RULE CHANGE REQUEST TO IMPLEMENT A GENERAL POWER SYSTEM RISK REVIEW

A. Name and address of rule change proponent

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This rule change request proposes changes to the National Electricity Rules (NER) to implement a generation power system risk review (GPSR) recommended in Chapter 7 of the AEMC's 'Mechanisms to Enhance Resilience in the Power System – Review of the South Australian Black System Event' report. Indicative legal drafting is provided following this rule change request.

B. 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.

<u>Scope of and requirements for the GPSR</u>

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.

C. 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.[1] 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 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

[1] AEMC, Emergency frequency control schemes, rule determination, 30 March 2017 p. ii

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.

D. 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.

E. 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

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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.

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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 accordancewith 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

5.20 A.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.

5.20 A.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.

5.20 A.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).

5.20 A.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.

5.20 A.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.