resilience

There are a number of frameworks in the NEM that consider cost benefit trade-offs, to determine an optimal level of security and resilience. These frameworks seek to balance the certain upfront costs of various resilience measures, against the avoided costs of uncertain but severe HILP-type events.

These frameworks evaluate the potential costs and benefits associated with achieving and maintaining a given level of power system resilience, through the use of various quantitative metrics. In some instances, these metrics are probabilistic in nature, and are complemented with deterministic measures. These frameworks are subsequently used to inform the setting of operational standards and investment decisions that address system resilience.

These various mechanisms for assessing the costs and benefits of resilience are largely separate and uncoordinated. As discussed further in this chapter, this lack of coordination may become problematic, as the power system faces new kinds of uncertainties. This may make it harder to identify the optimal combination of measures to deliver resilience, at the lowest cost to consumers.

This section first discusses the value or customer reliability (VCR), which is a key metric used as an input into the NER power system resilience frameworks. It then discusses several frameworks that quantify the costs and benefits of measures to manage risk and enhance system resilience.

5.2.1 Value of Customer Reliability

The Value of Customer Reliability (VCR) represents a customer's willingness to pay for a reliable supply of electricity.[80] It serves as a proxy for customer value of energy, and is used as an input for revenue regulation, planning, and operational purposes.

One of the key uses of the VCR is to quantify the economic costs of load shedding. It forms an input to SRAS procurement and NSCAS payments,[81] as well as informing the economic justification for implementing special protection schemes through the protected events framework.

The VCR itself is a composite value that reflects the preferences of a number of different customer groups, each of whom value a reliable supply differently. Some customers may be willing to pay more to avoid long outages of several hours duration, whereas others may place more value on avoiding short but disruptive outages during evening peak periods.[82]

The AER is currently developing new estimates of the VCR,[83] and is considering the development of different values for different outage durations and numbers of customers simultaneously affected. This reflects the potential for step changes in customer cost functions, based on the length of different outages.

In particular, the AER is developing a methodology for assessing the economic costs associated with widespread and long duration outages. This methodology will utilise a macroeconomic model to assess the economic and, to the extent possible, social costs

80 In this specific context, the term reliable supply does not distinguish between a supply interruption due to a security event (a disturbance on the system), or a reliability event (a lack of wholesale energy availability).

81 NSCAS refers to network support and control ancillary services.

82 AEMO, Value of Customer Reliability Review, Final Report, September 2014. P.1

83 AER, Values of Customer Reliability - Draft Decision, September 2019.

resulting from a set of outages ranging in severity from 1-2 GWh to 15 GWh of unserved energy.[84]

The Commission considers that this approach from the AER will assist in a number of system security regulatory frameworks that utilise probabilistic elements to assess the costs and benefits of resilience. As identified by the AER, these frameworks include the calculation of the system restart standard, and the declaration of protected events by the Reliability Panel.[85]

The way that the AER is calculating the VCR is a good representation of the kinds of approximations that are necessary in developing a methodology to reflect the costs and benefits of power system resilience. As discussed further below, this approximate value is then itself a key input into other frameworks designed to assess the costs and benefits of resilience.

The NER includes a number of regulatory frameworks that seek to balance the costs and benefits of actions to enhance system resilience. The methodological approaches used by policy makers within these frameworks provide useful examples of how to utilise both probabilistic and deterministic methods to assess the costs and benefits of measures to enhance power system resilience.

5.2.2 System restart frameworks

The NER sets out a framework for the procurement of system restart ancillary services (SRAS) which includes a requirement for the Reliability Panel to develop a system restart standard (SRS), and AEMO to procure SRAS to meet the SRS at the lowest cost.

The system restart standards defines the time to restore a given volume of load after a black system event, for each region of the NEM. One of the key NER obligations in relation to the development of the SRS is that it requires SRAS to be procured under the assumption that each region must be restarted independently from any other.[86] This deterministic requirement effectively guides, or acts as a minimum threshold, upon which the Reliability Panel then develops the SRS.

The SRS is defined by the Reliability Panel, and specifies the time, level and reliability of generation and transmission capacity to be available for restoring supply following a major supply disruption or black system event.[87]

When setting the SRS, the Reliability Panel considers various economic factors, including the trade-offs that exist between the cost of procuring restart services against the probability

84 Ibid, p.37. The AER notes that "the lower bound of the range (1-2 GWh of unserved energy) corresponds to a large regional town being without power for around 12 hours...[and] at the upper bound of the range, 15 GWh of unserved energy is larger than the SA Black System event, as it is of an extended duration of 10 hours and occurring during summer peak demand conditions." The AER also advised that it intends to limit its assessment to an amount of unmet demand of no more that 15 GWh, on the basis that other system security methods have been introduced so as to make the level of 15 GWh "sufficient for the applications we have identified".

85 Ibid, p.35.

86 Specifically, NER clause 8.8.3(aa)(2) requires that the SRS must: identify the maximum amount of time within which *system restart ancillary services* are required to restore *supply* in an *electrical sub-network* to a specified level, under the assumption that *supply* (other than that provided under a *system restart ancillary services agreement* acquired by AEMO for that *electrical sub-network*) is not available from any neighbouring electrical sub-network)

87 AEMC, Review of the System Restart Standard, Final Determination, 15 December 2016, p. ii.

weighted costs of a loss of supply over different timeframes.[88] At a high level, the Panel is ultimately guided by the principle that the economically optimal level of SRAS is where the probability weighted marginal benefit of procuring an additional restart service is approximately equal to the marginal cost of procuring that restart service.[89] This probabilistic approach complements the deterministic elements of the framework as described in the NER.

The Reliability Panel last determined the SRS in 2016, and engaged Deloitte Economics to develop a methodology and advise on the costs of procuring different SRAS volumes. The methodology adopted by Deloitte utilised probabilistic methods to inform its assessment of the probability of a HILP event, by extrapolating a trend from known events.[90] Deloitte also used VCR as a proxy to calculate the cost of these events.

The SRAS frameworks provide an illustrative example of how a combination of deterministic and probabilistic measures can be used to assess the costs and benefits of enhancing system resilience:

- By requiring sufficient SRAS to be procured so that each region can be restarted independently, the NER set a deterministic baseline level of SRAS capability. It can be argued that this deterministic "baseline" requirement is likely to shift the procurement of SRAS towards building in additional resilience. As discussed further in section 5.4.1, such a rule of thumb type approach may seek to bias towards over-procurement of resilience measures.
- The Reliability Panel then utilised a probabilistic methodology that estimated the probability of HILP events, by extrapolating from known trends. This is a clear demonstration of how policy makers can utilise probabilistic methods to provide some quantitative rigour to decision making, while acknowledging the limitations of this analysis.

This form of combined, hybrid approach could be used to assess the costs and benefits of resilience measures other than SRAS. This is discussed in more detail in section 5.2.3 below, and is discussed in terms of a potential future practical application in Chapter 6.

5.2.3 General resilience measures

In addition to system restart and network planning, the NER includes a number of other frameworks that include some consideration of the costs and benefits of resilience measures. For example:

- in order to maintain the safety and security of the national electricity system, AEMO procures ancillary services and operates the system to keep it within specific limits. While AEMO is guided by the NER and relevant standards, it also utilises its own discretion and expertise when deciding what actions are efficient to take in managing the system.

88 Ibid, p.ii

89 Ibid, p.29

90 Specifically, Deloitte advised that: "Estimating low probability events is difficult as there is often little data available to determine a probability distribution function. As such, extreme value theory is applied by extrapolating a trend of known events to determine the probability of unknown events."

- generators build, operate and maintain their generating systems in accordance with the NER access standards. The Commission considered costs and benefits of these measures when it last set the generator access standards in 2018.[91]
- Network service providers maintain and operate their networks in accordance with system standards and the requirements of the NER more generally. In particular, NSPs are required to consider the costs and benefits associated with management of non-credible contingencies as part of their system planning processes.[92]

5.3 Challenges to determining an optimal level of resilience in a modern power system

This next section steps through some of the challenges to the ability of existing NER frameworks to effectively assess the costs and benefits of resilience measures, given the new uncertainties faced by the power system.

While resilience cost-benefit decisions are already made through various NER frameworks, these decisions will become increasingly difficult as the power system transition continues. There is always likely to be some uncertainty associated with estimates of benefits associated with achieving a given level of system resilience. However, the power system transition has introduced new uncertainties, reflecting the increasingly distributed, variable and asynchronous nature of the generation fleet, coupled with the continued uptake of DER and use of special protection schemes, all of which make it harder to predict the kinds of events that will impact on the power system as well as how the system will respond to these events.

Many of the historic NEM regulatory frameworks utilise predominantly probabilistic methodologies to assess the costs and benefits of power system security resilience measures. In a power system where the probabilities of disturbance events were reasonably predictable, such approaches were largely appropriate for the management of risk. However, as power system conditions change and the extent of uncertainty increases, it is necessary to reassess whether these frameworks remain effective. In particular, we need to consider whether these frameworks can account for the increased input variability and associated uncertainty of a changing generation mix, as well as the increasing uncertainty of system response to disturbance events.

In addition to these internal challenges, the power system faces a number of new external challenges. In particular, as discussed in Chapter 4, anthropogenic climate change has increased both the probability and severity of extreme weather events, which makes it more difficult to forecast the frequency and severity of HILPs.[93] As the likelihood of HILP events are a key component in the calculation for risk mitigation investments, increased uncertainty regarding their occurrence and severity make it difficult to determine how much 'resilience' is required, and how much to spend on delivering resilience measures.

91 See: AEMC, Generator technical performance standards rule, October 2018.

92 Clause S5.1.8 of the NER requires NSPs to plan for non-credible contingencies that pose a risk to the stability of the power system, and develop emergency control schemes to manage these risks.

93 Intergovernmental Panel on Climate Change, Special Report: Global Warming of 1.5°C, Summary for policy makers, 2018. P. 7

These trends mean it will become increasingly difficult to forecast the scale, impact, cost and likelihood of HILP-type events. Even when factoring in the sophistication and improved accuracy of technical forecasting abilities, assessments of this type are always a 'best guess', or subject to a margin of error.[94]

Given these challenges, there is benefit in considering how NER regulatory frameworks can be updated to effectively assess the costs and benefits of power system resilience. While it is unlikely to be possible to account for and manage all risks and uncertainties, carefully designed and coordinated regulatory frameworks can go some way to identifying, quantifying and developing efficient system security resilience solutions.

5.4 Reconsidering the economics of resilience

As discussed in the previous section, there are marked challenges to determining an optimal level of resilience in a changing power system, due to the lack of coordination of existing mechanisms and the increasing uncertainty of the power system. Regulatory frameworks therefore need to be adapted in order to deliver more coordinated solutions, as well as more effectively assessing the full range of costs and benefits associated with resilience measures.

The remainder of this chapter describes a high level, conceptual guide for how to assess the costs and benefits of resilience. This guide may help inform parties to determine how much resilience is needed in the power system for system security.

The practical outworking of this conceptual discussion is explored further in Chapter 6. In that chapter, we consider specific changes to the NER regulatory frameworks for system security, to support better coordination and assessment of the costs and benefits of restoring power system resilience in the NEM.

Generally, there are three key concepts relevant to assessing the costs and benefits of power system resilience:

- A mix of probabilistic and deterministic methodologies, given the uncertainties underpinning resilience decisions. These hybrid approaches must be as transparent as possible.
- A "portfolio" approach to selecting resilience measures is most likely to provide the most effective power system resilience solution, at the lowest cost to consumers.
- Increased power system resilience may provide an extensive range of benefits, from immediate reductions in the risk of load shedding, to longer term improvements in market efficiency. The full extent of these benefits should be considered, when making decisions related to enhancing system resilience.

5.4.1 Probabilistic and deterministic approaches to decision making

Probabilistic methods work less effectively under conditions of uncertainty, making it harder to make efficient decisions. A hybrid decision making approach should be adopted for system

94 Such events are typically described with a probabilistic distribution that has a heavy or a 'fat' tail, which illustrates that the threat and the consequences posed by these events are distinct from the day-to-day risks of managing a power system, and markedly more severe.

security, utilising a mix of probabilistic methods guided by a deterministic framework, to account for increasing uncertainty.

Decision makers face two kinds of errors when relying on probabilistic methods to assess uncertain events. These occur where decision makers use an incorrect estimate of the actual probability of a HILP-type event.

- **Overestimation error:** In the first case, a decision maker over estimates the probability of an event. This results in the over procurement of power system resilience measures, such as unnecessary market constraints or asset over-build. This in turn results in an ongoing, incremental increase in the cost of energy for consumers.
- **Underestimation error:** In the second case, a decision maker underestimates probability, resulting in insufficient procurement of power system resilience measures. This imposes costs on consumers through significant load shedding (and flow on economic impacts), if the event occurs. This results in a delayed, but major cost impacts.

Both of these error types can drive material cost increases. However, these costs may be felt by customers in different ways. This is relevant to considerations of how to best incorporate deterministic elements into power system security regulatory frameworks.

Potential regulatory solutions

The most obvious way to address the impact of increasing uncertainty is to provide decision makers with better tools to assess power system security probabilities. More powerful modelling capabilities, informed by more accurate empirical data, will provide decision makers with greater confidence that probability functions reflect reality.

In the NEM, AEMO is rapidly improving its processes on both counts, through improvements to data gathering,[95] as well as through the development of more detailed and powerful power system modelling.[96]

However, there is also likely to be benefit in utilising deterministic methods, to complement probabilistic assessments. These deterministic methods provide boundaries and guide the use of probabilistic elements.

Given that the use of deterministic decision making implies an active (and potentially subjective) decision maker, it is important to consider the incentives faced by those decision makers.

A deterministic framework requires decision makers to assess and make a judgement call as to the probability of an event. As discussed above, there are costs associated with these judgement calls, based on whether decision makers over- or underestimate the probability of a HILP type event.

95 For example, see: AEMO DER register program, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/DER-program/DER-Register-Implementation; and AEMO/ARENA self forecasting program, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Solar-and-wind-energy-forecasting/Participant-forecasting

96 For example, see AEMO's proposed "Digital twin" of the power system, available at: https://www.aemo.com.au/-/media/Files/About_AEMO/Our_Vision/AEM037_Summary-booklet.pdf

Under both deterministic and probabilistic approaches, decision makers need to make assumptions about customers' preferences with regards to the risk of interrupted electricity supply. Typically, customers are assumed to be either risk/loss-neutral or risk/loss-averse (to varying degrees) in the cost-benefit assessment.[97] Varying these assumptions can result in different amounts of resilience being procured. In particular, an assumption of risk-aversion, compared to risk-neutrality, would result in more power system resilience being procured. It is therefore critical that such assumptions are made clearly and transparently. The following general measures can be implemented to support increased transparency.

Firstly, deterministic elements should be as clearly defined as possible. The system restart frameworks provide an example of this: while the system restart standard defines the speed and volume of restoration on the basis of a probabilistic marginal cost/benefit analysis, the NER define a minimum "baseline" of how many restart services must be procured in each region.[98]

In effect, this element of the regulatory frameworks sets a deterministic baseline, beyond which the Reliability Panel undertakes probabilistic analysis to determine an efficient level of SRAS. Clearly defining it in the NER means that it is fully transparent, and itself subject to assessment against the NEO through the rule change process.

Secondly, other statutory agents with appropriate powers can be included in the decision making process. For example, Ministers or other senior government representatives could be included in the decision making process, on the basis they are empowered to make decisions that reflect customer preferences.

Generally, increased use of deterministic approaches may be necessary, as the extent of uncertainty increases in the NEM power system. In Chapter 8, the Commission has explored a number of potential enhancements to the system security regulatory frameworks, to better utilise deterministic decision making methods.

5.4.2 Co-ordination of resilience measures

Existing resilience frameworks are spread throughout the NER and are not as coordinated as they could be - as such, they do not necessarily deliver integrated resilience measures. These disparate frameworks may become less effective, or result in inefficient outcomes, as the extent of uncertainty increases in the NEM.

The resilience of the power system can be restored most effectively and efficiently where there is coordination between system security resilience measures. This involves the development of a portfolio approach, which recognises the multiple dimensions to resilience. A coordinated, combined set of measures is most likely to deliver the lowest cost, most effective resilience solution.

97 Loss aversion being the principle that the "pain" of a loss is more material than the "utility" of a gain. See: Kahneman, D., & Tversky, A. (1979). Prospect theory: An analysis of decision under risk, Econometrica, 47, 263-291.

98 In 2015, the Commission made the *System restart ancillary services rule,* which explicitly required that each region must be capable of being restored on a standalone basis - that is, under the assumption that multiple regions have collapsed to a black system condition. In making this decision, the Commission acknowledged that it was making the rule on the basis of a very low probability, "worst case" scenario. See: AEMC, *System Restart Ancillary Services - final determination*, April 2015, p.66.

As described in Chapter 3, the Commission has characterised resilience as a combination of ***avoiding***, ***surviving***, ***recovering*** and ***learning*** from HILP events. This is achieved through using a combination of measures to make the system ***smarter***, ***stronger***, and more ***interconnected***.

Within the groupings of ***stronger***, ***smarter*** and ***interconnected***, specific mechanisms will deliver certain aspects of resilience, but may not by themselves be the most efficient way of delivering resilience. For example, making the system stronger by increasing the volumes of primary frequency response in a region will help to maintain frequency stability following a disturbance (and possibly provide other services, although these would be provided incidentally). However, this disturbance could also potentially be managed through the deployment of a special protection scheme, or through the use of operational measures, such as constraining an interconnector to provide active power "headroom". There are specific benefits from each measure, and each has its own set of associated costs. This is not to say that any of these measures is necessarily the optimal solution; rather, some combination is likely to deliver the greatest level of resilience, at the lowest overall cost.

Similarly, a combination of measures may be used across the ***avoid***, ***survive*** and ***recover*** elements of resilience. For instance, it may be possible to reduce the time to ***recover*** the system following a major supply disruption, by procuring additional SRAS. However, the black system itself may have been avoided through procuring additional services in the region, or changing operational profiles, to ***avoid*** the event in the first place. Again, each of these measures comes with its own costs and benefit.[99] Procuring only one is unlikely to represent the optimal solution; instead, some combination is likely to maximise resilience at the lowest overall cost.

The declared South Australia Protected Event provides an applied example of this concept of a portfolio approach. In proposing the South Australia protected event, AEMO's identified the following five 'means' for achieving a level of resilience against 'destructive' wind conditions (i.e. wind speeds above 140km/h):[100]

1. rely solely on existing protection schemes
2. incorporate more load and/or batteries into the existing protection scheme
3. implement an additional high-speed post-separation tripping scheme
4. upgrading of the existing protection scheme, and
5. upgrading of the existing protection scheme and limiting total import capacity over the Heywood interconnector to 250 MW during destructive wind conditions.

The last of these – a combination of mechanisms – was AEMO's recommended option, which was subsequently approved by the Reliability Panel.[101]

99 Here again decision makers may need to take into account customer loss aversion preferences if there is evidence this exists; customers may prefer to incur the ongoing, incremental costs of procuring additional services, over the "loss" of a major supply disruption. Decision makers may choose to weight between the two solutions accordingly.

100 AEMO, *AEMO Request for Protected Event Declaration*, November 2018

101 Reliability Panel, *AEMO request for protected event declaration, Final report*, 20 June 2019

Given the above, the Commission considers that when developing measures to manage HILPs, policy makers must not only identify the nature of the risk being addressed, but must also consider the full suite of resilience measures that can be utilised to manage that risk. Such an approach is critical, as the costs of managing such an event, as well as the costs of the event occurring, are material.

The Commission considers that a co-ordinated approach to restoring power system security resilience should involve the following:

- An assessment and identification of any gaps in the NER system security regulatory frameworks. The Commission has undertaken this assessment as part of this review, which is described in the next chapter.
- The development of new regulatory frameworks that allow for the more effective coordination of different measures to deliver a coordinated, portfolio approach to the restoration of system resilience. This review has begun the process of introducing such measures, through the new general power system risk review and protected events frameworks described in Chapters 7 and 8.
- Further work is needed to consider what other regulatory frameworks could be introduced to better coordinate resilience measures. The Commission intends to undertake further work to explore what these frameworks might look like. These potential future work streams are described in Chapter 6.

5.4.3 Consideration of the full economic benefits of resilience

The main benefit of increasing power system security resilience is to improve the ability of the system to respond to severe disturbances. Ultimately, this reduces the extent of unmet demand for energy due to security events. The main benefit of a resilience measure is therefore the extent to which it reduces the risk, and extent, of load shedding.

However, measures to restore the resilience of the power system can provide a number of other benefits.

Firstly, improving the system security resilience of the system may help to relax dispatch constraints, and therefore support more efficient market outcomes. As illustrated by the current situation in South Australia, a lack of available fault current is resulting in a weak system, which in turn requires AEMO to periodically constrain off significant volumes of asynchronous generation. Increasing the available fault current means that these constraints may be relaxed, which may in turn allow more low cost wind generation to be dispatched, reducing wholesale costs and potentially the cost of energy for consumers in South Australia.

Over the longer term, measures to enhance system security resilience may help to relieve structural impediments to the development of new generation. To the extent that a lack of system services means that the power system cannot support any further investment in asynchronous generation, measures to enhance resilience by increasing available volumes of these services may also support further investment in generation, and therefore reliability, over the longer term.

This is currently being considered by the Commission through the specific lens of the system strength work program. Currently, the system strength and inertia frameworks in the NEM are designed around the concept of providing "minimum" levels, to maintain the security of the power system.

More generally, the Commission considers that measures to enhance resilience should be viewed in terms of the full range of benefits they deliver. This can be achieved through the development of regulatory frameworks for system security that can identify and account for the full range of these benefits. Some of these regulatory frameworks to more effectively identify and account for the benefits of resilience are explored in the next chapter.

6 RESILIENCE GAP ANALYSIS AND FUTURE RESILIENCE WORK PROGRAM

This Chapter applies the framework for understanding resilience introduced in Chapter 3 to assess existing NER arrangements for resilience. On the basis of this assessment, the Commission has identified a need for new operational measures to enhance resilience. As a result, the review recommends enhanced operational frameworks including the generalised power system risk review and the protected operations framework which are presented in Chapters 7 and 8. These measures represent low risk, relatively incremental changes that should deliver material resilience benefits.

While this review is focussed on new operational arrangements for enhancing power system security resilience to indistinct events, the Commission is also progressing a number of projects relevant to other elements of power system resilience. For example, the current rule change requests related to primary frequency response and system restart ancillary services will also make the system more resilient by delivering new and enhancing existing services.

This chapter also considers where further opportunities may exist for future work programs to enhance the resilience of the power system. The Commission will work with the ESB, AEMO, the AER and the Reliability Panel to explore these opportunities.

This chapter first summarises the main recommendations of this review, then describes some of the other work programs currently on foot that will help to enhance the general resilience of the power system. Finally, we provide an overview of areas where opportunities may exist to further enhance the resilience of the NEM.

6.1 Introduction

The Commission has defined resilience as the ability of a power system to ***avoid***, ***survive***, ***recover*** and ***learn*** from HILP events. As discussed in Chapter 5, these elements of resilience are different but complementary, and should be considered holistically.

To complement this conceptual description of resilience, we have also defined the general sets of tools that can be used to provide resilience. These have been grouped into measures that make the system ***stronger***, more ***interconnected***, or ***smarter:***

- ***Stronger:*** These are the kinds of measures that make the system more resistant to non-credible events, including HILP events. Examples include new or tighter power system standards, or new system services that enhance levels of inertia and fault current.
- ***Interconnected:*** Measures to increase the degree of interconnection of the power system can also deliver enhanced resilience, by delivering network flow path redundancy and facilitating the sharing of system services across the power system. Examples typically include augmentation or the construction of new interconnectors between regions.
- ***Smarter:*** These are measures that typically focus on improving the operation of the power system. Examples include new measures to allow AEMO to change the general

operational profile of the system in the face of new risks and uncertainty, enhancements to emergency control schemes, better testing and control processes and better planning processes.

The resilience of the power system can be enhanced in many ways, using different combinations of the measures described above. As described in the preceding chapter, the cheapest way to deliver resilience will be to use a combination of measures to make the system ***smarter***, more ***interconnected*** and ***stronger*** overall, to improve the aggregate ability of the system to ***avoid***, ***survive, recover*** and ***learn*** from HILP events.

Recommendations in this review reflect the circumstances arising from the South Australian black system event and the 'gap' identified in existing work streams relevant to power system resilience. We have therefore focussed our recommendations in this review on measures that enhance operational resilience, by making the system ***smarter***. These reforms represent relatively incremental, low cost and low risk reforms to system security frameworks, which in combination should deliver material resilience benefits.

A number of other work programs are under way which are relevant to enhancing the system security of the power system. In particular, the Commission is progressing several rule changes related to the delivery of new services, to make the system ***stronger***. The Energy Security Board's post-2025 work will also be relevant to the resilience of the power system.

There are a number of opportunities for additional work to enhance the resilience of the NEM power system, in a coordinated and effective manner. In particular, the Commission's ongoing work program looking at AEMO interventions, system strength and system services, will be critical to enhancing the resilience of the power system over the medium to longer term.

New services will be needed for system security. This involves a number of considerations such as what are these services and how are they procured. In addition, we need to consider how much we procure which assists in defining the desired level of resilience of the system. These frameworks provide transparency as to what we are hoping to achieve through the use of these new system services. For example, they can help us decide whether we are procuring new services to manage the system for single credible contingencies, or to protect for more severe events.

This Chapter provides an overview of the Commission's consideration of resilience, including a summary of the resilience focus areas for this review. It then describes the other work streams currently under way that are relevant to system security, and concludes with a consideration of the development of new regulatory frameworks, to better coordinate measures to restore system security resilience.

6.2 An overall assessment of resilience measures

As described above, the Commission has conceptualised resilience through the lens of ***avoid***, ***survive***, ***recover*** and ***learn,*** in the context of measures that make the system ***stronger***, ***smarter***, and more ***interconnected.***

In order to focus our work in this review, the Commission undertook a high level gap analysis. The purpose of this gap analysis was to determine where opportunities existed for further work to enhance power system resilience which was not being addressed in other AEMC, AEMO, AER or ESB processes.

The gap analysis involved mapping existing, and potential NER frameworks against the conceptual categories of ***avoid***, ***survive***, ***recover*** and ***learn*** and the three areas of ***stronger***, ***smarter*** and ***more interconnected***. The outcomes of this gas analysis are set out below in Figure 6.1. The purpose of this mapping was to:

- highlight those areas where existing frameworks exist relevant to the resilience of the power system, or where new arrangements have been implemented since the South Australian black system event. These are set out in black in the table below.
- identify the immediate priority areas for consideration in this review. These are set out in blue in the table below.
- identify those areas where there are opportunities for further work to enhance resilience. These measures are either currently being progressed by the Commission or other market bodies, or represent areas where the Commission considers there is scope for further work.

Figure 6.1: Resilience gap analysis

	Avoid	Survive	Recover	Learn
Stronger	• Interconnector limits • Updated power system models • New power system standards • AEMO reforms to FCAS procurement	• Special protection schemes • Frequency control ancillary services • Network support & control ancillary services • Generator performance standards • Minimum fault/inertia levels • Primary frequency control • Reforms to system strength processes • New system services • DER standards • New special protection schemes	• GTPS update • New SRAS and restoration services	• AEMO incident reports
Interconnected	• Annual performance reviews • RIT-T • ISP-interconnections	• Annual performance reviews • RIT-T • ISP-interconnections	• More SRAS options • Inter-regional support during recovery	• ISP Group projects
Smarter	• Improvements to forecasting processes • Better modelling processes • Protected events framework • Enhanced protected operation framework • Reference events	• Underfrequency load shedding functionality • Refinements to SPS/SIPS • Coordination of protection schemes • Post cascade islanding services • Control software upgrade co-ordination and management of automation • Further enhancements to underfrequency control schemes	• Updated models aid SRAS procurement • More effective SRAS testing and restart processes	• AEMO incident reports • Frequency risk review • Generalised power system risk review

AEMC

From this analysis, the Commission has identified that operational measures to make the system ***smarter***, and enhance its ability to ***avoid***, ***survive*** and ***learn*** from HILP events, represented a clear gap area. This was on the basis that many of the areas highlighted in green above are currently the subject of active work programs being progressed by the ESB, AEMC or AEMO. The Commission has flagged other areas for future work, to develop regulatory frameworks for the coordinated restoration of system security resilience.

On this basis, we have focussed in this review on the development of new tools to enhance AEMO's ability to manage and protect the system from non-credible system security events, including HILP events. Each of these areas are summarised in the following sections.

6.3 Operational measures to enhance resilience

In this review of the South Australian black system event, the Commission has focussed on measures to enhance the resilience of the power system by making the system ***smarter***. These measures include the introduction of a generalised risk review and enhancements to the frameworks for protected events.

The proposed measures to make the system ***smarter*** represent a clear opportunity to enhance the overall resilience of the power system. These are also relatively incremental changes to existing frameworks compared to the other work programs, and so can likely be implemented at low cost and with relatively few associated risks.

This section provides a short overview of the two key areas where the Commission has proposed changes to the NER frameworks to enhance operational resilience. Chapters 7 and 8 then provides further detail as to the specifics of these measures.

6.3.1 Protected operations framework

The Commission is proposing a set of reforms to better manage the changing risk and uncertainty profile of the power system, as the generation mix shifts to being predominantly asynchronous, variable, and geographically dispersed.

We have also proposed standardising AEMO's consultation process for the development of reclassification criteria and protected operation declarations. These processes will now proceed in accordance with the Rules consultation process.

This shift means that the risks and uncertainties faced by the power system are increasingly indistinct in nature. They may occur over a wide area and are not easily attributed to the failure or removal from service of any particular power system asset. They may also be condition dependent, meaning that external conditions are relevant to the magnitude of the risk. In addition to this, the power system also faces increased uncertainty. As discussed in the previous chapter, this uncertainty makes the process of operating the system more complex and challenging.

Weather dependent risks and uncertainties are a key example of this changing profile. As the generation mix is increasingly dominated by wind and solar generation, changes in weather conditions will increasingly drive system risks. Given the wide area impact of weather events, these risks and uncertainties are likely to be indeterminate in nature, with multiple generating systems affected by a single weather system. While the impact of any individual generator may not be material, the aggregate impact on the power system may be significant.

Other indistinct risks and uncertainties include the mal-operation of control software at multiple locations in the power system, or a large scale cyber attack on power system control infrastructure. While the specific characteristics of these risks and uncertainties are different to the weather dependent risks described above, they are similar in that they are likely to impact multiple assets across the system.

The Commission has developed several reforms that are intended to make the system more resilient to these kinds of indistinct risks. These changes include:

- introducing a NER definition of indistinct events
- amending the existing protected events framework, to recognise that "standing" type risks, and uncertainties, may be both distinct and indistinct in nature, and
- the introduction of the protected operation mechanism, to allow AEMO to manage indistinct risks, and uncertainties, that are associated with abnormal conditions.

These mechanisms are addressed in detail in Chapter 8.

6.3.2 General power system risk review

The Commission has proposed changes to existing frameworks to recognise emerging risks, and uncertainties, and develop options to address these.

Under existing NER frameworks, AEMO is required to undertake the power system frequency risk review (PSFR review). The PSFR involves consideration of the frequency risks associated with non-credible contingencies. This review may result in NSPs undertaking a RIT-T, or AEMO applying for the declaration of a protected event by the Reliability Panel.

Recognising the changing nature of the NEM risk, and uncertainty profile, the Commission has recommended expanding the PSFR review to become a General Power System Review (GPSR). The scope of the GPSR will include consideration of:

- issues across both the transmission and distribution networks, including the impact of increased DER penetration, and
- a wider range of risks, including risks associated with voltage, system strength and inertia.

Recognising concerns raised by stakeholders as to the timeliness of the PSFR and protected events process, the Commission has also proposed:

- the GPSR be published at least yearly, through a streamlined process that allows AEMO to publish an approach paper and proceed directly to a final report, and
- the GPSR to be integrated into the overall planning process, including NSP annual planning processes and the ISP.

The GPSR is discussed in more detail in Chapter 7.

6.4 Ongoing work addressing power system resilience

There are a number of work programs currently underway which are relevant to the overall resilience of the power system.

These work programs are being progressed by the AEMC, AEMO, the AER and the ESB. This section provides a brief over of these work programs.

6.4.1 System strength and services

The Commission is currently progressing its *Investigation into system strength frameworks in the NEM* work program. This work program has already made a number of specific recommendations related to the interventions program itself, and is now considering issues related to the system strength frameworks, and the provision of system services more generally.

Some other issues being explored in the investigation include whether changes are required to the minimum system strength and "do no harm" frameworks, to facilitate timely and efficient investment in system strength services, and whether additional benefits could be realised by supporting the provision of system strength beyond minimum levels.

The investigation is also considering other system security services and how they interact. This is intended to facilitate a more holistic approach to the management of system security, avoiding opportunity costs that can arise where frameworks conflict and realising synergies between services and frameworks where possible and appropriate.

A discussion paper will be published in early 2020. These issues reflect the conceptual approach to the development of resilience measures, including ways to assess costs and benefits of resilience, as discussed in further detail in Chapter 5.

6.4.2 Primary frequency response

Primary frequency response (PFR) is an automatic change in active power from a generator or load, in response to a locally sensed deviation of power system frequency.[102]

The AEMC is currently considering two rule changes, from AEMO and Dr Peter Sokolowski, which propose to mandate that all capable scheduled and semi-scheduled generating units provide a primary frequency response once power system frequency moves outside a narrow defined frequency band. We are also considering a third rule change from AEMO that identifies disincentives in the NER to the provision of primary frequency response during normal operation.

PFR is a system service that helps to ***avoid*** the worst consequences of HILP events, by making the system ***stronger*** to HILP events. PFR stabilises power system frequency during normal operation, as well as following credible and non-credible disturbances. To the extent that PFR is provided by some portion of the generator fleet, it contributes to the overall resilience of the system by helping to ameliorate the frequency impacts of these disturbances. This can reduce the reliance on emergency mechanisms, such as emergency frequency control schemes, and reduces the risk and uncertainty associated with of cascading outages and black system events.

The AEMC currently plans to publish draft determinations on these PFR rule changes by the end of 2019.

102 The frequency of the NEM power system is nominally 50Hz. Disturbances that result in an imbalance of generation and load result in frequency deviations: a loss of generation relative to load will lead to a decrease in frequency, while a loss of load will increase frequency. These frequency deviations are managed through changing the provision of active power, by increasing or decreasing levels of generation or load.

6.4.3 System restart ancillary services, standards and testing

The AEMC is currently considering two rule change requests from AEMO and the AER that propose a number of changes to the frameworks for system restart following a black system event.

System restart ancillary services (SRAS) are currently provided by generators that have the ability to independently restart, or trip from the system and supply their own auxiliary loads, following a black system event. These SRAS providers then supply energy that is used to re-energise parts of the power system, to begin the process of restoring supply to customers. In doing so, SRAS help to ***restore*** the system following a HILP event, and make the system ***stronger.***

The rule change from AEMO proposes to introduce:

- new services to assist in the process of system restoration
- new access standards for all generators to provide these new restoration services
- broader scope for AEMO to procure SRAS, and
- a process for the physical testing of the restart pathways that will be used during an actual system restart.

