System Management PSOP Working Group

AGENDA

Meeting No.	10 / 2011
Location:	System Management 8 Joel Terrace, East Perth
Date:	Monday 12 December 2011
Time:	8.30 am – 4.30 pm

Item	Subject	Responsible	Time
1	**WELCOME AND APOLOGIES / ATTENDANCE**	**Chair**	5 minutes
2.	**MINUTES OF PREVIOUS MEETING**	**Chair**	10 mins
3.	**ACTIONS ARISING**	**Chair**	10 mins
4.	**PROCEDURE CHANGE STATUS**	**Chair**	5 mins
3.	**PSOP: Facility Outages** Discussion of the proposed amendment to the Facility Outages PSOP, reflecting the future commencement of rule change 'RC_2011_10 Competitive Balancing and Load Following Market'	**System Management**	30 mins
4.	**PSOP: Commissioning and Testing** Discussion of the proposed amendment to the Commissioning and Testing PSOP, reflecting the future commencement of rule change 'RC_2011_10 Competitive Balancing and Load Following Market'	**System Management**	30 mins
	10.00 am Morning tea		15 mins
5.	**PSOP: Power System Security** Discussion of the proposed amendment to the Power System Security PSOP, reflecting the future commencement of rule change 'RC_2011_10 Competitive Balancing and Load Following Market'	**System Management**	I hour

Item	Subject	Responsible	Time
6.	**PSOP: Dispatch** Discussion of the proposed amendment to the Dispatch PSOP, reflecting the future commencement of rule change ‘RC_2011_10 Competitive Balancing and Load Following Market’	**System Management**	I hour
	12.15 pm - Lunch		45 mins
7.	**PSOP: Monitoring and Reporting** Discussion of the proposed amendment to the Monitoring and Reporting PSOP, reflecting the future commencement of rule change ‘RC_2011_10 Competitive Balancing and Load Following Market’	**System Management**	I hour
8.	**PSOP: Ancillary Services** Discussion of the proposed amendment to the Ancillary Services PSOP, reflecting the future commencement of rule change ‘RC_2011_10 Competitive Balancing and Load Following Market’	**System Management**	I hour
	3.00 pm – Coffee Break		10 mins
9.	**PSOP: Communication & Control Systems** Discussion of the proposed amendment to the Communication and Control System PSOP, reflecting the future commencement of rule change ‘RC_2011_10 Competitive Balancing and Load Following Market’	**System Management**	I hour
10.	**OTHER BUSINESS** Discussion on any other matters that fall within the scope of the PSOP Working Group’s Terms of Reference.	**Chair**	15 mins
11.	**NEXT MEETING** The next PSOP Working Group meeting to be scheduled.	**Chair**	5 minutes

Minutes

Meeting:	9/2010
Location:	IMO Board Room Level 3, Governor Stirling Tower, 197 St Georges Terrace, Perth
Date:	Thursday, 28 October 2010
Time:	Commencing at 2.00pm until 4.20pm

Members in Attendance		
Phil Kelloway	System Management	Chair
Peter Ryan	Griffin Energy	Proxy
Clement Chan	Verve Energy	Proxy
Wesley Medrana	Synergy	
Steve Gould	Landfill Gas & Power (LGP)	
Debra Rizzi	Alinta	
Michael Frost	Perth Energy	Proxy
Bill Bowyer	Infigen Energy	Proxy
Jacinda Papps	Independent Market Operator (IMO)	
Fiona Edmonds	IMO	
Shannon Turner	IMO	Minutes
Also in Attendance		
Robbie Flood	Alinta	
Grace Tan	System Management	
Neil Hay	System Management	
Gavin White	System Management	
Apologies		
Rene Kuyper	Infigen Energy	Member
Shane Cremin	Griffin Energy	Member

Item	Subject	Action
1.	**WELCOME** The Chair opened the System Management Power System Operation Procedure (PSOP) Working Group meeting and welcomed members.	
	MEETING APOLOGIES / ATTENDANCE Apologies were received from Rene Kuypers (Infigen Energy) and Shane Cremin (Griffin Energy) The following additional attendees were noted:	

Item	Subject	Action
	• Grace Tan (System Management) • Neil Hay (System Management)	
2.	**MINUTES OF PREVIOUS MEETING** The minutes from meeting 9 of the Working Group, held 20 November 2009, were circulated prior to the meeting and accepted as a true record of the meeting.	
	ACTIONS ARISING The status of the actions arising were noted as follows: • **System Management ('SM') to investigate and confirm the accuracy requirement of SCADA data:** The chair undertook to provide an analysis of SCADA accuracy at the next meeting. • **Working Group members to provide their views in relation to application of tolerances by SM:** The Chair thanked members for providing a number of submissions in response to SM's request and advised that these had been collated and circulated to members prior to this meeting.	
3 &4.	**PSOP: Monitoring and Reporting and Discussion Paper: Proposed Tolerance Range** The Chair suggested combining agenda items 3 and 4 as they were both related. The Working Group agreed. The Chair introduced Neil Hay ('NH') who presented the initial position on tolerances that SM was intending to reflect in both PSOP's prior to commencement of the formal procedure change process. The main points discussed within the presentation are as follows. **System Management use of SCADA data** SM uses data acquired from its System Control and Data Acquisition (SCADA) systems, which is provided at approximately 4 second intervals, and which estimates the instantaneous power output of individual facilities in MW. In contrast, the Resource Plan values provided by the IMO, as part of market processes, measure energy intended to be produced over an interval of 30 minutes in MWh. To directly compare MW and MWh values, individual SCADA (MW) values must be converted into MWh values by averaging each interval. A final estimate of the MWh output by a facility within an interval can only be made after the end of that interval.	

Item	Subject	Action
	This creates some issues in relation to SM's performance of its obligations under clause 7.10, which it is hoping to resolve through progression of rule change RC_2009_22 'The use of tolerance levels by System Management' and associated changes with both the Monitoring and Reporting Protocol PSOP ('MRP') and Dispatch PSOP's **Resource Plan Monitoring – Rule Requirements** The format of resource plans is set out by clause 6.11 of the market rules must include: • intended time of sync/ desync to the network (to the minute) • energy to sent out or consumed within each interval (in MWh) • targets output of each facility at the end of each trading interval (in MW) Clause 7.10 imposes a range of obligations on IPP's and SM in relation to compliance with Resource Plans and Dispatch Instructions. In particular: • Clause 7.10.1 participants must comply with their resource plans; • Clause 7.10.4 SM must monitor participants compliance with 7.10.1; • Clause 7.10.5 unless there is a valid reason, and SM is aware of this (MR 7.10.5A), if an Market Participant ('MP') is not complying with MR7.10.1, SM must warn them and request them to return their facility to resource plan; and • MR 7.10.6 a MP must comply with a request under 7.10.5. **Real time vs Ex-post obligations** In practice, because of the need to wait until the end of an interval before calculating a MWh value based on the MW SCADA values. SM conducts its monitoring activity under MR 7.10.4 as part of a business day process run by the Market Operations group. However, SM's compliance under 7.10.5 must occur in real time and this requires SM to utilise additional information that allows it model, on a minute by minute basis, an "authorised dispatch" value in MW for direct comparison with SCADA data. SM's intention is to allow a MP to provide either one of three real time dispatch profiles to SM to allow SM to conduct its real time monitoring obligations to fulfil MR7.10., These are: 1. straight line interpolation inferred by SM based on a MP's resource plan (this is the default); 2. model based on an algorithm supplied by a MP; or	

Item	Subject	Action
	3. dispatch profile on a 'minute by minute' resolution supplied by an MP. Note: The current Dispatch PSOP establishes the basic requirement for provision of a dispatch profile to SM. This PSOP will be amended to allow a Market Participant to choose between providing SM with an algorithm or a dispatch profile in lieu of SM using a straight line interpolation to conduct real time monitoring. The process would then apply tolerances as per the amended Monitoring and Reporting PSOP around these values for the purposes of compliance monitoring that would come under MR 7.10.5. In response to a query from Perth Energy, SM confirmed that the approach would be at least initially relatively simplistic. For example, participants would not have the ability to lodge a range of possible algorithms and have SM choose one that is appropriate to the particular circumstances. However the participant could lodge a special circumstance by use of the dispatch profile option. **Meter data vs. SCADA data** Currently SM monitors real time and ex post MP compliance using SCADA data. SM only has access to this data source ie SM does not have access to the meter data that becomes apparent later, which is used by the IMO to settle the balancing market. Any monitoring activities undertaken by SM under the WEM rules allows the potential for a substantial variance between these two values. A tolerance for this variance is required in addition to a tolerance currently accounted for in the settlement process under MR 6.17.9 **Tolerance levels** When determining an appropriate level to set a tolerance that would apply to all facilities, it is necessary to take account of both deviations in generator output as a result of control issues, and the potential for material differences between meter and SCADA values (averaged over the hour). The WEM rules currently allows for the first source of possible deviations by applying a 3 MWhr / 6 MW tolerance under MR 6.17.9. However, this tolerance is only applied significantly later in the non-Stem settlement process and doesn't account for the data issues discussed above. Tolerances applied by SM as part of this new process must include an allowance for the tolerance applied in settlements plus an additional allowance for the possibility that SCADA data may differ from Meter data. This ameliorates the possibility that a participant operating in accordance with their resource plan (when measured by meter data) faces possible direction by SM	

Item	Subject	Action
	away from that level based on SM's inference of SCADA values. Such a situation is a clear case of market failure. Accordingly, SM proposes a value of 10MW (which includes 6MW under MR 6.17.9) as the broad 'default' tolerance that will apply to all scheduled generators in carrying out its monitoring obligations under MR 7.10. **Special Cases** In some cases, the general tolerance may not be appropriate because the accuracy of SCADA data is variable between facilities. SM proposes to treat these on a case-by-case by request initiated by the participant. A participant who believes that the default tolerance is not appropriate will be able to bring this information to SM, who after investigating the circumstances (by comparing historic SCADA and Meter values over a reasonable period (say 3 months) may approve a tolerance other than the default. Determination and review of a 'facility' specific tolerance must be conducted in accordance with the Monitoring and Reporting Protocol PSOP **Single Interval – Synchronisation/Desynchronisation** SM's tolerance range intends to allow for a MP to ramp up and ramp down a facility within single intervals. **Forced Outages** Forced Outages are an important issue in this context. Ensuring that SOCC is informed of any issues with a facility in a timely and accurate manner will be taken as an indication of compliance for the purposes of MR 7.10.5. However, in relation to MR 7.10.4 compliance will be dependent on whether a participant has entered the forced outage into SMIMTS. SM intends to conduct its ex-post monitoring compliance so as to be able to report compliance to the IMO in line with other data regarding a Trade Date. Market rule 7.13.1 sets out that this will be by noon on the first business day following the day which the Trading Day ends. If forced outages have been entered into SMMITS in by this time they will be taken into account when calculating compliance. Historically, our practice was to send SCADA data deviations to MP (taking account of tolerances) then wait 15 calendar days to provide any forced outages logged in SMMITS to the IMO. SM intended to seek agreement from MP's and the IMO to which process is most desired. SM also intends to cease the current practice of supplying	

Item	Subject	Action
	SCADA records to participants when notifying them of a breach. In response to a query from the IMO in relation to SM's intentions to improving the accuracy of SCADA data, SM undertook to revisit the development of a PSOP relating to SCADA measurement accuracy. *Action Point: System Management to resurrect the completion of a PSOP relating to SCADA data.* **PSOP Dispatch** SM advised that an amendment would be made to allow for participants to supply an algorithm to be used by SM in the calculation of a one minute dispatch profile. *Action Point: to amend PSOP Dispatch to allow for participant to supply an algorithm to be used instead of a straight line interpolation or dispatch profiles per minute by minute resolution.*	**SM** **SM**
5.	**PSOP Facility Outages** Meeting accepted changes to this PSOP. LGP noted that they would provide suggested amendments by email. *Action Point: SM to email word version of the Facility Outages PSOP to LGP.*	**SM**
6	**PSOP Commissioning and Testing** The Meeting accepted suggested changes to this PSOP *Action Point: SM to incorporate an additional "and" at section 5.3.3.*	**SM**
7.	**OTHER BUSINESS** LGP raised a general concern about the style of the PSOP's drafting, pointing out that overall the documents would benefit from an editorial review to improve readability and understanding in relation to MP's obligations. SM also undertook to change the style in which changes were market up on edited documents using a 'strikethough' style rather the current approach which utilises comments in the margin of the document. *Action Point: SM undertook to commence the process of revisiting each of the PSOP's in existence with a view to improving clarity/ legibility of the documents.*	**SM**
8.	**NEXT MEETING** Thursday 2 December 2010 to commence at 3:00pm and	**System Management**

Item	Subject	Action
	conclude 5:00pm	
CLOSED The Chair declared the meeting closed at 4.20pm.		

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Facility outages

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Version	Date	Author	Approver	Commenced	Comment
1	**3/11/11**	**B CONNOR**	**NOT APPROVED**		**DRAFT FOR INFORMAL CONSULTATION**
2	**5/12/11**	**B CONNOR**	**NOT APPROVED**		**SECOND DRAFT FOR PSOPWG**

DRAFT

RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with, the Wholesale Electricity Market Rules (Market Rules).
2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as 1 November 2011. These references are included for convenience only, and are not part of this procedure.
3. This Power System Operating Procedure is subservient to the Market Rules. In the event of conflict between this Procedure and the Market Rules or any other document, the order of precedence is as set out in the Market Rules **[MR 1.5.2]**
4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. Power System Operation Procedure – Communications and control
   b. Power System Operation Procedure – Commissioning and testing
   c. Power System Operation Procedure – Power system security

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. The Power System Operation Procedure: Facility Outages details procedures that System Management and Rule Participants must follow when planning for an outage of a Network, Generation, Load or Ancillary Service Facility.
8. The Facility Outage Procedure details the processes that enable Market Participants and Network Operators to gain agreement with System Management on the timing of outages of facilities; to resolve possible conflicts between Outage Plans of different participants and assist System Management in the management of system security.

2 COMMUNICATIONS AND CONTACTS

2.1 Participant Contacts

9. Depending on the circumstances, System Management may communicate directly with participants or request participants to seek resolution amongst themselves.
10. Market Participants and Network Operators must provide System Management with the communication details of the operating person(s) authorised to submit Outage Plans and outage cancellations for each of their facilities.
11. System Management will maintain a record of details as advised above and make them available to Market Participants and involved parties on an as needs basis.

2.2 System Management Contacts

12. System Management will from time to time advise Market Participants and Network Operators of its contact details and modes of communication, of persons who should be communicated with concerning outages.

2.3 Communication and publication of Outage Plans, Schedules and Approvals

13. Communication of outage notices and schedules shall be made through System Management's Market Information Technology System ("SMMITS") web interface or as directed by System Management from time to time.

3 SWIS EQUIPMENT LIST

The Market Rules ***[MR 3.18.2(a)&(b)]*** *require System Management to compile and maintain a list of all equipment in the SWIS that is subject to outage scheduling by System Management.*

14. In addition to the requirements of the Market Rules **[MR 3.18.2(c)]** the list of equipment will include:

a. all network circuits that could limit output from a generating facility during a planned outage of that circuit;

b. all EGC generating units;

c. all circuit breakers, switches and transformers operating at 330kV and 220kV;

d. all Non-EGC generating facilities with output ratings in excess of 10MW; and

e. any facilities contracted to provide Ancillary Services that are not covered by the above.

15. Generators and loads with a name plate capacity rating less than 10MW may be included in the equipment list, where outage scheduling is required for the maintenance of Power System Security and Power System Reliability, as specified in the Market Rules **[MR 3.18.2A].**

16. System Management must consider the following factors in making a decision on including or excluding the equipment:

a. the safety of equipment, personnel and the public; and

b. Power System Security and Power System Reliability.

4 OUTAGE SCHEDULE

*The requirements for System Management to maintain an outage schedule, containing information on all Scheduled Outages are specified in the Market Rules **[MR 3.18.4]**.*

17. The Outage Schedule will contain a list of all accepted and approved outages.

18. The Outage Schedule must contain the identity of the item of equipment and the planned starting and completion times of each Outage Plan accepted by System Management, up to three years ahead.

5 OUTAGE PLANS

19. System Management must accept an Outage Plan that:

a. contains the information specified submitted the Market Rules **[MR 3.18.6]**

b. is submitted in accordance with the requirements of this Procedure

Acceptance of an Outage Plan denotes acknowledgement by System Management only that the Outage Plan meets the requirements for a valid submission.

20. Market Participants and Network Operators must submit all outage plans and requests for on-the-day and day-ahead Opportunistic Maintenance through SMMITS or as otherwise directed from time to time.

21. System Management may require the Participant to clarify or provide additional information in relation to an accepted outage plan prior to Approval of the Outage Plan.

22. The time of lodgement of the Outage Plan shall be deemed as the time when the outage plan is transmitted to System Management and an acknowledgement of the submission has been provided.

5.1 Changes to an Outage Plan

The requirements for Market Participants or Network Operators to confirm or revise plans to remove from service or de-rate an item of equipment are specified in the Market Rules ***[MR 3.18.7, MR 3.18.8 and MR 3.18.9].***

23. A Market Participant or Network Operator wishing to change withdraw an Outage Plan pursuant to **[MR 3.18.8]** or **[MR 3.18.9]** must:

    a. if the Outage is planned to commence within 24 hours, inform System Management by telephone as soon as practicable and provide confirmation through SMMITS.

    b. otherwise, inform System Management through SMMITS.

