

Wholesale Electricity Market Design Summary

24 October 2012

Independent Market Operator

This document provides only a summary of the content of the Wholesale Electricity Market Rules.

No person or organisation should act on the basis of any matter contained in this report without considering the Wholesale Electricity Market Rules. For the Market Rules that are currently in force under the *Electricity Industry (Wholesale Electricity Market) Regulations 2004*, please refer to the Wholesale Electricity Market Rules (and any subsequent amendments) gazetted in the Western Australia Government Gazette.

Note that for the purposes of reading this document defined terms from the Market Rules, the Electricity Industry Act or Regulations have been capitalised. In these instances the definition as provided in the Market Rules, the Electricity Industry Act or the Regulations should be applied when reading this document.

The Independent Market Operator disclaims any responsibility for any liability arising from any act done or omission made in reliance on this report.

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Update History

Version	Date	Comments
1.2	21 September 2006	Market start
1.3	1 July 2012	Updates to reflect the introduction of the Balancing and Load Following Markets
1.4	24 October 2012	Updates to section 4.5 (Reviewable Decisions and Disputes) and Appendix 2

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1. Introduction

A Wholesale Electricity Market (WEM) for the South West Interconnected System of Western Australia (SWIS) commenced operation in September 2006¹. This market facilitates greater competition and private investment and allows generators and wholesale purchasers of electricity (such as retailers) greater flexibility as to how, and with whom, they sell or procure electricity. This market includes mechanisms for:

- Ensuring that adequate generation and demand-side management capacity is available to satisfy the ever-changing demand for electricity;
- Market Participants to adjust their contractual positions through a day-ahead short term energy market (STEM);
- On the day differences between contractual positions and physical outcomes to be traded through a competitive balancing market; and
- The competitive supply of the Load Following Ancillary Service (LFAS).

The objective of this document is to enable readers to gain a high level understanding of the market design and how it operates without having to work through the Market Rules. However, only the Market Rules can provide a complete and definitive description of the market. A copy of the most recent version of the consolidated unofficial Market Rules is available on the following Market Web Site: <http://www.imowa.com.au/market-rules>

This report is structured as follows:

- Section 2 provides an introduction to the basic features of the market to set the context for subsequent sections.
- Section 3 provides a description of the market governance regime.
- Section 4 presents a description of the administration of the market.
- Section 5 describes the various classes of market participation along with Facility registration requirements.
- Section 6 covers power system security and reliability issues, including outage planning.
- Section 7 describes the capacity mechanism.
- Section 8 outlines the procurement of Network Control Services as alternatives to transmission upgrades.

¹ The Reserve Capacity procurement process began in late 2004.

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- Section 9 covers the energy and LFAS markets.
- Section 10 provides a short description of metering issues.
- Section 11 describes the settlement process.
- Appendix 1 provides additional detail on the representation of Intermittent Loads, including how meter data is allocated between the Intermittent Load, any unmetered Non-Dispatchable Load at the same site, and any surplus generation that is registered.
- Appendix 2 provides a summary of the various processes in the market, and indicates who administers and participates in each process.

2. A Brief Overview of the Market

2.1 The Market Entities

The market comprises the following entities.

- The **Independent Market Operator (IMO)** is responsible for the operation and development of the Wholesale Electricity Market (WEM), including administering the rule change process. It also conducts long term (10 year) generation adequacy planning, amongst other things, to support the Reserve Capacity Mechanism.
- **System Management** is the “System Operator”. It conducts short and medium term (up to three years) system planning, including outage planning, and dispatches the power system in accordance with the Market Rules. It also schedules Verve Energy’s generation portfolio.
- A **Network Operator** is a party that operates, or intends to operate, a transmission or distribution network within the SWIS and must be registered². Network Operators can also be Metering Data Agents - the parties that provide meter data to the IMO. Western Power is the default Metering Data Agent if another Network Operator does not fill this function.
- A **Market Generator** is a party that operates a generating Facility that must be registered if it is to provide energy to the market. Subject to some exemptions in the rules, all generating Facilities above 10 MW must be registered. Registration of smaller generating Facilities is optional.
- A **Market Customer** is a retailer or any other party purchasing electricity from the market for the purpose of consumption or retail sale. Synergy is the Market Customer that supplies non-contestable retail customers and is the supplier of last resort to the retail market.
- **Independent Power Producers (IPPs)** are Market Generators other than Verve Energy.
- **Western Power**³ is a Network Operator. System Management is a ring-fenced business unit of Western Power.
- **Synergy** is the former retail business unit of Western Power (prior to disaggregation) and must be registered as a Market Customer. In most cases, the Market Rules apply to Synergy as they would for any other Market Customer. The main exception is that it is the only

² Unless System Management does not require information about the relevant network to maintain power system security and power system reliability and no Market Participant Registered Facilities are directly connected to it.

³ The names “Electricity Network Corporation”, “Electricity Retail Corporation” and “Electricity Generation Corporation” are defined in legislation. The Market Rules use the trading names for these entities which are, respectively, “Western Power”, “Synergy” and “Verve Energy”.

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retailer allowed to serve customers that do not have interval meters, requiring a different treatment of the load of these customers in settlement.

- **Verve Energy** is the former generation business unit of Western Power (prior to disaggregation) and must be registered as a Market Generator.⁴ In most cases, the Market Rules apply to Verve Energy as they would for any other Market Generator. The main exceptions are that:
 - Some of its Facilities (the “Verve Energy Balancing Portfolio”) follow a different scheduling process; and
 - It is required to make its capacity available to System Management to provide Ancillary Services.

All these entities must be registered as Rule Participants. This is automatic for System Management and the IMO. Becoming a Rule Participant requires an entity to comply with the Market Rules. Rule Participants that trade in the Reserve Capacity or energy market are automatically Market Participants. A single Rule Participant may be registered in more than one participant class. Appendix 2 provides more information on the different functions of these and other entities.

2.2 The Trading Mechanisms

The market supports the following trading mechanisms:

- **Reserve Capacity:** The primary role of the Reserve Capacity Mechanism is to ensure that there is adequate generation and Demand Side Management (DSM) capacity available each year to meet peak system requirements including a reserve margin. Each Market Customer is required to contract for “Capacity Credits” to cover their share of capacity procured to cover the total system requirement.

The IMO assigns Capacity Credits to suppliers of registered capacity. If there are insufficient Capacity Credits to meet requirements, the IMO will run an auction to procure more so as to cover the remaining requirements of Market Customers. Suppliers issued with Capacity Credits are, amongst other requirements, obliged to make that capacity available to the market and to participate in centralised outage planning. Market Customers who do not procure sufficient Capacity Credits bilaterally are required to fund capacity procured by the IMO. If an over-capacity situation arises, then the cost of the excess capacity is shared across all Market Customers, irrespective of whether they hold bilaterally traded Capacity Credits or not.⁵

⁴ Verve Energy has been given ministerial approval to act as the Market Participant for a number of small loads. Consequently it is also registered as a Market Customer but only to the extent required to serve these specific small loads.

⁵ A number of special cases exist whereby a Facility may obtain Capacity Credits through a different process, or can have its capacity offset against the capacity requirements of a Market Customer without actually holding Capacity Credits (see sections 7.10, 7.11 and 7.12).

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- **Bilateral Contracts:** Bilateral trades of energy and capacity occur between Market Participants and the IMO has no interest in how these trades are formed. However, Market Participants are required to submit bilateral schedule data pertaining to bilateral energy transactions to the IMO each day so that the transactions can be scheduled.
- **The Short Term Energy Market (STEM):** The STEM is a daily forward market for energy that allows Market Participants to trade around their bilateral energy position, producing a Net Contract Position.

Each “Scheduling Day”, the IMO collects half hour bilateral schedule data from each Market Generators describing bilateral energy trades between them and Market Customers for each “Trading Interval” of the following “Trading Day⁶”. The IMO calculates each Market Participant’s net bilateral position for each Trading Interval from this data. Each Scheduling Day, Market Participants also provide the IMO with supply and demand curves for each Trading Interval of the Trading Day. The IMO uses these supply and demand curves to determine STEM Offers and STEM Bids for each participant relative to its net bilateral position for each Trading Interval. A STEM Offer is an offer to increase the net supply of energy beyond the net bilateral position, while a STEM Bid is a bid to decrease the net supply of energy relative to that position. A STEM auction is run for each Trading Interval of the next Trading Day, determining a STEM clearing price and clearing quantities. The combined net bilateral position and STEM position of a Market Participant describes its Net Contract Position.

- **Dispatch/Balancing Process:** Market Participants (other than Verve Energy in respect of its portfolio) with registered generating or Dispatchable Load Facilities are required to provide Resource Plans for each of their Facilities to the IMO. Resource Plans specify the expected output of each Facility in each Trading Interval, including any self-supplied load.

Market Generators must also make Balancing Submissions for each Trading Interval, specifying prices at which their Facilities may be dispatched and by how much. From these submissions, the IMO compiles the Balancing Merit Order (BMO) and prepares market forecasts for participants to review and, subject to certain limits, update their Balancing Submission. IPPs schedule their Facilities, and System Management schedules Verve Energy’s portfolio, in response to market forecasts.

Leading into each Trading Interval, System Management uses the most recent BMO to determine and issue dispatch instructions to generators to meet the expected demand trend during the interval. System Management may only depart from the BMO if that is necessary to maintain system security and reliability criteria and in this regard may ultimately issue Dispatch Instructions to Demand Side Programmes or Dispatchable Loads if necessary. For that purpose, the IMO provides to System Management a Non-Balancing Dispatch Merit

⁶ The Trading Interval is a half hour. Each Trading Day comprises the 48 Trading Intervals from 8:00 AM. The Scheduling Day is the 24 hour period before each Trading Day.

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Order for Demand Side Programme and Dispatchable Load Facilities prepared from relevant participants' standing data.

After the Trading Day, the IMO determines from the final BMO and actual generation requirements a balancing price for each Trading Interval. Generators receive (pay) this Balancing Price for any quantity above (below) their NCP and Market Customers pay (receive) this Balancing Price for any quantity above (below) their NCP. Generators dispatched out of merit are eligible for constrained on or off compensation. If a Facility in the Non-Balancing Dispatch Merit Order was dispatched by System Management, it receives (pays) its standing data price (pay-as-bid) for deviations below (above) the relevant Resource Plan level.

2.3 Ancillary Services

Ancillary Services are essential for maintaining security and reliability of supply, thereby supporting the energy market. For example, they regulate voltage and frequency quality and respond to contingency events on the power system. System Management is required to procure adequate quantities of Ancillary Services and proposes requirements for each Ancillary Service for IMO approval.

System Management procures Ancillary Services either from Verve Energy (the default provider) or on a contestable basis from independent providers. In the latter respect, the WEM includes a contestable Load Following Ancillary Service (LFAS) market. LFAS compensates for differences between expected (as dispatched) and actual requirements during each Trading Interval.

2.4 Network Control Service

A Network Control Service could be thought of as an Ancillary Service, but is treated separately under the Market Rules. A Network Control Service is a service provided under contract to a Network Operator by generation or Demand Side Management that can be a substitute for transmission or distribution network upgrades. The Network Operator must advise the IMO of any Network Control Service Contracts (NCSC) and provide System Management with details it needs for dispatch purposes.

2.5 Prudential Obligations

Market Participants must meet prudential conditions for participating in the market. A Market Participant must maintain credit support to cover the IMO's estimate of the maximum amount that the participant is likely to owe the IMO during any 70 day period within 48 months, allowing for expected levels of Bilateral Contract coverage.

If at any time a Market Participant has inadequate credit support a Margin Call will be made by the IMO, and the participant will be required to provide further credit support within 1 Business Day, potentially in the form of a cash deposit. Failure to do so may result in the Market Participant being declared to be in default. Although the IMO has the power under the Market Rules to impose extremely firm measures, this does not preclude it from informally notifying a party of problems

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much earlier than required by the Market Rules so as to avoid a Margin Call being required. Use of this approach minimises the risk of having to declare a party to be in default.

2.6 Classes of Facilities

The following classes of Facilities can be registered in the market:

- A **Scheduled Generator** is a generator that can be scheduled to operate at a specified level ahead of real-time, and can be dispatched by System Management in real-time to a specified level. Most large generating plant falls into this category.
- A **Dispatchable Load** is a load that can be scheduled to operate at a specified level ahead of real-time, and can be dispatched by System Management up or down relative to that level.
- A **Non-Scheduled Generator** is generator that is either unable to be scheduled to operate at a specified level ahead of real-time, such as a wind farm or solar generator, or is sufficiently small to not generally require central coordination by System Management. These generators are generally self-dispatched by their operator but System Management can request them to reduce output in accordance with the BMO (or otherwise if necessary to ensure that system security requirements can be met).
- An **Interruptible Load** is a load that trips automatically in response to a frequency change. An Ancillary Service Contract will generally fund this Demand Side Management option. Being triggered automatically and typically for short periods, there are no pay-as-bid prices associated with Interruptible Loads. They are paid in accordance with Ancillary Service contracts with System Management.
- A **Demand Side Programme** comprises of associated load(s) that are interruptible or non-dispatchable which can be curtailed on request by a Market Customer⁷. A Demand Side Programme can be used by a Market Participant to manage its exposure to market prices. If System Management requires the curtailment of such load in the dispatch process, a pay-as-bid price applies to the amount of load curtailed. However, Capacity Credit payments are likely to be the primary form of compensation.