The AER's rule change aims to formalise responsibilities and communication processes to support more effective restart processes.

As part of these SRAS rule changes, the Commission intends to address an issue identified by the AER related to the purpose of local black start procedures (LBSPs).

The Commission intends to publish a draft determination for these rule changes by the end of 2019.

6.4.4 ESB work program

The ESB is currently progressing a number of work programs that are relevant to the resilience of the power system. These include:

- The post-2025 Market Design review. This review being undertaken by the ESB is considering the long term reforms needed to market design to account for the rapid changes currently in the NEM. Amongst a range of issues, this includes consideration of the need for new security services as well as ways to deal with increased generation variability.
- Converting the ISP into action. The process being undertaken by the ESB is intended to make the ISP actionable. It will deliver a regulatory framework surrounding the ISP, including governance, revenue approval processes, dispute resolution and a process to integrate the ISP into the broader planning and economic regulatory frameworks. Draft rules for this work program were published in November 2019.

Each of these processes speak to various elements of resilience. In particular, the ESB's Converting the ISP and the AEMC's COGATI reviews will be relevant to increasing the degree of ***interconnection*** of the system, which is relevant to the ability of the system to ***avoid***, ***survive*** and ***recover*** from HILP events. Furthermore, our proposal to integrate the GPSR with these broader planning processes, including the ISP, will support more effective ***learning*** to support better management of HILP events through the ISP process.

6.4.5 DER integration work program

The ESB is currently coordinating a work program across the three market bodies that is looking at integrating DER into the regulatory frameworks. Several elements of this work program are relevant to considerations of system security resilience.

This work program is considering a number of ways to address the effective market and technical integration of DER into the electricity system. These include considerations of market designs to capture the value of DER, various pilots and trials of DER, data and visibility reforms and enhancements to AEMO's modelling of how DER will behave during power system disturbances.

A key element of this work program for AEMO is the development of technical standards for DER. These standards will include requirements for DER to be capable of remaining connected and contributing to the stability of the system, during disturbance events.

6.5 Future work to enhance system resilience

This review has focussed on enhancing resilience through delivering new mechanisms to make the system ***smarter***, to help ***avoid, survive*** and ***learn*** from non-credible events, including HILP events. These reforms fill a gap that the Commission has identified in terms of the development of overall resilience frameworks. They also complement the various other processes underway to enhance system resilience, and are reasonably incremental, low risk measures which are likely to deliver material resilience benefits.

As discussed in Chapter 3, the general resilience of the power system has been eroded over time. Restoring and maintaining system resilience will require the co-ordinated development of regulatory mechanisms to identify the new risks and uncertainties faced by the system, and identify the optimal combination of measures to address them.

The Commission has also identified further opportunities to enhance the resilience of the power system, through a number of new regulatory frameworks to help make the system ***stronger***, ***smarter*** and more ***interconnected***. A future work-program is therefore recommended for the development of frameworks beyond those either in existence, under development, or considered in detail in this review.

This section explores potential future regulatory frameworks to coordinate enhancements to the resilience of the power system. In particular opportunities for future framework development are identified which will reinforce and complement each other, to provide a coordinated approach to restoring system resilience.

The Commission has grouped these longer term opportunities into the following complementary categories:

- **Top down, focussed measures:** these are specific, targeted developments that provide specific resilience benefits. For example, this could include measures for the purposeful management of specific non-credible contingencies through the declaration of a protected event and the consequent development of a special protection scheme.

- **Bottom up, generalised uplift measures:** these are general, non-targeted measures that strengthen the system and better enable it to manage non-credible contingency events. For example, the introduction of a mandatory primary frequency response obligation would represent a generalised resilience uplift, by increasing the overall ability of the system to deal with any disturbance.

This review has already proposed a number of operational measures for enhancing power system resilience. As described above, the AEMC has also established, or is currently progressing, a number of changes designed to deliver general system security resilience uplifts, such as the minimum inertia/fault level rules, the generator technical performance standards rules, ongoing work looking at system strength through the *Investigation into system strength frameworks*, and the current rule change requests related to primary frequency response and SRAS.

The Commission has however also identified a longer term need to consider a range of additional measures to enhance power system resilience in the context of a changing power system.

We have therefore recommended some areas of future work to consider the development of frameworks beyond those either underway or considered in detail in this review. This future work would be led by the AEMC, with input from AEMO, the AER, and the Reliability Panel, feeding into the ESB's 2025 work.

This section considers possible areas for consideration as scope items for any future work. These areas include:

- enhancing network planning and investment for resilience to manage specific non-credible contingencies.
- considering the development of additional, or changes to existing, system security standards made by the Reliability Panel or system standards specified in the schedule to Chapter 5 of the NER.
- enhancement to NER arrangements for emergency under frequency load shedding, and
- considering the potential for new system security services to be defined covering anti-cascade protection.

Each of these areas is briefly introduced below.

6.5.1 Reference events for enhanced resilience planning

The Commission considers that a particular top down measure that warrants further consideration is a framework to better identify critical non-credible contingencies in each region, and develop network solutions to address them. As discussed below, this framework could further build on the protected events framework, to provide a coordinated and transparent approach to restoring resilience in the NEM.

Reference events, or system design criteria

The concept of explicitly defining non-credible contingencies to inform network planning processes was raised in a submission by TasNetworks to the staff discussion paper that was published in August 2019. TasNetworks stated that:[103]

> accurately defining indistinct events and quantifying their probability will be challenging. As such, TasNetworks suggests consideration be given to the value of introducing a set of published 'system design criteria' for each region. Such criteria would clearly articulate the contingencies that 'must' be adequately managed, and by omission, would then define what remaining contingencies are to be managed on the basis of 'best endeavours'. In clearly identifying what the system has been designed to cope with, a better understanding and acceptance of risk, and risk outcomes, would be promoted across the entire stakeholder base.

The identification of these system design criteria, (also described here as "reference events") may provide a way to transparently define the specific non-credible contingencies that the power system should be planned and designed against. The Commission understands that in the Tasmanian network, these nominated non-credible contingencies are used as a form of calibrating mechanism in the design of EFCS and other network protection mechanisms.

Considered more broadly, this kind of approach could be used to improve the degree of transparency around the amount of resilience that is considered efficient and appropriate in each jurisdiction.

Existing arrangements do allow for networks to account for non-credible contingencies, such as through the application of the RIT-T. However, NSP stakeholders have argued that the overly probabilistic nature of this process makes it difficult to assess the need for resilience measures to deal with uncertain events.[104] Other NER based requirements for NSPs to consider and plan for non-credible contingencies are uncoordinated, and may not be as transparent as a reference events type process.[105]

Defining these reference events, or system design criteria, in each jurisdiction would provide a set of standardised non-credible contingencies, or indistinct events, against which network planning could be calibrated. This could bring additional clarity and transparency to NSP planning for resilience, potentially leading to more efficient outcomes in the long term interest of consumers.

As discussed in Chapter 5, measures like this must be carefully designed and specified, and must be fully transparent. To achieve this, the Commission considers the protected events framework could be developed into a "reference events" framework.

This approach could be designed on the basis of utilising a blend of deterministic and probabilistic methods. This would allow for the effective identification of critical non-credible

103 TasNetworks, Submission to staff discussion paper, p.7.

104 The Converting the ISP process, as well as the AER's new widespread long duration outage VCR, may be relevant to this issue.

105 For example, S5.1.8 of the NER requires NSPs to plan for non-credible contingencies that could threaten the stability of the power system, and install, maintain and upgrade control schemes to manage these events.

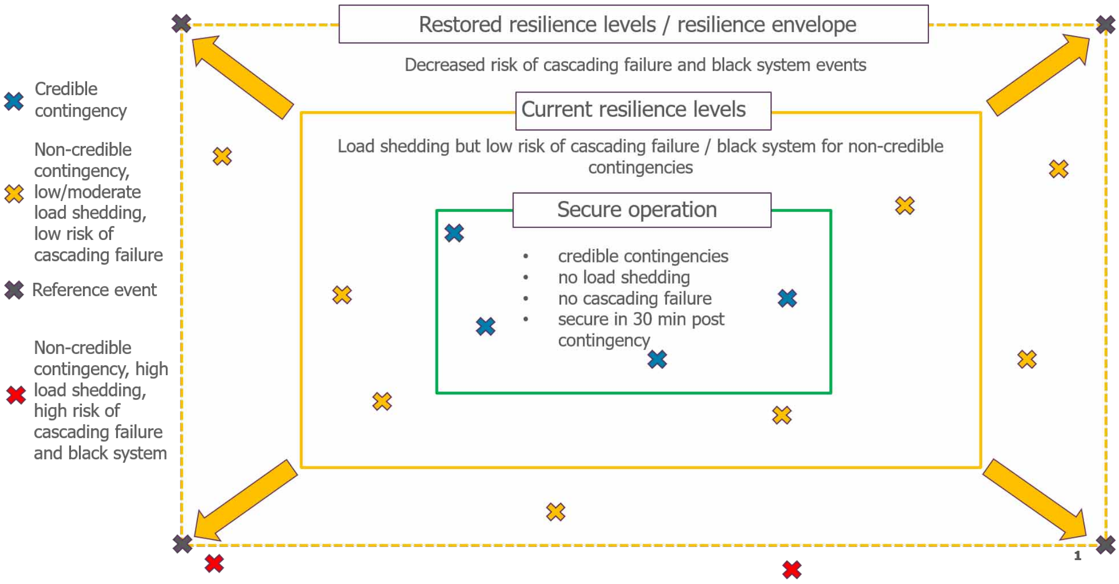
contingencies that all parties agree should be managed, combined with a transparent method to evaluate the costs and benefits of solutions to address those events.

As an example, deterministic methods could be incorporated into the protected events framework, to address the difficulties of applying largely probabilistic frameworks to uncertain HILP events. For example, a deterministic measure might include a NER clause that ex-ante identifies specific types of non-credible contingencies that AEMO and NSPs must automatically assess through the GPSR and APR processes.[106]

Defining these system design criteria could provide a resilience benefit in terms of managing the specific non-credible contingencies identified. However, it is likely that the measures used to address these specific non-credible contingencies would also enhance general power system resilience to other, unidentified non-credible contingencies.

The general concept of the reference event / system design criteria, is described in Figure 6.2 below.

Figure 6.2: Restoration of resilience through reference events



AEMC

The Commission intends to progress this work in conjunction with AEMO and in consultation with industry stakeholders, in early 2020. This will initially take the form of a scoping exercise, to consider whether there are likely to be any benefits associated with enhancing the protected events framework to enable the development of system design criteria.

106 These examples are included solely for the purposes of informing future discussion. This does not represent a Commission policy position.

6.5.2 Further development of system standards

System standards are standards that define the performance of the system, for key system parameters such as frequency or voltage.

Currently, the Reliability Panel is responsible for determining two of these standards: the frequency operating standard (FOS) and the system restart standard (SRS). These standards already speak to power system resilience; for example, the FOS defines the range of allowable system frequency for non-credible contingencies, including multiple contingency events and regional separation.[107]

System standards can be an effective measure for targeting critical elements of system performance relevant to resilience. They also share some elements of general uplift measures, in that they are relevant to whole of system performance. The Commission therefore considers the enhancement of existing standards, and the potential development of new system standards, could be an effective measure to complement other enhancements to system resilience.

The Commission considers there may be scope for the enhancement of existing standards, or the development of further standards, to help manage the risks of a changing power system risk and resilience profile.

The Commission intends to work with the Reliability Panel to consider whether the development of new standards might form a complementary measure, to enhance the overall resilience of the power system. This may take the form of an initial request to the Reliability Panel to undertake a scoping exercise, to

1. consider whether the existing standards can be enhanced to provide additional resilience in the power system, at an efficient cost to consumers; and
2. whether there is a need to consider the development of new system standards.

6.5.3 Emergency frequency control schemes

The control of system frequency is a core component of system resilience, particularly as maintaining frequency stability following a major disturbance is critical to avoiding a cascading failure. As existing NER arrangements may no longer be fit for purpose in this area, the Commission has identified emergency frequency load shedding as a scope item for a future system security resilience work stream.

Severe disturbances to frequency are managed by emergency frequency control schemes. Specifically, automatic under frequency load shedding schemes (UFLS) and over frequency generator shedding schemes (OFGS). These emergency mechanisms are designed to shed load and generation in a controlled manner, until changes frequency are arrested and other mechanisms can begin to return frequency to 50Hz.

107 The NER also allow for the development of other power system security standards by the Reliability Panel, under the general ability for the Panel to develop "Power system security standards". As part of the development of these power system security standards, the NER specifically contemplate the Panel developing "Contingency capacity reserve standards", which are defined as the standards used by AEMO to determine the levels of contingency capacity reserves necessary for power system security. The NER also set out specific system standards for NSP obligations for voltage control.

The effective function of UFLS has been affected by the growth of distributed energy resources (DER) within the distribution network. The presence of large volumes of DER within a load block can reduce the effectiveness of UFLS. For example, during a sunny period, large volumes of DER may mean that the net load shed by UFLS may be unpredictable, or not be as large as expected. Under extreme conditions, very high level of DER could actually mean that a load block is functioning as a net generator - shedding this load block could therefore exacerbate a system security event.

The Commission understands that AEMO has been progressing a work program in conjunction with DNSPs to enhance the performance of existing EFCS. We also understand that the AER has given some thought to the effectiveness of the NER clauses that describe load shedding. The Commission therefore intends to consult further with both the AER and AEMO to consider the NER frameworks for load shedding, and whether these remain fit for purpose given the changing risk profile of the power system.

6.5.4 New system services for system restoration

The Commission considers that the continued roll out of asynchronous generation, coupled with increased investment in utility scale storage, may unlock the potential for new services that may enhance overall system resilience. The Commission considers NER arrangements related to the provision of such services to be an appropriate scope item for a future resilience work stream.

The Commission is currently progressing a rule change request related to system restart ancillary services, standards and testing. A core element of this rule change relates to the development of new "restoration support services" associated with a major supply disruption. These services enhance the resilience of the system by supporting the process of restoring supply following a black system event.

In considering these rule changes, the Commission has identified additional workstreams, including:

- **Identification of additional services:** As described above, AEMO's rule change proposal includes the development of "system restoration support services". These services would help to stabilise frequency and voltage, in the early stages of a system restart following a system black. However, the capabilities that underpin these restoration services could also potentially be used in periods outside of a system restart. The Commission considers there is benefit in exploring how these capabilities might be more effectively utilised to further enhance the resilience of the power system.
- **NSP provision of system restoration support services:** In its rule change request, AEMO had proposed that the AEMC consider whether NSPs should be able to provide system restoration services. The Commission also considers that further thinking on this concept could be considered as part of a future system security resilience work program.
- **Anti-cascade protection:** A potential future work program may also consider the development of new services to protect the system from collapse, following commencement of a cascading failure. Such services, or mechanisms, would allow for blocks of generation and load to separate from the rest of the system, during a cascading

failure. This would entail a small block of load in close electrical proximity to a generation source, which can safely separate from the rest of the system when certain frequency or voltage triggers are reached. An asynchronous generator, coupled with load and a utility scale battery, may be combined to provide such a service.[108]

The Commission intends to work with the AER and AEMO to explore these concepts, building on the initial work through the system restart ancillary services, standards and testing rule change.

108 The ESCRI SA Battery Energy Storage System (BESS) is currently providing such a service in the NEM. The BESS has been designed to reduce unserved energy to Dalrymple following loss of supply. The scheme involves islanding the BESS with local load, the Wattle Point Wind Farm at reduced output and local rooftop PV. The resultant self sustaining island can then be resynchronised with the remainder of the grid when grid supply is restored. For more information, see: https://www.escri-sa.com.au/about/

7 GENERAL POWER SYSTEM RISK REVIEW

RECOMMENDATION 1: **THE GENERAL POWER SYSTEM RISK REVIEW**

The Commission recommends implementing a General Power System Risk review (GPSR) to replace the current Power System Frequency Risk review (PSFR). The GPSR is proposed with the following elements:

Scope of and requirements for the GPSR

The GPSR is recommended to consider, and identify options for the future management of, all events and conditions (including contingency events and indistinct events) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions.

The GPSR will specify six key risk areas which AEMO is required to consider when specifying the scope of the GPSR in each jurisdiction in which it is conducted. These six key risk areas are (AEMO may also consider any other risks it deems necessary):

- increases or decreases in frequency
- increases or decreases in voltage
- levels of inertia
- the availability of system strength services
- the prevalence of distributed energy resources, and
- the operation of special protection schemes.

In conducting the GPSR, AEMO may prioritise certain risks over others, or elect not to consider some of the six key risks. AEMO will be required to consult on its choice of risks and provide an explanation should certain risks, of the six listed, not be considered. This consultation should occur following publication of an approach paper (described below).

The GPSR process

The GPSR is to be conducted annually with AEMO required to consult with, and take into account, the views of Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs) in conducting the review.

A single final report will be published at the conclusion of the GPSR and an approach paper published at the commencement of the review. AEMO is to publicly consult for a period of at least 10 days following publication of the GPSR approach paper.

Links to NSP and AEMO planning processes

The GPSR is to be integrated into relevant AEMO and NSP planning processes. Specifically the recommended rule requires:

- TNSPs and DNSPs to take into account the outcomes from the recent GPSR in their Annual Planning Reviews
- AEMO to consider and have regard to the outcomes of the GPSR in conducting the ISP, and

An additional obligation is recommended to require TNSPs and DNSPs to consider in their APRs whether any special protection schemes and settings of protection systems or control systems of plant connected to its network are fit for purpose. This provision will provide for effective consideration of such risks in the GPSR.

A joint NSP planning obligation will also be imposed to assess the interactions between special protection schemes and settings of protection systems or control systems of plant connected to their respective networks, with a view to identifying the potential for adverse interactions.

The set of system security risks in the NEM that governments, network planning bodies, policy-makers, regulators and system operators must manage is changing, and are significantly different to those managed in the past.[109] As both the technology and generation mix throughout all levels of the power system undergoes a rapid transition, a set of new risks arise that must be first identified in order for it to be effectively managed.

This chapter proposes a single, broadly scoped risk review process to support management of this changing risk profile. A Generalised Power System Risk review (GPSR) is proposed as a comprehensive, periodic and integrated assessment of risks to the power system. Through this review, AEMO, in conjunction with TNSPs and DNSPs, would be required to conduct a holistic analysis of changing system risks that pose a threat to the operation of the power system. This change would enhance the identification of new system security risks, and actions necessary to help reduce the chance of cascading outages or major supply disruptions.

The GPSR expands on the existing Power System Frequency Risk (PSFR) review framework, which currently provides an assessment of frequency related risks to the power system.[110]

The Commission considers that identifying risks through the GPSR would support AEMO in progressing necessary actions to address these risks. In particular, the GPSR would take into account inputs from NSP planing processes, and would itself form an input into the Integrated System Plan. This would provide a long term, whole-of-system approach to planning for emerging risks. Furthermore, the existing framework for AEMO to recommend NSP assessment through the RIT-T, or for the declaration of a protected event by the Reliability Panel, will remain in place. This will provide AEMO with opportunities to progress necessary solutions to the risks identified in the GPSR.

109 The use of 'risk' in this chapter incorporates both concept of risks whose probability distributions are known, and Knightian uncertainty where probability distibutions are not know.

110 See Clause 5.20A.1 of the NER.

This chapter contains:

- An outline of existing arrangements for the PSFR
- the policy proposal for the GPSR included in the 15 August 2019 staff discussion paper
- A summary of submissions to the 15 August 2019 discussion paper
- The Commission's recommendation for expanding, broadening and streamlining the PSFR into the GPSR, with consideration for governance arrangements and actionable outcomes, and
- The Commission's recommendation to link outputs of the GPSR with planning processes and work streams in the NER and in the NEM

7.1 Existing arrangements for reviewing power system risks

The Power System Frequency Risk review (PSFR) was introduced in 2017 as a part of the Emergency Frequency Control Schemes (EFCS) rule change.[111] The PSFR is an integrated, transparent framework for the consideration and management of frequency risks associated with some non-credible contingencies. It requires AEMO, at least every two years and in collaboration with TNSPs, to consider non-credible contingency events that could involve uncontrolled increases or decreases in **frequency**, leading to cascading outages or major supply disruptions.

The PSFR has two main purposes. It seeks to reveal to the market:

- whether, in order to limit the consequences of some non-credible contingency events, there is a need to introduce, modify or adapt automatic schemes to shed load or generation, or
- whether it would be economic for AEMO to operate the power system in a way that limits the consequences of certain high consequence non-credible contingency events, should they occur. This process can lead to the declaration of a protected event by the Reliability Panel.[112]

The PSFR outlines a different process for AEMO to follow for each of these purposes. For the former, once a need to introduce, modify or adapt such an emergency frequency control scheme is identified:

- the assessment, design, implementation and monitoring of the scheme will largely proceed through the existing framework for NSP planning and investment decision-making in the National Electricity Rules (NER), and
- the Regulatory Investment Test for Transmission (RIT-T) or Distribution (RIT-D) will be used to assess the economic case for the change.

For the latter purpose, if AEMO identifies through the PSFR one or more non-credible contingency events which it considers it may be economically efficient to manage using existing ex-ante operational measures:

111 AEMC, Emergency frequency control schemes, rule determination, 30 March 2017 p. ii

112 Ibid.

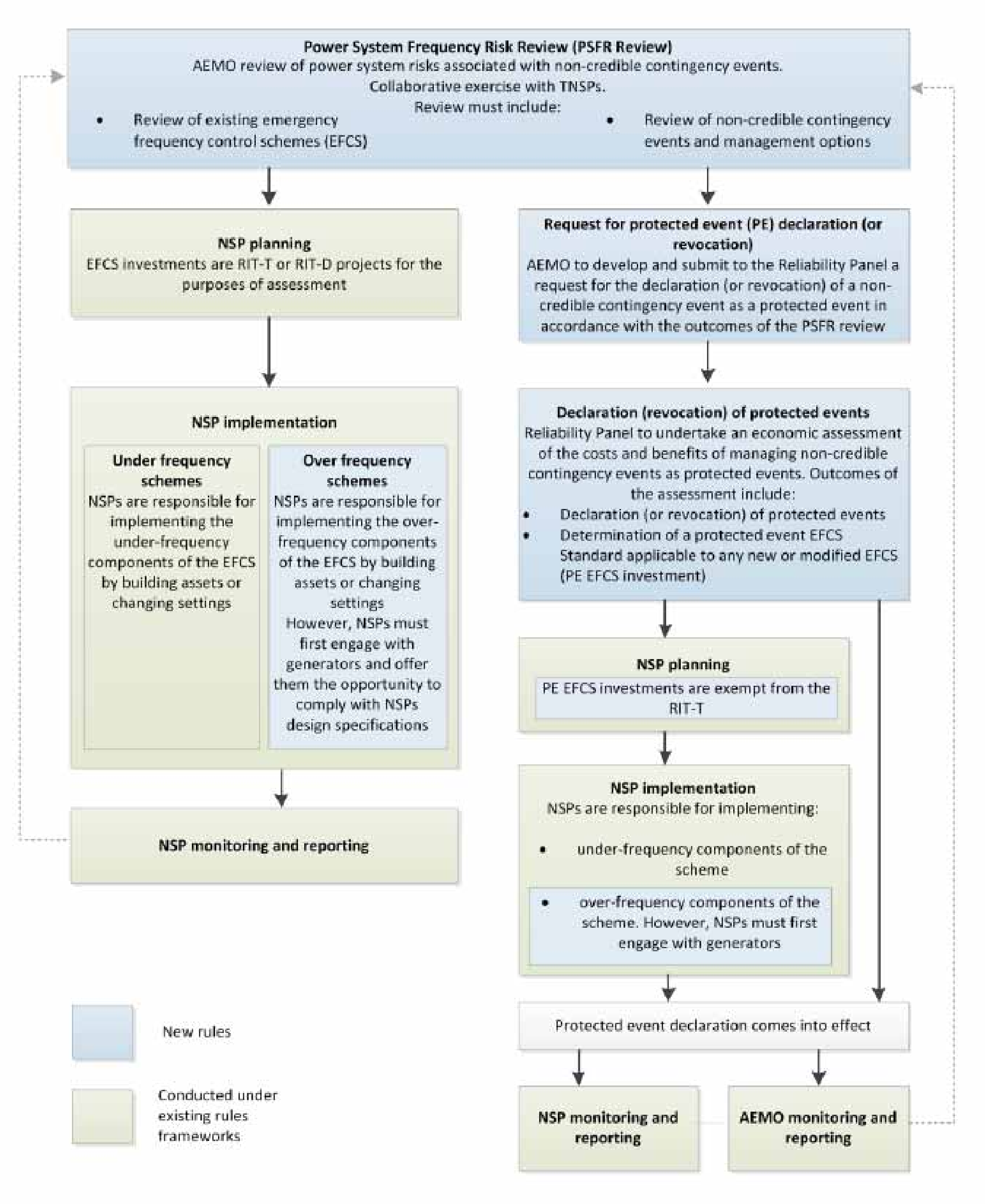
- AEMO can submit a request to the Reliability Panel to have the event declared to be a “protected event”
- such ex-ante measures may be used to manage an event either alone or in combination with a new or modified emergency frequency control scheme
- the Reliability Panel undertakes an economic assessment of the request by weighing the costs of the options for managing the event against the benefits of avoiding the consequences of the non-credible contingency event should it occur. Where the benefits of managing the event outweigh the costs of doing so, the Reliability Panel would declare the event a protected event, and
- where the efficient management option includes a new or modified emergency frequency control scheme, the Reliability Panel would set a "protected event Emergency Frequency Control Scheme (EFCS) standard", which is a set of target capabilities for the scheme.

Importantly, NSPs would be exempt from having to undertake a RIT-T or RIT-D for investments made as a part of a declared protected event. This is because the Reliability Panel would have already undertaken a cost benefit analysis of the operation recommended by AEMO in the PSFR. This process is detailed graphically in Figure 7.1.

Through its consultation with stakeholders, the Commission has identified a number of issues in relation to the current PFSR. In particular, the PSFR has been identified as being:

1. too narrow - the range of risks it considers is limited to only frequency risks for a range of non-credible contingency events
2. too shallow - it only requires AEMO to collaborate with TNSPs but not DNSPs. This does not provide for detailed consideration of system security risks arising from increased DER penetration
3. too slow - it takes too long for AEMO to undertake the PSFR process to identify a system need, and then too long to translate this need into an application to the Reliability Panel for declaring a protected event, and
4. not integrated - it is not sufficiently integrated into the broader planning arrangements undertaken by AEMO and NSPs.

Figure 7.1: Process flow of the Power System Frequency Risk Review



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7.2 Proposed changes to implement the GPSR

The discussion paper published on 15 August 2019 proposed a set of changes to address the shortcomings identified with the existing PSFR.

In particular, it was noted that a risk assessment framework should account for the full range of risks to power system security. These extend beyond frequency management, and may include consideration of factors such as voltage management, system and transient stability, system restoration and new types of operational risks resulting from managing a changing power system risk profile. This review should also extend beyond the large scale, transmission level power system, to consider emerging risks associated with the rapid uptake of DER at the distribution level.

The discussion paper therefore identified the opportunity to expand the scope of the PSFR to become a General Power System Risk Review' (GPSR review). This risk identification and assessment process would expand on the existing governance arrangements and areas of focus in the PSFR. The objective of a GPSR would be to provide a comprehensive stock-take of all security related risks existing in the NEM, as well as formulating an integrated, transparent framework that develops recommendations for addressing all risks in a systematic manner.

The changes proposed in the discussion paper included:

- better coordination of system risks and services
- consideration of risks associated with distributed energy resources, and
- a more frequent GPSR process.

These changes are discussed in more detail in the following sections.

7.2.1 Review coverage

Currently, the PSFR specifically considers frequency risks. However, this may not capture all possible risks associated with both non-credible contingency and indistinct events in the NEM.

A coordinated assessment of all system security risks, through the GPSR, will allow for the efficient identification of risks and assist in more co-ordinated solutions to address system needs. It was therefore proposed that the GPSR cover a general set of risks associated with the following:

- increases or decreases in frequency
- increases or decreases in voltage
- levels of inertia
- the availability of system strength services
- the prevalence of distributed energy resources, and
- the operation of special protection schemes.

AEMO would be able to consider these either alone or in combination, with discretion to consider any other risks it deems necessary in its review of such events and conditions.

7.2.2 Review frequency and process

The discussion paper recommended reforms to the review to help speed the process of identifying and delivering solutions to address emerging system risks. Existing arrangements are for the PSFR to be conducted biennially.[113] Given the speed at which the power system risk profile is changing, a biennial review process may be too infrequent to identify emerging risks and provide for their management in a timely manner.

The NER specifies that a PSFR is conducted according to a two stage draft and final report process.[114] Over this two stage process, AEMO must hold full consultations with TNSPs to assess system risks. Following publishing a draft report, AEMO must invite written submissions from stakeholders on its report, only after which they can submit recommendations to the Reliability Panel for new or modified EFCSs, or the declaration of a protected event. This process provides a transparent and systematic framework for identifying anticipated frequency risks. However, the process also makes delivery of the solutions to address these identified risks contingent on completion of a lengthy review process.[115]

The discussion paper therefore recommended this process be streamlined via introduction of a single stage expedited process to support faster identification of risks, and development of solutions to identify those risks.

7.2.3 Inclusion of DNSPs and risks from distributed generation

High penetrations of distributed generation have been identified as a new source of systemic risk for power system security. AEMO has identified a range of issues associated with DER for system security. These implications include:[116]

- evidence that significant proportions of DER can disconnect or cease operating during power system disturbances (up to 40 per cent), which in the future could translate into the sudden loss of hundreds of megawatts in regions like Queensland, Victoria of New South Wales
- under much smaller, localised distribution network voltage and frequency events, between 8 to 20 per cent of monitored DER was observed to reduce generation to zero over unpredictable periods, and
- observed behaviour of DER under disturbed system security conditions indicate small percentage of rooftop PV fails to comply with existing standards, posing risks to system security predictability.

Existing arrangements for the PSFR require AEMO to put in place arrangements to consult with and take into account the views of TNSPs in conducting the PSFR.[117] While consultation

113 Clause 5.20A.2 of the NER.

114 Clause 5.20A.3 of the NER.

115 After completion of its review process, AEMO can submit a request to the Reliability Panel for an event to be declared a protected event, which the Panel considers in a process that involves two stages of consultation and publication of a draft and final report. The Panel process for declaring a protected event can take approximately six months.

116 AEMO's Technical Integration of Distributed Energy Resources 2019. p. 4

117 Clause 5.20A.2(b) of the NER.

with DNSPs is not precluded by existing rule arrangements, the omission of a requirement to explicitly consult with DNSPs may mean that risks associated with increasing levels of DER penetration are not fully considered.

The discussion paper therefore proposed changes to NSP consultation arrangements in the GPSR. Specifically, it was recommended that AEMO also collaborate with DNSPs in developing the GPSR, to fully consider risks arising from increased DER. This would also provide better visibility of the performance of DER during non-credible contingency events.

7.3 Stakeholder views on discussion paper proposals

Submissions were broadly supportive of the discussion paper's proposal to expand the PSFR into a GPSR. Stakeholders however raised a range of issues and were concerned about the complexity, cost, and resources that would be involved with an annual assessment.

Generally, stakeholders supported expanding the scope of the review process beyond frequency to include voltage, inertia, fault level and other factors that create risks to power system security and resilience.[118] In particular, the AEC supported the expansion, considering the PSFR already a "beneficial process";[119] Stanwell Corporation considered the PSFR should be broadened and "embedded within AEMO's operational processes";[120] and Ergon Energy and Energex suggested "the risk review should include all relevant elements".[121] While supporting the proposal, AEMO considered it important for there to be flexibility to prioritise different sources of risk between reviews, promoting efficiency and value in reporting, and to balance the impacts of operational and institutional changes (such as rule changes) that may alter reporting processes.[122]

Stakeholders strongly supported including DNSPs and risks associated with DER in the GPSR.[123] SA Power Networks noted concerns over the management of reverse energy flows from high DER penetration and the implications for under frequency load shedding schemes.[124] Ergon Energy and Energex particularly noted the importance of risks to be considered by DNSPs, including "generation at risk, load shedding required to facilitate frequency or other contingency management activities, and voltage constraints in a particular area."[125]

While agreeing with the need to include DNSPs and DER related concerns in the review, PIAC also suggested that the process identify resilience opportunities rather than just risks and was also concerned that the number of DNSPs may make the process complex and potentially unmanageable. PIAC recommended exploring alternative mechanisms that would

118 Submissions to the discussion paper: AEMO, p. 15; PIAC, p. 6; AEC, p. 3; Ergon and Energex, p. 7.

119 AEC, submission to the discussion paper, p. 3.

120 Stanwell, submission to the discussion paper, p. 2.

121 Ergon and Energex, submission to the discussion paper, p. 7.

122 AEMO, submission to the discussion paper, p. 15.

123 Submissions to the discussion paper: TasNetworks, p. 6; SAPN, p. 2; Ergon and Energex, p. 7; PIAC, p. 6.

124 SAPN, submission to the discussion paper, p. 2.

125 Ergon and Energex, submission to the discussion paper, p. 7.

not make the process cumbersome or unmanageable, while still gathering "insight and data on DER from DNSPs without requiring all DNSPs in the NEM to be involved".[126]

There were a range of views regarding the frequency of the proposed review. Stanwell considered annual publication to be insufficient, instead favouring publication "at least quarterly to account for seasonal weather forecasts,"[127] AEMO, Ergon Energy and Energex, and TasNetworks were concerned about the burden of time and effort required in identifying a broad scope of risks, and the feasibility of doing this in a 12-month time frame.[128] Ergon Energy and Energex considered an annual publication would require "new processes for extensive forecasts and analysis in addition to existing DNSP functions.[129] AEMO suggested that the division of responsibilities between TNSP, DNSPs and AEMO be clearly set out to facilitate an annual review cycle.[130]

Stakeholders also noted the importance of integrating the review into existing planning processes. AEMO considered that clear linkages should be drawn in the rules between the GPSR and planning processes, including the ISP where appropriate. AEMO considered such linkages would enable AEMO to assess the impact of the occurrence of the risk under different development paths and facilitate stakeholder consultations to discern optimal options.[131] Ergon Energy and Energex also suggested drawing an explicit link between the GPSR and ISP.[132]

In addition to the ISP and NSP planning processes, the Australian Energy Regulator (AER) also flagged a need for the GPSR to consider the potential risks arising from protection scheme interactions. The AER specifically identified the importance of considering risks arising from the settings of the protection and control systems owned by NSPs including special protection schemes, along with any potential interactions with neighbouring NSPs. The AER suggest this could be undertaken annually through the NSP Annual Planning Reports.[133]

7.4 Review recommendations

The Commission considers that the introduction of a GPSR will allow for the effective recognition of emerging risks, and faster development of solutions to address these risks.

