2025 Policy statement amendment

Decision paper

13 March 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (Authority) is committed to promoting the future security and resilience of New Zealand's power system for consumers. The system operator plays a critical role in this by meeting its obligations under the Electricity Industry Participation Code 2010 (Code).

The 'policy statement' is a document incorporated by reference into the Code that describes how the system operator will meet some of its core Code obligations.

The system operator consulted with industry on an amendment to the policy statement as part of its two-yearly review requirements. It proposed some relatively uncontroversial changes and received one submission, from Meridian Energy. After considering this submission, the system operator proposed the amendment to the Authority unchanged.

The Authority has decided to implement the following changes proposed by the system operator:

- adding detail on how it would manage certain events it calls 'stability events'
- providing additional detail and clarity around how it would manage demand if required in short duration grid emergencies (eg, if there is insufficient generation to meet demand during a winter evening peak demand period due to a series of generating unit failures coinciding with poor weather conditions for wind generation)[1]
- providing a more equitable allocation of demand reductions between grid connected parties (large industrial consumers and distribution lines companies) if demand management is required in short duration grid emergencies.

We decided to implement these changes because they:

- help ensure smooth management of system events as participants are better prepared to respond in a timely manner, minimising any disruption to consumers electricity supply
- help ensure electricity supply is maintained to those consumers most in need during a grid emergency.

Next steps

The amended policy statement will come into force on 14 March 2025.

1 The system operator's emergency management plan and rolling outage plan documents provide details of how demand will be managed in extended grid emergencies such as energy shortages due to running out of water in major storage lakes for hydroelectric power stations.

Contents

1. Purpose

1.1. This paper sets out the Electricity Authority Te Mana Hiko (Authority) decision to implement the system operator's proposed amendment to the policy statement, a document incorporated by reference into the Electricity Industry Participation Code 2010 (Code).

2. Background

The system operator proposes changes to the policy statement

2.1. The policy statement primarily sets out the policies the system operator will use to meet its Code obligations for maintaining a stable and resilient power system.[2]

2.2. The system operator must comply with the policy statement in normal circumstances.[3]

2.3. The Code sets out the requirements and responsibilities for making changes to the policy statement.[4] This includes the following requirements on the system operator:

(a) The system operator is responsible for preparing and consulting on amendments to the policy statement.

(b) The system operator must review the policy statement at least once every two years. This helps ensure the system operator's policies continue to improve and adapt to an evolving power system.

(c) Following consultation, the system operator is required to finalise its proposal for the Authority's consideration.

(d) The system operator must provide a summary of submissions and its responses alongside its proposal.

The Authority implements any changes to the policy statement

2.4. Under the Code, after receiving the system operator's final proposal, the Authority may:

(a) approve the proposed amendments

(b) require further consultation before resubmitting the proposed amendments for approval

(c) decline to approve the proposed amendments.[5]

2.5. The Code does not explicitly set out any matters the Authority must consider in deciding whether to approve a proposal. The Authority is therefore guided by its

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2 Clause 8.11 of the Code sets out what the policy statement must contain. The policy statement is available on the Authority's website

3 Clause 8.8 of the Code requires the system operator to comply with the policy statement subject to clause 8.14. Under clause 8.14, the system operator may depart from the policy statement when a system security situation arises and such departure is required for the system operator to comply with the reasonable and prudent system operator standard specified in clause 7.1A(1).

4 Clauses 7.13 to 7.20 of the Code set out the processes by which a proposal to amend the policy statement may be initiated and consulted on.

5 Subclause 7.21(2) of the Code.

main statutory objective, which is "*to promote competition in, reliable supply by, and the efficient operation of the electricity industry for the long-term benefit of consumers.*"[6]

2.6. Under Section 131B of the Electricity Industry Act 2010 (Act), to give legal effect to an amendment to the Policy Statement proposed by the system operator:

(a) the amended Policy Statement must be of the same general character as the original

(b) the Authority must issue a notice to adopt the amendment as having legal effect as part of the Code.

3. The system operator reviewed the Policy Statement

The system operator consulted on several changes to the policy statement

3.1. In October 2024, the system operator conducted its regular review of the policy statement. This included public consultation on the proposed changes.

3.2. The system operator proposed three substantive changes to the policy statement:

(a) **Stability events**: outlining the nature and management of events affecting 'system stability' and committing to periodic review of mitigation measures based on the risk these events pose to the power system.

(b) **Demand management**: clarifying which circumstances the system operator will *request,* and which it will *instruct,* demand management in grid emergencies.

(c) **Demand allocation**: removing a process to use historical demand as the basis for allocating demand reductions across connected parties in emergency situations, allowing for a more equitable allocation where historical demand does not reflect current conditions.

3.3. The system operator also proposed several wording and typographical improvements to the policy statement.

3.4. Further information on these changes can be found in the system operator's consultation paper in Appendix A. Clean and track change versions of the amended Policy statement are provided at Appendices B and C, respectively.

Future enhancements to the security policy

3.5. In the consultation paper, the system operator also sought views on whether elements of their processes relating to 'low residual situations' should be included in the policy statement. Low residual situations occur when the system operator forecasts that there will be less than 200MW of generation capacity remaining after meeting demand at some point within the next 36 hours.[7]

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6 The Authority also has an additional objective to *"protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers"*, but this applies only to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers

7 Further information on low residual situations can be found in the Authority's [Potential solution for peak capacity issues] decision paper.

3.6. The system operator considers that *“it will be helpful for information about the system operator’s approach, triggers and process for managing Low Residual Situations to be more transparently available to participants, with an option being to include appropriate provisions in the Policy Statement.”*

3.7. These views were sought to inform a future review and consultation on the approach to managing low residual situations. This review is intended to be completed before winter 2025, and a potential outcome is for further changes to the policy statement in 2025.

Submissions and response

3.8. On 30 October 2024, the system operator provided a summary of submissions and its responses alongside its final proposal to the Authority.

3.9. The system operator received one submission, from Meridian Energy (Meridian).[8] In its submission, Meridian:

(a) supported “*the system operator’s intent of providing greater definition of its process around demand management*”

(b) recommended the system operator consider *“the intended linkages between the Code and Policy Statement and whether the terminology adopted in the Policy Statement gives appropriate effect to any cross-references intended.”* The system operator has stated that it considered this and *“is confident the terminology in the Policy Statement appropriately supports the emergency management and scarcity pricing provisions in the Code*”. The Authority agrees with the system operator’s view.

(c) supported the inclusion of low residual situation processes as part of a future review of the policy statement, and provided feedback on what parts of the process they considered would benefit from increased transparency.

3.10. The system operator stated it did not change its proposal following consultation.

4. The Authority has decided to amend the policy statement

The proposed amendment meets the Authority’s main statutory objective

4.1. The Authority has decided to approve the system operator’s proposed changes to the policy statement as it promotes both the reliability and efficiency limbs of the Authority’s main statutory objective.

4.2. The reliable supply of electricity to consumers is promoted by providing additional detail and clarity about the management of demand and system stability. This helps ensure smooth management of system events as participants are better prepared to respond in a timely manner, minimising any disruption to consumers electricity supply.

4.3. The efficient operation of the electricity industry is promoted by providing a more equitable allocation of demand reductions in a grid emergency.

8 Meridian’s full submission is on Transpower’s website.

4.4. A more equitable allocation of demand reductions between grid connected parties helps ensure electricity supply is maintained to those consumers who need it most. This is because grid connected parties like distribution lines companies will, where possible, prioritise the disconnection of less valuable loads when asked by the system operator to reduce demand. By contrast, if a connected party received a disproportionate share of the demand reduction allocation, they would more likely need to disconnect high value loads.

4.5. The Authority's additional objective with regards to consumers is not engaged, as the changes do not relate to dealings between participants and domestic and small business consumers. Although we are making improvements to demand management, these relate to the system operator's interactions with large industrial consumers and distribution lines companies only.

4.6. The Authority is also satisfied that the proposal has had adequate consultation, and that further consultation is not required.

Incorporation by reference

4.7. The amended policy statement has the same general character as the original material, and therefore meets the requirements of section 131B(2)(a) of the Act, enabling the Authority to give legal effect to the amendments as part of the Code.

4.8. The Authority has issued a notice under section 131B(2)(b) of the Act stating that the amended policy statement is given legal effect as part of the Code. The notice will be published in the Gazette.

5. Next steps

5.1. The amended policy statement will come into force on 14 March 2025.

6. Attachments

6.1. The following appendices are attached to this paper:

Appendix A: System operator's consultation paper

Appendix B: Track change version of amended policy statement

Appendix C: Clean version of amended policy statement

Appendix A System operator's consultation paper

2024 Policy Statement review

Consultation Information

October 2024

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Purpose - Invitation to comment

1. In its role as System Operator, Transpower has completed its regular review of the Policy Statement, required under clause 7.15(1) of the Electricity Industry Participation Code (**Code**). We invite comments on the proposed changes from interested parties.

2. The proposed changes arising from this review primarily concern aspects of the security policy. We propose to update the security policy (Chapter 1 of the Policy Statement) to more transparently reflect existing operational processes, particularly around management of credible events that threaten system stability, and practices for demand management. Further detail on the rationale for each change and their anticipated costs and benefits is presented in this paper. We have also taken the opportunity to make minor typographical updates. All amendments are detailed in Appendix 1.

3. In the course of the review we identified further areas of the security policy that could be improved by addition of detail about the process we follow to identify and mitigate low residual capacity situations near real time. We have not proposed any specific changes at this time. However, we are interested to hear participant's perspectives on how the security policy as a whole can be amended to improve understanding of and confidence in these processes. This information would usefully inform a review and consultation on our processes, parameters and communications for mitigating potential capacity shortfalls, that is planned for completion before winter 2025.

4. Interested parties may submit their responses to this consultation to the System Operator email (system.operator@transpower.co.nz) with the subject line "Policy Statement 2024". Submissions will be accepted until 5:00pm 23 October 2024. We will acknowledge receipt of all submissions. Submissions will be published to our website at Policy statement | Transpower.

5. If your submission contains confidential information, please provide a clearly labelled confidential version and a public version. Confidential information should be clearly identified. The responsibility for ensuring that confidential information is not included in a public version of the submission rests entirely with the party making the submission. Please note that all information provided to Transpower is subject to potential disclosure under the Official Information Act 1982.

Changes to Security Policy

6. We are proposing three substantive changes to the security policy (Chapter 1 in the Policy Statement):
   - **Stability events**: stability events will be reinstated as a class of credible event that may result in cascade failure of the power system, which we propose to classify as contingent events (defined at paragraph 12 in the Policy Statement)
   - **Demand management**: clarification of our operational practices around demand management, particularly with regards to requesting and instructing.
   - **Demand allocation**: removing detail around how demand management is allocated when reallocation is required.

Stability Events

7. We propose to include **stability events** as a new event class within the risk management policies in the security policy.

8. We define **stability event** as:

   *an event that prevents the power system from retaining **system stability** or prevents specific generation from maintaining stable operation within the power system.*

9. We define **system stability** as:

   the normal operating conditions expected to exist in the power system, where perturbations are being maintained within the expected range(s), in such a way that the power system dynamic behaviour is not resulting in any restriction on the normal operation of any generating unit, load or other connected equipment. This includes but is not limited to:
   - *voltage stability (ability to maintain steady state voltages at all buses in the system after being subjected to a disturbance):*
   - *rotor angular stability (ability of the synchronous machines in the power system to remain synchronised under normal operating conditions and to regain synchronism if subjected to a disturbance): or*
   - *control system stability (the ability of the control systems of any generating station to maintain stable operation during both the steady state and dynamic interactions with the power system, including but not limited to dynamic interactions with any other generating station).*

10. A substantially similar definition of stability event and related policies were included in versions of the Policy Statement before 2019 but were removed under the 2019 Policy Statement review. That review identified at the time that there was no particular need for events impacting system stability to be identified explicitly in the Policy Statement, and doing so was likely causing confusion in relation to the interpretation of how we implement risk management policies.

11. Five years' later, events which threaten system stability are becoming more frequent on the power system, principally as a result of increasing penetration of inverter-based generation. Depending on the nature of the event, managing the event may require constraining generation in a particular region, or managing demand.

12. Our current policy is to manage stability events in real time when potential instability is detected. This involves either applying a discretionary constraint to the dispatch solution to reduce generation from a particular generating station, or requesting or instructing demand management. These actions are

necessary to comply with the principal performance obligations set out in the Code and elaborated in the security policy.

13. To improve the visibility of stability events to market participants, we propose formally designating them as credible events, and classifying them as contingent events. The Policy Statement describes a contingent event as being:

    events where the impact, probability of occurrence, estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event.

14. We plan to operate the system with constraints on transmission and generation, and other possible mitigations, that are applied in the scheduling and dispatch processes before a stability event happens. However, where these constraints and other mitigations will not be effective we retain the right to request or instruct demand management.

15. Constraining generation in forward scheduling provides an additional benefit by supplying better information to the market on the likely dispatch outcomes for generation within regions potentially impacted by a stability event.

16. We also consider constraining generation to be preferable to demand management in the case of voltage stability as this action is likely to result in lower system cost than the cost of managing demand. This is reflected in our current operational practice of constraining generation on through discretionary constraints in real time. For other stability related issues constraining generation is expected to be the only effective operational option.

17. We propose to effect this policy through the following changes to the security policy:
    - insert a new class of credible event being a stability event (new clause 12.1.5A)
    - insert a new type of contingent event being a stability event (new list item (h) in clause 12.4)
    - insert corresponding definitions as detailed above at clauses 179 and 182A.

Question 1: Do you support the proposed changes to the risk management policy around classification and management of stability events? If not, why not?

Clarifying operational practices around demand management

18. The Code and Policy Statement provide for the use of demand management in grid emergencies. Paragraphs 73 to 84 of the Policy Statement describe the decision-making processes we employ in electing to manage demand, and describes principles used in calculating demand reduction allocations when considering reallocation of demand management instructions after an event.

19. Clause 6 of Technical Code B of Schedule 8.3 details that in response to a grid emergency arising out of an unsupplied demand situation, insufficient generation and frequency keeping, or insufficient transmission capacity, the System Operator may request demand reduction (subclauses (1)(b) and (2)(c)) and require the electrical disconnection of demand (subclauses (1)(d) and (2)(d)) (among other things).

20. We propose to insert in the policy statement clauses which clarify the circumstances under which we will take these actions and other actions allowed for in Technical Code B. We feel it is important to clarify

these steps in our operational processes as it has a consequential impact on the application of a load adjustment to the dispatch schedule, which is required under Schedule 13.3AA of the Code.

21. For example, we are proposing:
    - when we have determined that demand management may be required, we will request participants to reduce demand including controllable load in accordance with Technical Code B clause 6 (1)(b) or (2)(c); and
    - when we have determined that demand management is required, we will instruct one or more participants or the grid owner to electrically disconnect demand in accordance with Technical Code B clause 6 (1)(d) or (2)(d). (This also invokes clause 3 of Schedule 13.3AA to change in inputs used in calculating dispatch prices).

22. A Warning Notice or Grid Emergency Notice (the two types of formal notice under the Policy Statement) will be issued when demand management may be required. A Grid Emergency Notice will be issued when demand management is required.

23. We propose to effect this policy by inserting new clauses 74A and 74B into the policy statement.

24. This change comes at no cost but we expect the clarification in operational process will be of benefit to participants attempting to understand our processes when demand management may be or is required.

Question 2: Do you support the proposed changes to the security policy for clarifying operational practices around demand management? If not, why not?

Removing detail around process for demand reallocation

25. Clauses 79 to 81 of the policy statement provides detail around the process for determining demand management allocations after urgent action is taken requiring demand reduction. Clause 80 and its subclauses details a calculation methodology which would be applied in these circumstances. Particularly, these clauses focus on the equitable allocation of demand reduction across affected parties where demand reduction is required in a prolonged response to an event.

26. Clause 7 (20) of Technical Code B of Schedule 8.3 of the Code requires that where the System Operator requires the electrical disconnection of demand in accordance with the Technical Code, it must "to the extent practicable … use reasonable endeavours to ensure equity between connected asset owners when instructing the electrical disconnection of demand."

27. In practice, we allocate instructed demand reduction quantities proportionally by considering the current offtake of each connected asset owner, or otherwise as required by particular circumstances. For example, if 10% demand reduction is instructed in an area with three connected asset owners 'A', 'B' and 'C', and the connected asset owner's current offtake at the time of the instruction was 50 MW, 30 MW and 20 MW respectively, then the instructed reductions would be 5 MW, 3 MW and 2 MW respectively.

28. Under current operational process, this allocation methodology persists until the grid emergency is concluded and is not substituted by another methodology. Our current practice does not employ a different demand allocation methodology after a certain period.

29. Clause 79 of the Policy Statement describes the methodology to be applied after the initial instruction to reduce demand ("reallocating reduced demand"). This substitute methodology requires the System Operator to consider the historic offtake of each connected asset owner, being either the annual average peak demand (clause 80.1) or the total energy consumed (clause 80.2).

30. Considering each connected asset owner's historic offtake when reallocating demand reduction does not consider the current circumstances of each connected asset owner. For instance, a connected asset owner which last year operated an energy intensive facility with high demand, but has since reduced its demand, would be allocated a higher proportion of the available demand to the detriment of other connected asset owners in the region.

31. We believe the most equitable allocation methodology for demand management we can currently apply is basing demand allocations on the current offtake of each connected asset owner. Hence, we propose to revoke clauses 79 to 81, which could require us to use a sub-optimal methodology in some circumstances where a more appropriate methodology is available.

32. We expect that maintaining a single, simple demand allocation methodology that will be applied throughout a grid emergency is preferable to maintaining multiple demand allocation methodologies that are applied conditionally. We consider this change is beneficial in that it avoids a potential situation where demand management is not executed equitably and reduces confusion for participants around how demand management is executed.

33. Our work programme for the 2024/25 financial year includes a project investigating a more sophisticated demand allocation methodology based on use of near-term load forecasts. We believe this methodology would be superior to the currently used methodology of calculating allocations based on the current consumption at each connected asset owner. We will communicate changes to the demand allocation methodology as they are developed and implemented.

Question 3: Do you support the proposed changes to the security policy clarifying the methodology for determining demand management allocations? If not, why not?

Future enhancements to the security policy

34. The security policy does not currently provide for management about Low Residual Situations and potential capacity shortfalls. "Residual" is the term given to the remaining offered capacity for a given trading period after the required energy and instantaneous reserve has been scheduled. "Low Residual Situations" are situations where near-real time forward market schedules identify that Residual has dropped to a level that, given uncertainty in real time operating conditions, there is heightened risk of a grid emergency and potential for demand management to occur.

35. The trigger for a Low Residual Situation is (generally) a reduction of Residual to 200 MW or below in the forward schedules, including the Week-ahead Dispatch Schedule (WDS). We may also notify a Low Residual Situation where there is greater than 200 MW Residual scheduled if we have reduced confidence in either the demand forecast or the intermittent generation (wind and solar generation) forecasts. This reduced confidence is often associated with an uncertain weather forecast.

36. We currently notify Low Residual Situations using Customer Advice Notices (CANs), which may be followed by an industry briefing. Low Residual CANs were introduced in May 2019 and industry briefings were added to improve industry coordination and communication in response to the supply shortfall event on 9 August 2021. The process provides a framework for informing the industry of impending shortfalls in energy and reserve capacity and coordinating the response. The process is described in online information on the Transpower website.[1]

37. We continue to evolve our management of Low Residual Situations as we learn more each time a situation arises. This has included developing our process to also cover situations where it may be necessary to communicate to the general public that there is a heightened risk of capacity shortfall in a coming period. Depending on the situation, we may ask the public to be mindful of their electricity use over these periods, noting that while they could consider turning off electricity that they are not using, they should continue to use electricity they need and make sure they keep their homes warm.

38. We will communicate with the public through our website and Facebook channel as well as via the media, and we will invite lines companies and retailers to amplify our messages through their direct-to-consumer channels. This approach enables us to proactively communicate electricity supply risk so that people are not unnecessarily taken by surprise by power cuts, and it has an added purpose of giving the public an active role minimising the risk of power cuts happening by reducing demand on the system.

39. The approach to communicating with the public was developed alongside industry to address recommendations from the 9 August 2021 shortfall event. It was first tested in the inaugural pan-industry exercise in 2022 and developed further and socialised ahead of winters 2023 and 2024, including through our extended System Operator Industry Forums and pan-industry exercises. The approach was also at the centre of the pan-industry exercises in 2023 and 2024 held for communications and customer teams.

40. We applied our revised approach to communicating with the public to successfully mitigate the potential shortfall event on 10 May 2024. Subsequently participants asked for more clarity around when and how the approach would be used. As a result of this, we improved transparency of the risk assessment we apply to decide whether the potential for real consumer load to be shed warrants a public call to action. We also gave an undertaking that we will provide industry as much time as we can to resolve potential

[1] https://www.transpower.co.nz/system-operator/notices-and-reporting/notices-insufficient-generation

electricity supply shortfalls before asking consumers for support, provided there is sufficient time for meaningful action to be taken.

41. We consider it will be helpful for information about the system operator's approach, triggers and process for managing Low Residual Situations to be more transparently available to participants, with an option being to include appropriate provisions in the Policy Statement.

42. We also need to ensure that, around any Policy Statement provisions the system operator must comply with each time, we have the flexibility to learn and adapt our approach and communications to reflect the unique circumstances and risks for each Low Residual Situation and our learnings as they arise. Another risk of applying a more rigid structure to our decision-making around Low Residual Situations is the triggering mechanism, if not robustly defined, could lead to spurious notifications in situations where other information is available that means notifying a Low Residual Situation is not required.

43. We invite respondents to provide feedback on whether certain elements of the Low Residual Process should be included in the Policy Statement. This feedback will inform a review and consultation on our approach to managing Low Residual Situations, including process, parameters, triggers and communications which is planned for completion before winter 2025. An outcome of that review could be that we propose changes to the Policy Statement for the Authority's consideration.

Question 4: Do you consider elements of the Low Residual Situation process should be included in the Policy Statement? If so, which elements? Please provide rationale for your views.

Other proposed changes

45. Through our review we have taken the opportunity to make wording and typographical changes for consistency and clarity. Details of these changes, together with the substantive changes described above, are included in the table in Appendix 1.

46. A draft policy statement is provided as clean and red-lined versions as Appendices 2 and 3, respectively.

Appendix 1 Summary Table of Policy Statement amendments, per clause

Current Clause	Proposed Clause	Summary	Description of Change	Rationale
Security Policy				
12.1		Updated wording and converted bullets to numbering		Clarity and accommodates loss of system stability within the identification of potential credible events
	12.1.5A	Includes Stability Events as a potential contingent event class		Reflects the proposed arrangements for managing Stability Events
12.1.7	12.1A	Renumbered		Clarity
12.2		Reworded for clarity		Clarity
	12.4A	Renumbered		Clarity
12.4.2	12.4B	Renumbered		Clarity
12.5		Converted bullets to numbering		Clarity
12.5.1		Included footnote into clause wording		Clarity
12.5.4		Revoked		Specific controls for stability events are elaborated elsewhere so this clause has become redundant
	13A and 13B	New obligation to publish at-risk generation	Requires the system operator to publish a list of identified "at-risk generation" and describe the method it uses to create that list	Provides clarity on which generators must provide information for availability cost allocation
	17.1A	Quality levels for stability events	Describes the particularly quality levels which we will control to for stability events	
26.4		Removed words "post-event"	We apply power system stability limits for steady-state power flows as well as post-event power flows	Reflects current and continuing operational policy

Current Clause	Proposed Clause	Summary	Description of Change	Rationale
30.1		Reworded for clarity		Clarity
30.1.2		Reworded for clarity		Clarity
30.1.3		Reworded for clarity	Makes clear that the System Operator must, where practicable, provide the information 4 weeks in advance when the constraint could be of significant interest to participants - ie this is not an alternative to the two week period in 30.1.2.	
30.2		Reworded for clarity	Removed enumeration of the individual market schedule types, as following the Real Time Pricing project there are no market schedules which don't use security constraints	Clarity
31		Updated wording for consistency	Changed "aim" to "must endeavour"	Consistency
34		Revoked		The clause did not describe an obligation on the system operator
36		Updated wording for consistency	Changed "aim" to "must endeavour"	Consistency
43.3		Updated wording to specifically refer to voltage stability		Consistency with inserted provisions around system stability
58.1 and 58.2		Substituted "load shedding" with "AUFLS"		Clarity, to differentiate between automatic load shedding and manual demand management
64		Substituted "prior to" with "before"		Clarity
74 etc.		Removed "demand shedding"	Replace all uses of "demand shedding" with "demand management"	Duplicates meaning "Demand management"

Current Clause	**Proposed Clause**	**Summary**	**Description of Change**	**Rationale**
74		Updated demand management policy for Scenarios B and C	Where the event is a transient or dynamic stability limit is being exceeded (for either an initial defined event or a second defined event), updated policy to reflect that demand management may occur if this action would remedy the stability event	More accurately reflects operational practice.
	74A	Actions taken by the System Operator when demand management may be required	Elaborates on the rights available to the System Operator under Sch 8.3 Tech Code B cl 6	Clarity – defines when demand management is *requested* (as opposed to being instructed)
	74B	Actions taken by the System Operator when demand management is required	Elaborates on the rights available to the System Operator under Sch 8.3 Tech Code B cl 6	Clarity – defines when demand management is *instructed* (as opposed to being requested)
75		Updates clause to reflect insertion of clauses 74A and 74B		Clarity – describes the conditions necessary for the System Operator to issue demand reduction requests or instructions
75.1 and 75.2		Updated to include instructions to connected asset owners	Includes in the existing clauses the option for the System Operator to require demand management from connected asset owners without also specifying particular offtake points.	Clarity – reflects current operational process
79-81		Revoked		The System Operator will no longer seek to reallocate demand limits on the basis of historical consumption or peak loads
Future Formulation and Implementation Policy				
153 and 155		Updated “annual review cycle” to “two-yearly review cycle"		Reflecting current Code requirements for regular Policy Statement reviews
Glossary of Terms				
	160A	Inserted definition of automatic under-voltage load shedding (AUVLS)		Aids in understanding the scope of the emergency planning policies

Current Clause	Proposed Clause	Summary	Description of Change	Rationale
164		Replaced “demand shedding” with “demand management”		Removes duplication of the term and clarifies meaning
	169A	Insert definition of “market schedules”		Ease of reading
179	179	Reinvoke “stability events” as a definition	Include a comprehensive definition of stability events for the purposes of defining a new event class	
	182A	Insert definition of “system stability”	Include a definition of a stable system state as a state to which the system is restored following a stability event	

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Appendix B Track change version of amended policy statement

Policy statement

Contents

Introduction

PURPOSE

1. This is the **policy statement** referred to in part 8 of the **Code**.

1A. This **policy statement** takes effect from dd MMM yyyy.