Meter data and other details are recorded for the following types of load, but these are not treated as “Facilities” under the Market Rules:

- A **Non-Dispatchable Load** is load that is not a Dispatchable Load or an Interruptible Load. A large proportion of all SWIS load falls into this category.
- An **Intermittent Load** is a load that is normally fully supplied by a generator at the same site as the load without requiring any electricity to be supplied from a Network registered with

⁷ Note that a Demand Side Programme can not have a Interruptible Load already assigned Capacity Credits for the same period associated with it. Likewise an Intermittent Load can not be associated with a Demand Side Programme.

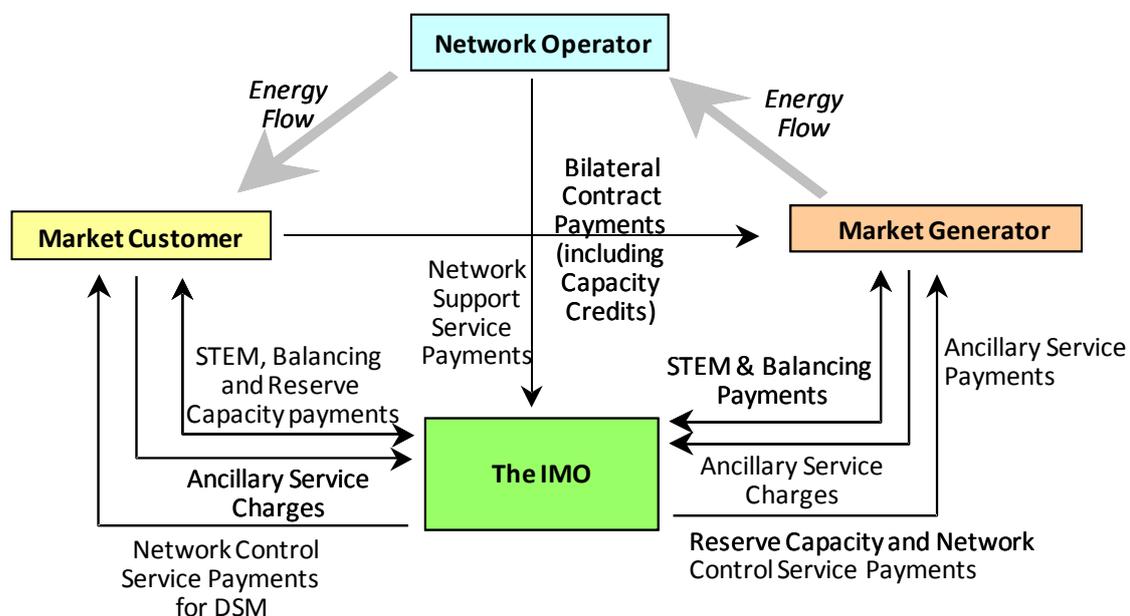
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the IMO. In effect, it is load normally served by embedded generation. An Intermittent Load only requires electricity from the network when its embedded generator is not fully operational, and consequently its exposure to funding Reserve Capacity is reduced. A Interruptible Load or Non-Dispatchable Load can simultaneously be an Intermittent Load if it satisfies the required registration conditions. Under special circumstances the generator serving an Intermittent Load can be at a different location (see section 7.10)

2.7 Market Settlement

The IMO is the party with which Market Participants settle WEM transactions other than the bilateral trade of energy and capacity, with Market Participants buying energy or capacity from, or selling energy or capacity to, the IMO. The IMO is responsible for performing settlement calculations and for invoicing and settling with Rule Participants. Exhibit 2-1 provides a simplified view of the major settlement cash flows.

Exhibit 2-1: An illustration of the settlement cash flows



Most energy is traded outside the IMO administered market via Bilateral Contracts between Market Customers and Market Generators. These Bilateral Contracts can have energy and capacity components. By trading energy bilaterally, Market Customers and Market Generators can reduce their exposure to the IMO administered energy market settlement processes. Where capacity is traded bilaterally the IMO reduces the market capacity charges for the relevant Market Customer and reduces the market capacity payments to the associated Market Generator.

Market Customers and Market Generators can modify their bilateral energy position through trading in the day ahead STEM, forming a Net Contract Position (NCP). Differences between actual net energy supplied or consumed and NCP quantities are bought and sold in the Balancing Market.

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While System Management is required to procure Ancillary Services the costs of these services are passed on to those participating in the market.

Settlement of the STEM occurs on a weekly basis⁸, while other transactions are settled monthly. It may take up to 30 days after the end of a month to receive all interval meter data for a month, so settlement for a Trading Day at the start of a month will not occur until about 70 days after that Trading Day. Settlement adjustments will be made up to 9 months after the initial settlement statement, allowing for resolutions of disagreements and improved meter data.

Where there is a default in payment to the IMO and credit support is inadequate to cover it, the IMO may temporarily reduce payments in market settlement to reflect the shortfall. If the amount is not resolved quickly then the outstanding amount will be recovered by a default levy. Default is expected to be a very rare event.

⁸ This is possible because STEM settlements do not rely on metered data (which is not available in this timeframe).

3. Market Governance

3.1 The Market Objectives

Changes to the Market Rules must be consistent with, and any policy directions given by the Minister must not be inconsistent with, the following Market Objectives:

- a) To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;
- b) To encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;
- c) To avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;
- d) To minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and
- e) To encourage the taking of measures to manage the amount of electricity used and when it is used.

3.2 The IMO

The IMO has the following functions:

- Maintaining and developing the Market Rules.
- Maintaining and developing Market Procedures relating to market operation and market administration.
- Approving Power System Operation Procedures (PSOPs) developed by System Management.
- Processing applications for participation, and for the registration, de-registration and transfer of facilities.
- Assessing generation and DSM capacity adequacy over the long term.
- Operating the Reserve Capacity Mechanism.
- Collecting Standing Data which Market Participants are required to submit and providing this data to System Management.
- Collecting Bilateral Contract submissions.

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- Operating the Short Term Energy Market (STEM).
- Collecting pay-as-bid balancing price data from Market Participants that are required to submit these, forming Non-Balancing Dispatch Merit Orders based on these and forwarding them to System Management.
- Collecting Resource Plans from Market Participants that are required to submit these and forwarding them to System Management.
- Collecting Balancing Submissions from Market Participants that are required to submit and revise these, compiling Balancing Merit Orders (BMOs) based on these, preparing and publishing Balancing Forecasts, and forwarding BMOs to System Management.
- Collecting LFAS Submissions from Market Participants that are eligible to submit and revise these, compiling LFAS Merit Orders based on these, preparing and publishing LFAS Forecasts, and forwarding LFAS Merit Orders to System Management.
- Conducting market settlement.
- Monitoring Rule Participants for compliance with the Market Rules, imposing penalties for Market Rule breaches categorised as less serious, and reporting more serious breaches to the Electricity Review Board.
- Commissioning audits of the IMO's and System Management's activities under the Market Rules. This relates especially to System Management's performance of the dispatch and security and reliability related processes.
- Reviewing and potentially reassessing certain decisions by System Management.
- Supporting the Economic Regulation Authority in its roles of market surveillance and monitoring market effectiveness.
- Publishing market information.

The IMO Board consists of three independent persons who are appointed by, and report to, the Minister for Energy. The Minister has the power to give policy directions to the IMO in respect of the operation of the market. Such directions would not impact on the day-to-day operations of the IMO, but would be taken into account by the IMO in its consideration of whether changes to the Market Rules were necessary. Any directions given by the Minister are required to be transparent and to be consistent with the Market Objectives.

3.3 System Management

System Management is a ring-fenced entity within Western Power, and has the following functions:

- Operating the power system to maintain security and reliability.

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- Developing and maintaining PSOPs.
- Setting requirements for and planning emergency load reduction and system restart.
- Determining Ancillary Service Requirements and procuring sufficient Ancillary Services to meet these requirements.
- Assessing system adequacy and security over short and medium term time frames.
- Coordinating planned outages for maintenance.
- Coordinating and, where applicable, conducting tests of equipment (Commissioning Tests and Reserve Capacity Tests).
- Scheduling Facilities within the Verve Energy portfolio.
- Issuing Dispatch Instructions to Market Generators⁹ and demand side resources.
- Activating LFAS providers (placing them under AGC control) in accordance with LFAS Merit Orders.
- Monitoring Rule Participants for rule breaches relating to dispatch and power system security and reliability, and reporting its findings to the IMO.
- Providing information on power system security and reliability to the IMO.
- Providing data required for settlement to the IMO.

The Market Rules are the primary mechanism setting out the obligations of System Management. While Technical Codes, developed under the Access Regime, place limits on how the power system should be operated, the Market Rules set out System Management's specific obligations.

3.4 The Market Advisory Committee

The Market Advisory Committee is an industry group made up of industry representatives and convened by the IMO. It has the function of advising the IMO and System Management on issues pertaining to proposed Market Rule and Market Procedure changes and general market operation issues. The Market Advisory Committee consists of approximately 14-15 members appointed by the IMO from nominated representatives of Market Generators (including Verve Energy), Market Customers (including Synergy), Network Operators and consumers plus a member nominated by the Minister to represent small consumers. The Minister and the Economic Regulation Authority may both appoint representatives to attend meetings of the Market Advisory Committee as observers.

⁹ Instructions to Facilities within the Verve Energy Portfolio are 'Dispatch Orders' under the Market Rules. Dispatch Orders reflect scheduling of portfolio resources by System Management on verve Energy's behalf and the overall portfolio being dispatched in accordance with the Balancing Merit Order relative to other Facilities.

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Where an issue to be addressed by the Market Advisory Committee is highly technical or specialised, the Market Advisory Committee may decide to form a working group of industry representatives to investigate and report back on the issue.

3.5 The Electricity Review Board

The Electricity Review Board is the primary appeals body, having the functions of:

- Imposing penalties for more serious categories of breaches of the Market Rules.
- Hearing appeals against IMO's decisions pertaining to rule breaches.
- Hearing claims from Rule Participants that the IMO has breached the Market Rules.
- Hearing appeals against Reviewable Decisions.
- At the behest of a Rule Participant, conducting a Procedural Review as to whether the IMO or System Management has correctly followed the rules pertaining to rule changes and procedure changes, and where appropriate over-turning rule change and procedure change decisions by the IMO if the IMO or System Management has failed to follow the outlined process.

3.6 The Economic Regulation Authority

The Market Rules also specify certain roles for the Economic Regulation Authority, which include:

- Approving that the correct processes have been followed by the IMO in determining the Maximum Reserve Capacity Price, Margin Values and Maximum STEM Price and Alternative Maximum STEM Prices.
- Approving efficient costs for the operation of the IMO and System Management.
- Market surveillance, including in relation to market power. These activities are undertaken in conjunction with the IMO.
- Monitoring and reporting to the Minister on the efficiency and effectiveness of the market, including the effectiveness of the IMO and System Management. Although Verve Energy is expected to be the primary focus of market power monitoring it is possible for other participants to have market power at particular times (e.g. high demand) or under particular network conditions (e.g. within a constrained region).

4. Market Administration

4.1 Market Rules

The IMO and Conflicts of Interest

The IMO maintains and develops the Market Rules. The IMO is an independent body charged with achieving the Market Objectives including through modification of the Market Rules. However, it is recognised that in some areas there are potential conflicts of interest in the IMO having administrative control of the rules that also govern its own practices and behaviour. The Market Rules include a number of features to address these issues.

Any rules that relate to issues where the IMO would face a possible conflict of interest were it to attempt to modify the Market Rules have been identified as “Protected Provisions”. The IMO is not able to change those provisions without the Minister’s approval of the amendment.

Any decision made by the IMO to amend a Market Rule can be appealed to the Electricity Review Board on procedural grounds. The Electricity Review Board is only able to overturn a rule change if the IMO has not followed the correct rule change process.

The IMO has an independent Board to which the Minister is able to issue policy directions concerning the broad development of the market. The Minister is not able to directly influence the operation of the market and policy directions must not be inconsistent with the Market Objectives. Where the Minister provides a direction, the IMO must develop one or more Rule Change Proposals for consultation with industry.

The Rule Change Process

There are no limits as to who can propose a rule change. Such proposals will need to be made to the IMO in a prescribed form, along with reasons as to why the proponent thinks the rule change is desirable.

Upon receiving a rule change proposal, the IMO must decide whether it considers that the proposed change warrants further investigation. The IMO must assess requests for rule changes against the Market Objectives and practical considerations. The only appeal option is to the Electricity Review Board, and then only in the case of process breaches by the IMO. That is, it is not possible to dispute the merit of the rule change. This restriction is necessary to stop so called “forum shopping” whereby parties repeatedly take the same issue to different forums.

A rule change may include an explicit wording change to the rules, or could be a more general identification of an issue with a general proposal as to how it could be addressed. In processing a Rule Change Proposal, the IMO develops amendments to the Market Rules to implement the proposed changes and consults with Rule Participants on the need and form of the rule amendment.

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There is a fast track rule change process for urgent rule changes or rule changes to correct manifest errors or to address minor issues. Under the fast track process the IMO undertakes a single round of consultation, and this process takes around 5 weeks at most. In an extreme circumstance the fast track process could be completed in as little as a 5 Business Days

The normal rule change process includes two rounds of formal consultation, with the second round allowing consultation on a draft report published by the IMO prior to the finalisation of the report, and will usually take around 19 weeks. In consulting on a Rule Change Proposal, the IMO may convene the Market Advisory Committee (and in certain situations must convene it), meet with interested parties, procure technical advisers, or establish a technical working group drawing on industry representatives if this is considered necessary to appropriately develop or evaluate changes.