In coming to its view, the Commission has taken stakeholder views into account including their general support for the concept of a GPSR, as put forward in the review's discussion paper. In particular stakeholders agreed to:

- expand the range of system security risks considered by the review
- include DNSP's and DER related issues within the review, and

126 PIAC, submission to the discussion paper, p. 6.
127 Stanwell, submission to the discussion paper, p. 2.
128 Submission to the discussion paper: TasNetworks, p. 6; AEMO, p. 15; Ergon Energy and Energex, p. 7.
129 Ergon Energy and Energex, submission to the discussion paper, p. 7.
130 AEMO, submission to the discussion paper, p. 15.
131 AEMO, submission to the discussion paper, p. 16.
132 Ergon Energy and Energex, submission to the discussion paper, p. 7.
133 AER, submission to the discussion paper, p. 2.

- link the GPSR into existing planning and minimum framework proposals.

The Commission has also considered areas where stakeholders raised concerns and made suggestions. To address stakeholder concerns, the Commission has made changes to the proposal put forward in the discussion paper. These changes are outlined in this section and include:

- expanding the range of system security risks to be considered but with flexibility for AEMO to prioritise and consider new risks
- an annual GPSR with a streamlined process
- effectively linking the GPSR with other power system planning processes, and
- consideration of protection scheme interactions.

7.4.1 Coverage of the review and flexibility for AEMO to prioritise the risks to be considered

The recommended GPSR will examine an expanded scope of risks beyond uncontrolled increases or decreases in frequency, to include a more comprehensive set of system security risks that could lead to cascading outages or major supply disruptions.

To provide guidance on the risks to be considered in the review, the Commission recommends that the NER specify six key risks to be considered in each GPSR. The six key risk areas are:

1. power system frequency risks (as currently considered in the PSFR)
2. power system voltage risks
3. risks arising from system strength
4. risks arising from levels of synchronous inertia,
5. risks arising from the effect of DER penetration and the potential for DER to increase the probability of cascading outages or major supply disruptions, and
6. risks arising from interactions between settings on Emergency Frequency Control schemes and connected plant control and protection schemes.

The Commission agrees with AEMO's view that there should also be flexibility to prioritise certain risks over others when undertaking the GPSR. Some risks may not be relevant in the region being considered or cease to be relevant, while others as yet unidentified will assume greater importance. This flexibility would allow AEMO and NSPs to make most efficient use of resources in responding to the most pressing risks present in a particular region of the NEM. To provide flexibility for AEMO, the following two types of flexibility are proposed to be embedded into the framework:

- flexibility for AEMO to consider new risks in the GPSR, on top of the six key risk areas, as it considers necessary, and
- flexibility for AEMO to focus its analysis on specific risk areas it considers more immediate than others.

AEMO would have discretion to consider only the risks they regard to be material in the area under assessment. This means that AEMO would have flexibility to not include a full assessment of all risks. AEMO would however be required to consult with both TNSPs and

DNSPs in prioritising the assessment of certain risks. In electing not to include an assessment of one of the six key risk areas, AEMO will be required to set out in the approach paper, discussed below, reasons why they do not consider a particular risk to be material.

7.4.2 A streamlined annual review process

The Commission considers that the GPSR should be conducted on an annual basis. Consistent with current arrangements for the PSFR,[134] for each key system security risk, the Commission recommends the review assess the likelihood of the event, identify possible outcomes and future management options, recommend a management option, and an outline of the time and cost of the option's implementation. The Commission however notes that flexibility around the frequency of the review may be considered as part of the rule change request to implement the GPSR. An annual review may not always be required in each region of the NEM.

The Commission considers an annual review cycle is required to identify emerging risks sufficiently quickly to allow for their effective management. While the Commission notes stakeholder concern regarding the resource requirements involved in an annual GPSR, the speed and scope of current, and expected, changes in the power system makes a biennial review not frequent enough. Further, as discussed above, AEMO will also have scope to prioritise and focus its resources on the consideration of those specific risks it considers material in the jurisdiction being considered.

To address stakeholder concerns regarding resource implications, the Commission has developed other measures to streamline the review process. The existing NER arrangements for the PSFR require a two stage process. This involves publication and consultation on a draft report prior to publication of a final report.[135] To streamline the review, the Commission recommends removing the requirement to publish and consult on a draft report. Removing the draft report requirement should streamline and reduce the administrative complexity of the review process. The proposed streamlined review process would instead require publication of:

- an approach paper at the commencement of the review process, and
- a single final report at the review's conclusion.

An approach paper would enhance transparency for all stakeholders and improve the process of interacting with TNSPs and DNSPs in conducting the review. The approach paper would assist the efficiency of the review process by promoting a common understanding of the process amongst stakeholders. The approach paper would require AEMO to set out:

- the system security risks they propose to prioritise in each region of the NEM
- proposed methods for assessing prioritised risks, and
- approach to collaborating with TNSPs and DNSPs during the review process.

134 Clause 5.20A.1(c) of the NER.

135 Clause 5.20A.2(a) of the NER.

Following publication of the approach paper, stakeholders would have a minimum 10-day period to comment on AEMO's priorities and methods. A 10-day consultation period is consistent with current arrangements for consultation on the draft PSFR report. AEMO may extend the consultation period if it chooses.

7.4.3 Links to other planning processes

Stakeholders supported the discussion paper's proposal to effectively integrate the GPSR with AEMO and NSP planning processes. Submissions from Ergon Energy and Energex, TasNetworks and AEMO all noted the benefits of capturing learnings from the GPSR in broader NEM planning and reporting processes. AEMO particularly considered that clear links should be established between the GPSR, NSP Annual Planning Reports, and AEMO's Integrated Systems Plan to assist those processes.

The Commission agrees with stakeholders that explicit links between NSP annual planning reviews, the ISP and GPSR, will support the integration of system security risks into planning more generally. Specifically, the review recommends requiring:

- NSPs, in their TAPRs and DAPRs, to consider findings from the most recent GPSR, and
- AEMO to consider findings from the most recent GPSR in its ISP.

7.4.4 Including risks from protection scheme interactions

In its submission to the review's discussion paper, the AER identified the importance of the review considering risks arising from the settings of the protection and control systems owned by NSPs, including special protection schemes. The AER suggested an additional obligation be imposed for annual assessment in the NSP Annual Planning Report.[136] This issue was also raised by a number of members of the technical working group, that was held in Melbourne on 16 August 2019.[137]

The Commissions agrees with the AER that unexpected outcomes from, and adverse interactions between, special protection schemes and plant control and protection settings represent a material risk that should be systematically assessed as part of a GPSR. The Commission therefore proposes to include these interactions as a key risk for consideration annually in each GPSR. In addition, the Commission recommends additional changes to annual planning review arrangements for each NSP are warranted to support the holistic consideration of such risks as part of the GPSR.

These changes codify in the NER a requirement for both TNSPs and DNSPs, in their internal reviews and reports and as a part of their joint planning obligations, to explore risks by maintaining, monitoring and reporting on the integrity of protection and control schemes, as well as the integrity of settings on all plant connected to their network. The review therefore recommends requiring:

136 AER, submission to the discussion paper, p. 2.

137 AEMC, technical working group minutes, https://www.aemc.gov.au/sites/default/files/2019-08/South%20Australia%20black%20system%20event%20review%20-%20technical%20working%20group%20minu....pdf

- TNSPs, as part of their transmission annual planning review obligations under clause 5.12.1 of the NER, to review the settings on all Emergency Frequency Control Schemes (EFCS) and connected plant relevant to their network, both new and existing, and the interactions between them
- DNSPs as part of their distribution annual planning review obligations under clause 5.13.1 of the NER, to review the settings on all Emergency Frequency Control Schemes (EFCS) and connected plant relevant to their network, both new and existing, and the interactions between them, and
- both TNSPs and DNSPs as part of their joint planning obligations under 5.14.1(d) to conduct joint planning in assessing the settings on all Emergency Frequency Control Schemes (EFCS) and connected plant relevant to their network, both new and existing, and the interactions between them.

7.5 Recommendation benefits

The recommended GPSR will promote the efficient operation and use of electricity services in the long term interests of consumers of electricity with respect to the safety and security of the national electricity system. It is in the long term interests of consumers that:

- emerging risks are identified promptly. Emerging risks that are not identified can not be effectively managed. The recommended GPSR would increase the frequency and speed of the review process to become an annual process sufficient to promptly identifying emerging risks
- risks to power system security are effectively assessed from all possible sources. The power system's transition to intermittent renewable generation and the closure of existing synchronous generation is changing the power system's risk and resilience profile. New risks are emerging as this process occurs. As an example, the existing PSFR may not fully consider the impact of DER on systemic system security outcomes, and
- all parties are effectively co-ordinated in the process of identifying and assessing emerging risks to the power system. The GPSR would assist the co-ordination of all parties responsible for managing the changing power system risk and resilience profile through its inclusion of AEMO, TNSPs, and DNSPs. Integrating the GPSR into NSP and AEMO planning processes would assist in the implementation of the lowest cost management processes overall, rather than adoption of a set of dis-jointed measures which may be less efficient.

Consumers will face inefficient costs if there is a reduction in the security of supply due to a failure to promptly and effectively identify emerging risks. If emerging risks are not efficiently and effectively identified, such that they can be efficiently managed, consumers are likely to experience an increase in the frequency and duration of major supply disruptions, or black system events. There would be an increase in cost and resource requirements for AEMO and NSPs in conducting a broader, more frequent review. However, we expect these costs to be minimal and necessary to address the changing risk profile of the system, given the rapid transition under way.

7.6 Suggested rule change and recommendation summary

The Commission has developed a suggested rule change request to implement the GPSR proposed in this chapter. This, along with indicative rule drafting, is provided in Appendix A. This section summarises the proposed changes to the NER.

- The Commission recommends amending existing requirements applying the PSFR to require AEMO to conduct a General Power System Risk review (GPSR). The GPSR should consider:
  - all events and conditions (including contingency events and indistinct events or conditions) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions, and
  - options for future management of these events and conditions.
- When reviewing events and conditions in the GPSR, the Commission recommends requiring AEMO to consider the following key risk areas (AEMO may also consider any other risks it deems necessary):
  - increases or decreases in frequency;
  - increases or decreases in voltage;
  - levels of inertia;
  - the availability of system strength services;
  - the prevalence of distributed energy resources; and
  - the operation of special protection schemes.
- AEMO may prioritise certain risks over others, or elect not to consider some risks in the GPSR. In establishing priorities, AEMO will be required to consult with both TNSPs and DNSPs. AEMO will be required to consult on its choice of risks and provide an explanation should certain risks, of the six listed, not be considered.

The general power system risk review process

- The Commission recommends requiring:
  - AEMO to undertake a GPSR no less than annually, and
  - AEMO to consult with, and take into account, the views of Transmission Network Service Providers and Distribution Network Service Providers in the conduct of a GPSR.
- The Commission recommends:
  - a single final report to be published at the conclusion of the GPSR
  - an approach paper be published at the commencement of the review specifying
    - — priorities in the risks to be assessed
    - — the approach and methodologies in assessing each risk
    - — information inputs and assumptions used, and
    - — apporach to interacting with TNSPs and DNSPs in conducting the review,

- a requirement for AEMO to invite written submissions to be made for a period of at least 10 days following publication of the GPSR approach paper.

Links to NSP and AEMO planning processes

- The Commission recommends requiring TNSPs and DNSPs to consider whether any special protection schemes and settings of protection systems or control systems of plant connected to its network are fit for purpose. This consideration includes:
  - an analysis and explanation of whether such settings are fit for purpose for the future operation if its network
  - a description of any interactions between the special protection schemes and such settings
  - a description of any interactions between the special protection schemes and such settings, and
  - a description of any proposed actions to be undertaken to address those interactions.
- The Commission recommends requiring TNSPs and DNSPs to take into account the outcomes from the recent GPSR review in their Annual Planning Reviews.
- The Commission recommends that joint planning processes also include a new requirement to assess the interactions between special protection schemes and settings of protection systems or control systems of plant connected to their respective networks, with a view to addressing any adverse impacts through joint planning.
- The Commission recommends a new requirement for AEMO to consider and have regard to the outcomes of the general power system risk review in its ISP.

8 MECHANISMS FOR ENHANCING OPERATIONAL RESILIENCE

RECOMMENDATION 2: SUMMARY OF RECOMMENDATION

The review recommends AEMO be provided with additional mechanisms to enhance power system resilience to indistinct events where indistinct events associated with abnormal conditions. Indistinct events are not considered contingency events as they do not involve the failure or removal from service of specific power system elements. Indistinct events are distributed, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. Risk and uncertainty arise from the difficulty predicting the aggregate size of these events, and the specific power system assets affected. Indistinct events may still involve rapid unexpected changes in aggregate generation or damage to power system assets.

The Commission recommends changes to the NER to:

- define an indistinct event
- clarify that standing risks from indistinct events can managed as a type of protected event and to enhance the protected event approval process,
- implement a new operational tool, protected operation, for AEMO to manage indistinct events the risk of which are strongly linked to abnormal conditions. Two types of protected operation are proposed:
  - pre-defined protected operation, and
  - ad-hoc protected operation.
- specify governance arrangements for protected operation

Indistinct event definition

The Commission recommends the NER define an indistinct event. This definition will reflect the following:

- indistinct events are distributed and act on multiple generation and network assets in an affected area, over time
- the specific power system elements associated with the event cannot be clearly defined and may involve the generating systems in a geographic area, rather a specific unit, and
- system security risks and uncertainties arise from the aggregate response of generation and other power system assets and may be uncertain and difficult to establish ex-ante.

Standing risks arising from indistinct events can be managed as a protected event

The Commission recommends retaining existing arrangements for protected events with the following changes:

- protected events are to apply only to the management of 'standing' events the occurrence of which are not a strong function of conditions. Management of risks from indistinct events that are a function of abnormal conditions would be through protected operation.
- clarify that indistinct events can be declared to be protected events, and
- introduce an expedited approval process for declaring protected events that are not controversial and are otherwise straight forward.

This recommendation does not otherwise propose changes to governance arrangements for protected events.

Implement protected operation as a means for AEMO to manage risks from indistinct risks given abnormal conditions

The Commission recommends implementing protected operation as a means for AEMO to manage risks from condition dependent indistinct events. Specifically, protected operation will manage risks arising from indistinct events the risk of which increase under abnormal conditions. Two types of protected operation are proposed:

- pre-defined protected operation, and
- ad-hoc protected operation

Pre-defined protected operation

AEMO would declare a period of protected operation to manage risks from specific indistinct events in accordance with criteria and actions pre-defined for management of risks from these specific events. The NER would set out requirements for the criteria specified and published by AEMO.

The protected operation framework will allow AEMO to take all necessary actions to manage risks arising from those events. This would provide AEMO with the flexibility it needs to manage the associated risks.

These actions could include constraining the dispatch of generation, or procuring additional system services. In doing so, AEMO would have the discretion to maintain the power system in a secure state for these identified indistinct events - this means that AEMO could take those actions necessary so that no load shedding occurs following the event.

The Commission considers that this new framework would benefit consumers by allowing AEMO to take all actions necessary to reduce the risks of major supply disruptions. However, these actions come at a cost, and it is important they are examined.

So that these costs are clearly examined and weighed against the consequences of indistinct events, the Commission recommends that AEMO follow a general cost minimisation principle when it assesses these events. However, recognising the difficulty of undertaking these kinds of assessments for uncertain events, we consider that when following this principle, AEMO would exercise its expert judgement as system operator in determining what is a reasonable set of actions to take.

To support transparency AEMO must assess, consult on, and publish details of its assessment.

Ad-hoc protected operation

The Commission considers that pre-defined protected operation would provide AEMO with clarity as to what actions would be taken to manage risks from indistinct events. This reduces uncertainty for AEMO. Equally however, AEMO should not be prevented, or consider themselves to be prevented, from taking necessary action to maintain the security of the system.

The Commission has therefore also proposed a flexible "ad-hoc" protected operation mechanism, to complement the pre-determined protected operation mechanism

Ad-hoc protected operation would allow AEMO to take any additional operational action necessary to prevent a cascading failure. It would apply to indistinct risks that had not yet been identified, or to provide AEMO with additional operational flexibility to take actions beyond those specified in any pre-defined criteria.

Ad-hoc protected operation is intended to be an emergency measure. On each occasion AEMO declares a period of ad-hoc operation, AEMO would need to report publicly, and to the Panel, as soon as practicable following the occasion. The NER would specify minimum requirements for AEMO's report.

Consultation and transparency measures

Enhanced consultation requirements are proposed for AEMO's use of protected operation.

This consultation will be public and undertaken in accordance with the rules consultation procedures.

These enhanced consultation arrangements will also apply to consultation on AEMO's development of criteria for reclassification.

Provision for Reliability Panel guidelines and oversight

If the Reliability Panel considers it necessary or desirable, it may elect to determine guidelines for pre-defined and ad-hoc protected operation. The Reliability Panel may also act in a general oversight role by considering AEMO's performance as part of its Annual Market Performance Review (AMPR).

8.1 Background

Chapter 6 identified operational frameworks for managing indistinct risks as a gap that should be addressed within the scope of this review. This chapter recommends operational arrangements for AEMO to enhance the resilience of the power system to indistinct events under abnormal operating conditions. This chapter discusses:

- the management of indistinct risks within the protected events framework

- the concept of protected operation, which would allow AEMO to manage condition dependent, indistinct risks that can be identified ex-ante, and for which pre-defined management actions can be prepared, and
- providing AEMO with authority to take ad-hoc actions to manage indistinct events that have either not been foreseen, or are yet to have management actions pre-defined.

Supporting the recommendations set out in this chapter are a set of governance arrangements that include:

- additional flexibility for AEMO to declare periods of pre-defined protected operation in accordance with published criteria
- a cost minimisation objective applying to AEMO's criteria and actions for pre-defined protected operation
- enhanced consultation and reporting requirements to maintain and transparency and confidence in AEMO's actions, and
- providing the Reliability Panel with the ability to specify guidelines applying to AEMO's declaration of protected operation (if required).

This chapter initially introduces the existing protected events framework and identifies a number of issues with existing arrangements given a changing power system risk, uncertainty and resilience profile.[138] The protected operations framework proposal put forward in the review's discussion paper is then presented, along with stakeholder views. An amended proposal, incorporating key stakeholder submissions, is then presented.

8.2 Existing protected events framework

The NER currently includes arrangements for AEMO to take operational measures to enhance power system resilience. There are two primary system security frameworks specified in the NEM for this purpose:

- **reclassification**, which provides for ex-ante adjustment of the technical envelope to maintain the power system in a secure state for the occurrence of non-credible contingency events that have become credible given the presence of abnormal conditions, and
- **protected events,** which provides for AEMO to take a mix of ex-ante and ex-post measures to prevent a cascading failure from a non-credible contingency event which the Reliability Panel has approved as a protected event.

The review recommends retaining existing arrangements for managing distinct contingency events except for consultation arrangements applying to AEMO's development of criteria for re-classification.[139] In this area the review recommends aligning consultation processes for both reclassification and protected operation (and will be discussed further in section 8.5.2).

138 The Commission here distinguishes between risk and uncertainty, defining risk as those random events with ascertainable probabilities, while uncertainty are those random events whose probabilities cannot be determine. Where necessary to distinguish between risk and uncertainty, this has been clearly identified.

139 Contingency events are considered 'distinct' as they relate to the failure or removal from service of specific identifiable power system elements.

Except for consultation arrangements, the review does not recommend changes to existing frameworks for managing distinct contingency events. Recommendations are focussed on extending the existing protected events framework to cover indistinct events.

8.2.1 Emergency Frequency Control Schemes rule change and protected events

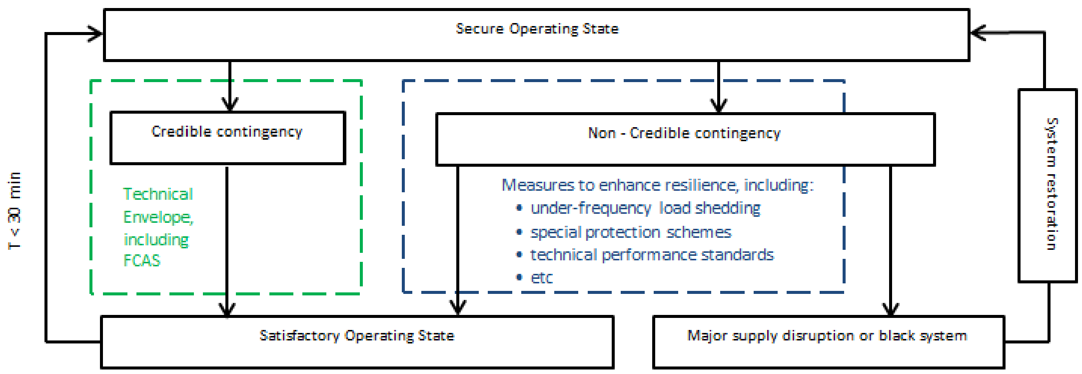
The protected events framework was implemented in 2017 as part of the Emergency frequency control schemes rule. This framework has the following key elements:[140]

- The Power System Frequency Risk Review (PSFR), which was discussed in Chapter 7, and
- Protected events - If AEMO identifies one (or more) non-credible contingency events which it considers may be economically efficient to actively manage, it can submit a request to the Reliability Panel to have the event declared to be a protected event.

Once declared as a protected event, AEMO is able to enhance the resilience of the power system by taking a mix of ex-ante and ex-post actions to prevent a cascading failure, given the occurrence of the non-credible contingency event.

The protected events framework enhances power system resilience by increasing the probability of the power system ultimately returning to a satisfactory operating state following the non-credible contingency event which has been declared as a protected event. Figure 8.1 illustrates how the protected event framework enhances resilience of the power system relative to arrangements for maintaining the system in a secure state. This is compared to the alternative of the event ending in a major supply disruption or black system event. These measures are illustrated in the dashed blue box, which complements arrangements for maintaining the power system in a secure state for credible contingencies (represented by the dashed green box).

Figure 8.1: System security block diagram - arrangements for resilience and a secure state



Source: AEMC

140 AEMC, Emergency frequency control schemes rule, final determination, p. 4.

Protected events are a subset of non-credible contingency events, as defined and discussed in Chapter 3. AEMO is not required to maintain the power system in a secure state for the occurrence of a non-credible event (that is, remaining in a satisfactory operating state after the event, with no load shedding) should this event occur.

As shown in Figure 8.1, controlled load shedding is allowed to occur following the occurrence of a protected event. Controlled automatic under frequency load shedding is a key component of the "survive" stage of resilience. Protected events include the use of measures such as controlled load shedding to prevent an uncontrolled, cascading failure and degradation to a black system.

Protected events

Under the current protected events framework, AEMO applies to the Reliability Panel (Panel) for the declaration of a protected event if it identifies a non-credible contingency event in the PSFR that represents a risk to power system frequency. The non-credible contingency needs to be considered to be sufficiently severe as to make actions to prevent a cascading failure economically efficient.

The Reliability Panel then undertakes an economic assessment of AEMO's application by weighing the costs of managing the event (including the costs to the market of any load shedding) against the avoided consequences of the non-credible contingency event should it occur. In determining the request, the Reliability Panel assesses:[141]

- the costs of the recommended option(s), including the cost of ex-ante measures and the costs of any new or modified emergency frequency control scheme (and any load or generation shedding associated with the option), against
- the avoided cost of the consequences of the non-credible contingency event, should it occur.

Where the costs of managing the event are outweighed by the benefits of avoiding a cascading failure, the Reliability Panel would declare the non-credible contingency event a protected event.

Importantly, the operational "target" for AEMO in managing the system for a protected event, is to avoid a cascading failure following occurrence of the event. This is very different to AEMO's operational targets for managing the system for a credible contingency, which is to keep the system in a satisfactory operating state, and return it to a secure operating state within 30 minutes of the contingency event occurring. A key aspect of these requirements is that load shedding should not occur for a credible contingency.[142] In contrast, load shedding can occur for protected events.

The declaration of a protected event covering high winds in South Australia

In its 2018 PSFR, AEMO concluded that the risk of significant loss of generation leading to the loss of the Heywood interconnector is heightened during periods where “destructive wind

141 AEMC, Emergency frequency control schemes rule, final determination, p. 64.

142 The specific NER mechanisms that set out this framework are spread across Chapter 4 and the schedules of Chapter 5 in the NER, as well as in the frequency operating standards.

conditions" (i.e. wind speeds above 140km/h) are forecast in the region. In 2018, AEMO applied to the Reliability Panel for the declaration of a protected event, defined as "the loss of multiple transmission elements causing generation disconnection in the South Australian region during forecast destructive wind conditions".[143]

The measures AEMO will apply to manage the risk of a cascading failure arising from destructive wind conditions are dependent on forecast wind conditions in South Australia. Based on weather forecasts issued by the Bureau of Meteorology, AEMO will take actions including constraining flows on the Heywood interconnector to 250 MW. The actions taken by AEMO are therefore condition dependent. They recognise that the probability of losing the Heywood interconnector, while not becoming credible, nevertheless increase during high wind conditions.

Following the declaration of the first protected event, AEMO and other stakeholders identified a number of issues with the existing process, arguing that it takes too long for the Reliability Panel to assess AEMO's application and declare a protected event, and is inflexible in its application.[144]

8.2.2 Limitations and issues with the existing framework

Following the consideration by the Panel, and the resulting declaration of the South Australian protected event, a number of limitations and issues have been identified with the existing framework.

The protected events framework was originally designed for the purpose of managing the risks of distinct, non-credible contingency events. It was not explicitly designed to manage indistinct, condition dependent risks (these were introduced in Chapter 3). Although the recently declared South Australian protected event was eventually defined on the basis of condition dependent risk (in particular, the presence of destructive winds), it was not immediately apparent that this outcome was consistent with the original design and intent of the framework.

AEMO also noted difficulties involved in defining an 'indistinct' event as a protected event. AEMO identified the following as shortcomings associated with the existing protected events framework:[145]

- Protected events are inflexible, with the operational management of a protected event limited to the measures approved as part of the declaration process. This makes it difficult to apply to a range of risks that may exist.
- The time needed to identify, develop, review, and eventually declare a protected event is too long to keep pace with the rapid transition in the power system. This leaves no option but for AEMO to intervene where it is possible to do so, often in costly ways. In that time, the rapid pace of change in the power system means that the nature of the risk will most likely have changed, and different challenges may be presenting themselves.

143 AEMC Reliability Panel, AEMO request for protected event declaration, Consultation paper, p. 7.

144 AEMO, submission to the issues and approach paper, p. 7.

145 AEMO, submission to the issues and approach paper, p. 7.

- The protected events framework addresses only non-credible contingencies that cause frequency disturbances identified as part of a PSFR. Non-credible contingencies can cause significant disruption via other phenomena without directly being frequency disturbance events.
- Like reclassification, the protected events framework only addresses risks of non-credible contingencies in the context of dispatch and real time system security management. AEMO note that in practice, it will never be possible to identify every discrete non-credible contingency that would have an unacceptably high impact if it occurred.

AEMO considered there are significant limitations on the ability to:

- predict the consequences of a proposed protected event (that is, the amount of unserved energy),
- determine the probability of occurrence (particularly if it is an event that has never happened before), or
- estimate the costs and benefits of a solution.

AEMO considered all of these assessments to be significantly challenging. AEMO considers that this forms a barrier to justifying the declaration of a protected event, making it an impractical tool to manage risks associated with non-credible contingency events in all but the simplest and most severe examples.[146]

The following section presents the review's proposed approach to extending the existing protected events framework to address these identified issues.

8.3 Proposed expanded protected events/operation framework

This section describes the expanded protected events/operation framework put forward in the review's discussion paper, which was published on 15 August 2019.[147] This proposal was developed to address shortcomings identified in respect of the existing protected events framework, in particular to be:

- more flexibly applied to a wider range of risks beyond those relating solely to frequency
- clearly applicable to non-credible, indistinct events, including HILP events
- clearly applicable to condition dependent risks, and
- faster and more efficiently approved.

Following stakeholder feedback to the discussion paper, the Commission has revised a number of the elements of the protected operation framework. In particular the Commission has made changes such that:

- Provide AEMO with enhanced flexibility to utilise pre-defined protected operation to maintain the power system in a secure state, without load shedding to certain indistinct risks associated to abnormal conditions, and

146 AEMO, Submission to staff discussion paper, p. 17.

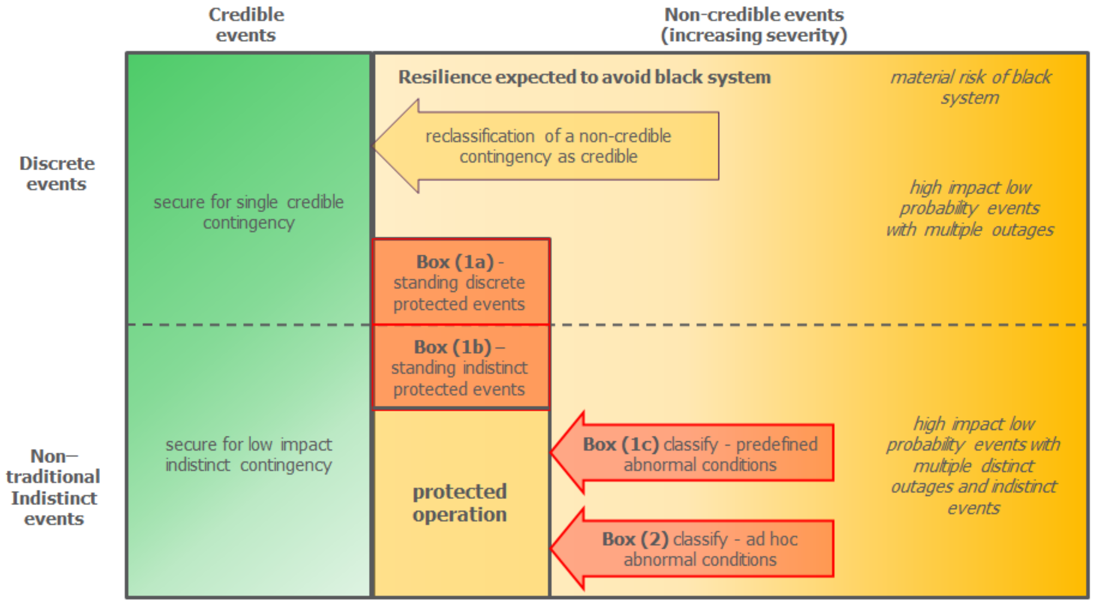
147 AEMC, Mechanisms to enhance resilience in the power system - review of the South Australia Black System event, 15 August 2019. Available at: https://www.aemc.gov.au/sites/default/files/2019-08/discussion_paper_-_sa_black_system_review_-_15_august_2019.pdf

- AEMO would be responsible for declaring protected operation periods, including setting the criteria and actions to be taken during the protected event period, subject to principle guidance in the NER and from the Panel.

These changes are discussed in detail in section 8.5 of this chapter.

The expanded protected events and operation framework, as proposed in the discussion paper, is summarised graphically in red alongside existing arrangements for managing distinct contingency events in Figure 8.2 below.

Figure 8.2: Elements of the enhanced protected events/operation framework



AEMC

The horizontal axis of Figure 8.2 represents the increasing severity of an event, with the less severe credible contingency events on the left and more severe non-credible contingency events (including indistinct HILP events) on the right. This figure will be referenced throughout this section as each of the elements making up the proposed framework are described.

The top two quadrants represent the existing framework for system security. The top left-hand quadrant represents the set of all distinct, credible contingency events for which existing arrangements require AEMO to maintain the power system in a secure state (green). The top right-hand quadrant represents the set of all distinct, non-credible events, for which emergency under frequency load shedding is implemented and system restart services are procured (yellow). Resilience mechanisms included in current frameworks include:

- non-credible contingency events can be reclassified as credible by AEMO, where it considers the event is reasonably possible given abnormal conditions (such as lightning or bushfires).
- protected events (Box 1a) are non-credible contingency events, declared as protected events by the Reliability Panel, following a request from AEMO. AEMO is required to take sufficient actions so that a protected event should not lead to a cascading outage.

The review has not considered changes to these existing arrangements, except some minor clarification and an enhanced consultation process for reclassification (as discussed in section 8.5.2). This review instead has focussed on extending arrangements for managing indistinct system security risks which are represented in the bottom two quadrants of the figure.

The bottom two quadrants include the green bottom left quadrant, for which an indistinct risk is considered to be reasonably possible and therefore credible. The discussion paper proposed a requirement to maintain the system in a secure state for indistinct risks which are considered reasonably possible and therefore credible. These arrangements were described as an N – 1 (plus) framework, and are discussed in more detail in Chapter 9.

The proposal put forward in the discussion paper focussed on arrangements in the bottom right-hand quadrant. This framework can be divided into the following three parts with each element described below:

- Box (1b) - standing indistinct protected events
- Box (1c) - pre-defined protected operation, and
- Box (2) – ad hoc protected operation.

Boxes 1(a) and 1(b) in Figure 8.2 represent standing protected events that manage temporally uncertain risks which are not strongly related to abnormal conditions. Box (1a) is the only element of the protected event framework that exists within the scope of existing power system security arrangements, since it is related to increasing power system resilience related to distinct, non-credible contingency events. Box (1b) can be seen as a clarification that indistinct events can be managed as protected events.

Apart from clarifying the treatment of indistinct events, significant changes are not proposed to the mechanism applying to standing protected events. As noted above, the focus of this review has been on the introduction of protected operation.

8.3.1 Protected operation

The existing protected event framework was not explicitly designed to manage condition dependent risks. While it does not preclude the use of measures to manage instinct condition dependent risks, the Commission considers it important to clarify the treatment of condition dependent indistinct risks, such as those arising from distributed weather events. Protected operation is introduced for this purpose.

The review's discussion paper proposed the introduction of "protected operation", as a new element to the existing protected event framework. The key difference between protected operation, and protected events as described above, is that it is designed to deal with indistinct risks that only become more probable where abnormal conditions apply.[148]

Because these indistinct risks only arise from time to time, the most efficient way for AEMO to manage them would be to take operational actions, rather than implementing standing measures. Protected operation would allow AEMO to alter how it operates the system by adjusting the technical envelope or taking other actions, for the limited time during which the relevant abnormal conditions occur, in order to enhance the general resilience of the power system.[149] This would enhance the ability of the system to avoid, survive and recover from the relevant risk, should it occur.

When a period of protected operation commences, AEMO would undertake actions with the ultimate goal of seeking to prevent an uncontrolled cascading outage. It would do this by increasing the resilience of the power system through changing the technical envelope, in accordance with a range of pre-determined actions approved by the Panel. Importantly, as with the existing traditional protected event, this would mean some load shedding could occur, provided that the system stayed stable and an uncontrolled cascading outage was prevented.