1B. References to the **system operator's** website in this policy statement refer to the system operator page on the **Transpower** website.

2. The **policy statement** ~~also~~:

   2.1 forms a transparent basis from which detailed procedures are developed to support compliance with the policy as well as a mechanism for continually improving existing practices.

   2.2 clarifies the risks being managed by policy and the key assumptions made in managing those risks.

SYSTEM OPERATOR POLICIES TO ACHIEVE THE PPOS AND DISPATCH OBJECTIVE

3. The policies by which the **system operator** must seek to achieve the various **PPOs** (and other deliverables) are set out in the sections of the **policy statement** as follows:

Avoid Cascade Failure

4. The policies to be adopted in respect of avoiding cascade failure are set out in:

   4.1 The Security Policy that:

      4.1.1 Outlines how commonly occurring events are to be managed with the intention to avoid exceeding:

         (a) Frequency limits.

         (b) **Asset** capability (including voltage limits), normally without **demand** ~~**shedding**~~**management** being required.

      4.1.2 Outlines the use of **automatic under-frequency load shedding** to manage **extended contingent events**, where **demand** may otherwise be shed to maintain the security policies and the requirement for emergency management procedures to manage extreme events.

   4.2 The Emergency Planning section of the Security Policy that details the emergency arrangements required for extreme events (or where the event cannot be satisfactorily managed through the normal application of the Risk Management policies).

4.3 The Dispatch Policy that details how the **system operator** intends to adjust scheduling and **dispatch** to maintain frequency and reserves for use in connection with the Security Policy.

Frequency

5. The policies to be adopted in respect of maintaining frequency are set out in:

5.1 The Security Policy, that:

5.1.1 Sets the overall objective for maintaining reserves for **contingent events** and **extended contingent events**.

5.1.2 Outlines the process for determining the required frequency reserves (as described in the sections on under-frequency and over-frequency management).

5.2 The Dispatch Policy, which describes the arrangements for **dispatching** these reserves.

6. The policies to be adopted for maintenance of the frequency within the **normal band**, and time keeping, are set out in the Dispatch Policy and the **procurement plan**.

Other Standards

7. The policies to be adopted in respect of the other **PPOs** are described in the Security Policy section on Management of Quality.

Restoration

8. The restoration process is described in the Emergency Planning section of the Security Policy.

Dispatch Objective

9. The Dispatch Policy describes the policies that must be adopted in respect of the **dispatch objective**.

9A The Dispatch Policy also describes the preparation and adjustment of the **dispatch schedule** for the purposes of producing **dispatch prices**.

INTERPRETATION

10. Any terms used in the **policy statement** which are defined in the **Act** or in Part 1 of the **Code** and which are not defined in the Glossary of Terms within the **policy statement**, have the same meaning as given to them in the **Code**. In the event of any inconsistency or conflict between the provisions of this **policy statement** and the rest of the **Code**, the rest of the **Code** shall prevail.

Chapter 1 - Security Policy

POLICY AND SCOPE

General Policy

11. The general policies the **system operator** intends to use to meet the **principal performance obligations** are as follows:

    11.1 Adopting processes intended to identify events, assess the risks of occurrence of those events in advance, categorise those event risks, and manage those defined events on the power system in real time in accordance with this **policy statement**.

    11.2 Applying **security constraints** on **dispatch**, in accordance with the Security Policy, given the **assets** and **ancillary services** made available to the **system operator**.

    11.3 Procuring, scheduling and **dispatching** reserves, where possible, with the **assets** and **ancillary services** made available to the **system operator**, to maintain the required frequency standards and to avoid cascade failure, for defined events.

    11.4 Managing voltage and available reactive support during real time, where possible given the **assets** and **ancillary services** made available to the **system operator,** in a manner intended to avoid cascade failure for defined events.

    11.5 Recommending and facilitating, to the extent considered to be reasonably appropriate and practicable by the **system operator,** co-ordination of advised planned **asset** outages to minimise the impact on security during **dispatch**.

    11.6 If reasonably requested by a **participant**, investigating, identifying and, to the extent reasonably practicable, resolving the cause of a non-compliance with harmonic levels, voltage flicker or voltage imbalance standards (sections 4.7, 4.8 and 4.9 of the **Connection Code**).

    11.7 Defining the circumstances under which **formal notices** must be sent in accordance with **Technical Code** B of Schedule 8.3 of the **Code** and, to the extent possible, determining the situations in advance that will potentially result in the initiation of **demand ~~shedding~~management,** including **unsupplied demand situations**.

RISK MANAGEMENT POLICIES

Identification and Application

12. The **system operator** must seek to manage the outcomes of events that may cause cascade failure by:

    12.1 identifying potential credible events (each an ‘event’) on the power system ~~as a result of **asset** failure~~ that may result in cascade failure, either as a result of **asset** failure or the inability to maintain **system stability** following a disturbance. At the date of this **policy statement** the **system operator** has identified the following credible events that may result in cascade failure, due to these events causing quality and/or power flow outcomes exceeding **asset** capability:

12.1.1 The loss of one of the following power system components:

- a **generating unit**; or
- a **transmission circuit**; or
- an **HVDC link** pole; or
- an **interconnecting transformer** (110 kV or 220 kV); or
- a busbar (220 kV, 110 kV or 66kV); or
- large load or load blocks; or
- reactive injections, both when provided as an **ancillary service** or when available from transmission **assets**:

12.1.2 The loss of both transmission circuits of a double circuit line:

12.1.3 The simultaneous loss of two or more of any of the components in 12.1.1:

12.1.4 The close consecutive loss of two or more of any of the components in 12.1.1:

12.1.5 The loss of the **HVDC link** bipole:

12.1.5A The loss or potential loss of **system stability** (a **stability event**):

12.1.6 Other credible events may be identified during the term of this **policy statement**. This may include events arising in particular temporary circumstances such as, for example, a credible event identified as potentially arising during commissioning~~:~~.

~~12.1.7 If, during the term of this **policy statement**, the **system operator** identifies~~ 12.1A if, having identified a further or other credible event then, subject to operational requirements and as soon as reasonably practicable~~, the **system operator** must~~:

~~• **advise**~~12.1A.1 **advising** such further credible event to all **participants**;

~~• invite~~12.1A.2 inviting **participants** to comment on such credible event;
and

~~• consider~~12.1A.3 considering **participants'** comments prior to it implementing mitigation measures for such credible event.

12.2 assessing each event, or category of events, to estimate the likely risks based on the potential impact on the power system (including on achievement of the **PPOs**), if the event or category of events occurs~~. Consequence assessment has taken and must take into consideration~~, considering mitigating factors such as:

- **AUFLS**.

- the provision of levels of reserves.

- the provision of **constraints** on **dispatch**.

- for asset related events, the probability of occurrence based on historical frequency of **asset** failure or other credible reliability information, provided that where the **system operator** has limited historical or other information for specific **assets**, it must consider generic information available to it regarding failure of that type of **asset**.

- for stability related events, the probability of occurrence based on historical events, provided that where the system operator has limited internal historical information it must consider relevant external information available to it.

- the estimated costs and benefits of identified risk management.

- the feasibility and availability of other potential mitigation measures.

12.3 assigning each of the assessed events to one of the following categories:

- **Contingent events:** Events where the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and **dispatch** processes pre-event.

- **Extended contingent events:** Events for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid **demand** ~~**shedding**~~**management** or maintain the same quality limits defined for **contingent events**.

- **Other events:**
  a) events that are considered to be uncommon and for which the impact, probability of occurrence and estimated cost and benefits do not justify implementing available controls, or for which no feasible controls exist or have been identified, other than unplanned **demand** ~~**shedding**~~**management**, **AUFLS** and other emergency procedures or restoration measures; or;
  b) events that have no impact or where no pre- or post-contingent management is required

12.4 categorising, at the date of this **policy statement**, the following credible events:

- **Contingent events**:

  a) the loss of a **transmission circuit**.

  b) the loss of an **HVDC link** pole.

c) the loss of a single **generating unit**.

d) the loss of both **transmission circuits** of a double circuit line, where the **system operator** has determined a high level of likelihood of occurrence based on historical information.

e) the loss of both **transmission circuits** of a double circuit line, where the **system operator** has been advised of a temporary change to environmental or system conditions that give reason to believe there is a high likelihood of occurrence of the simultaneous loss of both circuits. The **system operator** must make available on its website a range of environmental or system conditions that it considers may create a high likelihood of occurrence of simultaneous loss of both circuits (but this list may not be exhaustive and will not limit the definition of the **contingent event**).

f) the loss of reactive injections, both when provided as an **ancillary service** or when available from transmission assets.

g) the loss of the largest possible load block as a result of paragraphs a) to f) above for each **island**.

h) the loss of **system stability** (due to a **stability event**).

- **Extended contingent events:**

a) the sudden loss of the **HVDC link** bipole.

- **Other events:**

a) the loss of a 66kV busbar not connected to the **core grid**.

b) the loss of both **transmission circuits** of a double circuit line.

c) the simultaneous loss of two or more of any of the components in clause 12.1.1.

d) the close consecutive loss of two or more of any of the components in clause 12.1.1.

12.~~4.1~~ 4A categorising the following assets ~~are categorised~~, as either a **contingent event**, **extended contingent event** or **other event** according to a methodology and categorisations made available on its website:

a) a 220kV, 110kV or 66kV busbar connected to the core grid;

b) a 220kV or 110kV interconnecting transformer.

12.~~4.2~~4B inviting industry to comment on any proposed changes to the methodology referred to in clause 12.4~~.1~~ before those changes come into effect~~.~~:

12.5 applying, where possible, the following principles in implementing controls for each of the following category of risk:

12.5.1 For **contingent events**, the **system operator** must endeavour to schedule and **dispatch** sufficient reserves to provide **asset** redundancy, maintain the levels of quality defined in clauses 17.1 and 17.1.A of the Security Policy, and plan to avoid post-event unplanned **demand** ~~**shedding**~~**management**, taking into account any other agreed control ~~measures~~[1]measures (for example, demand inter-trips, run-back schemes, and **Automatic Under Voltage Load Shedding (AUVLS)**) advised to and agreed by the **system operator**.

12.5.2 For **extended contingent events**, the **system operator** must plan to maintain the levels of quality defined in clause 17.2 of the Security Policy through a combination of **AUFLS**, the provision of reserves, **asset** redundancy, **demand** ~~**shedding**~~**management**, and acceptance of greater quality disturbances than for **contingent events**, taking into account any other agreed control measures (for example **special protection schemes** and automatic under voltage load shedding schemes) advised to and agreed by the **system operator**. These control measures do not preclude the **system operator** taking action before an **extended contingent event** occurs, such as **network** reconfiguration, but do preclude the **system operator** changing any **price responsive schedule**, **non-response schedule** and **dispatch schedule** by applying **constraints** that will result in generation being dispatched out of merit order.

12.5.5 For **other events**, no planned controls have been identified, other than **demand** ~~**shedding**~~**management**, **AUFLS** and other emergency or restoration procedures.

- ~~If, in the **system operator's** reasonable opinion, a credible event is likely to lead to a loss of system stability, the **system operator** may rely on **demand shedding** to maintain the power system within identified transient and/or dynamic stability limits in accordance with clause 74.~~

12.5.4 *[Revoked]*

13. The **system operator** must:

13.1 In addition to reviews of the **policy statement** in accordance with the **Code**, review the identification, assessment and assignment of potential credible events as classified in clause 12.4 at least once in each five year period.

13.2 Make available on its website, prior to the commencement of each review of credible events, its intended methodology for identifying and assessing the risks to which the risk management policies are directed.

13.3 Invite comments from **registered participants** as to its process and the content of the review.

13.4 Make available on its website an explanation and summary of conclusions for each review of credible events completed under clause 13.1.

13A. The **system operator** must maintain and make available on its website a list of at risk generation, determined by identification of **generating units** and other **assets** connected to the power system whose loss during a **contingent event** would cause a loss of **injection** to the **grid** likely to require provision of **instantaneous reserve**.

13B. The **system operator** may identify the **assets** described in clause 13A through the review described in clause 13 or at any other time as a result of **commissioning** or **decommissioning assets** or changes to the **grid**.

14. In determining and applying the methodology in clause 13, the **system operator** must, where appropriate, apply risk management principles consistent with the Australia and New Zealand risk management standard AS/NZS ISO 31000.

~~[1] For example, demand inter-trips, run-back schemes, and Automatic Under Voltage Load Shedding(AUVLS).~~

Quality Limits and Actions Associated with Events

15. The **system operator**:

    15.1 is entitled to rely on information regarding **asset** performance advised by **asset owners** in **asset capability statements**.

    15.2 must use reasonable endeavours ~~(including planned **demand** interruption or **demand shedding**)~~ to **dispatch assets** in a manner so they remain within their stated **asset** capability.

16. Where the **assets** and **ancillary services** made available to the **system operator** are insufficient to achieve the quality levels set out in clauses 17 and 18**,** the **system operator** must follow the **demand ~~shedding~~management** policies in clause 74**.** Where clause 74 provides that **demand ~~shedding~~management** will not occur, the **system operator** may be unable to achieve the quality levels set out in clauses 17 and 18.

17. The quality levels the **system operator** plans to achieve for **contingent events** (including **stability events**) and **extended contingent events** are set out below. The ability to achieve the quality levels is entirely dependent on sufficient **assets** and **ancillary services** being made available to the **system operator** and the accuracy of the stated capabilities of those **assets** and **ancillary services**.

    17.1 For a **contingent event**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of a **contingent event:**

        17.1.1 No **asset** will exceed its stated load carrying, thermal or voltage capability.

        17.1.2 Subject to clause 40**, grid** voltage will be within the range set out in clause 8.22(1) of the **Code**.

        17.1.3 No **demand** is interrupted other than contracted reserves and/or **interruptible load** contracted or pre-arranged to be interrupted.

        17.1.4 Frequency in either **island** will not drop below 48Hz or rise above 52Hz in the North Island or 55 Hz in the South Island.

        17.1.5 Frequency in either **island** will be restored to within 50 Hz +/- 0.75 Hz within 1 minute.

        17.1.6 **Instantaneous reserves** will be restored within 30 minutes.

        17.1.7 ~~Voltage~~**System stability** ~~of the power system~~ is maintained.

        17.1.8 Where required by agreements for higher levels of quality, clause 8.6 or clause 17.29 of the **Code**, the quality targets of such agreements will be met.

    17.1A For **stability events**, in addition to the quality levels detailed in clause 17.1:

        17.1A.1 Oscillations must be adequately controlled (in terms of both amplitude and damping) such that they do not interrupt or prevent regular operation of the power system.

17.1A.2 Synchronous **generating units** will not experience loss of rotor angle stability for any identified **stability event**.

17.1A.3 If a **generating unit** is unexpectedly **electrically disconnected** during an event it will be reconnected as soon as practicable, subject to assessment that it will then remain connected.

17.2 For **extended contingent events**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of an **extended contingent event**:

17.2.1 No **asset** will exceed its stated load carrying or thermal capability.

17.2.2 Voltage stability of the power system is maintained.

17.2.3 **Target grid voltages** will be as determined under clause 41.

17.2.4 Other grid voltages may be outside the range determined under clause 41. Where this is the case the **system operator** will respond to return these voltages to within the limits determined under clause 41 as soon as practicable.

17.2.5 Disconnected **demand** will be restored as soon as practicable.

17.2.6 Frequency in either **island** will be restored to within the **normal band** as soon as reasonably practicable.

17.3 For **extended contingent events**, the **system operator** may use one or more of the following actions during and after the occurrence of an **extended contingent event**:

17.3.1 The **system operator** may declare a **grid emergency** if it believes the quality levels may not be met after an **extended contingent event**.

17.3.2 **Demand** ~~shedding~~**management** and **AUFLS** may be used.

18. *[Revoked]*

SECURITY MANAGEMENT

Security Constraints

18A *[Revoked]*

18B *[Revoked]*

19. *[Revoked]*

20. *[Revoked]*

21. *[Revoked]*

22. *[Revoked]*

23. *[Revoked]*

24. *[Revoked]*

25. *[Revoked]*

26. The **system operator** must, from time to time:

    26.1 analyse a range of credible transmission, generation, and power flow scenarios.

    26.2 identify **contingent events, extended contingent events** and **other events** that the **system operator** considers may reasonably impact its ability to meet the **PPOs**.

    26.3 identify and input transmission capability limits for **grid assets** in **SPD** to maintain operation within the stated capability (as advised by **grid owners**) after a **contingent event**.

    26.4 identify and input power system stability limits in **SPD** to maintain ~~post-event~~ operation within such stability limits.

27. Using the transmission capability limits and the power system stability limits identified in clause 26 the **system operator** must for each **trading period** develop **security constraints** which it will apply during the relevant **trading period**.

27A The **system operator** may use either automated or non-automated processes to develop the **security constraints** under clause 27. Non-automated processes will be used in situations where the automated processes do not generate appropriate **security constraints**.

28. The **security constraints** which are developed using automated processes under clause 27 are those which arise as a consequence of either or both the transmission capability limits and the power system stability limits being equal to or greater than the applicable **constraint percentage threshold**. **Security constraints** developed using non-automated processes apply regardless of **constraint percentage threshold**.

29. The **system operator** may amend, re-amend, add, remove or exclude the **security constraints** developed under clause 27 before and during **trading periods** when the **system operator** reasonably considers this is required to meet its obligations under the **Code**.

30. Notwithstanding the provisions of clause 29, the **system operator** must:

    30.1 Make available on its website information about **security constraints** developed using non-automated processes under clause 27A~~ excluding~~, other than **discretionary security constraints** and **frequency keeping constraints.** ~~The information provided under this clause 30.1 must:~~

Where practicable, ~~occur four weeks prior to~~ the ~~date on which the **security constraints** are intended to be first used, where the **system operator** identifies an outage or **security constraint** that could be of significant interest to **participants.**~~information must:

- ~~Otherwise where practicable, occur two weeks prior to the date on which the **security constraints** are intended to be first used.~~

~~Include~~30.1.1 contain a~~ brief~~ summary of the security constraint design, ~~such summary to be reasonably~~ sufficient for participants to be able to assess the effect of the limits ~~or~~imposed by the security constraint~~.~~, and:

30.1.2 be made available at least two weeks prior to first use of the **security constraint** in scheduling, and:

30.1.3 despite clause 30.1.2, be made available at least four weeks prior to first use of the **security constraint** in scheduling where the constraint could be of significant interest to participants.

30.1A if the system operator makes a change to a **security constraint** of one of the types described in clause 30.1 and the change is made within two weeks before it is intended to be first used~~,~~:

30.1A.1 if practicable, make available details of the change on the its website in advance; but

30.1A.2 if it is not made available in advance, make available details of the change as soon as practicable.

30.1B correctly apply **security constraints** regardless of whether or not the information on the **Transpower** website about the power system stability limits or **security constraints** is complete or up to date.

30.2 notify the **WITS manager** when a **security constraint** other than a **frequency keeping constraint** or general market-node constraint has been applied to **SPD** ~~for use in—~~

~~(a) the **price-responsive schedules;**~~

~~(b) the **non-response schedules;**~~

~~(c) the **dispatch schedule;**~~

~~(d) the **week-ahead dispatch schedule**; and~~

and where the calculated value of the constraint exceeds the **constraint publication threshold.**

30.3 *[Revoked]*

30.4 provide to the **WITS manager**, for making available on **WITS**, in respect of each **security constraint** notified pursuant to clause 30.2**:**

- the form of the **security constraint**;
- the limit of the **security constraint**;
- the **trading periods** to which the **security constraint** has been applied to **SPD**; and

- where applicable, the previous limit of the **security constraint**.

30.4A *[Revoked]*.

30.5 provide to the **WITS manager**, for making available on **WITS**, information about **grid asset** outages, including start and end times, applied to~~—~~ the **market schedules** and the **week-ahead dispatch schedule**.

~~(a) the **price-responsive schedule;** and~~

~~(b) the **non-response schedule;** and~~

~~(c) the **week-ahead dispatch schedule**.~~

30B The **system operator** must make available on its website a set of generation scenarios that it will use to develop indicative **security constraints** under clause 30C~~,~~ and may amend the generation scenarios from time to time. The **system operator** will place any amendments on its website and at the same time notify **participants** of these amendments.

30C Subject to clause 30F, the **system operator** must develop indicative **security constraints** for a **notified planned outage** if it is requested to do so by a **participant** in relation to a specific outage where:

(a) the **system operator** considers it likely that the outage will have a widespread impact on competition or efficiency, taking into account the information provided by the requesting **participant**; and

(b) the request is made more than two weeks prior to the notified start date of the outage.

30D The intent of the indicative **security constraints** developed under clause 30C is to provide an indication of the market system constraints that may be developed for the **notified planned outage** under clause 27.

30E The **system operator** must make available information detailing indicative **security constraints** developed under clause 30C to **participants** on the **Planned Outage Co-ordination Process** website. The information made available must include a summary of the limits or **security constraint** design, such summary to be reasonably sufficient for **participants** to assess the effect of the **security constraint**.

30F The **system operator** may decline to develop indicative **security constraints** under clause 30C if the **system operator** reasonably believes that sufficient relevant historical **security constraint** information has already been made available to **participants** after the **changeover date**. If the **system operator** declines a request pursuant to this clause, it must advise the requesting **participant** where the relevant historical **security constraint** information can be located.

30G The **system operator** must make available on the **Transpower** website a description of the process it will use to develop indicative **security constraints** under clause 30C~~,~~. The **system operator** may amend the process from time to time.

30H Where the **system operator** declines a request to develop indicative **security constraints** on the grounds that the criteria in clause 30C do not apply, the **participant** may request the **system operator** to agree to develop the indicative **security constraints**. Such an agreement may not be unreasonably withheld but may, in the **system operator's** discretion, include the requirement for the requesting **participant** to pay the reasonable costs of the **system operator** in developing the indicative **security constraints**.

Under-Frequency Management

31. The **system operator** must ~~aim~~endeavour to schedule sufficient reserves, subject to **asset** and **ancillary service** availability and clause 33A, to meet the specified under-frequency limits and avoid cascade failure for:

    31.1 The maximum amount of **MW** injection that could be lost, due to the occurrence of a single **contingent event**; and

    31.2 The **extended contingent events**, allowing for **automatic under-frequency load shedding**.

32. In modelling reserve requirements, the **system operator** must:

    32.1 Apply the **Reserves Management Tool**

    32.2 Use the most recent **asset** capability information provided by **asset owners,** subject to:

    - the requirements of the **RMT** specification (including **asset** performance modelling) from time to time agreed between the **system operator** and the **Authority**;
    - any **asset** assessments the **system operator** needs to carry out; and
    - a reasonable time delay allowing for the system operator to modify the **RMT** to include the latest **asset** capability information.

    32.3 Include the impact of **dispensations** and **equivalence arrangements**.

32A Where **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **system operator** reasonably considers it cannot rely upon the **asset** capability information provided, the **system operator**:

    32A.1 may apply an adjustment factor considered reasonable by the **system operator** based on its current knowledge about the performance of the power system, to account for the fact that the **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **asset** capability information provided is reasonably considered unreliable; and

    32A.2 must notify the **asset owner** within 3 **business days** following any decision to apply an adjustment factor.

33. To maintain a dispatchable **SPD** solution where there are insufficient **offers** and/or **reserve offers** in the current **trading period**, the **system operator**, using the **SPD software**, must—

33.1 for a pre-event shortage relating to a **contingent event**, **dispatch** all remaining **offered instantaneous reserve,** and, if the quantity of **instantaneous reserve dispatched**, together with **AUFLS**, is insufficient to meet the under-frequency standard in clause 7.2A of the **Code** applicable to an **extended contingent event**, reduce **demand** in accordance with the **demand management** policies; and

33.2 for a pre-event shortage relating to an **extended contingent event** that requires the **dispatch** of **instantaneous reserves** in addition to **automatic under-frequency load shedding**, **dispatch** all remaining **offered instantaneous reserve** and reduce **demand** in accordance with the **demand management** policies.

33A Following the occurrence of an **under-frequency event** in which **interruptible load** has been triggered, the **system operator** may temporarily set the reserve requirements to zero. The **system operator** must then restore the reserve requirements in accordance with the methodology set out in clause 84.

33B For the purposes of the **event charge** calculation pursuant to clause 8.64 of the **Code**, the **system operator** will use the methodology it makes available on its website.