24. If changes in outage plans are minor and do not materially impact power system security or other outage plans, and do not change the timing of the outage, System Management may accept these changes without requiring the plan to be resubmitted.

5.2 Outage Plans lodged within the final six weeks

The requirements applying to an Outage Plan first submitted within 6 weeks of the commencement time of the outage are specified in the Market Rules ***[MR 3.18.7A].***

25. In assessing whether to reject an Outage Plan pursuant to [MR 3.18.7A], System Management will take into account:

    a. If the Outage Plan arises from a need to carry out relatively urgent and unforeseen maintenance on its facility, when the Market Participant or Network Operator became aware of the need; and

    b. Whether the nature of the work to be carried out on the facility makes it difficult to plan times accurately ahead, or the work is contingent on actions outside the control of the Market Participant or Network Operator.

26. When System Management is unable to assess an Outage Plan in the time available, System Management will require the Market Participant or Network Operator to resubmit the Outage Plan.

5.3 Grouping of Associated Outage Plans

The requirements for Market Participants and Network Operators to coordinate outages are specified in the Market Rules ***[MR 3.18.5C].***

27. In the situation where a close interdependency exists between outages on multiple Facilities, System Management will assess the associated Outage Plans together and may approve, review or reject the group as a whole.

6 ACCEPTANCE OF OUTAGE PLANS

6.1 Assessment of Outage Plans

28. A Market Participant or Network Operator must make application for the acceptance of an outage plan via SMMITS unless otherwise directed by System Management.

29. System Management must use reasonable endeavours to respond to a request for a Proposed Outage Plan received from a Market Participant or Network Operator within 10 business days of receipt of a generation plan and within 20 business days of receipt of a transmission plan.

30. System Management must take all reasonable steps to expedite assessments of all submitted Outage Plans.

6.2 Adequacy criteria for assessing the acceptability of Outage Plans

31. System Management will assess the acceptability of Outage Plans using the criteria specified in the Market Rules **[MR 3.18.11 and MR 3.18.12],** based on the information specified in the Power System Operating Procedure: Power System Security**.**

System Management may find an Outage Plan to be acceptable, acceptable under some circumstances, or not acceptable. The actions System Management is required to take in each case are specified in the Market Rules ***[MR 3.18.13].***

6.3 Criteria for selection of Outage Plans in event of conflicting Outage Plans

System Management must adhere to the criteria for the selection and prioritisation of outage plans as specified in the Market Rules ***[MR 3.18.14].***

32. System Management must notify all affected Market Participants and Network Operators of any decision made pursuant to **[MR 3.18.14]** via SMMITS or as otherwise directed, and will use reasonable endeavours to confirm its decision by telephone.

6.4 Acceptance of non-complying Outage Plan for reasons of System Security

The Market Rules provide for System Management to permit an Outage Plan to proceed even if it does not meet the criteria for acceptance as specified in the Market Rules ***[MR 3.18.11(e)].***   *This situation could, for example, arise in relation to outages intended to address ongoing plant unreliability.*

33. Where an Outage Plan does not meet the criteria for acceptance specified in Paragraph 31, System Management may still accept the Outage Plan if it considers that the increased security risk over the period of the outage is less

than the longer-term risk reduction that would be achieved by allowing the outage to go ahead.

34. If System Management accepts an Outage Plan pursuant to Paragraph 33, System Management must document its estimation of the extent of the risk including the likelihood and consequences, and ongoing advantages that arise over the longer term, as a result of accepting an Outage Plan.

7 CHANGES TO POWER SYSTEM CONDITIONS AFFECTING SCHEDULED OUTAGES

35. Where System Management's forecast of power system conditions for a period coinciding with an Outage Plan occurs, such that the Outage Plan would no longer meet the criteria for acceptance, System Management may withdraw its acceptance of the Outage Plan and either deem that that the Outage Plan is unacceptable, or deem that the Outage Plan is acceptable under certain circumstances.

36. Where System Management withdraws its acceptance of an Outage Plan, it must inform the relevant Market Participant or Network Operator of its decision via SMMITS. System Management will use reasonable endeavours to confirm its decision by telephone.

8 PRE-ACCEPTED OUTAGES

37. No earlier than 8am on the 7th day prior to the trading day in which the outage commences, a Market Participant may make a request via telephone for an outage where this communication may be deemed as a request for Acceptance ('Pre-Accepted Outage').

38. Where requesting a Pre-Accepted Outage, a Market Participant must first telephone System Management, where contact details will be advised from time to time, and obtain a verbal agreement that there is a likelihood that the request can be approved.

39. Following the telephone call in Paragraph 38 or as otherwise directed, the Market Participant must provide the Proposed Outage Plan via SMMITS.

40. System Management will apply the approval framework in accordance with Section 10 of this Procedure to the Proposed Outage Plan. Where System Management approves the request, the telephone conversation seeking approval to submit the Pre-Accepted Outage will be deemed as satisfying the request for Acceptance.

9 APPROVAL OF SCHEDULED OUTAGES

*The requirements for a Market Participant or Network Operator to request approval of a Scheduled Outage Plan are specified in the Market Rules **[MR 3.19.1].***

*The criteria that System Management must adhere to when assessing whether to grant approval of Scheduled Outage requests are specified in the Market Rules **[MR 3.19.6].***

41. A Market Participant or Network Operator must make application for, and receive, approval of an accepted Outage Plan prior to conducting the Outage referred to in the Outage Plan.

42. The application referred to in Paragraph 41 must be made via SMMITS, or as otherwise directed by System Management.

43. At the time the request is made the Market Participant or Network Operators must also advise System Management of any change to the information contained in the Outage Plan.

44. Before approving a Scheduled Outage request, System Management may at its sole discretion require a Market Participant's or Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing. System Management will reject any Scheduled Outage request where the relevant Market Participant or Network Operator does not comply with such a request.

*Paragraph 44 relates to System Management's right under the Market Rule **[MR 3.19.3A(c)]** to reject an outage request that it considers to be made principally to avoid exposure to Reserve Capacity refunds.*

45. Notification by System Management of either an approval or rejection of a Scheduled Outage will be made via SMMITS**.**

10 OPPORTUNISTIC MAINTENANCE

Opportunistic Maintenance refers to approved outages that are carried out without previously having been subject to Acceptance. Applications for opportunistic maintenance generally carry a lower probability of acceptance because more of the factors governing power system security are 'locked in' by the time such an application is made.

*The requirements for a Market Participant or Network Operator to request approval of an Opportunistic Maintenance Outage are specified in the Market Rules **[MR 3.19.2(a)]** ("Day-ahead opportunistic maintenance") and **[MR 3.19.2(b)]** ("On the day opportunistic maintenance").*

*The criteria that System Management must adhere to when assessing whether to grant approval for Opportunistic Maintenance Outage requests are specified in the Market Rules **[MR 3.19.6].***

46. System Management must not approve an Opportunistic Maintenance request which will require any change in scheduled energy or ancillary services.

As a consequence of Paragraph 46, a non-EGC generator cannot have an Opportunistic Maintenance request approved that would result in the generator being unable to comply with its Resource Plan.

47. Before approving an Opportunistic Maintenance request System Management may at its sole discretion require a Market Participant's or

Network Operator's authorised personnel included in the relevant contact list to make a written declaration that the unit is available prior to the outage commencing**.** System Management will reject any day-ahead Opportunistic Maintenance request where the relevant Market Participant or Network Operator does not comply with such a request.

*Paragraph 47 relates to System Management's right under the Market Rule **[MR 3.19.3A(c)]** to reject an outage request that it considers to be made principally to avoid exposure to Reserve Capacity refunds.*

10.1 Day-ahead Opportunistic Maintenance

48. A Market Participant or Network Operator must make application for the approval of a day-ahead Opportunistic Maintenance outage request by telephone, and confirm the request via SMMITS or as otherwise directed by System Management.
49. System Management must provide confirmation of its approval or rejection via SMMITS as soon as practicable.
50. The request for approval of a day-ahead Opportunistic Maintenance Outage must be received by System Management no later than 8:00am of the day that the request for approval is due.
51. System Management must either approve or reject the day-ahead Opportunistic Maintenance Outage and inform the Market Participant and Network Operator of its decision before 8:00 am of the Scheduling Day.
52. System Management will not approve a request for a day-ahead Opportunistic Maintenance request after 12:00 pm on the Scheduling Day.

10.2 On-the-day Opportunistic Maintenance

53. System Management will advise a Market Participant or Network Operator of the decision to approve or reject a request for an on-the-day Opportunistic Maintenance outage by telephone or as otherwise directed.
54. Subsequently System Management shall log an approval and note a written notation reflecting the outcome.

11 OUTAGE RECALLS

55. When a situation arises where the power system security is at risk and the cancellation of outages could potentially alleviate the situation, System Management will consider all current Planned Outages and outages in progress and assess whether rejecting one or more Planned Outages or recalling equipment will assist the situation.

In a High-Risk Operating State, System Management may cancel or defer planned outages that have not yet commenced. In an Emergency Operating State, System Management may additionally recall to service Facilities that are on outage according to their Outage Contingency Plans.

56. If in the view of System Management there is benefit in this action, it may contact the Market Participant or Network Operator and discuss the impact of rejecting the outage or recalling the equipment to service.

57. The Market Participant or Network Operator must cooperate with System Management and determine when the equipment can be returned to service and the best way of proceeding with such action. The Market Participant or Network Operator must give this information to System Management as soon as practical.

58. Market Participants and Network Operators must comply with the directions of System Management to the extent that they are required to do so under the prevailing Operating State.

12 SUBMISSION OF FORCED OUTAGES AND CONSEQUENTIAL OUTAGES

*The requirements for Forced or Consequential Outages are specified in the Market Rules **[MR 3.21].***

59. Where equipment is unavailable or de-rated, the relevant Market Participant or Network Operator experiencing the unavailability or de-rating must communicate the nature of that unavailability or de-rating by telephone to System Management as soon as practicable, using contact details that are advised from time to time **[MR 3.21.7].**

60. The relevant Market Participant or Network Operator must, upon request, inform System Management of the equipment's status and provide a good-faith estimate of the likely return to service time.

61. The Market Participant or Network Operator must provide a full and final description of the outage to System Management, via SMMITS or as otherwise directed by System Management, including whether the equipment has suffered a Forced Outage or a Consequential Outage, by midnight on the date specified in the Market Rules **[MR 3.21.7].**

13 FORCED OUTAGE AND CONSEQUENTIAL OUTAGE INFORMATION FOR THE IMO

62. System Management must record the information provided by a Market Participant or Network Operator relating to each Forced Outage and Consequential Outage in accordance with the Market Rules **[MR 3.21].**

63. System Management will communicate this information and any additional information relevant to the event to the IMO in accordance with the timelines specified in the Market Rules **[MR 7.13.1A and MR 7.3.4].**

64. System Management will only transmit to the IMO Forced Outage and Consequential Outage information it has been advised by a Market Participant or Network Operator in accordance with the Market Rules.

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure: Commissioning and testing

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1	**3/11/11**	**B CONNOR**	**NOT APPROVED**		**DRAFT FOR INFORMAL CONSULTATION**
2	**5/12/11**	**B CONNOR**	**NOT APPROVED**		**SECOND DRAFT FOR PSOPWG**

RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with, the Wholesale Electricity Market Rules (Market Rules).
2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as 1 November 2011. These references are included for convenience only, and are not part of this procedure.
3. This Power System Operating Procedure is subservient to the Market Rules. In the event of conflict between this Procedure and the Market Rules or any other document, the order of precedence is as set out in the Market Rules **[MR 1.5.2]**
4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. Power System Operation Procedure – Dispatch
   b. Power System Operation Procedure – Facility outages

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. The Power System Operation Procedure: Commissioning and Testing ('Procedure') details procedures that System Management and Market Participants must follow when planning and conducting tests on Generators, Demand Side Programs, Interruptible Loads and Dispatchable Loads.

8. The Commissioning and Testing Procedure covers the following processes:

   a. the planning and implementation of Commissioning Tests for particular generation systems that wish to verify their output capability, in accordance with the Market Rules **[MR 3.21A]**; and

   b. the planning and implementation of Reserve Capacity Tests in accordance with the Market Rules **[MR 4.25]**

*Tests other than Commissioning Tests and Reserve Capacity Tests may be undertaken by way of balancing movements provided that the Facility conducting the tests follows its Dispatch Instructions and remains within its Tolerance Range at all times during the test. Such testing by Verve Energy may be undertaken by way of variation to the plant schedule **[MR 7.6A.2(a)].***

2 COMMISSIONING TESTS

2.1 Market Participant to submit Commissioning Test plan

Participants are advised to contact System Management to discuss possible network conditions that might influence the Commissioning Test plan prior to submitting a Commissioning Test plan. System Management will use reasonable endeavors to assist the Market Participant.

9. Any Market Participant wishing to conduct a Commissioning Test **[MR 3.21A.3]** must provide System Management with a Commissioning Test plan that:

   a. includes, at a minimum, the information specified in Appendix A of this Procedure,

   b. is transmitted in the form specified in Section 2.2 of this Procedure.

10. System Management may, at its discretion, vary the requirements set out in Appendix A for a particular Facility.

11. System Management may, at its discretion, consider Commissioning Test plans submitted after the timing requirement provided in the Market Rules **[MR 3.21A.4]**, but will notify the IMO of a breach of the timing requirement if it accepts such a Commissioning Test plan.

12. System Management will not approve Commissioning Test plans submitted less than 2 days prior to the commencement of the first Trading Day covered by the Commissioning Test plan.

2.2 Communication in relation to Commissioning Test plans

13. System Management will advise Market Participants of contact details and modes of communication for the submission of Commissioning Test plans.
14. A Market Participant must comply with the communication requirements set by System Management pursuant to Paragraph 15 of this Procedure.
15. Market Participants must provide System Management with the communication details of the operating person(s) authorised to submit Commissioning Test plans for each of their facilities.
16. System Management may prepare a communication protocol to apply between System Management and a Market Participant concerning a commissioning test being carried out on the Trading Day.

2.3 Assessment and Approval of Commissioning Test plans

17. System Management may refuse to approve a Commissioning Test plan if it reasonably believes that the conditions stipulated in the Market Rules **[MR 3.21A.3]** have not been met.

[MR 3.21A.3] *states that:* *"System Management may approve a Commissioning Test only for a new generating system that is yet to commence operation, or for an existing generating system that has undergone significant maintenance".* *System Management will generally interpret "significant maintenance" to mean maintenance work following which the Facility cannot be reasonably assured of operating at a satisfactory level of reliability for its full output.* ***[MR 3.21A.3]*** *states that:* *"System Management must accept a request for a Commissioning Test unless:* *(a) in its opinion inadequate information is provided in the request; or* *(b) in its opinion the conduct of the test at the proposed time would pose a threat to Power System Security or Power System Reliability; or* *(c) in the case of a new generating system that is yet to commence operation, the proposed Commissioning Test Period is greater than four months".* *System Management will generally endeavour to accommodate the requested Commissioning Test plan, including by scheduling any additional ancillary services required to maintain power system security, provided the Commissioning Test plan is broadly consistent with expected network conditions at the time of each proposed test.*

18. Where System Management requires additional information to make an assessment of a draft Commissioning Test plan, System Management will request such information from the Market Participant, and the Market Participant must provide the information as soon as practicable.

19. System Management will consider the criteria set out in Appendix B in assessing the expected impact of the draft Commissioning Test plan on power system security and power system reliability.

20. If System Management approves the draft Commissioning Test plan, it may schedule additional ancillary services during the Commissioning Test Period consistent with its powers under the Market Rules.

Additional Ancillary Services requirements will generally be in accordance with the guidelines set out in Appendix C but System Management may vary the application of those guidelines if required to maintain power system security or power system reliability.

At the time of writing the Market Rules allow System Management some discretion in the quantity of Load Following Ancillary Service scheduled, but not in the quantities of Spinning Reserve or Load Rejection Reserve.

21. Where a Commissioning Test plan has not been approved System Management must provide an explanation for its decision in accordance with the Market Rules **[MR 3.21A.10(a)].** The Market Participant may then submit a new Commissioning Test plan which should take into account the explanation provided by System Management.

2.4 Update of Commissioning Test plan

22. If System Management delays or cancels a Commissioning Test **[MR 3.21A.11],** the affected Market Participant must submit a new Commissioning Test plan prior to undertaking any commissioning tests.

23. At any stage where a Market Participant becomes aware of conditions which may prevent the generating Facility from conforming to the approved Commissioning Test plan **[MR 3.21A.13]**, they must:

    a. if the Commissioning Test Period has commenced, immediately notify System Management; and

    b. either withdraw the Commissioning Test plan or provide amended plans in accordance with this Procedure to System Management for approval as soon as practicable.

2.5 Conduct of Commissioning Tests

24. For each "test window" in the approved Commissioning Test plan, System Management will pre-issue Dispatch Instructions to the Market Participant for all Trading Intervals in the test window prior to commencement of the test window.

25. The Market Participant must seek System Management's verbal approval to commence any test in the Commissioning Test plan. If the Market Participant's advice regarding the timing of the test is inconsistent with the current Dispatch Instruction(s) for the Trading Intervals affected, System Management will deem the Market Participant to have declined the Dispatch

Instruction in accordance with Paragraph 88 of the Power System Operating Procedure “Dispatch”.