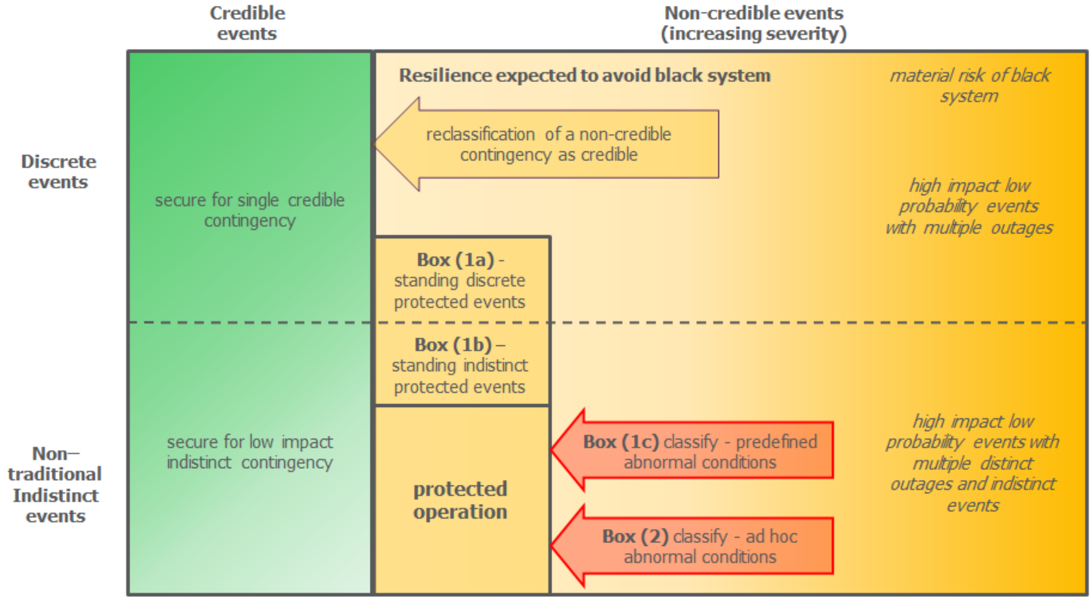
This section steps through two types of protected operation (indicated in red in Figure 8.3) being:

1. Box (1c) - pre-defined protected operation, and
2. Box (2) – ad hoc protected operation.

148 Note that 'probable' risks in this case are non-credible in that their probability of occurrence is not sufficiently high to be considered reasonably possible and therefore credible.

149 It should be noted that protected operation can be undertaken independent or in combination with standing actions under a protected event for the region.

Figure 8.3: Pre-defined and ad-hoc protected operation



AEMC

Box (1c) - pre-defined protected operation

Box (1c) in the figure represents indistinct non-credible events that become more likely only during abnormal conditions (such as severe storms) and which carry an associated risk of causing a cascading outage only during these periods. Pre-defined protected operation would involve AEMO:

- pre-identifying the risk through the GPSR (discussed in Chapter 7)
- specifying criteria setting out the specific circumstances which would see it enter into a period of protected operation, and
- the actions it would take to prevent a cascading failure given the applicable conditions.

The model of protected operation proposed in the discussion paper intended that pre-defined protected operation would be approved by the Reliability Panel, following consideration of the costs and benefits in the same way as protected events are currently approved. [150]

Box (2) – ad hoc protected operation

Pre-defined protected operation is designed to provide clarity as to what actions will be taken, and under what conditions these actions should be taken. This clarity supports the

150 The Commission now considers that AEMO should be responsible for determining the dimensions of a protected operation period, subject to meeting a cost minimisation objective and undertaking a transparent consultation process. Further detail on this revised protected operation approval mechanism is provided in section 8.5.2 on governance.

secure operation of the power system, in that there is reduced uncertainty for AEMO as to what actions should be undertaken.

Equally however, AEMO should not be prevented, or consider themselves to be prevented, from taking necessary action to maintain the security of the system. Flexibility is required so that AEMO can adjust and take necessary actions as the needs arise.

The Commission has therefore also proposed the concept of "ad-hoc" protected operation, to complement the pre-determined protected operation mechanism.

Not all risks to the power system can be anticipated. It is therefore important for AEMO to have sufficient flexibility to take action to prevent cascading events arising from an emergent risk to the power system. The consequences of AEMO not taking these actions in such circumstances are likely severe, such as separation of regions, major supply disruptions and even a black system condition.

Ad-hoc protected operation could be utilised in circumstances when AEMO considers that abnormal conditions mean that it is more likely that an indistinct event could occur, but where this indistinct event had not been anticipated. Ad-hoc actions may also be used to augment those included in AEMO's pre-defined criteria when circumstances require. Ad-hoc protected operation will therefore provide AEMO with the level of operational flexibility necessary to depart from the actions defined in its pre-defined criteria under an emergency situation.

Box (2) in the figure represents AEMO's actions to enhance the resilience of the power system to indistinct risks which have not been pre-identified, or where additional actions to those specified in the pre-defined criteria are required. These indistinct risks may be unanticipated, or when AEMO has identified a new and severe indistinct risk to the power system but there has been insufficient time to complete the process for a conditional protected operation process as described in Box (1c).

Examples of such ad hoc indistinct events could potentially include:

- an entirely new set of abnormal conditions that had not previously been identified through a declared protected operation period
- abnormal conditions that are similar to those in an existing declared pre-defined protected operation, but were not envisaged at the time that the specific conditional protected operation period was proposed by AEMO
- the emergence of a cyber-security threat, where AEMO could apply ex-ante measures to improve the ability of the power system to survive, should it actually be attacked in an unpredictable way.

This ad-hoc power is proposed as an emergency mechanism to provide AEMO with clear authority to take action to prevent a cascading failure and potentially a major supply disruption. As this authority would not require any pre-identification or planning, a set of special governance arrangements are proposed. These arrangements are expanded on in detail in section 8.3.2 on governance arrangements.

Options for mitigating risks using protected operation

During a period of protected operation (either ad hoc or pre-defined), AEMO would be able to strengthen the power system by taking ex-ante measures to increase the ability of the power system to survive non-credible indistict events. Such measures may include:

- increasing the procurement of ancillary services (e.g. FCAS), including sourcing FCAS on a regional basis
- constraining interconnector flows to lower levels, to provide headroom, to managed more variable flows should the event occur, and
- dispatching or directing one or more synchronous generating units to provide additional fault level and inertia.

In addition, AEMO may increase the ability of the power system to ***avoid***, or at least reduce the impact of, a potential event by taking ex-ante actions that reduce the likelihood and severity of the event. Such actions could include pre-emptively constraining down specific wind or solar generating systems in a controlled manner.

How is protected operation different from reclassification?

Protected operation is intended to manage indistinct risks with a probability of occurrence, that is dependent on the occurrence of specific, abnormal conditions. The two arrows into a protected operation state, depicted as boxes (1c) and (1b), resemble the arrow under existing arrangements representing the re-classification of distinct non-credible contingencies when abnormal conditions apply. There are however, some important differences.

The existing framework, when applied to distinct contingency events, allows the reclassification of a non-credible contingency event that can be established as having become reasonably possible, and therefore credible given the presence of abnormal conditions. As the non-credible contingency event has become credible, AEMO is then able to adjust the technical envelope in accordance with criteria that it has established, consulted on, and published and take other actions such that the power system is secure (able to be returned to a secure state following a contingency within 30 minutes, with no load shed) to the occurrence of the re-classified event.

In contrast, the discussion paper proposed protected operation as considering the consequences of *non-credible* events which *cannot* be established as being reasonably possible and therefore credible given applicable conditions. Considering consequences in determining the actions taken to manage a non-credible indistinct event, on the basis of costs and benefits, is different to reclassification which only considers the probability of the contingency event.

The version of protected operation proposed in the discussion paper also did not mandate the power system be maintained in a secure state for these events, as is required for the management of *credible* events. Protected operation only mandated that actions be taken to prevent a cascading failure and major supply disruption. This is a "lower bar" requirement than that for credible contingencies, and is consistent with the rationale for the existing protected events framework in the NER.

The final version of protected operation recommended by the Commission in this final report, differs from this original design in a number of ways. These differences are explored in more detail later in this Chapter.

8.3.2 Governance Framework

Actions taken under the protected events/operations framework will influence not only system security outcomes but also market outcomes and the risks faced by market participants. A clear governance framework is therefore critical to delivering efficient outcomes for consumers.

The review's discussion paper, published on 15 August, proposed indistinct risks requiring management as a protected event or through pre-defined protected operation are to be identified through the GPSR process with measures pre-approved by the Panel as follows:

- In line with existing arrangements, standing protected events (distinct and indistinct) and pre-defined protected operation would be approved by the Reliability Panel following consideration of the economic costs and benefits of protecting against the identified risks. In applying to the Panel for approval, AEMO would propose a set of pre-defined actions to be taken to manage the identified risk. Following approval by the Reliability Panel, AEMO would incorporate the approved actions into its power system security guidelines, and other relevant operational procedures.
- The speed of Panel approval would be increased for applications which are non-controversial. Governance arrangements for protected events and pre-defined protected operation would provide for an expedited version of the current two stage Panel approved process. An expedited process would allow the Reliability Panel to declare a protected event or period of pre-defined protected operation following a single round of stakeholder consultation, provided the Reliability Panel considers that AEMO’s recommendation to be sound and stakeholders do not raise issues that require further analysis.
- Any application by AEMO for a protected event or period of protected operation would need to include details of the event being proposed as a protected event/for protected operation and the mechanism that could lead to a cascading outage. AEMO would specify the details of the actions proposed to manage this risk in addition of details of the costs and benefits taking into account uncertainty in the probability of the proposed risk arising.

Transparency and market information requirements involving the issuance of market notices were proposed to remain the same as under the existing protected event framework. For protected operation AEMO would be required to publish a notice to the market:

- when it is aware of an increased risk due to the abnormal conditions potentially being present
- when it considers that the conditions have been met and it is entering a period of protected operation, including what ex-ante measures it is undertaking during this period, and

- when the abnormal conditions cease and protected operation no longer applies.

Additional governance arrangements for ad-hoc protected operation

The discussion paper proposed an ad-hoc power as an emergency mechanism to provide AEMO with authority to take action to prevent a cascading failure and potentially a major supply disruption, where a risk has not been previously identified. This ad-hoc power provides AEMO with significant discretion. This discretion necessitates a set of strong accountability and transparency arrangements, to provide market participants with confidence in its application.

The following special governance arrangements were proposed in the discussion paper for ad-hoc protected operation:

- AEMO would develop criteria specifying how it would make any decision to enter a period of ad-hoc protected operation with the Panel having an option to make guidelines applying to AEMO's use of this ad-hoc protected operation power,
- additional reporting and review obligations to provide accountability and for learning purposes. Post incident reporting would be required on each occasion that AEMO uses its ad-hoc powers. Post event reporting would provide the Panel and stakeholders with an explanation of AEMO's decision-making and assist stakeholders to plan for similar events should that occur in the future, and
- Market notification and transparency arrangements would apply to inform market participants in line with the proposal for standing protected events and protected operation (as described above).

While the discussion paper provided for ad-hoc protected operation, provision was recommended for the Panel to issue guidelines regarding AEMO's use of its ad-hoc power. AEMO would also face a requirement to explicitly review the risks managed on each occasion it has used its ad-hoc power in the next GPSR. This would allow AEMO to incorporate experience from the use of its ad-hoc power.

As mentioned above, the final version of governance arrangements for protected events proposed by the Commission in this report, differs from that presented in the staff discussion paper. This is explored in more detail later in this Chapter.

8.4 Stakeholder views on proposed approach

A number of stakeholders commented on the proposed introduction of the protected operation framework, with governance being a key concern.

Stakeholders considered governance arrangements should provide AEMO with flexibility to manage a wider set of risks but in a transparent and accountable manner.[151] In particular the AEC considered that it was important for confidence that an appropriate balance is struck through the governance processes ultimately underpinned by rules obligations. The AEC considered such governance arrangements to be at times inconvenient and burdensome, but a necessity of operating a market.[152]

151 Submissions to the discussion paper: AEC, p. 2; Stanwell, p. 2; AER, p. 1.

A number of stakeholders supported a role for the Reliability Panel in approving protected events and pre-defined protected operation in a transparent manner following consideration of costs and benefits.[153] Meridian supported the suggestion that the Reliability Panel could have a key role to play in setting appropriate guidelines and reviewing developments in this area.[154]

Some stakeholders had concerns over the proposal to provide AEMO with an ad-hoc power to declare protected operation without pre-approval from the Panel. These stakeholders considered that while there are cases where the market operator could be granted the power of ad-hoc action to constrain the market, this should be done with caution. Some stakeholders were concerned that ad-hoc powers, due to their ease of operation, could quickly devolve into a first rather than last resort action and the incentive to develop predictable, methodical approaches ahead of time is lost.[155] The AEC as well as Ergon and Enegex further considered that ex-post reporting was required to assess whether appropriate actions were taken by AEMO in declaring a period of ad-hoc protected operation.[156]

While there was broad support for the proposed framework, some stakeholders also raised concerns about the level of apparent complexity. Stanwell considered the proposed framework to be complex and disjointed. Stanwell considered that resilience needs to be recognised as an operating characteristic of the power system and embedded more appropriately within existing frameworks. In this respect, Stanwell considered an outcomes-based approach to be preferable to event codification.[157]

AEMO strongly supported the general concept of protected operation but not the requirement for pre-approval from the Reliability Panel. AEMO considered protected operation should be developed as a framework that allows a response to increased threat levels due to abnormal conditions – what it viewed as credible threats to the power system that could result in indistinct events.[158] AEMO therefore proposed that protected operation be utilised as a mechanism for the power system to be maintained in a secure state, without load shedding, to indistinct events rather than as a mechanism to prevent a cascading failure.[159]

- AEMO considered protected operation should be a flexible, ongoing measure, and not only for as yet unidentified risks or as an interim measure pending declaration of protected events.
- AEMO considered it is neither practical nor desirable to prescribe a complete list of risk circumstances or response measures, or a maximum permitted level of response. AEMO stated that such limits, while an interesting economic exercise, are more likely to cause system failures by preventing it from applying professional judgement drawn from experience and observation of current conditions.

152 AEC, submission to the discussion paper, p. 2.
153 Submissions to the discussion paper: Meridian, p. 2; Stanwell, p. 3; TasNetworks, p. 4
154 Meridian, submission to the discussion paper, p. 2.
155 Submission to the discussion paper: AEC, p. 3; Stanwell, p. 2.
156 Ergon and Enegex, submission to the discussion paper, p. 8.
157 Stanwell, submission to the discussion paper, p. 2.
158 AEMO, submission to the discussion paper, p. 3.
159 AEMO, submission to the discussion paper, p. 18.

- AEMO considered that what they view as an inflexible set of parameters removes part of the essential role of the independent system operator. AEMO noted that power system controllers are then placed in the position of going against their professional judgement or disregarding the Rules.

8.5 Revised proposal

Following engagement with stakeholders and working closely with AEMO, the Commission has refined a number of the proposed policy positions that were outlined in the discussion paper. In particular, the Commission has revised its proposed approach to protected operation to provide additional flexibility for AEMO to efficiently manage indistinct risks through protected operation where those risks relate to abnormal conditions.

This section presents details of these changes in the context of the overall mechanism, and associated governance framework, introduced in section 8.3. The key areas of change (relative to the proposal put forward in the discussion paper) include:

- **AEMO would be responsible for the ex-ante determination of criteria and methods for managing risks under pre-defined protected operation, subject to guidance from principles set out in the NER and from the Panel (if required):** The Commission has made a number of changes to governance arrangements to provide an enhanced role for AEMO. These changes include:
  - AEMO will follow a general cost minimisation principle, which would require it to reasonably assess costs and benefits of the actions necessary to manage indistinct risks and to implement and publish pre-defined criteria applying to the actions it will take under protected operation.
  - The Commission considers AEMO would exercise its expert judgement in assessing whether the benefits of taking these actions are likely to outweigh relevant costs. This reflects the difficulty of assessing the costs and benefits of events that are inherently uncertain. We consider that when making its assessment, AEMO would acknowledge the uncertainty of these events, and exercise its expert judgement as system operator in determining what is a reasonable set of actions to take.
  - The Reliability Panel would have no direct role in approving the ex-ante criteria for, and methods of, managing indistinct risks under pre-defined protected operation. However, the Panel may develop additional guidelines applying to AEMO's application of protected operation if considered be required.
  - An enhancement of consultation requirements applying to AEMO's development of criteria applying to its management of indistinct event risks.
- **AEMO may maintain the system in a secure state for protected operations:** The Commission has proposed some changes to enhance flexibility, by enabling AEMO to utilise pre-defined protected operation to maintain the power system in a secure state, without load shedding to certain indistinct risks associated with abnormal conditions. This would be subject to AEMO following the general cost minimisation principle discussed above. Equally however, AEMO should not be prevented, or consider themselves to be prevented, from taking necessary action to maintain the security of the system. The

Commission has therefore also proposed a flexible "ad-hoc" protected operation mechanism, to complement the pre-determined protected operation mechanism.

8.5.1 Revised mechanism and extension of protected operation

The Commission recommends AEMO have the authority to use pre-defined protected operation to maintain the power system in a secure state to indistinct risks associated with abnormal conditions. We consider this is necessary given that in some regions of the NEM the functionality of emergency under frequency load shedding indicate that load shedding is inappropriate.

The proposal for pre-defined protected operation put forward in the discussion paper provided for AEMO to take actions to prevent a cascading failure arising from indistinct events. It did not provide for AEMO to take action to maintain the power system in a secure state (that is, to keep the system in a satisfactory state after an event, without load shedding).

The revised mechanism provides additional flexibility for AEMO to take management actions over and above those required to prevent a cascading failure where reasonable consideration of costs and benefits, including an assessment of the functionality of emergency under frequency load shedding, indicate that load shedding is inappropriate. These management actions may extend to maintaining the power system in a secure state, without the occurrence of any load shedding.

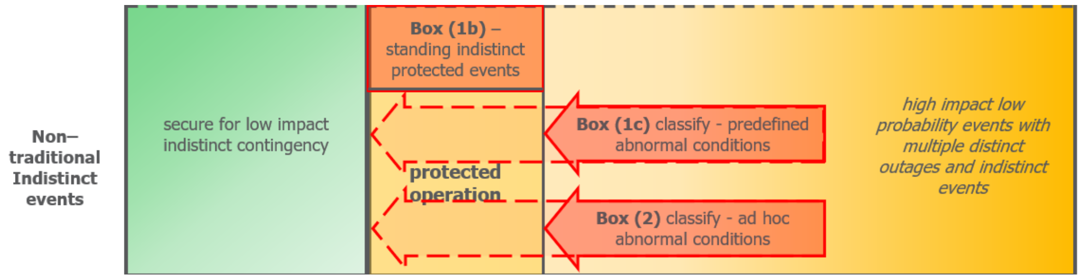
As discussed in more detail in section 8.5.2, this decision by AEMO to keep the system in a secure state would be implemented in accordance with a general cost minimisation principle.

As a specific example of where AEMO may maintain the power system in a secure state to indistinct risks under this revised approach, AEMO have advised that it is difficult to establish how much load shedding is possible, without ending up in a cascading failure.[160] The Commission appreciates that the system response to disturbance events has become more uncertain, and emergency under-frequency load shedding systems in parts of the NEM may no longer be effective at certain times. This uncertainty may justify AEMO taking additional actions to maintain the system in a secure state, where controlled load shedding may not be a feasible solution.

The Commission's amended proposal can be visualised as the dashed extension to the arrows in Figure 8.4 below. This dashed arrow indicates the extent of actions AMEO may take to manage risks associated with indistinct events. This approach involves AEMO, at a minimum, avoiding cascading failure, but also provides for AEMO to take further actions including to maintain the system in a secure state during protected operation, where the benefits of this action exceed the costs.

160 This advice was provided through workshops between AEMC and AEMO staff.

Figure 8.4: Amended protected event framework



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8.5.2 Revised governance framework for pre-defined protected operation

Aspects of the review's proposal, as put forward in the discussion paper, were refined in response to feedback from stakeholders and additional discussion with AEMO. In particular, the Commission has revised its proposed approach to protected operation to provide additional flexibility for AEMO to use protected operation to efficiently manage indistinct risks. Revisions to the proposed governance framework were necessary to provide this enhanced flexibility while maintaining efficiency, transparency, and accountability.

The revised governance framework includes changes from the proposal put forward in the discussion paper to:

- Alter roles and responsibilities to:
  - change the role of the Reliability Panel from approving AEMO's proposed actions and criteria, to one of monitoring and developing guidelines for AEMO to follow in assessing costs and benefits (if required), and
  - provide AEMO with the authority to define criteria, and the actions that will be taken to manage specific risks during a period of pre-defined protected operation.
- AEMO’s use of protected operation would be subject to a NER defined cost minimisation principle, which would require AEMO to consider and assess the potential costs and benefits of its proposed actions for managing risks from identified indistinct events.
- The Commission recognises the difficulty of undertaking these kinds of assessments for events that are inherently uncertain. We consider that in following a general cost minimisation principle, AEMO would acknowledge the uncertainty of these events, and exercise its expert judgement as system operator in determining what is a reasonable set of actions to take.
- Public consultation requirements would deliver transparency and provide for all parties to have input into AEMO's management of risks and reasonable consideration of costs and benefits.

Provide for AEMO to define criteria, and the actions that will be taken to manage specific risks during a period of pre-defined protected operation

The principles of effective allocation risks, roles and responsibilities require regulatory arrangements to:

- allocate risk and the accountability for decisions related to the management of risk to those parties best placed to manage them, and
- roles and responsibilities should be allocated on the basis of experience of organisations. Allocation of responsibilities should also reflect the primary function of the organisation.

Providing AEMO with the authority to pre-define criteria specifying the characteristics of the risks, and actions taken to manage those risks, is consistent with the principles specified above. AEMO is the party which is responsible for managing system security under the NER and is therefore the party which is best placed to specify the approach for managing power system risks arising from indistinct events. AEMO is also the party with the skills, information, and experience which makes it best placed to define approaches to managing identified indistinct risks.

The principles of efficient framework design, and effective governance however require AEMO to define and follow criteria setting out the actions it will take to manage identified indistinct risks where possible. Clear criteria are important to provide clarity and predictability for market participants on AEMO's likely actions, as well as to effectively manage their operations and make investment decisions.

However, while it is important for AEMO to follow clearly defined criteria, it is also important that AEMO's has operational flexibility to depart from pre-defined criteria under emergency circumstances. Excessively rigid requirements that do not provide such flexibility for AEMO - or, more specifically, are perceived by AEMO operators as not allowing them the ability to depart from procedures - are unlikely to be in the long term interests of consumers, given the high levels of uncertainty that apply to indistinct events.

Recognising this issue, the protected operation framework provides AEMO with the authority to take ad-hoc actions, subject to additional reporting and transparency requirements - this is described in the next section. Authority to take ad-hoc actions, combined with additional reporting and transparency obligations, balance AEMO's need for operational flexibility with transparency and confidence provided by AEMO following its pre-defined criteria.

The importance of AEMO defining and following published criteria is illustrated by experience from the 2007 Victorian bushfires. These circumstances gave rise to current NER arrangements that require AEMO to define criteria when making reclassification decisions. These events are relevant to, and have informed the Commission's consideration of the issues associated with AEMO's management of risks due to indistinct events in abnormal conditions.

BOX 1: DEFINED CRITERIA - EXPERIENCE FROM THE 2007 VICTORIAN BUSH FIRES

Current NER arrangements requiring AEMO to define, consult on, publish, and follow criteria when making re-classification decisions arose from a rule change made by the Commission in response to events during the 2007 Victorian bush fires. These events illustrate the importance of defined criteria for bringing consistency to decision-making around the actions taken by AEMO to manage heightened risks to system security in abnormal conditions.

Current NER arrangements arose from an investigation of the load shedding event in Victoria on 16 January 2007 when bush fires caused transmission lines in Victoria to fail resulting in the separation of the National Electricity Market (NEM) into three electrical islands, causing significant load shedding in Victoria.

In response to this event, the *Reclassification of contingency event* rule was made to improve the transparency, consistency and rigour of the process for managing risks to power system security during abnormal conditions. The Commission considered that a defined framework requiring AEMO (at the time NEMMCO) to develop, consult on, and publish criteria to guide its decisions on reclassification was required. Such a framework would:

- promote more robust and reliable reclassification decisions that better reflect the risk posed to the power system and the NEM
- improve the consistency of AEMO's reclassification decisions enabling Market Participants to more reliably predict and plan for when AEMO will reclassify a contingency event, and
- the requirement to consult on the development of the criteria would improve the transparency of AEMO's reclassification processes, and would help to create robust criteria.

AEMC, Reclassification of Contingency Events, Rule Determination, 2 October 2008,

Implementing a cost minimisation objective

The Commission's revised proposal would also allow AEMO to use pre-defined protected operation to maintain the system in a secure state, without load shedding.

In line with the principle of efficient framework design, these changes would require AEMO to consider the costs and benefits of taking action to manage the identified indistinct event.

The Commission acknowledges the difficulty of assessing costs and benefits from actions to manage indistinct event risk. Indistinct events are, by their nature, uncertain. This uncertainty means that it is not possible to accurately determine, ex-ante, the exact benefits of certain actions.

While it may not be possible to precisely determine a perfect cost benefit trade off, the Commission considers that approximations can be made to provide a general assessment of the efficiency of certain actions.

This is in line with our analysis in Chapter 5 on the economics of resilience, where the Commission acknowledged that a probabilistic type of cost benefit assessment type approach may not always be practicable when AEMO undertakes these kinds of assessments. For this reason, we are proposing that the NER remain non-specific as to how AEMO should meet the cost minimisation objective. Accordingly, AEMO would have scope to decide what assumptions and methodologies it uses when determining protected operation periods, subject to the objective of minimising costs.

The cost minimisation objective will also be clearly qualified regarding the accuracy required from any consideration of costs and benefits. This qualification will allow AEMO to make general assessment of possible ranges of costs and benefits sufficient to demonstrate the likelihood that their proposed actions will be consistent with the principle of efficient framework design. The requirement for AEMO to consult on its general assessment of costs and benefits (detailed in the next section) will also provide stakeholders with the opportunity to contribute to the accuracy of AEMO's assessment.

This cost minimisation objective will make AEMO's objectives clear in performing this role and provide confidence to market participants and consumers in the actions AEMO takes to manage risks from indistinct events.

The cost minimisation principle should not conflict or impeded AEMO's obligation to meet its power system security responsibilities. Any rule change request on this issue will make it clear that this is the case.

Enhanced consultation arrangements (for both re-classification and protected operation)

Enhanced consultation arrangements are proposed as a fundamental part of the amended framework to provide all stakeholders with confidence in AEMO's performance in its role and exercise of its powers. Enhanced consultation arrangements are particularly important given the additional flexibility provided to AEMO in this amended proposal.

These enhanced consultation arrangements are recommended as applying to both reclassification and protected operation. Actions taken under both the protected operations and reclassification frameworks will influence not only system security outcomes but also market outcomes and the risks faced by market participants.

The AER, in its compliance report, identified a need for broad consultation on the development of criteria for reclassification and the importance of the process via which this consultation occurs.[161] The Commission has considered the AER's views in this area and notes that existing requirements for consultation on AEMO's criteria for reclassification do not specify consultation with end users nor include details of the process via which consultation is to occur. As AEMO's decisions on reclassification and protected operation will influence market outcomes for all participants, including end users, the Commission considered any consultation should be public.[162]

Therefore, the Commission considers that enhanced consultation arrangements should apply to both reclassification and protected operation and:

161 AER, Black system event compliance report, p. 56.

162 Existing arrangements for consultation on the criteria applying to re-classification are specified in Clause 4.2.3B(d)(1), which requires that in establishing, reviewing or amending the criteria AEMO must first consult with Relevant stakeholders including Market Participants, Transmission Network Service Providers, Jurisdictional System Security Coordinators and relevant emergency services agencies.

- specify a process via which consultation should occur, and
- include a requirement for public consultation including with end users and consumer representatives.

The Commission therefore considers enhanced consultation arrangements should be conducted in accordance with the rules consultation procedures to maximise the rigour and robustness of the consultation process.[163] This is consistent with other consultation requirements for AEMO's development of guidelines impacting market operation, such as the Market Ancillary Service Specification.[164]

Enhanced consultation requirements applying to protected operation should also specify the matters AEMO is required to consult on. These include:

- the criteria it would use to determine the presence of abnormal conditions.
- how the presence of the abnormal conditions would increase the likelihood of the identified risk
- what additional ex-ante measures that AEMO would use when the power system enters a period of protected operation. These may be described as a range of potential actions
- the costs and benefits, to the extent reasonably possible, of AEMO's proposed actions including full details of AEMO's cost and benefit assessment, and
- how often these criteria likely to be met, and hence how often AEMO is likely to enter protected operation to mitigate the risk of the protected event occurring.

8.6 Recommendation benefits

The mechanisms for enhancing operational resilience recommended in this chapter will promote the long term interests of consumers as they should efficiently, transparently, and accountably enhance the safety and security of the national electricity system.

Given the changing power system risk profile and the increasing risks arising from indistinct events, existing frameworks which are solely built around managing distinct contingency events are no longer sufficient to efficiently manage all risks to the power system, particularly under abnormal conditions.

The recommended mechanisms will promote the long term interests of consumers because:

- market design and regulatory arrangements are flexible enough to respond and evolve as circumstances change. The proposed rule does not specify the particular actions AEMO is to take or limit the risks arising from indistinct events to be managed. The proposed rule sets out a framework within which AEMO can manage the risks that will change over time. This flexibility is important given the rate at which the power system risk and resilience profile is changing
- responsibility for determining and implementing actions to manage identified risks are allocated on the basis of organisational skill and experience. The proposed protected

163 The rules consultation procedures are defined in part F of NER Chapter 8.

164 Clause 3.11.2(d) of the NER.

operation framework places responsibility for assessing and implementing actions for the management of identified risks with AEMO as the party with the skills, experience, and information necessary to perform this role

- actions taken to manage risks associated with indistinct events are efficient. The recommended protected operation framework includes a cost minimisation objective that will require AEMO to consider, to the extent possible given the uncertainties involved, whether the costs of the actions to manage the identified risks are justified by the benefits from improved security
- the recommended protected operation framework is transparent, with appropriate levels of organisational accountability. Efficient investment and operational decisions are supported by market participant confidence in AEMO's actions. The recommended protected operation framework provides for transparency, and accountability through the requirements for AEMO to determine, consult on, and publish pre-defined criteria applying to its use of protected operation. Specifically, AEMO will be required to:
  - consult according to the rules consultation procedures. This will provide transparency supporting market confidence in the actions AEMO is taking to manage identified risks. Market participants will also be able to contribute to AEMO's development of criteria thereby resulting in a more informed and robust overall solution than would have been the case in the absence of effective consultation
  - publish protected operation criteria. This will provide reasonable levels of predictability on AEMO's actions to manage identified risks and will enhance the ability of market participants to make decisions to manage their own market and investment risk,
  - report each 6 months, and following each use of ad-hoc protected operation, which will provide accountability as to AEMO's actions. Additional accountability will be provided for through the Reliability Panel's making of guidelines (if required) applying to AEMO's use of protected operation.

In addition, it would promote the long term interests of consumers for AEMO to have operational flexibility to depart from its pre-defined criteria under emergency circumstances. Excessively rigid requirements that do not provide such flexibility for AEMO are unlikely to be in the long term interests of consumers given the high levels of uncertainty that apply to indistinct events. The protected operation framework provides AEMO with the authority to take ad-hoc actions subject to additional reporting and transparency requirements. Authority to take ad-hoc actions, combined with additional report and transparency obligations, balances AEMO's need for operational flexibility with transparency and confidence provided by AEMO following its pre-defined criteria.

8.7 Summary recommendations and suggested rule change request

The Commission has developed a suggested rule change request to implement the extended protected events/operation framework described in this chapter. This suggested rule change request is presented in Appendix B of this report.

Indicative rule drafting has not been included, as the Commission is aware of two options for implementing changes to the NER to action the recommended protected operations framework. These are described in section 8.6.1 below. As the Commission has not yet had time to understand the full implications associated with these two implementation options, and considers that further stakeholder engagement on the preferred approach to implementation is warranted, we have left the assessment of the preferable implementation method to the consideration of the rule change request itself. This will allow consideration of both implementation approaches to be considered comprehensively with stakeholders.

8.7.1 Summary of recommendations

This section summarises the key elements of the proposed protected events/operation framework to be included in any rule change, before setting out the two different approaches to implementing the framework in the rules. This summary is as follows:

Definition for indistinct event

The NER should be amended to include a definition of an indistinct event and/or condition. A definition for indistinct events may include the following:

- An indistinct event or condition may be defined as an event or condition affecting the power system that is likely to:
  - occur over a period of time, rather than being sudden or instantaneous
  - be widespread or otherwise affect more than one location, and
  - involve the non-credible failure or removal from operational service multiple generation units and/or transmission elements that are not reasonably identifiable,
- and has been declared as such by *AEMO:*
  - consistent with any guidelines by the Reliability Panel with respect to the declaration of indistinct events or conditions.

Protected Events

Existing NER arrangements for protected events should be clarified to specifically include indistinct events.

The Reliability Panel, on the advice of AEMO, would determine which non-credible contingency events and indistinct events/conditions are to be protected events. A request for declaration of a non-credible contingency event as a protected event or for the revocation of such a declaration may only be submitted by AEMO.

An expedited Reliability Panel process will be specified in the rules for AEMO applications that are not considered controversial. For such applications the Panel will issue a consultation paper and consult for a minimum of 10 days. The Panel will publish a single final report if no objections are raised.

Protected Operation

Pre-defined protected operation

The NER should be amended such that protected operation would be defined in being as respect of indistinct events/conditions that involve risks the probability of which increase under abnormal conditions. Protected operation would involve AEMO:

- pre-identifying the risk through the GPSR
- specifying and publishing:
  - criteria setting out the specific circumstances which would see it enter into a period of protected operation in response to these conditions
  - the actions it would take to prevent a cascading failure, or maintain the system in a secure state given the applicable conditions.

The NER would set out requirements for the criteria specified and published by AEMO.

The extent of the actions AEMO may take to manage certain risks under protected operation will be determined through an assessment of the costs and benefits. The NER will implement a cost minimisation principle to apply to AEMO's consideration of costs and benefits of actions to manage risks using protected operation. AEMO will have scope and flexibility to exercise its judgement in the identification of the costs and benefits of the actions taken to address indistinct risks.

AEMO may use protected operation to maintain the power system in a secure state without load shedding, or minimise load shedding, on the basis of its assessment of the costs and benefits of doing so. AEMO must assess, consult on, and publish details of the cost and benefit assessment. The NER would set out requirements for this assessment of costs and benefits.

Consultation and transparency measures

Enhanced consultation requirements are proposed for AEMO's use of protected operation. This consultation would be public and undertaken in accordance with the rules consultation procedures. The rules would specify minimum requirements for the matters AEMO is required to consult on including (but not limited to):

- the criteria AEMO would use to determine the presence of abnormal conditions such that a declaration of protected operation is justified
- what additional ex-ante measures that AEMO would use when the power system enters a period of protected operation
- the reasonably assessed cost and benefits of AEMO's proposed management actions
- the information AEMO would utilise in assessing the extent of the risks and management actions taken to be taken, and
- the details of any analytical methods and probabilistic assessment tools utilised to determine the type and extent of measures AEMO is to take under the applicable conditions.

These enhanced consultation arrangements would also apply to consultation on AEMO's development of criteria for reclassification.

Ad-hoc protected operation

The NER would provide for AEMO to declare a period of ad-hoc protected operation to avoid a cascading failure associated with an indistinct risk/condition which has not been pre-identified. Ad-hoc actions are to apply to indistinct risks that are un-anticipated, or when AEMO has identified a new and severe indistinct risk to the power system but there has been insufficient time to complete the process for a conditional protected operation.