Time Error Management

34. ~~The **system operator** contracts with an **ancillary service agent** to provide **frequency keeping** and manage frequency time error within the limits required in clause 7.2C of the **Code**. The procurement of this service is described in the **procurement plan**.~~*[Revoked]*

Over-Frequency Management

35. For the over-frequency elements of the **PPOs**, the **system operator** procures **over frequency reserves** in accordance with the **procurement plan**.

36. The **system operator** must ~~aim~~endeavour to **dispatch over frequency reserves** when necessary to maintain the frequency below 52 Hz in the North Island and 55 Hz in the South Island for **contingent** and **extended contingent events**. In determining the quantity of **over frequency reserves** to be **dispatched** in the South Island, the **system operator** must take into account the actual amount of **demand**, the **HVDC link** transfer, and the number and capacity of the units able to be **dispatched** for **over frequency reserves** at the time.

Rate of Occurrence of Frequency Fluctuations

37. *[Revoked]*

38. The **system operator** may recommend changes to the **procurement plan**, **policy statement** or **Code**, or take other action available to it under the **Code**, with the intent to correct a significant negative trend regarding the rate of **frequency fluctuations**.

Purchaser Step Changes

39. *[Revoked]*

39A Clause 8.18 of the **Code** provides that **purchasers** must limit the magnitude of any instantaneous change in the **offtake** of **electricity** and net rates of change in **offtake** to the levels the system **operator** requires.

39B As at the date this **policy statement** comes into effect, the **maximum instantaneous demand change limit** and net rates of change in **offtake** for **electricity** allowable for each **purchaser** within each **island** is 40 **MW** per minute with no more than a 75 **MW** change in any 5 minute period.

39C The **system operator** may specify a **maximum instantaneous demand change limit** and rate of change in **offtake** in relation to a particular **purchaser** that is different from the limit and the rate specified in clause 39B.

39D Clauses 39A and 39B do not apply to step changes and rates of change occurring during independent action or restoration in a **grid emergency**.

Voltage Management

40. The **system operator** must plan to manage **grid** voltage as follows:

 40.1 Following **a contingent event**, voltage will be maintained within the ranges specified in clause 8.22(1) of the **Code** except where, for a particular **GXP** or region, there is a **wider voltage agreement** in place.

 40.2 Where a **wider voltage agreement** applies, the voltage within that **GXP** or region will, following a **contingent event**, be managed so voltage stability is maintained and voltage does not go outside the lesser of the capability of the affected **assets**, as set out in the **asset capability statements** for those **assets**, or the voltage limit agreed in the **wider voltage agreement**.

 40.3 Following an **extended contingent event**, voltage will be maintained within the ranges determined under clause 41.1.

41. To manage voltage and control voltage excursions within the quality limits set out in clause 17 of this Security Policy the **system operator** must:

 41.1 Determine a set of **target grid voltages** at selected key locations (selected by the **system operator**) to be maintained during normal operations. For the purpose of clause 17 the **system operator** has determined that the **target grid voltages** will be within the range in clause 8.22(1) of the **Code**.

 41.2 Recommend to **asset owners** appropriate tap positions for transformers, which have off load tap changers, given the expected range of **dispatch** scenarios.

42. The **system operator** may vary **target grid voltages** for specific **dispatch** scenarios.

43. The **system operator** must monitor voltage trends in real time at key locations determined by the **system operator** and, subject to **asset** availability and **ancillary services**, it must endeavour to **dispatch** sufficient

reactive resources to:

43.1 Achieve **target grid voltages**.

43.2 Manage voltage for a **contingent event**.

43.3 Maintain post event operation within voltage stability limits.

44. The **system operator** must **dispatch generating plant** to:

44.1 Maintain a specific voltage during **dispatch.**

44.2 Provide specific **reactive power** outputs (refer also to the **security constraints** section of this Security Policy).

45. The **system operator** must **dispatch** available static reactive devices so that dynamic reactive reserves are available to provide **voltage support** for **contingent events** and **extended contingent events**.

46. In **dispatching** static and dynamic reactive resources, the **system operator** must use the following principles:

46.1 The **system operator** will first **dispatch relevant freely available reactive resources**.

46.2 Where insufficient **relevant freely available reactive resources** are available to maintain **target grid voltages**, the **system operator** will **dispatch** additional reactive resources as procured in accordance with the **procurement plan**.

46.3 Where the **system operator** believes the reactive resources **dispatched** under clause 46.1 and clause 46.2 are insufficient to address voltage management requirements the **system operator** will apply a combination of:

- Procurement and **dispatch** of additional reactive resources as an emergency departure from the **procurement plan** in accordance with clause 8.47 of the **Code**.

- **Security constraints** to provide additional reactive resources through the **dispatch** of generation.

47. If the **dispatch** of reactive resources under clause 46 is not sufficient to provide voltage support for managing a **contingent event** or an **extended contingent event** the **system operator** may commence **demand ~~shedding~~management** in accordance with the Emergency Planning section of this Security Policy.

Management of Quality

48. If the **system operator** receives a request to investigate and resolve a security of supply or reliability problem under clause 7.2D of the **Code** and, in the **system operator's** opinion, the problem is not likely to cause cascade failure, the **system operator** must:

48.1 Act on a written request by a **participant** or the **Authority** to identify the cause of the problem.

48.2 Investigate the cause of the problem. An investigation may include:

- Requests for further information from **asset owners**.
- Testing and measurement.
- Analysis of those measurements, including system modelling.
- Application of **constraints** on **dispatch** and reconfiguration of **assets** to identify potential resonance and sources.

48.3 Where identified, notify the relevant **asset owner** that is causing the problem and invoice any reasonable costs associated with investigating the problem.

48.4 Keep account of its costs in relation to the studies and invoice in accordance with the **Code** and the **System Operator Service Provider Agreement**.

48.5 If the problem has not been rectified and continues to persist then, in the absence of a requirement in the **Code** for **asset owners** to meet the relevant standards, the **system operator** must:

- Notify the **Authority** of the problem.
- **Advise** the actions that could be taken to rectify the problem.

49. The **system operator** must assess any problem in relation to clause 7.2D of the **Code** to ascertain whether that problem may lead to cascade failure. If the problem could lead to cascade failure the **system operator** must seek to identify the cause of the problem and, if any problem remains unaddressed:

49.1 Issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** requesting a response of the relevant **participants** to correct the problem.

49.2 Rely on the co-operation of the relevant **participants**, or the co-operation of **asset owners** as required by clause 8.26 of the **Code**.

Regional long term contingency planning

50. The **system operator** may from time to time identify, in a region, a material or on-going power system limitation or power system situation where the **system operator** believes there is a reasonable probability it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** to plan to comply and comply with the **PPOs.**

51. When the **system operator** identifies a power system limitation or power system situation under clause 50, it may establish and facilitate a forum of relevant **asset owner**s and interested **participants** to work jointly with it to assist it plan to comply and to comply with the **PPOs**. The **system operator** must establish a forum when:

51.1 it believes there is a reasonable possibility that:

51.1.1 without suitable contingency planning and information exchange, regionally material **demand** ~~**shedding**~~**management** may be required in order for it to comply with the **PPOs**; or

51.1.2 it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** for credible **dispatch** scenarios over an extended period of time in any region or regions; and

51.2 co-ordination of multiple **participants** in a region or regions would be required to mitigate the situation identified by it; and

51.3 no single **participant** is able or willing to act unilaterally to resolve the situation identified by it; and

51.4 ~~The **system operator**~~it considers there is sufficient time prior to a situation identified under clause 50 occurring in which to plan to minimise the impact of the situation.

52. In establishing and facilitating a forum described under clause 51, the **system operator** must:

52.1 Invite as contributing parties those **participants** it reasonably believes may be:

52.1.1 affected by the situation; or

52.1.2 able to assist with it planning to comply and to comply with the **PPOs** by reducing the potential need for recourse to the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** (or similar).

52.2 Arrange for **participants** in the forum to undertake such analysis of regional load **demand**, **asset** performance, and such other matters the **system operator** and **participants** in the forum consider relevant, and agree upon the necessary or desirable means to minimise the risk to the **system operator** having to rely on taking emergency actions under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** with the **assets** and generation **offers** likely to be available.

52.3 Use a planning horizon, for such forums, of no longer than 3 years.

53. Nothing in clauses 50 to 52 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code.**

Outage Planning

54. To meet its obligations under **Technical Code** D of Schedule 8.3 of the **Code**, the **system operator** must:

54.1 Carry out the assessment of all **notified planned outages** referred to in clause 3 of **Technical Code** D of Schedule 8.3 of the **Code**.

54.2 **Notify** relevant **asset owners** of **notified planned outages** where it considers such **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** close to or in real time in order to comply with the **PPOs**. When making such notifications the **system operator** may request that relevant **asset owners** notify it of suitable changes to the **notified**

planned outages.

54.3 Endeavour, where the relevant **asset owner**s fail to notify it of suitable changes to the **notified planned outages** in clause 54.2, to facilitate arrangements with the relevant **asset owner**s that will result in changes to the **notified planned outages** so that such outages will not result in the **system operator** relying on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.4 Re-assess the **notified planned outages** following the notification of any changes by relevant **asset owner**s under clause 54.2 or the facilitation of any arrangements in clause 54.3.

54.5 Advise the relevant **asset owner**s whether or not, following the re-assessment, it believes the relevant **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.6 Re-assess **notified planned outages** following receipt of any material, new information relating to the said **notified planned outages** or the power system which it believes may impact its ability to plan to comply, and comply with the **PPOs**.

55. Where the **system operator** reasonably identifies **notified planned outages** that may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs** and relevant **asset owners** are unable or unwilling to develop and notify the **system operator** of suitable changes to such outages, it may, where, in its reasonable opinion, there is insufficient time to otherwise plan to avoid **demand** ~~**shedding**~~**management** or where the expected period of risk is for a short duration, issue a **formal notice** and rely on emergency action under the
Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code**.

56. Nothing in clauses 54 to 55 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code**.

EMERGENCY PLANNING

General

57. The following sections set out the general policies for dealing with emergencies relating to security issues. They do not limit the powers of the **system operator** under the **Code** in respect of emergencies, and the **system operator** always retains the right to exercise its rights and powers under the **Code** in relation to emergencies.

58. To manage events greater than those catered for by the Risk Management Policies, or where the event cannot be satisfactorily managed through the normal application of the Risk Management Policies, the **system operator**

may rely on:

58.1 the ~~load shedding~~**AUFLS** and **AUVLS** provisions of clauses 8.19(5) and 8.24 of the **Code**.

58.2 the load shedding systems and independent action defined in **Technical Code** B of Schedule 8.3 of the **Code**.

58.3 **asset owner** compliance with the provisions of the **Code**.

58.4 the use of **standby residual shortfall notices** to advise **participants** when it believes there is or may be a **standby residual shortfall.**

58.5 any other means made available by **asset owners** that are assessed by the **system operator** as being capable of mitigating the need for **demand** ~~**shedding**~~**management**.

Standby Residual Shortfall

59. In the event the **system operator** identifies a **standby residual shortfall**:

59.1 if the **standby residual shortfall** is greater than the **standby residual shortfall threshold**, it must use reasonable endeavours to send to the **WITS manager**, for making available on **WITS**, a **standby residual shortfall notice**; and

59.2 it may, for such time as it believes reasonable and prudent, rely on **participant**s making such new **generator offers** and/or **reserve offers** it believes will be sufficient to mean that a **standby residual shortfall** no longer exists.

60. If there is a **standby residual shortfall**, and **participants** do not make sufficient new **generator offers** and/or **reserve offers**, the **system operator** may, in accordance with clause 4 of **Technical Code** D of Schedule 8.3 of the **Code**, request an **asset owner** of **assets** which are the subject of an outage or **notified planned outage** to keep those **assets** in service, with the intention of reducing the likelihood of the **system operator** having recourse to the Emergency Planning section of this **policy statement**.

61. *[Revoked]*

Formal Notices

62. The **system operator** must issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** where a **participant's** response is required to mitigate a risk and where the only other action available to the **system operator** will be ~~to shed~~ **demand** **management**.

62A The **system operator** may issue the following types of **formal notices**:

62A.1 A Grid Emergency Notice which declares a **grid emergency** in accordance with clause 13.97 of the **Code**.

62A.2 *[Revoked]*

62A.3 A Warning Notice which advises participants that **grid emergency** conditions are anticipated.

63. Where the **system operator** has identified a situation requiring the use of the

controls in this Emergency Planning section of the Security Policy prior to one hour before the start of the relevant **trading period**, the **system operator** must issue a Warning Notice.

64. Where the **system operator** has identified a situation requiring the use of the controls under this Emergency Planning section of the Security Policy within one hour ~~prior to~~before the start of the relevant **trading period** or during the relevant **trading period**, the **system operator** must issue a Grid Emergency Notice.

65. A Grid Emergency Notice must be issued whenever, or as soon as practicable after any of the events set out in clause 74 have occurred or the **system operator** determines they will occur and when the **system operator** considers that it will be unable to mitigate the situation without **participant** independent action, **grid** reconfiguration or **demand** ~~**shedding**~~**management**.

66. If the **system operator** decides to declare a **grid emergency**, it must make the declaration by issuing a **formal notice** orally or in writing. **Formal notices** may be issued orally in circumstances where either or both of the following situations exist:

    66.1 There is, in its view, insufficient time available to the **system operator** before the emergency arises to issue a written **formal notice**.

    66.2 One **participant** is**,** or a restricted number of **participants** are, required to, or able to, take specific action in accordance with **Technical Code** B of Schedule 8.3 of the **Code**, to alleviate a **grid emergency**.

67. **Formal notices** issued in writing must be sent to all **participants** that, in the **system operator's** view, may be able to assist in the mitigation of the **grid emergency** or will have a significant interest in the occurrence and nature of the **grid emergency**. All **formal notices** issued in writing must be shown on~~ the~~ its website as soon as reasonably practicable after being first sent to **participants**.

68. In addition to the content of a **formal notice** in clause 5 of **Technical Code** B of Schedule 8.3 of the **Code**, the **system operator** must use reasonable endeavours to include in every **formal notice** issued details of **assets**, which are relevant to the cause of the relevant **grid emergency** and the return to service of such **assets**, where such advice would assist it to plan to comply and to comply with the **PPOs**. The ability of the **system operator** to include details of such affected **assets** is subject to the ability and willingness of the owners of affected **assets** to make such details available to other **participants**.

69. The **system operator** must send to **participants** the report it provides to the **Authority** under clause 13.101(1)(a) of the **Code**.

70. Security levels must be re-assessed and **participants** advised as soon as reasonably practicable after the **system operator** is aware of any need to change the status of a **formal notice**. The **system operator** must revise the **formal notice** if:

    70.1 A situation is alleviated prior to the start of the **trading periods** for which the **formal notice** was issued.

    70.2 The start or end ~~time period~~times for which a situation exists, or is expected to exist, changes from the ~~**trading periods**~~times set out in the **formal notice**.

70.3 The electrical or geographical region affected changes from that set out in the **formal notice**.

71. There may be other notices issued by the **system operator** that, by definition, are not **formal notices** issued in accordance with **Technical Code** B of Schedule 8.3 of the **Code**.

Demand Management

72. *[Revoked]*

73. Where the **system operator** considers that the **dispatch** of available **assets** and **ancillary services** (and the application of the policies set out in other sections of this Security Policy) is not or is likely not to be sufficient or sufficiently timely to mitigate a situation, the **system operator** must ~~declare a **grid emergency** and~~ apply clause 74 in determining whether to initiate **demand** ~~**shedding**~~**management**.

74. **Demand ~~Shedding~~Management** scenarios:

Scenario	**Event giving rise to a grid emergency situation**	**Prior to 1 hour**	**Within 1 hour**	**Demand management policy**
A) Steady State, including steady state after an event has occurred.	Any **asset** is exceeding or is forecasted to exceed the advised capability limit stated in the **asset capability statement.**	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Voltage instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Transient or dynamic instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency.**
	Frequency keeping is unable to be maintained.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency.**
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a risk of significant **asset** damage.		Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Public safety is at risk.		Declare a **grid emergency**.	**Demand management** may occur if the **system operator** considers it appropriate in the specific circumstances.

Scenario	**Event giving rise to a grid emergency situation**	**Prior to 1 hour**	**Within 1 hour**	**Demand management policy**
	Independent action has been taken in accordance with **Technical Code** B of Schedule 8.3 of the **Code** to restore the **system operator**'s **PPO**s.		Declare a **grid emergency**.	**Demand management** may occur depending on the nature of the **grid emergency** and whether the **system operator** considers it appropriate in the specific circumstances.
	Restoration is required after a loss of supply and: ▪ **grid** reconfiguration and/or **demand management** is required; and ▪ more than one instruction to one or more **participants** is required to effect restoration.		Declare a **grid emergency**.	Refer to restoration policy (as contained in clause 84).
	An **unsupplied demand situation** occurs		Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
B) For a defined event.	Any **asset** will exceed the advised capability limit stated in the **asset capability statement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	A voltage stability limit is being exceeded.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	A transient or dynamic stability limit is being exceeded.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand management** may occur if **participant** responses do not mitigate the **grid emergency** and **demand management** would remedy the **stability event**.
	Frequency keeping will not be able to be maintained for a defined event.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for an **extended contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.2, **demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	There is a shortage of **instantaneous reserve** for a **contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.1, rely on the operation of **AUFLS** where sufficient to ensure compliance with the frequency **PPO**.
C) For a second defined event (after an event has occurred[2]).	Any **asset** will exceed the advised capability limit stated in the **asset capability statement** for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event or **asset owners** have advised the risks of exceeding capability are unacceptable.
	A voltage stability limit would be exceeded for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event
	A transient or dynamic stability limit is being exceeded for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur if **participant** responses do not mitigate the **grid emergency** and **demand management** would remedy the **stability event**.

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a second defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event. (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for a binding second **contingent event**.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event and **AUFLS** is insufficient to ensure the frequency **PPO** can be met.

[2]And where there are insufficient means to operate the power system to the requirements of the security policy following the event.

Demand Management Process

74A. Where the **system operator** determines that **demand management** may be required if **participant** responses to a **formal notice** do not mitigate a situation, the **system operator** may:

74A.1 request the **grid owner** to reconfigure the **grid**:

74A.2 request **participants** to increase **offers** and **reserve offers** and/or:

74A.3 request **participants** to reduce **demand** including **controllable load**.

74B. Where the **system operator** determines that **demand management** is required, the **system operator** may:

74B.1 instruct the **grid owner** to reconfigure the **grid**:

74B.2 instruct one or more **participants** to reduce **controllable load**:

74B.3 instruct one or more **participants** to reduce **demand** (either by a specific **MW** or percentage of **MW**):

74B.4 instruct one or more **participants** or the **grid owner** to **electrically disconnect demand** and/or:

74B.5 take any other reasonable action to alleviate the **grid emergency**.

Allocation of Demand Reduction

75. Where a **formal notice** is issued, and the **system operator** requests or instructs any **purchaser(s)** and/or **distributor(s) to** reduce **demand** ~~(as provided for~~ in accordance with clauses ~~6(1)(b) and 6(2)(c) of **Technical Code** B of Schedule 8.3 of the **Code**)~~74A or 74B, the **system operator** may include the following in the (verbal or written) **formal notice**:

  75.1 The **connected asset owners** from which, or the **offtake** point or points (**grid exit points**) at which, a **demand** reduction is required, which may be selected by the **system operator** at its discretion;

  75.2 Either the quantity of demand reduction required ~~at~~from the relevant **connected asset owners** or at the relevant **offtake** points (**grid exit points**~~),~~) as applicable, or the maximum **demand** which may be taken by the relevant **connected asset owners** or at the relevant **offtake** points (**grid exit points**~~);~~) as applicable;

  75.3 The time(s) for which the **demand** reduction is required.

75A. Where a **formal notice** is issued instructing the reduction of **demand** in accordance with clause 75, as soon as practicable after the notice is issued the **system operator** must provide the information described in the notice to its systems to comply with schedule 13.3AA of the **Code**.

76. *[Revoked]*

77. Without limiting its rights under **Technical Code** B of Schedule 8.3 of the **Code**, where **demand** from any **offtake** point is not reduced in accordance with the demand allocations specified in the **formal notice**, the **system operator** may require a relevant **distributor** to reduce **demand** in accordance with the process or processes agreed under clause 7(19) of **Technical Code** B of Schedule 8.3 of the **Code**.

78. In determining any demand allocations to be specified in the **formal notice**, the **system operator** must use reasonable endeavours to avoid a **demand** reduction of greater than 25% at a single **point of connection**, excepting when the total reduction of **demand** required in the affected region exceeds 25%.

~~79. After any urgent action to require **demand** reduction under **Technical Code** B of Schedule 8.3 of the **Code** the **system operator** must assess whether to proceed to restoration action, or to re-allocate reduced **demand** before restoration.~~

~~80. When it is judged by the **system operator** to be appropriate to re-allocate reduced **demand** the **system operator** must, in the absence of any agreement pursuant to clause 81, act to the extent practicable in accordance with the following allocation methodology:~~

  ~~80.1 To manage a peak capacity constraint each affected **offtake** point will be allocated a pro-rata share of the peak **demand** capacity, in the ratio of the annual average peaks of the **offtake** point **demand** and the total **demand** of the affected region. The annual average peak **demands** will be the averages of the five summer or five winter peaks for the previous year, with winter and summer periods defined as for **grid owner** transmission ratings.~~

  ~~80.2 To manage an energy capacity constraint, energy allocated for each affected **offtake** point shall be a pro rata calculation based on a~~

~~proportion of the energy consumed at the **offtake** point to the total energy consumed in the constrained region. In order to account for seasonal changes and different load characteristics this proportion will vary each month as a weighted average of:~~

~~80.2.1 75% of the proportion of energy consumed for the 12 months to the previous 30 June, and~~

~~80.2.2 25% of the proportion of energy consumed in the three months of the year up until the previous 30 June, starting one month before and ending one month after the calendar month during which energy allocation is to take place.~~

~~81. The **system operator** may use an alternative methodology to that in clause 80, where such alternative methodology has been formally agreed between the **system operator** and directly affected **distributors**.~~

79. *[Revoked]*

80. *[Revoked]*

80.1 *[Revoked]*

80.2 *[Revoked]*

81. *[Revoked]*

Restoration

82. The **system operator** must procure **black start**. The procurement details for these facilities are included in the **procurement plan**.

83. The **system operator** may rely on the synchronising facilities defined in **Technical Code** A of Schedule 8.3 of the **Code** to allow reconnection of sections of the **grid** and to connect generation to the **grid** during restoration.

84. Where restoration is required, the **system operator** must use the following methodology to re-establish normal operation of the power system by:

84.1 Addressing any aspects involving public safety.

84.2 Addressing any aspects involving avoidance of damage to **assets**.

84.3 Stabilising any remaining sections of the **grid** and connected **assets** and the voltage and frequency of the **grid**, through the combination of manual **dispatch instruction** and allowing automatic action of **ancillary services** and governor and voltage regulation operation by **generating plant**, and including any necessary disconnection of **demand**.

84.4 Actioning the steps set out in clauses 84.5, 84.6, 84.7 and 84.8 below in the order or in parallel as is judged by the **system operator**, at the time, as most effectively allowing reconnection of **demand**. The order that **assets** are **dispatched** will be influenced by availability, technical, geographic and other factors influencing rapid restoration of **demand**.

84.5 Restoring the transmission, generation, and/or **ancillary service assets** that failed when such restoration assists commencement of steps set out in clauses 84.6 and 84.7, where necessary utilising **black**

start facilities.

84.6 Restoring any disconnected **demand** (which includes any triggered **interruptible load**) at the rate permitted by the security and capability of the available combined generation and transmission system.

84.7 **Dispatching** additional generation and **ancillary services**, where such additional resources are needed to allow **demand** to be reinstated and necessary quality levels to be maintained.

84.8 Seeking revised **offers** where insufficient **offers** exist to achieve the restoration objectives.

84.9 Restoring normal security and power quality of the **grid** system to the levels set out in the **PPOs** and this Security Policy. If the reserve requirements have been set to zero under clause 33A, the actions taken under this clause must include restoring the reserve requirements to the levels set out in the Under-Frequency Management Policy.

84.10 Restoring energy injection levels to the values contained in an updated **dispatch schedule**.

Chapter 2 - Dispatch Policy

84A. The **system operator** must follow the process described by the Dispatch Process Statement to achieve the **dispatch objective**. Clauses 84B to 84O constitute the Dispatch Process Statement.

Software

84B. The **system operator** must include SPD in the **software** it uses for scheduling and **dispatch**.

84C. The **system operator** must use the reserve management tool (RMT) to assess the likely primary frequency response provided by connected generators and load to determine the minimum quantity of **instantaneous reserve** required to meet the frequency standards defined by clauses 7.2A(5) – (7) of the **Code**.

Week-ahead Dispatch Schedule

84D. The **system operator** must endeavour to prepare a week-ahead dispatch schedule once per day for the period from 14:00 hours the following day to 23:59 hours six days' hence.

84E. The week-ahead dispatch schedule must include as its inputs the inputs for the **non-response schedule** described in Part 13 of the Code, excluding ramp rates.

84F. When the **system operator** has completed a week-ahead dispatch schedule, the **system operator** must make the schedule results available to the **WITS Manager** for publication on **WITS**. The schedule results must include prices for each grid exit point, grid injection point and reference point.