26. If subsequent updates to the Balancing Merit Order render the Dispatch Instructions referred to in Paragraph 24 “out of merit”, System Management will issue new Dispatch Instructions consistent with the Balancing Merit Order.

3 RESERVE CAPACITY TESTS

27. System Management will provide Market Participants nominated by the IMO to undertake a Reserve Capacity Test under the Market Rules **[MR 4.25.2 (a) ii.]** with an Operating Instruction directing them to undertake the test in accordance with the test parameters provided by the IMO to System Management under **[MR 4.25.7].**

28. In considering whether it is possible to conduct the test in accordance with **[MR 4.25.8]**, System Management will consider the applicable criteria set out in Appendix B.

APPENDIX A COMMISSIONING TEST PLAN STANDARD FORM TEMPLATE

COMMISSIONING TEST PROFORMA

Generator Details

Market Participant:

Facility Designation:

Contact Details:

	Operational	Commercial
Email		
Mobile		
Phone		
Fax		

Fuel Types:

Fuel "1"	Fuel "2"	Fuel "3"

Test Details

Test Period:

Start Time (dd/mm/yyyy HH:MM)	End Time (dd/mm/yyyy HH:MM)

Purpose of Test(s):

System Under Test:

Test Description

Contingency Plan(s):

Timelines

Day	Net Output		Fuel Mix	Trip Risk	Specific Tests			
(dd/mm/yyyy)	MW Active Power	MVAr Reactive Power	"1", "2", "3", "1&2", "1&3", "2&3", or All	Low, Medium, or High	Technical Rule, Table A11.1	Technical Rule, Table A11.2	(other specify)	(other specify)
8:00								
8:30								
9:00								
9:30								
10:00								
10:30								
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	6:30								
	7:00								
	7:30								

APPENDIX B PREFERRED TIMES FOR COMMISSIONING TESTING

The commissioning of some new generators may take place so that the generator will be available for commercial load before the time of summer peak. Regardless of the time of year during which a generator is being commissioned it should be commissioned according to the following 'time of day' periods.

The testing of ramp up capability between load points could occur when there is an increase in system loads in the periods leading up to morning and evening peaks. The preferred time however to do these tests is during the middle of the day when the load profile is relatively flat and plant movements minimal. This allows for easier configuration of load following and spinning reserve. The generator output should be held at a steady value during evening peaks. Ramp down and decommitment should take place after evening peak, or before evening peak period begins.

A general principle to be observed is that commissioning should only take place when there is sufficient plant on the system to maintain system security. This would tend to rule out commissioning during periods of low over night system load.

Load rejection or trip tests should be done during times of flat load profile, and with maximum spinning reserve.

Requirements for specific tests are shown below.

C tests (Note that these tests are compulsory)

C2A Step changes to AVR voltage reference with PSS out of service.	
Generator Output and Test Sequence	System Conditions
(i) 50% rated MW	System base load OR typical conditions and typical connection at Generator
(ii) 100% rated MW	System base load OR typical conditions and typical connection at Generator

C2B Step changes to AVR voltage reference with PSS in service.	
Generator Output and Test Sequence	System Conditions
(i) 50% rated MW	System base load OR typical conditions and connection at Generator
(ii) 100% rated MW	System base load OR typical conditions and connection at Generator

C3A Step changes to AVR voltage reference with PSS out of service.	
Generator Output	System Conditions
100% rated MW	(i) System minimum load with no other generation on the same bus OR relatively weak connection to Network
100% rated MW	(ii) System maximum load with maximum generation on the same

	bus OR relatively strong connection to Network

C3B Step changes to AVR voltage reference with PSS in service.	
Generator Output	System Conditions
100% rated MW	(i) System minimum load with no other generation on the same bus OR relatively weak connection to Network
100% rated MW	(ii) System maximum load with maximum generation on the same bus OR relatively strong connection to Network

C4 Step change of MVA on the transmission system.	
Generator Output and Test Sequence	System Conditions
(i) 50% rated MW with PSS out of service	System base load OR typical conditions and connection at Generator
(ii) 50% rated MW with PSS in service	System base load OR typical conditions and connection at Generator

C5 Real power load rejection (generator trip test)	
Generator Output and Test Sequence	System Conditions
(i) 25% rated MW	To be done at time of flat system load profile
(ii) 50% rated MW	To be done at time of flat system load profile
(iii) 100% rated MW	To be done at time of flat system load profile

C6 Steady state over-excitation limiter (OEL) operation	
Generator Output and Test Sequence	System Conditions
(i) 100% rated MW	After peak or during decommitment
(ii) 75% rated MW	After peak or during decommitment
(iii) 50% rated MW	After peak or during decommitment
(iv) 25% rated MW	After peak or during decommitment
(v) min MW output	After peak or during decommitment

C7 Steady state under-excitation limiter (UEL) operation	
Generator Output and Test Sequence	System Conditions
(i) 100% rated MW	After peak or during decommitment

(ii) 75% rated MW	After peak or during decommitment
(iii) 50% rated MW	After peak or during decommitment
(iv) 25% rated MW	After peak or during decommitment
(v) min MW output	After peak or during decommitment

C9 MVAR capability at full MW output	
Generator Output	System Conditions
MW and MVAR output levels set to 100% of rated values and maintained for one hour.	System Maximum load and maximum generation in high ambient temperature.

S TESTS (these tests, though not compulsory, may be included in a commissioning programme)

S1 (a) and **S2** (a) and **S1** (b) Load rejection (reactive power)	
Generator reactive power output	Generator real power output
(a) -30% rated MVAR	0 or Min MW output
(b) +25% rated MVAR	0 or Min MW output

S5 AVR / OEL changeover	
Generator Output	System Conditions
100% rated MW output.	To be done at time of flat system load profile

S6 AVR / UEL changeover	
Generator Output	System Conditions
100% rated MW output	To be done at time of flat system load profile

S8 Tripping of an adjacent generating unit.	
Generator Output	System Conditions
At a level sufficiently below its rated output so that in combination with LF and SR generators it will assist with maintaining system frequency	To be done at time of flat system load profile

S10 Step changes added to and subtracted from governor / load reference (Note this test is not a ramp rate test.)

Generator Output	System Conditions
Output at 50-85% rated MW (a) 2.5% step increase in MW demand signal (b) 2.5% step decrease in MW demand signal (c) Equivalent of 0.05 HZ subtracted from governor speed reference (d) Equivalent of 0.1 HZ added to governor speed reference	To be done at time of flat system load profile

APPENDIX C GUIDELINES FOR ADDITIONAL ANCILLARY SERVICES DURING COMMISSIONING TESTS

C tests (note that these tests are compulsory):

C2A Step changes to AVR voltage reference with PSS out of service.		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 50% rated MW	100%	Bid 50% at floor and 50% at cap
(ii) 100% rated MW	100%	Bid 100% at floor and 0% at cap

C2B Step changes to AVR voltage reference with PSS in service.		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 50% rated MW	100%	Bid 50% at floor and 50% at cap
(ii) 100% rated MW	100%	Bid 100% at floor and 0% at cap

C3A Step changes to AVR voltage reference with PSS out of service.		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
100% rated MW	100%	Bid 100% at floor and 0% at cap
100% rated MW	100%	Bid 100% at floor and 0% at cap

C3B Step changes to AVR voltage reference with PSS in service.		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
100% rated MW	100%	Bid 100% at floor and 0% at cap
100% rated MW	100%	Bid 100% at floor and 0% at cap

C4 Step change of MVA on the transmission system.		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 50% rated MW with PSS out of service	100%	Bid 50% at floor and 50% at cap
(ii) 50% rated MW	100%	Bid 50% at floor and 50% at cap

with PSS in service		

C5 Real power load rejection (generator trip test)		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 25% rated MW	100% + load rejection amount	Bid 12.5% at floor and 87.5% at cap for trip interval
(ii) 50% rated MW	100% + load rejection amount	Bid 25% at floor and 75% at cap for trip interval
(iii) 100% rated MW	100% + load rejection amount	Bid 50% at floor and 50% at cap for trip interval

C6 Steady state over-excitation limiter (OEL) operation		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 100% rated MW	100%	Bid 100% at floor and 0% at cap
(ii) 75% rated MW	100%	Bid 75% at floor and 25% at cap
(iii) 50% rated MW	100%	Bid 50% at floor and 50% at cap
(iv) 25% rated MW	100%	Bid 25% at floor and 75% at cap
(v) min MW output	100%	Bid min at floor and remainder at cap

C7 Steady state under-excitation limiter (UEL) operation		
Generator Output and Test Sequence	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(i) 100% rated MW	100%	Bid 100% at floor and 0% at cap
(ii) 75% rated MW	100%	Bid 75% at floor and 25% at cap
(iii) 50% rated MW	100%	Bid 50% at floor and 50% at cap
(iv) 25% rated MW	100%	Bid 25% at floor and 75% at cap
(v) min MW output	100%	Bid min MW output at floor and remainder at cap

C9 MVAR capability at full MW output

Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
MW and MVAR output levels set to 100% of rated values and maintained for one hour.	100%	Bid 100% at floor and 0% at cap

S TESTS (these tests, though not compulsory, may be included in a commissioning programme).

S1 (a) and **S2** (a) and **S1** (b) Load rejection (reactive power)		
Generator reactive power output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
(a) -30% rated MVAR	70%	Bid min MW output at floor and remainder at cap
(b) +25% rated MVAR	70%	Bid min MW output at floor and remainder at cap

S5 AVR / OEL changeover		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
100% rated MW output.	100%	Bid 100% at floor and 0% at cap

S6 AVR / UEL changeover		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
100% rated MW output	100%	Bid 100% at floor and 0% at cap

S8 Tripping of an adjacent generating unit.		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
At a level sufficiently below its rated output so that in combination	100% + amount supplied by generator to be tripped	Bid initial amount at floor and remainder at cap. For adjacent generator bid MW to be tripped

with LF and SR generators it will assist with maintaining system frequency		at floor and remainder at cap, and then for the interval of tripping 0% at floor and 0% at cap

S10 Step changes added to and subtracted from governor / load reference (Note this test is not a ramp rate test.)		
Generator Output	Additional load following and/or spinning reserve	Indicative Balancing Market submission
Output at 50-85% rated MW (a) 2.5% step increase in MW demand signal (b) 2.5% step decrease in MW demand signal (c) Equivalent of 0.05 HZ subtracted from governor speed reference (d) Equivalent of 0.1 HZ added to governor speed reference	100%	Bid 50-85% at floor and 50-15% at cap (a) Bid (50-85%) + 2.5% at floor and (50-15%) – 2.5% at cap (b) Bid (50-85%) - 2.5% at floor and (50-15%) + 2.5% at cap (c) Bid (50-85%) - MW equivalent of 0.05 HZ for the generator at floor and (50-15%) + MW equivalent of 0.05 HZ for the generator at cap (d) Bid (50-85%) + MW equivalent of 0.1 HZ for the generator at floor and (50-15%) – MW equivalent of 0.1 HZ for the generator at cap

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Power System Security

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CONTROL PAGE

Version	Date	Author	Approver	Commenced	Comment
1	**3/11/11**	**B CONNOR**	**NOT APPROVED**		**DRAFT FOR INFORMAL CONSULTATION**
2	**5/12/11**	**B CONNOR**	**NOT APPROVED**		**SECOND DRAFT FOR PSOPWG**

RELATIONSHIP WITH MARKET RULES

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4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. SWIS Technical Rules and Operating Standards
   b. Power System Operation Procedure – Dispatch
   c. Power System Operation Procedure – Ancillary Services
   d. Power System Operation Procedure – Communications and Control Systems.
   e. Power System Operation Procedure – Facility outages
   f. Power System Operation Procedure – Commissioning and testing

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. This procedure documents the obligations on:

   a. System Management in respect of the management of power system security

   b. Market Participants in respect of the provision of information to, and response to directions by, System Management and the operation of their Facilities.

8. The Power System Security Procedure details the processes that take place each Scheduling Day, each Trading Interval and in real time to ensure that the power system is managed within the Dispatch Criteria at all times.

9. This Procedure covers all Facilities forming part of the power system and subject to direction by System Management, including Scheduled Generators, Unscheduled Generators, Demand-Side Programs, Dispatchable Loads and Networks.

2 ASSESSMENT OF POWER SYSTEM SECURITY

Maintenance of power system security essentially means taking all required actions to ensure that the Dispatch Criteria can be satisfied at all times. Since some actions must be taken in advance, assessing power system security must be done not only in real time but also on a forward-looking basis.

10. System Management will use assessments of power system security as the basis for deciding what actions to take, permit, mandate or prohibit in respect of the operation of the power system.

11. System Management may, as a result of a power system security assessment, do any of the following:

    a. Issue Dispatch Advisory notices in relation to an actual or forecast change in Operating State

    b. Issue Dispatch Advisory notices in relation to technical constraints

    c. Issue Dispatch Instructions and Dispatch Orders consistent with its powers under the prevailing Operating State

    d. Cancel or recall outages consistent with its powers under the prevailing Operating State

    e. Issue Operating Instructions consistent with the contract, or Market Rules provisions, to which those instructions relate

    f. Disconnect, or direct the disconnection of, Facilities consistent with its powers under the prevailing Operating State

    g. Direct Facilities to change reactive power output as required for voltage control.

2.1 Assessment outside the Balancing Horizon

12. System Management will base its assessment of power system security for any future time outside the current Balancing Horizon on the adequacy of generation and SWIS network capacity to meet forecast load, ancillary services and ready reserve requirements within the Technical Envelope, assuming:

    a. Generation and network availability in accordance with the latest approved outage plans,

    b. System load level based on the SEDM forecast for the mean system load, plus two standard deviations,

    c. Intermittent generation at the mean forecast level minus two standard deviations,

    d. n-1 level of contingency for all credible network contingency events,

    e. n-2 level of contingency for the transmission network, applicable for system load up to 80% of peak,

    f. Full coverage of all Ancillary Services is maintained, including any additional quantities required to support approved commissioning and testing activities,

    g. Any additional constraints System Management is required to manage are appropriately dealt with.

A requirement for n-1 for generation contingencies is not included in part d, since the ancillary services standard for spinning reserve establishes this.

Part g envisages management of fuel during gas supply emergencies.

2.2 Assessment within the Balancing Horizon

13. System Management will base its assessment of power system security for any future time outside the current Trading Interval but within the current Balancing Horizon on the adequacy of generation capacity to meet forecast load, ancillary services and ready reserve requirements within the Technical Envelope, assuming:

    a. Network availability in accordance with the latest approved outage plans and forced outage notifications,

    b. Generation availability and ramp rate limits in accordance with the latest Forecast Balancing Merit Order (Forecast BMO) and forced outage notifications,

    c. n-1 level of contingency for all credible network contingency events,

    d. n-2 level of contingency for the transmission network, applicable for system load up to 80% of peak

    e. Three scenarios each, representing the forecast mean, plus one standard deviation, and minus one standard deviation, for system load and non-scheduled generation forecasts,

f. Full coverage of all Ancillary Services is maintained, including any additional quantities required to support approved commissioning and testing activities,

g. Any additional constraints System Management is required to manage are appropriately dealt with, including but not limited to generator runback and load trip schemes.

It is envisaged that assessment within the balancing horizon will be based on examination of a security-constrained dispatch plan for each of the three scenarios referred to in e. above. Dispatch Advisory notices would be generated for:

-Breaches of constraints identified in the dispatch solution, some of which would correspond to forecast changes in Operating State,

-Dispatches that substantially violate certain standing data limitations such as minimum generation, minimum up / down times, startup times

-Facilities whose output changes from zero to non-zero, or vice versa, between the three scenarios referred to in d. above.

-Other situations described in the Market Rules, such as loss of communications.

2.3 Real-time assessment

14. System Management will assess power system security for the current Trading Interval on is ability to meet the forecast system load, based on:

   a. Generation availability and ramp rate limits according to the Balancing Merit Order (BMO), unless advised otherwise by a Market Participant,

   b. Which facilities are currently committed, or are able to be committed, within the Trading Interval,

   c. System Management's current forecasts of load and non-scheduled generation,

   d. The impact of automatic schemes in place to manage network constraints,

   e. The adequacy of ancillary services for the prevailing conditions,

   f. System Management's current ability to communicate with those Facilities and/or control them directly.

3 MANAGEMENT OF POWER SYSTEM OPERATING STATE

Each Operating State has a defined set of conditions, one or more of which must be met before the system can be placed in that state. System Management's powers and discretion increase as the Operating State is escalated.

3.1 Forecasting changes in Operating State

15. If System Management forecasts that the power system Operating State may need to change in the future, then System Management will issue a Dispatch Advisory notice to inform the market of that fact.

16. System Management will deem that the power system Operating State will need to be escalated in the future (“forecast a change in Operating State”) if, and only if, all of the following conditions are satisfied:

    a. The power system is forecast to meet one or more of the conditions for the escalated Operating State in some time period in the future, but not in the immediately preceding period,

    b. System Management is able to take actions that will result in the conditions referred to in Section a above being alleviated

    c. System Management’s powers under the escalated Operating State would permit it to take the actions referred to in Part b, but its powers under the currently prevailing Operating State would not permit it to do so,

    d. The actions referred to in Part b can be taken, and will have effect, prior to the start of the relevant time period.

In plain language, if SM can foresee something adverse occurring that it requires increased powers to deal with, but time remains for the market to correct the problem, it will advise the market that “the Operating State is forecast to escalate” but will take no direct action to intervene at this time

17. System Management will deem that the power system Operating State may be de-escalated in the future if the power system is forecast not to meet any of the conditions for the prevailing Operating State in the applicable time period and is not required to remain in the prevailing Operating State pursuant to Paragraph 16 for any subsequent time periods.