On each occasion AEMO declares a period of ad-hoc operation AEMO would need to report publicly, and to the Panel, as soon as practicable following the occasion. The NER would specify minimum requirements for AEMO's report.

AEMO would also face a requirement to explicitly review the risks managed on each occasion it has used its ad-hoc power in the next GPSR. This would allow AEMO to incorporate experience from the use of its ad-hoc power.

General transparency measures

Transparency and market information requirements involving the issuance of market notices are proposed to remain the same as under the existing protected event framework. AEMO would be required to publish a notice to the market:

- when it is aware of an increased risk due to the abnormal conditions potentially being present
- when it considers that the conditions have been met and it is entering a period of protected operation, including what ex-ante measures it is undertaking during this period, and
- when the abnormal conditions cease and protected operation no longer applies.

AEMO would be required to issue a public report on its use of the protected operation framework each 6 months in line with current arrangements for reclassification.

Provision for Reliability Panel guidelines and oversight

If the Reliability Panel considers it necessary or desirable, it would determine guidelines for pre-defined and ad-hoc protected operation. The Reliability Panel may also act in a general oversight role by considering AEMO's performance as part of its Annual Market Performance Review (AMPR).

8.7.2 Implementation options - protected operation

The amended proposal provides for protected operation to be used as a mechanism for maintaining the power system in a secure state to condition dependent indistinct risks. Maintaining the power system in a secure state without load shedding may involve adjusting the technical envelope with the associated market impacts.[165] If AEMO is to maintain the system in a secure state for indistinct events where justified, then there are two broad options for implementation:

- Option A - to implement arrangements parallel to the existing contingency classification system in line with the existing implementation of protected events, or

165 Clause 4.2.4(b)(2) of the NER.

- Option B - to implement as a part of an extended contingency classification system.

The Commission notes that pros and cons are associated with either approach to implementation. This review therefore does not recommend an approach to implementing protected operation in the NER, but instead sets out both approaches such that they can be explored in detail with stakeholders through the rule change process. This review sets out the two options at a conceptual level for stakeholders to consider.

In addition, the Commission intends to hold a workshop on the proposed changes, and potential implementation paths early 2020, in order to assist in the consideration of implementation ahead of the rule change request being submitted.

Option A - Implement via a parallel framework

The proposed protected operation process may be implemented through a framework that sits parallel to the existing contingency classification framework. This is equivalent to the existing implementation of protected events, and is broadly consistent with international practice.

BOX 2: INTERNATIONAL PRACTICE

The Commission considered international practice surveying practices in Texas ERCOT, US South West Power Pool, and Scotland in this area. All of these jurisdictions have high penetrations of intermittent renewable generation and face risks of an indistinct nature.

None of these jurisdictions define a sudden change in the output of wind or solar generation due to changes in the weather as a type of contingency. They all consider a contingency to requires some kind of equipment failure. These include some form of 'risk loading' which is applied in conjunction with the traditional contingency approach to adjust the operating envelope. These jurisdictions (and informal comments from several others), therefore, agree that such changes in wind and solar generation due to weather effects should be treated in the same way as a contingency for planning and operating purposes. However, as discussed further below, this is typically done through a parallel mechanism. All three sample systems include system load, conventional generation availability, weather, and, now, wind and solar generation as part of their approach to addressing uncertainty in parallel to existing arrangements for managing system security due to contingency events:

- The Electric Reliability Council of Texas (ERCOT) uses a probabilistic method to select the wind generation forecast. The fundamental elements in dealing with generation uncertainty are incorporated into three types of generation-reserve ancillary services. As system operation constantly moves from day-ahead to real-time the amount of reserves required is adjusted to reflect the updated uncertainties, especially those related to weather.
- The Southwest Power Pool treats the uncertainty related to wind is one of three components (load error, resource error, and wind/solar generation error) that determine required operating reserves in the SPP. Since its launch the Uncertainty Response team

has established an automatic process to estimate the three error components that determine the required reserves.

Protected events are currently implemented in relevant rule clauses on a case by case basis. In a similar manner, implementing protected operation via a parallel framework may include the following key elements:

- defining indistinct events separately from the existing definition of contingency event, and
- adding references to indistinct events into relevant rule clauses on a case by case basis, including clause 4.2.4(a), which describes the secure operating state

Implementing protected operation via a parallel framework requires 'indistinct events' to be defined separately to contingency event. This approach retains contingency event in its traditional meaning as applying to failure and removal from operational service of one or more generating units or transmission elements.

Option B - Implement via a change to the definition of contingency event

Indistinct events could also be integrated into rules arrangements through changing the definition of contingency event. This may be achieved by redefining and expanding the existing concept of a contingency event beyond the failure or removal from service of generation or transmission equipment, to cover any unplanned event that causes a sudden change in the balance of available supply and demand. Most importantly, it must be clear that contingency events can impact identified assets or be distributed across multiple assets, including load.

This approach would provide for indistinct (dispersed and non-quantifiable) events, by taking steps within AEMO's control to increase the resilience of the power system to those events, such that the power system is expected to remain in a satisfactory operating state should those events occur.

- A contingency event would no longer be limited to something that causes the failure or removal from service of a generating unit or major transmission element. It may be redefined as an event that would be expected to result in a sudden and unplanned change in the availability or operability of generation, networks or scheduled load. This allows the contingency framework to account for sudden reductions in operation, as might occur on the triggering of run back schemes or known control scheme actions.
- A credible contingency may still be defined as a contingency that is considered reasonably possible in the surrounding power system circumstances. The management of credible contingency events can take one of two forms depending on whether the plant at risk from the contingency can be specifically identified (i.e. distinct) or not (i.e. indistinct). Indistinct events would only be credible in abnormal conditions.

This approach would automatically incorporate indistinct credible contingency events in arrangements for the secure operation of the power system and technical envelope, during periods AEMO consider involving abnormal conditions. This approach allows AEMO to maintain the system in a secure state to what it considers to be indistinct events during abnormal conditions.

Changing the definition of contingency event to include indistinct events is in some ways simpler than the parallel framework approach. It allows AEMO to maintain the system in a secure state to what is considers to be indistinct events during abnormal conditions.

However, further thought would need to be given to::

- Differences in transparency and governance arrangements for the management of indistinct risks, which may have different characteristics to distinct contingency events (i.e. probabilistic assessment of the degree of risk rather than deterministic treatment of distinct events)
- The need to think through flow on impacts of amending the definition, given that it the definition of contingency event is a fundamental concept in the NER. This would also require thinking through any unintended consequences.

The issues in considering both of the implementation approaches:

- a) adapting the current contingency framework; and
- b) a parallel framework,

will be explored in detail through the rule change process next year.

9 MANAGING INDISTINCT RISKS IN NORMAL OPERATING CONDITIONS

RECOMMENDATION 3: RECOMMENDATION SUMMARY

The Commission recommends that AEMO and the AEMC continue to conduct additional investigations into the management of indistinct risks to power system security which may apply under normal operating conditions. The Commission recommends AEMO:

- consider the extent of sources of indistinct event risk under normal conditions in the first GPSR
- specifically consider DER related sympathetic tripping risk in this assessment
- assess the probabilistic combination of distinct contingency events and sources of uncertainty under normal operating conditions identified in table 2 of AEMO's submission to the review's discussion paper, and
- monitor interconnector flows to characterise the extent to which additional mechanisms for maintaining interconnector flows against their secure limits are required.

The Commission intends to continue discussions with AEMO on the probabilistic assessment of indistinct risks and their management under normal operating conditions, and other interested stakeholders, on these issues in early 2020.

This will proceed in parallel with AEMO conducting assessments as part of its first GPSR so that detailed rule frameworks are both developed as quickly as possible but informed by detailed assessment by AEMO and involve extensive consultation with stakeholders.

This chapter considers arrangements for managing risks to power system security associated with "indistinct events" which are reasonably possible and therefore may be considered credible under normal operating conditions.[166]

The chapter is structured as follows:

- background is provided on issue identified by the AER during the pre-black system event period that motivated the proposal put forward in the review's discussion paper
- existing arrangements are then described with issues identified
- a description of the proposal put to stakeholders in the review's discussion paper
- stakeholder feedback on the discussion paper's proposal
- AEMO's proposal and the amended approach to protected operation, and
- a program for future work and investigation.

166 Indistinct events are introduced in Chapter 3 as being associated with distributed events, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. There is substantial uncertainty as to the aggregate size of these events, which are not discrete but may still involve rapid changes in aggregate generation or damage to power system assets. These kinds of indistinct risks can have similar impacts to those associated with the discrete events.

9.1 Background

In its compliance report on the South Australian black system event, the AER identified a number of issues related to the operational management of risks to power system security due to high wind speeds in South Australia during the pre-event period on 28 September 2016. These issues included the extent to which the current contingency classification framework, as set out in the NER, (which was explained in Chapter 3) could be applied to manage the system security risks that arose arising during the pre black system event period.

During the pre-event period, given forecast wind speeds, AEMO identified the risk of rapid reduction in wind farm output, causing risks to interconnector flows. To manage this risk, AEMO took a number of actions including arranging for several network assets that were on outages to be bought back into service.[167]

However, AEMO did not adjust the technical envelope to manage the risk of separation between South Australia and Victoria. More specifically, it did not constrain the Heywood interconnector and bring on additional generation in the South Australian region. AEMO did not take this operational action since it did not consider reductions in wind generation associated with high wind speeds to represent a contingency event, as defined in the rules.[168]

In its compliance report, the AER considered that this situation represented a risk to power system security. This was because the actual metered flows on the Heywood interconnector were sufficiently high to raise the possibility of separation between South Australia and Victoria, had the 260 MW largest credible contingency occurred at the same time. That is, the unplanned reduction in wind farm output from multiple wind farms in the South Australia mid north pushed Heywood flows to a point where, had the identified credible contingency (loss of Lake Bonney wind farm) occurred; there would have been a real risk of excessive flows tripping the Heywood interconnector.[169]

The concept and definition of a contingency event is directly relevant to the structural issues identified through the AER’s assessment of the events of 28 September 2016. This is because the AER found that AEMO did not identify forecast wind feathering events as a contingency event. This meant that AEMO did not then reclassify the loss of generation (due to feathering across multiple affected wind farms) from non-credible to credible contingency status, which in turn meant it did not take ex-ante action to manage the potential consequences of this event.

In response to the AER's compliance findings, the Commission's issues and approach paper identified the management of credible indistinct risks as a systemic issue for consideration in this review.[170]

167 AER, Black system event compliance report, p. 30.
168 AER, Black system event compliance report, p. 52.
169 Ibid.
170 AEMC, Issues and approach paper, p. 25.

9.2 Existing arrangements

Under existing frameworks for power system security, as introduced in Chapter 3, identification of an event as a contingency event is a crucial first step, before AEMO can take actions to address the risks due to the event.

Through its engagement with the AER's compliance investigation, AEMO set out that it considered that the NER contingency identification, classification and reclassification framework in its current form caters only for the loss of large generating units or transmission elements, which are sudden and unpredictable events. AEMO argued that dispersed and non-instantaneous variations in supply or demand, such as caused by unexpected reductions in wind generation such as was experienced during the pre South Australian black system period, are instead addressed through the dispatch process and are not considered a security issue.[171]

As noted in Chapter 3, Clauses 4.2.4 and 4.2.5 of the NER governing the secure operating state and power system security specify that the technical envelope is set to maintain the system in a secure state to the set of credible contingency events. The current criteria for maintaining the power system in a secure state can be described as an N - 1 requirement. This requirement obliges AEMO to maintain the system in a satisfactory state, and avoid load shedding, in response to the loss of any single network element or generating system.

As noted in Chapter 3, the power system's risk profile is changing to include risks of a more indistinct nature. For example, the unexpected reductions in wind farm generation due to high wind speeds during the pre-black system event period on 28 September 2016 can be considered to be an indistinct event where system security risks arose in respect of the aggregate change in generation across a number of generating units, rather than a specific failure or removal from operational service of a specific generating unit.

As AEMO did not consider the sudden, unplanned reduction in wind farm generation to be a contingency event in the South Australian system black event,[172] the risks were not effectively managed through existing system security frameworks. This situation illustrates the need to clarify and extend NER arrangements, to clearly provide for system security risks arising from indistinct events.

9.3 Proposal for the management of credible indistinct event

On the basis of the issues identified above, the discussion paper published on 15 August 2019 included a proposed solution to manage these kinds of credible, indistinct risks. The "N - 1 (plus)" model described in that paper is summarised in this section.

Fit for purpose system security arrangements should account for the range of risks to power system security. As the risk profile of the power system changes, there is a need to introduce flexibility into how AEMO manages the technical envelope to account for risks, including those from indistinct events. The proposal put forward in the discussion paper was a

171 AER, Black system event compliance report, p. 52.

172 Ibid

conceptual idea, to amend the criteria for a secure state to move beyond an N - 1 approach, to an "N - 1 (plus)" model, where the (plus) accounted for the additional actions taken to manage indistinct risks, as a function of forecast conditions.

9.3.1 Proposal for an N - 1 (plus) arrangement

The N – 1 (plus) approach would allow the technical envelope to be dynamically adjusted to account for indistinct risks that are probabilistically assessed as being reasonably possible, and therefore credible, given a set of forecast conditions. This would allow for considering risk from indistinct events alongside distinct contingency events such that additional headroom on power system elements such as interconnectors may be provided where, and when necessary.

The proposed N - 1 (plus) approach was put forward in response to the system security risks identified from the Heywood interconnector flows arising due to unexpected variability in South Australia wind generation during the pre-event period. However, it was noted that it could potentially be an approach applicable to all types of indistint events that could be shown to be reasonably possible and not solely limited to managing risks arising from wind.[173]

The N - 1(plus) framework modified the existing framework for maintaining a secure state such that there was a "plus" representing indistinct event risk that is factored into the operation of the system.[174] The plus can be considered to be probabilistically assessed 'MW at risk' given forecast conditions.

The discussion paper considered value of the (plus) may be considered could be broken into two categories:

- MW at risk considered reasonably possible at the same time as a credible contingency event (i.e. the risk that the indistinct event and credible contingency event would occur in combination), and
- MW at risk considered reasonably possible, and therefore credible on a stand-alone basis, but which are not reasonably possible to occur in combination with a distinct credible contingency.

The first of these two categories identifies a certain amount of risk which must be guarded against occurring at the same time as the largest credible contingency. This case would see 100 per cent of the additional risk (probabilistically assessed as being reasonably possible) included in the (plus) and added on top of the arrangements for managing the set of distinct credible contingency events.

As an example, a possible N – 1 (plus) criteria could require AEMO to operate the power system by setting the technical envelope to account for the largest distinct credible contingency, plus the amount of risk that is considered reasonably possible in the area being

173 The discussion paper focused mainly on uncertainty associated with variable renewable generation, on the basis that this was the main issue identified by the AER in its compliance assessment. However, the main issue is uncertainty generally, which may result from sources other than variable renewable generation. For example, uncertainty around the response of DER may have significant impacts on the power system and would be captured by the N-1 plus mechanism.

174 References to 'risk' in this chapter incorporate quantifiable risks and un-quantifiable uncertainties.

considered given forecast conditions up to 24 hours ahead of real time. In effect, this N - 1 (plus) approach builds in an amount of "headroom" above the largest distinct credible contingency, to account for the risk from indistinct events (such as but not limited to forecast levels of stochastic renewable generation variability).[175]

The second category represents MW at from indistinct events considered reasonably possible, and therefore credible on a stand-alone basis. These are considered not to be reasonably possible to occur in combination with a distinct credible contingency. The probability of the two conditions occurring together would be too low to be considered reasonably possible by the system operator. However, it is still worth considering this category as this largest amount of risk that could be considered reasonably possible on a stand-alone basis during a given forecast period.[176]

The decision as to what is reasonably possible, and therefore which of the two categories would be used, would obviously change over time. As more information becomes available closer to real time, AEMO will be better positioned to decide what events have become reasonably possible. The discussion paper proposed a way that AEMO might do so, through applying a probabilistic approach for this purpose.

9.3.2 Utilising a probabilistic measure for characterising risk arising from indistinct events

A probabilistic approach could be used to characterise the risk associated with generation and load from indistinct events. A probabilistic approach would allow this risk to be directly characterised in terms of its probability distribution. A confidence level could then be applied to assess the MWs at risk, given a set of forecast conditions. The outcome of this process would allow the additional headroom considered under the N – 1 (plus) approach (i.e. the quantity of the "plus") to be determined on an ongoing basis as forecasts evolve.

A probabilistic approach is already utilised in forecasting reserve levels in the NEM, as part of the reliability framework. The declaration of lack of reserve conditions (LOR) rule change changed the process of declaring low reserve levels in the NEM from being a deterministic process, based on the largest contingency, to utilising a probabilistic approach. This change was made to allow AEMO to account for factors not currently considered when assessing reserve conditions such as forecast error in load and generation.[177]

As a result of this rule change, AEMO implemented the forecasting uncertainty measure (FUM) as a probabilistic approach that is incorporated into the forecasting of reserves that will be in the market.[178] This approach is implemented through use of a Baysian belief network and involves characterising the magnitude of forecast error according to forecast lead time, temperature, wind, solar, and other forecast weather conditions. The Baysian

175 As above, the risk associated with variable generation is provided here as an explanatory example. It is not the only source of uncertainty that can be managed by the N-1 plus mechanism.

176 We note that the potential combination of risks arising from contingency events and indistinct events may be complex and not solely additive, or exclusive in nature.

177 AEMC, Declaration of lack of reserve conditions – final determination, p. ii

178 AEMO's initial submission to the review's issues and approach paper proposed using a FUM type approach for the purpose of probabilistically assessing risk arising from renewable generation variability. AEMO, Submission to the issues and approach paper, p. 4

belief network produces a distribution of possible forecast errors that may arise from applicable conditions. LOR levels are then triggered on the basis of the largest of the distinct contingency based approach and forecast uncertainty.[179]

While the current application of the FUM is for reliability, a similar approach could also be applied to characterising risk to system security from credible indistinct events. For example, considering variability driven by variable generation as a function of a wider set of risk factors than simply the set of distinct credible contingencies.

9.3.3 Thresholds applying to system security risks from credible indistinct events

In contrast to the discrete change in generation associated with a distinct contingency, risk arising from indistinct events exists on a spectrum of speed and significance.

Under certain circumstances risks from unexpected wind or solar generation variation may be sufficiently rapid and large to impact system security. At other times, the risk may be small enough to be considered immaterial from a system security perspective. To incorporate these events in system security frameworks, a view would need to be taken on the speed and size of the unexpected generation variability that qualifies as a risk to system security.

The Reliability Panel considered this matter when it amended the definition of generation event in the Frequency Operating Standard to include rapid ramping. The Panel specified sub 30 second variability and a magnitude of at least 50 MW as the speed and significance thresholds to qualify as a generation event for frequency management purposes. The 30 second threshold was selected to reflect limitations in the response speed of the regulation FCAS system.[180]

The other relevant threshold involves risk from the unexpected generation variability that would be required to pose a system security risk.

For example, one of the defining characteristics of the kind of indistinct events that give rise to such risks, such as a storm front, is their distributed nature given that it will impact wide areas of the network as the storm front moves across. The areas considered when setting specific variability size thresholds may be informed by the particular system risks being considered. Thresholds relating to frequency or transient stability may be defined at a regional level considering all variable generation within that region. In contrast, thresholds relating to voltage or system strength may be best defined at a sub-regional, or even generating system level, given their more localised nature.

9.4 Stakeholder feedback on proposal

A number of stakeholders provided substantive commentary on the N - 1 (plus) proposal that was described in the discussion paper. Ergon, AER, ENA, Stanwell, PIAC, TasNetworks, SAPN & the AEC, supported amending arrangements to incorporate indistinct events that are reasonably possible and therefore credible.[181] Supportive stakeholder views included:

179 AEMO, Reserve level declaration guidelines, p. 6.

180 Reliability Panel, *Review of the frequency operating standard - stage one final determination,* p. 23.

181 Submission to the discussion paper: Ergon and Energex, p. 7; AER, p. 1; ENA, p. 4; Stanwell, p. 1; AEC, p. 3; TasNetworks, p. 4.

- TasNetworks considered that there is merit in reviewing the criterion used to define a secure operating state noting that there are a number of Renewable Energy Zones (REZs) likely to be developed with the potential for highly correlated responses to prevailing weather conditions. TasNetworks suggested the use of dynamic operating margins to implement the (plus) for this purpose.[182]
- ENA supported changing the criteria for a secure state to manage the consequences of any short-term supply-side variability including, but not limited to increased generation variability due to distributed weather conditions.[183]
- AEC considered network constraints that vary with conditions to be a necessity. However, they considered it crucial that processes are as mechanised, predictable and transparent as possible.[184]
- Ergon Energy and Energex agreed that the criterion for a secure state should be holistic and consider all potential risks to the secure system.[185]

The AEC considered that for widespread rapid changes in renewable output, it should be readily possible to calculate this probability and impact through analysis of historical renewable output in different weather conditions and then to publish a formulaic calculation of how real-time weather will be taken into account.[186]

AEMO's initial submission to the discussion paper supported mechanisms which assist in the management of risks during normal operation, including, but not limited to, weather contingencies. AEMO however did not support the detailed proposal put forward in the review's discussion paper for the following reasons:

- AEMO considered that the N - 1 (plus) proposal canvassed in the discussion paper to be narrowly defined (limited to renewable generation variability); that it assumed an ability to forecast and quantify the consequences of indistinct risks on power system assets; and ultimately did not adequately address the most pressing threats to the system during normal operations.[187]
- AEMO considered that interconnector flow management, such as observed during the pre-event period of 28 September 2016, no longer remains an issue in the NEM. AEMO considered it normal for interconnectors to often exceed their constraint levels at times during a dispatch interval, sometimes materially, because they absorb changes in generation and demand within the two interconnected regions. AEMO considered this to be normal and that it does not indicate the power system is not secure.[188]

182 TasNetworks, submission to the discussion paper, p. 4.
183 ENA, submission to the discussion paper, p. 4.
184 AEC, submission to the discussion paper, p. 3.
185 Ergon and Energex, submission to the discussion paper, p. 7.
186 AEC, submission to the discussion paper, p. 3.
187 AEMO, submission to the discussion paper, p. 2.
188 AEMO, submission to the discussion paper, p. 6.

- AEMO did not consider that the combinations of conditions that produce variability are readily predictable, therefore it considered it is impossible to specify parameters that would enable AEMO to determine an appropriate 'plus'.[189]
- AEMO considered more pressing risks to require management including less predictable variability that occurs more frequently and on a much larger scale from all sorts of weather conditions (both common and extreme), price-related or technical output changes, demand variation, unexpected behaviour of non-scheduled generation, and dispatch nonconformance.[190]

AEMO proposed an enhanced version of protected operation be adopted for keeping the power system secure to indistinct risks during abnormal conditions, such as during damaging wind conditions. AEMO considered protected operation to be a more desirable approach to managing risks under abnormal conditions than the N - 1 (plus) proposal put forward in the discussion paper.[191]

On 23 October 2019, AEMO submitted an additional, supplementary submission to the review which acknowledged that in expected 'normal' conditions there is always a possibility, perhaps even a reasonable possibility, of significant very fast ramping or multiple disconnection events from related causes at any time. AEMO suggested that further time and resources be dedicated to undertake detailed technical and economic analysis and stakeholder engagement. This could then support the development, testing and automation of suitable criteria and processes.[192]

9.5 Amended proposal and recommendation

The N - 1 (plus) approach developed in the discussion paper was intended to provide AEMO with a mechanism to maintain the system in a secure state to risks from indistinct events, which were normally non-credible but became credible given forecast conditions. The N - 1 (plus) approach was intended to include credible indistinct events arising from all forecast conditions, both normal and abnormal.

The recommended approach to pre-defined protected operation (allowing AEMO to maintain the system in a secure state for risks from indistinct events where efficient to do so), discussed in Chapter 8, would provide AEMO with a mechanism to keep the system secure to indistinct conditions that are credible, given the presence of abnormal conditions. The protected operation framework therefore addresses a key aspect of the N - 1 (plus) approach. Therefore, the Commission considers that this removes the need for N – 1 (plus) for the management of indistinct risks associated with abnormal conditions.

As a result of this change to protected operation, the N – 1 (plus) framework that was developed in the discussion paper would now be used to manage indistinct risks that are *not* associated with abnormal conditions. It should be noted that there are some significant indistinct risks which are present during normal operating conditions. For example, the

189 AEMO, submission to the discussion paper, p. 13.

190 AEMO, submission to the discussion paper, p. 5.

191 AEMO, submission to the discussion paper, p. 3.

192 AEMO, supplementary submission to the discussion paper, p. 2.

sympathetic tripping of DER in response to a credible or non credible contingency event represents an indistinct risk which falls into this category.

AEMO acknowledge that there is a need to manage risks from indistinct events that can arise during normal operation.[193] AEMO however suggested that further time and resources be dedicated to undertake detailed technical and economic analysis, as well as stakeholder engagement, around the nature of such risks and how they are best managed. AEMO considered this additional investigation would support the development, testing and automation of suitable criteria and processes.[194]

The Commission agrees with AEMO that further time and resources should be dedicated to undertaking detailed technical and economic analysis and stakeholder engagement, prior to implementing a framework in the rules for managing risks from indistinct events arising during normal operation. For these reasons the Commission is not recommending a specific set of arrangements be implemented for management of credible risks from indistinct events outside of abnormal conditions, as part of this review of the South Australian black system event. The first GPSR is an occasion on which AEMO may give detailed consideration to these issues. The Commission also proposes ongoing engagement with AEMO on these matters. Further discussion is provided in section 9.6 on this point.

9.5.1 Specific issues in the management of credible levels of sympathetic DER tripping

AEMO acknowledged that there is a need to manage indistinct risks that can arise during normal operation.[195] AEMO's submission to the review's discussion paper put forward the following set of common sources of variability or uncertainty on operational time frames requiring management.[196]

193 AEMO, supplementary submission to the discussion paper, p. 1.

194 AEMO, supplementary submission to the discussion paper, p. 2.

195 AEMO, supplementary submission to the discussion paper, p. 1.

196 AEMO, submission to the discussion paper, p. 12.

Figure 9.1: AEMO list of common sources of variability or uncertainty in operational time-frames

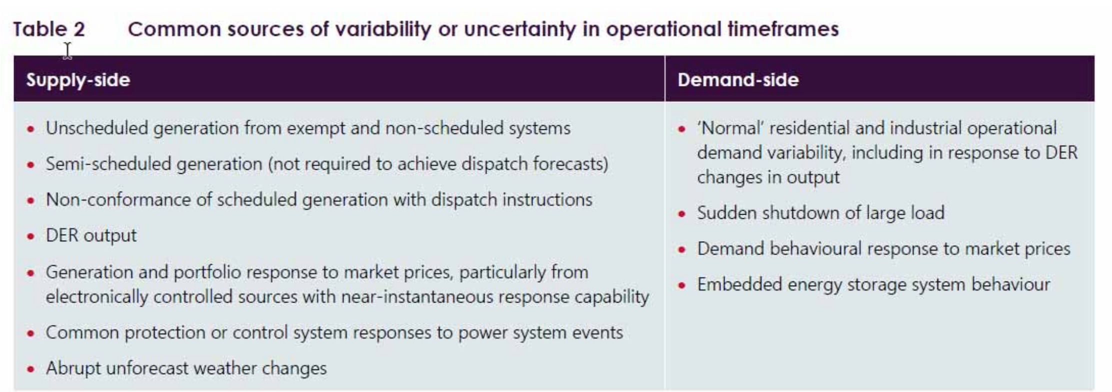

Table 2 Common sources of variability or uncertainty in operational timeframes

Supply-side	Demand-side
• Unscheduled generation from exempt and non-scheduled systems • Semi-scheduled generation (not required to achieve dispatch forecasts) • Non-conformance of scheduled generation with dispatch instructions • DER output • Generation and portfolio response to market prices, particularly from electronically controlled sources with near-instantaneous response capability • Common protection or control system responses to power system events • Abrupt unforecast weather changes	• 'Normal' residential and industrial operational demand variability, including in response to DER changes in output • Sudden shutdown of large load • Demand behavioural response to market prices • Embedded energy storage system behaviour

AEMO, submission to the discussion paper page 12

Based on the sources of risk identified by AEMO and set out in Figure 9.2 (AEMO Table 2), there are a large range of sources of such indistinct risk that may not be associated with abnormal conditions, including:

- Unscheduled generation from exempt and non-scheduled systems
- Non conformance of non and semi-scheduled generation including generation and portfolio response to market prices, particularly from electronically controlled sources with near-instantaneous response capability
- Common protection or control system responses to power system events
- DER output including sympathetic distributed energy resource tripping to credible contingency events not associated with abnormal conditions
- Demand behavioural response to market prices.

Of these sources, the Commission considers sympathetic tripping of DER in response to a credible contingency event to be a particularly important source of risk during normal operating conditions. The amount of MW at risk from such sympathetic tripping is a function of forecast conditions, time of day, and season. It represents a risk that is present every day, particularly given the significant uptake of DER in the NEM.

The Commission further notes that of the three specific power system events introduced in Chapter 3 (and Appendix D), sympathetic DER tripping during the 9 August 2019 UK load shedding event, occurred in response to a credible contingency event in conditions that were not considered to be abnormal. The Commission therefore considers that sympathetic DER tripping represents a key uncertainty that could be incorporated into a “plus”, for management alongside credible distinct events.

In addition to sympathetic DER tripping, the other sources of risk listed above could also be assessed as part of a "plus". The extent to which the "plus" is in addition to the N - 1 will depend on the characteristics of the specific risks themselves and the extent to which they can be considered consequential to a contingency event.

The Commission understands that there are complex factors that need to be considered in determining the treatment of these risks in combination with discrete contingency events. AEMO is best placed to give detailed consideration to this issue as part of its proposed detailed investigations. As noted above, the first GPSR may be a suitable process through which AEMO gives further consideration to these issues. The Commission also intends to work further with AEMO and stakeholders to explore ways in which these risks can be effectively and transparently accounted for in operation of the power system.

9.6 Summary of recommendations and future work

Given that the recommendations for protected operations address the majority of the concerns discussed in this chapter, the Commission has not proposed specific arrangements to manage credible indistinct events in this review of the South Australian black system event.

Instead, the Commission recommends that AEMO conduct additional investigations into the management of risks from indistinct events to power system security which may apply under normal operating conditions. The Commission understands that AEMO intend to conduct these investigations shortly, following its consideration of the first GPSR. The Commission will work closely with AEMO on these investigations in order to consider future enhancements to the regulatory framework that would be made.

In particular the Commission recommends AEMO:

- consider the extent of sources of indistinct event risk under normal conditions in the first GPSR
- specifically consider DER related sympathetic tripping risk in this assessment
- assess the probabilistic combination of distinct contingency events and sources of uncertainty under normal operating conditions identified in table 2 of AEMO's submission to the review's discussion paper
- monitor interconnector flows to characterise the extent to which additional mechanisms for maintaining interconnector flows against their secure limits is required.

The Commission intends to continue discussions with AEMO on the probabilistic assessment of indistinct risks and their management under normal operating conditions, and other interested stakeholders, on these issues in early 2020.

This will proceed in parallel with AEMO conducting assessments as part of its first GPSR so that detailed rule frameworks are both developed as quickly as possible but informed by detailed assessment by AEMO and involve extensive consultation with stakeholders.

10 MARKET SUSPENSION

RECOMMENDATION 4: RECOMMENDATION SUMMARY

The Commission recommends clarifying the applicability of existing market rules and to provide AEMO with appropriate flexibility to prioritise arrangements for system security during a period of market suspension.

The Commission recommends that AEMO continues to comply with existing provisions of the NER that explicitly relate to periods of market suspension (such as pricing arrangements under clause 3.14.5); and NER requirements be clarified on:

- the applicability of market rules during market suspension, and
- flexibility for AEMO's to prioritise core system security requirements during a period of market suspension.
- for remaining provisions of the NER, AEMO has some flexibility where compliance with a particular rule would impose a material risk on its ability to maintain power system security during the market suspension.

It is also proposed that AEMO be required to inform the market of its decision to prioritise certain obligations during periods of market suspension. In doing so, it is proposed that AEMO report, as soon as practicable, on those provisions of the rules with which compliance would impose a material risk on its ability to maintain power system security, the reasons why it considers that compliance would pose such a risk, and whether it proposes any alternative arrangements to apply.

10.1 Background

The NER allows for the spot market in a region to be suspended due to abnormal circumstances which make the normal operation of the market impossible. One of these circumstances was the South Australian black system event. On 28 September 2016, following the black system in South Australia, AEMO declared the spot market in the South Australian region suspended in accordance with its powers in the NER.[197]

During the period of market suspension which followed the South Australian black system event, AEMO and market participants restored the power system, established the causes of the black system, and implemented new arrangements to maintain system security. During this time, AEMO and market participants had to navigate power system complexities under unprecedented circumstances, as well as achieving the safe restoration of the power system.[198]

197 AEMO, Black system event incident investigation, p. 82.

198 AER, Black system event compliance report, p.157.

The length of the market suspension period following the South Australian black system event was 13 days and was one of only two market suspension periods in the history of the NEM.[199] This lengthy period of market suspension, given applicable circumstances, exposed a set of issues with the existing framework for market suspension in the NER.[200] These included:

- arrangements for market suspension pricing
- whether certain NER clauses apply during a period of market suspension, and
- the flexibility available to AEMO to prioritise certain core system security functions during a period of market suspension.

Following the South Australian black system event, the Commission progressed two rule changes on market suspension pricing.[201] These rule changes addresses the material issues associated with market suspension pricing that arose following the black system event in South Australia. This chapter therefore focusses on the other systemic issues identified in respect of NER arrangements applying to market suspension.

10.2 Current arrangements

The NER allows AEMO to suspend the operation of the spot market in a region. AEMO may declare the spot market suspended if any of the following occur:[202]

- a black system has occurred
- the relevant jurisdiction has directed AEMO to do so, or
- it determines it has become impossible to operate the spot market in accordance with the NER.

When it suspends the market, AEMO must publish a notice of market suspension. The market remains suspended until such time as AEMO issues a notice that the suspension has been removed. When the market is suspended, the NER set out specific arrangements related to how spot prices will be set.[203]

The NER specifies a limited set of requirements specifically relating to market suspension. In particular:

- NER clause 3.14.4(e) explicitly allows AEMO to issue directions to Registered Participants in accordance with clause 4.8.9.

199 The first market suspension occurred on 8 April 2001 for a period of two hours affecting all regions of the NEM following a market systems (IT system) failure.

200 The length of the market suspension period in South Australia, being 13 days, was due to a direction from the South Australian minister. On 29 September at 18:25 hrs AEMO revoked its declared black system condition. Following this revocation, the South Australian government issued a ministerial direction under the Essential Services Act 1981 (SA) requiring AEMO to maintain the market suspension. On 6 October 2019, the South Australian Government further advised AEMO that the ministerial direction to maintain suspension is extended by an additional seven days. The South Australian Government revoked its direction on 11 October 2019 and the market resumed on 11 October 2019, 13 days after the black system event.