The IMO Board makes a final decision on a rule amendment and if the rule change relates to a Protected Provision will seek the Minister's approval. The decision of the Minister is not subject to appeal. The IMO's decision and its reasons are published on the market website, together with a time and date when accepted rule changes will come into force.

4.2 Market Procedures

The IMO develops and changes Market Procedures that relate to market operation and administrative market matters, while System Management develops Power System Operation Procedures (PSOPs) pertaining to areas of the market such as short and medium system planning, security and reliability, and dispatch. However, the IMO is responsible for approving all new, replacement and amended Market Procedures.

Market Procedures tend to have more procedural detail than the Market Rules and undergo more frequent refinements and updates.

Any Rule Participant may notify the IMO or System Management that it considers a procedure change may be appropriate. Where the IMO or System Management determines to not progress a proposed change to a Market Procedure or PSOP then reasons for the decision must be published. Both the IMO and System Management are subject to the same process for developing new procedures or making changes to existing procedures. Once either the IMO or System Management proposes a change, the IMO publishes a Procedure Change Proposal, requests submissions from the public, and may convene the Market Advisory Committee. The issues addressed in the Market Procedures can be quite technical and specialised, so the Market Advisory Committee may decide to nominate a Working Group to consider an issue or suggestion. There are standing Working Groups for considering IMO Market Procedure changes (IMO Procedure Change and Development Working Group) and considering System Management PSOPs (System Management Procedure Change and Development Working Group). Where the change relates to the IMO's Market Procedures, the IMO prepares a report on the Procedure Change Proposal which includes the amended wording, feedback received on the change, together with a time and date for the new Market Procedure to come into force. Where the change relates to System Management's procedures, System Management prepares the report and submits this to the IMO for approval of the new, replacement or amended Market Procedure.

4.3 Market Parameters

The market makes use of a number of parameters, the values of which may materially change the cost and benefits of participating in the market for some Market Participants.

The IMO sets and maintains the following price caps based on principles established in the Market Rules:

- The Maximum Reserve Capacity Price.
- The Maximum STEM Price, which applies to STEM Submissions and, subject to the Facility's loss factor, Balancing Submissions for non-liquid fuelled capacity.
- The Alternative Maximum STEM Price, which exceeds the Maximum STEM Price, applying to STEM Submissions and, subject to the Facility's loss factor, Balancing Submissions for liquid fuelled capacity.

Note that the Minimum STEM Price is set at negative \$1,000 per MWh under the Market Rules.

As well as defining the limits that participants can bid and offer, these prices define the most extreme STEM and Balancing Market clearing prices that can occur. For further detail on the most up to date market price limits refer to the IMO website.

The IMO reviews all the price caps annually and, if, after consultation with the industry and submits proposed new values to the Economic Regulation Authority for approval. The Economic Regulation Authority's approval of these limits is based on whether or not the IMO has set values in a manner consistent with requirements specified in the Market Rules. Note that in addition to this annual review, the Alternative Maximum STEM Price is updated monthly based on changes in oil.

Network Operators are required by the Market Rules to determine for each connection point in their network annual static Loss Factors reflecting average marginal losses. The IMO may audit this calculation process if a participant believes that a Loss Factor is incorrect.

4.4 Enforcement of the Market Rules

The IMO monitors the compliance of Rule Participants with the Market Rules and Market Procedures. System Management monitoring obligations are outlined in the Market Rules and include the performance of Market Participants and Network Operators in the dispatch process and in relation to short and medium term system security and reliability, and reports outcomes to the IMO. System Management is also required to report any other breaches of the Market Rules and Market Procedures of which it is aware. Rule Participants are also able to report alleged rule breaches by System Management and other Rule Participants (excluding the IMO) to the IMO, and alleged rule breaches by the IMO to the Electricity Review Board. The latter will be done through an independent person nominated by the Minister.

When the IMO becomes aware of a rule breach by a Rule Participant, it must log the breach, warn the relevant Rule Participant that it appears to be breaching the Market Rules or Market Procedures, and investigate whether a breach has occurred. Following the investigation, the IMO may then consider whether any enforcement action should be undertaken, which may include issuing a civil penalty or making an application to the Electricity Review Board for an order.

The classes of civil penalties under the Regulations for breaches of the Market Rules are:

- Category A for less serious offences, such as failure to provide information when required to provide that information.
- Categories B and C for more serious rule breaches, such as those involving system security or payments.

For Category A breaches, the IMO will decide whether to impose any penalty but any decision can be appealed to the Electricity Review Board. The IMO will investigate and report Category B and C breaches to the Electricity Review Board. The Electricity Review Board will then decide whether a rule breach has occurred and whether to impose any penalty. Any such decision can only be appealed to the Courts on questions of law. Any penalties for breach of the Market Rules are subject to maximum values set in the Regulations.

4.5 Reviewable Decisions and Disputes

In the Market Rules some decisions of the IMO and System Management are designated as Reviewable Decisions. The Reviewable Decision process applies to certain areas in the Market Rules where the IMO and System Management have some discretion in decisions that have a significant effect on Rule Participants. Some of these decisions are subject to a merits review, others – to a procedural review. If a Rule Participant wants to appeal a Reviewable Decision, it can apply to the Electricity Review Board to have the decision reviewed. Any determination reached by the Electricity Review Board will not be subject to appeal, except to the Courts on questions of law.

The dispute resolution process covers disputes between Rule Participants, but does not apply to Reviewable Decisions under the Market Rules. The dispute resolution process sets out two stages to be followed. Under the first stage the Rule Participants attempt to resolve disputes between themselves. A Rule Participant may send a dispute notice to another Rule Participant (which may include the IMO or System Management), and the parties to the dispute must make reasonable endeavours to meet on one or more occasions, as necessary. If they fail to resolve a dispute between themselves within a period agreed by all the parties, or 60 days if there was no agreed timeframe, then the dispute must move to the second stage and the parties to the dispute must give consideration to using independent mediation and/or arbitration to resolve the dispute. Finally the parties may resort to litigation or other court processes.

4.6 Budgets and Fees

The Economic Regulation Authority periodically determines the respective efficient operational costs (Allowable Revenues) of the IMO and System Management. These efficient costs effectively represent a long run view of what it will cost to run the IMO and System Management. Every year the IMO submits a budget to the Minister, which must be consistent with the Allowable Revenue set by the Economic Regulation Authority. System Management's budget, which must also be consistent with the Allowable Revenue set by the Economic Regulation Authority, is developed through a budgeting process with ministerial oversight. In particular, System Management's approved budget is based on Western Power budget as approved by the Minister in accordance with the process outlined in the Electricity Corporations Act 2005. The IMO provides advice to the Minister on whether System Management's approved budget is consistent with the Allowable Revenue determined by the Economic Regulation Authority.

The IMO recovers its budgeted costs, System Management's costs and that portion of the Economic Regulation Authority's budget relating to its Wholesale Electricity Market activities through a per MWh fees applied to generation and consumption in the SWIS.

5. Rule Participation

5.1 Rule Participant Classes

Anyone subject to the Market Rules is a Rule Participant. Since different rules relate to different types of participants, a number of Rule Participant classes are defined, as shown in Exhibit 5-1. A Rule Participant can belong to more than one class, except where this is explicitly restricted.

Exhibit 5-1: Rule Participant classes

Person	Registration Requirements.
Owns, controls or operates a Transmission or Distribution Network in or connected to the SWIS.	<p>Must register as a Network Operator, except in the following situations (in which case registration is optional):</p> <ul style="list-style-type: none"> • The person is exempted because System Management does not require information about the Facility, or • No Market Participant Facilities are connected to it, or • The IMO has exempted the person from the requirement to register. <p>A person who intends to own, control or operate a network may also register.</p>
Owns, controls or operates a generating Facility with a rated capacity of greater than 10 MW that is connected to a network in the SWIS.	<p>Must register as a Market Generator unless the IMO has exempted the person from the requirement to register (in which case registration is optional).</p> <p>A person who intends to own, control or operate such a generator may also register.</p>
Owns, controls or operates a generating Facility, with a rated capacity of less than or equal to 10 MW, but greater than 0.005 MW, which is connected to a network in the SWIS.	<p>The person has the option to register as a Market Generator but this is not compulsory.¹⁰</p> <p>A person who intends to own, control or operate such a generator may also register.</p>
Sells or intends to sell electricity to customers in the SWIS.	<p>Must register as a Market Customer if selling to Contestable Customers unless the IMO has exempted the person from the requirement to register (in which case registration is optional).</p> <p>A person who intends to sell electricity to consumers may also register.</p>

¹⁰ If such a person also has a generating Facility with capacity over 10 MW then registration is compulsory.

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Person	Registration Requirements.
Intends to enter into an Ancillary Service Contract with System Management.	Must register as an Ancillary Service Provider if not registered in any other Participant Class. May not register as an Ancillary Service Provider if already registered in another Participant Class.
Any other person who sells or purchases electricity or another service contemplated by the Market Rules to or from the IMO.	Must register as either a Market Generator or Market Customer , as determined by the IMO, unless the IMO has exempted the person from the requirement to register (in which case registration is optional).
System Management	Automatically registered as System Management.
IMO	Automatically registered as the IMO.

The Market Rules place the obligation to register on owners, operators and controllers of Facilities. If more than one person is involved, and if those people reach an agreement as to which of them will accept the obligations under the Market Rules, then the intention is that the IMO can exempt the others from being Rule Participants under its exemption powers noted in Exhibit 5-1.

A Rule Participant must also:

- Be resident in, or have a permanent establishment, in Australia.
- Not be an externally administered body corporate, or under a similar form of administration under any laws applicable to it in any jurisdiction.
- Not be immune from suit in respect of the obligations of the Rule Participant under these Market Rules.
- Be capable of being sued in its own name in a court in Australia.

A Rule Participant that participates in any aspect of the Reserve Capacity Mechanism, bilateral energy trade, the STEM, or the Dispatch/Balancing process is referred to as a Market Participant. A party that is both a Market Generator and a Market Customer is a single Market Participant.

With the exception of the IMO and System Management, it is necessary for parties wanting to become Rule Participants to apply to the IMO. In applying for Rule Participant status, a party must accept the obligation to comply with the relevant Market Rules.

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5.2 Facility Registration and Deregistration

The classes of Facilities that can be registered are shown in Exhibit 5-2. All of these Facilities must be connected to the SWIS. Facility registration will not be permitted if the applicant has not already been approved as a Rule Participant.

Exhibit 5-2: Classes of Facility that can be registered

Facility Class	Definition	Restrictions
Network	A transmission or distribution asset.	Cannot be any other type of Facility.
Scheduled Generator	A generator that can meaningfully have its energy scheduled prior to real-time and controlled in real time relative to the scheduled level.	Must be registered if above 10 MW. Smaller generators above 0.2 MW may also register. Cannot be an intermittent generator. Cannot be registered in any other class of Facility.
Non-Scheduled Generator	A generator that cannot meaningfully have its energy scheduled prior to real-time.	Must be below 10 MW or have intermittent output (e.g. wind generator). Must be above 0.005 MW in capacity. Cannot be registered in any other class of Facility.
Dispatchable Load	A load that can meaningfully have its energy scheduled prior to real-time.	Must be above 0.2 MW in capacity. Cannot be registered in any other class of Facility.
Interruptible Load	A load, which while generally non-dispatchable, can be interrupted automatically under certain conditions.	Cannot be registered in any other class of Facility.
Demand Side Programme	A load(s) controlled by request from a Market Customer which while generally non-dispatchable, which System Management may curtail on request under certain conditions with respect to system security.	Cannot be registered in any other class of Facility.

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Non-Dispatchable Load is not required to be registered¹¹, though Market Customers serving non-Dispatchable Load will need to register the locations at which they have load.

An Interruptible Load can simultaneously be an Intermittent Load. An Intermittent Load is normally fully supplied by a generator at the same site as the load without requiring any electricity to be supplied from a Network registered with the IMO. In effect, it is load normally served by embedded generation. An Intermittent Load only requires electricity from the network when its embedded generator is not fully operational, and consequently its exposure to funding Reserve Capacity is reduced. Under special circumstances the generator serving an Intermittent Load can be at a different location (see section 7.10).

A specific Facility, as registered in the market, will not necessarily correspond to a single physical generating unit. For example, a wind farm must be treated as a single Facility, while a group of scheduled generating units at one location may be treated as a single Facility. Market Participants may, at the time of registering a Facility, and with the IMO's approval, aggregate Facilities. The IMO would consult with System Management before approving aggregation of Facilities.

When considering an application for an aggregated or disaggregated Facility, the IMO will consider factors such as control and monitoring equipment, metering of separate components, outage scheduling requirements and any effects on power system reliability and security. For instance, the IMO might not allow two generating units at one location from aggregating because it needs one of those units to be explicitly schedulable for an Ancillary Service. Any registered aggregate Facility will trade based on the net metered position of the aggregated Facility, not on the separate generation and consumption of its components. For the purposes of allocating Spinning Reserve costs aggregated facilities will be treated at the individual facility level.