3.2 Changing Operating State

18. If System Management deems it necessary to change the power system Operating State, then System Management will issue a Dispatch Advisory notice to inform the market of that fact.

19. System Management will escalate the power system Operating State if the power system currently meets one or more of the conditions for the escalated Operating State

20. System Management will escalate the power system Operating State if all of the following conditions are satisfied:

    a. The power system is forecast to meet one or more of the conditions for the escalated Operating State in some time period in the future,

    b. System Management’s powers under the escalated Operating State would permit it to take the actions to address the conditions referred to in Part a, but its powers under the currently prevailing Operating State would not permit it to do so, and

    c. Any further delay would result in the actions to address the conditions referred to in Part a not being able to be taken, or not being able to have effect, prior to the start of the relevant time period.

At the point SM can no longer wait for the market to correct an issue, it will escalate the Operating State to give itself the powers to deal with the issue directly.

21. System Management will de-escalate the Operating State if the power system does not currently meet any of the conditions for the prevailing Operating State and is not required to remain in the prevailing Operating State pursuant to Paragraph 19.

3.3 Conditions for Operating States

22. The conditions for each of the Operating States are specified in the Market Rules **[MR 3.3.1, 3.4.1 and 3.5.1].**

4 MANAGEMENT OF THE TECHNICAL ENVELOPE

*System Management has an obligation to operate the power system "within the Technical Envelope". System Management characterise the Technical Envelope as a **dynamic set of constraints.** Some of the constraints describing the Technical Envelope are a function of the Operating State.*

The constraints comprising the Technical Envelope are derived from standing data equipment limits, ancillary services standards, network operating standards (and exceptions to them), and security constraints.

Some of the TE constraints (relating to equipment limits, for example) will be able to be watched through the pre-dispatch. Others (e.g. voltage) won't be able to be watched in the Dispatch Planning Tool, but may be examined in other systems (e.g. TSM).

23. System Management will set the Technical Envelope as permissively as possible within the requirements of the Market Rules.

24. The Technical Envelope is established and maintained by System Management by organising elements of:

    a. Standing Data provided by Market Participants

    b. Operating Standards such as Frequency and Voltage Limits specified in the Technical Rules,

    c. Ancillary Services Standards specified in the Market Rules, and

    d. Security Constraints provided by Network Operators in consultation with System Management.

25. System Management will manage the power system to ensure operation within the Technical Envelope at all times, by:

    a. Maintaining definitions of the constraints that comprise the Technical Envelope

    b. Keeping current the data that quantifies the constraints

    c. Operating the power system within the constraints.

4.1 Equipment limits

***[MR 3.2.1]** states that:*

"An equipment limit means any limit on the operation of a Facility's equipment that is provided as Standing Data for the Facility to System Management by the IMO in accordance with clause 2.34.1(b)."

26. Equipment Limit information will include all Standing Data thermal ratings for generator and network equipment that form the SWIS, and any other elements of Standing Data that are relevant to the capability of the equipment to operate at a particular level of output.

27. The IMO must provide the Standing Data and any revisions of the Standing Data to System Management as soon as practicable.

28. In setting Equipment Limits, System Management will have regard to any additional information that it becomes aware of, including but not limited to notification by the operator of the equipment of a full or partial de-rating.

Where there are changes to the commissioning status of generation or transmission facilities or equipment, the boundaries of the Technical Envelope will be dynamically updated in System Management's SCADA system. System Management will also update the network and generator topology accordingly.

29. System Management will deem the Balancing Merit Order (BMO) and Forecast Balancing Merit Order (Forecast BMO) information provided to it by the IMO to constitute changes to Standing Data in accordance with the following rules:

    a. The maximum generation capability of a Balancing Facility will be taken to be the sum of the tranche quantities for which it appears that are not priced at either Price Cap

    b. The emergency operating range of a Balancing Facility will be taken to be the sum of the tranche quantities for which it appears that are priced at the upper Price Cap

    c. The minimum stable generation capability of a Balancing Facility will be taken to be the sum of the tranche quantities for which it appears that are priced at the lower Price Cap

    d. The maximum ramp rate capability of a Balancing Facility will be taken to be the Facility's offered ramp rate

    e. The minimum restart time of a Balancing Facility will be taken to be the period for which the Facility has an offered quantity of zero.

30. System Management must maintain a list of all Equipment Limits, and must ensure that, where Equipment Limits are managed using System Management's SCADA monitoring system, the SCADA database is updated as required to reflect the current Equipment Limits.

Where necessary, System Management will review and update plant ratings on a monthly basis using semi-automated data comparison procedures.

31. System Management must arrange for the SCADA system to monitor, as applicable, the voltage, current, real power flow and/or reactive power flow within each item of equipment or Facility for which Equipment Limits is provided, for which it has operating authority.

32. Plant rating limits will be incorporated into System Management's equipment ratings database and the SCADA system which triggers alarms in the System Management System Operations Control Centre ('SOCC') when limits are breached.

33. System Management must update the SCADA database with any new Equipment Limit prior to the data becoming operational.

34. Where System Management becomes aware that a generator Standing Data is inaccurate or will become inaccurate in the future, System Management must notify IMO of this as soon as practicable and update any associated Equipment Limits.

4.2 Security limits

The definition of a Security Limit is specified in the Market Rules ***[MR 3.2.3].***

"A Security Limit means any technical limit on the operation of the SWIS as a whole, or on a region of the SWIS, necessary to maintain Power System Security, including both static and dynamic limits, and including limits to allow for and to manage contingencies."

35. Each Network Operator must determine the Security Limits applicable to its Network.

36. A Network Operator must consult with System Management in determining any Security Limits applicable to its Network.

37. The Security Limits will be those technical requirements and standards in the Technical Rules that represent constraints on the operation of the SWIS, imposed for the purpose of managing electricity quality and security.

38. System Management must maintain a list of all Security Limits provided by Network Operators that represents actual or potential constraints on the transfer of energy across the SWIS network, in System Management's SCADA system and review the currency of these from time to time.

4.3 Operating Standards

The SWIS Operating Standards are defined in the Technical Rules. They comprise standards for frequency, time error and voltage.

39. System Management must operate the power system in such a way that the SWIS Operating Standards are met at all times.

4.4 Ancillary Services Standards

The Ancillary Standards are defined in the Market Rules ***[MR 3.10]****.*

40. System Management must operate the power system in such a way that the Ancillary Services Standards are met at all times.

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

DRAFT

Power System Operation Procedure: Dispatch

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Version	Date	Author	Approver	Commenced	Comment
1	**3/11/11**	**B CONNOR**	**NOT APPROVED**		**DRAFT FOR PUBLIC CONSULTATION**
2	**30/11/11**	**B CONNOR**	**NOT APPROVED**		**SECOND DRAFT FOR PSOPWG**

RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with, the Wholesale Electricity Market Rules (Market Rules).
2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as at 1 November 2011. These references are included for convenience only, and are not part of this procedure.
3. This Power System Operating Procedure is subservient to the Market Rules. In the event of conflict between this Procedure and the Market Rules or any other document, the order of precedence is as set out in the Market Rules **[MR 1.5.2]**
4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. SWIS Technical Rules and Operating Standards
   b. Power System Operation Procedure – Power System Security
   c. Power System Operation Procedure – Ancillary Services
   d. Power System Operation Procedure – Communications and Control Systems
   e. Power System Operation Procedure – Commissioning and Testing.
   f. Power System Operation Procedure – Monitoring and Reporting.

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. The Dispatch Procedure details the processes that take place each Scheduling Day and Trading Day to determine how generation, transmission and Demand Side Management Facilities will be dispatched.

8. This Procedure covers both Verve Energy and non-Verve Energy facilities. It covers both System Management's general dispatch obligations, and those relating to scheduling Verve Energy plant as a service provided to Verve Energy.

9. This procedure documents the obligations on:

    a. System Management in respect of the scheduling and dispatch of Market Participants' Facilities and the provision of information to the IMO and to Market Participants on dispatch-related matters

    b. Market Participants in respect of the provision of information and the operation of their Facilities

    c. The IMO in respect of the provision of information.

2 MANAGEMENT OF DISPATCH INFORMATION

10. System Management must store, and maintain from time to time, all necessary data needed to carry out the following processes:

    a. preparing the information submitted to the IMO on the Scheduling Day;

    b. planning for dispatch;

    c. issuing dispatch advisories

    d. issuing Dispatch Instructions and Dispatch Orders; and

    e. preparing the ex-post Settlement and Monitoring data.

11. The IMO must provide all new and updated data in the Standing Data relating to a Trading Day to System Management as soon as practical for updating of System Management's Information Technology Systems in accordance with the Market Rules

3 DISPATCH CRITERIA

12. When scheduling and dispatching Market Participant's Facilities, System Management will at all times seek to meet the criteria described in the Market Rules **[MR 7.6]**.

The criteria are, in order of priority: a. *to enable operation of the SWIS within the Technical Envelope Parameters appropriate for the applicable Operating State;* *b. to minimise involuntary load shedding on the SWIS; and* *c. to maintain Ancillary Services to meet the Ancillary Services standards appropriate for the applicable Operating State.*

For the avoidance of doubt, the satisfying the Dispatch Criteria will always take precedence over other dispatch rules such as adherence to the Balancing Merit Order.

4 SCHEDULING AND DISPATCH OF VERVE ENERGY PLANT

13. System Management's and Verve Energy's obligations for scheduling and dispatching Verve Energy facilities are set out in the Market Rules **[MR 7.6A]**.

14. Verve Energy will provide System Management with a set of dispatch guidelines for its Verve Energy Balancing Portfolio in a form agreed between Verve Energy and System Management.

15. System Management will prepare a Verve Energy Dispatch Plan daily for Verve Energy plant in a form agreed between Verve Energy and System Management.

16. Verve Energy may update the Verve Energy Balancing Portfolio Dispatch Guidelines from time to time and advise System Management of the date and time from which the updated Guidelines are to take effect.

17. Communication of the Verve Energy Balancing Portfolio Dispatch Guidelines may be made by any means satisfactory to both Verve Energy and System Management.

18. Communication of, and consultation in relation to, the information referred to in **[MR 7.6A.2 (c)]** will normally be by means of ~~the~~ an electronic interface ~~between Verve Energy and System Management described in the Power System Operating Procedure "Communications and Control Systems"~~. Verve Energy and System Management may communicate by other means where necessary provided that all communications create, or are subsequently verified by, an electronic record.

5 PRE GATE CLOSURE

5.1 Forecasting Relevant Dispatch Quantity

19. System Management will derive forecasts of Relevant Dispatch Quantity (in MW), and forecast EOI quantity for non-scheduled generators, from a pre-dispatch plan.

20. The pre-dispatch plan referred to in Paragraph 19 will be produced using a mathematical program based on the same formulation used to create Dispatch Instructions (refer Section 6.3 below).

21. Upon receiving a Forecast BMO from the IMO, System Management will formulate any constraints necessary to maintain power system security and use those constraints when producing the pre-dispatch plan referred to in Paragraph 19**.**

22. System Management will report any pre-dispatch constraints binding, and any pre-dispatch constraints violated, via Dispatch Advisory notices as described in Section 5.8 of this Procedure.

23. System Management ~~will~~ may communicate warnings to individual Market Participants if it detects significant discrepancies between Standing Data equipment limits and the pre-dispatch plan.

The warnings referred to in Paragraph 23 are for information only. It remains the Market Participant's responsibility to ensure their balancing submissions reflect the physical capabilities of their facilities at all times.

5.2 Constraints used in the pre-dispatch plan

24. The constraints referred to in Paragraph 21 may include, as appropriate, constraints to ensure:

    a. Maintenance of Ancillary Services standards

    b. Appropriate use of contracted services, including Dispatch Support Services and Network Control Services

    c. Maintenance of the Ready Reserve Standard

    d. Adherence to Equipment Limits

    e. Maintenance of overall system security

    f. Appropriate management of fuel, if and to the extent that System Management is required to manage such constraints during a ~~gas~~ fuel supply emergency.

5.3 Load forecasts

25. System Management is required by the Market Rules to provide load forecasts daily to Verve Energy **[MR 7.6A.2(b)]** and twice daily to the IMO **[MR 7.2.1]**.

System Management will generally update its own load forecasts more frequently and will use the latest updated load forecasts to produce the forecasts referred to in Paragraph 25.

26. Load forecasts provided in relation to Paragraph 25 will utilise the most recent information available to System Management at the time the forecast is produced.

27. Load forecasts provided in relation to Paragraph 25 will separately itemize, for each Trading Interval in the Trading Day, the following data on a sent-out, loss-adjusted basis:

    a. SWIS System Load, in MW, at the end of the Trading Interval

    b. Total energy, in MWh, over the trading interval

    c. Forecast Non-Scheduled Generation, in MW, at the end of the Trading Interval

    d. Forecast energy from Non-Scheduled Generation, in MWh, over the trading interval.

    e. Forecast energy from commissioning generators, in MWh, over the trading interval

28. The SWIS System Load will be calculated as the combined energy (or power) exported from all generating facilities connected to each Network Operator's networks, as measured at the generating facility's connection points.

Load forecasts are considered to be for system demand in the absence of any curtailment by Non-Balancing Facilities (i.e. demand-side management). Forecast curtailment will be communicated to the market via a Dispatch Advisory notice.

29. Load forecasts will be provided to Verve Energy through System Management's xxxxxx system or any other electronic medium agreed between System Management and Verve Energy.

30. Load forecasts will be provided to the IMO electronically via the System Management – IMO Interface.

31. System Management must provide the information referred to in Paragraph 25 to the IMO within the timeframe stipulated in the Market Rules **[MR 7.2.3B(a)]** and confirmation of receipt must be made by the IMO within the relevant timeframe **[MR 7.2.3D]**.

32. If System Management fails to provide the information referred to in Paragraph 25 within the stipulated timeframe, the IMO must contact System Management and System Management must provide it by alternative means by the timeframe stipulated in the Market Rules **[MR 7.2.3C]**.

5.4 Significant discrete loads

33. To come

5.5 Forecasts of non-scheduled generation

34. Where so required by System Management, if applicable, each Market Generator must provide, for each of its Intermittent Generators with a maximum output capacity exceeding 10 MW the data specified in the Market Rules **[MR 7.2.5]**.

35. Where so required by System Management, if applicable, each Market Generator must provide, for each of its Intermittent Generators with a maximum output capacity exceeding 10 MW, modelling data sufficient to allow System Management to forecast the output of that Intermittent Generator. The modelling data provided shall include, but not necessarily be limited to, identification of the main independent variables affecting output and the function relating those variables to output. All modelling data shall be provided on, or be sufficient to allow conversion to, a sent-out basis.

36. The Non-Scheduled Generator forecast information must be submitted to System Management via xxxxxx unless an alternative medium agreed between System Management and the Market Participant.

37. Where System Management considers that the forecast of sent-out energy for an Intermittent Generator is not reflective of the level of output actually occurring or likely to occur, System Management may estimate expected intermittent generation output using the information provided under Paragraph

35 and may substitute this data for part or all of the data provided for that Intermittent Generator.

38. System Management may utilise other forecast data where required, if Non-Scheduled Generator forecast data is received late or if sections of data are missing. This may be output data derived from recordings of injection levels from past Trading Intervals, or a separate forecast derived for that purpose.

39. Where conditions permit a more extended forecast, Non-Scheduled Generators must utilise reasonable endeavours to provide System Management with the required information covering the next two full Trading Days of forecast information.

40. System Management must not disclose the information referred to in Paragraph 35 to any other party, or use it for any purpose other than to assist in reviewing Ancillary Service requirements and corresponding dispatch plans during the Trading Day in accordance with the Market Rules **[MR 7.2.6].**

5.6 Forecasts of ancillary services demand

41. System Management must determine the estimated Ancillary Service requirements for each Market Participant that is a provider of Ancillary Services in accordance with the Market Rules **[MR 7.2.3A]**.

42. System Management must submit the Ancillary Service forecast data calculated pursuant to the Market Rules **[MR 7.2.3A]** to the IMO by the relevant time **[MR 7.2.3B(b)]** and confirmation of receipt must be made by the IMO within the relevant timeframe **[MR 7.2.3D]**.

43. If the IMO fails to receive this information within the initial stipulated timeframe, the IMO must contact System Management and System Management must provide it by alternative means by the delayed timeframe stipulated in the Market Rules **[MR 7.2.3C]**. Confirmation of receipt of such information must be made by the IMO within the relevant timeframe **[MR 7.2.3D]**.

5.7 Updating the Verve Energy Dispatch Plan

44. System Management is required to notify the Verve Energy of significant changes to the Verve Energy Dispatch Plan **[MR 7.6A.2(f)].**

45. The changes referred to in Paragraph 44 will be deemed to be significant when they indicate:

    a. previously uncommitted generating plant is expected to be committed, or previously committed generating plant is expected to be de-committed;

    b. fuel expenditure is forecast to be outside the limits set by Verve Energy; or

    c. System Management expects to need to dispatch plant in Verve Energy's balancing portfolio outside the Verve Energy Balancing Portfolio Dispatch Guidelines described in Paragraph 14.

46. System Management must transmit the revised Verve Energy Dispatch Plan to Verve Energy as soon as practicable through [a new electronic interface].

47. Verve Energy may request changes to the Verve Energy Dispatch Plan, which System Management must use reasonable endeavours to accommodate.