201 In October 2017 the AEMC made a final ruling that simplifies the process for setting prices if the spot market is suspended, and establishes a simpler, more workable market suspension pricing framework. On 15 November 2018 the AEMC made a final rule establishing a new compensation framework so that certain Market Participants who incur losses during a market suspension event can be compensated.

202 Clause 3.14.3 of the NER.

203 Clauses 3.14.4 and 3.14.5 of the NER.

- NER clause 3.14.5(b) provides AEMO with discretion to determine whether it is practicable to determine spot prices in accordance with clause 3.8 and 3.9 of the NER during a period of market suspension.
- NER clause 3.14.5(d)(2) and (3) allows AEMO discretion as to when the market can be restored from suspension (pending approval from the relevant jurisdiction in circumstances where the jurisdiction had directed AEMO to suspend the market).

Existing arrangements however do not explicitly set out the applicability of other market frameworks during a period of market suspension.

10.2.1 Issues identified with current arrangements

During the market suspension period, AEMO was subject to a South Australian government ministerial direction to provide sufficient power system inertia to maintain the expected Rate of Change of Frequency (RoCoF) of the South Australian power system to within +/- 3Hz/s.[204] AEMO implemented this direction by maintaining a minimum of three thermal synchronous generator units in-service at all times. AEMO achieved this through a mix of clause 4.8.9 directions and quick energy constraints in the absence of a formal direction.[205]

In its assessment of the South Australian black system event, the AER made a number of findings in relation to AEMO's actions during the period.[206] These findings relate to the issuance of market notices and the use of quick energy constraints on individual generators as a means of implementing the SA ministerial direction to maintain the expected Rate of Change of Frequency (RoCoF) of the South Australian power system to within +/- 3Hz/s.[207]

On 5 October 2016, AEMO was sufficiently confident in the system to restart NEMDE and provide dispatch instructions issued by the standard methods. This means that, following 5 October, generators were making bids and NEMDE was automatically determining a merit order and issuing dispatch instructions to Market Participants. Following the restart of NEMDE, it became more difficult for AEMO to maintain three synchronous generators on-line to manage power system security as required by the SA ministerial direction.[208] It was at this time AEMO elected to constrain certain synchronous generators in South Australian on. In implementing this arrangement, AEMO considered the use of 4.8.9 directions.[209] When AEMO is considering intervening in the market by issuing a direction, the NER require it to immediately publish a notice of any foreseeable circumstances that may require it to intervene.[210]

204 Ibid, p. 161.

205 Ibid. A quick energy constraint is a process whereby AEMO manually changes the dispatch process to achieve a specific outcome, such as ensuring a generator is online. This is explored further later on in the paper.

206 The AER found AEMO to be non-compliant in terms of its administrative obligations to issue market notices, when there were foreseeable circumstances that may have required AEMO to intervene in the market through clause 4.8.9 directions. The AER also found administrative non-compliances where market notices were not issued sufficiently immediately. In making these findings, the AER did not elect to take any enforcement action. Ibid., p. 16.

207 AER, Black system event compliance report, p. 157.

208 AER, Black system event compliance report, p. 171.

209 AER, Black system compliance report, p. 157.

210 Clause 4.8.5A(a) of the NER.

AEMO considered that, it was under unique pressures during this period to maintain system security and should be allowed a degree of flexibility as to what elements of the NER should be prioritised. More specifically, AEMO considered that system operators should have the ability to prioritise efforts to ensure that the system is operated securely and safely, over meeting obligations that are more administrative in nature, such as issuing market notices. This issue was identified in the Commission's issues and approach paper as a key structural issue to be addressed in the review.[211]

10.2.2 Systemic issue identified

Existing arrangements do not specify the applicability of arrangement applying to operation of the power system during a period of market suspension outside those areas noted in section 10.2 of this chapter. The AER's compliance investigation identified different interpretations on the degree to which NER arrangements (which are silent of their applicability during a period of market suspension) apply when the market is suspended.[212] AEMO considered that, due to the adverse circumstances that are likely to apply, it should have discretion on whether to comply with more administrative NER requirements, such as requirements to issue market notices when complying with such a requirement would impose a material risk on its ability to maintain power system security.[213]

10.3 Stakeholder submissions

In its submission to the issues and approach paper for this review, AEMO raised a number of issues in relation to the circumstances that arose during the market suspension period following the South Australian black system, particularly the applicability of market rules and the flexibility available to AEMO to prioritise certain core functions over more administrative requirements.[214] No other stakeholders commented on issues related to market suspension.

AEMO argued that during a period of market suspension, it should be afforded a degree of flexibility, and that an overly prescriptive framework could unintentionally create additional risks to system security. AEMO's submission considered that NER arrangements needed to be sufficiently flexible for AEMO to address the range of conditions that may apply during a period of market suspension.[215]

AEMO also expressed the view that current uncertainty in the applicability of market rules was best addressed through the application of flexible principles, rather than detailed specification of obligations that should, should not, or could apply during a period of market suspension. AEMO recommended the rules be amended to reflect the principle that AEMO would always endeavour to operate the power system and market during suspension in accordance with the NER, to the extent it is reasonably practicable to do so.[216]

211 AEMC, Issues and approach paper, p. 44.
212 AER, Black system event compliance report, p 159.
213 Ibid.
214 AEMO, Submission to Issues and Approach paper, p.8.
215 Ibid, p. 8.
216 Ibid.

10.4 Review recommendations

10.4.1 Applicability of market rules during a period of market suspension

The Commission appreciates that a period of market suspension may be associated with a significant level of uncertainty in terms of underlying power system conditions. AEMO is likely to be managing complex power system matters and other market participants are also likely to be facing significant levels of uncertainty during this period.

Co-operation and co-ordination between AEMO and market participants will be important in resolving the issues that led to the market being suspended. In this context, additional sources of uncertainty have the potential to undermine this co-operation and compromise or delay market restart. Uncertainty as to the applicability of the NER is one source of uncertainty in this regard.

Clarity on the actions of AEMO and other market participants will therefore be particularly important. The clear applicability of the NER provides all market participants with certainty and therefore enhances the potential for co-ordination. To provide this clarity, the Commission recommends that the NER be clarified that AEMO must continue to comply with existing rules during a period of market suspension except where the rules provide explicit provisions for flexibility.

The Commission however, notes that flexibility, within clear limits, will also be important for AEMO given the adverse circumstances likely to apply.

10.4.2 Flexibility available to AEMO during a period of market suspension

Existing rule arrangements already provide limited flexibility for AEMO to comply with certain NER requirements, to the extent practicable, during a period of market suspension. Specifically, AEMO has some flexibility regarding compliance with NER provisions relating to central dispatch, spot market operation and price determination during a period of market suspension. However, this flexibility is specific, in that it refers to particular clauses, and is silent as to the remainder of the NER.

During the period immediately following such an event, and the subsequent system restoration, the power system is likely to be in a condition where system security is compromised and new risks may emerge rapidly. The Commission considers that silence in the rules has the potential to create uncertainty for market participants and AEMO during a period where system security issues are likely to be significant.

Given resourcing constraints, in addressing highly uncertain conditions during a period of market suspension, AEMO may need to prioritise compliance with NER requirements applying to system security. This may reasonably include AEMO putting less emphasis on administrative rules requirements that do not directly relate to maintaining the security and safety of the system.

The Commission therefore considers that clarity should be provided to AEMO in respect of certain market arrangements where strict compliance may compromise AEMO's ability to meet its system security obligations. In providing this flexibility however, the Commission also considers it important to provide other market participants with transparency and certainty as to AEMO's actions, the reasons justifying a need to prioritise system security arrangements over other market rules.

10.4.3 Transparency and governance arrangements

The Commission considers that any additional flexibility provided to AEMO to prioritise rule obligations for system security over others during a period of market suspension should be focussed and subject to clear transparency and governance obligations.

Transparency arrangements are required as a clear sense of AEMO's actions during the market suspension will reduce uncertainty for participants, and reduce the risk of inefficient decision-making. Therefore, the Commission also recommends that AEMO should be required to, as soon as practicable, inform the AER and all affected participants of:

- the provisions of the NER with which compliance would pose a direct risk to AEMO's ability to maintain power system security during the suspension
- the reasons why AEMO considers that compliance would pose such a risk, and
- any arrangements to apply during the suspension, or for a period during the suspension, to achieve the objective of those provisions of the NER to the extent reasonably practicable.

10.5 Recommendation benefits

The recommended changes to arrangements for market suspension are in the long term interests of consumers as they will promote the safety and security of the national electricity system.

As previously noted, the NER allows AEMO to suspend the operation of the spot market in a region. AEMO may declare the spot market suspended if any of the following occur:

- a black system has occurred
- the relevant jurisdiction has directed AEMO to do so, or
- it determines it has become impossible to operate the spot market in accordance with the NER

In each of these cases, there is likely to be significant uncertainty as to the safety and security of the national electricity system. As noted, current arrangements do not include a transparent framework which provides AEMO and market participants with clarity on the applicability of market rules during a period of market suspension with clear flexibility to prioritise system security related matters.

Clarifying the applicability of rules arrangements during a period of market suspension, providing AEMO with flexibility to reasonably prioritise system security arrangements, and enhancing transparency as to AEMO's actions during a period of market suspension will enhance AEMO's ability to resolve the matters leading to the market suspension and therefore advance the NEO by enhancing the safety and security of the national electricity system. It will also help market participants and policy-makers make more efficient decisions during a period of market suspension since arrangements applying to all parties will be clearer.

It is possible that participants may face some uncertainty as to how AEMO may choose to use its power to prioritise compliance with power system security elements of the NER. However, this uncertainty is countered by the fact that the proposed rule retains the overarching requirement for AEMO to comply with the NER. Furthermore, AEMO must also follow transparency obligations when it decides to use these powers. This should help to limit the degree of uncertainty, by providing some transparency as to how AEMO will use its powers. Therefore the Commission considers the costs of uncertainty to be outweighed by the benefits of this additional flexibility.

More generally, by making AEMO's processes explicit for prioritising different elements of the NER, the proposed rule addresses the uncertainty identified by the AER in its assessment of the SA black system event - that is, the uncertainty as to the applicability of the various elements of the NER during a period of market suspension. All parties including AEMO, the AER and market participants, will benefit from clarity as to the applicability of market rules during a period of market suspension.

Enhanced transparency would assist the AER in its compliance activities, will enhance market participant confidence in AEMO's actions and assist co-ordination between AEMO and market participants.

10.6 Recommendation summary and example rule change

This section summarises the proposed changes to the NER. The Commission has developed a suggested rule change request to implement the increase in flexibility proposed in this chapter. That suggested rule change is presented in Appendix C.

The Commission recommends that AEMO continues to comply with existing provisions of the NER that explicitly relate to periods of market suspension (such as pricing arrangements under clause 3.14.5); and NER requirements be clarified on:

- the applicability of market rules during market suspension, and
- flexibility for AEMO's to prioritise core system security requirements during a period of market suspension.
- for remaining provisions of the NER, AEMO has some flexibility where compliance with a particular rule would impose a material risk on its ability to maintain power system security during the market suspension.

ABBREVIATIONS

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Commission	See AEMC
MCE	Ministerial Council on Energy
NEL	National Electricity Law
NEO	National electricity objective
NERL	National Energy Retail Law
NERO	National energy retail objective
NGL	National Gas Law
NGO	National gas objective
BSE	Black system event
COAG	Council of Australian Governments
ESB	Energy security board
NSP	Network service provider
TNSP	Transmission network service provider
DNSP	Distribution network service provider
GPSR	General power system risk review
EAPT	Emergency Alcoa pot line trip
SPS	Special protection scheme
EFCS	Emergency frequency control scheme
DER	Distributed energy resources
PFR	Primary frequency response
HILP	High impact low probability
COGATI	Coordination of generation and transmission assessment review
PSFR	Power system frequency risk review
RIT-T	Regulatory investment test - transmission
RIT-D	Regulatory investment test - distribution
ISP	Integrated system plan
FOS	Frequency operating standard
AEST	Australian eastern standard time
SRAS	System restart ancillary service
FCAS	Frequency control ancillary service
MW	Mega watts
UFLS	Under frequency load shedding
SRS	System restart standard

RoCoF	Rate of change of frequency
NEMDE	National electricity market dispatch engine
ERCOT	Electric reliability council of Texas
SPP	South west power pool

A SUGGESTED RULE CHANGE REQUEST - GENERAL POWER SYSTEM RISK REVIEW

This suggested rule change request is provided for stakeholder information. It proposes changes to the NER to implement a generation power system risk review (GPSR) recommended in Chapter 7 of this report. Indicative legal drafting is provided following this suggested rule change request.

A.1 Nature and scope of the issue being addressed

The NEM's generation mix has changed markedly in recent years, with the reduced operation, mothballing or retirement of a large number of synchronous thermal generating units, coupled with the rapid deployment of inverter connected / asynchronous renewable generation resources, at both transmission and distribution levels. This changing generation mix is changing the power system risk and resilience profile which includes increasing levels of:

- *generation and load risk and uncertainty* - The changing generation mix is changing both the events and types of uncertainty regarding generation output. Unlike the failure of thermal generators, unexpected variation from variable generation is often not related to internal failure of the unit, but rather involve weather conditions, such as changes in sunlight intensity or wind speeds. These changes are generally distributed, and can affect a significant number of units and systems in a surrounding area. This means that system security risks may arise from an external event, such as a storm front passing across a region, and require the aggregate impact across all the generating units in the affected area to be considered, rather than the loss of a specific unit.
- *system response risk and uncertainty* - In addition to new types of generation and load uncertainty, the response of the power system itself to disturbances is also becoming more uncertain. This increase in uncertainty is due to factors including reduction in the level of inertia and fault level as synchronous units have retired, as well as a more complex demand side, due to an increased prevalence of DER. Other factors, such as increasing prevalence of network protection schemes, also increase the complexity and therefore the uncertainty, of power system response to a disturbance.

The Power System Frequency Risk review (PSFR) was introduced in 2017 as a part of the Emergency Frequency Control Schemes rule change.[217] The PSFR is an integrated, transparent framework for the consideration and management of frequency risks associated with some non-credible contingencies. It requires AEMO, at least every two years and in collaboration with TNSPs, to consider non-credible contingency events that could involve uncontrolled increases or decreases in frequency, leading to cascading outages or major supply disruptions.

217 AEMC, Emergency frequency control schemes, rule determination, 30 March 2017 p. ii

The AEMC's review of the South Australian black system event identified a range of shortcomings with the existing PSFR given the changing power system risk and resilience profile. In particular, the PSFR was identified as being:

1. *too narrow* - the range of risks it considers are limited to only frequency risks for a range of non-credible contingency events
2. *too shallow* - it only requires AEMO to collaborate with TNSPs but not DNSPs. This does not provide for detailed consideration of system security risks arising from increased DER penetration
3. *too slow* - The existing PSFR process occurs too infrequently and it takes too long to effectively identify emerging risks in a rapidly changing power system, and
4. *not integrated* - The existing PSFR is not sufficiently integrated into the broader planning arrangements undertaken by AEMO and NSPs.

Given the changing power system risk and resilience profile, this rule change proposes changes to the NER to broaden the existing PSFR beyond frequency to become a more frequent and holistic General Power System Risk review (GPSR) process for effectively identifying emerging risks to power system from all sources.

The following section describes the proposed rule in terms of how it addresses each of the shortcomings of the existing PSFR.

A.2 Description of the rule proposed to be made

This purpose of this rule change request is to seek changes to the NER to deliver a process for transparently assessing and identifying emerging risks to power system security. The proposed rule builds on the existing PSFR by expanding it to become a GPSR. The following rule description specifies arrangements for:

- enhancing the breadth of the sources of risk considered to include a wider range of sources of risk beyond frequency
- deepening the review to formally include DNSPs and account for systemic risks at the distribution network level, including those arising from high penetrations of distributed energy generation
- increasing the speed and frequency of the review to become an annual process, to allow for more effective early identification of emerging risks to the power system, and
- fully integrating the review with other AEMO and NSP planning processes to enhance learning from the review.

The following description of the proposed rule is divided into the following elements:

- scope of and requirements for the GPSR
- process of conducting the GPSR, and
- effectively linking the GPSR to other planning processes.

Scope of and requirements for the GPSR

The NER should amend existing arrangements for a PSFR to consider, and identify options for the future management of, all events and conditions (including contingency events) the occurrence of which AEMO expects, alone or in combination, would be likely to lead to cascading outages, or major supply disruptions.

It is proposed that the GPSR will specify six key risk areas which AEMO is required to consider when specifying the scope of the GPSR in each jurisdiction in which it is conducted. These six key risk areas include (AEMO may also consider any other risks it deems necessary):

- increases or decreases in frequency;
- increases or decreases in voltage;
- levels of inertia;
- the availability of system strength services
- the prevalence of distributed energy resources; and
- the operation of special protection schemes.

In conducting the GPSR, AEMO may prioritise certain risks over others, or elect not to consider some of the six key risks. Some may cease to be relevant, while others as yet unidentified will assume greater importance. In establishing priorities, AEMO would be required to consult with both TNSPs and DNSPs. AEMO would be required to consult on its choice of risks and provide an explanation should certain risks, of the six listed, not be considered as priorities for assessment. This consultation should occur following publication of an approach paper (described below).

The general power system risk review process

It is proposed that the GPSR is to be conducted no less than annually with AEMO required to consult with, and take into account, the views of Transmission Network Service Providers and Distribution Network Service Providers in conducting the GPSR.

The timing requirements should be explored through the rule change request. Requiring a full review every year may not be required in each NEM region.

A single final report would be published at the conclusion of the GPSR and an approach paper be published at the commencement of the review. The approach paper would specify:

- priorities in the risks to be assessed
- the approach and methodologies in assessing each risk
- information inputs and assumptions used, and
- approach to consulting with TNSPs and DNSPs.

The rule proposes that AEMO publicly consult for a period of at least 10 business days following publication of the GPSR approach paper.

Links to NSP and AEMO planning processes

It is proposed that the GPSR be integrated into relevant AEMO and NSP planning processes. Specifically proposed changes:

- require TNSPs and DNSPs to take into account the outcomes from the recent GPSR in their Annual Planning Reviews
- require AEMO to consider and have regard to the outcomes of the general power system risk review in conducting the ISP.

To account for special risks arising from special protection schemes and the settings of protection systems or control systems of plant connected to its network, the rule change request is for an additional obligation to require TNSPs and DNSPs to consider, in their APRs whether any special protection schemes and settings of protection systems or control systems of plant connected to its network are fit for purpose for the future operation of its network. This provision will provide for effective consideration of such risks in the GPSR.

A joint NSP planning obligation would also be imposed to assess the interactions between special protection schemes and settings of protection systems or control systems of plant connected to their respective networks, with a view to identifying the potential for adverse interactions.

A.3 How the proposed rule advances the National Electricity Objective

This rule change request seeks changes to the NER that would advance the National Electricity Objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.

The recommended GPSR will promote the efficient operation and use of electricity services in the long term interests of consumers of electricity with respect to the safety and security of the national electricity system. It is in the long term interests of consumers that:

- emerging risks are identified promptly. Emerging risks that are not identified can not be effectively managed. The recommended GPSR would increase the frequency and speed of the review process to become an annual process sufficient to promptly identifying emerging risks
- risks to power system security are effectively assessed from all possible sources. The power system's transition to intermittent renewable generation and the closure of existing synchronous generation is changing the power system's risk and resilience profile. New risks are emerging as this process occurs. As an example, the existing PSFR may not fully consider the impact of DER on systemic system security outcomes, and
- all parties are effectively co-ordinated in the process of identifying and assessing emerging risks to the power system. The GPSR would assist the co-ordination of all parties responsible for managing the changing power system risk and resilience profile through its inclusion of AEMO, TNSPs, and DNSPs. Integrating the GPSR into NSP and AEMO planning processes would assist in the implementation of the lowest cost management processes overall, rather than adoption of a set of dis-jointed measures which may be less efficient.

Consumers will face inefficient costs if there is a reduction in the security of supply due to a failure to promptly and effectively identify emerging risks. If emerging risks are not efficiently and effectively identified, such that they can be efficiently managed, consumers are likely to experience an increase in the frequency and duration of major supply disruptions, or black system events. There would be an increase in cost and resource requirements for AEMO and NSPs in conducting a broader, more frequent review. However, we expect these costs to be minimal and necessary to address the changing risk profile of the system, given the rapid transition under way.

A.4 Impact of the proposed rule on affected parties

Early identification of emerging risks and uncertainties will provide for their efficient management and reduce the probability of cascading failures leading to major supply disruptions and black system events.

Customers would benefit from an improvement in the security of supply from the early identification of emerging risks and uncertainties to the power system thereby enabling their effective and efficient management. Early identification and management of emerging risks and uncertainties will reduce the probability and expected economic costs to customers from cascading failures leading to major supply disruptions and black system events.

While the additional costs incurred by NSPs and AEMO in conducting the review would ultimately be borne by consumers, as explained in the above section, these additional resources are likely to be efficient and in line with the NEO given the improvement in system security from early identification and prompt management of such risks.

NSPs and AEMO would face additional direct costs and resource requirements associated with conducting the review. As these measures represent an incremental expansion on existing arrangements, these costs are not entirely additional to those that would be incurred in the absence of the rule as all parties can adapt and expand existing processes. The proposed rule would also link effectively into existing AEMO and NSP planning processes. This link to existing planning processes would provide for the greatest possible value to come from the review and the investment of resources in conducting the review.

CHAPTER 5

5. Network Connection Access, Planning and Expansion

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Part D Network Planning and Expansion

***

5.10.2 Definitions

In this Part D and schedules 5.8, 5.9 and 5.4A:

emergency control scheme includes an *emergency frequency control scheme*.

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5.12 Transmission annual planning process

5.12.1 Transmission annual planning review

(a) Each *Transmission Network Service Provider* must analyse the expected future operation of its *transmission networks* over an appropriate planning period, taking into account the relevant forecast *loads*, any future *generation*, *market network service*, demand side and *transmission* developments and any other relevant data.

(b) Each *Transmission Network Service Provider* must conduct an annual planning review which must:

(1) incorporate the forecast *loads* as submitted or modified in accordance with clause 5.11.1; and

(1a) include a review of, and interactions between:

(i) any special protection schemes on its *network*; and

(ii) settings of *protection systems* or *control systems* of *plant connected* to its *network* (including consideration of whether such settings are fit for purpose for the future operation of its *network*);

(2) include a review of the adequacy of existing *connection points* and relevant parts of the *transmission system* and planning proposals for future *connection points*; and

(3) take into account the most recent *NTNDP* and *general power system* ~~*frequency*~~ *risk review*; and

(4) consider the potential for *augmentations*, or non-*network* alternatives

to *augmentations*, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the *market*;

(5) consider the condition of *network* assets; and

(6) consider the potential for replacements of *network* assets, or *non-network options* to replacements of *network* assets, that are likely to provide a net economic benefit to all those who produce, consume and transport electricity in the *market*.

(c) The minimum planning period for the purposes of the annual planning review is 10 years for *transmission networks*.

5.12.2 Transmission Annual Planning Report

(a) Subject to paragraph (b), by 30 June each year all *Transmission Network Service Providers* must *publish* a *Transmission Annual Planning Report* setting out the results of the annual planning review conducted in accordance with clause 5.12.1.

(b) If a *Network Service Provider* is a *Transmission Network Service Provider* only because it owns, operates or controls *dual function assets* then it may *publish* its *Transmission Annual Planning Report* in the same document and at the same time as its *Distribution Annual Planning Report*.

(c) The *Transmission Annual Planning Report* must be consistent with the TAPR Guidelines and set out:

(1) the forecast *loads* submitted by a *Distribution Network Service Provider* in accordance with clause 5.11.1 or as modified in accordance with clause 5.11.1(d), including at least:

(i) a description of the forecasting methodology, sources of input information, and the assumptions applied in respect of the forecast *loads*;

(ii) a description of high, most likely and low growth scenarios in respect of the forecast *loads*;

(iii) an analysis and explanation of any aspects of forecast *loads* provided in the *Transmission Annual Planning Report* that have changed significantly from forecasts provided in the *Transmission Annual Planning Report* from the previous year; and

(iv) an analysis and explanation of any aspects of forecast *loads* provided in the *Transmission Annual Planning Report* from the previous year which are significantly different from the actual outcome;

(1A) for all *network* asset retirements, and for all *network* asset de-ratings that would result in a *network constraint*, that are planned over the minimum planning period specified in clause 5.12.1(c), the following information in sufficient detail relative to the size or significance of the asset:

(i) a description of the *network* asset, including location;

(ii) the reasons, including methodologies and assumptions used by the *Transmission Network Service Provider* for deciding that it is necessary or prudent for the *network* asset to be retired or de-rated, taking into account factors such as the condition of the *network* asset;

(iii) the date from which the *Transmission Network Service Provider* proposes that the *network* asset will be retired or de-rated; and

(iv) if the date to retire or de-rate the *network* asset has changed since the previous *Transmission Annual Planning Report*, an explanation of why this has occurred;

(1B) for the purposes of subparagraph (1A), where two or more *network* assets are:

(i) of the same type;

(ii) to be retired or de-rated across more than one location;

(iii) to be retired or de-rated in the same calendar year; and

(iv) each expected to have a replacement cost less than $200,000 (as varied by a cost threshold determination),

those assets can be reported together by setting out in the *Transmission Annual Planning Report*:

(v) a description of the *network* assets, including a summarised description of their locations;

(vi) the reasons, including methodologies and assumptions used by the *Transmission Network Service Provider*, for deciding that it is necessary or prudent for the *network* assets to be retired or de-rated, taking into account factors such as the condition of the *network* assets;

(vii) the date from which the *Transmission Network Service Provider* proposes that the *network* assets will be retired or de-rated; and

(viii) if the calendar year to retire or de-rate the *network* assets has changed since the previous *Transmission Annual Planning Report*, an explanation of why this has occurred;

(1C) any special protection schemes and settings of *protection systems* or *control systems* identified under clause 5.12.1(b)(1a), including at least:

(i) an analysis and explanation of whether such settings are fit for purpose for the future operation of its *network*;

(ii) a description of any interactions between the special protection schemes and such settings; and

(iii) a description of proposed actions to be undertaken to address any adverse interactions;

(2) planning proposals for future *connection points*;

(3) a forecast of *constraints* and inability to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction* over 1, 3 and 5 years, including at least:

(i) a description of the *constraints* and their causes;

(ii) the timing and likelihood of the *constraints*;

(iii) a brief discussion of the types of planned future projects that may address the *constraints* over the next 5 years, if such projects are required; and

(iv) sufficient information to enable an understanding of the *constraints* and how such forecasts were developed;

(4) in respect of information required by subparagraph (3), where an estimated reduction in forecast *load* would defer a forecast *constraint* for a period of 12 months, include:

(i) the year and months in which a *constraint* is forecast to occur; (ii)

the relevant *connection points* at which the estimated reduction in forecast *load* may occur;

(iii) the estimated reduction in forecast *load* in MW needed; and

(iv) a statement of whether the *Transmission Network Service Provider* plans to issue a request for proposals for *augmentation*, replacement of *network* assets, or a *non-network option* identified by the annual planning review conducted under clause 5.12.1(b) and if so, the expected date the request will be issued;

(5) for all proposed *augmentations* to the *network* and proposed replacements of *network* assets the following information, in sufficient detail relative to the size or significance of the project and the proposed operational date of the project:

(i) project/asset name and the month and year in which it is proposed that the asset will become operational;

(ii) the reason for the actual or potential *constraint*, if any, or inability, if any, to meet the *network* performance requirements set out in schedule 5.1 or relevant legislation or regulations of a *participating jurisdiction,* including *load* forecasts and all assumptions used;

(iii) the proposed solution to the *constraint* or inability to meet the *network* performance requirements identified in subparagraph (ii), if any;

(iv) total cost of the proposed solution;

(v) whether the proposed solution will have a *material inter-network impact.* In assessing whether an *augmentation* to the *network* will have a *material inter-network impact* a *Transmission Network*

Service Provider must have regard to the objective set of criteria *published* by *AEMO* in accordance with clause 5.21 (if any such criteria have been *published* by *AEMO*); and

(vi) other reasonable *network options* and *non-network options* considered to address the actual or potential *constraint* or inability to meet the *network* performance requirements identified in subparagraph (ii), if any. Other reasonable *network* and *non-network options* include, but are not limited to, *interconnectors*, *generation* options, demand side options, *market network service* options and options involving other *transmission* and *distribution networks*;

(6) the manner in which the proposed *augmentations* and proposed replacements of *network* assets relate to the most recent *NTNDP* and the development strategies for current or potential *national transmission flow paths* that are specified in that *NTNDP*;

(6A) for proposed new or modified emergency ~~frequency~~ control schemes, the manner in which the project relates to the most recent *general power system* ~~*frequency*~~ *risk review*;

(7) information on the *Transmission Network Service Provider's* asset management approach, including:

(i) a summary of any asset management strategy employed by the *Transmission Network Service Provider*;

(ii) a summary of any issues that may impact on the system *constraints* identified in the *Transmission Annual Planning Report* that has been identified through carrying out asset management; and

(iii) information about where further information on the asset management strategy and methodology adopted by the *Transmission Network Service Provider* may be obtained.

(8) any information required to be included in a *Transmission Annual Planning Report* under:

(i) clause 5.16.3(c) in relation to a *network* investment which is determined to be required to address an urgent and unforeseen *network* issue; or

(ii) clauses 5.20B.4(h) and (i) and clauses 5.20C.3(f) and (g) in relation to *network* investment and other activities to provide *inertia network services*, *inertia support activities* or *system strength services*.

(9) emergency controls in place under clause S5.1.8, including the *Network Service Provider's* assessment of the need for new or altered emergency controls under that clause;

(10) *facilities* in place under clause S5.1.10;

(11) an analysis and explanation of any other aspects of the *Transmission*

Annual Planning Report that have changed significantly from the preceding year's *Transmission Annual Planning Report*, including the reasons why the changes have occurred; and

(12) the results of joint planning (if any) undertaken with a *Transmission Network Service Provider* under clause 5.14.3 in the preceding year, including a summary of the process and methodology used by the *Transmission Network Service Providers* to undertake joint planning and the outcomes of that joint planning.

(d) A *declared transmission system operator* for all or part of the *declared shared network* must provide to *AEMO* within a reasonable period of receiving a request, such information as reasonably requested by *AEMO* to enable it to comply with:

(1) clause 5.12.1(b)(5);

(2) clause 5.12.1(b)(6);

(3) clause 5.12.2(c)(1A);

(4) clauses 5.12.2(c)(4), (5) and (6) as they relate to the proposed replacement of *network* assets; and

(5) clause 5.12.2(c)(7).

5.13 Distribution annual planning process

5.13.1 Distribution annual planning review

Scope

(a) A *Distribution Network Service Provider* must:

(1) subject to paragraph (b), determine an appropriate forward planning period for its distribution assets; and

(2) analyse the expected future operation of its *network* over the forward planning period in accordance with this clause 5.13.1.

(b) The minimum forward planning period for the purposes of the *distribution* annual planning review is 5 years.

(c) The *distribution* annual planning review must include all assets that would be expected to have a material impact on the *Distribution Network Service Provider's network* over the forward planning period.

Requirements

(d) Each *Distribution Network Service Provider* must, in respect of its *network*:

(1) prepare forecasts covering the forward planning period of *maximum demands* for:

(i) sub-transmission lines;

(ii) zone substations; and

(iii) to the extent practicable, primary distribution feeders, having regard to:

(iv) the number of customer *connections*;

(v) *energy* consumption; and

(vi) estimated total output of known *embedded generating units*;

(2) identify, based on the outcomes of the forecasts in subparagraph (1), limitations on its *network*, including limitations caused by one or more of the following factors:

(i) forecast *load* exceeding total capacity;

(ii) the requirement for asset refurbishment or replacement;

(iii) the requirement for *power system security* or *reliability* improvement;

(iv) design fault levels being exceeded;

(v) the requirement for *voltage* regulation and other aspects of quality of supply to other *Network Users*; and

(vi) the requirement to meet any *regulatory obligation or requirement*;

(3) identify whether corrective action is required to address any system limitations identified in subparagraph (2) and, if so, identify whether the *Distribution Network Service Provider* is required to:

(i) carry out the requirements of the *regulatory investment test for distribution*; and

(ii) carry out demand side engagement obligations as required under paragraph (f); ~~and~~

(4) take into account any *jurisdictional electricity legislation*;~~.~~

(5) take into account the most recent *general power system risk review*; and

(6) include a review of, and interactions between:

(i) any special protection schemes on its *network*; and

(ii) settings of *protection systems* or *control systems* of *plant connected* to its *network* (including consideration of whether such settings are fit for purpose for the future operation of its *network*).

Demand side engagement obligations

(e) Each *Distribution Network Service Provider* must develop a strategy for:

(1) engaging with non-network providers; and

(2) considering *non-network options*.

(f) A *Distribution Network Service Provider* must engage with non-network providers and consider *non-network options* for addressing system limitations in accordance with its demand side engagement strategy.

(g) A *Distribution Network Service Provider* must document its demand side engagement strategy in a demand side engagement document which must be *published* by no later than 31 August 2013.

(h) A *Distribution Network Service Provider* must include the information specified in schedule 5.9 in its demand side engagement document.

(i) A *Distribution Network Service Provider* must review and *publish* a revised demand side engagement document at least once every three years.

(j) A *Distribution Network Service Provider* must establish and maintain a facility by which parties can register their interest in being notified of developments relating to *distribution network* planning and expansion. A *Distribution Network Service Provider* must have in place a facility under this paragraph (j) no later than the date of publication of the *Distribution Network Service Provider's* demand side engagement document under paragraph (g).

5.13.2 Distribution Annual Planning Report

(a) For the purposes of this clause 5.13.2:

DAPR date means for a *Distribution Network Service Provider*:

(1) the date by which it is required to *publish* a *Distribution Annual Planning Report* under *jurisdictional electricity legislation*; or

(2) if no such date is specified in *jurisdictional electricity legislation*, 31 December.

(b) By the DAPR date each year, a *Distribution Network Service Provider* must *publish* the *Distribution Annual Planning Report* setting out the results of the *distribution* annual planning review for the forward planning period.

Note

Under clause 5.12.2(b), if a person is a *Transmission Network Service Provider* only because it owns, operates or controls *dual function assets* then it may *publish* its *Transmission Annual Planning Report* in the same document and at the same time as its *Distribution Annual Planning Report* under this clause 5.13.2.

(c) A *Distribution Network Service Provider* must include the information specified in schedule 5.8 in its *Distribution Annual Planning Report*.

(d) Despite paragraph (c), a *Distribution Network Service Provider* is not required to include in its *Distribution Annual Planning Report* information required in relation to transmission-distribution connection points if it is required to do so under *jurisdictional electricity legislation*.

(e) As soon as practicable after it *publishes* a *Distribution Annual Planning Report* under paragraph (b), a *Distribution Network Service Provider* must *publish* on its website the contact details for a suitably qualified staff member of the *Distribution Network Service Provider* to whom queries on the report may be directed.

5.13.3 Distribution system limitation template

(a) The *AER* must develop and *publish* a system limitation template in accordance with paragraph (c) and having regard to paragraph (b). The system limitation template must be developed by the *AER* in consultation with *Distribution Network Service Providers* and any persons who have identified themselves to the *AER* as having an interest in the form or contents of the system limitation template.