Non-Response Schedule and Security Assessment

84G. In preparing the **non-response schedule** as required under Part 13 of the Code, to plan to comply with the principal performance obligations the system operator must use the **non-response schedule** to conduct regular security assessments for the schedule period. The **system operator** must use the results of the security assessment to make adjustments to inputs to subsequent **non-response schedules** and the **dispatch schedule** to achieve the **dispatch objective**.

84H. The **system operator** may adjust the **demand** input to the **non-response schedule** at a **non-conforming GXP** where it reasonably believes the demand quantity represented by the **nominated non-dispatch bids** for the **non-conforming GXP** is unreliable.

84I. The **system operator** must use the **non-response schedule** to schedule and dispatch **frequency keeping ancillary services**, and use frequency keeping constraints to adjust scheduled frequency keeping units' active power capacities for use in the **dispatch schedule**.

84J. In making its security assessment, in addition to any adjustments required under clause 84G the **system operator** may:

84J.1. request the **grid owner** to make changes to **notified planned outages**;

84J.2. identify potential **contingent events** and **extended contingent events** and make changes to the **instantaneous reserve** requirements;

84J.3. assess power flows to identify and assess possible transmission security restrictions, capacity restrictions, or voltage conditions on the **grid** and make changes to **security constraints**;

84J.4. identify shortfalls in standby capacity reserves and reschedule **frequency keeping** assets.

84K. Where the **system operator** has made adjustments to the inputs to the **non-response schedule** or the **dispatch schedule** described in clauses 84H to 84J, the adjustments must also be applied to the **price-responsive schedule**.

Dispatch Schedule

84L. The **system operator** must prepare the expected profile of **demand** for the **dispatch schedule** and publish its methodology on its **website**. The expected profile of **demand** must consist of:

84L.1. a measurement or estimate of the current system **demand**; and

84L.2. an estimate of the change in system **demand** in the next dispatch interval; and

84L.3. any **demand** information required to comply with schedule 13.3AA of the **Code**.

84M. The **system operator** may depart from the **dispatch schedule**, or adjust the **dispatch schedule** to comply and plan to comply with the **dispatch objective** by applying discretionary constraints, for situations requiring:

84M.1. dispatching a **generating unit** to simulate a change to the **offer** which has not been entered electronically through **WITS**;

84M.2. setting a **dispatchable load purchaser's nominated dispatch bid** to a **nominated non-dispatch bid** to simulate a change to the **nominated bid** which has not been entered electronically through **WITS**;

84M.3. dispatching a **generation unit** to minimum output to avoid loss of reserve capacity within the unit's restart cycle time;

84M.4. dispatching reserve capacity immediately to respond to a **contingent event** or **extended contingent event**;

84M.5. dispatching one or more **generating units** to a minimum **active power** output to provide **reactive power**;

84M.6. dispatching one or more **generating units** prior to the start time of a **notified planned outage** to enable the outage to proceed at the planned time;

84M.7. dispatching one or more **generating units** to allow switching operations to be undertaken in support of a **notified planned outage**;

84M.8. dispatching **generating units** to provide for management of a NZAS **reduction line change operation**;

84M.9. adjusting the power order on the **HVDC Link** prior to a **notified planned outage** to enable the outage to proceed at the planned time;

84M.10. instructing blocking or de-blocking a **pole** of the **HVDC Link** to provide for a feasible power order;

84M.11. adjusting the limits of **HVDC Link** capacity to avoid the need to schedule additional **instantaneous reserve** to cover the **extended contingent event** risk;

84M.12. adjusting the ramp rate of the **HVDC Link** to provide reserve capacity for an imminent system event; or

84M.13. increasing the amount of scheduled **instantaneous reserve** to cover an **extended contingent event** where system conditions have deviated from modelled system conditions for the current **trading period**.

84N. When the **system operator** has adjusted the **dispatch schedule** by applying a discretionary constraint of the type referred to in clause 84M, the system operator must make available to the **WITS Manager** for publication on **WITS** the equation and limit of the discretionary constraint.

84O. The **system operator** must publish on its **website** the post-schedule checks it uses to assess the accuracy of **dispatch prices** and **dispatch reserve prices**.

Dispatch Notification Participation

84P. In assessing an application to become a **dispatch notification purchaser** under clause 13.3E, or a **dispatch notification generator** under clause 13.3F of the **Code**, the **system operator** may decline an application if:

84P.1. for an application from a potential **dispatch notification purchaser**, the total capacity of the **dispatch-capable load station(s)** to be **bid** at a single **point of connection** to the **grid** is 30 MW or more; or

84P.2. the **system operator** requires the applicant to provide real time indications and measurements in accordance with Technical Code C or offers in accordance with 8.25 for the **assets** proposed to be **offered** or **bid;** or

84P.3. the applicant is unable to demonstrate functional systems for submission of **nominated bids** or **offers** to **WITS**, and receipt and acknowledgement of **dispatch notifications**; or

84P.4. the combined total capacity of **assets offered** or **bid** by **dispatch notification purchasers** and **dispatch notification generators** at a single **point of connection** to the **grid** exceeds an amount the **system operator** reasonably considers would threaten the **system operator's** ability to comply or plan to comply with the **PPOs**.

84Q. The **system operator** may suspend or revoke approval for a **dispatch notification purchaser** or **dispatch notification generator** under clauses 13.3E(4) or 13.3F(4) of the **Code** if:

84Q.1. the **participant** submits 3 or more rejection acknowledgements to **dispatch notifications** within a continuous 48-hour period;

84Q.2. the **participant** submits 5 or more rejection acknowledgements to

dispatch notifications within a continuous 30-day period;

84Q.3. the **participant** submits rejection acknowledgements to 3 consecutive **dispatch notifications;**

84Q.4. the **participant** fails to meet any of the criteria described in clause 84P.

85. *[Revoked]*

86. *[Revoked]*

86A. *[Revoked]*

87. *[Revoked]*

88. *[Revoked]*

88A. *[Revoked]*

88B. *[Revoked]*

88C. *[Revoked]*

89. *[Revoked]*

90. *[Revoked]*

91. *[Revoked]*

92. *[Revoked]*

92A. *[Revoked]*

93. *[Revoked]*

93A. *[Revoked]*

93B. *[Revoked]*

93C. *[Revoked]*

Chapter 3 – Compliance Policy

POLICY AND SCOPE

General Policy

94. The **system operator** must have systems in place to ensure it is able to efficiently carry out its functions in accordance with the following specific obligations under the **regulations** and **Code**:

    94.1 Proactively monitoring and reporting the **system operator's** compliance with its obligations under the **regulations** and **Code**.

    94.2 Monitoring and reporting **asset owner** compliance with the following obligations under the **Code**:

    - The **asset owner performance obligations**.
    - Obligations under the **technical codes**.
    - Obligations under **dispensations**.
    - Obligations under **equivalence arrangements**.
    - Obligations under **alternative ancillary service arrangements**.

    94.3 Receiving **asset** capability information and carrying out assessments of **asset** capability.

    94.4 Commissioning **assets**.

    94.5 Issuing **dispensations** and **equivalence arrangements**.

COMPLIANCE AND PERFORMANCE MONITORING

95. The **system operator** must have processes in place to achieve and maintain compliance with its obligations under the **regulations** and **Code** and must monitor its own performance for the purpose of:

    95.1 Meeting the **system operator**'s review and reporting obligations under the **regulations** and **Code**.

    95.2 Providing a basis for improvement and increased efficiency in the performance of its services over a period of time.

System Operator Compliance with Obligations under the **Regulations** and **Code**

96. The **system operator** must:

    96.1 Identify the obligations with which it must comply under the **regulations** and **Code** and document procedures for compliance with such obligations.

    96.2 Whenever the **system operator** identifies that it may have breached the **Code**, investigate the incident to determine:

96.2.1 Any contributory causes including any acts or omissions of other persons and secondary events and incidents.

96.2.2 Any mitigating factors.

96.2.3 Any corrective action necessary by the **system operator**, including any process changes, training issues, or areas where a change to the **Code** may be required.

Asset Owner Compliance and Performance Monitoring

97. The **system operator** must proactively monitor and report on **asset owner** compliance with:

97.1 **AOPOs** and the **technical codes**.

97.2 **Dispensations** and **equivalence arrangements**.

97.3 **Alternative ancillary services arrangements**.

Compliance with AOPOs and Technical Codes

98. To monitor **asset owner** compliance with the **AOPOs** and **technical Codes**, the **system operator** must:

98.1 Review the content of **asset capability statements** received from **asset owners** under **Technical Code** A of Schedule 8.3 of the **Code** to assure itself, as far as is reasonably practicable, of an **asset owner's** ability to comply with the **AOPOs** and relevant **technical codes**.

98.2 In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, review the information provided in the **asset capability statements**, to establish or confirm the limitations in the operation of the **asset** in question that the **system operator** needs to know for the safe and efficient operation of the **grid**.

98.3 In accordance with **Technical Code** A of Schedule 8.3 of the **Code**, rely on the results of any tests carried out under a **test plan** or a commissioning plan, to establish or confirm **asset** capability in accordance with the **AOPOs** and the **technical code** requirements.

98.4 *[Revoked]*

98.5 In accordance with clause 8.4 of the **Code** and following the receipt of an **asset capability statement**, and subject to any tests carried out under a **test plan** or commissioning plan, rely on the **assets** and information about such **assets** made available to the **system operator** unless the **system operator** considers, acting reasonably and based on the information received by or otherwise known to the **system operator**, that it should not rely upon the accuracy of an **asset owner's asset capability statement**.

98.6 During **dispatch**, log suspected or actual **asset owner** non-compliance with the **AOPOs** and the **technical codes** based upon information that is available to the **system operator** when fulfilling its **dispatch** obligations under the **Code**.

98.7 Where the **system operator** has non-confidential information on which it has relied in determining, under clause 98.5, not to rely on the accuracy of an **asset owner asset capability statement**, it must notify such information to the relevant **asset owner** as soon as reasonably practicable.

Compliance with Dispensations and Equivalence Arrangements

99. The **system operator** must undertake any specific monitoring required as a condition of a **dispensation** or **equivalence** **arrangement.** ~~**arrangement.**~~

Compliance with Alternative Ancillary Services Arrangements

100. The **system operator** must, following consultation with the relevant **asset owner**, specify any requirements to facilitate proactive compliance monitoring of the **alternative ancillary services arrangement** as a condition of the **system operator's** approval of such arrangements under Schedule 8.2 of the Code.

Asset Owner Non-Compliance

101. Where the **system operator** suspects that an **asset owner** may have breached or has breached any specific obligation under the **regulations**, **Code** or conditions of any **equivalence arrangement**, **dispensation** or **alternative ancillary services arrangement**, the **system operator** must:

101.1 consider the circumstances to see if there are reasonable grounds for believing a breach has occurred.

101.2 seek such further information from a relevant **asset owner** as may be necessary to undertake such consideration.

101.3 determine in accordance with clause 8.27(2) of the **Code** whether to **dispatch** the **asset** or configuration of **assets** that it does not reasonably believe complies with the **AOPOs**, **technical code**, **dispensation** or **equivalence arrangement** in question.

101.4 assess any potential impact of the non-compliance on its ability to continue to comply with the **PPOs** and notify such impact to the **Authority**.

101.5 tell **participants** of its intention to revoke or amend a **dispensation** or **equivalence arrangement** in accordance with clause 8.35 of the **Code**, or its intention to revoke or amend any **alternative ancillary services arrangement** in accordance with clause 8.52 of the **Code**.

Urgent Change Notice

102. The **system operator** must make available on its website an **urgent change notice** form to inform the **system operator** of an urgent or temporary change in **asset** capability where clause 2(6)(b) of **Technical Code** A of Schedule 8.3 of the **Code** does not apply. An urgent or temporary change in **asset** capability is a change where the **asset owner**:

102.1 unexpectedly becomes aware the capability of an **asset** may differ from the capability described in the most recent **asset capability statement** provided to the **system operator** in respect of such **asset** and there is no practicable opportunity to lodge a new **asset capability statement** in accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, and

102.2 needs to perform further investigations to determine or confirm the actual capability of the **asset**.

103. An **urgent change notice** will apply for the period specified in the **urgent change notice** and will be the **asset owner's** best assessment (based on the information it has to hand) as to the actual capability of the relevant **asset**. On receipt of an **urgent change notice** by the **system operator**, the most recent **asset capability statement** in respect of the relevant **asset** will be deemed to be amended to reflect the capability set out in the **urgent change notice**.

104. When the **system operator** receives an **urgent change notice** it must as soon as reasonably possible:

104.1 assess the impact the urgent or temporary change in **asset** capability will have on the **system operator's** ability to plan to comply or comply with its **PPOs**.

104.2 endeavour to agree with the **asset owner** any necessary operating conditions or limitations required as a result of the temporary change in **asset** capability.

104.3 advise the **asset owner** of any conditions or constraints that the **system operator** will apply in respect of the **dispatch** of the **asset** (and it must update the **asset owner** if it changes these constraints or conditions at any time).

ASSET CAPABILITY INFORMATION

General Policy

105. In assessing the performance of an asset to assist the **system operator** to plan to comply and comply with the **principal performance obligations** and the **dispatch objective**, the **system operator** will only use information supplied by the **asset owner** through an **asset capability statement**.

106. *[Revoked]*

General Information Required from Asset Owners

107. In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must **advise** a standard format **asset capability statement** for the following types of **asset owner**:

107.1 **generators** for **generating units** connected to the **grid** and to a **local network**.

107.2 **grid owners**.

107.3 **distributors**.

ASSET CAPABILITY ASSESSMENTS

General Asset Capability Assessment

108. The **system operator** has identified a number of areas where **asset** performance can have a significant impact on the **system operator's** ability to comply with the **PPOs**. These include:

108.1 **asset owner** protection systems.

108.2 **generator asset** capability:

- Voltage.
- Frequency.
- Fault ride-through capability.

108.3 **grid owner asset** capability:

- Voltage.
- **HVDC link** frequency capability.
- South Island **AUFLS**.

108.4 **distributor asset** capability:

- North Island **AUFLS**.
- Frequency response capability of unoffered generation on the **distributor**'s network
- Fault ride-through capability of **generating units** on the **distributor**'s network.

Asset Owner Protection Systems

Grid Owners

109. The **system operator** may rely upon **grid owner** compliance with the **technical codes** in the design and configuration of the **grid owner's assets** (including its connections to other persons) and associated protection arrangements, as contained in Subpart 2 of Part 8 of the **Code** and Schedule 8.3 of the **Code**.

110. In accordance with clause 4(5)(b) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** and the **grid owner** must agree the locations to check synchronism and **grid owner** confirmation of this synchronism must be requested in the **asset capability statement**.

111. *[Revoked]*

111.1 *[Revoked]*

111.2 *[Revoked]*

111.3 *[Revoked]*

111.4 *[Revoked]*

112. *[Revoked]*

112.1 *[Revoked]*

112.2 *[Revoked]*

113. *[Revoked]*

Generator Asset Capability Assessment

Voltage

114. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant reactive capability** with respect to the **AOPOs** set out in clause 8.23 of the **Code** by;

114.1 assuming:

- the **generating plant** and the **grid** bus are represented as a two-bus system.
- the **generating plant's** outputs are net **active power** and **reactive power** after accounting for local supply or auxiliary load and are measured at the **generating plant** terminal entering the **generating plant** transformer
- the **generating plant** has a terminal voltage control range of +/- 5% unless otherwise stated in the relevant **asset capability statement**.

114.2 Verifying compliance with the reactive power requirements of clause 8.23 of the **Code** by assessing:

- the **generating plant** reactive power range when importing and exporting at full load with respect to the standards.
- the ability of **generating plant**, when importing and exporting **reactive power** at full load, to maintain the voltage within the ranges set out in the tables set out in clause 8.23 of the **Code**.
- the ability for **generating plant** to be connected over the operating ranges set out in clause 8.22 of the **Code** considering:
- **generating plant** reactive power range.
  - **Generating plant** transformer tap range, including the requirement for on-load tap changers.
  - **Generating plant** terminal voltage range.
  - **Generating plant** voltage stability when small voltage perturbations are applied to excitors.

Voltage Fault Ride Through

114A For the purpose of carrying out an assessment of fault ride through compliance under clause 8.25A of the **Code**, the **system operator** must make available on its website a summary of the assumptions used in the assessment.

Frequency

115. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

115.1 assessing the **generating plant** trip settings.

115.2 modelling **generating plant** and governor performance to analyse frequency performance.

115.3 assessing **generating plant** performance when islanded.

115.4 modelling **generating plant** governors and excitors to confirm stability when voltage perturbations are applied to excitors and load changes are applied to governors.

Grid Owner Asset Capability Assessment

Voltage

116. To enable the **system operator** to manage the risk of cascade failure, the **system operator** must:

116.1 assess the information **grid owners** provide regarding the details of the operational voltage range capability of their **assets** described in their **asset capability statements**.

116.2 model the performance of dynamic reactive power devices to establish stability and to obtain parameters for the **system operator** to model the system dynamics for planning and system security analysis.

HVDC Frequency Capability

117. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **HVDC Owner** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

117.1 assessing the **HVDC Owner** trip settings.

117.2 modelling the **HVDC link** performance to analyse its frequency performance.

Automatic Under-Frequency Load Shedding (AUFLS)

117A. To manage its risk of cascade failure, the **system operator** must:

117A.1 request that the South Island **grid owner** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

117A.2 maintain a register of **AUFLS** profiling statements to determine the minimum **AUFLS** percentage available at any time.

117A.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

Distributor Asset Capability Assessment

Automatic Under-Frequency Load Shedding (AUFLS)

118. To manage its risk of cascade failure, the **system operator** must:

118.1 request that North Island **distributors** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

118.2 maintain a register of **AUFLS** profiling statements to determine the minimum **AUFLS** percentage available at any time.

118.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

COMMISSIONING ASSETS

General Policy

119. The **system operator** must carry out the following actions in relation to commissioning:

119.1 To ascertain whether the commissioning will affect the **system operator's** ability to plan to comply and comply with the **PPO** objectives, evaluate **asset owner** compliance with the **AOPOs** and the **technical codes**, using the information provided by the **asset owner** in accordance with clauses 2 and 3 of **Technical Code** A of Schedule 8.3 of the **Code**, at the following stages:

- Planning.
- Building and prior to commissioning.
- During commissioning.
- On completion of commissioning.

119.2 Make available on its website a ~~`~~'Connection and Dispatch ~~Guide`~~Guide' that describes the studies undertaken by the **system operator** at different stages of commissioning and the timeframes for assessment required by the **system operator** at different stages of commissioning. This guide must state the information required from **asset owners** at each of the above stages, including information required by the **asset capability statements** in the form listed on its website for each **asset** that is proposed to be connected, or is connected to, or forms part of the **grid**.

120. The **system operator** must assess **asset capability statements** provided to the **system operator** by **asset owners** for **assets** that are being commissioned or modified at each of the following stages:

120.1 Prior to the completion of planning for the construction of an **asset.**

120.2 At completion of construction of an **asset**.

120.3 At completion of commissioning of an **asset**.

120.4 At any time the **asset owner** updates the **asset capability statement** during any stage of commissioning.

121. Upon receipt of an **asset capability statement**, the **system operator** must carry out any assessments necessary and notify the **asset owner**:

121.1 whether the **system operator** requires any further information to determine whether the **asset** will, in its reasonable opinion, meet the requirements of the **AOPOs** and the **technical codes**.

121.2 whether, on the basis of the information provided by the **asset owner** and any assumptions made by the **system operator** and notified to the **asset owner**, the **asset** will in the **system operator**'s reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**.

121.3 whether the **system operator**'s decision is based on any specific conditions and / or assumptions.

121.4 if the **system operator** is not satisfied the **asset** will in its reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**, of any appropriate actions required for the **asset owner** to achieve compliance, including application for a **dispensation** or **equivalence arrangement**.

122. If appropriate, the **system operator** may repeat the process described in clause 121 until the **system operator** is reasonably satisfied the **asset** will meet the requirements of the **AOPOs** and the **technical codes.**

Commissioning Plan

123. When the **asset owner** notifies the **system operator** the **asset** is, or will be, ready for commissioning, the **system operator** must require the **asset owner** to provide a commissioning plan to meet the requirements of clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**. In order to assess the commissioning plan, the **system operator** may require the commissioning plan to address the following matters (in addition to the specific matters set out at clauses 2(7) and 2(8) of **Technical Code** A of Schedule 8.3 of the **Code**):

123.1 Proposed dates and times for commissioning and testing activities.

123.2 Preliminary stability check.

123.3 Proposed reactive output.

123.4 Configuration.

123.5 Control system tuning.

123.6 Any other matters which the **system operator** reasonably considers relevant to enabling the **system operator** to plan to comply, and to comply, with its **PPOs**.

Dispatch for Commissioning

124. *[Revoked]*

125. The **system operator** will only **dispatch** commissioning **assets** solely for commissioning purposes.

During Commissioning

126. During commissioning of the **asset**, the **system operator** must review the results of the various tests to:

126.1 confirm the results of any previous assessments of the **asset** carried out prior to commissioning.

126.2 re-assess compliance of the **asset** with the **AOPOs** and the **technical codes**.

Final Assessment

127. Upon receipt of a final **asset capability statement** from the **asset owner** after commissioning, the **system operator** must:

127.1 complete a final assessment of the **asset** for compliance with the **AOPOs** and the **technical codes**.

127.2 finalise the assessment process of any request for **dispensation** or **equivalence arrangement** in accordance with this Compliance Policy.

Test Plan

128. The **system operator** must make available on the **Transpower** website:

128.1 a template for a **system test** that can be used by **asset owners** where the circumstances in clause 2(6)(c) of **Technical Code** A of Schedule 8.3 of the **Code** apply. If the **system operator** agrees to **dispatch** the **asset** referred to in a **test plan** submitted to it by an **asset owner** using the template, it must thereafter consider any **asset** capability information in the **test plan** that differs from that contained in the most recent **asset capability statement** provided to the **system operator** in respect of such **asset** to replace the relevant **asset** capability information for the duration agreed in the **test plan**.

128.2 the companion guides for **asset** testing, which assists **asset owners** to implement the requirements for **asset** testing in clauses 2(6) to (8) and 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** and testing after modification and **commissioning**. The companion guides for **asset** testing must:

128.2.1 be reviewed not less than once in each period of five years. When carrying out each review the **system operator** must invite comments from **registered participants** as to the process and the content of the review.

128.2.2 outline the information from **asset** testing undertaken by **asset owners** under clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** that will assist the **system operator** understand the nature of the tests carried out and the results thereof.

128.2.3 describe suggested standards or appropriate methodology for the routine testing of **assets** set out in Appendix B of

Technical Code A of Schedule 8.3 of the **Code**.

128.2.4 describe the tests that **asset owners** can undertake after modification and **commissioning** to ensure the provision of appropriate information to the **system operator** in accordance with clauses 2(2) and 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**.

128.2.5 describe the tests that an **ancillary service agent** may be requested by the **system operator** to undertake to demonstrate an **asset** is capable of meeting the technical requirements and performance standards set out in a relevant **ancillary service** procurement contract.

DISPENSATIONS AND EQUIVALENCE ARRANGEMENTS

General Policy

129. To facilitate the operation of the processes under the **Code** for the approval of **equivalence arrangements** and grant of **dispensations**, the **system operator** must provide the following information:

129.1 Contact details for communication with the **system operator** on application, information, and revision of information or cancellation of the application or other matters relating to **equivalence arrangements** and **dispensations**.

129.2 A pro forma application form for **dispensations** or **equivalence arrangements**.

129A. The **system operator** must make its assessment of an application for a **dispensation** or an **equivalence arrangement** based on the information it has and the circumstances existing at the time. Information relevant to the **system operator's** assessment includes:

(a) the content of the regulations and **Code**.

(b) the content of the **policy statement** and **procurement plan**.

(c) power system **assets**, availability, and outages.

(d) knowledge regarding **asset** capability.

129B. The **system operator** must consider any request for a **dispensation** or **equivalence arrangement** by the relevant **asset owner** prior to the **asset** in question being commissioned.

Terms and Conditions of Dispensations and Equivalence Arrangements

130. The **system operator** may approve such a request subject to reasonable conditions including, without limitation, the following:

130.1 Any approval granted by the **system operator** for a **dispensation** or **equivalence arrangement** prior to the **asset** in question being commissioned will terminate after 2 years from the approval date if the **asset** is not commissioned.

130.2 If required, the **asset owner** may apply to the **system operator** to extend the 2 year term. The **system operator** may not unreasonably withhold such consent.

131. *[Revoked]*

131A. **Dispensations** and **equivalence arrangements** are subject to review at the time the **system operator** produces or reviews the **system security forecast** in accordance with clause 8.15 of the **Code**. The purpose of the review is to ascertain whether there has been any material change in circumstances or to the assumptions on which the **dispensation** was granted or the **equivalence arrangement** approved.

131B. Under Part 8 of the **Code** the **system operator** may revoke or vary a **dispensation**, or revoke an **equivalence arrangement**, in certain circumstances.

132. *[Revoked]*

Dispensation, Equivalence Arrangement and Alternative Ancillary Service Arrangements Register

133. The following must apply to the **publication** of information on the **system operator register:**

133.1 The **system operator register** must contain no information which has been designated a commercially sensitive by the relevant **asset owner**.

133.2 The **system operator** must designate an employee role to be responsible for managing the **system operator register**.

133.3 The **system operator** must maintain an up to date copy of the **system operator register** and make it available to **registered participants** at no cost on the **system operator's** website at all reasonable times.

133A. The **system operator** must make available on its website a list of current **dispensations**, **equivalence arrangements** and **alternative ancillary services arrangements**.