System Management has an obligation to consult with Verve Energy in preparing the Verve Energy Dispatch Plan ***[MR 7.6A.2(d)].***

5.8 Dispatch Advisory notices

48. The requirements for the issue and release of Dispatch Advisory notices to Market Participants and the IMO are specified in the Market Rules **[MR 7.11].**

49. Dispatch Advisories may arise as a result of one or more of:

    a. Conditions detected in the pre-dispatch plan

    b. Conditions detected in the dispatch plan

    c. Real-time monitoring thresholds being reached

    d. Conditions detected or forecast manually by System Management Controllers.

Types of Dispatch Advisory notices are listed in Appendix 1.

50. System Management will transmit Automatic Dispatch Advisory notices half hourly, as soon as practicable after the completion of each Trading Interval, and at other times if required. Manually generated Dispatch Advisory notices will be transmitted as soon as practicable.

51. System Management will transmit Dispatch Advisory notices through xxxxxx.

52. Where there is a communication failure or insufficient time to issue such a notice, System Management may convey the content of the notice including any direction via telephone or such other means as are practicable at the time, but must provide confirmation in the form of a formal Dispatch Advisory notice as soon as practicable.

53. System Management has an obligation under the Market Rules **[MR 7.11.6AA]** to ensure that confidential information is not disclosed in Dispatch Advisory notices.

5.9 Content and management of Dispatch Advisory notices

54. Each occurrence of a condition triggering a Dispatch Advisory notice will result in a separate Dispatch Advisory notice being produced.

55. Each Dispatch Advisory notice will contain:

    a. an issue time,

    b. a commencement time, being the time at which the conditions triggering the Dispatch Advisory notice are expected to occur

    c. an ending time, being the time at which the conditions triggering the Dispatch Advisory notice are expected to cease

    d. A Dispatch Advisory Type field

e. A text field for the detailed content of the Dispatch Advisory notice.

56. Dispatch Advisory notices will remain in force until withdrawn.

57. Withdrawal of Dispatch Advisory notices will occur as follows:

   a. Dispatch Advisory notices issued pursuant to the pre-dispatch plan or dispatch plan will cover one trading interval and will be deemed to have been withdrawn at the end of that trading interval;

   b. Dispatch Advisory notices issued retrospectively in response to events that have already occurred will be deemed to have been withdrawn at the later of the time of issue and the ending time. Such DAs may also be withdrawn by issuing a withdrawal notification.

   c. Dispatch Advisory notices issued in circumstances not covered above are issued when required and expire automatically at the ending time unless withdrawn earlier.

5.10 Pre-issuing of Dispatch Instructions

58. Where System Management determines that a specific Facility is required to operate in a particular way in a future period for the maintenance of power system security, System Management may issue Dispatch Instructions to the required Facility prior to the normal issuance time.

59. Where the Facility referred to in Paragraph 58 would be required to be dispatched pursuant to Part b of Paragraph 72, System Management will observe the Facility's Standing Data minimum response time when issuing Dispatch Instructions to that Facility.

60. Where System Management determines that a Non-Balancing Facility will be required to operate in a future period for the maintenance of power system security, System Management will issue Dispatch Instructions to the required Facility in accordance with that Facility's notice period.

61. System Management may recall Dispatch Instructions issued pursuant to Paragraph 58 or Paragraph 60 that are due to take effect in a trading interval that has not yet commenced.

6 POST GATE CLOSURE

6.1 Bona fide changes to physical status of plant

62. The Market Rules **[MR 7A.2.10]** require a Market Participant, except Verve Energy in respect of the Verve Energy Balancing Portfolio, to update their Balancing Submission if after gate closure they become aware that the Balancing Submission does not reflect the physical capabilities of their Facilities.

63. If the circumstances described in Paragraph 62 occur, and reflect a reduction or expected reduction in the capability of the Market Participant's facility or facilities, the affected Market Participant must also advise System Management of the nature and extent of that reduction as soon as practicable.

64. When advised in accordance with Paragraph 63, System Management will for any Trading Intervals for which it expects to receive no further updates to the Balancing Merit Order:

   a. Assess power system security in accordance with the Power System Operating Procedure “Power System Security” and take any required actions resulting from that assessment

   b. Immediately issue a Dispatch Advisory notice specifying the extent of the reduction in capacity and whether the affected Facility is marginal, above or below the balancing point.

   c. Immediately issue a Dispatch Instruction to the affected Facility as though the notification referred to in Paragraph 63 had not been received.

   d. Immediately following the issue of the Dispatch Instruction referred to in Part c, issue a new Dispatch Instruction to the affected Facility consistent with the advice referred to in Paragraph 63.

   e. Deem the affected Facility to have refused to comply with the Dispatch Instruction referred to in Part c above.

   f. Deem the affected Facility to have refused to comply with any future Dispatch Instruction instructing the affected Facility to operate above its advised reduced capability, notwithstanding that such a Dispatch Instruction has not yet been issued.

6.2 Commitment of generating plant

65. The obligations of System Management and Market Participants in respect of commitment and de-commitment of generating plant are set out in the Market Rules **[MR 7.9]**.

66. A Non-Verve Energy Participant must communicate confirmation of expected time of synchronization and de-synchronisation under the Market Rules via telephone **[MR 7.9.1].**

67. System Management must log the reasons when permission to synchronise or de-synchronise is refused.

6.3 Creation of Dispatch Instructions and Dispatch Orders

68. System Management will create Dispatch Instructions and Dispatch Orders in such a way as to ensure the Dispatch Criteria **[MR 7.6.1]** are met at all times.

69. System Management will, wherever practicable, create Dispatch Instructions and Dispatch Orders using a mathematical program.

70. The Market Rules **[MR 7.6.1A, 7.6.1AA. 7.6.1B, 7.6.1C]** stipulate the priority rules that System Management must follow in formulating Dispatch Instructions.

71. In determining which Facility or Facilities best meet the Dispatch Criteria when dispatching out-of-merit in accordance with [MR 7.6.1B (b)], System Management will consider, in order, each Facility in the Balancing Merit Order until either:

a. System Management has determined that issuing Dispatch Instructions out of merit to either or both of the next two Facilities in the BMO would resolve the issue leading to out-of-merit dispatch.

b. System Management has determined that issuing Dispatch Instructions out of merit to either or both of the next two Facilities in the BMO would not resolve the issue leading to out-of-merit dispatch.

72. If System Management makes a determination in accordance with Part b of Paragraph 71, System Management will:

a. Dispatch, in order, either or both of the next two Facilities out of merit to the extent that doing so will resolve the issue leading to out of merit dispatch

b. Dispatch such other units as System Management determines are required in accordance with [MR 7.6.1B (c)].

Paragraphs 71 and 72 essentially mean that System Management will only go to the next two Facilities in the BMO before it starts looking for the best unit to resolve the issue on technical grounds. The rationale for this approach is that the further the Facility being considered is from the balancing point, the less chance the Facility will be in a position to respond. (When System Management calls a Facility under Part c, it is required to observe standing data response time).

[MR 7.6.1B states that:

"In seeking to meet the Dispatch Criteria System Management must, subject to clause 7.6.1C, issue Dispatch Instructions in the following, descending order of priority:

(a) Dispatch Instructions to Balancing Facilities in the order and for the quantities they appear in the BMO, taking into account Ramp Rate Limits;

(b) a Dispatch Instruction to a Balancing Facility Out of Merit but only to the next Facility or Facilities, and associated quantity in the BMO that System Management reasonably considers best meets the Dispatch Criteria, taking into account the associated Ramp Rate Limit;

(c) a Dispatch Instruction to any Balancing Facility Out of Merit, taking into account the Ramp Rate Limit and non-ramp rate Standing Data limitations and any other relevant information available to System Management; and

(d) a Dispatch Instruction to a Non-Balancing Facility in accordance with the Non-Balancing Dispatch Merit Order, taking into account Standing Data limitations."

73. System Management must **[MR 7.6.1A]** give priority to the dispatch of a Registered Facility under a Network Control Service (NCS) contract if doing so would assist System Management to meet the Dispatch Criteria. System Management will consider that a Network Control Service contract will assist it to meet the Dispatch Criteria if System Management considers that:

a. The dispatch of the power system without calling upon the NCS Contract would adversely affect power system security; and

b. Dispatching the facilities covered by the NCS contract according to the terms of the contract would prevent the circumstances described in Part a above from arising or alleviate them if they have already arisen.

74. System Management may **[MR 7.6.1AA]** give priority to the issuing of Operating Instructions that call on Ancillary Services, NCS or Supplementary Capacity Contracts, or enable a Test. System Management will, as far as possible without breaching its obligations in relation to maintaining power system security, apply its discretion in the following manner:

    a. NCS Contracts will be called upon in accordance with Paragraph 73 or as agreed with the applicable Network Operator;

    b. Ancillary Services Contracts will be called upon in accordance with the terms of the Contract; in accordance with System Management's approved Ancillary Services Plan; and in a way that at all times meets the Ancillary Services Standards;

    c. Supplementary Capacity Contracts will be called upon in accordance with the terms of the Contract;

    d. Tests will be scheduled in accordance with the Power System Operating Procedure "Commissioning and Testing".

75. Any agreements with Verve Energy in relation to the provision of Ancillary Services, including those embodied in the Verve Energy Balancing Portfolio Dispatch Guidelines, will be considered to be an Ancillary Services Contract for the purposes of Paragraph 74.

76. System Management must **[MR 7.6.1B]** take into account ramp rate limits when formulating Dispatch Instructions in accordance with the Balancing Merit Order. For the avoidance of doubt:

    a. A facility that is below the balancing point in the BMO and is not dispatched for its full offered quantity, but that is dispatched for the maximum quantity its Ramp Rate Limit implies it is capable of achieving in the Trading Interval, will be considered to have been dispatched "in merit";

    b. A facility that is above the balancing point in the BMO and is dispatched for a non-zero quantity, being the minimum quantity its Ramp Rate Limit implies it is capable of achieving, will be considered to have been dispatched "in merit".

System Management will not consider Standing Data minimum generation constraints when formulating Dispatch Instructions in accordance with the BMO. Participants must prepare their balancing submissions in such a way as to achieve either dispatch above minimum generation, or de-commitment. When System Management issues dispatch instructions out of merit in accordance with [MR 7.6.1B(b)], it will however observe minimum generation constraints.

6.4 Creation of Operating Instructions

77. System Management will issue Operating Instructions to call on services provided under Network Control Service Contract, an Ancillary Service Contract, or a Supplementary Capacity Contract; or in connection with a Test.

78. System Management will deem Verve Energy's obligations as the default provided of Ancillary Services to be an Ancillary Services Contract for the purposes of Paragraph 77.

System Management will thus issue Operating Instructions to the Verve Balancing Portfolio and/or Verve Stand Alone Facilities when calling on Verve to provide Ancillary Services other than Load Following Ancillary Service.

79. Where System Management identifies, based on the BMO or Forecast BMO, that a Facility's Balancing Submission is inconsistent with an Operating Instruction to that Facility, System Management may send a warning to the market participant.

The obligation to ensure dispatch consistent with OIs remains with the participant. Any warning from System Management is provided for information only.

80. Where a Market Participant with a contract to provide Ancillary Services or Network Control Service provides the contracted service automatically and in accordance with the terms of the contract, System Management will communicate the Operating Instruction to the relevant Market Participant as early as practicable.

81. Where System Management is required to call on Network Control Service from a Facility whose Standing Data notice period is less than gate closure,

    a. Option 1: Issue OI for NCS before gate closure to allow NCS Facility to update bids and offers in the normal timeframe

    b. Option 2: Issue OI immediately after gate closure based on forecast BMO. Allow NCS Facility to update its balancing submission after gate closure. Would require change to Rule 7A.2.10

Discuss with the IMO

Note the above only applies where the NCS is for the provision of real power. Calling an NCS contract for reactive power will be done by a direction, i.e. outside the market.

6.5 Issuing of Dispatch Instructions and Operating Instructions

82. The Market Rules detail the requirements for Dispatch Instructions **[MR 7.7.2** and **MR 7.7.3]** and Operating Instructions **[MR 7.7.3A]**.

83. All Dispatch Instructions and Operating Instructions for a facility remain in force until superseded by a new Dispatch Instruction or Operating Instruction.

Dispatch Instructions for Trading Intervals that have not yet commenced can be withdrawn, but a Dispatch Instruction for the current Trading Interval will simply be overridden by a subsequent Dispatch Instruction.

Dispatch Instructions to curtailable loads will be expressed in terms of "quantity of curtailment".

84. System Management will issue Dispatch Instructions electronically via one of the following methods (in order of preference):

    a. SCADA, if available

    b. System Management's Business-to-Business electronic interface

    c. E-mail

    d. Telephone, with subsequent confirmation by one of the means above.

85. System Management will respect standing data Minimum Response Times when issuing Dispatch Instructions to units out of merit for system security reasons, unless advised otherwise by the Market Participant concerned.

86. Where it is not practicable for System Management to issue Dispatch Instructions in the manner described in Paragraph 84, System Management may use such other means as it deems best suited to the circumstances and the requirements of Paragraph 84 shall be deemed to have been fulfilled.

87. Where a Market Participant, for a generating facility which does not carry an obligation to provide a Spinning Reserve or Load Following ancillary service and satisfies the two following criteria:

    a. if the system frequency moves above 50.8Hz or below 49.2Hz; and

    b. if the generator facility's governor automatically moves the generator away from its most recent Dispatch Instruction to a point outside its Tolerance Range in a manner that assists reducing the frequency deviation,

    then System Management will deem the abovementioned movement to be within the unit's Tolerance Range.

System Management requires that each generating unit operating in parallel with the SWIS must have its governor enabled and governor response set at 4% droop, and have governor frequency dead band of less than 0.05 Hz, in accordance with the Technical Rules. Refer to clauses 3.3.4.4 (d) and (e) of the Technical Rules

The above paragraph is included to ensure that penalties are not imposed upon Generators that respond to assist in the event of a system emergency.

6.6 Response to Dispatch Instructions

88. Where a Market Participant advises System Management that it cannot follow its Dispatch Instruction, System Management will:

    a. Issue a new DI to the Market Participant consistent with their advised capability, and tag the original DI for compliance.

System Management is obliged to use the generator to the maximum extent possible: If the DI says move upwards from A to C and the generator advises it can only deliver B, System Management must take B and cannot direct the generator to remain at A.

b. Issue DIs to other Facilities as required.

c. Issue a Dispatch Advisory notice to advise the market of dispatch out of merit.

89. Where System Management does not receive confirmation that a DI has been received within 60 seconds if the time of issuance, System Management will deem the DI to have been refused. System Management will then:

a. Send the Market Participant concerned a new DI instructing them to stay at the output specified on their last accepted DI

b. Tag the DI to which the Facility did not respond as non-compliant

c. Issue DIs to other Facilities as required.

d. Issue a Dispatch Advisory notice to advise the market of dispatch out of merit.

6.7 Dispatch of generating unit for system security

90. System Management may issue a Dispatch Instruction requiring a Facility not forming part of the Verve Energy Balancing Portfolio to move from zero generation to positive generation, or vice versa, where doing so is necessary to maintain power system security.

Dispatch Instructions referred to in Paragraph 90 are implicitly instructions to synchronise and operate (commit) or de-synchronise (de-commit). The Dispatch Instruction protocol does not allow for explicit commit / de-commit instructions.

91. When the system is forecast to move into a High Risk Operating State, System Management will observe as far as practicable the BMO or Forecast BMO for the trading intervals in which the threat to power system security occurs when selecting the unit or units to commit.

92. When the system is in a high risk operating state, is in, or is forecast to move into, an Emergency Operating State, System Management will select the unit or units to commit that provide the most flexibility for System Management to deal with current or potential threats to power system security.

In general, Paragraph 92 will result in the preferential commitment of large, fast-moving and/or flexible generating units.

7 TRADING INTERVAL

7.1 Real-time monitoring during trading interval

93. System Management will monitor the operation of the power system in real time and will issue Dispatch Instructions to re-balance if it considers that it is prudent to do so.

94. System Management will not routinely re-balance during a Trading Interval (including to return load following facilities to their base point prior to the end

to the interval) but will re-balance "on demand"; in the event of contingencies; and on the half-hour.

95. In determining whether it is prudent to re-balance, System Management will consider a range of factors including but not limited to:

    a. System frequency
    b. Position of LFAS Facilities relative to their base point
    c. Any reduction in Spinning Reserve
    d. The behaviour of Balancing Facilities, in particular facilitate outside their Tolerance Range
    e. Significant changes in load or wind forecasts
    f. The behaviour of commissioning generators
    g. The time remaining till end of interval.

System Management will establish Tolerance Range [MR 2.13.6D] and Facility Tolerance Ranges [MR 2.13.6E] according to the requirements of the Market Rules.

96. If the Facility is outside its Tolerance Range and System Management determines it is prudent to re-balance, System Management will:

    a. Tag the affected Facility as non-compliant with their DI
    b. Issue the affected Facility with a new DI to stay at its current output level
    c. Issue new DIs as required in accordance with the BMO, skipping the affected Facility.

97. If the Facility is outside its Tolerance Range and System Management determines that no re-balancing is required, System Management will tag the affected Facility as non-compliant with their DI.

System Management may follow up verbally with the Market Participant but will take no further action for so long as re-balancing is not required.