(b) The purpose of the system limitation template is to facilitate the publication by *Distribution Network Service Providers* of information on system limitations referred to in their *Distribution Annual Planning Reports* in a useable, consistent, accessible format to assist third parties to propose alternative options to address system limitations.

(c) The system limitation template must:

(1) provide a template for the reporting of the following information:

(i) the name (or identifier) and location of *substations*, sub-transmission lines, zone substations and, where appropriate, primary feeders, where there is a system limitation or a projected system limitation during the forward planning period that has been identified in a *Distribution Network Service Provider's Distribution Annual Planning Report*;

(ii) the estimated timing (months(s) and year) of the system limitation or projected system limitation identified in subparagraph (i);

(iii) the *Distribution Network Service Provider*'s proposed option to address the system limitation;

(iv) the estimated capital or operating cost of the proposed option; and

(v) the amount by which peak demand at the location of the system limitation or projected system limitation would need to be reduced in order to defer the proposed solution, and the dollar value to the *Distribution Network Service Provider* of each year of deferral; and

(2) include a statement that any information provided using the system limitation template must be read in conjunction with the reporting *Distribution Network Service Provider's Distribution Annual Planning Report*.

(d) At the same time as it *publishes* its *Distribution Annual Planning Report* each year, a *Distribution Network Service Provider* must *publish* a report which contains the information specified in paragraph (c) in the form required by the system limitation template.

***

5.14 Joint planning

5.14.1 Joint planning obligations of Transmission Network Service Providers and Distribution Network Service Providers

(a) Subject to paragraphs (b) and (c):

(1) each *Distribution Network Service Provider* must conduct joint planning with each *Transmission Network Service Provider* of the *transmission networks* to which the *Distribution Network Service Provider's networks* are *connected*; and

(2) each *Transmission Network Service Provider* must conduct joint planning with each *Distribution Network Service Provider* of the *distribution networks* to which the *Transmission Network Service Provider's networks* are *connected*.

(b) In the case of the *declared shared network* of an *adoptive jurisdiction*, the relevant *declared transmission system operator*, the relevant *Distribution Network Service Provider*, *AEMO* and any *interested party* that has informed *AEMO* of its interest in the relevant plans, shall conduct joint planning.

(c) For the purposes of this clause 5.14.1, a *Transmission Network Service Provider* does not include a *Network Service Provider* that is a *Transmission Network Service Provider* only because it owns, controls or operates *dual function assets*.

(d) The relevant *Distribution Network Service Provider* and *Transmission Network Service Provider* must:

(1) assess the adequacy of existing *transmission* and *distribution networks* and the assets associated with transmission-distribution connection points over the next five years and to undertake joint planning of projects which relate to both *networks* (including, where relevant, *dual function assets*);

(2) use best endeavours to work together to ensure efficient planning outcomes and to identify the most efficient options to address the needs identified in accordance with subparagraph (4);

(3) identify any limitations or constraints:

(i) that will affect both the *Transmission Network Service Provider's* and *Distribution Network Service Provider's network*; or

(ii) which can only be addressed by corrective action that will require coordination by the *Transmission Network Service Provider* and the *Distribution Network Service Provider*; and

(3a) assess the interactions between special protection schemes and settings of *protection systems* or *control systems* of *plant* between their respective *networks* (as reviewed under clauses 5.12.1(b)(1a) and 5.13.1(d)(6)) with a view to addressing any adverse impacts through joint planning;

(4) where the need for a joint planning project is identified under subparagraphs (3) or (3a):

(i) jointly determine plans that can be considered by relevant *Registered Participants*, *AEMO*, *interested parties*, and parties registered on the demand side engagement register of each *Distribution Network Service Provider* involved in joint planning;

(ii) determine whether the joint planning project is a RIT-T project or a RIT-D project; and

(iii) may agree on a lead party to be responsible for carrying out the *regulatory investment test for transmission* or the *regulatory investment test for distribution* (as the case may be) in respect of the joint planning project.

(e) If a *Network Service Provider*, as the lead party for one or more *Network Service Providers*, undertakes the *regulatory investment test for transmission* or the *regulatory investment test for distribution* (as the case may be) in respect of a joint planning project, the other *Network Service Providers* will be taken to have discharged their obligation to undertake the relevant test in respect of that project.

5.14.2 Joint planning obligations of Distribution Network Service Providers and Distribution Network Service Providers

(a) *Distribution Network Service Providers* must undertake joint planning with other *Distribution Network Service Providers* where there is a requirement to consider the need for any *augmentation* or *non-network options* that affect more than one *Distribution Network Service Provider's network*.

(b) *Distribution Network Service Providers* involved in joint planning may agree on a lead party to be responsible for carrying out the *regulatory investment test for distribution* in respect of the joint planning project.

(c) If a *Distribution Network Service Provider*, as the lead party for one or more *Distribution Network Service Providers*, undertakes the *regulatory investment test for distribution* in respect of a joint planning project, the other *Distribution Network Service Providers* will be taken to have discharged their obligation to undertake the *regulatory investment test for distribution* in respect of that project.

5.14.3 Joint planning obligations of Transmission Network Service Providers

Transmission Network Service Providers must undertake joint planning if:

(a) a possible credible option to address a *constraint* in a *transmission network* is an *augmentation* to the *transmission network* of another *Transmission Network Service Provider*; and

(b) that *constraint* is not already being considered under other processes under the *Rules*.

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5.20 National transmission planning

In this rule:

NSCAS trigger date means for any *NSCAS gap* identified in clause 5.20.2(c)(8)(i), the date that the *NSCAS gap* first arises.

NSCAS tender date means for any *NSCAS gap* identified in clause 5.20.2(c)(8)(i), the date or indicative date that *AEMO* would need to act so as to call for offers to acquire *NSCAS* to meet that *NSCAS gap* by the relevant NSCAS trigger date in accordance with clause 3.11.3(c)(4).

5.20.1 Preliminary consultation

(a) By no later than 30 January each year, *AEMO* must *publish*:

(1) a document that sets out the *NTNDP inputs* that it proposes to use for the preparation or revision of the *NTNDP* for the following calendar year; and

(2) a document (the **statement of material issues**):

(i) summarising the issues *AEMO* considers to be the material issues involved in the preparation or revision of the *NTNDP* for the following calendar year; and

(ii) giving an indication of *AEMO's* preliminary views on how those issues should be resolved; and

(3) the *inertia requirements methodology* and the *system strength requirements methodology*.

(b) At the same time as it *publishes* the documents referred to in paragraph (a), *AEMO* must *publish* an invitation for written submissions to be made to *AEMO* within a period (at least 30 *business days*) specified in the invitation on:

(1) the proposed *NTNDP inputs*; and

(2) the content of the *NTNDP* as it applies for the current year, including the location of the current and potential *national transmission flow paths* identified in the *NTNDP*; and

(3) the issues raised in the statement of material issues; and

(4) the *inertia requirements methodology* and the *system strength requirements methodology*.

(c) A person may make a written submission to *AEMO* on the proposed *NTNDP inputs*, the content of the *NTNDP* as it applies for the current year, the *inertia requirements methodology*, the *system strength requirements methodology* or an issue raised in the statement of material issues within the period specified in the invitation.

5.20.2 Publication of NTNDP

(a) By no later than 31 December each year, *AEMO* must *publish* the *NTNDP* for the following year.

(b) In preparing the *NTNDP* that is to be *published* under paragraph (a), *AEMO* must:

(1) take into account the submissions made in response to the invitation referred to in clause 5.20.1(b); and

(2) consider the following matters:

(i) the quantity of electricity that flowed, the periods in which the electricity flowed, and *constraints* on the *national transmission flow paths* over the previous year;

(ii) the forecast quantity of electricity that is expected to flow, the periods in which the electricity is expected to flow, and the magnitude and significance of future *network losses* and *constraints*, on the current and potential *national transmission flow paths* over the year in which the *NTNDP* is to apply or some other period to which a scenario that is used for the purposes of the *NTNDP* applies;

(iii) the projected capabilities of the *national transmission grid*, and the *network support and control ancillary services* required to support the existing and future capabilities of the *national transmission grid*, under each of the scenarios that is being used for the purposes of the *NTNDP*;

(iv) relevant intra-jurisdictional developments and any incremental works that may be needed to co-ordinate *national transmission flow path* planning with intra-jurisdictional planning;

(iv1) outcomes of the *general power system risk review*; and

(v) such other matters as *AEMO*, in consultation with the *participating jurisdictions*, considers appropriate; and

(3) have regard to the following documents:

(i) the most recent *Transmission Annual Planning Reports* that have been *published*;

(ii) the most recent *statement of opportunities* that has been *published*;

(iii) the most recent gas statement of opportunities published under the National Gas Law;

(iv) the current revenue determination for each *Transmission Network Service Provider*;

(iv1) the most recent *general power system risk* review; and

(v) any other documents that *AEMO* considers relevant.

(c) An *NTNDP* that is *published* under paragraph (a) must:

(1) consider and assess an appropriate course for the efficient development of the *national transmission grid* for a planning horizon of at least 20 years from the beginning of the year in which the *NTNDP* applies; and

(2) take into account all *transmission elements* which are part of, or materially affect, the transmission capability of any current or potential *national transmission flow paths*; and

(3) take into account all *NSCAS* provided; and

(4) identify a range of credible scenarios for the geographic pattern of the demand for, and supply of, electricity for the planning horizon of the

NTNDP; and

(5) identify the location of current *national transmission flow paths* and specify their transmission capability; and

(6) identify the location of the potential *national transmission flow paths* over the planning horizon of the *NTNDP* under each of the scenarios referred to in subparagraph (3); and

(7) specify a development strategy for each current and potential *national transmission flow path* in accordance with clause 5.20.3; and

(8) include an assessment that identifies:

(i) any *NSCAS gap*; and

(ii) for any *NSCAS gap* identified in subparagraph (i) required to maintain *power system security* and reliability of *supply* of the *transmission network* in accordance with the *power system security standards* and the *reliability standard*, the relevant NSCAS trigger date;

(iii) for any *NSCAS gap* identified in subparagraph (i) required to maintain *power system security* and reliability of *supply* of the *transmission network* in accordance with the *power system security standards* and the *reliability standard*, the relevant NSCAS tender date;

(9) report on *NSCAS* acquired by *AEMO* in the previous *NTNDP* year; and

(10) include a summary of the information specified in rule 3.7A in relation to congestion on each current *national transmission flow path*; and

(11) include a consolidated summary of the *augmentations* proposed by each *Transmission Network Service Provider* in the most recent *Transmission Annual Planning Reports* they have *published* and an analysis of the manner in which the proposed *augmentations* relate to the *NTNDP* and any previous *NTNDP*; and

(12) summarise the material issues arising from the submissions received in response to the invitation referred to in clause 5.20.1(b), explain how those issues have been addressed in the *NTNDP* and give reasons for not addressing any of those issues in the *NTNDP*; and

(13) describe the boundaries of the *inertia sub-networks* and related *inertia requirements* determined by *AEMO* under rule 5.20B since the last *NTNDP* and details of *AEMO's* assessment of any *inertia shortfall* and *AEMO's* forecast of any *inertia shortfall* arising at any time within a planning horizon of at least 5 years; and

(14) describe the *system strength requirements* determined by *AEMO* under rule 5.20C since the last *NTNDP* and details of *AEMO*'s assessment of any *fault level shortfall* and *AEMO's* forecast of any *fault level shortfall* arising at any time within a planning horizon of at least 5 years.

(d) *AEMO* must *publish* the first *NTNDP* (the *NTNDP* **for 2011**) no later than 31

December 2010.

(e) If, after the *publication* of the most recent *NTNDP*, *AEMO* becomes aware of information that shows the *NTNDP* to be incorrect in a material respect, *AEMO* must *publish* a correction of the *NTNDP* as soon as practicable.

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5.20A Frequency and risk management planning

5.20A.1 General ~~P~~power system ~~frequency~~ risk review

(a) *AEMO* must, through a *general power system ~~frequency~~ risk review* under this rule, review:

(1) ~~*non-credible*~~ on a prioritised basis, events and conditions (including *contingency events*) the occurrence of which *AEMO* expects, alone or in combination, would be likely to lead~~involve uncontrolled increases or decreases in *frequency* (alone or in combination) leading~~ to *cascading outages*, or *major supply disruptions*;

(2) current arrangements for management of the events and conditions~~*non-credible contingency events*~~ described in sub-paragraph (1); and

(3) options for future management of those events and conditions.

(b) the options referred to in subparagraph (a)(3) may include:

(1) new or modified emergency ~~frequency~~ control schemes;

(2) declaration of the event as a *protected event*;

(3) *network augmentation*; and

(4) non-*network* alternatives to *augmentation*.

(b1) For the purposes of the review under paragraph (a), *AEMO* must consider events and conditions that present a material risk of *cascading outages* or *major supply disruptions* associated with any or a combination of:

(1) increases or decreases in *frequency*;

(2) increases or decreases in *voltage*;

(3) levels of *inertia*;

(4) the availability of *system strength services*;

(5) the operation or interaction of special protection schemes; and

(6) any other factors *AEMO* deems appropriate, including those arising on *distribution networks*.

(c) a *general power system ~~frequency~~ risk review* must~~,~~:

(1) identify ~~*non-credible*~~ events and conditions~~*contingency events*~~ referred to in paragraph (a) that *AEMO* considers should be priorities for assessment having regard to:

(i) the likely *power system security* outcomes if the event or condition occurs;

(ii) the likelihood of the event or condition occurring;

(iii) whether in *AEMO's* opinion there are reasonably likely to be options for management of the event or condition that are technically feasible, and (on the basis of *AEMO's* preliminary assessment of the estimated costs and benefits of that option) are economically feasible; and

(iv) other factors that *AEMO* considers relevant;

(2) for events and conditions identified under subparagraph (1):

(i) assess options for future management of the event or condition that are technically and economically feasible;

(ii) assess the expected costs and time for implementation of each option and any other factors that *AEMO* considers should be taken into account in selecting a recommended option; ~~and~~

(iii) identify the recommended option or range of options; and

(iv) after consultation with *Transmission Network Service Providers* and *Distribution Network Service Providers*, include an explanation of the reason why certain events and conditions were, or were not, considered by *AEMO* to be priorities for assessment.

(3) for current *protected events*:

(i) assess the adequacy and costs of the arrangements for management of the event;

(ii) consider whether to recommend a request to the *Reliability Panel* to revoke the declaration of the event as a *protected event*; and

(iii) except where a recommendation is to be made under subparagraph (ii), identify any need for changes to the arrangements for management of the event and where applicable, identify the options for change and in relation to each option, the matters referred to in subparagraphs (2)(ii) and (iii); and

(4) assess the performance of existing emergency ~~frequency~~ control schemes and identify any need to modify the scheme.

5.20A.2 General ~~P~~power system ~~frequency~~ risk review process

(a) *AEMO* must undertake a *general power system* ~~*frequency*~~ *risk review* no less than annually~~at least every two years~~.

(b) *AEMO* must put in place arrangements it considers appropriate to consult with and take into account the views of *Transmission Network Service Providers* *and Distribution Network Service Providers* in the conduct of a *general power system* ~~*frequency*~~ *risk review*.

(c) Where *AEMO* is considering a new or modified emergency ~~frequency~~ control scheme, *AEMO* must consult with *Distribution Network Service Providers* whose *distribution system* is likely to be directly affected by the scheme.

(d) When undertaking a *general power system* ~~*frequency*~~ *risk review*, including the assessment of the risks identified in clause 5.20A.1(b1): ~~*AEMO* may~~

(1) *AEMO* may consult with *Network Service Providers* and~~consult with~~ any other parties it considers appropriate, including without limitation, *Jurisdictional System Security Coordinators*; and~~.~~

(2) *AEMO* must, on commencement of the *general power system risk review*, publish an approach paper setting out:

(i) priorities in the risks to be assessed;

(ii) the approach and methodologies in assessing each risk;

(iii) information inputs and assumptions used; and

(iv) *AEMO*'s approach to consulting with *Transmission Network Service Providers* and *Distribution Network Service Providers*,

and invite written submissions to be made within a period of at least 10 *business days* specified in the invitation.

5.20A.3 General ~~P~~power system ~~frequency~~ risk review report

(a) ~~On completion of a *power system frequency risk review*,~~ As soon as reasonably practicable following receipt of submissions, *AEMO* must publish a ~~draft~~ report setting out its findings and recommendations on the matters set out in clause 5.20A.1~~, and invite written submissions to be made within a period of at least 10 *business days* specified in the invitation. *AEMO* must publish its final report as soon as reasonably practicable following the receipt of submissions.~~

(b) Where a *general power system* ~~*frequency*~~ *risk review* identifies the need for a new or modified emergency ~~frequency~~ control scheme (alone or in combination with the declaration of a *protected event*) the report under this clause must:

(1) specify the areas of the *power system* to which the emergency ~~frequency~~ control scheme will apply and whether it is an *over frequency scheme*, *under frequency scheme*, or both; and

(2) include the anticipated time required to design, procure and commission the new or modified scheme.

(c) Where, as the result of a general power system ~~frequency~~ *risk review*, *AEMO* recommends seeking declaration or revocation of a *non-credible contingency event* as a *protected event*, the report under this clause must include the proposed timetable for submission of a request to the *Reliability Panel* under clause 5.20A.4 or clause 5.20A.5 (as applicable).

5.20A.4 Request for protected event declaration

(a) *AEMO* must develop and submit to the *Reliability Panel* a request for declaration of a *non-credible contingency event* as a *protected event* in accordance with the recommendations of a general *power system* ~~frequency~~ *risk review* and taking into account any guidelines issued by the *Reliability Panel* under clause 8.8.1(a)(2d) as to the timing and content of requests under this clause.

(b) A request under this clause must include:

(1) information explaining the nature and likelihood of the *non-credible contingency event* and the consequences for the *power system* if the event were to occur including *AEMO's* estimate of *unserved energy*;

(2) options for managing the *non-credible contingency event* as a *protected event*, *AEMO's* recommended option or range of options and the rationale for the recommendation;

(3) for each recommended option under subparagraph (2), *AEMO*'s estimate of the additional costs to operate the *power system* in accordance with the *power system* security principles in clause 4.2.6 if the event is declared to be a *protected event* including a description of the mechanisms that may be used;

(4) where a recommended option for managing the *non-credible contingency event* includes a new or modified *emergency frequency control scheme*:

(i) the *target capabilities* proposed to be included in the *protected event EFCS standard* for the scheme, the rationale for the proposed *target capabilities* and the corresponding expected *power system security* outcomes including *AEMO's* estimate of *unserved energy* associated with operation of the scheme; and

(ii) *AEMO's* estimate of the costs to procure and commission the scheme and maintain its availability and performance, including upfront costs and ongoing maintenance costs;

(5) *AEMO's* proposals for other matters that may be determined by the *Reliability Panel* under clause 8.8.4 in connection with the request; and

(6) other information *AEMO* considers reasonably necessary to assist the *Reliability Panel* to consider the request.

5.20A.5 Request to revoke a protected event declaration

(a) If *AEMO* recommends in a general *power system* ~~frequency~~ *risk review* that a *non- credible contingency event* should no longer be managed as a *protected event*, *AEMO* must submit to the *Reliability Panel* a request to revoke the declaration of a *non-credible contingency event* as a *protected event* in accordance with the recommendations of the *general power system ~~frequency~~ risk review*.

(b) A request under this clause must include:

(1) information explaining the nature of the *non-credible contingency event* and the consequences for the *power system* if the event were to cease to be managed as a *protected event*; and

(2) other information *AEMO* considers reasonably necessary to assist the *Reliability Panel* to consider the request.

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S5.1.10.1a Emergency ~~frequency~~ control schemes

(a) In this clause S5.1.10.1a, **emergency control scheme** includes an *emergency frequency control scheme.*

(a1) A *Network Service Provider* must:

(1) cooperate with *AEMO* in the conduct of *general power system ~~frequency~~ risk reviews* and provide to *AEMO* all information and assistance reasonably requested by *AEMO* in connection with *general power system ~~frequency~~ risk reviews*; and

(2) provide to *AEMO* all information and assistance reasonably requested by *AEMO* for the development and review of *EFCS settings schedules*.

(b) Where a *protected event EFCS standard* has been determined for an emergency ~~frequency~~ control scheme applicable in respect of a *Network Service Provider's transmission* or *distribution system*, the *Network Service Provider* must:

(1) design, procure, commission, maintain, monitor, test, modify and report to *AEMO* in respect of, the emergency ~~frequency~~ control scheme;

(2) perform its obligations under subparagraph (1) so as to achieve the availability and operation of the scheme in accordance with the *protected event EFCS standard;* and

(3) coordinate with *AEMO* in relation to the monitoring and testing of the scheme once it is in operation.

(c) A *Network Service Provider* must use reasonable endeavours to achieve commissioning of a new or upgraded emergency ~~frequency~~ control scheme within the time contemplated by the relevant *general power system ~~frequency~~ risk review* or, where applicable, *AEMO's* request to the *Reliability Panel* for declaration of a *non-credible contingency event* as a *protected event* and the decision of the *Reliability Panel* with respect to that request.

(d) For an *over frequency scheme*:

(1) a *Network Service Provider* must identify which elements of the scheme (if any) can be implemented by *facilities* provided by a *Generator* for

the *Generator's generating unit* or by modification to the *facilities* of the *Generator* or by changes to the settings of *protection systems* or *control systems* for the *Generator's generating units*.

(2) Where those opportunities are identified, the *Network Service Provider* must notify the *Generator* concerned of the opportunity and must request the *Generator* to negotiate with the *Network Service Provider* to reach agreement on the modifications to be made and the other arrangements required by the *Network Service Provider* to comply with its obligations with respect to the scheme (including commissioning, testing, monitoring and future modification).

(3) If the *Generator* declines the request, or if the *Generator* agrees to the request but good faith negotiations do not result in agreement being reached in a reasonable time (having regard to the implementation timetable for the scheme), the *Network Service Provider* may make other arrangements to implement the relevant elements of the scheme.

(4) If the *Generator* accepts the request, the *Generator* and the *Network Service Provider* must each negotiate in good faith with respect to the matters referred to above.

(e) Nothing in paragraph (d) is intended to prevent the exercise of rights under a *connection agreement*.

(f) Nothing in paragraph (d) is intended to constitute or require an *application to connect* for the purposes of rule 5.3 or rule 5.3A. If clause 5.3.9 applies in respect of alterations for an *over frequency scheme* the subject of negotiations under paragraph (d), the *Network Service Provider* cannot charge a fee under clause 5.3.9(e) for assessment of a submission in respect of those alterations.

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Schedule 5.8 Distribution Annual Planning Report

Note

The local definitions in clause 5.10.2 apply to this schedule.

For the purposes of clause 5.13.2(c), the following information must be included in a *Distribution Annual Planning Report*:

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(n) a regional development plan consisting of a map of the *Distribution Network Service Provider's network* as a whole, or maps by regions, in accordance with the *Distribution Network Service Provider's* planning methodology or as required under any *regulatory obligation or requirement*, identifying:

(1) sub-transmission lines, zone substations and transmission-distribution connection points; and

(2) any system limitations that have been forecast to occur in the forward planning period, including, where they have been identified, overloaded primary distribution feeders; and~~.~~

(o) information on any special protection schemes and associated settings identified under clause 5.13.1(d)(6) , including at least:

(1) an analysis and explanation of whether such associated settings are fit for purpose for the future operation of its *network*;

(2) a description of any interactions between the special protection schemes and such associated settings; and

(3) a description of any proposed actions to be undertaken to address those interactions.

B SUGGESTED RULE CHANGE REQUEST - ENHANCING OPERATIONAL RESILIENCE

This suggested rule change request is presented for stakeholders information. It proposes changes to the NER to implement the protected operation framework recommended in Chapter 8 of this report.

B.1 Nature and scope of the issue being addressed

The proposed rule seeks to enhance power system resilience by introducing protected operation for the management of risks and uncertainty from indistinct events associated with abnormal conditions. The proposed rule would also clarify that standing risks and uncertainty from indistinct events can also be declared as protected events.

The power system has always faced risk from a range of sources. Existing frameworks codified the types of events risks, and uncertainties that existed in the power system at the time they were developed. In particular, the NER defined the term 'contingency event' to capture the set of events that represented material risk to power system security at that time.

Contingency events involve distinct risks from the sudden unexpected loss of a specific generating system or network element. The distinct nature of these events, and their association with specific power system assets, means that the effect on the power system of a finite number of specific events needed to be modelled to understand the range of possible outcomes to be protected against.

Existing frameworks are built around the concept of a contingency event. Risks to system security from events that do not qualify as contingency events are therefore difficult to manage under existing arrangements.

The risk to power system security from 'indistinct events' are increasing as the NEM's generation mix transitions. The AEMC South Australian black system review further identified a need to amend existing frameworks to allow for management of 'indistinct events' which are not associated with the failure or removal from service of a single discrete power system element.

Indistinct events and a changing power system risk and resilience profile

The NEM's generation mix has changed markedly in recent years, with the reduced operation, mothballing or retirement of a large number of synchronous thermal generating units, coupled with the rapid deployment of inverter connected / asynchronous renewable generation resources, at both transmission and distribution levels. This changing generation mix is changing the power system risk and resilience profile which includes increasing levels of:

- *generation and load risk and uncertainty* - The changing generation mix is changing both the events and types of uncertainty regarding generation output. Unlike the failure of thermal generators, unexpected variation from variable generation is often not related to internal failure of the unit, but rather involve weather conditions, such as changes in sunlight intensity or wind speeds. These changes are generally distributed, and can affect a significant number of units and systems in a surrounding area. This means that system security risks may arise from an external event, such as a storm front passing across a region, and require the aggregate impact across all the generating units in the affected area to be considered, rather than the loss of a specific unit.

- *system response risk and uncertainty* - In addition to new types of generation and load uncertainty, the response of the power system itself to disturbances is also becoming more uncertain. This increase in uncertainty is due to factors including reduction in the level of inertia and fault level as synchronous units have retired, as well as a more complex demand side, due to an increased prevalence of DER. Other factors, such as increasing prevalence of network protection schemes, also increase the complexity and therefore the uncertainty, of power system response to a disturbance.

Indistinct events are becoming more significant given this changing power system risk and resilience profile. Indistinct risks are associated with distributed events, such as weather conditions, which act on multiple generation and network assets in an affected area, over time. An indistinct event is one where the system security risk does not arise from a single specific asset, or the specific asset(s) involved are not reasonably identifiable ex-ante. Therefore, unlike distinct contingency events, indistinct events cannot be characterised in terms of a contingency event involving the failure or removal from a service of one or more easily identifiable power system elements. Existing frameworks for managing risks to the power system from contingency events are therefore unsuited to managing these new sources of risk. This rule change request seeks to extend existing arrangements to manage indistinct risks under abnormal conditions.

Enhancing power system resilience given a changing power system risk and resilience profile

The majority of the disturbances that affect the operation of a power system can and are classed as credible contingencies. These are disturbances that occur reasonably frequently, with small to moderate impacts, which can easily be modelled. The NER requires AEMO to operate the power system in a secure operating state, without load shedding, for the occurrence of any credible contingency event.

AEMO is not required to maintain the power system in a secure state to non-credible events. The power system's ability to avoid and survive a cascading failure and potential black system event is related to the resilience of power system security. Resilience is a concept which speaks to the ability of a power system to avoid, survive, recover and learn, from non-credible events in the context of measures that make the system stronger, smarter, and more interconnected.

While AEMO is not required to maintain the power system in a secure state for non-credible events, existing NER arrangements provide mechanisms for managing the risks of certain non-credible contingency events. Given the presence of heightened risks due to abnormal conditions, reclassification allows AEMO to, in accordance with criteria it has developed, re-classify certain non-credible contingency events as credible, and maintain the system in a secure state without load shedding should they occur. The existing protected events framework also provides AEMO with a mechanism to maintain the power system in a resilient state to non-credible events where it is efficient to take action to avoid a cascading failure.

Both of these frameworks however are limited to managing distinct contingency events and are not well suited to addressing risks arising from indistinct events.

The AEMC's review of the South Australian black system event identified a need to extend existing frameworks to maintain power system in a resilience state to indistinct events, the probability of which increases due to abnormal conditions. This rule change request seeks to implement the recommendations put forward by the review in this area. In particular, the rule change request proposes:

- clarifying the applicability of protected events for the management of indistinct events, and
- introducing protected operation as a new tool for AEMO to use for managing condition dependent indistinct risks under abnormal conditions.

B.2 Description of the rule proposed to be made

This purpose of this rule change request is to seek amendments to the NER to provide AEMO with mechanisms to enhance power system resilience to indistinct events under abnormal conditions.

The main changes proposed are:

- Introduction of the new definition of an indistinct event
- Clarify that standing risks from indistinct events can be managed as a type of protected event and to enhance the protected event approval process
- Implement a new operational tool, protected operation, for AEMO to manage indistinct events, the risk of which are strongly linked to abnormal conditions. Two types of protected operation are proposed:
  - pre-defined protected operation, and
  - ad-hoc protected operation.
- Specify governance arrangements for protected operation

Indistinct event definition

The proposed rule implements an operational mechanism for AEMO to enhance power system resilience to indistinct events. A new NER definition of an indistinct event would be required to implement the mechanism described in this rule change request.

An indistinct event may be defined as an event affecting the power system which:

- occurs over a period of time, rather than being sudden or instantaneous;
- can be widespread or otherwise affect more than one single power system element; and
- involves the non-credible failure or removal from operational service of multiple generation units and/or transmission elements that are not reasonably identifiable.

Standing risks arising from indistinct events can be managed as a protected event

This rule change is to retain existing arrangements for protected events with the following changes:

- protected events are to apply only to the management of 'standing' events, the occurrence of which are not a strong function of conditions. Risks from indistinct events that are a function of abnormal conditions would be managed through protected operation
- clarify that indistinct events can be declared to be protected events, and
- introduce an expedited approval process for declaring protected events that are not controversial or are otherwise straight forward.

The rule change request proposes an expedited Reliability Panel process to be specified for the approval of distinct and indistinct protected events that are relatively straight forward and not considered controversial. For such applications the Panel would issue a consultation paper and consult for a minimum of 10 business days. If no objections are raised, the Panel would then publish a single final report setting out its decision.

This rule change request does not propose changes to governance arrangements for protected events other than the introduction of an expedited process just described. The Reliability Panel, on the advice of AEMO, would remain the party to determine which non-credible contingency events and indistinct events are to be protected events and approve the management actions proposed by AEMO on the basis of an assessment of costs and benefits.

Implement protected operation as a means for AEMO to manage risks from indistinct risks given abnormal conditions

This rule change request proposes the implementation of the protected operation framework, as a means for AEMO to manage risks from condition dependent indistinct events. Specifically, protected operation will manage risks arising from indistinct events, the risk of which increases under abnormal conditions. Two types of protected operation are proposed:

- pre-defined protected operation, and
- ad-hoc protected operation

Pre-defined protected operation

This rule change request proposes to allow AEMO to declare a period of protected operation to manage risks from specific indistinct events in accordance with criteria and actions pre-defined for management of risks from these specific indistinct events. Pre-defined protected operation would involve AEMO:

- Pre-identifying, through the GPSR, an indistinct event the risk of which increases during abnormal conditions
- for the identified indistinct event, AEMO specifying and publishing:
    - criteria setting out the specific abnormal conditions which would see it enter into a period of protected operation in response to the event,
    - its approach to assessing the level of risk arising from the indistinct event, and

- the actions it would take to prevent a cascading failure, or maintain the system in a secure state (following consideration of the costs and benefits), given the occurrence of the abnormal conditions.

The NER would set out requirements for the criteria specified and published by AEMO.

The proposed rule would allow AEMO to take actions to manage risks arising from pre-identified indistinct events. These actions are those which represent the lowest overall cost approach to managing the identified risk.

In determining what actions should be taken, the proposed rule is for AEMO to follow a cost minimisation principle, which will be defined in the NER.

The cost minimisation principle should not conflict or impede AEMO's obligation to meet its power system security responsibilities. This rule change request should read to be clear that this is the case.

In particular, in terms of the actions taken during a period of protected operation, AEMO must, at a minimum, take actions to minimise the risk of a cascading failure. However, AEMO may also elect to take actions above this, to maintain the power system in a secure state, without load shedding.

To support transparency AEMO must assess, consult on, and publish details of the cost and benefit assessment used to determine the efficiency of the proposed set of management actions. It should also publish the criteria for entering a protected operation period and the range of actions that will be taken by AEMO during a protected operation period.

Ad-hoc protected operation

The rule change proposes an "ad-hoc" version of protected operation, which would allow AEMO to declare a period of ad-hoc protected operation where a risk has arisen from an indistinct event that was not been pre-identified or had management actions pre-defined.

Ad-hoc actions would apply to indistinct risks that are unanticipated, or when AEMO has identified a new and severe risk from an indistinct event but there has been insufficient time to complete the process for a conditional protected operation.

Ad-hoc protected operation is intended to be an emergency measure. On each occasion AEMO declares a period of ad-hoc operation, AEMO would need to report publicly, and to the Panel, as soon as practicable following the occasion. The rule change proposes to specify minimum requirements for AEMO's report, including details of:

- the nature of the abnormal conditions and why these conditions increased risk from an indistinct event sufficiently to justify the use of an ad-hoc protected operation
- the measures that AEMO took to mitigate this risk
- the direct costs of declaring a period of ad-hoc protected operation
- any actions AEMO intends to take to account for this kind of event in the future.

The rule also requires AEMO to explicitly review the risks managed on each occasion it has used its ad-hoc power in the next GPSR. This would allow AEMO to incorporate experience from the use of its ad-hoc power.

Consultation and transparency measures - protected operation

Transparency and market information requirements involving the issuance of market notices are proposed to remain the same as under the existing protected event framework.

Enhanced consultation requirements are proposed for AEMO's use of protected operation. These consultation arrangements require AEMO to consult on:

- the nature of the abnormal conditions and why these conditions increased risk from an indistinct event sufficiently to justify any use of an ad-hoc protected operation
- how AEMO has/will assess the risk arising from the indistinct events, including any assumptions used
- the range of options for managing the risks considered by AEMO and the indicative costs of each
- the indicative benefits associated with the options considered by AEMO for managing the risk
- how the chosen option satisfies the principle of cost minimisation, and
- details of how AEMO will implement protected operation.

AEMO would be required to publicly consult in accordance with the rules consultation procedures.

In line with its current requirements applying to re-classification, AEMO is to report publicly, and to the Panel, on its use of the protected operation framework every six months.

Consultation and transparency measures - reclassification

These enhanced consultation arrangements would also apply to consultation on AEMO's development of criteria for reclassification. Currently, the NER do not set out a clear process for how AEMO should consult and publish information on its reclassification process.

Public consultation is important given the potential impacts on market operation and price outcomes associated with any additional constraints applied to protect against risks from either distinct or indistinct events.

Consultation in accordance with the rules consultation procedures would bring reclassification and protected operation in line with other AEMO system security procedures with significant effects of market outcomes such as the Market Ancillary Services Specification.