The registration process for a Facility involves providing information on the Facility such that the IMO can determine whether the Facility satisfies the criteria for being registered, and so that the IMO and System Management can adjust their databases to accommodate the Facility. The registration information is used for the purposes of trading and operating in the WEM by the IMO: and for dispatch purposes by System Management.

A deregistration process exists where deregistration could mean the Facility is closing or being transferred to another Rule Participant. A Facility cannot be deregistered while providing Capacity Credits to the market though the Facility, complete with its Capacity Credits, can be transferred to another Rule Participant.

5.3 Prudential Requirements

Market Participants are subject to prudential requirements as a fundamental requirement for participation in the market.

There are two parameters associated with each Market Participant:

¹¹ Though in certain special circumstances they need to be recorded within the market systems, e.g. when associated with an Intermittent Load (see section 7.10).

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- **Credit Limit:** This limit is the maximum net amount that the Market Participant is likely to owe the IMO within the maximum two month period between being scheduled and being settled in the market, where this amount is not expected to be exceeded more than once in a 48 month period.
- **Credit Support:** This is a guarantee of unconditional payment of a set level of funds to the IMO where the Guarantor of this payment cannot be a Rule Participant and must have a satisfactory credit rating.

Market Participants must generally¹² provide Credit Support to cover their own Credit Limit. The level of risk exposure for the IMO is a function of how much energy is traded by a Market Participant.

A Market Participant's Trading Limit is a prudential factor multiplied by its Credit Limit. The prudential factor is 0.87, which has been calculated by taking a ratio of the number of days before a margin call is issued to the maximum number of subsequent days before a participant would be suspended for non-payment. If the prudential factor were to equal one, then a margin call could only be made once a Market Participant's debt to the IMO reached its Credit Limit, after which the debt could continue to increase until the participant was suspended a number of days later.

If a Market Participant is getting close to its Trading Limit they may voluntarily pay a security deposit to the IMO as a guarantee against future payments. Thus, at any time, the outstanding amount that a Market Participant owes the IMO is the greater of:

- Zero; and
- The total net amount owed to the IMO by that Market Participant at that time less any security deposit, including amounts for which no settlement statement has yet been provided and which therefore could be an estimate.

The amount by which a Market Participant's trading limit exceeds the outstanding amount is the trading margin. If the trading margin drops to zero or below, then the IMO may issue a margin call notice to the Market Participant. The Market Participant must respond within one business day of the margin call notice being issued to either increase its security deposit or provide more credit support so that the trading margin returns to a positive value (i.e. the outstanding amount ceases to exceed the trading limit).

If need be, the IMO can draw down on a Market Participant's credit support to settle a transaction entered into by that Market Participant.

In the event of actual settlement default, the IMO can claim a Market Participant's credit support to the extent required to cover the amount outstanding. If the Suspension Event is not remedied within

¹² Independent bodies subject to prudential supervision or central borrowing authorities of states or territories and with excellent credit ratings are allowed to be providers of financial guarantees, which can count as a Market Participant's Credit Support. If a Market Participant conforms to the requirements to be a provider of Credit Support then it is exempt from the need to provide Credit Support.

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the time specified in the Cure Notice issued by the IMO then the IMO may issue a Suspension Notice, which may include conditions which limit the Participants participation in the market (e.g. they may be allowed to continue activities such as the supply of energy which offsets their debts). If a Market Participant defaults on payment, such that the IMO has inadequate revenue to settle the market, then the IMO will raise a default levy from all Market Participants in accordance with the settlement rules so as to secure the funds required to complete settlement.

6. Power System Security and Reliability

6.1 Operating States and System Management Powers

System Management has the role of ensuring the maintenance of system security and reliability within the SWIS over the short and medium term. To achieve this, System Management must operate the power system within a technical envelope that accounts for the operating and Ancillary Services standards in the Market Rules, PSOPs and relevant technical codes.

The powers of System Management in operating the system are based around three operating states:

- A **Normal Operating State**, when the power system is in a secure and reliable state and operating within normal operating ranges. In a Normal Operating State, System Management must observe normal system security standards and operating limits, while maintaining adequate Ancillary Services and dispatching generators, where necessary, based on the Balancing Merit Order (covered in section 9.4) to the extent allowed by network constraints. System Management may deviate from the BMO to avoid a High Risk or Emergency Operating State.
- A **High Risk Operating State** exists when operating the power system in its normal operating range would expose the power system to a higher than normal probability of serious consequences in the event of a generator, transmission or other equipment failure. Some examples include a risk of interruption of gas supply, a bush fire threatening transmission lines, or a shortage of Ancillary Services. In a High Risk Operating State, System Management can take steps to increase the security of the power system, dispatch Facilities Out Of Merit, cancel or defer Planned Outages and apply security limits appropriate to the High Risk Operating State.
- An **Emergency Operating State** exists when operating the power system in its normal operating range would require the involuntary curtailment of load. In an Emergency Operating State, System Management is able to cancel or defer Planned Outages, direct Market Participants and Network Operators, and ultimately take whatever actions are necessary to restore the power system to a Normal Operating State. Where a Normal Operating State would not immediately be achievable System Management may take any actions it considers required to restore the SWIS to a High Risk Operating State.

System Management determines what operating state the power system is in, and must inform the market and the IMO of any changes in state via Dispatch Advisories described in section 9.4. System Management provides reports to the IMO on incidents involving Emergency Operating States. If System Management dispatches Out of Merit then they are required to advise the Market of this, and the corresponding reason.

6.2 Ancillary Services

System Management proposes requirements for Ancillary Services, based upon standards set out in the Market Rules. The IMO is responsible for approving these requirements. System Management is required to procure Ancillary Services and its options for procuring them include:

- In respect of Load Following, the LFAS Market (described in section 9.5).
- Making use of Verve Energy's resources (as default provider), including for LFAS if back-up capability is required.
- In respect of other Ancillary Services, if Verve Energy lacks adequate resources or the Ancillary Services can be obtained at a lower cost, through contracting with third parties. Any such contracting must be on a least cost basis and may involve a competitive tender.

System Management budgets the cost of procuring Ancillary Services, where budgeted costs must be in accordance with those approved by the Economic Regulation Authority. However, System Management does not fund Ancillary Services. Rather, the IMO recovers the costs of the Ancillary Services from Market Participants through the wholesale market settlement systems, and uses the revenue received to fund Ancillary Services procurement. The details and costs of the services provided are published on the market website.

The following Ancillary Services are defined in the Market Rules:

- **Load Following (LFAS)** is the primary mechanism in real-time to ensure that supply and demand are continuously balanced. It compensates for variations in load and intermittent generation relative to what System Management anticipated when issuing Dispatch Instructions for the Trading Interval and also compensates for normal generation deviations. LFAS is provided by generators which are capable of being regulated under centralised Automatic Generation Control (AGC) to maintain system frequency.
- **Spinning Reserve** is capacity held in reserve to respond rapidly should an on-line Facility experience a sudden Forced Outage. This service can be provided by spare on-line generation capacity, Dispatchable Loads and interruptible loads (i.e. loads that reduce automatically if the system frequency drops).
- **Load Rejection Reserve** is generation which can rapidly decrease output should a sudden loss of load occurs (for example, due to system fault). This service can be particularly important overnight when generating units can be operating at minimum loading and are unable to decrease their output in the time frame required.
- **Dispatch Support** ensures that voltage levels around the power system are maintained, and includes other services required to support the security and reliability of the power system that are not covered by other Ancillary Services.

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- **System Restart** allows parts of the power system to be re-energised by black start equipped generation capacity following a system wide black out. Unlike other generators, black start equipped generators can be started up without requiring a supply of energy from the transmission network.

In addition to managing these Ancillary Services, System Management must maintain adequate Ready Reserve. Ready Reserve is additional capacity, which may not be synchronised, that System Management can call on to provide energy in the 15 minute to four hour period following a contingency event. There is no additional payment for Ready Reserve as the cost of keeping the capacity available is funded via the Reserve Capacity Mechanism (see section 7).

There are special circumstances under which Ancillary Service and Ready Reserve Requirements may be relaxed, such as in emergency situations or where, in the case of Spinning Reserve or Ready Reserve, the Reserve Capacity is actually being activated to provide energy following a contingency event.

The IMO allocates the cost of Ancillary Services between Market Participants on the following basis:

- The monthly cost of Load Following is allocated amongst Market Participants in proportion to their monthly share of contributing quantity (metered load and Non-Scheduled Generation).
- The monthly cost of Spinning Reserve is borne by generators in proportion to the deemed risk that the generator imposes on the system, based on the output of the generator in each Trading Interval during the month.
- The monthly costs for Load Rejection Reserve, Dispatch Support and System Restart are recovered from Market Customers in proportion to their monthly metered consumption.

6.3 Medium and Short Term Planning

Projected Assessment of System Adequacy (PASA)

The IMO is required to forecast generation adequacy over a period of 10 years and to ensure that sufficient Reserve Capacity is procured. System Management assesses capacity adequacy and undertakes availability planning over the short and medium term.

The medium-term PASA process is an integrated assessment of system security and reliability over a rolling 36-month time horizon. The available level of generation and transmission capacity is reported by week, with this data being updated monthly. Capacity adequacy is assessed for high, medium, and low demand scenarios. This process is conducted in order to ensure that System Management, Market Participants and Network Operators are informed of projected conditions on the power system and to allow them to take appropriate actions. In particular, the information will help System Management to form a view of the power system conditions likely to apply at different times in the future, assisting it to schedule outages and plan the secure and reliable operation of the power system.

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The short-term PASA is similar to the medium-term PASA, but considers a three-week horizon, with results reported for four 6-hour periods per day, and updated at least once each week, or more often if required. This finer resolution is required to support operational planning, such as determining how much Ancillary Service capability is required in a given part of a day and to facilitate final approval of outages.

Market Participants and Network Operators are required to provide information to System Management for each of the PASA horizons:

- Network Operators provide information on changes to transmission capacities and ratings of equipment, proposed outage timings, access quantities at entry and exit points.
- Market Generators update their available generating Facility capacities and Ancillary Service capabilities, including adjustments reflecting outages or Facility closure and other constraints on supply capability. Market Generators will also provide estimates of their expected energy output levels.
- Market Consumers provide information on factors that will change the amount of energy they purchase.

The PASA results are made available via the Market Web Site and will include:

- Load scenarios used in the PASA.
- Forecast total available generation capacity by six hour or weekly periods (as applicable).
- Information on the timing, size and duration of expected capacity shortfalls.
- Forecast transmission capacity between potentially constrained regions, under normal conditions and some contingency scenarios, and the likelihood of constraints.
- Details of planned Commissioning Tests.
- Possible security problems, including fuel supply problems that could affect market or dispatch outcomes.

Outage Planning and Scheduling

System Management compiles a list of all equipment on the power system that is required to be subject to outage scheduling by System Management, including partial outages and de-ratings. This list includes all transmission network Facilities, Facilities holding Capacity Credits, and any other equipment that must be subject to System Management outage scheduling if the security and reliability of the SWIS is to be maintained. Market Participants may request that the IMO reassess the inclusion of their equipment on this list.

Market Participants notify System Management of their outage plans for up to three years ahead. The notification includes details of the reason for the proposed outages, the timing and duration of

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the proposed outage, potential risks with respect to the intended duration of the outage, and contingency plans should the Facility need to be returned to service prior to the scheduled outage completion time. Market Participants must also advise System Management of any changes to plans previously submitted.

Based on the outage plans and the power system security and reliability criteria, System Management forms a provisional schedule of outage plans that:

- Maintains security and reliability of the power system, or if it is not possible to achieve that, is the most prudent outage plan for managing the risks to the power system.
- Shows no bias towards a Market Participant or Network Operator in accepting outages.

Most outages are normally notified to System Management well in advance of their commencement, and typically more than a year before the event for generators. However, while participants can notify System Management of outages until a few days before the event, System Management may reject such applications if the submitting participant has allowed insufficient time for System Management to assess the impact of the outage. There are requirements under the Market Rules for Network Operators to co-ordinate outages with any impacted Market Participants.

Facilities with capacities of less than 10 MW need only inform System Management of Planned Outages. System Management does not actually schedule those outages, but passes the information on to the IMO as it is required in assessing compliance with Reserve Capacity Obligations and the general availability of capacity.

Where outages are scheduled by System Management, competition between participants and the security and reliability criteria will mean that it will not always be possible to schedule a Facility outage at the time its operator wants the outage. If System Management cannot determine an outage plan that accommodates the requirements of all parties, then it will first negotiate with affected parties for up to 15 Business Days, and if no agreement is reached, it will decide which outages are scheduled and which are not. In making such a decision, System Management must have regard for:

- Maintaining the reliability and security of the power system.
- The date and time at which System Management was notified of the outage.
- The urgency of any required maintenance.
- The implication of rescheduling the outage.

Where System Management determines that an outage cannot occur at the time the participant has requested, the participant may request that the IMO reassesses the decision. Such requests must be made within ten Business Days of System Management's decision but not later than five business days prior to the outage commencing. Any such requests can only be on the grounds that System

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Management has failed to follow the outage planning process in the Market Rules. The IMO will consult with System Management but the IMO's decision will be final.

If a Market Participant's outage plan is rejected, it and System Management must work to determine an alternative time for the outage.