Cancellation of Arrangements

134. The **system operator** must consider any request for cancellation of a **dispensation** or **equivalence arrangement** by the relevant **asset owner** provided that the request must:

134.1 be in writing.

134.2 be accompanied by a description of how compliance for that **asset**, for which the **dispensation** or **equivalence arrangement** was originally sought, is now achieved.

134.3 include an updated **asset capability statement**.

134.4 include any results from **system tests** carried out to confirm compliance with the **AOPOs** and **technical codes**.

Chapter 4 – Conflict Of Interest Policy

General Policy

134A This Conflict of Interest Policy sets out the methods the **system operator** must use to manage possible, actual or perceived conflicts of interest that arise within **Transpower** between its **system operator** functions and any of its other **participant** functions, including the **grid owner** function. A conflict of interest is any situation where one of the following persons has a material interest in the outcome of a **system operator** function:

- **Transpower**, other than in its capacity as the system operator.
- A **Transpower** employee, contractor or director involved in carrying out the function.

134B. Some examples of **system operator** functions where conflicts of interest and where questions of independence and impartiality may arise include:

- procurement of **ancillary services** or **alternative ancillary services**.
- **causer** recommendations.
- **dispensation** and **equivalence arrangement** decisions.
- **outage** co-ordination.
- **Code** compliance monitoring and reporting.

GENERAL APPROACH

135. The **system operator** must:

135.1 identify potential conflicts of interest that arise in the performance of the **system operator's** functions, including by providing easily accessible means by which **Transpower** personnel and persons external to **Transpower** can (anonymously if they wish through its website) notify the **system operator** of potential conflicts of interest.

135.2 investigate and assess the materiality of each conflict of interest that has been identified.

135.3 apply methods to manage each conflict of interest that are appropriate for the materiality of the conflict of interest.

135.3A record all potential conflicts of interest in the Conflicts of Interest Register as they arise, including the **system operator's** assessment of materiality for each conflict of interest and the methods used to manage each conflict of interest.

135.4 report to the **Authority** in the **system operator's** monthly report under clause 3.14 of the **Code**, and on the **Authority's** request, on:

135.4.1 any new conflict of interest that has arisen since the last report, including the nature of the conflict of interest, the date the conflict of interest was identified and notified to the **Authority** (if prior to the monthly report), the reason it has arisen, assessment of materiality and the methods by which it was or will be managed.

135.4.2 any breaches of this Conflict of Interest Policy.

135.4A report to the **Authority** in the **system operator's** annual report under clause 7.11 of the **Code**, on the **system operator's** compliance with its obligations under the **Code**, including:

135.4A.1 the background of any event that warranted the system operator undertaking internal performance review and report findings;

135.4A.2 a description of the event;

135.4A.3 the means by which the conflict of interest was managed; and

135.4A.4 any departures from or proposed changes to policy.

135.5 Treat all **participants** in an even-handed way, including by applying the same processes and standards to its dealings with all **participants**.

135.6 [Revoked]

136. [Revoked]

137. [Revoked]

THE MEANS TO MANAGE CONFLICT OF INTEREST

138. The **system operator** must employ any or all of the following methods to manage conflicts of interest, taking into account the circumstances and materiality of the conflict of interest:

138.1A Appoint an independent person to oversee the management of the conflict of interest.

138.2A Appoint an independent expert to conduct an evaluation or investigation on behalf of, or to advise, the **system operator**.

138.3A Establish independent document and information management systems.

138.4A Establish a communication management system between the relevant parts of Transpower New Zealand Limited, which may include call logs, document logs, meeting minutes and specified points of contact.

138.5A Establish a clear division of management and staff roles. This may include the establishment of separate teams that are physically isolated from each other.

138.6A Advise any relevant non-confidential information considered material in maintaining a transparent and impartial process.

138.7A Any other method the **system operator** identifies and considers appropriate to manage the conflict of interest, which the **system operator** must **advise** as soon as reasonably practicable.

138.1 [Revoked]

138.2 [Revoked]

138.3 [Revoked]

138.4 [Revoked]

138.5 [Revoked]

138.6 [Revoked]

138.7 [Revoked]

138.8 [Revoked]

139. [Revoked]

140. [Revoked]

141. [Revoked]

142. [Revoked]

143. [Revoked]

143.1 [Revoked]

143.2 [Revoked]

143.3 [Revoked]

143.4 [Revoked]

143.5 [Revoked]

143.6 [Revoked]

144. [Revoked]

145. [Revoked]

145.1 [Revoked]

145.2 [Revoked]

146. [Revoked]

146.1 [Revoked]

146.2 [Revoked]

146.3 [Revoked]

146.4 [Revoked]

147. [Revoked]

148. [Revoked]

148.1 [Revoked]

148.2 [Revoked]

149. [Revoked]

149.1 [Revoked]

149.2 [Revoked]

149.3 [Revoked]

149.4 [Revoked]

150. [Revoked]

151. [Revoked]

152. [Revoked]

152.1 [Revoked]

152.2 [Revoked]

152.3 [Revoked]

152.4 [Revoked]

Chapter 5 – Future Formulation and Implementation Policy

Policy and Scope

153. The **Code** contains provisions that require the **system operator** to be consulted on the impact of proposed **Code** changes. This ensures that where necessary, the impact of **Code** changes can be reflected in the **policy statement** by making timely changes outside the ~~annual~~two-yearly review cycle.

154. The **system operator** maintains operational review processes that capture issues for which possible change to the **policy statement** may be desirable. Such matters are logged for consideration during the next review of the **policy statement**. The matters logged include issues raised with the **system operator** by **participants** and the **Authority**.

155. If an issue is identified requiring urgent attention and change to the **policy statement** outside the ~~annual~~two-yearly review cycle the **system operator** must bring the matter to the attention of the **Authority**. The **system operator** must seek the **Authority's** assistance in implementing the required change, such as by **Code** change, change to the **policy statement** or approval of an exemption.

156. [Revoked]

156.1 [Revoked]

156.2 [Revoked]

156.3 [Revoked]

156.4 [Revoked]

156.5 [Revoked]

156.6 [Revoked]

156.7 [Revoked]

156.8 [Revoked]

Chapter 6 - Statement of Reasons for Adopting Policies and Means

157. The **system operator** has adopted the policies and means set out in the **policy statement** for the following reasons:

157.1 The **system operator** believes they are the policies and means that will best enable it to comply with the **principal performance obligations**.

157.2 They are policies and means that in large measure have been used successfully for many years.

157.3 To the extent the policies and means represent changes from those adopted previously it is because the **system operator** believes no previous policy or means existed or a previous policy or means did not adequately meet the needs of the **system operator**.

157.4 The **system operator** consulted widely when it developed the policies and means set out in the **policy statement** and took into account the views of **participants**.

This statement is made for the purposes of clause 8.11(3)(d) of the **Code**.

Glossary of Terms

158. **Advise** means the **system operator** placing information or other material required to be provided or made available under the **policy statement** on its website. The **system operator** must use its best endeavours to send an e-mail to **participants** telling them the information or other material has been placed on the **system operator's** website.

159. **Asset outage constraints** are a sub-set of **security constraints.** They are **security constraints** previously developed and used by the **system operator** temporarily in response to earlier advised **asset** outages. They are retained by the **system operator** for possible future re-use. They are often applied at short notice.

160. **AUFLS** means **automatic under-frequency load shedding** systems.

160A. **Automatic under-voltage load shedding** and **AUVLS** means automatic shedding of electrical load when voltage falls below the relevant pre-set voltage.

161. **Changeover date** means 28 March 2011.

162. *[Revoked]*

162A. **Constraint percentage threshold** means the threshold at which constraints developed by automatic processes are applied to schedules in the market system, expressed as a percentage of the limit of the constraint. This threshold is **advised** from time to time by the **system operator**, following consultation with **participants.** Separate constraint percentage thresholds may be **advised** for constraints developed under automated and non-automated processes.

162B **Constraint publication threshold** means the threshold at which constraints are published on **WITS**, expressed as a percentage of a constraint limit. This threshold is **advised** from time to time by the **system operator,** following consultation with **participants.**

163. **Contingent events** are as defined in clauses 12.3 and 12.4.

164. **Demand ~~shedding~~management** means an unplanned interruption of **demand** initiated by the **system operator**. The **system operator's demand management** ~~also has the same meaning~~process is described in clauses 74A and 74B.

164A. **Discretionary security constraint** means a **security** constraint applied to **SPD** by the **system operator** that represents a departure from the **dispatch schedule** pursuant to clause 13.70 of the **Code**.

165. **Dynamic load distribution factor** means the proportion of a regional load being drawn at a **GXP** within that region. The **dynamic load distribution factors** are derived from actual load on a regularly updated basis in real time.

166. *[Revoked]*

167. **Extended contingent events** are as defined in clauses 12.3 and 12.4.

168. **Fixed load distribution factor** means the proportion of the regional load forecast assigned to a **GXP** within that region. The **fixed**

load distribution factors are set for a specified **trading period** based on the actual load for the same **trading period** in the previous week or in the previous fortnight.

169. **Frequency keeping constraints** means **security constraints** applied by the **system operator** in scheduling and **dispatch** for the purposes of maintaining a frequency keeper within its offered **asset** capability limits.

169A. **Market schedules** means, collectively, the **price-responsive schedule**, **non-response schedule** and the **real-time dispatch schedule**.

170. **Maximum instantaneous demand change limit** is the **MW** amount specified from time to time by the **system operator** under clause 39 for **demand** changes that may be made by any **purchaser** within a 1 minute and a 5 minute period.

170A [Revoked]

171. **Other events** are as defined in clause 12.3.

172. [Revoked]

173. **Planned Outage Co-ordination Process** means the process by which the **system operator** receives, assesses and provides feedback on outage notifications in accordance with **Technical Code** D of Schedule 8.3 of the **Code**.

173AA **Reduction line change operation** means the planned or unplanned NZAS reduction line removal and restoration process at Tiwai Aluminum smelter.

173A. **Regulations** means the regulations made pursuant to subpart 1 of Part 5 of the **Act** as may be amended from time to time.

174. **Relevant freely available reactive resources** are reactive resources that exist, the **dispatch** of which will support voltage at the affected location, which are available to the **system operator** at no **procurement plan** cost and without requiring the application of a **security constraint** to provide reactive resources. They include **grid owner assets** capable of providing reactive support and made available, and generation **dispatched**, and required to provide reactive support in accordance with the **voltage support AOPOs**.

175. **Reserves Management Tool** and **RMT** mean the reserves management **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

176. **Scheduling Pricing and Dispatch** and **SPD** mean the scheduling, pricing and dispatch **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

177. *[Revoked]*

178. **Security constraint** is a constraint that is used to maintain the security and stability of the power system.

~~179. *[Revoked]*~~

179. A **stability event** is an event that prevents the power system from regaining **system stability** or prevents specific **generating units** from maintaining

stable operation within the power system. These events include, but are not limited to:

- for voltage stability, the tripping (with or without fault) of a **generating unit** or a transmission circuit;
- for rotor angle stability, a fault on the grid (which may or may not result in consequent outages of transmission equipment);
- for control system stability, any normal or abnormal operating conditions resulting in unexpected control system behaviour.

180. A **standby residual shortfall** is a situation when there are either insufficient **generator offers** and **instantaneous reserve** offers following a **contingent event** to schedule sufficient reserves for a second event and/or there are insufficient **generator offers** to restore **interruptible load** following a **contingent event**.

181. A **standby residual shortfall notice** is a notice issued by the **system operator** to selected **participants** in which it advises that a **standby residual shortfall** has been identified.

181A. **Standby residual shortfall threshold** means the threshold above which a **standby residual shortfall notice** must be issued**,** such threshold being determined from time to time by the **system operator** and notified by the **system operator** to **participants**.

182. **System Operator Service Provider Agreement** means the **market operation service provider agreement** for the provision of **system operator** services.

182A. **System stability** is the normal operating conditions expected to exist in the power system, where perturbations are being maintained within the expected range(s), in such a way that the power system dynamic behaviour is not resulting in any restriction on the normal operation of any **generating unit**, load or other connected equipment. This includes, but is not limited to:

- voltage stability (ability to maintain steady state voltages at all buses in the system after subjected to a disturbance);
- rotor angular stability (ability of the **synchronous** machines in the power system to remain **synchronised** under normal operating conditions and to regain **synchronism** if subjected to a disturbance; or
- control system stability (the ability of the control systems of any **generating unit** to maintain stable operation during both the steady state and dynamic interactions with the power system, including but not limited to dynamic interactions with any other **generating unit**).

183. **Target grid voltages** are voltages determined by the **system operator** under clause 41.1 of the Security Policy at selected locations on the **grid** where the voltage is greater than, or equal to 50kV.

184. **Temporary security constraints,** which include **asset outage constraints**, are **security constraints** which are applied in scheduling and **dispatch** to supplement **permanent security constraints** and account for temporary **grid** configuration, transmission capability and system conditions.

185. **Test plan** means:

185.1 a routine test plan agreed pursuant to clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code**;

185.2 a remedial test plan agreed pursuant to clause 8(3)(a) of **Technical**

Code A of Schedule 8.3 of the **Code**; or

185.3 a test plan agreed between the **system operator** and an **asset owner** under clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**.

186. **Transmission circuit** means:

186.1 any transmission line owned by a **grid owner**.

186.2 any distribution line owned by a **participant** to which not less than a sum of 60 **MW** of **generation** is connected and which distribution line is connected to the **grid** primarily for the purpose of **injection** into the **grid**.

187. **Urgent change notice** is a notice issued to the **system operator** by a **participant** in accordance with clause 102.

188. **Week-ahead dispatch schedule** means a schedule produced by the **system operator** for the 260 **trading periods** beginning at 14.00 hours of the next **day** using:

188.1 Generation **offers** or, where no revised **offer** exists, generation **offers** for the previous week.

188.2 Forecast **grid** configuration, including any **notified planned outages.**

188.3 Anticipated **demand** using **fixed load distribution factors**.

188.4 **Nominated bids** or, where no revised **nominated bid** exists, **nominated bids** for the previous week.

189. **Wider voltage agreement** is an arrangement where the **grid owner** has informed the **system operator**, in writing that:

189.1 The **grid owner** has agreed with other affected **asset owners** at a **GXP** or in a region that the **system operator** may operate outside the ranges set out in clause 8.22(1) of the **Code**.

189.2 Where the **grid owner** has not identified any other affected **asset owners** at a **GXP** or in a region, **the grid owner** agrees with the **system operator** to operate the **grid owner's assets** outside the ranges set out in clause 8.22(1) of the **Code**.

Appendix C Clean version of amended policy statement

Policy statement

Contents

Introduction

PURPOSE

1. This is the **policy statement** referred to in part 8 of the **Code**.

1A. This **policy statement** takes effect from 14 March 2025.

1B. References to the **system operator's** website in this policy statement refer to the system operator page on the **Transpower** website.

2. The **policy statement**:

    2.1 forms a transparent basis from which detailed procedures are developed to support compliance with the policy as well as a mechanism for continually improving existing practices.

    2.2 clarifies the risks being managed by policy and the key assumptions made in managing those risks.

SYSTEM OPERATOR POLICIES TO ACHIEVE THE PPOS AND DISPATCH OBJECTIVE

3. The policies by which the **system operator** must seek to achieve the various **PPOs** (and other deliverables) are set out in the sections of the **policy statement** as follows:

Avoid Cascade Failure

4. The policies to be adopted in respect of avoiding cascade failure are set out in:

    4.1 The Security Policy that:

        4.1.1 Outlines how commonly occurring events are to be managed with the intention to avoid exceeding:

            (a) Frequency limits.
            (b) **Asset** capability (including voltage limits), normally without **demand management** being required.

        4.1.2 Outlines the use of **automatic under-frequency load shedding** to manage **extended contingent events**, where **demand** may otherwise be shed to maintain the security policies and the requirement for emergency management procedures to manage extreme events.

    4.2 The Emergency Planning section of the Security Policy that details the emergency arrangements required for extreme events (or where the event cannot be satisfactorily managed through the normal application of the Risk Management policies).

4.3 The Dispatch Policy that details how the **system operator** intends to adjust scheduling and **dispatch** to maintain frequency and reserves for use in connection with the Security Policy.

Frequency

5. The policies to be adopted in respect of maintaining frequency are set out in:

5.1 The Security Policy, that:

5.1.1 Sets the overall objective for maintaining reserves for **contingent events** and **extended contingent events**.

5.1.2 Outlines the process for determining the required frequency reserves (as described in the sections on under-frequency and over-frequency management).

5.2 The Dispatch Policy, which describes the arrangements for **dispatching** these reserves.

6. The policies to be adopted for maintenance of the frequency within the **normal band**, and time keeping, are set out in the Dispatch Policy and the **procurement plan**.

Other Standards

7. The policies to be adopted in respect of the other **PPOs** are described in the Security Policy section on Management of Quality.

Restoration

8. The restoration process is described in the Emergency Planning section of the Security Policy.

Dispatch Objective

9. The Dispatch Policy describes the policies that must be adopted in respect of the **dispatch objective**.

9A The Dispatch Policy also describes the preparation and adjustment of the **dispatch schedule** for the purposes of producing **dispatch prices**.

INTERPRETATION

10. Any terms used in the **policy statement** which are defined in the **Act** or in Part 1 of the **Code** and which are not defined in the Glossary of Terms within the **policy statement**, have the same meaning as given to them in the **Code**. In the event of any inconsistency or conflict between the provisions of this **policy statement** and the rest of the **Code**, the rest of the **Code** shall prevail.

Chapter 1 - Security Policy

POLICY AND SCOPE

General Policy

11. The general policies the **system operator** intends to use to meet the **principal performance obligations** are as follows:

11.1 Adopting processes intended to identify events, assess the risks of occurrence of those events in advance, categorise those event risks, and manage those defined events on the power system in real time in accordance with this **policy statement**.

11.2 Applying **security constraints** on **dispatch**, in accordance with the Security Policy, given the **assets** and **ancillary services** made available to the **system operator**.

11.3 Procuring, scheduling and **dispatching** reserves, where possible, with the **assets** and **ancillary services** made available to the **system operator**, to maintain the required frequency standards and to avoid cascade failure, for defined events.

11.4 Managing voltage and available reactive support during real time, where possible given the **assets** and **ancillary services** made available to the **system operator,** in a manner intended to avoid cascade failure for defined events.

11.5 Recommending and facilitating, to the extent considered to be reasonably appropriate and practicable by the **system operator,** co-ordination of advised planned **asset** outages to minimise the impact on security during **dispatch**.

11.6 If reasonably requested by a **participant**, investigating, identifying and, to the extent reasonably practicable, resolving the cause of a non-compliance with harmonic levels, voltage flicker or voltage imbalance standards (sections 4.7, 4.8 and 4.9 of the **Connection Code**).

11.7 Defining the circumstances under which **formal notices** must be sent in accordance with **Technical Code** B of Schedule 8.3 of the **Code** and, to the extent possible, determining the situations in advance that will potentially result in the initiation of **demand management,** including **unsupplied demand situations**.

RISK MANAGEMENT POLICIES

Identification and Application

12. The **system operator** must seek to manage the outcomes of events that may cause cascade failure by:

12.1 identifying potential credible events (each an ‘event’) on the power system that may result in cascade failure, either as a result of **asset** failure or the inability to maintain **system stability** following a disturbance. At the date of this **policy statement** the **system operator** has identified the following credible events that may result in cascade failure, due to these events causing quality and/or power flow outcomes exceeding **asset** capability:

12.1.1 The loss of one of the following power system components:

- a **generating unit**; or
- a **transmission circuit**; or
- an **HVDC link** pole; or
- an **interconnecting transformer** (110 kV or 220 kV); or
- a busbar (220 kV, 110 kV or 66kV); or
- large load or load blocks; or
- reactive injections, both when provided as an **ancillary service** or when available from transmission **assets**:

12.1.2 The loss of both transmission circuits of a double circuit line:

12.1.3 The simultaneous loss of two or more of any of the components in 12.1.1:

12.1.4 The close consecutive loss of two or more of any of the components in 12.1.1:

12.1.5 The loss of the **HVDC link** bipole:

12.1.5A The loss or potential loss of **system stability** (a **stability event**):

12.1.6 Other credible events may be identified during the term of this **policy statement**. This may include events arising in particular temporary circumstances such as, for example, a credible event identified as potentially arising during commissioning.

12.1A if, having identified a further or other credible event then, subject to operational requirements and as soon as reasonably practicable:

12.1A.1 **advising** such further credible event to all **participants**;

12.1A.2 inviting **participants** to comment on such credible event; and

12.1A.3 considering **participants'** comments prior to it implementing mitigation measures for such credible event.

12.2 assessing each event, or category of events, to estimate the likely risks based on the potential impact on the power system (including on achievement of the **PPOs**), if the event or category of events occurs, considering mitigating factors such as:

- **AUFLS**.
- the provision of levels of reserves.
- the provision of **constraints** on **dispatch**.

- for asset related events, the probability of occurrence based on historical frequency of **asset** failure or other credible reliability information, provided that where the **system operator** has limited historical or other information for specific **assets**, it must consider generic information available to it regarding failure of that type of **asset**.

- for stability related events, the probability of occurrence based on historical events, provided that where the system operator has limited internal historical information it must consider relevant external information available to it.

- the estimated costs and benefits of identified risk management.

- the feasibility and availability of other potential mitigation measures.

12.3 assigning each of the assessed events to one of the following categories:

- **Contingent events:** Events where the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and **dispatch** processes pre-event.

- **Extended contingent events:** Events for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid **demand management** or maintain the same quality limits defined for **contingent events**.

- **Other events:**
  a) events that are considered to be uncommon and for which the impact, probability of occurrence and estimated cost and benefits do not justify implementing available controls, or for which no feasible controls exist or have been identified, other than unplanned **demand management**, **AUFLS** and other emergency procedures or restoration measures; or;
  b) events that have no impact or where no pre- or post-contingent management is required

12.4 categorising, at the date of this **policy statement**, the following credible events:

- **Contingent events**:

  a) the loss of a **transmission circuit**.

  b) the loss of an **HVDC link** pole.

  c) the loss of a single **generating unit**.

  d) the loss of both **transmission circuits** of a double circuit line, where the **system operator** has determined a high level of likelihood of occurrence based on historical information.

e) the loss of both **transmission circuits** of a double circuit line, where the **system operator** has been advised of a temporary change to environmental or system conditions that give reason to believe there is a high likelihood of occurrence of the simultaneous loss of both circuits. The **system operator** must make available on its website a range of environmental or system conditions that it considers may create a high likelihood of occurrence of simultaneous loss of both circuits (but this list may not be exhaustive and will not limit the definition of the **contingent event**).

f) the loss of reactive injections, both when provided as an **ancillary service** or when available from transmission assets.

g) the loss of the largest possible load block as a result of paragraphs a) to f) above for each **island**.

h) the loss of **system stability** (due to a **stability event**).

- **Extended contingent events:**

  a) the sudden loss of the **HVDC link** bipole.

- **Other events:**

  a) the loss of a 66kV busbar not connected to the **core grid**.

  b) the loss of both **transmission circuits** of a double circuit line.

  c) the simultaneous loss of two or more of any of the components in clause 12.1.1.

  d) the close consecutive loss of two or more of any of the components in clause 12.1.1.

12.4A categorising the following assets, as either a **contingent event**, **extended contingent event** or **other event** according to a methodology and categorisations made available on its website:

a) a 220kV, 110kV or 66kV busbar connected to the core grid:

b) a 220kV or 110kV interconnecting transformer.

12.4B inviting industry to comment on any proposed changes to the methodology referred to in clause 12.4 before those changes come into effect:

12.5 applying, where possible, the following principles in implementing controls for each of the following category of risk:

12.5.1 For **contingent events**, the **system operator** must endeavour to schedule and **dispatch** sufficient reserves to provide **asset** redundancy, maintain the levels of quality defined in clauses 17.1 and 17.1.A of the Security Policy, and plan to avoid post-event unplanned **demand management**, taking into account any other agreed control measures (for example, demand inter-trips, run-back schemes, and **Automatic Under Voltage Load Shedding (AUVLS)**) advised to and agreed by the **system operator**.

12.5.2 For **extended contingent events**, the **system operator** must plan to maintain the levels of quality defined in clause 17.2 of the Security Policy through a combination of **AUFLS**, the provision of reserves, **asset** redundancy, **demand management**, and acceptance of greater quality disturbances than for **contingent events**, taking into account any other agreed control measures (for example **special protection schemes** and automatic under voltage load shedding schemes) advised to and agreed by the **system operator**. These control measures do not preclude the **system operator** taking action before an **extended contingent event** occurs, such as **network** reconfiguration, but do preclude the **system operator** changing any **price responsive schedule**, **non-response schedule** and **dispatch schedule** by applying **constraints** that will result in generation being dispatched out of merit order.

12.5.5 For **other events**, no planned controls have been identified, other than **demand management**, **AUFLS** and other emergency or restoration procedures.

12.5.4 *[Revoked]*

13. The **system operator** must:

13.1 In addition to reviews of the **policy statement** in accordance with the **Code**, review the identification, assessment and assignment of potential credible events as classified in clause 12.4 at least once in each five year period.

13.2 Make available on its website, prior to the commencement of each review of credible events, its intended methodology for identifying and assessing the risks to which the risk management policies are directed.

13.3 Invite comments from **registered participants** as to its process and the content of the review.

13.4 Make available on its website an explanation and summary of conclusions for each review of credible events completed under clause 13.1.

13A. The **system operator** must maintain and make available on its website a list of at risk generation, determined by identification of **generating units** and other **assets** connected to the power system whose loss during a **contingent event** would cause a loss of **injection** to the **grid** likely to require provision of **instantaneous reserve**.