Provision for Reliability Panel guidelines and oversight

If the Reliability Panel considers it necessary or desirable, it may elect to determine guidelines for pre-defined and ad-hoc protected operation. The Reliability Panel may also act in a general oversight role by considering framework performance as part of its Annual Market Performance Review (AMPR).

Options for implementation

There are two broad approaches to implementing this proposed change in the NER being:

- Option A - to implement arrangements parallel to the existing contingency classification system, or
- Option B - to implement as a part of an extended contingency classification system

This example rule change request does not recommend a specific approach to implementing protected operation in the NER. Stakeholders are invited to consider the issues outlined in Chapter 8 when developing rule change requests.

B.3 How the proposed rule advances the National Electricity Objective

This rule change request seeks changes to the NER that will advance the National Electricity Objective, which is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.

The mechanisms for enhancing operational resilience proposed will promote the long term interests of consumers as they should efficiently, transparently, and accountably enhance the safety and security of the national electricity system.

Given the changing power system risk profile and the increasing risks arising from indistinct events, existing frameworks which are solely built around managing distinct contingency events are no longer sufficient to efficiently manage all risks to the power system, particularly under abnormal conditions.

The recommended mechanisms will promote the long term interests of consumers because:

- market design and regulatory arrangements are flexible enough to respond and evolve as circumstances change. The proposed rule does not specify the particular actions AEMO is to take or limit the risks arising from indistinct events to be managed. The proposed rule sets out a framework within which AEMO can manage the risks that will change over time. This flexibility is important given the rate at which the power system risk and resilience profile is changing
- responsibility for determining and implementing actions to manage identified risks are allocated on the basis of organisational skill and experience. The proposed protected operation framework places responsibility for assessing and implementing actions for the management of identified risks with AEMO as the party with the skills, experience, and information necessary to perform this role
- actions taken to manage risks associated with indistinct events are efficient. The recommended protected operation framework includes a proposed cost minimisation objective
- the recommended protected operation framework is transparent, with appropriate levels of organisational accountability. Efficient investment and operational decisions are supported by market participant confidence in AEMO's actions. The recommended protected operation framework provides for transparency, and accountability through the

requirements for AEMO to determine, consult on, and publish pre-defined criteria applying to its use of protected operation. Specifically, AEMO will be required to:

- consult according to the rules consultation procedures. This will provide transparency supporting market confidence in the actions AEMO is taking to manage identified risks. Market participants will also be able to contribute to AEMO's development of criteria thereby resulting in a more informed and robust overall solution than would have been the case in the absence of effective consultation
- publish protected operation criteria. This will provide reasonable levels of predictability on AEMO's actions to manage identified risks and will enhance the ability of market participants to make decisions to manage their own market and investment risk, and
- report each 6 months, and following each use of ad-hoc protected operation, which will provide accountability as to AEMO's actions. Additional accountability will be provided for through the Reliability Panel's making of guidelines (if required) applying to AEMO's use of protected operation.

In addition, it would promote the long term interests of consumers for AEMO to have operational flexibility to depart from its pre-defined criteria under emergency circumstances. Excessively rigid requirements that do not provide such flexibility for AEMO are unlikely to be in the long term interests of consumers given the high levels of uncertainty that apply to indistinct events. The protected operation framework provides AEMO with the authority to take ad-hoc actions subject to additional reporting and transparency requirements. Authority to take ad-hoc actions, combined with additional report and transparency obligations, balances AEMO's need for operational flexibility with transparency and confidence provided by AEMO following its pre-defined criteria.

B.4 Impact of the proposed rule on affected parties

Participants affected by the proposed rule, if made, include:

- AEMO
- Market participants

AEMO is directly affected by the proposed rule because of its role as described in this rule change request. AEMO would incur costs in terms of the administrative process of assessing and determining protected operations periods. However, these costs should be minimal and outweighed by the significant security and resilience benefits of implementing the protected operation framework.

Market participants would be affected by the proposed rule as AEMO would take a range of actions including maintaining the power system in a secure state where it is efficient to do so. AEMO may therefore adjust the technical envelope and constrain the power system during certain periods. Constraining the power system would change dispatch and market price outcomes impacting market efficiency.

However, the proposal for protected operation would be for the management of risks from indistinct events during abnormal conditions. Overall cost impacts would therefore be limited by the duration during which the additional constraints apply. Short term actions to constrain the power system to either avoid, or minimise the amount of load shedding from an indistinct event will therefore be limited in their overall market impact.

More generally, the proposed rule manages overall costs, through the requirement that AEMO's actions to manage risks arising from indistinct events be efficient and in line with a cost minimisation principle. Costs to market participants would therefore be included in the assessment conducted by AEMO to chose the lowest cost approach to managing the identified risk.

The transparency requirements imposed by the rule, including the requirement to issue market notices and for AEMO to consult on its proposed actions in accordance with the rules' consultation procedures are included to provide market participants with confidence in AEMO's exercise of its powers.

C SUGGESTED RULE CHANGE REQUEST - MARKET SUSPENSION

This suggested rule change request is presented for stakeholders information. It proposes changes to the NER to implement the changes to market suspension arrangements recommended in Chapter 10 of this report.

C.1 Nature and scope of the issue being addressed

Existing arrangements provide for AEMO to suspend the operation of the spot market in a region:[218]

When it suspends the market, AEMO must publish a notice of market suspension. The market remains suspended until such time as AEMO issues a notice that the suspension has been removed. When the market is suspended, the NER set out specific arrangements related to how spot prices will be set.[219] The NER also specifies a limited set of requirements specifically relating to market suspension. In particular:

- NER clause 3.14.4(e) explicitly allows AEMO to issue directions to Registered Participants in accordance with clause 4.8.9.
- NER clause 3.14.5(a) provides for AEMO to determine dispatch, spot and ancillary service prices under rules 3.8 and 3.9, to the extent practicable. If not practicable, then the market suspension pricing schedule applies.
- NER clauses 3.14.5(d)(2) and (3) then allows AEMO discretion to determine when it is practicable to resume central dispatch and the determination of prices under rules 3.8.and 3.9, (pending approval from the relevant jurisdiction in circumstances where the jurisdiction had directed AEMO to suspend the market).

Existing arrangements however do not explicitly set out the applicability of other provisions of the NER during a period of market suspension, and the extent to which AEMO must comply with these elements. Other than the provisions relating to market suspension pricing and provided for under clauses 3.14.4 and 3.14.5 (noted above), the NER are silent on the extent other NER provisions apply during a period of market suspension. The silence on the applicability of other elements of the NER during a period of market suspension has the potential to create uncertainty for market participants and AEMO, and compromise efforts by AEMO to co-ordinate with market participants to resolve the issues which have resulted in suspension of the market.

A period of market suspension may be accompanied by challenging or uncertain power system conditions. AEMO's power system operations staff may face unique challenges during this time. A rigid requirement for AEMO to comply with all elements of the NER, particularly those of a more administrative nature, may compromise its ability to focus on and prioritise actions needed to manage the security and safety of the power system during this period.

218 NER clause 3.14.3.

219 NER clause 3.14.4 and 3.14.5.

For AEMO to effectively resolve such issues, it needs to have appropriate levels of flexibility to prioritise. Failure to appropriately prioritise, given limited resources, during a period of market suspension may compromise the safety and security of the power system.

Current rule arrangements do not explicitly provide AEMO with flexibility to prioritise core system security requirements during a period of market suspension. This rule change request seeks to provide AEMO with such flexibility.

This rule change request proposes to amend the NER by:

1) clarifying the applicability of market rules during a period of market suspension thereby reducing uncertainty for AEMO and market participants

2) providing AEMO with flexibility to prioritise system security obligations if compliance with a rule provision (particularly an obligation of a more administrative nature) would place a material risk on their ability to maintain power system security during a period of spot market suspension, and

3) specifying transparency arrangements applying to any prioritisation of system security over other NER obligations by AEMO during a period of market suspension.

C.2 Description of the rule proposed to be made

This rule change request proposes to clarify the applicability of existing market rules and provide AEMO with appropriate flexibility to prioritise arrangements for system security during a period of market suspension.

When AEMO has declared the spot market to be suspended, it is proposed that:

- AEMO continues to comply with existing provisions of the NER that explicitly relate to periods of market suspension (such as pricing arrangements under clause 3.14.5); and
- for remaining provisions of the NER, AEMO has some flexibility where compliance with a particular rule would impose a material risk on its ability to maintain power system security during the market suspension.

It is also proposed that AEMO be required to inform the market of its decision to prioritise certain obligations during periods of market suspension. In doing so, it is proposed that AEMO report, as soon as practicable, those provisions of the rules with which compliance would impose a material risk on its ability to maintain power system security, the reasons why it considers that compliance would pose such a risk, and whether it proposes any alternative arrangements to apply.

To implement the above proposal, the rule change request seeks amendments to clause 3.14.4 of the NER that:

- clarifies which provisions of the NER continue to apply during periods of market suspension (such as pricing arrangements under clause 3.14.5);
- provides additional flexibility where it is impossible to comply with a rule obligation (particularly an administrative-type requirement) without materially risking AEMO's ability to maintain power system security; and

- imposes reporting requirements on AEMO to demonstrate to the market why it chose to priorities certain system security obligations.

C.3 How the proposed rule advances the National Electricity Objective

This rule change request would advance the National Electricity Objective, which is to:

promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to -

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety and security of the national electricity system.

The relevant aspects of the NEO in this case include promoting efficient operation and use of electricity services in the long term interests of consumers of electricity with respect to the safety and security of the national electricity system.

As previously noted, the NER allows AEMO to suspend the operation of the spot market in a region. AEMO may declare the spot market suspended if any of the following occur:

- a black system has occurred
- the relevant jurisdiction has directed AEMO to do so, or
- it determines it has become impossible to operate the spot market in accordance with the NER

In each of these cases, there is likely to be significant uncertainty as to the safety and security of the national electricity system. As noted, current arrangements do not include a transparent framework which provides AEMO and market participants with clarity on the applicability of market rules during a period of market suspension with clear flexibility to prioritise system security related matters.

Clarifying the applicability of rules arrangements during a period of market suspension, providing AEMO with flexibility to reasonably prioritise system security arrangements, and enhancing transparency as to AEMO's actions during a period of market suspension will enhance AEMO's ability to resolve the matters leading to the market suspension and therefore advance the NEO by enhancing the safety and security of the national electricity system. It will also help market participants and policy-makers make more efficient decisions during a period of market suspension since arrangements applying to all parties will be clearer.

It is possible that participants may face some uncertainty as to how AEMO may choose to use its power to prioritise compliance with power system security elements of the NER. However, this uncertainty is countered by the fact that the proposed rule retains the overarching requirement for AEMO to comply with the NER. Furthermore, AEMO must also follow transparency obligations when it decides to use these powers. This should help to limit the degree of uncertainty, by providing some transparency as to how AEMO will use its powers. Therefore the Commission considers the costs of uncertainty to be outweighed by the benefits of this additional flexibility.

More generally, by making AEMO's processes explicit for prioritising different elements of the NER, the proposed rule addresses the uncertainty identified by the AER in its assessment of the SA black system event - that is, the uncertainty as to the applicability of the various elements of the NER during a period of market suspension. All parties including AEMO, the AER and market participants, will benefit from clarity as to the applicability of market rules during a period of market suspension.

Enhanced transparency would assist the AER in its compliance activities, will enhance market participant confidence in AEMO's actions and assist co-ordination between AEMO and market participants.

C.4 Impact of the proposed rule on affected parties

The above proposal, if made, will affect AEMO, the AER, and market participants.

It is possible that participants may face some uncertainty as to how AEMO may choose to use its power to prioritise compliance with power system security elements of the NER. More specifically, participants may face some uncertainty as to AEMO's actions, if it elects to not comply with administrative elements of the NER, such as the issuance of market notices. This uncertainty may create some costs for market participants, and ultimately customers, if it results in less efficient operational decision-making.

However, this uncertainty is countered by the fact that the proposed rule retains the overarching requirement for AEMO to comply with the NER. Furthermore, AEMO must also follow transparency obligations when it decides to use these powers. This should help to limit the degree of uncertainty, by providing some transparency as to how AEMO will use its powers. Therefore the costs of uncertainty are outweighed by the benefits.

More generally, by making AEMO's processes explicit for prioritising different elements of the NER, the proposed rule addresses the uncertainty identified by the AER in its assessment of the SA black system event - that is, the uncertainty as to the applicability of the various elements of the NER during a period of market suspension. All parties including AEMO, the AER and market participants, will benefit from clarity as to the applicability of market rules during a period of market suspension.

Enhanced transparency would assist the AER in its compliance activities, will enhance market participant confidence in AEMO's actions and assist co-ordination between AEMO and market participants.

AEMO would also be provided with enhanced scope to transparently and efficiently prioritise system security considerations during a period of market suspension, where reasonable to do so. This would help to reduce the security risks associated with a period of market suspension, ultimately benefiting market participants and customers.

D DETAILS OF RELEVANT SYSTEM SECURITY EVENTS

This review is motivated by the circumstances arising prior to, during, and following the SA black system event on 28 September 2016. Since that time, the Commission is aware of two additional system security incidents which are relevant to considering systemic issues associated with a changing risk and resilience profile. This section discusses the:

- Queensland and South Australia system separation on 25 August 2018, and
- UK Low Frequency Demand Disconnection Event on 9th August 2019

D.1 Queensland and South Australia system separation on 25 August 2018

On Saturday 25 August 2018 at 13:11 PM, there were lightning strikes on the transmission towers that support the two circuits of 330 kV QLD-NSW interconnector (QNI), eventually leading to both circuits tripping due to faults and unexpected protection settings.

As a consequence, QLD islanded two seconds later (13:11:41 PM). As QNI was transferring 865 MW from QLD to NSW, QLD experienced an immediate generation surplus following the QNI trip which resulted in over-frequency condition in QLD while the remainder of the NEM underwent a supply deficit as well as under-frequency condition.

In response to this frequency drop, Basslink responded based on its FAS automatic setup, with 130 MW flow increase in the interconnector, which in turn caused a supply deficit in Tasmania and under-frequency load shedding (UFLS) of 80 MW.

The generating units in South Australia (including the Hornsdale battery system) also started increasing their output to help the system frequency, which led to a rapid rise in active power flowing through the Heywood interconnector and eventually its trip based on the Emergency APD Portland Tripping scheme, after around 8 seconds from the QNI trip.

At the time of separation, Heywood was transferring 430 MW from SA to VIC. This caused a frequency rise in SA and a further frequency drop in NSW and VIC, which led to activation of multiple UFLS schemes (around 1 GW in total, primarily smelters) in these two states. Droop response and AGC from synchronrous generating systems then restored the frequency in the mainland, followed by the restoration of loads and re-synchronisation of the separated states within around two hours.

The key facts that are relevant to understand from this event is that:

- Overall the NEM was not operating under low-inertia conditions, as 96 per cent of dispatched generation was synchronous;
- The RoCoF value in QLD following QNI trip was approximately 0.8 Hz/sec: this relatively high value is attributed to low inertia condition due to 23% of total generation being non-synchronous generators, mostly PV units;
- Wind output in the NEM was negligible, around 1.5%, and did not provide frequency response. In fact, a few wind farms disconnected in SA due to incorrect protection settings;

- Transmission-connected PV, about 3% across the NEM, contributed to lowering the frequency when QLD and SA were isolated, but the response were too slow to contribute to limit the frequency zenith in the two islanded states;
- The 6.3 GW distributed (behind the meter) PV were producing about 50% of their maximum output capability and responded to over-frequency events similarly to the transmission-connected PV. However, 15% of the PV panels installed before October 2016 got disconnected at all, and 15% in QLD and 30% in SA did not provide high frequency response as required by the standards;
- The Hornsdale battery system provided very fast low-frequency and high-frequency responses before and after Heywood's trip, respectively.

Some key observations that the Commission has taken from this event:

- There was no lower contingency or regulation FCAS scheduled in QLD, therefore the primary frequency control struggled after QNI trip, and the high-frequency response from PV effectively provided resilience to the system. However, response from a portion of the PV fleet in other jurisdictions did not accord with relevant Australian Standards.
- There was no raise FCAS enabled in Tasmania, hence any issue with high frequency (as it happened) could only be dealt with by UFLS, in principle;
- Even after separation of QLD and SA, the AGC signal was only based on the measurements in VIC-NSW, so wrongly sending raising signals to QLD and SA too. Similarly, it took two to three 5-minutes dispatch intervals before NEMDE stopped sending wrong export target signals for the (now open) interconnectors in QLD and SA;
- 50 per cent of raise contingency FCAS was allocated in QLD and SA, so it could not help the main system going under-frequency after separation of the two states.

D.2 9th August 2019 UK Low Frequency Demand Disconnection Event

On Friday 09 August at 4:52pm the Great Britain (GB) transmission system was operating as normal. Heavy rain and lightning were taking place throughout England and in particular in the area north to London, when a transmission circuit was hit by a lightning strike. The protection system tripped the circuit and cleared the fault in 0.1 s, and the line went back to normal operation after 20 s. In the meantime:

- Hornsea off-shore wind farm reduced its output almost instantaneously (two out of three of the wind farm modules disconnected from the grid, totalling some 750 MW out of the declared 800 MW output – for a nominal capacity of 1.2 GW), due to unusual voltage fluctuation coincident with the lightning;
- Little Balford gas power station (which is a Combined Cycle Gas Turbine - CCGT) reduced its output over about 90 s for about 400 MW – total plant loss of about 650 MW);
- About 500 MW of "nearby" embedded generation was lost almost instantaneously, due to transient voltage disturbances caused by the lightning (about 150 MW) and high ROCOF due to the above generation loss (some 500 MW) - National Grid claimed that some 500 MW loss was expected as "normal" for lightning strikes on a transmission line.

The total power loss from transmission generation was thus about 1.4 GW, plus the embedded 0.5 GW, for a total loss of nearly 1.8 GW. This loss represented approximately 5% of the total GB electricity load at the time of the event. The frequency response reserves (equivalent to Australian FCAS) were sized for 1 GW, according to the standards which we understand is based on the largest online generator (a nuclear power plant) minus load damping effect.

The available frequency response (including almost 500 MW of battery storage) operated relatively well and stopped the frequency at 49.1 Hz after about 15 s (650 MW of response was delivered within 10 s, while 900 MW were delivered in 20 s).

However, when the frequency was recovering at about 49.2 Hz and rising owing to the frequency response intervention, further loss of the first gas turbine unit made the frequency drop to 48.8 Hz, which is the first stage of the Low Frequency Demand Disconnection (LFDD) scheme, equivalent to Australia UFLS. At that point all frequency response was exhausted and there was no other option to stop the frequency drop and help the system recover. The further loss of the second turbine unit, after a few seconds, did not cause a significant impact and the frequency kept rising thanks to the joint operation of the available 1 GW frequency response, load relief, and 1 GW LFDD.

About 1.1 million customers, corresponding to 1 GW, or about 5% of the current demand connected to the distribution network, were in fact disconnected through LFDD. This included also some rails services, Birmingham airport and a few hospitals, which made the media headlines. Power was restored between 15 and 50 minutes after the event, with good coordination between National Grid and distribution networks.

The key facts that are relevant to understand from this event is that:

- The power losses from the wind farm and the CCGT plant were independent of each other but (apparently) both dependent on the lightning strike, given the dynamics of the event and the almost coincident loss of the two wind farm modules and the steam turbine module of the CCGT plant;
- Lightning strikes are usual: that day there were many (tens if not hundreds across the system), and normally they are managed without any issue;
- The transmission line protection system operated well;
- The Loss of Mains protection on embedded generation operated as expected under the lightning conditions and the relevant voltage dynamics on the transmission system, and National Grid was prepared for a 500 MW event;
- LFDD largely worked as expected;
- National Grid’s analysis indicates that the system overall operated according to the transmission system Security and Quality of Supply Standards (SQSS) operational criteria (the equivalent of the NER in Australia) – see also my further comments below.

Some key observations that the Commission has taken from this event:

- Everything worked as expected but the system response was unexpected with significant under frequency load shedding in response to a single credible lighting strike;

- The system response included the unexpected failure of two major generating units being the offshore wind plant and the CCGT plant would both be impacted by the specific lightning that was taking place.
- National Grid explicitly considered the amount of forecast embedded generation that could be lost due to such an event. National Grid considered 500 MW of potential DER loss was "appropriate" for a risk of a transmission fault in the area;
- The loss of DER was due on Vector Shift settings (about 150 MW, related to voltage phase angles created by a fault on transmission circuits) and then ROCOF (about 350 MW, given that "old" embedded generators still have 0.125 Hz/s settings, and the frequency went down by about 0.4 Hz during the first 3 s)
- National Grid treats the loss of embedded generation as independent of the largest distinct contingency and so the scheduled frequency response is sized to cover the larger of the two but not both events;
- The wind farm control settings have now been retuned to address sub-seconds voltage events as the one experienced and which triggered disconnection;
- It also seems that the 950 MW demand disconnections scheme also triggered substantial (almost 600 MW) embedded generation disconnection, so that the net demand disconnection was actually only 350 MW – this is further uncertainty that is introduced in the operational envelop which may call for additional reserves;
- Some further 200 MW of embedded generation tripped at the frequency threshold of 49 Hz, exacerbating the cascading before demand disconnection;
- National Grid do not explicitly describe the loss of embedded generation as contingency event, possibly because this loss is not relevant to the transmission system and therefore not formal part of the formal system security arrangements in the UK.
- National Grid describe the "extremely rare and unexpected" event as seen from National Grid is the loss of the transmission-connected plants, independent of each other but associated with the lightning strike, as these plants were not supposed to de-load or trip following lightning (while DER LoM trip was expected) – so basically a N-2 generation loss but conditional to a N-1 transmission circuit contingency which caused a cumulative power infeed loss larger than the credible loss of the largest generation plant

E THE IMPACT OF HIGH-IMPACT, LOW-PROBABILITY EVENTS ON THE COMPETITIVENESS OF HIGH ENERGY USERS

While the Commission considers the needs of all energy users, both large and small, in applying the national energy objectives, the terms of reference for this Review highlight the particular importance of the needs of high energy users.

This section outlines:

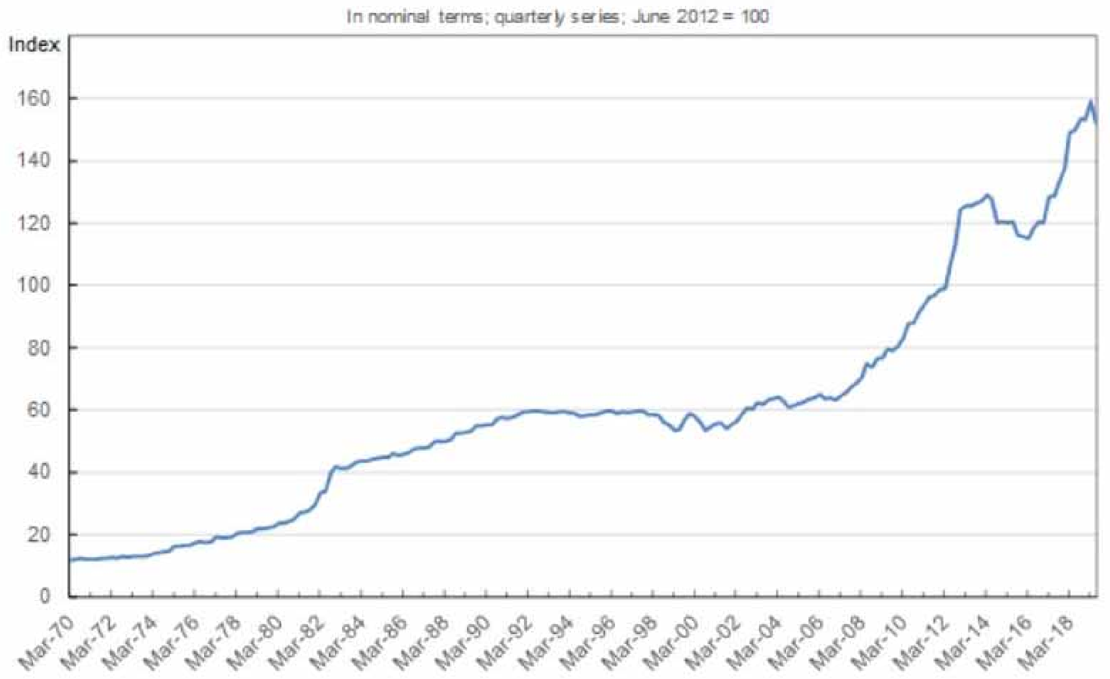
- the energy context for Australian high energy users
- The ways energy can contribute as a factor of production
- work programs currently underway and recently completed that supports the needs and competitiveness of high energy users in the NEM.

Background

The competitiveness of an industry or firm, especially energy intensive ones, is directly linked to their energy costs. All else equal, an increase in energy costs will lead to a reduction in the competitiveness of that firm or industry.

Energy-intensive industries include the manufacturing sector. In nominal terms, electricity prices paid by Australia's manufacturers have more than doubled over the past decade; in contrast, in the decade prior to 2009, manufacturers' electricity prices rose just 15 per cent (Figure 1.3). When combined with relatively high labour costs and, for some periods of time, a high exchange rate, these forces have steadily eroded the international competitiveness of energy-intensive industries in Australia.

Figure E.1: The price of electricity paid by Australian manufacturers



Source: Australian Bureau of Statistics, *Producer price indexes,* Cat No. 6427.0 (Table 14)

Electricity, as a main input to production for high energy users, impacts on their competitiveness in two key ways: (i) price, and (ii) reliability of supply. As noted above and shown in Figure 1.3, high electricity prices can erode competitiveness. So can a lack of reliable and secure power supply, especially for users that are not able to cost-effectively flex or vary their demand in response to changing system conditions. In the case of reliability, high energy users may find it costly to flex their demand during peak demand periods (which is typically when the overall supply-demand balance is tightest). Similarly, fluctuating voltage, frequency, and other system security parameters might damage equipment and increase operating costs.

While price and reliability and security of supply are crucial to all businesses, these may be most acute for high energy users as electricity is a larger proportion of their cost base (and even more acute for high energy users with relatively inflexible demand, such as smelters).

Work programs assisting the competitiveness of high energy users

The AEMC has a considerable work program underway aimed at enhancing power system security and reducing electricity prices, both of which can contribute towards the improved competitiveness of high energy users. This work program includes the following:[220]

220 The work program underpins the AEMC's five priority areas of reform (generator access and transmission pricing; power system security; integrating DER; digitalisation of energy supply; and aligning financial incentives with physical needs). More information is available here: https://www.aemc.gov.au/our-work/our-forward-looking-work-program

1. The Commission is currently working through a rule change request seeking to introduce a mechanism for wholesale demand response in the national electricity market. The mechanism introduced under the draft rule is designed to provide greater opportunities for consumers to participate in the wholesale market by bidding in demand reductions as a substitute for generation, thereby unlocking under-utilised demand response in the national electricity market (NEM). The mechanism will promote greater demand side transparency, as well as price and reliability related benefits. The Commission recently extended the time for making a final determination for this rule change request until 11 June 2020, with an expected 2nd draft determination to be released in March 2020. This follows supplementary information being recieved from AEMO.
2. The Commission has received rule change requests from the AER and AEMO in relation to improving system restart services. The proposed changes are aimed at preserving and improving the capability to restart a power system in transition. The NEM is moving rapidly away from the traditional synchronous generation and load centres that characterised the grid when the current SRAS framework was introduced. It has been observed that this shift has adverse consequences for the ability to restart the power system using existing SRAS-capable generation in the event of a major supply disruption (a black system), and subsequently to progressively restore supply.
3. The Coordination of Generation and Transmission Access (COGATI) is a body of work undertaken by the AEMC to address the NEM current significant transformation due to an unprecedented number of generators seeking to connect to the network. The transforming generation fleet and generation mix has implications for how generation interacts with transmission, with reform being required to better coordinate investment and operation in these two areas.
4. Stable frequency is an important part of maintaining a secure power system, which is being considered through the primary frequency response rule changes submitted by AEMO and Prof. Peter Sokolowski. Frequency varies whenever electricity supply does not exactly match consumer demand and uncontrolled changes in frequency can cause blackouts. As the generation mix changes to include more variable generation we need new ways to control frequency to deliver better frequency performance across the system.
5. The RRO is designed to support reliability in the National Electricity Market (NEM) by incentivising retailers and some large energy users to contract or invest in dispatchable and 'on demand' resources. The Australian Energy Market Operator (AEMO) will identify any potential reliability gaps in each NEM region in the coming five years using its Electricity Statement of Opportunities. This should provide investors certainty that there are sufficient frameworks in the electricity industry to ensure reliability is maintained long term.

F REVIEW TERMS OF REFERENCE

Included over page.

COAG Energy Council
Chair

Mr John Pierce
Chair
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

Dear Mr ~~Pierce~~ John

As you are aware, at its meeting of 7 October 2016, the Council of Australian Governments (COAG) Energy Council (the Council) agreed to direct the Australian Energy Market Commission (AEMC) to review the factors which contributed to the 'black system' event experienced in South Australia (SA) on 28 September 2016. I am writing to request the AEMC undertake this review as per the attached Terms of Reference (TOR).

The review should build on work being conducted by the Australian Energy Regulator (AER) and the Australian Energy Market Operator (AEMO), focused on the compliance of market participants with requirements in the National Electricity Law and National Electricity Rules and technical issues contributing to the event respectively. The AEMC should consult with AEMO, the AER, ElectraNet, SA Power Networks and the SA Government in conducting the review, along with other stakeholders as appropriate. The AEMC is requested to advise the Council on how it proposes to conduct the review by 1 February 2017, with the final report provided within six months of the completion of both AEMO's investigation report and the AER's compliance report on the 'black system' event.

If you require further information, please contact Mr James O'Toole, Assistant Secretary, Electricity Branch, Department of the Environment and Energy at james.o'toole@environment.gov.au or on (02) 6275 9023.

Yours Sincerely

The Hon Josh Frydenberg MP
Chair
COAG Energy Council
December 16

Secretariat
GPO Box 787
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TERMS OF REFERENCE

REVIEW OF THE SYSTEM BLACK EVENT IN SOUTH AUSTRALIA ON 28 SEPTEMBER 2016

1. BACKGROUND

South Australia experienced a 'system black' event at 16:18 AEST on Wednesday 28 September 2016. The event occurred during a period of extreme weather.

The Australian Energy Market Operator's (AEMO) updated preliminary report indicates that, immediately prior to the event, a mix of South Australian wind (883 MW) and gas generation (330MW) and imports from Victoria (613MW) were meeting 1895MW of electricity demand from South Australian consumers.

AEMO's updated preliminary report indicates that the sequence of events resulting in system black included the loss of three major transmission lines, generation reductions at a number of wind farms coinciding with a voltage drop at each generator's connection point, a resulting overload and trip of the Heywood interconnector with Victoria leading to the islanding of South Australia from the rest of the National Electricity Market (NEM). This resulted in a rapid reduction in power system frequency, which was greater than the design of the under frequency load shedding scheme, and greater than performance standards required of generation. Accordingly, frequency ultimately fell to zero and generation tripped off to avoid damage.

As required under clause 4.8.15 of the National Electricity Rules, AEMO is currently undertaking a detailed examination of the technical issues that contributed to the event, including a thorough examination of how each component of the electricity system responded. AEMO is also required to report on the suspension of the spot market under clause 3.14 of the Rules. AEMO published a preliminary report on 5 October 2016, an update to the preliminary report on 19 October 2016, and is expected to publish further reports as more information and data is provided.

In addition, the Australian Energy Regulator (AER) is given powers under Section 15 of the National Electricity Law to investigate compliance with the Law and the Rules by market participants and AEMO.

The potential for system black events, such as that experienced by South Australia on 28 September 2016, has led to the initiation of several work streams focused on identifying, and developing solutions to address, vulnerabilities in the grid architecture and operational processes as an increasing proportion of renewable generation is integrated into the NEM.

The Australian Energy Market Commission (AEMC) is conducting the System Security Market Frameworks Review, in cooperation with AEMO. As part of this work the AEMC is considering a number of rule change requests focused on the procurement of and standards for ancillary services which can support power system security. The AEMO's Future Power System Security (FPSS) programme is examining operational challenges arising from the changing generation mix, and technical options to address these challenges. While these work streams are operating to separate timelines, they are interdependent and are expected to collectively inform advice to Ministers on potential system-wide reforms.

2. PURPOSE

The purpose of this review is to build on the work currently being conducted by the AEMC and AEMO through identification of any systemic issues that contributed to the system black event in South Australia, or affected the response, and provide a report to Ministers on:

- Any recommended actions or amendments to the regulatory frameworks, whether the NEL, NER or other jurisdictional instruments, that should be taken to address these broader systemic issues; and/or
- How the recommendations will be addressed in the AEMC's ongoing work programme, to the extent that there are suggested changes to the NER.

The Council of Australian Governments (COAG) Energy Council requests this report under section 6 of the *Australian Energy Market Commission Establishment Act (SA) 2004*.

3. SCOPE

In carrying out this review, the AEMC must have regard to the National Electricity Objective, in particular to have regulatory frameworks that support investment in and operation of infrastructure that provides for the long term interests of consumers.

The AEMC will need to consider the incident report prepared by AEMO under the rules noted above and any compliance reporting on these events by the AER.

In particular the AEMC should take into account any reporting by the AEMO and the AER on:

- the causes of the system black event, including the role of the transmission sector and the role of the generation sector in contributing to the event or the response;
- why a state-wide system black event occurred, rather than being contained within limited parts of the network;
- any conclusions as to whether the power system security frameworks and procedures specified in the National Electricity Rules operated effectively leading up to, during and following the event, in particular, the effectiveness of power system restart processes following the event; and
- any implications of vulnerabilities identified with respect to the South Australian electricity system for the stability and security of the grid as a whole.

The AEMC should take into account any other reports prepared and published concerning the SA events including the findings to date of any of its own current studies that may be relevant. The work of the review should be complementary to, and inform where appropriate, the broader Independent Review into the Reliability and Stability of the National Electricity Market underway.

In the light of any issues identified through the reports or otherwise, the AEMC must consider and report on:

- the needs of high energy users to maintain secure and reliable energy supplies so that they maintain international competitiveness, and how these needs may be met;
- the nature of the economic costs of disruption to the power system, similar to the system black event that occurred in South Australia on 28 September 2016;
- the effectiveness of the power system security framework established under the National Electricity Rules, and other relevant regulatory frameworks to manage high impact, non-credible events;
- any improvements in existing processes, tools available to the system operator or to components of the electricity system in South Australia (for example, the availability of additional ancillary/system balancing services, additional interconnection with eastern states) that would assist in preventing a recurrence of the events experienced; and
- whether additional synchronous generation (or any viable alternative technology with equivalent functionality) in the South Australian region would have helped in preventing the black system event on 28 September 2016 in SA.

4. CONSULTATION

In conducting the review, the AEMC must consult with AEMO, ElectraNet, SA Power Networks, the AER and the South Australian Government. The AEMC may consult with other stakeholders, including consumers and high energy users, as necessary to complete the review.

The AEMC will provide its report to the COAG Energy Council six months after the conclusion of both AEMO's investigation report and the AER's compliance report. The AEMC will provide to the COAG Energy Council an approach setting out how it proposes to carry out its work and including the provision of updates and status reports.