7.2 Formulation and issuing of intermediate Dispatch Instructions and Dispatch Orders

98. System Management may issue one or more Dispatch Instructions to a single facility within an interval.

System Management will need to issue intermediate Dispatch Instructions and Dispatch Orders to manage intra-period changes in ramp rate, contingency events, fluctuations in net system load outside the load following range, and for other reasons.

7.3 Ancillary Services monitoring and activation

99. Where the applicable Ancillary Services contract allows for the automatic activation of the service, System Management will issue an Operating Instruction in advance in accordance with Paragraph 80.

Where the Verve Portfolio is providing Spinning Reserve or Load Rejection, the Operating Instruction will be issued to the Verve Portfolio and individual plant dispatched in accordance with the Verve Dispatch Guidelines.

100. If, in the opinion of System Management, a Facility providing Load Following Ancillary Service is not performing adequately and either:

   a. the Facility comprises more than 20% of the LFAS requirement; or

   b. The LFAS output on other LFAS Facilities, in aggregate, is greater than 70% range,

   then System Management will enable LFAS allocation on the Verve Energy back up load following Facility and disable LFAS allocation on the non-performing Facility.

101. In all other cases where, in the opinion of System Management, a Facility providing Load Following Ancillary Service is not performing adequately, System Management will investigate the reasons for non-performance and may at its discretion initiate the disabling of the non-performing LFAS Facility and enabling of the Verve backup LFAS Facility.

102. In the event of an LFAS Facility trip, System Management will immediately enable the backup Verve LFAS Facility.

7.4 Constrained operation of a Non-Scheduled Generator

103. System Management may issue a Dispatch Instruction to a Non-Scheduled Generator to restrict the MW or MWh output of the Generator over specified Trading Intervals where the Dispatch Criteria are not being met, to restrict the variability that is occurring in the MW output from the Facility, if a High Risk Operating State or Emergency Operating State exists, or if adherence to the Balancing Merit Order requires it.

104. The reasons for non-observance of the dispatch criteria may include, but are not limited to the following:

   a. the Ancillary Service Requirements are not being satisfied;

   b. operation of the Non-Scheduled Generator Facility is causing voltage swings in the region of the Facility's connection to the Network to exceed the range permitted by the Technical Rules or Security Limits;

   c. operation of the Non-Scheduled Generator is causing Equipment Limits or Security Limits to be exceeded; or

   d. operation of the Non-Scheduled Generator is causing frequency deviations to exceed the normal frequency operating range.

7.5 Constraining operation of multiple Non-Scheduled Generators.

105. Where there are a number of Non-Scheduled Generators operating at high output during light system demand conditions, a reduction in the output of one or more Intermittent Generators may be needed to meet the dispatch criteria.

106. Where the requirement for a reduction or constraint in the output of Intermittent Generators can be attributed to a single Non-Scheduled Generator, a Dispatch Instruction requiring output to be constrained down must be issued to that Non-Scheduled Generator.

107. The quantity of output reduction sought from the Non-Scheduled Generator in Paragraph 106 is the quantity that ensures that Non-Scheduled Generator is not the source of the conflict with the Dispatch Criteria

108. Where System Management considers that the conflict with the Dispatch Criteria is due to the operation of two or more Non-Scheduled Generators, then System Management will constrain down the Non-Scheduled Generators in proportion to their contribution to the conflict with the Dispatch Criteria.

7.6 Voltage control

109. System Management may, in accordance with the technical Rules, direct a Facility to change its reactive power output to assist with voltage control on the SWIS.

The present Technical Rules require "The overriding objective of a generating Facility's voltage control system is to maintain the specified voltage range at the connection point. Each Generator must therefore provide sufficient reactive power injection into, or absorption from, the transmission or distribution system to meet the reactive power requirements of its loads, plus all reactive power losses required to deliver its real power output at system voltages within the ranges specified in the relevant connection agreement for normal operation and contingency conditions."

110. If a direction pursuant to Paragraph 109 reduces the MW output capacity of the Facility below its DI, System Management will deem this reduction to be a consequential outage due to a network constraint.

SM would then have to increase MW output from the next generator on the BMO. SM would issue a DA and DIs for this instance. Similarly if voltage issues on the network required SM to modify the generation plan across the SWIS (say move MW generation from one part of the SWIS to another to remove the voltage constraint), SM would have to issue a DA, dispatch as per BMO if market did respond or dispatch out of merit as per standing data if market didn't respond.

8 DISPATCH SETTLEMENT DATA

111. The requirements for System Management to provide settlement data to the IMO are specified in the Market Rules **[MR 7.13].**

112. System Management must submit the data to the IMO's WEMS system in a format agreed with the IMO.

113. The IMO must confirm with System Management receipt of the data.

114. If the IMO has not received the data by 12.10 PM of the required business day, the IMO must contact System Management and request the data be re-sent.

115. If the data is not with IMO by 12.20 PM, System Management and IMO should confirm the cause of the data failure and if necessary, agree an alternative method of transferring the data.

8.1 Quantification of Constrained off Quantities.

116. Where System Management requires a Non-Scheduled Generator to reduce output and where the Market Generator is to be compensated for the reduction, System Management must provide the IMO with an estimate of the reduction in MWh output of the Generating Facility as a consequence of System Management issuing the Dispatch Instruction to reduce output **[MR 7.13.1.eC]**.

117. System Management must make an estimate of the actual output of the Non-Scheduled Generator over each Trading Interval for which the Dispatch Instruction applies. This may be through access to MWh metering at the Generator Facility, or by measuring the instantaneous MW output from the Non-Scheduled Generator MW output using System Management's SCADA system, and integrating these measurements over each Trading Interval to produce a MWh estimate.

118. System Management must make an assessment of the MWh output that would have been achieved by the Non-Scheduled Generator should the Dispatch Instruction not have been issued. The assessment must be produced using the algorithm chosen for this purpose (refer Paragraph 120).

119. System Management must make an estimate of the constrained off quantities caused by the Dispatch Instruction for each Trading Interval the Dispatch instruction applies to, by subtracting the measured output (Paragraph 117) from the assessment of output that would otherwise have occurred (Paragraph 118).

8.2 Choice of Algorithm for Assessing Constrained off MWh Quantities

120. System Management may use, at its discretion, any of the following means to estimate the quantity referred to in Paragraph 118:

a. a predictive algorithm provided by the Market Participant, providing an assessment of generator MWh output from relevant independent variables over the Trading Interval;

b. a predictive algorithm provided by System Management, providing an assessment of generator MWh output from relevant independent variables over the Trading Interval;

c. an assessment by System Management based on output of the Intermittent Generator in a past Trading Interval under similar conditions; or

d. an estimate using Participant data provided to System Management that uses output data from particular generating units that continue to operate unconstrained after the Dispatch Instruction, with the output data subsequently grossed up to represent the output from all generating units that otherwise would have operated.

121. System Management must, from time to time, consult with the relevant Market Generator concerning the choice of option selected by System Management in Paragraph 120.

9 ADMINISTRATION AND REPORTING IN RELATION TO VERVE ENERGY

9.1 Appointment of Representative

122. Verve Energy and System Management shall:

a. each appoint a representative who will act as the formal point of contact with regard to the operation of this procedure.

b. provide each other and the IMO with the name, title and contact details of its representative.

c. maintain the appointed representative's currency.

9.2 Failure of Parties to meet obligations

123. The requirements for System Management to report to the IMO any instance where it believes that Verve Energy has failed to meet its obligations under this procedure are specified in the Market Rules **[MR 7.6A.5(c)], [MR 7.6A.5(d)], [MR 7.6A.5(e)].**

124. The reports referred to in Paragraph 123 must be submitted to the IMO within 2 business days of the occurrence of the event, or within 2 business days of either party becoming aware of the event.

9.3 Keeping of Records

125. The requirements for Verve Energy and System Management to retain records created by the operation of this procedure are specified in Market Rules **[MR 7.6A.6].**

9.4 Failure to Agree on an issue within the Procedure

126. The requirements for System Management and Verve Energy to address and reach agreement on any issues arising from the application of this procedure are specified in the Market Rules **[MR 7.6A.5(b)].**

127. Where agreement cannot be reached and arbitration is required, the party seeking arbitration must, in good faith, seek to agree with the other party on an arbitrator.

128. If, within 7 days, the parties are unable to agree on an arbitrator, the IMO shall be the arbitrator.

129. Within 7 days of the appointment of an arbitrator, the party seeking arbitration must provide the arbitrator with a report setting out:

a. a description of the issue in dispute;

b. the background to the dispute and a description of the endeavours of the parties to resolve the issue; and

c. the position of both parties on the issue, including what is required to resolve the dispute.

130. The party submitting the report must provide a copy of the report to the other party at the same time the report is submitted to the arbitrator.

131. The other party must submit its own report on the issue to the arbitrator within 2 business days of the receipt of the report noted in subsection (4).

132. In reviewing the issue, the arbitrator must have regard to the following:

a. the content of this procedure;

b. the Market Rules and procedures; and

c. the appropriateness of any section of this procedure relevant to the issue, and its alignment with market objectives, Market Rules and other procedures.

133. The arbitrator may seek further information from either party, and this information should be provided within 2 Business Days of receipt of the request.

134. The arbitrator must provide its draft recommendation to Verve Energy and System Management within two weeks of the receipt of the report in subsection (5). Both parties have 2 Business Days to provide the arbitrator with comments on the draft recommendation.

135. The arbitrator must, within 2 Business Days of receiving comments, issue a binding decision.

APPENDIX 1: LIST OF DISPATCH ADVISORY NOTICE TYPES

DA type code	Description
	Change in Power System Operating State
	Energy shortfall
	Energy surplus
	Ramp rate shortfall
	Ancillary Service shortfall
	Ready Reserve shortfall
	Change in outage status
	Out-of-merit dispatch
	Excessive intermittency
	Commitment risk
	Communications / IT issue
	Fuel management issue
	Other

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Monitoring and Reporting Protocol

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RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with, the Wholesale Electricity Market Rules (Market Rules).
2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as 1 November 2011. These references are included for convenience only, and are not part of this procedure.
3. This Power System Operating Procedure is subservient to the Market Rules. In the event of conflict between this Procedure and the Market Rules or any other document, the order of precedence is as set out in the Market Rules **[MR 1.5.2]**
4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

COMMENCEMENT

5. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

6. The Power System Operation Procedure: Monitoring and Reporting Protocol ('Procedure') details procedures that System Management must follow to monitor Rule Participant's compliance with Market Rules and the Power System Operation Procedures, and to provide information about breaches, or other information the IMO may request, to the IMO.

7. This Procedure details the processes that System Management will follow to monitor Rule Participant's compliance with Market Rules and the Power System Operation Procedures, and to provide information about breaches, or other information the IMO may request, to the IMO.

8. In performing its functions under the Market Rules, System Management may be required to disclose certain information to Market Participants and Network Operators. In selecting the information that may be disclosed, System Management will utilise best endeavours and act in good faith to disclose only the information reasonably required by the application of the Market Rules.

2 MONITORING COMPLIANCE OF MARKET PARTICIPANTS

The requirements for System Management to monitor and report Rule Participants behaviour within respective Tolerance Range and Facility Tolerance Ranges, as applicable, are specified in the Market Rules ***[MR 2.13.6, MR 2.13.6A, MR 2.13.6B, MR 2.13.6C]****.*

9. Specific Market Rules that must be monitored by System Management are specified in the Market Rules **[MR 2.13.9]**. System Management must monitor Rule Participant compliance in accordance with the primary measures summarised in Appendix 1.

10. To the extent that specific monitoring activities in this Procedure are inconsistent with the Market Rules, the Market Rules prevail.

11. System Management may provide information to Market Participants relating to compliance issues. In no way does this provision of this information, or lack thereof, obviate a Market Participant from complying with the Market Rules or Power System Operation Procedures.

3 GENERAL MONITORING PROCESSES

12. Where possible, System Management will use automated methods to determine compliance.

13. System Management will utilise information methods including, but not limited to:

    a. communication to System Management;

b. SCADA;

c. information provided by the IMO including Standing Data and Resource Plans; and

d. outage information.

14. In determining whether a given activity is in accordance with the Market Rules, System Management may request further information from Market Participants.

4 GENERATOR TOLERANCE RANGE

4.1 Principles to be used in determination of Tolerance Ranges

15. System Management will in general apply the following formula in determining the generator Tolerance Ranges:

Tolerance Range (MW) = MAX (6, MIN [5% NPC, 4*ROC])

Where:

NPC is the name plate capacity of the generator, expressed in MW

ROC is the dispatched average ramp rate of a scheduled generator in a particular Trading Interval, expressed in MW per minute.

Note ROC term is not applied for non-scheduled generators.

4.2 Determination of Tolerance Range for all Facilities

The requirements System Management must adhere to when determining a monitoring Tolerance Range to apply to all Facilities for the purposes of System Management's reporting of alleged breaches of clause 7.10.1 are stipulated in the Market Rules. System Management must consult with Rule Participants prior to setting the Tolerance Range. ***[MR 2.13.6D]***

System Management must conduct the consultation process in Paragraph 16 of this Procedure in good faith and allow relevant stakeholders reasonable opportunity to comment ***[MR 2.21.4].***

16. System Management will initiate consultation by providing the proposed Tolerance Range(s) to the IMO for publication, and inviting Rule Participants to provide submissions.

17. The period available for submissions under Paragraph 16 must not be less than six weeks.

18. System Management must submit its responses to each issue raised in submissions received from Rule Participants to the IMO for publication.

4.3 Determination of Facility Tolerance Range for specific Facilities

19. If System Management considers that the Tolerance Range for all Facilities is not suitable for a particular facility it may determine a Facility Tolerance Range for that particular Facility.

20. If a Market Participant considers that the Tolerance Range for all Facilities is not suitable for its particular Facility, the Market Participant may submit an application by email to System Management stating the reasons why the Tolerance Range is not suitable for the Facility concerned. System Management may then, in accordance with Paragraph 19, determine a Facility Tolerance Range for the Facility.

21. The circumstances in which System Management will generally exercise its discretion to determine a Facility Tolerance Range include, but are not limited to:

    a. first time entry of small loads into the SWIS;

    b. generators with excessively variable output; or

    c. any other exceptional circumstances which System Management considers reasonable.

22. System Management must consult with Market Participants prior to setting a specific Facility Tolerance Range **[MR 2.13.6E].** System Management must follow the same consultation process in Section 4.2 of this Procedure prior to setting a specific Facility Tolerance Range for a particular facility.

23. System Management may determine a specific Facility Tolerance Range to apply to a particular facility. In making this determination System Management must consider the following:

    a. the variability of generation/load movement on the SWIS at any point in time;

    b. individual Facility ramping behaviour;

    c. the proportion of Facilities required to comply with Resource Plans synchronised on the system during an average Trading Day;

    d. Standing Data and any operating constraints on the Market Participant's Facility of which System Management is aware; and

    e. any other factors that may influence the real time operation of the SWIS. **[MR 2.13.6E]**

4.4 Changes to Tolerance Ranges

24. System Management must review the Tolerance Range and all Facility Tolerance Ranges at least annually **[MR2.13.6G].** System Management must follow the same consultation process in Section 4.1 of this Procedure prior to setting a Tolerance Range and a specific Facility Tolerance Range(s).

25. Following a review, System Management may vary the Tolerance Range or a specific Facility Tolerance Range(s) **[MR 2.13.6G].** Varied Tolerance Range and Facility Tolerance Range(s) are effective from the date specified by System Management, as published by the IMO on the Market Web Site **[MR 2.13.6D** and **MR 2.13.6E].**

26. Where the IMO gives a direction to System Management to vary a specific Facility Tolerance Range in accordance with the Market Rules **[MR 2.13.6H],** that direction will apply until the Facility Tolerance Range is varied with clause 2.13.6G of the Market Rules **[MR 2.13.6I].**

27. At least 14 Business Days prior to the date from which a change to the specific Facility Tolerance Range becomes effective, System Management must submit to the IMO for publication on the Market Web Site:

    a. the reasons for System Management's decision to apply a specific Facility Tolerance Range in place of a the Tolerance Range;

    b. any submissions received from Market Participants;

    c. the applicable Facility Tolerance Range; and

    d. an effective date for the commencement of the applicable Facility Tolerance Range. [MR 2.13.6E]

28. Where a specific Facility Tolerance Range is determined, this Facility Tolerance Range will apply to a particular Facility in place of the Tolerance Range.

4.5 Reporting of Forced Outages and Consequential Outages

*The requirements for Market Participants to provide details of Forced Outages are specified in the Market Rules **[MR 3.21]**.*

29. System Management will determine the availability of facilities based on communications from the relevant Market Participant, including but not limited to (as applicable):

    a. Electronic communications via e-mail or SMMITS

    b. Voice communications

    c. SCADA

30. Final details of Forced Outages must be provided to System Management via SMMITS in accordance with the Market Rules **[MR 3.21.7]** and the Power System Operating Procedure: Facility Outages.

*The SMMITS system will not accept Forced Outages notified outside the timeframe indicated in the Market Rules **[MR 3.21.7]**.*

31. System Management will investigate any communication relating to facility availability that is not in accordance with the information contained in SMMITS as per the Market Rules **[MR 3.21.7]**.

32. System Management must keep a record of all Consequential Outages of which is it aware and report these to the IMO via an electronic transfer medium in accordance with the Market Rules **[MR 3.21.7 and MR 3.21.11].**

4.6 Electricity Generation Corporation

*The requirements for the Electricity Generation Corporation (**EGC**) to comply with directions are specified in the Market Rules **[MR 7.6A]**.*

33. As required by the Market Rules **[MR 7.6A.4]**, System Management may only consider dispatch compliance of EGC where non-compliance of a direction could endanger Power System Security.