Outages that are scheduled via the process in the Market Rules ("accepted outages") cannot commence until outage approval is granted ("approved outages"). System Management is required to give final approval of an outage two days before outage commencement. This final outage approval process allows System Management to manage outages close to their commencement, and potentially delay them if the outage will endanger the power system. Given the time constraints, no reassessment of these final outage approvals is possible, but the IMO may reassess decisions after the event where participants allege that System Management has breached the outage approval process in the Market Rules. Market Participants and Network Operators may also be able to schedule Opportunistic Maintenance with System Management at short notice (e.g. on the day before or on the day), provided System Management determines that such maintenance would not affect system reliability or security and provided System Management has adequate time to assess the impact of the outage.

If an outage was scheduled with System Management at least one year prior to its commencement but was delayed or cancelled by System Management within 48 hours of its commencement then the affected party can apply for compensation. Compensation is only payable for the additional maintenance costs directly incurred by a Market Participant or Network Operator in the deferment or cancellation of the relevant maintenance, and includes labour and equipment costs specifically related to the maintenance. This compensation is funded from Market Customers based on their monthly energy purchases. If the compensation required exceeds \$50,000 then the IMO may spread the recovery of the compensation over up to six months so as to minimise the volatility of settlement payments by Market Customers.

Where outages are approved by System Management they are designated as Planned Outages, and the Reserve Capacity obligations of the Market Participant are reduced during the impacted Trading Intervals accordingly. A similar reduction applies for Consequential Outages, which are due to failure of other components of the power system (e.g. transmission lines) that prevent a Reserve Capacity provider from meeting its obligations. All other outages are Forced Outages. Market Participants are obliged to inform System Management of Forced Outages as soon as practicable, and to provide information concerning when the Facility will return to service. Market Participants will be required to refund Reserve Capacity payments in the event their equipment suffers Forced Outages (see section 7.6).

Commissioning Tests

Those seeking to conduct Commissioning Tests on new generators or generators returning to service from significant maintenance must schedule those tests with System Management and complete all required Commissioning Tests prior to the start of the relevant Capacity Year. For a new generator

that is late entering the market a Commissioning Test period of four months total duration can be held.

6.4 Other Duties of System Management

Other duties of System Management include:

- Planning and making arrangements for, and coordination of, automatic under frequency load shedding, including a priority order designed to protect high priority loads in the event of a supply shortage.
- Maintaining plans for system restart.

6.5 Performance of System Management

The IMO coordinates investigations into major disturbances on the power system, and requires that System Management and other relevant Market Participants provide the IMO with a report explaining events and their actions soon after each event. These reports will be published on the IMO website.

At least every three months System Management must provide to the IMO a report summarising all instances of involuntary load shedding, shortages of Ancillary Services and Emergency Operating States occurring, including details of actions taken by System Management.

System Management assists the IMO to conduct reviews of the Ancillary Service requirements and procurement process and the process for scheduling outages. These reviews take place at least every five years, but may be carried out more frequently if required. Market Participants and Network Operators are able to make submissions to these reviews, and the results are public.

7. The Reserve Capacity Mechanism

7.1 Overview

The Reserve Capacity Mechanism is intended to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options at all times so as to:

- Meet the expected peak demand plus a margin to cover generation outages while maintaining minimum requirements to maintain system frequency; and
- Remove the need for high and volatile energy prices that are required in markets like the NEM to provide adequate revenue for peaking facilities and to trigger new investment. Instead, energy prices are capped at lower levels (relative to the NEM) with the Reserve Capacity Mechanism contributing to generator capital costs. The Reserve Capacity mechanism may fully fund the capital costs for peaking facilities, and contribute towards a base load unit's capital costs.

The IMO administers the Reserve Capacity Mechanism.

Annual Reserve Capacity Requirements are specified by the IMO and published in a Statement of Opportunities Report that considers the capacity requirements of the SWIS for the next 10 years. Each Market Customer is allocated a share of the Reserve Capacity Requirement, called its Individual Reserve Capacity Requirement (IRCR), and is required to secure Capacity Credits to cover that requirement. A Capacity Credit is a notional construct under the Market Rules reflective of installed generation capacity or Demand Side Management capacity from a Facility that has been certified by the IMO. Each Capacity Credit is equivalent of 1 MW of Reserve Capacity. A Market Customer can either procure Capacity Credits bilaterally from Capacity Credit suppliers, or it can purchase them from the IMO. If the requirement for Capacity Credits is not met through bilateral trades, the IMO may run an annual auction to procure Capacity Credits for on-sale to Market Customers.

7.2 The Statement of Opportunities Report

Each year the IMO prepares a Statement of Opportunities Report outlining projected capacity requirements for the SWIS and projected capacity shortfalls for each of the next ten years. This report indicates opportunities for supply and demand augmentations that would improve the adequacy and security of the power system. The IMO does not consider transmission planning, as this is addressed by Network Operators, but the Statement of Opportunities Report may make use of transmission planning information provided by Network Operators.

The Statement of Opportunities report is released in June each year and is used to set the Reserve Capacity Requirement for the "the Capacity Year" starting in October two years later.

To develop the Statement of Opportunities Report, the IMO is empowered to request information from Rule Participants regarding their expected future system usage and available generation,

demand side and transmission capacities. The IMO also takes into account probable new projects where appropriate.

The IMO determines the capacity required in each Capacity Year that should be sufficient to:

- Meet the forecast peak demand plus a reserve margin equal to the greater of 8.2% of peak demand or the capacity of the largest generating unit¹³ while being able to maintain normal frequency control. Peak demand forecasts are calculated to a probability level that the forecast would not be expected to be exceeded in more than one year out of ten.
- Limit expected energy shortfalls to 0.002% of annual energy consumption including transmission losses.

Both generation and demand-side options are considered in covering these requirements.

For the process of procuring Reserve Capacity, the IMO also determines an Availability Curve including:

- The MW capacity required in the SWIS for more than 24, 48 or 72 hours per year.
- The minimum amount of generating capacity required to maintain system security and reliability (i.e. so that any Demand Side Management procured for Reserve Capacity reasons is not so large as to undermine the ability of System Management to maintain the security and reliability of the SWIS).

7.3 Capacity Credits and the Reserve Capacity Auction

Generation and Demand Side Management Facilities capable and willing to contribute capacity must apply to the IMO for Certified Reserve Capacity applicable to the Capacity Year. This certification indicates the contribution of a Facility to meeting the capacity requirement in the Capacity Year, and also bestows obligations on that Facility. The primary obligations associated with Certified Reserve Capacity, which become binding only once the Certified Reserve Capacity is converted to Capacity Credits, are:

- For Market Generators other than Intermittent Generators, to make that capacity available to the market, in the form of Bilateral Contract positions, STEM submissions, Balancing submissions and capacity contracted to provide Ancillary Services, and to make any unscheduled capacity available in real-time.
- For demand side facilities, including but not limited to Demand Side Programmes, Dispatchable Loads and Interruptible Loads, to make that capacity available in real-time if required and subject to adequate notification being given.

¹³ Peak demand and reserve margin calculations account for losses and occasional demand from Intermittent Loads (which are normally supplied by on-site generation).

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- For Intermittent Generators, to generate to the greatest extent possible when requested by System Management to do so in real-time, or to reduce generation when requested by System Management.

The exact quantity of capacity a Facility must make available may vary with ambient temperature and the recent operation of the Facility. In addition, Facilities holding Capacity Credits must:

- Submit to outage scheduling by System Management.
- Submit to Reserve Capacity Tests and Verification Tests (for Demand Side Programmes).

In certifying Reserve Capacity, the IMO makes use of a range of information provided by the applicant, historic performance data, and tests of the Facility.

As a condition of certification of Facilities that have not yet been commissioned, the IMO requires the payment of a Reserve Capacity Security equal to about 25% of the value of the annual payments the Facility would receive if scheduled. This security will be returned to the Market Participant if the Facility fails to secure Capacity Credits or when it first reaches an output level that fully satisfies its capacity obligations. If a Facility operates at a level equivalent to 90% of its Required Level in any two Trading Intervals or the participant provides the IMO with a report from an independent expert specifying that the Facility can operate at an equivalent level then the security will be returned at the end of the year (provided the IMO is satisfied the Facility is in Commercial Operation). If a Facility operates at a level equivalent to 100% of its Required Level in any two Trading Intervals during the relevant Capacity Year then it may request its Reserve Capacity Security to be returned immediately. If these requirements are not met during the Capacity Year then the IMO will draw down on the security.

Market Participants can also apply for conditional certification or Early Certified Reserve Capacity some years before the auction. The information required is the same as for the normal certification processes. Conditional certification provides potential investors with greater certainty in securing financing and when negotiating Bilateral Contracts. Similarly the Early Certified Reserve Capacity process allows new generation projects with long lead times to secure Capacity Credits earlier, providing greater certainty for investors and financiers.

Early Certified Reserve Capacity, and subsequently assigned Capacity Credits, are granted for the applicable Capacity Year without the requirement to re-apply for Certified Reserve Capacity during the usual certification window. Where conditional certification has been granted, when the Market Participant applies for final certification, if no information upon which the conditional certification was based has changed and all approvals required normally for certification are provided, then it will automatically be certified.

The operators of all other Facilities holding Certified Reserve Capacity will, in August or September of each year, indicate to the IMO:

- How much Certified Reserve Capacity they intend to trade bilaterally.

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- How much Certified Reserve Capacity they intend to offer to the IMO via the Reserve Capacity Auction.
- Whether they want to terminate any Certified Reserve Capacity (e.g. because they no longer intend to go forward with the development of a new generation project).

In determining which bilateral trades can contribute to satisfying the required Reserve Capacity, the IMO will generally accept bilateral trades in order of decreasing availability until all trades are exhausted or until the Reserve Capacity requirements are satisfied. However, there are a number of additional rules imposed on this process:

- The IMO is required to accept capacity from Facilities that are in service or are committed.
- If the Reserve Capacity Requirement is not met from Facilities that are in service or committed, and if multiple Facilities that are not committed have the same availability but not all are required, then the IMO will apply the following selection criteria to determine which Facility or Facilities will be accepted. The same criteria will be applied to determine which one of two or more Facilities will be accepted when the Facilities are mutually exclusive (e.g. because they will be constructed on the same site if accepted):
 - Facilities that are operational or committed will be accepted first
 - Then Facilities can demonstrate having secured financing will be accepted
 - Then Facilities with the greatest quantity of Certified Reserve Capacity will be accepted ahead of Facilities with lower Certified Reserve Capacity
 - Then Facilities identified in Expressions of Interest will be accepted ahead of other Facilities
 - And finally, if the above steps have not resolved the matter, the IMO will accept Facilities based on the order in which they applied for Certified Reserve Capacity, including applications for Conditional Certified Reserve Capacity.

If enough Certified Reserve Capacity is traded bilaterally to meet the Reserve Capacity Requirements of the SWIS then no Reserve Capacity Auction will be held, and all the Certified Reserve Capacity accepted through the bilateral trade process will be granted Capacity Credits. If more Capacity Credits are assigned through the Reserve Capacity Mechanism than are required, the price paid by the IMO for Capacity Credits will be scaled down. The price of Capacity Credits in this case will be determined by spreading the theoretical total cost of required Capacity Credits over the number of Capacity Credits that have actually been assigned.

If the total capacity traded bilaterally does not fully cover the total Reserve Capacity Requirement (or there is a shortage in any Availability Class), then:

- The bilaterally traded Reserve Capacity would be granted Capacity Credits,
- The capacity difference between the Reserve Capacity Requirement and the bilaterally traded Reserve Capacity in each Availability Class would be procured via a Reserve Capacity auction.

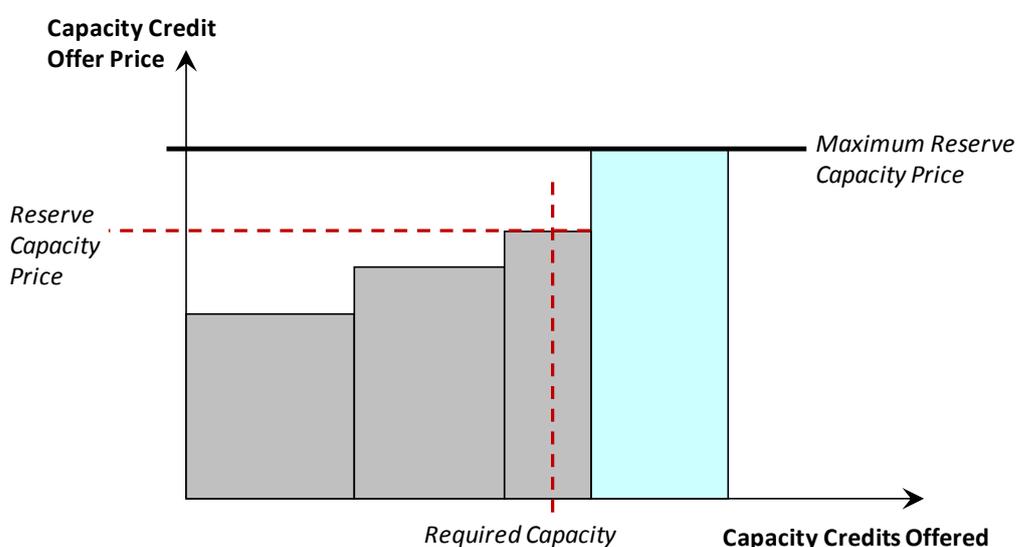
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- Any capacity procured in the auction would be granted Capacity Credits.