13B. The **system operator** may identify the **assets** described in clause 13A through the review described in clause 13 or at any other time as a result of **commissioning** or **decommissioning assets** or changes to the **grid**.

14. In determining and applying the methodology in clause 13, the **system operator** must, where appropriate, apply risk management principles consistent with the Australia and New Zealand risk management standard AS/NZS ISO 31000.

Quality Limits and Actions Associated with Events

15. The **system operator**:

15.1 is entitled to rely on information regarding **asset** performance advised by **asset owners** in **asset capability statements**.

15.2 must use reasonable endeavours to **dispatch assets** in a manner so they remain within their stated **asset** capability.

16. Where the **assets** and **ancillary services** made available to the **system operator** are insufficient to achieve the quality levels set out in clauses 17 and 18**,** the **system operator** must follow the **demand management** policies in clause 74**.** Where clause 74 provides that **demand management** will not occur, the **system operator** may be unable to achieve the quality levels set out in clauses 17 and 18.

17. The quality levels the **system operator** plans to achieve for **contingent events** (including **stability events**) and **extended contingent events** are set out below. The ability to achieve the quality levels is entirely dependent on sufficient **assets** and **ancillary services** being made available to the **system operator** and the accuracy of the stated capabilities of those **assets** and **ancillary services**.

17.1 For a **contingent event**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of a **contingent event:**

17.1.1 No **asset** will exceed its stated load carrying, thermal or voltage capability.

17.1.2 Subject to clause 40**, grid** voltage will be within the range set out in clause 8.22(1) of the **Code**.

17.1.3 No **demand** is interrupted other than contracted reserves and/or **interruptible load** contracted or pre-arranged to be interrupted.

17.1.4 Frequency in either **island** will not drop below 48Hz or rise above 52Hz in the North Island or 55 Hz in the South Island.

17.1.5 Frequency in either **island** will be restored to within 50 Hz +/- 0.75 Hz within 1 minute.

17.1.6 **Instantaneous reserves** will be restored within 30 minutes.

17.1.7 **System stability** is maintained.

17.1.8 Where required by agreements for higher levels of quality, clause 8.6 or clause 17.29 of the **Code**, the quality targets of such agreements will be met.

17.1A For **stability events**, in addition to the quality levels detailed in clause 17.1:

17.1A.1 Oscillations must be adequately controlled (in terms of both amplitude and damping) such that they do not interrupt or prevent regular operation of the power system.

17.1A.2 Synchronous **generating units** will not experience loss of rotor angle stability for any identified **stability event**.

17.1A.3 If a **generating unit** is unexpectedly **electrically disconnected** during an event it will be reconnected as soon as practicable, subject to assessment that it will then remain connected.

17.2 For **extended contingent events**, the **system operator** plans to achieve the following quality conditions during and after the occurrence of an **extended contingent event**:

17.2.1 No **asset** will exceed its stated load carrying or thermal capability.

17.2.2 Voltage stability of the power system is maintained.

17.2.3 **Target grid voltages** will be as determined under clause 41.

17.2.4 Other grid voltages may be outside the range determined under clause 41. Where this is the case the **system operator** will respond to return these voltages to within the limits determined under clause 41 as soon as practicable.

17.2.5 Disconnected **demand** will be restored as soon as practicable.

17.2.6 Frequency in either **island** will be restored to within the **normal band** as soon as reasonably practicable.

17.3 For **extended contingent events**, the **system operator** may use one or more of the following actions during and after the occurrence of an **extended contingent event**:

17.3.1 The **system operator** may declare a **grid emergency** if it believes the quality levels may not be met after an **extended contingent event**.

17.3.2 **Demand management** and **AUFLS** may be used.

18. *[Revoked]*

SECURITY MANAGEMENT

Security Constraints

18A *[Revoked]*

18B *[Revoked]*

19. *[Revoked]*

20. *[Revoked]*

21. *[Revoked]*

22. *[Revoked]*

23. *[Revoked]*

24. *[Revoked]*

25. *[Revoked]*

26. The **system operator** must, from time to time:

26.1 analyse a range of credible transmission, generation, and power flow scenarios.

26.2 identify **contingent events, extended contingent events** and **other events** that the **system operator** considers may reasonably impact its ability to meet the **PPOs**.

26.3 identify and input transmission capability limits for **grid assets** in **SPD** to maintain operation within the stated capability (as advised by **grid owners**) after a **contingent event**.

26.4 identify and input power system stability limits in **SPD** to maintain operation within such stability limits.

27. Using the transmission capability limits and the power system stability limits identified in clause 26 the **system operator** must for each **trading period** develop **security constraints** which it will apply during the relevant **trading period**.

27A The **system operator** may use either automated or non-automated processes to develop the **security constraints** under clause 27. Non-automated processes will be used in situations where the automated processes do not generate appropriate **security constraints**.

28. The **security constraints** which are developed using automated processes under clause 27 are those which arise as a consequence of either or both the transmission capability limits and the power system stability limits being equal to or greater than the applicable **constraint percentage threshold**. **Security constraints** developed using non-automated processes apply regardless of **constraint percentage threshold**.

29. The **system operator** may amend, re-amend, add, remove or exclude the **security constraints** developed under clause 27 before and during **trading periods** when the **system operator** reasonably considers this is required to meet its obligations under the **Code**.

30. Notwithstanding the provisions of clause 29, the **system operator** must:

30.1 Make available on its website information about **security constraints** developed using non-automated processes under clause 27A, other than **discretionary security constraints** and **frequency keeping constraints.** Where practicable, the information must:

30.1.1 contain a summary of the security constraint design, sufficient for participants to be able to assess the effect of the limits imposed by the security constraint, and:

30.1.2 be made available at least two weeks prior to first use of the **security constraint** in scheduling, and:

30.1.3 despite clause 30.1.2, be made available at least four weeks prior to first use of the **security constraint** in scheduling where the constraint could be of significant interest to participants.

30.1A if the system operator makes a change to a **security constraint** of one of the types described in clause 30.1 and the change is made within two weeks before it is intended to be first used:

30.1A.1 if practicable, make available details of the change on the its website in advance; but

30.1A.2 if it is not made available in advance, make available details of the change as soon as practicable.

30.1B correctly apply **security constraints** regardless of whether or not the information on the **Transpower** website about the power system stability limits or **security constraints** is complete or up to date.

30.2 notify the **WITS manager** when a **security constraint** other than a **frequency keeping constraint** or general market-node constraint has been applied to **SPD** and where the calculated value of the constraint exceeds the **constraint publication threshold.**

30.3 *[Revoked]*

30.4 provide to the **WITS manager**, for making available on **WITS**, in respect of each **security constraint** notified pursuant to clause 30.2**:**

- the form of the **security constraint**;
- the limit of the **security constraint**;
- the **trading periods** to which the **security constraint** has been applied to **SPD**; and
- where applicable, the previous limit of the **security constraint**.

30.4A *[Revoked]*.

30.5 provide to the **WITS manager**, for making available on **WITS**, information about **grid asset** outages, including start and end times, applied to the **market schedules** and the **week-ahead dispatch schedule**.

30B The **system operator** must make available on its website a set of generation scenarios that it will use to develop indicative **security constraints** under clause 30C and may amend the generation scenarios from time to time. The **system operator** will place any amendments on its website and at the same time notify **participants** of these amendments.

30C Subject to clause 30F, the **system operator** must develop indicative **security constraints** for a **notified planned outage** if it is requested to do so by a **participant** in relation to a specific outage where:

(a) the **system operator** considers it likely that the outage will have a widespread impact on competition or efficiency, taking into account the information provided by the requesting **participant**; and

(b) the request is made more than two weeks prior to the notified start date of the outage.

30D The intent of the indicative **security constraints** developed under clause 30C is to provide an indication of the market system constraints that may be developed for the **notified planned outage** under clause 27.

30E The **system operator** must make available information detailing indicative **security constraints** developed under clause 30C to **participants** on the **Planned Outage Co-ordination Process** website. The information made available must include a summary of the limits or **security constraint** design, such summary to be reasonably sufficient for **participants** to assess the effect of the **security constraint**.

30F The **system operator** may decline to develop indicative **security constraints** under clause 30C if the **system operator** reasonably believes that sufficient relevant historical **security constraint** information has already been made available to **participants** after the **changeover date**. If the **system operator** declines a request pursuant to this clause, it must advise the requesting **participant** where the relevant historical **security constraint** information can be located.

30G The **system operator** must make available on the **Transpower** website a description of the process it will use to develop indicative **security constraints** under clause 30C. The **system operator** may amend the process from time to time.

30H Where the **system operator** declines a request to develop indicative **security constraints** on the grounds that the criteria in clause 30C do not apply, the **participant** may request the **system operator** to agree to develop the indicative **security constraints**. Such an agreement may not be unreasonably withheld but may, in the **system operator's** discretion, include the requirement for the requesting **participant** to pay the reasonable costs of the **system operator** in developing the indicative **security constraints**.

Under-Frequency Management

31. The **system operator** must endeavour to schedule sufficient reserves, subject to **asset** and **ancillary service** availability and clause 33A, to meet the specified under-frequency limits and avoid cascade failure for:

31.1 The maximum amount of **MW** injection that could be lost, due to the occurrence of a single **contingent event**; and

31.2 The **extended contingent events**, allowing for **automatic under-frequency load shedding**.

32. In modelling reserve requirements, the **system operator** must:

32.1 Apply the **Reserves Management Tool**

32.2 Use the most recent **asset** capability information provided by **asset owners,** subject to:

- the requirements of the **RMT** specification (including **asset** performance modelling) from time to time agreed between the **system operator** and the **Authority**;
- any **asset** assessments the **system operator** needs to carry out; and
- a reasonable time delay allowing for the system operator to modify the **RMT** to include the latest **asset** capability information.

32.3 Include the impact of **dispensations** and **equivalence arrangements**.

32A Where **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **system operator** reasonably considers it cannot rely upon the **asset** capability information provided, the **system operator**:

32A.1 may apply an adjustment factor considered reasonable by the **system operator** based on its current knowledge about the performance of the power system, to account for the fact that the **asset** capability information has not been provided, the **asset** capability information provided is incomplete, or the **asset** capability information provided is reasonably considered unreliable; and

32A.2 must notify the **asset owner** within 3 **business days** following any decision to apply an adjustment factor.

33. To maintain a dispatchable **SPD** solution where there are insufficient **offers** and/or **reserve offers** in the current **trading period**, the **system operator**, using the **SPD software**, must—

33.1 for a pre-event shortage relating to a **contingent event**, **dispatch** all remaining **offered instantaneous reserve,** and, if the quantity of **instantaneous reserve dispatched**, together with **AUFLS**, is insufficient to meet the under-frequency standard in clause 7.2A of the **Code** applicable to an **extended contingent event**, reduce **demand** in accordance with the **demand management** policies; and

33.2 for a pre-event shortage relating to an **extended contingent event** that requires the **dispatch** of **instantaneous reserves** in addition to **automatic under-frequency load shedding**, **dispatch** all remaining **offered instantaneous reserve** and reduce **demand** in accordance with the **demand management** policies.

33A Following the occurrence of an **under-frequency event** in which **interruptible load** has been triggered, the **system operator** may temporarily set the reserve requirements to zero. The **system operator** must then restore the reserve requirements in accordance with the methodology set out in clause 84.

33B For the purposes of the **event charge** calculation pursuant to clause 8.64 of the **Code**, the **system operator** will use the methodology it makes available on its website.

Time Error Management

34. *[Revoked]*

Over-Frequency Management

35. For the over-frequency elements of the **PPOs**, the **system operator** procures **over frequency reserves** in accordance with the **procurement plan**.

36. The **system operator** must endeavour to **dispatch over frequency reserves** when necessary to maintain the frequency below 52 Hz in the North Island and 55 Hz in the South Island for **contingent** and **extended contingent events**. In determining the quantity of **over frequency reserves** to be **dispatched** in the South Island, the **system operator** must take into account the actual amount of **demand**, the **HVDC link** transfer, and the number and capacity of the units able to be **dispatched** for **over frequency reserves** at the time.

Rate of Occurrence of Frequency Fluctuations

37. *[Revoked]*

38. The **system operator** may recommend changes to the **procurement plan**, **policy statement** or **Code**, or take other action available to it under the **Code**, with the intent to correct a significant negative trend regarding the rate of **frequency fluctuations**.

Purchaser Step Changes

39. *[Revoked]*

39A Clause 8.18 of the **Code** provides that **purchasers** must limit the magnitude of any instantaneous change in the **offtake** of **electricity** and net rates of change in **offtake** to the levels the system **operator** requires.

39B As at the date this **policy statement** comes into effect, the **maximum instantaneous demand change limit** and net rates of change in **offtake** for **electricity** allowable for each **purchaser** within each **island** is 40 **MW** per minute with no more than a 75 **MW** change in any 5 minute period.

39C The **system operator** may specify a **maximum instantaneous demand change limit** and rate of change in **offtake** in relation to a particular **purchaser** that is different from the limit and the rate specified in clause 39B.

39D Clauses 39A and 39B do not apply to step changes and rates of change occurring during independent action or restoration in a **grid emergency**.

Voltage Management

40. The **system operator** must plan to manage **grid** voltage as follows:

    40.1 Following **a contingent event**, voltage will be maintained within the ranges specified in clause 8.22(1) of the **Code** except where, for a particular **GXP** or region, there is a **wider voltage agreement** in place.

    40.2 Where a **wider voltage agreement** applies, the voltage within that **GXP** or region will, following a **contingent event**, be managed so voltage stability is maintained and voltage does not go outside the lesser of the capability of the affected **assets**, as set out in the **asset capability statements** for those **assets**, or the voltage limit agreed in the **wider voltage agreement**.

    40.3 Following an **extended contingent event**, voltage will be maintained within the ranges determined under clause 41.1.

41. To manage voltage and control voltage excursions within the quality limits set out in clause 17 of this Security Policy the **system operator** must:

    41.1 Determine a set of **target grid voltages** at selected key locations (selected by the **system operator**) to be maintained during normal operations. For the purpose of clause 17 the **system operator** has determined that the **target grid voltages** will be within the range in clause 8.22(1) of the **Code**.

    41.2 Recommend to **asset owners** appropriate tap positions for transformers, which have off load tap changers, given the expected range of **dispatch** scenarios.

42. The **system operator** may vary **target grid voltages** for specific **dispatch** scenarios.

43. The **system operator** must monitor voltage trends in real time at key locations determined by the **system operator** and, subject to **asset** availability and **ancillary services**, it must endeavour to **dispatch** sufficient reactive resources to:

    43.1 Achieve **target grid voltages**.

    43.2 Manage voltage for a **contingent event**.

    43.3 Maintain post event operation within voltage stability limits.

44. The **system operator** must **dispatch generating plant** to:

    44.1 Maintain a specific voltage during **dispatch.**

    44.2 Provide specific **reactive power** outputs (refer also to the **security constraints** section of this Security Policy).

45. The **system operator** must **dispatch** available static reactive devices so that dynamic reactive reserves are available to provide **voltage support** for **contingent events** and **extended contingent events**.

46. In **dispatching** static and dynamic reactive resources, the **system operator** must use the following principles:

46.1 The **system operator** will first **dispatch relevant freely available reactive resources**.

46.2 Where insufficient **relevant freely available reactive resources** are available to maintain **target grid voltages**, the **system operator** will **dispatch** additional reactive resources as procured in accordance with the **procurement plan**.

46.3 Where the **system operator** believes the reactive resources **dispatched** under clause 46.1 and clause 46.2 are insufficient to address voltage management requirements the **system operator** will apply a combination of:

- Procurement and **dispatch** of additional reactive resources as an emergency departure from the **procurement plan** in accordance with clause 8.47 of the **Code**.

- **Security constraints** to provide additional reactive resources through the **dispatch** of generation.

47. If the **dispatch** of reactive resources under clause 46 is not sufficient to provide voltage support for managing a **contingent event** or an **extended contingent event** the **system operator** may commence **demand management** in accordance with the Emergency Planning section of this Security Policy.

Management of Quality

48. If the **system operator** receives a request to investigate and resolve a security of supply or reliability problem under clause 7.2D of the **Code** and, in the **system operator's** opinion, the problem is not likely to cause cascade failure, the **system operator** must:

48.1 Act on a written request by a **participant** or the **Authority** to identify the cause of the problem.

48.2 Investigate the cause of the problem. An investigation may include:

- Requests for further information from **asset owners**.

- Testing and measurement.

- Analysis of those measurements, including system modelling.

- Application of **constraints** on **dispatch** and reconfiguration of **assets** to identify potential resonance and sources.

48.3 Where identified, notify the relevant **asset owner** that is causing the problem and invoice any reasonable costs associated with investigating the problem.

48.4 Keep account of its costs in relation to the studies and invoice in accordance with the **Code** and the **System Operator Service Provider Agreement**.

48.5 If the problem has not been rectified and continues to persist then, in the absence of a requirement in the **Code** for **asset owners** to meet the relevant standards, the **system operator** must:

- Notify the **Authority** of the problem.
- **Advise** the actions that could be taken to rectify the problem.

49. The **system operator** must assess any problem in relation to clause 7.2D of the **Code** to ascertain whether that problem may lead to cascade failure. If the problem could lead to cascade failure the **system operator** must seek to identify the cause of the problem and, if any problem remains unaddressed:

    49.1 Issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** requesting a response of the relevant **participants** to correct the problem.

    49.2 Rely on the co-operation of the relevant **participants**, or the co-operation of **asset owners** as required by clause 8.26 of the **Code**.

Regional long term contingency planning

50. The **system operator** may from time to time identify, in a region, a material or on-going power system limitation or power system situation where the **system operator** believes there is a reasonable probability it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** to plan to comply and comply with the **PPOs.**

51. When the **system operator** identifies a power system limitation or power system situation under clause 50, it may establish and facilitate a forum of relevant **asset owner**s and interested **participants** to work jointly with it to assist it plan to comply and to comply with the **PPOs**. The **system operator** must establish a forum when:

    51.1 it believes there is a reasonable possibility that:

        51.1.1 without suitable contingency planning and information exchange, regionally material **demand management** may be required in order for it to comply with the **PPOs**; or

        51.1.2 it would have to rely on taking emergency action under the Emergency Planning section of the **policy statement** for credible **dispatch** scenarios over an extended period of time in any region or regions; and

    51.2 co-ordination of multiple **participants** in a region or regions would be required to mitigate the situation identified by it; and

    51.3 no single **participant** is able or willing to act unilaterally to resolve the situation identified by it; and

    51.4 it considers there is sufficient time prior to a situation identified under clause 50 occurring in which to plan to minimise the impact of the situation.

52. In establishing and facilitating a forum described under clause 51, the **system operator** must:

    52.1 Invite as contributing parties those **participants** it reasonably believes may be:

        52.1.1 affected by the situation; or

52.1.2 able to assist with it planning to comply and to comply with the **PPOs** by reducing the potential need for recourse to the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** (or similar).

52.2 Arrange for **participants** in the forum to undertake such analysis of regional load **demand**, **asset** performance, and such other matters the **system operator** and **participants** in the forum consider relevant, and agree upon the necessary or desirable means to minimise the risk to the **system operator** having to rely on taking emergency actions under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** with the **assets** and generation **offers** likely to be available.

52.3 Use a planning horizon, for such forums, of no longer than 3 years.

53. Nothing in clauses 50 to 52 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code.**

Outage Planning

54. To meet its obligations under **Technical Code** D of Schedule 8.3 of the **Code**, the **system operator** must:

54.1 Carry out the assessment of all **notified planned outages** referred to in clause 3 of **Technical Code** D of Schedule 8.3 of the **Code**.

54.2 **Notify** relevant **asset owners** of **notified planned outages** where it considers such **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code** close to or in real time in order to comply with the **PPOs**. When making such notifications the **system operator** may request that relevant **asset owner**s notify it of suitable changes to the **notified planned outages**.

54.3 Endeavour, where the relevant **asset owner**s fail to notify it of suitable changes to the **notified planned outages** in clause 54.2, to facilitate arrangements with the relevant **asset owner**s that will result in changes to the **notified planned outages** so that such outages will not result in the **system operator** relying on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.4 Re-assess the **notified planned outages** following the notification of any changes by relevant **asset owner**s under clause 54.2 or the facilitation of any arrangements in clause 54.3.

54.5 Advise the relevant **asset owner**s whether or not, following the re-assessment, it believes the relevant **notified planned outages** may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs**.

54.6 Re-assess **notified planned outages** following receipt of any material, new information relating to the said **notified planned outages** or the power system which it believes may impact its ability to plan to comply, and comply with the **PPOs**.

55. Where the **system operator** reasonably identifies **notified planned outages** that may require it to rely on taking emergency action under the Emergency Planning section of the **policy statement** or **Technical Code** B of Schedule 8.3 of the **Code** to plan to comply, and comply with the **PPOs** and relevant **asset owners** are unable or unwilling to develop and notify the **system operator** of suitable changes to such outages, it may, where, in its reasonable opinion, there is insufficient time to otherwise plan to avoid **demand management** or where the expected period of risk is for a short duration, issue a **formal notice** and rely on emergency action under the Emergency Planning section of the **policy statement** and **Technical Code** B of Schedule 8.3 of the **Code**.

56. Nothing in clauses 54 to 55 (inclusive) shall be construed to restrict or compromise the ability of the **system operator** to rely, when it believes it appropriate, on the Emergency Planning or any other section of the **policy statement** or the **Code**.

EMERGENCY PLANNING

General

57. The following sections set out the general policies for dealing with emergencies relating to security issues. They do not limit the powers of the **system operator** under the **Code** in respect of emergencies, and the **system operator** always retains the right to exercise its rights and powers under the **Code** in relation to emergencies.

58. To manage events greater than those catered for by the Risk Management Policies, or where the event cannot be satisfactorily managed through the normal application of the Risk Management Policies, the **system operator** may rely on:

58.1 the **AUFLS** and **AUVLS** provisions of clauses 8.19(5) and 8.24 of the **Code**.

58.2 the load shedding systems and independent action defined in **Technical Code** B of Schedule 8.3 of the **Code**.

58.3 **asset owner** compliance with the provisions of the **Code**.

58.4 the use of **standby residual shortfall notices** to advise **participants** when it believes there is or may be a **standby residual shortfall.**

58.5 any other means made available by **asset owners** that are assessed by the **system operator** as being capable of mitigating the need for **demand management**.

Standby Residual Shortfall

59. In the event the **system operator** identifies a **standby residual shortfall**:

59.1 if the **standby residual shortfall** is greater than the **standby residual**

shortfall threshold, it must use reasonable endeavours to send to the **WITS manager**, for making available on **WITS**, a **standby residual shortfall notice**; and

59.2 it may, for such time as it believes reasonable and prudent, rely on **participant**s making such new **generator offers** and/or **reserve offers** it believes will be sufficient to mean that a **standby residual shortfall** no longer exists.

60. If there is a **standby residual shortfall**, and **participants** do not make sufficient new **generator offers** and/or **reserve offers**, the **system operator** may, in accordance with clause 4 of **Technical Code** D of Schedule 8.3 of the **Code**, request an **asset owner** of **assets** which are the subject of an outage or **notified planned outage** to keep those **assets** in service, with the intention of reducing the likelihood of the **system operator** having recourse to the Emergency Planning section of this **policy statement**.

61. *[Revoked]*

Formal Notices

62. The **system operator** must issue a **formal notice** in accordance with clause 5 of **Technical Code** B of Schedule 8.3 of the **Code** where a **participant's** response is required to mitigate a risk and where the only other action available to the **system operator** will be **demand management**.

62A The **system operator** may issue the following types of **formal notices**:

62A.1 A Grid Emergency Notice which declares a **grid emergency** in accordance with clause 13.97 of the **Code**.

62A.2 *[Revoked]*

62A.3 A Warning Notice which advises participants that **grid emergency** conditions are anticipated.

63. Where the **system operator** has identified a situation requiring the use of the controls in this Emergency Planning section of the Security Policy prior to one hour before the start of the relevant **trading period**, the **system operator** must issue a Warning Notice.

64. Where the **system operator** has identified a situation requiring the use of the controls under this Emergency Planning section of the Security Policy within one hour before the start of the relevant **trading period** or during the relevant **trading period**, the **system operator** must issue a Grid Emergency Notice.

65. A Grid Emergency Notice must be issued whenever, or as soon as practicable after any of the events set out in clause 74 have occurred or the **system operator** determines they will occur and when the **system operator** considers that it will be unable to mitigate the situation without **participant** independent action, **grid** reconfiguration or **demand management**.

66. If the **system operator** decides to declare a **grid emergency**, it must make the declaration by issuing a **formal notice** orally or in writing. **Formal notices** may be issued orally in circumstances where either or both of the following situations exist:

66.1 There is, in its view, insufficient time available to the **system operator** before the emergency arises to issue a written **formal notice**.

66.2 One **participant** is**,** or a restricted number of **participants** are, required to, or able to, take specific action in accordance with **Technical Code** B of Schedule 8.3 of the **Code**, to alleviate a **grid emergency**.

67. **Formal notices** issued in writing must be sent to all **participants** that, in the **system operator's** view, may be able to assist in the mitigation of the **grid emergency** or will have a significant interest in the occurrence and nature of the **grid emergency**. All **formal notices** issued in writing must be shown on its website as soon as reasonably practicable after being first sent to **participants**.