34. System Management must have regard to good electricity practice in determining whether EGC conduct could endanger Power System Security.

5 ALLEGED BREACHES

*Where System Management determines that there is sufficient basis for suspecting non-compliance with a Market Rule or Market Procedure, System Management is obliged to report the matter to the IMO. The requirements for System Management to allege breaches of the Market Rules or Market Procedures are specified in the Market Rules **[MR 2.13.8]**.*

*Where System Management determines an alleged breach by a Market Participant satisfies the criteria within clause 2.13.6B of the Market Rules, System Management is not required to report this alleged breach to the IMO **[MR 2.13.6B].***

*In determining an alleged breach by a Market Participant, System Management must take account of the Tolerance Range or Facility Tolerance Range for a particular facility determined in accordance with the Market Rules **[MR 2.13.6D and MR 2.13.6E]**.*

*Where the party causing the alleged breach is the IMO, System Management must report the alleged breach to the person appointed by the Minister as specified in the Market Rules **[MR 2.13.8]**.*

35. Before alleging a breach with the IMO, System Management may request an explanation from the relevant Rule Participant.

APPENDIX 1 PRIMARY MEASURES USED TO MONITOR

Clause	Description	Proposed Measures
3.4.6	Market Participants must comply with System Management directions and endeavour to assist System Management during high risk operating state.	Following a High Risk Operating State, SM will investigate the actions of all Market Participants in receipt of a direction to ensure that any directions were complied with.
3.4.8	Market Participant must immediately inform System Management if cannot comply with direction.	Monitored through compliance with directions. All such notifications will be logged, and investigated.
3.5.8	Market Participants must comply with System Management directions and endeavour to assist System Management during emergency operating state.	Monitored through compliance with directions.
3.5.10	Market Participant must immediately inform System Management if cannot comply with direction.	Monitored through compliance with directions. All such notifications will be logged, and investigated.
3.6.5	Networks must implement load shedding plans.	This will be identified through observation, and the required reporting for the Under Frequency Load Shedding Plan will be monitored.
3.6.6B	Networks must comply with manual disconnection instructions from System Management.	This will be identified through observation of SCADA data following such an instruction.
3.16.4	Market Participants must provide MT-PASA information.	Any Market Participant not providing required information will be investigated.
3.16.7	Market Participants must provide MT-PASA information.	Any Market Participant not providing required information will be investigated.
3.16.8A	Market Participants must provide additional MT-PASA information requested by System Management.	Any Market Participant not providing required information will be investigated.
3.17.5	Market Participants must provide ST-PASA information.	Any Market Participant not providing required information will be investigated.
3.17.6	Market Participants must update ST-PASA information if it changes.	SM will monitor the actual situation of facilities and will identify any anomalies with the PASA.

Clause	Description	Proposed Measures
3.18.2(f)	Market Participant must comply with outage scheduling and approval process if Facility listed on the equipment list in 3.18.2(f)	System Management will monitor discrepancies between planned and actual outage times and report these variations as an alleged breach.
3.21A.2	Market Participant must request Commissioning Test trials from System Management.	This will be determined by observation. Any facility that should provide a plan and does not will be investigated.
3.21A.12	Market Participant must conform to the Commissioning Test plan approved by System Management.	This will be determined by observation.
3.21A.13	Market Participant must inform SM if it cannot conform to the Commissioning Test plan approved by System Management.	This will be determined by observation. Any facility that should provide such notification and does not will be investigated.
3.21B.1	Except when given a Planned Outage, a Market Participant must seek permission from System Management before putting a Scheduled Generator (holding Capacity Credits) into a state where it will take more than four hours to resynchronise the Scheduled Generator.	This will be determined by observation at the point where a Market Participant is called to dispatch their facility and is unable. Any facility that failed to provide such notification, which caused the failure to dispatch to the facility to the relevant level, will be investigated
3.21B.2	Market Participant must make request in accordance with 3.21B.1 not less than two hours prior to the facility ceasing to be able to be re-synchronised within four hours, including particular information as per the Market Rules.	Notification will be logged and investigated where appropriate.
4.10.2	Market Participant who claims alternative fuel must have on site fuel or uninterruptible fuel supply.	This will be determined by observation should the IMO instruct SM.
4.25.13	Market Participant who claims alternative fuel must have on site fuel or uninterruptible fuel supply.	Subject to the IMO's instruction, this will be determined by observation by System Management
7.2.5	Each Market Generator must by 10am each day provide to System Management for each of its Intermittent Generators with capacity exceeding 10 MW its most current forecast of the MWh energy output of the Intermittent Generator in accordance with the Market Rules.	This will be determined by observation. Any facility that should provide such forecast information and does not will be investigated.

Clause	Description	Proposed Measures
7.5.5	Market Participant can only switch fuels under certain circumstances.	Any fuel change notification will be logged and investigated where appropriate.
7.7.6 (b)	Market Participant must confirm receipt of Dispatch Instruction	This will be monitored electronically by System Management's IT systems.
7.10.1	Market Participant must comply with resource plan, dispatch instructions or directions from System Management.	This will be monitored electronically by System Management's IT systems..
7.10.3	Market Participant must inform System Management where it cannot comply.	This will be determined by observation.
7.10.6	Market Participant must comply with System Management direction to follow resource plan etc, or inform System Management if it cannot.	This will be determined by investigation following a warning issued under 7.10.5.
7.10.6A	Market Participant that cannot remain within tolerance must notify SM.	This will be determined by observation.
7.11.7	Market Participants and networks must comply with System Management directions.	This will be determined by observation.

ELECTRICITY INDUSTRY ACT

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WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Ancillary Services

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1	**3/11/11**	**B CONNOR**	**NOT APPROVED**		**DRAFT FOR INFORMAL CONSULTATION**
2	**5/12/11**	**B CONNOR**	**NOT APPROVED**		**SECOND DRAFT FOR PSOPWG**

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RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. SWIS Technical Rules and Operating Standards
   b. Power System Operation Procedure – Power System Security
   c. Power System Operation Procedure – Dispatch
   d. Power System Operation Procedure – System Restart Overview

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. The following ancillary services are covered by this PSOP: Spinning Reserve, Load Rejection, Black Start, and Dispatch Support. Load Following Ancillary Service is also covered to the extent of facility requirements only.

> *Procurement of Load Following Ancillary Service is covered by the Market Rules [Chapter 7B]. Forecasting requirements for Load Following Ancillary Service is covered in the Power System Operating Procedure, "Dispatch".*

8. This Procedure documents the processes defined in the Market Rules **[MR 3.11.11, 3.11.14 and 3.11.15]:**

   a. determining Ancillary Service Requirements;

   b. preparing budget proposals for providing Ancillary Services; and

   c. entering into Ancillary Service Contracts, including the process for conducting competitive tender processes for the awarding of such contracts.

> *The definitions for each of the Ancillary Services are specified in the Market Rules **[MR 3.9]**.*

2 FACILITY REQUIREMENTS FOR ANCILLARY SERVICES

> *System Management requires that each generating unit operating in parallel with the SWIS must have its governor enabled and governor response set at 4% droop, and have governor frequency dead band of less than 0.05 Hz. Refer to clauses 3.3.4.4 (d) and (e) of the Technical Rules*
>
> *The Power System Operating Procedure 'Dispatch' contains provisions to ensure that penalties are not imposed upon Generators acting to assist in the event of a system emergency.*

2.1 Load Following Ancillary Service

9. All generating units providing Load Following Ancillary Service must meet the following requirements:

   a. The generator governing system must accept and respond to AGC signals that order the output of the generator to be raised or lowered to a desired level set by the AGC at a desired ramp rate.

   b. The generator must be fitted with a monitoring device that can send signals to the AGC at least once every eight seconds for each of the following quantities: generator output level; dispatch point in MW; high economic limit in MW; low economic limit in MW; high operating limit in MW; low operating limit in MW.

   c. The time to respond to a signal from the AGC that orders the generator output to be either raised or lowered must be five seconds or less.

   d. The control of the generator must be selectable between 'Local Control' and 'Remote Control'. Selection of 'Local Control' must enable local control and disable remote control and selection of ‘Remote Control’ must enable remote control and disable local control.

e. The unit control dead band tolerance must be less than 1% of unit capacity for unit capacity of 10 MW or less; and less than 2% of unit capacity where unit capacity exceeds 10MW.

f. The generator must be able to achieve a minimum raise ramp rate of at least 2 MW/min for each 10 MW of offered load following service

g. The generator must be able to achieve a minimum lower ramp rate of at least 2 MW/min for each 10 MW of offered load following service

h. For the range of output over which the offered load following would be provided, the generator must be able to achieve continuously the minimum required ramp rates.

i. The generator must not have a forced outage rate that would compromise its ability to deliver the load following service.

2.2 Spinning Reserve Ancillary Service

10. System Management must ensure that the facilities scheduled to provide Spinning Reserve are collectively capable of meeting the Spinning Reserve standard over all the time periods defined in the Market Rules **[MR 3.9.3].**

[MR 3.9.3] *states that “Spinning Reserve response is measured over three time periods following a contingency event. A provider of Spinning Reserve Service must be able to ensure the relevant Facility can:*

(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 60 seconds; or

(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 6 minutes; or

(c) respond appropriately within 6 minutes and sustain or exceed the required response for at least 15 minutes,

for any individual contingency event.”

11. System Management will certify Generating Units to provide Spinning Reserve in one or more Classes, designated Class A, Class B and Class C, corresponding to the time periods specified in the Market Rules.

Units meeting the capability requirements may be certified to provide more than one class of Spinning Reserve.

12. Generating Units can be certified for Class A Spinning Reserve for the amount that they can increase their output within 6 seconds, and sustain for at least 60 seconds, with a maximum acceptable decay thereafter to a level not below the initial output plus 10%.

13. Units can be certified for Class B Spinning Reserve for the amount that they can increase their output within 60 seconds, and sustain for at least 6 minutes, with a maximum acceptable decay thereafter to a level not below the initial output plus 10%.

14. Units can be certified for Class C Spinning Reserve for the amount that they can increase their output within 6 minutes, and sustain for at least 15 minutes, with a maximum acceptable decay thereafter to a level not below the initial output plus 10%.

15. Generating Units certified for Class A Spinning Reserve must provide their Class A response by way of droop governor response.

16. Generating Units certified for Class B Spinning Reserve must provide their Class B response through one or more of:

    a. Droop governor response

    b. AGC response where appropriate.

17. Generating Units certified for Class C Spinning Reserve must provide their Class C response through one or more of:

    a. Droop governor response

    b. AGC response where appropriate

    c. Operator action to increase power output of the Generating Unit.

18. System Management may set upper limits on ramp-up rate for specific Generating Units certified to provide Spinning Reserve, which the operators of those units must observe when acting in accordance with their Spinning Reserve obligations.

Units capable of very high ramp rates may cause frequency to overshoot and cause over speed trips of slower-responding steam units. System Management will set requirements under Paragraph 18 based on a maximum allowable system-wide ramp-up rate.

19. System Management may set additional requirements for automatic control over Generation Facilities that are not manned continuously, as a condition of certifying those facilities to provide Spinning Reserve.

20. System Management will evaluate the quantity of Spinning Reserve that a Generating Unit can be certified to provide in each class using on one of the following methods, in order of preference:

    a. By assessing the unit's response to actual system events based on data held by or provided to System Management, or

    b. By assessing the unit's Standing Data, control system settings, and other relevant information.

21. System Management may define, evaluate and apply other parameters describing a unit's ability to provide Spinning Reserve and use those parameters in scheduling units to provide spinning reserve if required.

It is anticipated that scheduling spinning reserve will take account of the operating range over which the unit can provide reserve, the impact of ramping on spinning reserve response, auxiliary plant status and potentially other factors.

22. System Management may revise from time to time the quantity of Spinning Reserve that a Generating Unit is certified to provide based on the unit's response to actual system events.

2.3 Load Rejection Ancillary Service

23. System Management must ensure that the facilities scheduled to provide Load Rejection are collectively capable of meeting the Load Rejection standard over all the time periods defined in the Market Rules **[MR 3.9.3].**

> ***[MR 3.9.7]*** *states that "Load Rejection Reserve response is measured over two time periods following a contingency event. A provider of Load Rejection Reserve Service must be able to ensure that the relevant Facility can:*
>
> *(a) respond appropriately within 6 seconds and sustain or exceed the required response for at least 6 minutes; or*
>
> *(b) respond appropriately within 60 seconds and sustain or exceed the required response for at least 60 minutes,*
>
> *for any individual contingency event."*

24. System Management will certify Generating Units to provide Load Rejection reserve in one or more of the time periods specified in the Market Rules, designated Class A and Class B.
25. Generating Units can be certified for Class A Load Rejection reserve for the amount that they can decrease their output within 6 seconds, and sustain or exceed for at least 6 minutes.
26. Generating Units can be certified for Class B Load Rejection reserve for the amount that they can decrease their output within 6 minutes, and sustain or exceed for at least 60 minutes.
27. Generating Units certified for Class A Load Rejection reserve must provide their Class A response through one or more of:
    a. Droop governor response
    b. AGC response where appropriate.
28. Generating Units certified for Class B Load Rejection reserve must provide their Class B response through one or more of:
    a. Droop governor response
    b. AGC response where appropriate.
    c. Operator action to reduce power output of the Generating Unit, including by tripping the unit if required.
29. System Management may set additional requirements for automatic control over Generation Facilities that are not manned continuously, as a condition of certifying those facilities to provide Load Rejection reserve.
30. System Management will evaluate the quantity of Load Rejection reserve that a Generating Unit can be certified to provide in each class using on one of the following methods, in order of preference:
    d. By assessing the unit's response to actual system events based on data held by or provided to System Management, or
    e. By assessing the unit's Standing Data, control system settings, and other relevant information.

31. System Management may define, evaluate and apply other parameters describing a unit's ability to provide Load Rejection Reserve and use those parameters in scheduling units to provide load rejection if required.

It is anticipated that scheduling load rejection reserve will take account of the operating range over which the unit can provide reserve, the impact of ramping on load rejection response, and potentially other factors.

32. System Management may revise from time to time the quantity of Load Rejection reserve that a Generating Unit is certified to provide based on the unit's response to actual system events.

2.4 System Restart Ancillary Service

***[MR 3.9.8]** states that Black Start or "System Restart Service is the ability of a Registered Facility which is a generation system to start without requiring energy to be supplied from a Network to assist in the re-energisation of the SWIS in the event of system shut-down".*

For the purpose of System Restart the SWIS is divided into the following sub-networks: north metropolitan; south metropolitan, south country, north country and eastern goldfields. Presently the only sub networks from which it is possible to restore the SWIS are the north metropolitan, the south metropolitan and the north country.

33. In addition to the requirements of **[MR 3.9.8]** System Management requires that a System Restart generator must:

    a. be capable of closing its generator output circuit breaker onto a de-energised or dead bus;

    b. be able to re-energise a restart path or section of the Network nominated by System Management;

    c. be capable of dead load pick-up of at least 15% of its maximum output;

    d. be capable of operating in isochronous governor mode to set and control at 50 Hz the frequency of the power system it is being used to restore;

    e. be capable of operating in droop governor mode according to the requirements of clause 3.3.4.4 of the Technical Rules when no longer required by System Management to be the generator setting system frequency but still required to support system restoration.

34. For System Restart Generation Facilities that are not manned continuously, System Management may require a degree of automatic control over the Facility. The required level of control will be determined on a case by case basis and will be formalized between the Service Provider and System Management in a legally binding agreement.

2.5 Dispatch Support Ancillary Service

35. System Management will establish facility requirements for providers of Dispatch Support Ancillary Service on a case-by-case basis. The

requirements will be specified in any applicable Expression of Interest and/or Tender documentation and in any contract established with the Service Provider.

[MR 3.9.9] states that "Dispatch Support Service is any other ancillary service that is needed to maintain Power System Security and Power System Reliability that are not covered by the other Ancillary Service categories. Dispatch Support Service is to include the service of controlling voltage levels in the SWIS, where that service is not already provided under any Arrangement for Access or Network Control Service Contract."

Dispatch support includes the use of out of merit generation, the use of location specific generation in sub-networks, and the use of generation for system voltage support.; in general ancillary services not covered elsewhere.

3 ANCILLARY SERVICES PLANNING AND REPORTING

36. System Management must **[MR 3.11.11]** produce an annual Ancillary Services Report for submission to the IMO. The report must:

    a. Cover all Ancillary Services,

    b. Provide the total quantity of Ancillary Services provided in the preceding year,

    c. Provide an assessment of the adequacy of the Ancillary Services provided in the preceding year,

    d. Detail the costs (with estimates for the remainder of the year if required) of providing each bilaterally procured Ancillary Service,

"Bilaterally procured" ancillary services excludes those services procured through a central market, such as Load Following Ancillary Service, since System Management has no reasonable basis to estimate the cost of such services.

    e. Provide the total estimated quantity required of each Ancillary Service in the coming year,

    f. Provide details of any forecasting methodologies to be used in scheduling Ancillary Services,

    g. State the assumptions and circumstances that were relevant to System Management's determination of quantities,

    h. Provide the total estimated cost of each bilaterally procured Ancillary Service,

    i. Specify how each Ancillary Service is to be procured.

37. The report will cover the financial year commencing on 1 July and finishing on 30 June of the year following.

38. Where System Management is required to amend the Ancillary Services Requirements, this should be carried out as soon as practical and resubmitted to the IMO.