Each auction, if required, would be held in September as a simple tender to supply the IMO with Capacity Credits. An offer would be made to the IMO to provide the Capacity Credits available from a Facility at a price per Capacity Credit per year. A maximum offer price would be defined at a level commensurate with the expected cost of a new entrant peaking plant in the SWIS. The maximum offer price is the Maximum Reserve Capacity Price to apply in the Capacity Year for which the auction is being held. Note that through an auction only whole facilities will be cleared, not a part of a facility.

Exhibit 7-1 illustrates the basic Reserve Capacity Auction clearing process.

Exhibit 7-1: The Reserve Capacity Auction



Four offers are shown. Each offer represents that part of a Facility's Reserve Capacity that is being offered into the auction. The offers are ranked in order of price until the Reserve Capacity requirement is covered. In this instance, the third block of capacity would be cleared in full, meaning that more Reserve Capacity would be scheduled than is required.

In Exhibit 7-1 the grey shaded area indicates the three offers scheduled. The fourth offer, which was priced at the maximum allowed price, would not be scheduled and consequently would receive no payment.

Some additional rules are imposed on the auction:

- There are limits on the amount of capacity that can be scheduled from sources that have limited availability over the year. This allows such resources to be scheduled to serve peak capacity, which has short duration, but not base-load demand. In effect, the auction is conducted to cover the requirement of the Availability Class with the highest availability first. Any surplus offers and offers for the Availability Class with the second highest availability are

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used to cover the requirements of the second highest Availability Class, and so forth. There are not separate prices for each Availability Class, though, with the highest priced offer scheduled from any Availability Class setting the price.

- If there are offers associated with mutually exclusive Facilities (e.g. because they are yet to be built but will all be built on the same site) then the auction will be run for each permutation of such Facilities, and the result used will be that which provides the capacity required at lowest cost, or, if there is shortfall of capacity, minimises that shortfall without regard for cost.
- If the reserve requirement is exceeded by more than 100 MW, because the last source of supply that could be scheduled was bigger than needed, the IMO would be allowed to accept offers from a smaller, otherwise not cleared (and hence more expensive per MW) Facility in place of a larger cleared Facility if this would reduce the overall cost of Reserve Capacity. In this case, the normal price would still apply, with additional compensation being paid to the Facility that offered a higher price than the clearing price but was scheduled.

Where Capacity Credits are traded bilaterally rather than being included in the auction and the bilateral arrangement ceases during the Capacity Year, then the IMO will still pay the Facility holding the Capacity Credit the prevailing auction price. However, a Capacity Credit assigned through an auction is committed to the IMO for the entire Capacity Year, and cannot therefore be bilaterally transferred to a retailer during that Capacity Year.¹⁴ The certification of Reserve Capacity offered into an auction, but not scheduled, would terminate, as the capacity either has insufficient availability or is not required for the Capacity Year. In these cases any Reserve Capacity Security that the IMO is holding for the relevant Market Participant will be returned.

Once issued, those who have procured Capacity Credits via the bilateral trade process are free to trade those Capacity Credits (i.e. the ability to use them to avoid funding Capacity Credits through the IMO settlement process) with others. However the obligation to provide the capacity associated with a Capacity Credit will always remain with the Facility associated with the Capacity Credit. Capacity Credits procured by the IMO through the auction will be held by the IMO for the term of those Capacity Credits and consequently cannot be traded again.

Normally, the obligations associated with Capacity Credits will be in effect for the 12 months from October 1, starting in Year 3 of the Capacity Cycle for which the relevant Market Participant sought to have its Facility certified. There are some exceptions to this:

- New Facilities, that were constructed to be available for the start of the Capacity Year, will have Capacity Credit obligations that take effect from their commissioning date, which must be between 1 June and 1 October of Year 3 of the Capacity Cycle. This requirement assures that these Facilities are available for the summer peak period.

¹⁴ This is required to prevent the operators of Facilities holding Capacity Credits from bidding unreasonably high prices, in the knowledge that if they fail to be scheduled in the auction they can still secure adequate revenue through a pre-existing and confidential option to activate a bilateral trade for their Capacity Credits.

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- Facilities may be decommissioned during the two months prior to the end of the Capacity Year without restricting their ability to provide Capacity Credits prior to their date of decommissioning. This requirement assures that these Facilities are available for the summer peak period.

7.4 Reserve Capacity Special Price Arrangements

A new entrant Facility that does not have Bilateral Contracts to fund its capacity but which can be funded by selling Capacity Credits to the IMO in an auction is unlikely to enter the market based on the Reserve Capacity Price in a single year. While that price might be high enough to cover the Facility's cost for the year, there is the risk that the Reserve Capacity Price in subsequent years could be lower.

To assist new Facilities entering the market in an auction situation to finance their project without Bilateral Contracts a Long Term Special Price Arrangement (LT-SPA) option is available. If capital costs of at least 10% of the Maximum Reserve Capacity Price per MW are incurred in supplying new capacity, either from an upgrade of an existing Facility or developing a new Facility, then that Facility is eligible for a LT-SPA. This arrangement will allow the Market Participant to receive the (inflation adjusted) auction price it earns in the first year in each year the LT-SPA applies. The duration of the LT-SPA can be selected by the Market Participant, but must not exceed 10 years. A holder of a LT-SPA will be required to apply to have its capacity re-certified each year, and the LT-SPA will only be paid on the lesser of the capacity actually certified in each year and the original capacity upon which the LT-SPA was granted.

A Short Term Special Price Arrangement (ST-SPA) will also be used to address situations where an offer is cleared in an auction but the clearing price is less than its offer price. This could arise because a small expensive Facility is accepted as providing a lower cost auction solution than accepting a low cost, but large Facility. In this case, if the Facility is not covered by a LT-SPA, it will receive a ST-SPA applicable to the Capacity Year to cover the difference between the auction price and its offer price.

As noted above, Capacity Credits sold to the IMO via the auction cannot be traded bilaterally for the year the IMO holds the Capacity Credits. In the case of a LT-SPA the Capacity Credits can be traded bilaterally following the Capacity Year to which the original auction related. The LT-SPA will be suspended if a covered Facility sells the Capacity Credit bilaterally, but will resume if that bilateral arrangement ends within the term of LT-SPA. Since capacity sold through the auction for one Capacity Year cannot be traded bilaterally, there is no need for equivalent arrangements for the ST-SPA.

7.5 Supplementary Reserve Capacity

If the IMO considers at any time during the six months prior to the Capacity Year that there will be insufficient capacity available to maintain Power System Security and Reliability it may seek to acquire additional supplementary capacity. This supplementary capacity may be priced higher than capacity acquired through a Reserve Capacity Auction, but the contracts will have a term of not more than 12 weeks. This auction will only be open to load reduction options, generation systems that are

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not currently Registered Facilities and existing generation and load reductions options but only to the extent that the capacity does not hold Capacity Credits in the current Reserve Capacity Cycle

Those offering to provide supplementary capacity would specify the availability restrictions on their capacity, an availability cost, and a usage cost reflecting costs directly incurred (e.g. a stand-by generator's fuel cost). The IMO would schedule the offers so as to minimise the expected cost, based on the expected number of hours for which the supplementary capacity will be required.

Those providing supplementary capacity will have their rights and obligations governed by a contract with the IMO rather than the Market Rules. This allows supplementary capacity to be provided by parties that are not Rule Participants. A standard Supplementary Capacity Contract exists, but the IMO can negotiate variations to the standard conditions where this is required to secure sufficient capacity or to minimise costs.

7.6 Reserve Capacity Refunds

Providers of Capacity Credits who fail to meet to meet their Reserve Capacity Obligation Quantity have to pay a refund that reflects a measure of the value to the system of the capacity shortfall.

Different rates of refund apply at different times of day and at different times of year. Refund rates are relatively small at times when the SWIS has abundant capacity and are relatively high at times when the risk of load curtailment is higher (during summer months).

Measures are included to ensure that Capacity Credit providers will not be required to refund more during a year than they receive through Capacity Credit income in that year. Reserve Capacity refunds are intended to discourage non-compliance in a Trading Interval while capping the risk if non-compliance over a long time frame is unavoidable.

These refunds will be collected in the first instance by the IMO and then rebated to all Market Customers in proportion to their IRCRs (see section 7.7). This effectively compensates all Market Customers for the reduction in the overall security of the system.

7.7 Funding the Reserve Capacity Auction

All Market Customers will have an ICR equal to the share of the Reserve Capacity Requirement allocated to them based on their expected contribution to historic system peak demand. During the course of a Capacity Year the IMO updates IRCRs monthly. These updates take account of end-use customers shifting between retailers, new end-use customers entering the market, and existing end-use customers leaving the market. While the ICR of each Market Customer changes each month, the total of these quantities sums to the Reserve Capacity Requirement.

A Market Customer's ICR will typically equal its contribution to system peak load, plus an additional reserve margin. Thus a Market Customer with a load of 100 MW at times of system peak consumption might have an Individual Reserve Capacity Requirement of 115 MW, where the additional 15 MW ensures that there is adequate generation available at peak times even if some

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generation capacity is unavailable. Intermittent Loads are a special case and are discussed further in section 7.10.

Market Customers who do not hold enough Capacity Credits for a given Trading Month will be required to fund the Targeted Reserve Capacity Cost. This is the cost of Capacity Credits procured by the IMO, including under Special Price Arrangements, up to the Reserve Capacity Requirement. Where the IMO has procured Capacity Credits in excess of the Reserve Capacity Requirement then the cost of the surplus Capacity Credits are recovered via the Shared Reserve Capacity Cost discussed below. Because of Special Price Arrangements, not all Capacity Credits cost the IMO the same amount, so the most expensive mix of Capacity Credit costs will be recovered via the Targeted Reserve Capacity Cost. The Targeted Reserve Capacity Cost is allocated in proportion to each Market Customer's Capacity Credit shortfall. The purpose of this Targeted Reserve Capacity Cost is to provide an incentive for Market Customers to contract bilaterally for capacity well before it is required, and to contract with reliable providers.

The IMO on a monthly basis determines the Shared Reserve Capacity Cost. This cost comprises:

- The cost of Capacity Credits procured by the IMO that are surplus to the requirements of the market.
- Plus the cost of Supplementary Capacity payments for that month to the extent that this is not offset through the IMO claiming security posted by a provider of Capacity Credits that fails to satisfy their obligations.
- Less any refunds paid by Capacity Credit providers who fail to satisfy their obligations and by Intermittent Loads.
- Less any revenue beyond that required to fund Supplementary Capacity payments earned by the IMO where it has claimed the security posted by a provider of Capacity Credits that fails to ever satisfy its obligations.

Less any amount drawn under a Reserve Capacity Security that is to be distributed to Market Customers, after funding any Supplementary Reserve Capacity. The Shared Reserve Capacity Cost is allocated between all Market Customers in proportion to their Individual Reserve Capacity Requirement. This approach is used because the components of the Shared Reserve Capacity Cost cannot meaningfully be assigned to any individual Market Customer.

7.8 Capacity Credit Allocation Process

Capacity Credits applicable to the current Capacity Year that have been traded bilaterally between a supplier of Reserve Capacity and a Market Customer are recognised in settlement of the wholesale market. The benefit of such a transfer is that it reduces the payment required to be made by the Market Customer to the IMO, and reduces the payment required from the IMO to the Reserve Capacity supplier. This will allow the supplier and Market Customer to trade capacity at a bilaterally agreed price and will reduce prudential requirements for the Market Customer. Market Customers

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that do not have bilaterally contracted capacity are also exposed to the financial costs of procuring additional capacity.

Following each Trading Month, the suppliers of Capacity Credits inform the IMO of which Capacity Credits are being traded bilaterally, and with whom. Because different Capacity Credits may be settled at different prices, e.g. because of Special Price Arrangements, the supplier of Capacity Credits has to indicate which group of Capacity Credits is being used in a bilateral trade so the IMO knows how much to pay for other Capacity Credits.

The IMO reviews submissions from Capacity Credit suppliers and accepts those that meet the format requirements. However, before accepting individual transactions contained in the submission it will check them to ensure that no Market Customer is allocated more Capacity Credits than it is required to provide. If the IMO finds any such cases, it will notify that Market Customer and require it to nominate which Capacity Credits it does not want to take up. This measure is designed to ensure the Market Customers do not hold on to Capacity Credits they do not need, thus preventing others from getting the benefit of them. The IMO will only confirm the transactions with the Capacity Credit suppliers once this process is completed.

7.9 Reserve Capacity and Generator Investment Strategies

Holding of Reserve Capacity Auctions in September of Year 1 is to allow time for peaking plant to enter the market based solely on the auction revenue. Base load plant is unlikely to be able to profitably enter the market solely on Reserve Capacity revenues, so this type of plant is more likely to trade Capacity Credits bilaterally. However, should base load plant have any spare capacity that spare capacity can be offered into the auction to gain additional revenue.

Since Reserve Capacity Auctions are held two years prior to the obligation commencing, if an existing Facility's capacity is offered into the Reserve Capacity Auction but not scheduled then its owner will have two years to assess what to do. After that time it will cease receiving Reserve Capacity payments, but will be allowed to continue participating in the energy market. However, without a Reserve Capacity payment, either from the auction or via bilateral trade, the Facility may no longer be economically viable. This is an appropriate outcome, because the fact that the Facility's capacity has not been traded bilaterally or cleared in the auction suggests that the market can acquire new capacity at a lower cost or does not need the additional capacity.