68. In addition to the content of a **formal notice** in clause 5 of **Technical Code** B of Schedule 8.3 of the **Code**, the **system operator** must use reasonable endeavours to include in every **formal notice** issued details of **assets**, which are relevant to the cause of the relevant **grid emergency** and the return to service of such **assets**, where such advice would assist it to plan to comply and to comply with the **PPOs**. The ability of the **system operator** to include details of such affected **assets** is subject to the ability and willingness of the owners of affected **assets** to make such details available to other **participants**.

69. The **system operator** must send to **participants** the report it provides to the **Authority** under clause 13.101(1)(a) of the **Code**.

70. Security levels must be re-assessed and **participants** advised as soon as reasonably practicable after the **system operator** is aware of any need to change the status of a **formal notice**. The **system operator** must revise the **formal notice** if:

70.1 A situation is alleviated prior to the start of the **trading periods** for which the **formal notice** was issued.

70.2 The start or end times for which a situation exists, or is expected to exist, changes from the times set out in the **formal notice**.

70.3 The electrical or geographical region affected changes from that set out in the **formal notice**.

71. There may be other notices issued by the **system operator** that, by definition, are not **formal notices** issued in accordance with **Technical Code** B of Schedule 8.3 of the **Code**.

Demand Management

72. *[Revoked]*

73. Where the **system operator** considers that the **dispatch** of available **assets** and **ancillary services** (and the application of the policies set out in other sections of this Security Policy) is not or is likely not to be sufficient or sufficiently timely to mitigate a situation, the **system operator** must apply clause 74 in determining whether to initiate **demand management**.

74. **Demand Management** scenarios:

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
A) Steady State, including steady state after an event has occurred.	Any **asset** is exceeding or is forecasted to exceed the advised capability limit stated in the **asset capability statement.**	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Voltage instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Transient or dynamic instability is or is about to occur.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency.**
	Frequency keeping is unable to be maintained.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency.**
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a risk of significant **asset** damage.		Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	Public safety is at risk.		Declare a **grid emergency**.	**Demand management** may occur if the **system operator** considers it appropriate in the specific circumstances.

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
	Independent action has been taken in accordance with **Technical Code** B of Schedule 8.3 of the **Code** to restore the **system operator**'s **PPO**s.		Declare a **grid emergency**.	**Demand management** may occur depending on the nature of the **grid emergency** and whether the **system operator** considers it appropriate in the specific circumstances.
	Restoration is required after a loss of supply and: ▪ **grid** reconfiguration and/or **demand management** is required; and ▪ more than one instruction to one or more **participants** is required to effect restoration.		Declare a **grid emergency**.	Refer to restoration policy (as contained in clause 84).
	An **unsupplied demand situation** occurs		Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
B) For a defined event.	Any **asset** will exceed the advised capability limit stated in the **asset capability statement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	A voltage stability limit is being exceeded.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	A transient or dynamic stability limit is being exceeded.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand management** may occur if **participant** responses do not mitigate the **grid emergency** and **demand management** would remedy the **stability event**.
	Frequency keeping will not be able to be maintained for a defined event.	Issue a Warning Notice	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency**.

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.	Issue a Warning Notice.	Declare a **grid emergency**.	**Demand management** will occur if **participant** responses do not mitigate the **grid emergency** (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for an **extended contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.2, **demand management** will occur if **participant** responses do not mitigate the **grid emergency**.
	There is a shortage of **instantaneous reserve** for a **contingent event**.	Issue a Warning Notice.	Declare a **grid emergency**.	Subject to clause 33.1, rely on the operation of **AUFLS** where sufficient to ensure compliance with the frequency **PPO**.
C) For a second defined event (after an event has occurred[2]).	Any **asset** will exceed the advised capability limit stated in the **asset capability statement** for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event or **asset owners** have advised the risks of exceeding capability are unacceptable.
	A voltage stability limit would be exceeded for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event
	A transient or dynamic stability limit is being exceeded for a second defined event.		Declare a **grid emergency**.	**Demand management** may occur if **participant** responses do not mitigate the **grid emergency** and **demand management** would remedy the **stability event**.

Scenario	Event giving rise to a grid emergency situation	Prior to 1 hour	Within 1 hour	Demand management policy
	The **grid**, or part of the **grid**, will operate outside the ranges specified in clause 8.22(1) of the **Code** for a second defined event unless a **wider voltage agreement** applies. Alternatively, a **wider voltage agreement** applies and that part of the **grid** affected is or is about to be operated outside of the limits agreed in the **wider voltage agreement**.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event. (refer to clause 8(2) of **Technical Code** B of Schedule 8.3 of the **Code**).
	There is a shortage of **instantaneous reserve** for a binding second **contingent event**.		Declare a **grid emergency**.	**Demand management** may occur where the **system operator** reasonably believes there is a significantly elevated risk of a second defined event and **AUFLS** is insufficient to ensure the frequency **PPO** can be met.

[2]And where there are insufficient means to operate the power system to the requirements of the security policy following the event.

Demand Management Process

74A. Where the **system operator** determines that **demand management** may be required if **participant** responses to a **formal notice** do not mitigate a situation, the **system operator** may:

74A.1 request the **grid owner** to reconfigure the **grid**:

74A.2 request **participants** to increase **offers** and **reserve offers** and/or:

74A.3 request **participants** to reduce **demand** including **controllable load**.

74B. Where the **system operator** determines that **demand management** is required, the **system operator** may:

74B.1 instruct the **grid owner** to reconfigure the **grid**:

74B.2 instruct one or more **participants** to reduce **controllable load**:

74B.3 instruct one or more **participants** to reduce **demand** (either by a specific **MW** or percentage of **MW**):

74B.4 instruct one or more **participants** or the **grid owner** to **electrically disconnect demand** and/or:

74B.5 take any other reasonable action to alleviate the **grid emergency**.

Allocation of Demand Reduction

75. Where a **formal notice** is issued, and the **system operator** requests or instructs any **purchaser(s)** and/or **distributor(s) to** reduce **demand** in accordance with clauses 74A or 74B, the **system operator** may include the following in the (verbal or written) **formal notice**:

75.1 The **connected asset owners** from which, or the **offtake** point or points (**grid exit points**) at which, a **demand** reduction is required, which may be selected by the **system operator** at its discretion;

75.2 Either the quantity of demand reduction required from the relevant **connected asset owners** or at the relevant **offtake** points (**grid exit points**) as applicable, or the maximum **demand** which may be taken by the relevant **connected asset owners** or at the relevant **offtake** points (**grid exit points**) as applicable;

75.3 The time(s) for which the **demand** reduction is required.

75A. Where a **formal notice** is issued instructing the reduction of **demand** in accordance with clause 75, as soon as practicable after the notice is issued the **system operator** must provide the information described in the notice to its systems to comply with schedule 13.3AA of the **Code**.

76. *[Revoked]*

77. Without limiting its rights under **Technical Code** B of Schedule 8.3 of the **Code**, where **demand** from any **offtake** point is not reduced in accordance with the demand allocations specified in the **formal notice**, the **system operator** may require a relevant **distributor** to reduce **demand** in accordance with the process or processes agreed under clause 7(19) of **Technical Code** B of Schedule 8.3 of the **Code**.

78. In determining any demand allocations to be specified in the **formal notice**, the **system operator** must use reasonable endeavours to avoid a **demand** reduction of greater than 25% at a single **point of connection**, excepting when the total reduction of **demand** required in the affected region exceeds 25%.

79. *[Revoked]*

80. *[Revoked]*

80.1 *[Revoked]*

80.2 *[Revoked]*

81. *[Revoked]*

Restoration

82. The **system operator** must procure **black start**. The procurement details for these facilities are included in the **procurement plan**.

83. The **system operator** may rely on the synchronising facilities defined in **Technical Code** A of Schedule 8.3 of the **Code** to allow reconnection of sections of the **grid** and to connect generation to the **grid** during restoration.

84. Where restoration is required, the **system operator** must use the following methodology to re-establish normal operation of the power system by:

84.1 Addressing any aspects involving public safety.

84.2 Addressing any aspects involving avoidance of damage to **assets**.

84.3 Stabilising any remaining sections of the **grid** and connected **assets** and the voltage and frequency of the **grid**, through the combination of manual **dispatch instruction** and allowing automatic action of **ancillary services** and governor and voltage regulation operation by **generating plant**, and including any necessary disconnection of **demand**.

84.4 Actioning the steps set out in clauses 84.5, 84.6, 84.7 and 84.8 below in the order or in parallel as is judged by the **system operator**, at the time, as most effectively allowing reconnection of **demand**. The order that **assets** are **dispatched** will be influenced by availability, technical, geographic and other factors influencing rapid restoration of **demand**.

84.5 Restoring the transmission, generation, and/or **ancillary service assets** that failed when such restoration assists commencement of steps set out in clauses 84.6 and 84.7, where necessary utilising **black start** facilities.

84.6 Restoring any disconnected **demand** (which includes any triggered **interruptible load**) at the rate permitted by the security and capability of the available combined generation and transmission system.

84.7 **Dispatching** additional generation and **ancillary services**, where such additional resources are needed to allow **demand** to be reinstated and necessary quality levels to be maintained.

84.8 Seeking revised **offers** where insufficient **offers** exist to achieve the restoration objectives.

84.9 Restoring normal security and power quality of the **grid** system to the levels set out in the **PPOs** and this Security Policy. If the reserve requirements have been set to zero under clause 33A, the actions taken under this clause must include restoring the reserve requirements to the levels set out in the Under-Frequency Management Policy.

84.10 Restoring energy injection levels to the values contained in an updated **dispatch schedule**.

Chapter 2 - Dispatch Policy

84A. The **system operator** must follow the process described by the Dispatch Process Statement to achieve the **dispatch objective**. Clauses 84B to 84O constitute the Dispatch Process Statement.

Software

84B. The **system operator** must include SPD in the **software** it uses for scheduling and **dispatch**.

84C. The **system operator** must use the reserve management tool (RMT) to assess the likely primary frequency response provided by connected generators and load to determine the minimum quantity of **instantaneous reserve** required to meet the frequency standards defined by clauses 7.2A(5) – (7) of the **Code**.

Week-ahead Dispatch Schedule

84D. The **system operator** must endeavour to prepare a week-ahead dispatch schedule once per day for the period from 14:00 hours the following day to 23:59 hours six days' hence.

84E. The week-ahead dispatch schedule must include as its inputs the inputs for the **non-response schedule** described in Part 13 of the Code, excluding ramp rates.

84F. When the **system operator** has completed a week-ahead dispatch schedule, the **system operator** must make the schedule results available to the **WITS Manager** for publication on **WITS**. The schedule results must include prices for each grid exit point, grid injection point and reference point.

Non-Response Schedule and Security Assessment

84G. In preparing the **non-response schedule** as required under Part 13 of the Code, to plan to comply with the principal performance obligations the system operator must use the **non-response schedule** to conduct regular security assessments for the schedule period. The **system operator** must use the results of the security assessment to make adjustments to inputs to subsequent **non-response schedules** and the **dispatch schedule** to achieve the **dispatch objective**.

84H. The **system operator** may adjust the **demand** input to the **non-response schedule** at a **non-conforming GXP** where it reasonably believes the demand quantity represented by the **nominated non-dispatch bids** for the **non-conforming GXP** is unreliable.

84I. The **system operator** must use the **non-response schedule** to schedule and dispatch **frequency keeping ancillary services**, and use frequency keeping constraints to adjust scheduled frequency keeping units' active power capacities for use in the **dispatch schedule**.

84J. In making its security assessment, in addition to any adjustments required under clause 84G the **system operator** may:

84J.1. request the **grid owner** to make changes to **notified planned outages**;

84J.2. identify potential **contingent events** and **extended contingent events** and make changes to the **instantaneous reserve** requirements;

84J.3. assess power flows to identify and assess possible transmission security restrictions, capacity restrictions, or voltage conditions on the **grid** and make changes to **security constraints**;

84J.4. identify shortfalls in standby capacity reserves and reschedule **frequency keeping** assets.

84K. Where the **system operator** has made adjustments to the inputs to the **non-response schedule** or the **dispatch schedule** described in clauses 84H to 84J, the adjustments must also be applied to the **price-responsive schedule**.

Dispatch Schedule

84L. The **system operator** must prepare the expected profile of **demand** for the **dispatch schedule** and publish its methodology on its **website**. The expected profile of **demand** must consist of:

84L.1. a measurement or estimate of the current system **demand**; and

84L.2. an estimate of the change in system **demand** in the next dispatch interval; and

84L.3. any **demand** information required to comply with schedule 13.3AA of the **Code**.

84M. The **system operator** may depart from the **dispatch schedule**, or adjust the **dispatch schedule** to comply and plan to comply with the **dispatch objective** by applying discretionary constraints, for situations requiring:

84M.1. dispatching a **generating unit** to simulate a change to the **offer** which has not been entered electronically through **WITS**;

84M.2. setting a **dispatchable load purchaser's nominated dispatch bid** to a **nominated non-dispatch bid** to simulate a change to the **nominated bid** which has not been entered electronically through **WITS**;

84M.3. dispatching a **generation unit** to minimum output to avoid loss of reserve capacity within the unit's restart cycle time;

84M.4. dispatching reserve capacity immediately to respond to a **contingent event** or **extended contingent event**;

84M.5. dispatching one or more **generating units** to a minimum **active power** output to provide **reactive power**;

84M.6. dispatching one or more **generating units** prior to the start time of a **notified planned outage** to enable the outage to proceed at the planned time;

84M.7. dispatching one or more **generating units** to allow switching operations to be undertaken in support of a **notified planned outage**;

84M.8. dispatching **generating units** to provide for management of a NZAS **reduction line change operation**;

84M.9. adjusting the power order on the **HVDC Link** prior to a **notified planned outage** to enable the outage to proceed at the planned time;

84M.10. instructing blocking or de-blocking a **pole** of the **HVDC Link** to provide for a feasible power order;

84M.11. adjusting the limits of **HVDC Link** capacity to avoid the need to schedule additional **instantaneous reserve** to cover the **extended contingent event** risk;

84M.12. adjusting the ramp rate of the **HVDC Link** to provide reserve capacity for an imminent system event; or

84M.13. increasing the amount of scheduled **instantaneous reserve** to cover an **extended contingent event** where system conditions have deviated from modelled system conditions for the current **trading period**.

84N. When the **system operator** has adjusted the **dispatch schedule** by applying a discretionary constraint of the type referred to in clause 84M, the system operator must make available to the **WITS Manager** for publication on **WITS** the equation and limit of the discretionary constraint.

84O. The **system operator** must publish on its **website** the post-schedule checks it uses to assess the accuracy of **dispatch prices** and **dispatch reserve prices**.

Dispatch Notification Participation

84P. In assessing an application to become a **dispatch notification purchaser** under clause 13.3E, or a **dispatch notification generator** under clause 13.3F of the **Code**, the **system operator** may decline an application if:

84P.1. for an application from a potential **dispatch notification purchaser**, the total capacity of the **dispatch-capable load station(s)** to be **bid** at a single **point of connection** to the **grid** is 30 MW or more; or

84P.2. the **system operator** requires the applicant to provide real time indications and measurements in accordance with Technical Code C or offers in accordance with 8.25 for the **assets** proposed to be **offered** or **bid;** or

84P.3. the applicant is unable to demonstrate functional systems for submission of **nominated bids** or **offers** to **WITS**, and receipt and acknowledgement of **dispatch notifications**; or

84P.4. the combined total capacity of **assets offered** or **bid** by **dispatch notification purchasers** and **dispatch notification generators** at a single **point of connection** to the **grid** exceeds an amount the **system operator** reasonably considers would threaten the **system operator's** ability to comply or plan to comply with the **PPOs**.

84Q. The **system operator** may suspend or revoke approval for a **dispatch notification purchaser** or **dispatch notification generator** under clauses 13.3E(4) or 13.3F(4) of the **Code** if:

84Q.1. the **participant** submits 3 or more rejection acknowledgements to **dispatch notifications** within a continuous 48-hour period;

84Q.2. the **participant** submits 5 or more rejection acknowledgements to

dispatch notifications within a continuous 30-day period;

84Q.3. the **participant** submits rejection acknowledgements to 3 consecutive **dispatch notifications;**

84Q.4. the **participant** fails to meet any of the criteria described in clause 84P.

85. *[Revoked]*

86. *[Revoked]*

86A. *[Revoked]*

87. *[Revoked]*

88. *[Revoked]*

88A. *[Revoked]*

88B. *[Revoked]*

88C. *[Revoked]*

89. *[Revoked]*

90. *[Revoked]*

91. *[Revoked]*

92. *[Revoked]*

92A. *[Revoked]*

93. *[Revoked]*

93A. *[Revoked]*

93B. *[Revoked]*

93C. *[Revoked]*

Chapter 3 – Compliance Policy

POLICY AND SCOPE

General Policy

94. The **system operator** must have systems in place to ensure it is able to efficiently carry out its functions in accordance with the following specific obligations under the **regulations** and **Code**:

94.1 Proactively monitoring and reporting the **system operator's** compliance with its obligations under the **regulations** and **Code**.

94.2 Monitoring and reporting **asset owner** compliance with the following obligations under the **Code**:

- The **asset owner performance obligations**.
- Obligations under the **technical codes**.
- Obligations under **dispensations**.
- Obligations under **equivalence arrangements**.
- Obligations under **alternative ancillary service arrangements**.

94.3 Receiving **asset** capability information and carrying out assessments of **asset** capability.

94.4 Commissioning **assets**.

94.5 Issuing **dispensations** and **equivalence arrangements**.

COMPLIANCE AND PERFORMANCE MONITORING

95. The **system operator** must have processes in place to achieve and maintain compliance with its obligations under the **regulations** and **Code** and must monitor its own performance for the purpose of:

95.1 Meeting the **system operator**'s review and reporting obligations under the **regulations** and **Code**.

95.2 Providing a basis for improvement and increased efficiency in the performance of its services over a period of time.

System Operator Compliance with Obligations under the **Regulations** and **Code**

96. The **system operator** must:

96.1 Identify the obligations with which it must comply under the **regulations** and **Code** and document procedures for compliance with such obligations.

96.2 Whenever the **system operator** identifies that it may have breached the **Code**, investigate the incident to determine:

96.2.1 Any contributory causes including any acts or omissions of other persons and secondary events and incidents.

96.2.2 Any mitigating factors.

96.2.3 Any corrective action necessary by the **system operator**, including any process changes, training issues, or areas where a change to the **Code** may be required.

Asset Owner Compliance and Performance Monitoring

97. The **system operator** must proactively monitor and report on **asset owner** compliance with:

97.1 **AOPOs** and the **technical codes**.

97.2 **Dispensations** and **equivalence arrangements**.

97.3 **Alternative ancillary services arrangements**.

Compliance with AOPOs and Technical Codes

98. To monitor **asset owner** compliance with the **AOPOs** and **technical Codes**, the **system operator** must:

98.1 Review the content of **asset capability statements** received from **asset owners** under **Technical Code** A of Schedule 8.3 of the **Code** to assure itself, as far as is reasonably practicable, of an **asset owner's** ability to comply with the **AOPOs** and relevant **technical codes**.

98.2 In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, review the information provided in the **asset capability statements**, to establish or confirm the limitations in the operation of the **asset** in question that the **system operator** needs to know for the safe and efficient operation of the **grid**.

98.3 In accordance with **Technical Code** A of Schedule 8.3 of the **Code**, rely on the results of any tests carried out under a **test plan** or a commissioning plan, to establish or confirm **asset** capability in accordance with the **AOPOs** and the **technical code** requirements.

98.4 *[Revoked]*

98.5 In accordance with clause 8.4 of the **Code** and following the receipt of an **asset capability statement**, and subject to any tests carried out under a **test plan** or commissioning plan, rely on the **assets** and information about such **assets** made available to the **system operator** unless the **system operator** considers, acting reasonably and based on the information received by or otherwise known to the **system operator**, that it should not rely upon the accuracy of an **asset owner's asset capability statement**.

98.6 During **dispatch**, log suspected or actual **asset owner** non-compliance with the **AOPOs** and the **technical codes** based upon information that is available to the **system operator** when fulfilling its **dispatch** obligations under the **Code**.

98.7 Where the **system operator** has non-confidential information on which it has relied in determining, under clause 98.5, not to rely on the accuracy of an **asset owner asset capability statement**, it must notify such information to the relevant **asset owner** as soon as reasonably practicable.

Compliance with Dispensations and Equivalence Arrangements

99. The **system operator** must undertake any specific monitoring required as a condition of a **dispensation** or **equivalence arrangement.**

Compliance with Alternative Ancillary Services Arrangements

100. The **system operator** must, following consultation with the relevant **asset owner**, specify any requirements to facilitate proactive compliance monitoring of the **alternative ancillary services arrangement** as a condition of the **system operator's** approval of such arrangements under Schedule 8.2 of the Code.

Asset Owner Non-Compliance

101. Where the **system operator** suspects that an **asset owner** may have breached or has breached any specific obligation under the **regulations**, **Code** or conditions of any **equivalence arrangement**, **dispensation** or **alternative ancillary services arrangement**, the **system operator** must:

101.1 consider the circumstances to see if there are reasonable grounds for believing a breach has occurred.

101.2 seek such further information from a relevant **asset owner** as may be necessary to undertake such consideration.

101.3 determine in accordance with clause 8.27(2) of the **Code** whether to **dispatch** the **asset** or configuration of **assets** that it does not reasonably believe complies with the **AOPOs**, **technical code**, **dispensation** or **equivalence arrangement** in question.

101.4 assess any potential impact of the non-compliance on its ability to continue to comply with the **PPOs** and notify such impact to the **Authority**.

101.5 tell **participants** of its intention to revoke or amend a **dispensation** or **equivalence arrangement** in accordance with clause 8.35 of the **Code**, or its intention to revoke or amend any **alternative ancillary services arrangement** in accordance with clause 8.52 of the **Code**.

Urgent Change Notice

102. The **system operator** must make available on its website an **urgent change notice** form to inform the **system operator** of an urgent or temporary change in **asset** capability where clause 2(6)(b) of **Technical Code** A of Schedule 8.3 of the **Code** does not apply. An urgent or temporary change in **asset** capability is a change where the **asset owner**:

102.1 unexpectedly becomes aware the capability of an **asset** may differ from the capability described in the most recent **asset capability**

statement provided to the **system operator** in respect of such **asset** and there is no practicable opportunity to lodge a new **asset capability statement** in accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**, and

102.2 needs to perform further investigations to determine or confirm the actual capability of the **asset**.

103. An **urgent change notice** will apply for the period specified in the **urgent change notice** and will be the **asset owner's** best assessment (based on the information it has to hand) as to the actual capability of the relevant **asset**. On receipt of an **urgent change notice** by the **system operator**, the most recent **asset capability statement** in respect of the relevant **asset** will be deemed to be amended to reflect the capability set out in the **urgent change notice**.

104. When the **system operator** receives an **urgent change notice** it must as soon as reasonably possible:

104.1 assess the impact the urgent or temporary change in **asset** capability will have on the **system operator's** ability to plan to comply or comply with its **PPOs**.

104.2 endeavour to agree with the **asset owner** any necessary operating conditions or limitations required as a result of the temporary change in **asset** capability.

104.3 advise the **asset owner** of any conditions or constraints that the **system operator** will apply in respect of the **dispatch** of the **asset** (and it must update the **asset owner** if it changes these constraints or conditions at any time).

ASSET CAPABILITY INFORMATION

General Policy

105. In assessing the performance of an asset to assist the **system operator** to plan to comply and comply with the **principal performance obligations** and the **dispatch objective**, the **system operator** will only use information supplied by the **asset owner** through an **asset capability statement**.

106. *[Revoked]*

General Information Required from Asset Owners

107. In accordance with clause 2(5) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must **advise** a standard format **asset capability statement** for the following types of **asset owner**:

107.1 **generators** for **generating units** connected to the **grid** and to a **local network**.

107.2 **grid owners**.

107.3 **distributors**.

ASSET CAPABILITY ASSESSMENTS

General Asset Capability Assessment

108. The **system operator** has identified a number of areas where **asset** performance can have a significant impact on the **system operator's** ability to comply with the **PPOs**. These include:

108.1 **asset owner** protection systems.

108.2 **generator asset** capability:

- Voltage.
- Frequency.
- Fault ride-through capability.

108.3 **grid owner asset** capability:

- Voltage.
- **HVDC link** frequency capability.
- South Island **AUFLS**.

108.4 **distributor asset** capability:

- North Island **AUFLS**.
- Frequency response capability of unoffered generation on the **distributor**'s network
- Fault ride-through capability of **generating units** on the **distributor**'s network.

Asset Owner Protection Systems

Grid Owners

109. The **system operator** may rely upon **grid owner** compliance with the **technical codes** in the design and configuration of the **grid owner's assets** (including its connections to other persons) and associated protection arrangements, as contained in Subpart 2 of Part 8 of the **Code** and Schedule 8.3 of the **Code**.

110. In accordance with clause 4(5)(b) of **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** and the **grid owner** must agree the locations to check synchronism and **grid owner** confirmation of this synchronism must be requested in the **asset capability statement**.

111. *[Revoked]*

111.1 *[Revoked]*

111.2 *[Revoked]*

111.3 *[Revoked]*

111.4 *[Revoked]*

112. *[Revoked]*

112.1 *[Revoked]*

112.2 *[Revoked]*

113. *[Revoked]*

Generator Asset Capability Assessment

Voltage

114. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant reactive capability** with respect to the **AOPOs** set out in clause 8.23 of the **Code** by;

114.1 assuming:

- the **generating plant** and the **grid** bus are represented as a two-bus system.
- the **generating plant's** outputs are net **active power** and **reactive power** after accounting for local supply or auxiliary load and are measured at the **generating plant** terminal entering the **generating plant** transformer
- the **generating plant** has a terminal voltage control range of +/- 5% unless otherwise stated in the relevant **asset capability statement**.