39. In requiring System Management to amend the Ancillary Services Requirements, or any other part of the Ancillary Service Performance

Report, the IMO must recognise and have due regard to commitments already made by System Management through the detailed contract discussions it has had with prospective new Ancillary Service Providers, as well as contracts it may have entered into.

*The requirements that must be followed by the IMO and System Management when auditing the Ancillary Service Requirements are defined in the Market Rules **[MR 3.11.6]**.*

4 DETERMINATION OF ANCILLARY SERVICE REQUIREMENTS

*System Management must determine the Ancillary Service Requirements in order to meet particular standards and requirements in accordance with the Market Rules **[MR 3.11.1].***

40. In its analysis of Ancillary Service Requirements, System Management must have regard to the conditions and situations applying during the year, including:
    a. the commissioning or decommissioning of new facilities;
    b. the performance of facilities that give rise to the need for additional Ancillary Services;
    c. the risk associated with non-availability or non-performance of Ancillary Service sources;
    d. the variability and predictability of demand on the SWIS; and
    e. any other factor System Management reasonably considers necessary.

*Other factors that System Management must have in regard to Ancillary Service Requirements are defined in the Market Rules **[MR 3.11.5]**.*

41. System Management will use the following information in its determination of Ancillary Service Requirements:
    a. Medium Term PASA studies;
    b. Equipment Limits and Security Limit information received by System Management from the IMO or Participants; and
    c. Any other information that System Management considers relevant to the determination.
42. System Management may seek further information from Market Participants and Ancillary Service Providers in order to complete its determination of Ancillary Service Requirements where this information is relevant to the assessment.
43. Participants and Ancillary Service Providers must make every reasonable endeavour to provide this information to System Management in the form requested, and as soon as practical.

4.1 Determination of required quantities for specific Ancillary Services

44. The required quantity of Spinning Reserve will be the minimum Spinning Reserve quantity required to meet the Ancillary Services Standard for Spinning Reserve

> ***[MR 3.10.2.]*** *states that "the standard for Spinning Reserve Service is a level which satisfies the following principles:*
>
> *(a) the level must be sufficient to cover the greater of:*
>
> *i. 70% of the total output, including Parasitic Load, of the generation unit synchronised to the SWIS with the highest total output at that time; and*
>
> *ii. the maximum load ramp expected over a period of 15 minutes;*
>
> *(b) the level must include capacity utilised to meet the Load Following Service standard under clause 3.10.1, so that the capacity provided to meet the Load Following requirement is counted as providing part of the Spinning Reserve requirement;*
>
> *(c) the level may be relaxed by up to 12% by System Management where it expects that the shortfall will be for a period of less than 30 minutes; and*
>
> *(d) the level may be relaxed following activation of Spinning Reserve and may be relaxed by up to 100% if all reserves are exhausted and to maintain reserves would require involuntary load shedding. In such situations the levels must be fully restored as soon as practicable."*

45. System Management will consider System Interruptible Loads (SILs) to contribute to meeting the requirements for all classes of Spinning Reserve.

46. The required quantity of Load Rejection Reserve Ancillary Service will be the minimum Load Rejection Reserve quantity required to meet the Ancillary Services Standard for Load Rejection Reserve.

47. The required quantity of Load Following Ancillary Service will be the minimum Load Following quantity required to meet the Ancillary Services Standard for Load Following Ancillary Service.

4.2 Reassessment of Ancillary Service Requirements

48. During the period over which the Ancillary Service Requirements apply, System Management must monitor the conditions giving rise to its determination.

49. The Market Rules provide for the circumstances in which System Management may reassess the level of Ancillary Service Requirements during the year in accordance with the Market Rules **[MR 3.11.3]**.

50. Where System Management considers that changes to circumstances are significant and in System Management's view may give rise to adverse effects on Power System Security or Power System Reliability, System Management must prepare a report to the IMO setting out the circumstances and making a recommendation to revise the Ancillary Service Requirements.

51. System Management may recommend to the IMO one or more actions to improve the situation described Paragraph 51 of this Procedure, examples of which are:

   a. contracting or arranging additional Ancillary Service;

   b. operating with reduced security levels; and

   c. restricting the actions of a Participant or Participant's Facility that might be giving rise to the increased need for Ancillary Services.

52. System Management must undertake the agreed course of action as soon as practical after it is approved by the IMO.

5 PROCUREMENT OF ANCILLARY SERVICES

53. System Management will procure Ancillary Services in accordance with the approved Ancillary Services Report.

> *"Procurement" refers to all acquisition of paid-for ancillary services, whether by means of contract or through a central market.*

54. System Management will obtain Ancillary Services via bilateral contract where it considers that it:

   a. cannot meet the Ancillary Service Requirements through utilising Verve Energy facilities and currently-contracted facilities; or

   b. can obtain a less expensive alternative to Ancillary Services provided by Verve Energy.

> *Verve Energy is effectively the "provider of last resort" for Spinning Reserve, Load Rejection Reserve and Load Following Ancillary Service, and has obligations under the Market Rules to ensure the Standards for those services can be maintained.*

55. Each year, System Management must consider whether Paragraph 56(b) of this Procedure applies and include its views within the Ancillary Services Report, prepared pursuant to the Market Rules **[MR 3.11.11]**.

56. System Management must give consideration to using a competitive tender process for the procurement, if System Management considers that doing so would minimise the cost of meeting the Ancillary Service Requirements.

57. Where System Management determines to use a competitive tender process, the following phases will apply:

   a. the issuing of an Expression of Interest;

   b. the calling of competitive tenders (if required);

   c. the assessment of tenders according to the criteria in the Market Rules and as published during the procurement process; and

   d. the formalising of the necessary contracts and agreements.

58. System Management may vary or otherwise not proceed with any of the phases of the competitive tender process where System Management considers that adherence to the phases of the competitive tender process

would not seek to minimise the cost of meeting the Ancillary Service Requirements.

5.1 Expression of Interest

59. Where System Management determines to use a competitive tender process, it must first issue a request for an Expression of Interest for the supply of the relevant Ancillary Service.
60. The request must be published by System Management in a form and location that System Management reasonably considers will be seen m\by the maximum number of potential providers of the relevant Ancillary Service.
61. System Management must provide the necessary consultation and assistance where requested by respondents to assess the capability of their facilities to meet the technical specification.
62. System Management must determine from the responses to the request for Expression of Interest whether there is sufficient interest to proceed with a competitive tender. In making this determination, System Management must give due weight to:
    a. the likelihood of the respondents meeting the technical requirements of the Ancillary Services;
    b. the need to minimise the cost of procuring the necessary Ancillary Service Requirements and meet the commercial criteria which the tendered services will be subject to; and
    c. whether sufficient Ancillary Services will be available from Verve Energy and other contracted sources.
63. System Management must complete its evaluation of the responses to the Expression of Interest within a reasonable period of time.
64. System Management will prepare a short-list of parties to be invited to compete in the subsequent competitive tender, based on responses received in the Expression of Interest process.
65. System Management may publish a notice advising of its conclusion on whether to proceed with a competitive tender process following the completion of its evaluations.

5.2 Competitive Tenders

66. If a decision is made to continue with a competitive tender process, System Management must issue a request for tenders at the earliest practical date following the evaluation of responses received in the Expression of Interest process.
67. The request for tenders for the supply of one or more Ancillary Services should be provided by letter and electronic form to parties who have been short-listed during the Expression of Interest process
68. The request for tenders must be accompanied by:

a. a template contract covering the Ancillary Services for which tenders are sought; and

b. a description of the tender assessment criteria.

69. System Management shall establish and review from time to time internal processes governing the competitive tender process.

5.3 Assessment criteria

70. System Management should apply transparent criteria when evaluating a tender for supply of an Ancillary Service. To be acceptable, the minimum requirements of a proposal are that it should meet the technical requirements set out in the standard form Ancillary Service Supply Contract and the requirements specified in the Market Rules **[MR 3.11.8** and **MR 3.11.8A].**

71. The factors listed above are not exclusive, and System Management may take into account any other factor consistent with the objectives of the Market Rules.

72. System Management must document the results of its evaluations, including the reasons for accepting or rejecting each contract proposal.

6 ANCILLARY SERVICES CONTRACTS

6.1 Contracts for the Supply of Ancillary Services

73. System Management must prepare standard form contracts to be used for situations where System Management contracts to purchase Ancillary Services.

74. The contract should set out the following, as a minimum:

a. a technical description of the applicable Ancillary Service;

b. the performance requirements of the Ancillary Service;

c. testing requirements to determine performance and compliance of the service;

d. the facilities from which each service will be provided;

e. the process by which Ancillary Services will be made available;

f. the process by which Ancillary Services will be dispatched;

g. the post-event information both parties must provide;

h. the prices and payment structure;

i. information disclosure;

j. commercial terms and conditions; and

k. a mechanism for resolution of disputes.

6.2 Contracts for the Supply of Spinning Reserve and Load Rejection Reserve Ancillary Services

75. In addition to the requirements in the Market Rules, Ancillary Service Providers other than Verve Energy who wish to provide Spinning Reserve and/or Load Rejection Reserve Ancillary Services must enter into a contract with System Management covering those services. The contract will cover all commercial and technical matters relevant to the supply, and be consistent with Market Rules and this Procedure.

76. The requirements that System Management must follow where an Ancillary Service Contract has been entered into are specified in the Market Rules **[MR 3.11.10].**

6.3 Provision of Ancillary Services without a contract

77. Under a Normal Operating State or a High Risk Operating State all Ancillary Services required by the SWIS will be provided either by the LFAS market, by Verve Energy Facilities as an obligation under the Market Rules, or by other facilities under a separate Ancillary Service contract.

78. Under an Emergency Operating State as defined within the Market Rules **[MR 3.4** and **MR 3.5]** and in the Power System Operation Procedure – Power System Security, System Management may direct a Market Generator to provide Ancillary Services to the extent necessary to return to a High Risk Operating State or Normal Operating State where that facility is physically capable of providing such services, regardless of whether that Facility has an Ancillary Service contract.

6.4 Settlement Data

79. When System Management has entered into an Ancillary Service Contract with a Rule Participant, System Management must as soon as practicable and not less than 20 Business Days prior to the Ancillary Service Contract taking effect, provide the IMO with the information specified in **[MR 3.22.2]**

80. The information to be provided by System Management to the IMO for each Rule Participant holding an Ancillary Service Contract for a Trading Month is specified in **[MR 3.22.2]**, and is to be provided by the date specified in **[MR 9.16.2(a)]**

ELECTRICITY INDUSTRY ACT

ELECTRICITY INDUSTRY (WHOLESALE ELECTRICITY MARKET) REGULATIONS 2004

WHOLESALE ELECTRICITY MARKET RULES

Power System Operation Procedure:

Communications and control systems

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Version	Date	Author	Approver	Commenced	Comment
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RELATIONSHIP WITH MARKET RULES

1. This Procedure has been developed in accordance with, and should be read in conjunction with, the Wholesale Electricity Market Rules (Market Rules).
2. References to particular Market Rules within the Procedure in bold and square brackets **[MR XX]** are current as xxxxxx. These references are included for convenience only, and are not part of this procedure.
3. This Power System Operating Procedure is subservient to the Market Rules. In the event of conflict between this Procedure and the Market Rules or any other document, the order of precedence is as set out in the Market Rules **[MR 1.5.2]**
4. This Power System Operating Procedure may include explanatory text, including quotations from the Market Rules. Such explanatory text is for information only, does not form part of the Procedure, and is italicised and contained in a rectangular box.

RELATED DOCUMENTS

5. This document is related to, and should be read in conjunction with, the following documents:
   a. Power System Operation Procedure – Communications and control
   b. Power System Operation Procedure – Commissioning and testing
   c. Power System Operation Procedure – Power system security

COMMENCEMENT

6. This market procedure has effect from the date of commencement of Rules Change Proposal RC_2011_10.

1 SCOPE

7. The Communications and Control Systems Procedure details System Management's requirements for the Communications and Control Systems needed to support the dispatch process.

8. This Procedure sets out the communications and control systems required to be in place to enable System Management to dispatch:

   a. Scheduled Generators, Non-Scheduled Generators, Dispatchable and Curtailable Loads that are controlled directly by the Market Participant;

   b. Scheduled or Non-Scheduled Generators where System Management, by agreement with the Market Participant, has operational control of that Facility; and

   c. Interruptible Loads whose operation may be triggered by a fall in power system frequency.

9. The Procedure specifies the main features of the speech, data and control systems that need to be in place between the Facility and System Management for the purpose of:

   a. issuing, acknowledging and responding to Dispatch Instructions, Dispatch Orders and directives;

   b. monitoring the MW output and connection status of the Facility; and

   c. enabling prompt response to directions of System Management in the event of a High Risk Operating State or Emergency Operating State.

2 ASSOCIATED PROCEDURES AND STANDARDS

10. The following Power System Operation Procedures are associated with this Communications and Control Systems Procedure:

   a. Power System Operation Procedure - Dispatch

   b. Power System Operation Procedure - Operational Data Points for Generating Plant

3 OPERATIONAL COMMUNICATIONS AND CONTROL SYSTEMS REQUIREMENTS FOR FACILITIES

3.1 Balancing Facilities not excluded from Balancing Facility Requirements

11. All Balancing Facilities not excluded from the Balancing Facility Requirements pursuant to [MR xx.xx] must:

   c. Be able to receive and respond to Dispatch Instructions and Operating Instructions via System Management's market participant interfaces, as published by System Management from time to time;

d. Comply with the Power System Operating Procedure: Operational Data Points for Generating Plant

e. Have backup communications systems in place in accordance with Section x.x

3.2 Balancing Facilities excluded from Balancing Facility Requirements

12. All Balancing Facilities excluded from the Balancing Facility Requirements pursuant to [MR xx.xx] must:

    a. Comply with the Power System Operating Procedure: Operational Data Points for Generating Plant; and

    b. Either have both voice and e-mail communications in place for the receipt of Dispatch Instructions, or have an Operational Control Agreement with System Management

3.3 Facilities providing Load Following Ancillary Service

13. All Facilities providing Load Following Ancillary Service must be connected to System Management's Automatic Generation Control (AGC) system.

3.4 Facilities providing Spinning Reserve

14. All Facilities providing Class A Spinning Reserve as defined in the Power System Operating Procedure: Ancillary Services must be connected to System Management's Automatic Generation Control (AGC) system.

3.5 Demand-side programs

15. A Market Customer who operates a Demand-side program must provide a telephone contact that allows System Management to communicate Dispatch Instructions to the Market Customer.

16. A Market Customer who operates a Demand-side program exceeding 10MW capacity must be able to receive and respond to Dispatch Instructions and Operating Instructions via System Management's market participant interfaces, as published by System Management from time to time.

3.6 Facilities providing Network Control Service, System Restart Service or Dispatch Support Service; Interruptible loads

17. The communications and control system requirements an Interruptible Load, a Facility providing Network Control Service, a Facility providing System Restart Service or a Facility providing Dispatch Support Service shall be in accordance with the contract under which the service is provided.

4 GENERATORS OPERATED BY SYSTEM MANAGEMENT

18. This section applies to Participants with Scheduled or Non-Scheduled Generators remotely operated by System Management under an agreement between the Market Participant and System Management [MR 7.8].

19. Under the agreement referenced in Paragraph 18, System Management may execute a number of Dispatch Instructions or Dispatch Orders relating to that facility through remote control facilities located in System Management's premises.

20. Before an operating agreement for remote operation and control is entered into, the Market Participant must acknowledge that System Management bears no liability or responsibility for failure of the Market Participant's Generation Facility to obey a Dispatch Instruction, or to comply with the Market Participant's Resource Plan.

4.1 Electronic Transmission of Dispatch Instructions and Dispatch Orders through AGC

21. Automatic Generation Control (AGC) refers to equipment operated by System Management, which sends signals to Generating facilities participating in the AGC scheme to automatically adjust their output so as to maintain frequency or restore frequency within the Normal Operating Frequency Band.

22. Scheduled and Non-Scheduled Generators may have their Dispatch Instructions or Dispatch Orders transmitted electronically from System Management to the Generator Facility via System Management's AGC system.

23. A Generation Facility participating in System Management's AGC system will receive from the AGC a Dispatch Instruction or Dispatch Order in the form of an electronic control signal transmitted directly to the generator unit(s) output control or governing system. This signal will set the amount of required increase or decrease in generator output. The generating unit(s) will react to this signal within a timeframe and ramping rate agreed between the Market Participant and System Management.

24. Dispatch Instructions and Dispatch Orders generated by the AGC system will be limited to increase and decrease of generator output .

25. Connection of a Generation Facility to the AGC system will be through mutual agreement between the relevant Market Participant and System Management.

5 LOSS OF COMMUNICATION FACILITIES

26. Where a major loss of communications occurs, the electronic data/control systems and some of the voice communication circuits referred to in section 5 of this Procedure may become unavailable. Market Participants and System Management must then revert to speech communications, including the use of back up speech facilities for the transfer of all Dispatch Instructions, Dispatch Orders and other operational information.

27. Where System Management's Control Centre has been evacuated and dispatch services shift to System Management's emergency control centre, an Emergency Operating State will exist. Contact with System Management will be via a series of emergency telephone numbers.
28. System Management must provide Market Participants with an emergency contact list to be used in these circumstances.
29. Market Participants must provide System Management with an emergency contact list to be used in these circumstances.