Pre-conditions for a new Facility to be commissioned to be certified to provide Reserve Capacity will include evidence of network system studies and acceptance of an Access Proposal from its Network Operator, and evidence of any necessary environmental approvals. While this may take some time to obtain, holding a Bilateral Contract for Capacity Credits allows Market Participants to commit to building new Facilities in the knowledge that once they have secured all necessary approvals they will be able to secure the benefits of the Reserve Capacity regime.

As described in section 7.3, a process exists for conditional certification of Reserve Capacity for Facilities under development so that they can have certainty as to the quantity of Capacity Credits they will hold some years prior to the normal application time. This will facilitate financing and the

formation of Bilateral Contracts. Additionally there is the ability for a facility with a longer build time to apply for Early Certified Reserve Capacity.

7.10 Intermittent Loads

The Market Customers serving Intermittent Loads will have to fund Capacity Credits for those Intermittent Loads. However, Intermittent Loads will have less impact on a Market Customer's IRCR than other loads. The reason for this is that Intermittent Loads only need to purchase energy from the market when the generator supplying that Intermittent Load is not available. Suppose that a regular load of 100 MW contributes 115 MW to a Market Customer's IRCR. In the case of an Intermittent Load of 100 MW, its own generator covers the first 100 MW of capacity required¹⁵, so the Intermittent Load is not required to contribute more than 15 MW to a Market Customer's IRCR.

A Market Customer with a Intermittent Load has to pay the prevailing Reserve Capacity Price for its Intermittent Load, unless it has procured the capacity bilaterally.

A generator serving an Intermittent Load need not generally be registered – rather the load/generator combination is registered as a single Facility. However the IMO will assess the generating Facility's ability to provide capacity as if it were a Reserve Capacity provider and the Intermittent Load cannot exceed the capacity that the IMO considers the generator has available. To the extent that a generator has capacity beyond that required to serve the Intermittent Load, then that extra generation capacity can be registered and can provide capacity and energy to the market beyond that required to supply the Intermittent Load.

Generators serving Intermittent Load are effectively providing Reserve Capacity, albeit without formally holding Capacity Credits. Consequently they have obligations. The generators are subject to System Management outage planning, for instance. Further, if the generator is not operating then the metered net load will increase. When this happens, and if the generator is not on a Planned Outage, the Intermittent Load will be subject to Intermittent Load Refunds. These are like Reserve Capacity Refunds and reflect the fact that the generator is unavailable. An Intermittent Load should not exceed its nominated level of output (by more than a tolerance of 3%) except when its generator is on a Planned Outage if the load wishes to avoid Intermittent Load Refunds. Note that Intermittent Load refunds over a Capacity Year are not capped to the income received from Capacity Credit payments (as is the case with refunds for other generation and load facilities). To the extent that unmetered load exists at the location that is not part of the Intermittent Load, this can be registered as Non-Dispatchable Load and any consumption beyond the Intermittent Load can be associated with this load. This Non-Dispatchable Load would have to fund Capacity Credits like any other non-Intermittent Load.

Appendix 1 provides additional detail on the representation of Intermittent Loads, including how meter data is allocated between the Intermittent Load, any unmetered Non-Dispatchable Load at the

¹⁵ When assessing an application to treat a load as an Intermittent Load, the IMO will assess how much Certified Reserve Capacity the embedded generator supplying that Intermittent Load can provide. This must be enough to fully supply the Intermittent Load.

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same site, and any generation capacity beyond that required to serve the Intermittent Load that is registered.

7.11 Capacity Credits for new small generators

The standard Reserve Capacity processes provide for a 2-year timeline between the bilateral trade/auction process and the commencement of the obligations associated with Capacity Credits. This is done to allow time for new peaking generators to be installed if required. However, small generators can be installed much more quickly. For this reason, Non-Scheduled Generators of capacity not exceeding 1 MW can secure Capacity Credits on a shorter timeline. When such a generator begins operating its operator can apply to the IMO for Capacity Credits from the start of the next Capacity Year (1 October). It can reapply for Capacity Credits each year until the commencement of the first Capacity Year for which it could have secured Capacity Credits through the normal process since the Facility commenced operation.

7.12 Capacity Credits for Demand Side Programmes

An issue for Market Customers wishing to provide demand response to the market is that it can be difficult to get wholesale customers to contract to provide curtailability for more than about a year ahead of time. To accommodate this, the market allows a Market Customer to apply for a Demand Side Programme to be assigned Capacity Credits and obligations (although it is not a physical Facility). The Market Customer must provide sufficient evidence to the IMO for it to reasonably expect that the capacity from the Demand Side Programme is likely to be available for the relevant Capacity Year.

Closer to the start of the Capacity Year the Market Customer will enter contracts for demand response and then apply to the IMO to associate the relevant loads with the Demand Side Programmes .

The Capacity Credits and obligations belong to the Demand Side Programme. System Management will issue Dispatch Instructions to the Demand Side Programme and the relevant Market Customer is responsible for ensuring that each of the associated loads provides the required curtailment of load.

7.13 Capacity Credits for Intermittent Generators

Capacity Credits for Intermittent Generator facilities are determined based on the output of candidate facilities in peak Trading Intervals from years prior to the certification period. The determination of the quantity of Capacity Credits to be assigned to these facilities relies on a measure of demand known as Load for Scheduled Generation, which identifies the Trading Intervals where surplus capacity is lowest and therefore the system is under greatest stress. An overview of the calculation of LSG and the determination of Capacity Credits for Intermittent Generators is available on the following IMO Market Web Page:

http://www.imowa.com.au/f179,2019308/LSG_help_guide_10Feb2012.pdf

8. Network Control Service

Network Control Services are services that can be provided by local generation or Demand Side Management as substitutes for an upgrade to a transmission or distribution network. Network Operators procure Network Control Service contracts, under the Access Code, where the generation or Demand Side Management option is less expensive than the transmission upgrade.

Network Operators must advise the IMO and System Management of Network Control Service contracts they have entered into, including certain settlement details. System Management may issue real-time dispatch instructions to a Network Control Service Facility as required, within the capacity and availability limits of the contract. A Facility providing Network Control Service must be a Registered Facility and can participate in the energy market. However, when a Network Control Service is dispatched by System Management, the Facility is not eligible for any constrained on or off payments. When a Network Control Service contract is dispatched by System Management, the IMO must advise the relevant Network Operator of the quantity and balancing market payments involved. Any other payments under a Network Control Service contract are a matter between the Network Operator and the contracted party.

9. The Energy Market

9.1 Introduction

The Energy Market, as used in the Market Rules, describes all mechanisms for trading energy, and includes trades via:

- Bilateral Contracts
- The Short Term Energy Market (STEM)
- The Balancing Market

An LFAS Market also operates in parallel to the Balancing Market.

Each of these components is described in this section.

9.2 Bilateral Contracts

Bilateral Contracts are agreements formed between wholesale market suppliers (i.e. generators) and wholesale market consumers (i.e. retailers and directly connected loads) for the provision of energy. These Bilateral Contracts are formed on a purely commercial basis, and the market has no role or interest in how they are formed, or in the conditions they impose on the parties subject to those contracts. The IMO does not operate any secondary trading market for Bilateral Contracts.

Whether a Bilateral Contract has a term of one Trading Interval or multiple years, it provides the holders with certainty over their settlement position with respect to that transaction. To the extent that one of the parties cannot conform to their contractual requirements, because of an outage of a generator, transmission or network security constraints, low demand or some other situation, then those parties will be individually liable to settle their deviations from the contract position. This places discipline on the market to only form Bilateral Contracts that reflect a reasonable expectation of the ability of the network to facilitate the delivery of that energy. Note that there is no concept of physical, path dependent, transmission rights in the SWIS, rather each network user is granted a right to inject or withdraw up to an amount of energy specified in their access contract with their network service provider.

The holders of a Bilateral Contract must make a Bilateral Submission to the IMO on the Scheduling Day, being the day prior to the day on which the Trading Day begins. These Bilateral Submissions must be balanced, in the sense that the total Loss Adjusted energy to be supplied to the network must match the total Loss Adjusted energy to be taken from the network. If a Market Participant is both a Market Generator and a Market Customer and wishes to cover its own load with its generation then it should include in its Bilateral Submission that it is supplying itself. The IMO allows Bilateral Submissions to be made between 8:00 AM on the day being seven days prior to the start of the Scheduling Day until 8:50 AM on the Scheduling Day. The information included in Bilateral Submissions is:

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- The identity of the submitter
- The total Loss Adjusted net energy, in MWh, to be supplied by the submitter, where energy supplied has a positive sign
- The total Loss Adjusted net energy, in MWh, assigned to each Market Participant supplied by the submitter, where energy consumed has a negative sign

The total Loss Adjusted net energy to be supplied (as defined in the previous point) plus the sum of the total loss adjusted net energy to be consumed by each Market Participant under that submission must equal zero. This indicates that the submission is balanced. The loss adjustments are based on static loss factors fixed for a year and reflecting average marginal losses between a fixed Reference Node and each injection or off-take point in the SWIS. These are set annually by Network Operators and published by the IMO.

Once a Bilateral Contract Submission is accepted, the energy is scheduled.

Early on the Scheduling Day, System Management produces a demand forecast for each Trading Interval of the Trading Day and provides that to the IMO which publishes it by 8:00 AM. A report is also produced at 8:30 AM allowing Market Participants to see the bilateral trades that impact them. The demand forecast and the 8:30 AM report allow Market Participants to revise their Bilateral Contract positions (by contacting the submitting Market Generator where required) prior to the submission window closing at 8:50 AM.

An option will also be available whereby Market Participants can submit standing Bilateral Submissions. A standing Bilateral Submission comprises a Bilateral Submission for each of the seven days of a Trading Week (i.e., Sunday, Monday, Tuesday etc). If a Market Participant does not make a Bilateral Submission to the IMO for a Trading Day then the IMO uses the standing Bilateral Submission corresponding to the day of the week of the Trading Day. Market Participants are obliged to update their standing Bilateral Submissions if they become inaccurate. Alternatively, if the inaccuracy is only for a short period, the Market Participant can make a Bilateral Submission each day during that period so that the standing Bilateral Submission is not used.

9.3 The Short Term Energy Market

Outline

The Short Term Energy Market (STEM) is an energy-only forward market operated by the IMO on the Scheduling Day to facilitate trading around Bilateral Contract positions. The STEM is run for every Trading Interval of the Trading Day, and determines a single clearing price for each Trading Interval as well as the quantities that participants have been cleared to sell to or purchase from the IMO. The auction is designed so that the IMO purchases the same amount of energy it sells, so that it has no net exposure.

The STEM schedules are contracts between suppliers and the IMO and between the IMO and consumers. If a Market Participant has made a Bilateral Submission indicating that it will supply 100

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MWh of energy, and then the IMO purchases 10 MWh from it in the STEM, then the net bilateral position of the Market Participant is to supply the market with 110 MWh.

The primary role of the STEM is to provide a mechanism for economic energy trade between Market Participants. This allows those trading under Bilateral Contracts to change their position, while allowing those not trading under Bilateral Contracts to take a position.

Participation

Participation in the STEM is open to all Market Participants, but is not compulsory. However, those Market Participants operating non-intermittent generators that hold Capacity Credits are required to make adequate energy available to the market to cover their Reserve Capacity contract obligations.

STEM Submissions

STEM Submissions are made to the IMO between 9:00 AM and 9:50 AM of each Scheduling Day. Accepted submissions will be used in the STEM auctions run between 10:00 AM and 10:30 AM.

To aid Market Participants in forming their STEM Submissions, the IMO will by 9:00 AM on the Scheduling Day report for each Trading Interval of the Trading Day:

- the total demand to be supplied under Bilateral Contract;
- the forecast demand; and
- information on the Reserve Capacity available (including information on outages).

A standing STEM Submission option exists for STEM Submissions. As for standing Bilateral Submissions these apply for each of the 7 days of a Trading Week and will be used if no STEM Submission is made. Market Participants are obliged to update their standing STEM Submissions if they become inaccurate. Alternatively, if the inaccuracy is only for a short period, the Market Participant can submit a STEM Submission each day during that period so that the standing STEM Submission is not used.

One of the features of STEM Submissions is that liquid fuelled generation can be offered at a higher price than non-liquid fuelled generation and at the same price as bids for demand. If a STEM Submission included a single offer curve to sell and a bid curve to buy relative to a Bilateral Contract position, then it would not be transparent as to what price each individual generator was offered at each level of output. To overcome this, Market Participants must offer their entire supply and consumption capacity in the STEM Submission in the form of a generation Portfolio Supply Curve and a Portfolio Demand Curve. From these curves, the IMO generates offers to buy energy and bids to sell energy relative to the net bilateral position of the Market Participant.

A STEM Submission for a Trading Day comprises the following information:

- A **Portfolio Supply Curve** for each Trading Interval of the Trading Day. A Portfolio Supply Curve is made up of price-quantity pairs where the cumulative quantity offered represents all the

energy being offered to the market from the Market Participant's generation resources. If the Market Participant is a Market Customer only then a zero quantity must be entered. If this portfolio is made up of X MW of Facilities operating on non-liquid fuel (e.g. gas or coal) and Y MW of Facilities operating on liquid fuel (e.g. distillate or oil) then the first X MW of the supply curve must contain prices less than the Maximum STEM Price while the last Y MW must contain prices less than the Alternative Maximum STEM Price. All prices must be greater than the Minimum STEM Price and the cumulative quantity of supply offered must increase with increasing price.