114.2 Verifying compliance with the reactive power requirements of clause 8.23 of the **Code** by assessing:

- the **generating plant** reactive power range when importing and exporting at full load with respect to the standards.
- the ability of **generating plant**, when importing and exporting **reactive power** at full load, to maintain the voltage within the ranges set out in the tables set out in clause 8.23 of the **Code**.
- the ability for **generating plant** to be connected over the operating ranges set out in clause 8.22 of the **Code** considering:
- **generating plant** reactive power range.
  - **Generating plant** transformer tap range, including the requirement for on-load tap changers.
  - **Generating plant** terminal voltage range.
  - **Generating plant** voltage stability when small voltage perturbations are applied to excitors.

Voltage Fault Ride Through

114A For the purpose of carrying out an assessment of fault ride through compliance under clause 8.25A of the **Code**, the **system operator** must make available on its website a summary of the assumptions used in the assessment.

Frequency

115. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **generating plant** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

115.1 assessing the **generating plant** trip settings.

115.2 modelling **generating plant** and governor performance to analyse frequency performance.

115.3 assessing **generating plant** performance when islanded.

115.4 modelling **generating plant** governors and excitors to confirm stability when voltage perturbations are applied to excitors and load changes are applied to governors.

Grid Owner Asset Capability Assessment

Voltage

116. To enable the **system operator** to manage the risk of cascade failure, the **system operator** must:

116.1 assess the information **grid owners** provide regarding the details of the operational voltage range capability of their **assets** described in their **asset capability statements**.

116.2 model the performance of dynamic reactive power devices to establish stability and to obtain parameters for the **system operator** to model the system dynamics for planning and system security analysis.

HVDC Frequency Capability

117. For the purpose of carrying out assessments under **Technical Code** A of Schedule 8.3 of the **Code** the **system operator** must assess **HVDC Owner** frequency capability with respect to the **AOPOs** set out in clauses 8.17 to 8.21 of the **Code**, by:

117.1 assessing the **HVDC Owner** trip settings.

117.2 modelling the **HVDC link** performance to analyse its frequency performance.

Automatic Under-Frequency Load Shedding (AUFLS)

117A. To manage its risk of cascade failure, the **system operator** must:

117A.1 request that the South Island **grid owner** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

117A.2 maintain a register of **AUFLS** profiling statements to determine the minimum **AUFLS** percentage available at any time.

117A.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

Distributor Asset Capability Assessment

Automatic Under-Frequency Load Shedding (AUFLS)

118. To manage its risk of cascade failure, the **system operator** must:

118.1 request that North Island **distributors** provide an **AUFLS** load profiling statement on their **asset capability statement** that states the minimum percentage of **AUFLS** load for each block armed to trip.

118.2 maintain a register of **AUFLS** profiling statements to determine the minimum **AUFLS** percentage available at any time.

118.3 incorporate **AUFLS** relay testing and confirmation of load profiling in the **test plan**.

COMMISSIONING ASSETS

General Policy

119. The **system operator** must carry out the following actions in relation to commissioning:

119.1 To ascertain whether the commissioning will affect the **system operator's** ability to plan to comply and comply with the **PPO** objectives, evaluate **asset owner** compliance with the **AOPOs** and the **technical codes**, using the information provided by the **asset owner** in accordance with clauses 2 and 3 of **Technical Code** A of Schedule 8.3 of the **Code**, at the following stages:

- Planning.
- Building and prior to commissioning.
- During commissioning.
- On completion of commissioning.

119.2 Make available on its website a 'Connection and Dispatch Guide' that describes the studies undertaken by the **system operator** at different stages of commissioning and the timeframes for assessment required by the **system operator** at different stages of commissioning. This guide must state the information required from **asset owners** at each of the above stages, including information required by the **asset capability statements** in the form listed on its website for each **asset** that is proposed to be connected, or is connected to, or forms part of the **grid**.

120. The **system operator** must assess **asset capability statements** provided to the **system operator** by **asset owners** for **assets** that are being commissioned or modified at each of the following stages:

120.1 Prior to the completion of planning for the construction of an **asset.**

120.2 At completion of construction of an **asset**.

120.3 At completion of commissioning of an **asset**.

120.4 At any time the **asset owner** updates the **asset capability statement** during any stage of commissioning.

121. Upon receipt of an **asset capability statement**, the **system operator** must carry out any assessments necessary and notify the **asset owner**:

121.1 whether the **system operator** requires any further information to determine whether the **asset** will, in its reasonable opinion, meet the requirements of the **AOPOs** and the **technical codes**.

121.2 whether, on the basis of the information provided by the **asset owner** and any assumptions made by the **system operator** and notified to the **asset owner**, the **asset** will in the **system operator**'s reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**.

121.3 whether the **system operator**'s decision is based on any specific conditions and / or assumptions.

121.4 if the **system operator** is not satisfied the **asset** will in its reasonable opinion meet the requirements of the **AOPOs** and the **technical codes**, of any appropriate actions required for the **asset owner** to achieve compliance, including application for a **dispensation** or **equivalence arrangement**.

122. If appropriate, the **system operator** may repeat the process described in clause 121 until the **system operator** is reasonably satisfied the **asset** will meet the requirements of the **AOPOs** and the **technical codes.**

Commissioning Plan

123. When the **asset owner** notifies the **system operator** the **asset** is, or will be, ready for commissioning, the **system operator** must require the **asset owner** to provide a commissioning plan to meet the requirements of clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**. In order to assess the commissioning plan, the **system operator** may require the commissioning plan to address the following matters (in addition to the specific matters set out at clauses 2(7) and 2(8) of **Technical Code** A of Schedule 8.3 of the **Code**):

123.1 Proposed dates and times for commissioning and testing activities.

123.2 Preliminary stability check.

123.3 Proposed reactive output.

123.4 Configuration.

123.5 Control system tuning.

123.6 Any other matters which the **system operator** reasonably considers relevant to enabling the **system operator** to plan to comply, and to comply, with its **PPOs**.

Dispatch for Commissioning

124. *[Revoked]*

125. The **system operator** will only **dispatch** commissioning **assets** solely for commissioning purposes.

During Commissioning

126. During commissioning of the **asset**, the **system operator** must review the results of the various tests to:

126.1 confirm the results of any previous assessments of the **asset** carried out prior to commissioning.

126.2 re-assess compliance of the **asset** with the **AOPOs** and the **technical codes**.

Final Assessment

127. Upon receipt of a final **asset capability statement** from the **asset owner** after commissioning, the **system operator** must:

127.1 complete a final assessment of the **asset** for compliance with the **AOPOs** and the **technical codes**.

127.2 finalise the assessment process of any request for **dispensation** or **equivalence arrangement** in accordance with this Compliance Policy.

Test Plan

128. The **system operator** must make available on the **Transpower** website:

128.1 a template for a **system test** that can be used by **asset owners** where the circumstances in clause 2(6)(c) of **Technical Code** A of Schedule 8.3 of the **Code** apply. If the **system operator** agrees to **dispatch** the **asset** referred to in a **test plan** submitted to it by an **asset owner** using the template, it must thereafter consider any **asset** capability information in the **test plan** that differs from that contained in the most recent **asset capability statement** provided to the **system operator** in respect of such **asset** to replace the relevant **asset** capability information for the duration agreed in the **test plan**.

128.2 the companion guides for **asset** testing, which assists **asset owners** to implement the requirements for **asset** testing in clauses 2(6) to (8) and 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** and testing after modification and **commissioning**. The companion guides for **asset** testing must:

128.2.1 be reviewed not less than once in each period of five years. When carrying out each review the **system operator** must invite comments from **registered participants** as to the process and the content of the review.

128.2.2 outline the information from **asset** testing undertaken by **asset owners** under clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code** that will assist the **system operator** understand the nature of the tests carried out and the results thereof.

128.2.3 describe suggested standards or appropriate methodology for the routine testing of **assets** set out in Appendix B of **Technical Code** A of Schedule 8.3 of the **Code**.

128.2.4 describe the tests that **asset owners** can undertake after modification and **commissioning** to ensure the provision of appropriate information to the **system operator** in accordance with clauses 2(2) and 2(5) of **Technical Code** A of Schedule 8.3 of the **Code**.

128.2.5 describe the tests that an **ancillary service agent** may be requested by the **system operator** to undertake to demonstrate an **asset** is capable of meeting the technical requirements and performance standards set out in a relevant **ancillary service** procurement contract.

DISPENSATIONS AND EQUIVALENCE ARRANGEMENTS

General Policy

129. To facilitate the operation of the processes under the **Code** for the approval of **equivalence arrangements** and grant of **dispensations**, the **system operator** must provide the following information:

129.1 Contact details for communication with the **system operator** on application, information, and revision of information or cancellation of the application or other matters relating to **equivalence arrangements** and **dispensations**.

129.2 A pro forma application form for **dispensations** or **equivalence arrangements**.

129A. The **system operator** must make its assessment of an application for a **dispensation** or an **equivalence arrangement** based on the information it has and the circumstances existing at the time. Information relevant to the **system operator's** assessment includes:

(a) the content of the regulations and **Code**.

(b) the content of the **policy statement** and **procurement plan**.

(c) power system **assets**, availability, and outages.

(d) knowledge regarding **asset** capability.

129B. The **system operator** must consider any request for a **dispensation** or **equivalence arrangement** by the relevant **asset owner** prior to the **asset** in question being commissioned.

Terms and Conditions of Dispensations and Equivalence Arrangements

130. The **system operator** may approve such a request subject to reasonable conditions including, without limitation, the following:

130.1 Any approval granted by the **system operator** for a **dispensation** or **equivalence arrangement** prior to the **asset** in question being commissioned will terminate after 2 years from the approval date if the **asset** is not commissioned.

130.2 If required, the **asset owner** may apply to the **system operator** to extend the 2 year term. The **system operator** may not unreasonably withhold such consent.

131. *[Revoked]*

131A. **Dispensations** and **equivalence arrangements** are subject to review at the time the **system operator** produces or reviews the **system security forecast** in accordance with clause 8.15 of the **Code**. The purpose of the review is to ascertain whether there has been any material change in circumstances or to the assumptions on which the **dispensation** was granted or the **equivalence arrangement** approved.

131B. Under Part 8 of the **Code** the **system operator** may revoke or vary a **dispensation**, or revoke an **equivalence arrangement**, in certain circumstances.

132. *[Revoked]*

Dispensation, Equivalence Arrangement and Alternative Ancillary Service Arrangements Register

133. The following must apply to the **publication** of information on the **system operator register:**

133.1 The **system operator register** must contain no information which has been designated a commercially sensitive by the relevant **asset owner**.

133.2 The **system operator** must designate an employee role to be responsible for managing the **system operator register**.

133.3 The **system operator** must maintain an up to date copy of the **system operator register** and make it available to **registered participants** at no cost on the **system operator's** website at all reasonable times.

133A. The **system operator** must make available on its website a list of current **dispensations**, **equivalence arrangements** and **alternative ancillary services arrangements**.

Cancellation of Arrangements

134. The **system operator** must consider any request for cancellation of a **dispensation** or **equivalence arrangement** by the relevant **asset owner** provided that the request must:

134.1 be in writing.

134.2 be accompanied by a description of how compliance for that **asset**, for which the **dispensation** or **equivalence arrangement** was originally sought, is now achieved.

134.3 include an updated **asset capability statement**.

134.4 include any results from **system tests** carried out to confirm compliance with the **AOPOs** and **technical codes**.

Chapter 4 – Conflict Of Interest Policy

General Policy

134A This Conflict of Interest Policy sets out the methods the **system operator** must use to manage possible, actual or perceived conflicts of interest that arise within **Transpower** between its **system operator** functions and any of its other **participant** functions, including the **grid owner** function. A conflict of interest is any situation where one of the following persons has a material interest in the outcome of a **system operator** function:

- **Transpower**, other than in its capacity as the system operator.
- A **Transpower** employee, contractor or director involved in carrying out the function.

134B. Some examples of **system operator** functions where conflicts of interest and where questions of independence and impartiality may arise include:

- procurement of **ancillary services** or **alternative ancillary services**.
- **causer** recommendations.
- **dispensation** and **equivalence arrangement** decisions.
- **outage** co-ordination.
- **Code** compliance monitoring and reporting.

GENERAL APPROACH

135. The **system operator** must:

135.1 identify potential conflicts of interest that arise in the performance of the **system operator's** functions, including by providing easily accessible means by which **Transpower** personnel and persons external to **Transpower** can (anonymously if they wish through its website) notify the **system operator** of potential conflicts of interest.

135.2 investigate and assess the materiality of each conflict of interest that has been identified.

135.3 apply methods to manage each conflict of interest that are appropriate for the materiality of the conflict of interest.

135.3A record all potential conflicts of interest in the Conflicts of Interest Register as they arise, including the **system operator's** assessment of materiality for each conflict of interest and the methods used to manage each conflict of interest.

135.4 report to the **Authority** in the **system operator's** monthly report under clause 3.14 of the **Code**, and on the **Authority's** request, on:

135.4.1 any new conflict of interest that has arisen since the last report, including the nature of the conflict of interest, the date the conflict of interest was identified and notified to the **Authority** (if prior to the monthly report), the reason it has arisen, assessment of materiality and the methods by which it was or will be managed.

135.4.2 any breaches of this Conflict of Interest Policy.

135.4A report to the **Authority** in the **system operator's** annual report under clause 7.11 of the **Code**, on the **system operator's** compliance with its obligations under the **Code**, including:

135.4A.1 the background of any event that warranted the system operator undertaking internal performance review and report findings;

135.4A.2 a description of the event;

135.4A.3 the means by which the conflict of interest was managed; and

135.4A.4 any departures from or proposed changes to policy.

135.5 Treat all **participants** in an even-handed way, including by applying the same processes and standards to its dealings with all **participants**.

135.6 [Revoked]

136. [Revoked]

137. [Revoked]

THE MEANS TO MANAGE CONFLICT OF INTEREST

138. The **system operator** must employ any or all of the following methods to manage conflicts of interest, taking into account the circumstances and materiality of the conflict of interest:

138.1A Appoint an independent person to oversee the management of the conflict of interest.

138.2A Appoint an independent expert to conduct an evaluation or investigation on behalf of, or to advise, the **system operator**.

138.3A Establish independent document and information management systems.

138.4A Establish a communication management system between the relevant parts of Transpower New Zealand Limited, which may include call logs, document logs, meeting minutes and specified points of contact.

138.5A Establish a clear division of management and staff roles. This may include the establishment of separate teams that are physically isolated from each other.

138.6A Advise any relevant non-confidential information considered material in maintaining a transparent and impartial process.

138.7A Any other method the **system operator** identifies and considers appropriate to manage the conflict of interest, which the **system operator** must **advise** as soon as reasonably practicable.

138.1 [Revoked]

138.2 [Revoked]

138.3 [Revoked]

138.4 [Revoked]

138.5 [Revoked]

138.6 [Revoked]

138.7 [Revoked]

138.8 [Revoked]

139. [Revoked]

140. [Revoked]

141. [Revoked]

142. [Revoked]

143. [Revoked]

143.1 [Revoked]

143.2 [Revoked]

143.3 [Revoked]

143.4 [Revoked]

143.5 [Revoked]

143.6 [Revoked]

144. [Revoked]

145. [Revoked]

145.1 [Revoked]

145.2 [Revoked]

146. [Revoked]

146.1 [Revoked]

146.2 [Revoked]

146.3 [Revoked]

146.4 [Revoked]

147. [Revoked]

148. [Revoked]

148.1 [Revoked]

148.2 [Revoked]

149. [Revoked]

149.1 [Revoked]

149.2 [Revoked]

149.3 [Revoked]

149.4 [Revoked]

150. [Revoked]

151. [Revoked]

152. [Revoked]

152.1 [Revoked]

152.2 [Revoked]

152.3 [Revoked]

152.4 [Revoked]

Chapter 5 – Future Formulation and Implementation Policy

Policy and Scope

153. The **Code** contains provisions that require the **system operator** to be consulted on the impact of proposed **Code** changes. This ensures that where necessary, the impact of **Code** changes can be reflected in the **policy statement** by making timely changes outside the two-yearly review cycle.

154. The **system operator** maintains operational review processes that capture issues for which possible change to the **policy statement** may be desirable. Such matters are logged for consideration during the next review of the **policy statement**. The matters logged include issues raised with the **system operator** by **participants** and the **Authority**.

155. If an issue is identified requiring urgent attention and change to the **policy statement** outside the two-yearly review cycle the **system operator** must bring the matter to the attention of the **Authority**. The **system operator** must seek the **Authority's** assistance in implementing the required change, such as by **Code** change, change to the **policy statement** or approval of an exemption.

156. [Revoked]

156.1 [Revoked]

156.2 [Revoked]

156.3 [Revoked]

156.4 [Revoked]

156.5 [Revoked]

156.6 [Revoked]

156.7 [Revoked]

156.8 [Revoked]

Chapter 6 - Statement of Reasons for Adopting Policies and Means

157. The **system operator** has adopted the policies and means set out in the **policy statement** for the following reasons:

157.1 The **system operator** believes they are the policies and means that will best enable it to comply with the **principal performance obligations**.

157.2 They are policies and means that in large measure have been used successfully for many years.

157.3 To the extent the policies and means represent changes from those adopted previously it is because the **system operator** believes no previous policy or means existed or a previous policy or means did not adequately meet the needs of the **system operator**.

157.4 The **system operator** consulted widely when it developed the policies and means set out in the **policy statement** and took into account the views of **participants**.

This statement is made for the purposes of clause 8.11(3)(d) of the **Code**.

Glossary of Terms

158. **Advise** means the **system operator** placing information or other material required to be provided or made available under the **policy statement** on its website. The **system operator** must use its best endeavours to send an e-mail to **participants** telling them the information or other material has been placed on the **system operator's** website.

159. **Asset outage constraints** are a sub-set of **security constraints.** They are **security constraints** previously developed and used by the **system operator** temporarily in response to earlier advised **asset** outages. They are retained by the **system operator** for possible future re-use. They are often applied at short notice.

160. **AUFLS** means **automatic under-frequency load shedding** systems.

160A. **Automatic under-voltage load shedding** and **AUVLS** means automatic shedding of electrical load when voltage falls below the relevant pre-set voltage.

161. **Changeover date** means 28 March 2011.

162. *[Revoked]*

162A. **Constraint percentage threshold** means the threshold at which constraints developed by automatic processes are applied to schedules in the market system, expressed as a percentage of the limit of the constraint. This threshold is **advised** from time to time by the **system operator**, following consultation with **participants.** Separate constraint percentage thresholds may be **advised** for constraints developed under automated and non-automated processes.

162B **Constraint publication threshold** means the threshold at which constraints are published on **WITS**, expressed as a percentage of a constraint limit. This threshold is **advised** from time to time by the **system operator,** following consultation with **participants.**

163. **Contingent events** are as defined in clauses 12.3 and 12.4.

164. **Demand management** means an unplanned interruption of **demand** initiated by the **system operator**. The **system operator's demand management** process is described in clauses 74A and 74B.

164A. **Discretionary security constraint** means a **security** constraint applied to **SPD** by the **system operator** that represents a departure from the **dispatch schedule** pursuant to clause 13.70 of the **Code**.

165. **Dynamic load distribution factor** means the proportion of a regional load being drawn at a **GXP** within that region. The **dynamic load distribution factors** are derived from actual load on a regularly updated basis in real time.

166. *[Revoked]*

167. **Extended contingent events** are as defined in clauses 12.3 and 12.4.

168. **Fixed load distribution factor** means the proportion of the regional load forecast assigned to a **GXP** within that region. The **fixed load distribution factors** are set for a specified **trading period** based on

the actual load for the same **trading period** in the previous week or in the previous fortnight.

169. **Frequency keeping constraints** means **security constraints** applied by the **system operator** in scheduling and **dispatch** for the purposes of maintaining a frequency keeper within its offered **asset** capability limits.

169A. **Market schedules** means, collectively, the **price-responsive schedule**, **non-response schedule** and the **real-time dispatch schedule**.

170. **Maximum instantaneous demand change limit** is the **MW** amount specified from time to time by the **system operator** under clause 39 for **demand** changes that may be made by any **purchaser** within a 1 minute and a 5 minute period.

170A [Revoked]

171. **Other events** are as defined in clause 12.3.

172. [Revoked]

173. **Planned Outage Co-ordination Process** means the process by which the **system operator** receives, assesses and provides feedback on outage notifications in accordance with **Technical Code** D of Schedule 8.3 of the **Code**.

173AA **Reduction line change operation** means the planned or unplanned NZAS reduction line removal and restoration process at Tiwai Aluminum smelter.

173A. **Regulations** means the regulations made pursuant to subpart 1 of Part 5 of the **Act** as may be amended from time to time.

174. **Relevant freely available reactive resources** are reactive resources that exist, the **dispatch** of which will support voltage at the affected location, which are available to the **system operator** at no **procurement plan** cost and without requiring the application of a **security constraint** to provide reactive resources. They include **grid owner assets** capable of providing reactive support and made available, and generation **dispatched**, and required to provide reactive support in accordance with the **voltage support AOPOs**.

175. **Reserves Management Tool** and **RMT** mean the reserves management **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

176. **Scheduling Pricing and Dispatch** and **SPD** mean the scheduling, pricing and dispatch **software** used by the **system operator** as agreed with the **Authority** pursuant to the **System Operator Service Provider Agreement**.

177. *[Revoked]*

178. **Security constraint** is a constraint that is used to maintain the security and stability of the power system.

179. A **stability event** is an event that prevents the power system from regaining **system stability** or prevents specific **generating units** from maintaining stable operation within the power system. These events include, but are not limited to:

- for voltage stability, the tripping (with or without fault) of a **generating unit** or a transmission circuit:
- for rotor angle stability, a fault on the grid (which may or may not result in consequent outages of transmission equipment):
- for control system stability, any normal or abnormal operating conditions resulting in unexpected control system behaviour.

180. A **standby residual shortfall** is a situation when there are either insufficient **generator offers** and **instantaneous reserve** offers following a **contingent event** to schedule sufficient reserves for a second event and/or there are insufficient **generator offers** to restore **interruptible load** following a **contingent event**.

181. A **standby residual shortfall notice** is a notice issued by the **system operator** to selected **participants** in which it advises that a **standby residual shortfall** has been identified.

181A. **Standby residual shortfall threshold** means the threshold above which a **standby residual shortfall notice** must be issued**,** such threshold being determined from time to time by the **system operator** and notified by the **system operator** to **participants**.

182. **System Operator Service Provider Agreement** means the **market operation service provider agreement** for the provision of **system operator** services.

182A. **System stability** is the normal operating conditions expected to exist in the power system, where perturbations are being maintained within the expected range(s), in such a way that the power system dynamic behaviour is not resulting in any restriction on the normal operation of any **generating unit**, load or other connected equipment. This includes, but is not limited to:

- voltage stability (ability to maintain steady state voltages at all buses in the system after subjected to a disturbance):
- rotor angular stability (ability of the **synchronous** machines in the power system to remain **synchronised** under normal operating conditions and to regain **synchronism** if subjected to a disturbance: or
- control system stability (the ability of the control systems of any **generating unit** to maintain stable operation during both the steady state and dynamic interactions with the power system, including but not limited to dynamic interactions with any other **generating unit**).

183. **Target grid voltages** are voltages determined by the **system operator** under clause 41.1 of the Security Policy at selected locations on the **grid** where the voltage is greater than, or equal to 50kV.

184. **Temporary security constraints,** which include **asset outage constraints**, are **security constraints** which are applied in scheduling and **dispatch** to supplement **permanent security constraints** and account for temporary **grid** configuration, transmission capability and system conditions.

185. **Test plan** means:

185.1 a routine test plan agreed pursuant to clause 8(2) of **Technical Code** A of Schedule 8.3 of the **Code**;

185.2 a remedial test plan agreed pursuant to clause 8(3)(a) of **Technical Code** A of Schedule 8.3 of the **Code**; or

185.3 a test plan agreed between the **system operator** and an **asset owner** under clause 2(6) of **Technical Code** A of Schedule 8.3 of the **Code**.

186. **Transmission circuit** means:

186.1 any transmission line owned by a **grid owner**.

186.2 any distribution line owned by a **participant** to which not less than a sum of 60 **MW** of **generation** is connected and which distribution line is connected to the **grid** primarily for the purpose of **injection** into the **grid**.

187. **Urgent change notice** is a notice issued to the **system operator** by a **participant** in accordance with clause 102.

188. **Week-ahead dispatch schedule** means a schedule produced by the **system operator** for the 260 **trading periods** beginning at 14.00 hours of the next **day** using:

188.1 Generation **offers** or, where no revised **offer** exists, generation **offers** for the previous week.

188.2 Forecast **grid** configuration, including any **notified planned outages.**

188.3 Anticipated **demand** using **fixed load distribution factors**.

188.4 **Nominated bids** or, where no revised **nominated bid** exists, **nominated bids** for the previous week.

189. **Wider voltage agreement** is an arrangement where the **grid owner** has informed the **system operator**, in writing that:

189.1 The **grid owner** has agreed with other affected **asset owners** at a **GXP** or in a region that the **system operator** may operate outside the ranges set out in clause 8.22(1) of the **Code**.

189.2 Where the **grid owner** has not identified any other affected **asset owners** at a **GXP** or in a region, **the grid owner** agrees with the **system operator** to operate the **grid owner's assets** outside the ranges set out in clause 8.22(1) of the **Code**.