- A **Portfolio Demand Curve** for each Trading Interval of the Trading Day. A Portfolio Demand Curve is a demand curve made up of price-quantity pairs where the cumulative quantity bid represents all the energy that the Market Participant might potentially purchase from the market. If the Market Participant is a Market Generator only then a zero quantity must be entered. All prices must be greater than the Minimum STEM Price and less than the Alternative Maximum STEM Price and the cumulative quantity of energy consumption must increase with decreasing price.
- A **Fuel Declaration**. This states what fuel each dual fuelled generator was assumed to be using when forming the Portfolio Supply Curve. This information is provided to System Management and is also used for market monitoring purposes.
- An **Ancillary Service Declaration**. Prior to the STEM Submission process commencing each day, System Management advises Ancillary Service providers (via the IMO) of the capacity they should hold out of the STEM for each Trading Interval so as to keep that capacity available for Ancillary Service provision. Market Participants who are providers of Ancillary Services must declare for each Trading Interval how much of the required quantity is assumed to be provided by liquid fuelled generation and how much is assumed to be provided by non-liquid fuelled generation. This information serves to excuse the Market Participant from the Reserve Capacity obligation to offer capacity into the STEM.
- An **Availability Declaration**. Market Participants must declare for each of their generators the greater of maximum energy the Facility could produce less the amount assumed for it in the participant's Portfolio Supply Curve or zero. The maximum energy calculation takes account of the Facility's Standing Data, commitments to provide Ancillary Services or unavailability due to an outage (provided the outage has been reported to the IMO). This information is used for market monitoring.

The various declarations allow the IMO and regulatory bodies to see what assumptions went into forming the Portfolio Supply Curve. To the extent that actual behaviour is observed to deviate from the declarations then this may flag the need for an investigation of the incident (though it does not necessarily mean that the Market Participant has done anything wrong).

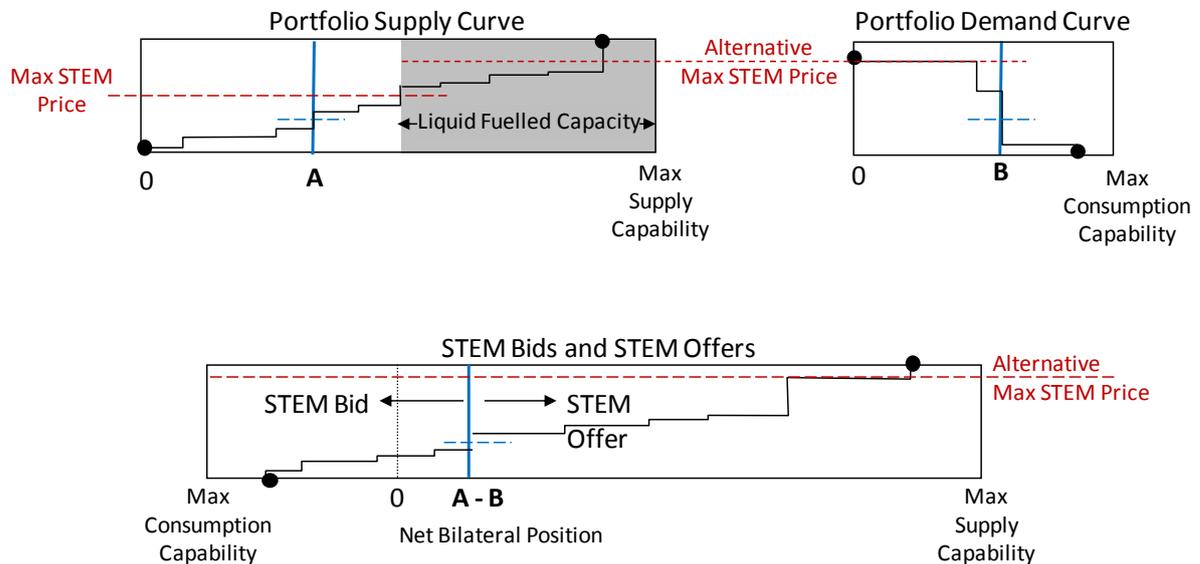
Establishing STEM Offers and Bids

Given a Market Participant's Portfolio Supply Curve, Portfolio Demand Curve, and Net Bilateral Position, the IMO can deduce the Market Participant's STEM Offers and STEM Bids.

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The top two curves in Exhibit 9-1 illustrate a Market Participant's Portfolio Supply Curve and Portfolio Demand Curve for a Trading Interval. The bottom curve illustrates how the IMO forms the STEM Bids and STEM Offers.

Exhibit 9-1: The Portfolio Supply Curve, Portfolio Demand Curve & STEM Bids and Offers



Some points to note about the Portfolio Supply Curve and Portfolio Demand Curve in Exhibit 9-1.

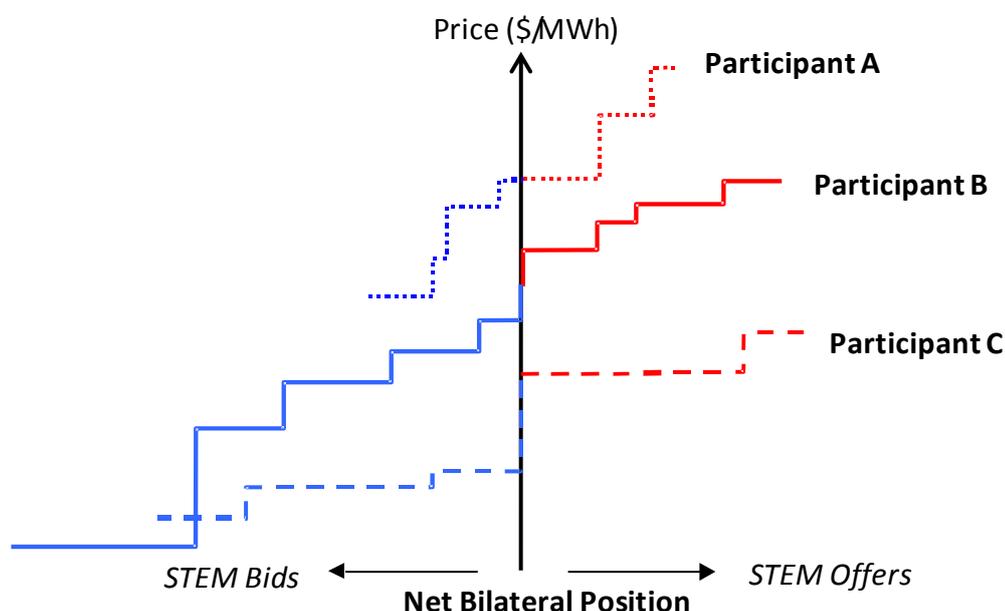
- Although not explicitly shown, the minimum price that can be offered is the Minimum STEM Price.
- The shaded area of the Portfolio Supply Curve shows the capacity that is liquid fuelled and which can therefore be offered up to the Alternative Maximum STEM Price.
- When the Market Participant formed its Portfolio Supply Curve it expected quantity A to be traded under Bilateral Contracts. Likewise, when it formed its Portfolio Demand Curve it expected quantity B to be traded under Bilateral Contracts. The Market Participant does not tell the IMO the values of A and B, but it does need to be aware of the quantity (i.e. the level of contract coverage) for each portfolio so that it can ensure that its price-quantity pairs are consistent with its net bilateral position. The short dotted horizontal lines centred on points A and B indicate the price corresponding to the net bilateral position (A-B) in the bottom curve. If the IMO is to produce STEM Offers and Bids that match the Market Participant's expectation then the Market Participant must ensure that:
 - Demand not traded bilaterally is bid at a price lower than that corresponding to the net bilateral position.
 - Generation not traded bilaterally is offered at a higher price.

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The bottom part of Exhibit 9-1 shows an individual Market Participant's STEM Offers and Bids relative to its Net Bilateral Position.¹⁶ The IMO forms the lower curve in Exhibit 9-1 by determining the net quantity of energy that the Market Participant is willing to provide at every possible price. Having formed such a curve, the IMO identifies the quantity corresponding to the net Bilateral Position. Relative to this point, everything with a higher price is a STEM Offer and everything with a lower price is a STEM Bid.

Each Market Participant will have its own set of STEM Offers and Bids. Different Market Participants will have different prices associated with their Net Bilateral Positions. This is illustrated for three Market Participants in Exhibit 9-2.

Exhibit 9-2: STEM bids and offers are defined relative to net bilateral contract positions



The Net Bilateral Positions of the three participants shown in Exhibit 9-2 will all be different. We cannot tell from Exhibit 9-2 whether each of the participants is solely a generator, solely a consumer or some mix of the two. Thus:

- Any of the participants could be a generator only with a positive Net Bilateral Position indicating it is a net supplier. Its STEM Bids would reflect a decrease in generation while its STEM Offers would reflect an increase in generation.

¹⁶ Where a Market Participant is both a Market Generator and a Market Customer then it has only one Net Bilateral Position. It does not have a separate Net Bilateral Position as a Market Customer from that as a Market Generator. In defining its STEM Offers and Bids relative to that position it must configure its Portfolio Supply Curve and Portfolio Demand Curve to produce the desired STEM Offers and Bids.

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- Any of the participants could be a load only with a negative Net Bilateral Position indicating it is a net consumer. Its STEM Bids would reflect an increase in consumption while its STEM Offers would reflect a decrease in consumption.
- Any of the participants could be both a supplier and a consumer, in which case its Net Bilateral Position could be positive or negative. Its STEM Bids would reflect a combination of a decrease in generation and an increase in consumption while its STEM Offers would reflect a combination of an increase in generation and a decrease in consumption.

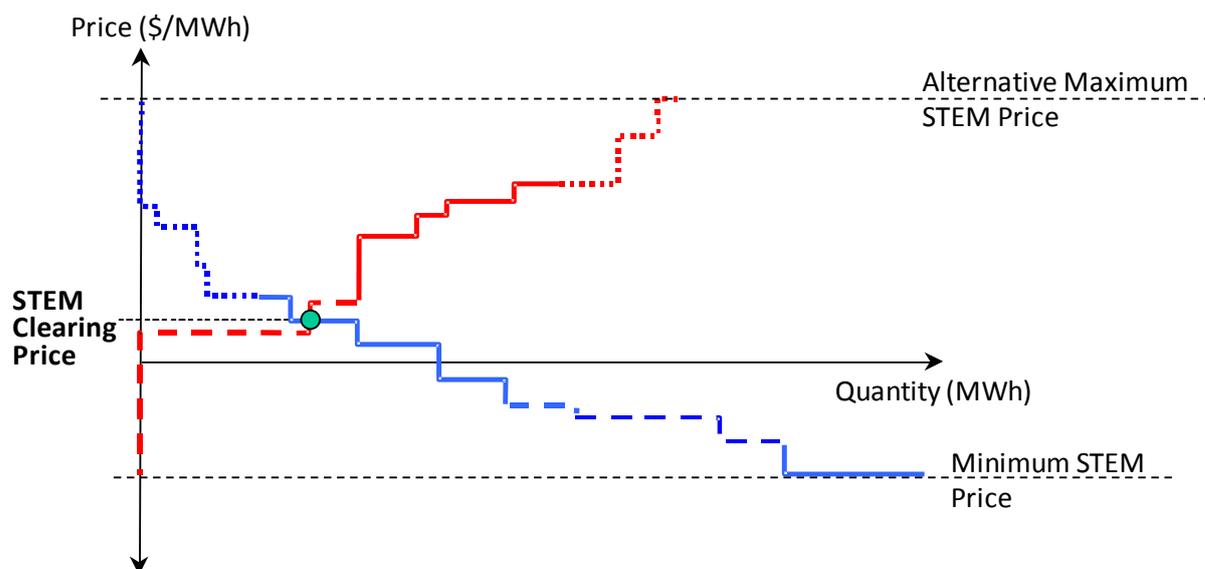
In the discussion that follows we assume that Participant A is a generator only. We do not need to know what the nature of Participants B and C are.

The three participants are unlikely to have exactly the same expectation as to what the STEM price will be. We see that Participant A expects a relatively high price while Participant C expects a relatively low price. Because Participant A expects a high price, it is prepared to pay a high price under its STEM Bid to buy out of its contract position, and hence avoid the need to run expensive generation. Participant C expects a lower price. Its STEM Offers are at relatively low prices because it has lots of low cost under-utilised generation capacity. It is apparent that a result of the STEM auction should be that some of Participant A's STEM Bids are accepted, with its generation being reduced as a result, with Participant C's lower cost STEM Offers being utilised to replace that generation.

STEM Auction

To see how the auction works, we must form all the STEM Offers into one aggregate offer, and all the STEM Bids into one aggregate bid. In Exhibit 9-2 the STEM Bids are shown as a reduction in net supply relative to the Net Bilateral Position as prices fall but in Exhibit 9-3 the bid curve is reversed as it represents an increase in gross demand as prices fall.

Exhibit 9-3: The STEM auction



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Exhibit 9-3 shows the same information as is shown in Exhibit 9-2, but the information has been re-organised to show the point where the total STEM Bids accepted equals the total STEM Offers accepted. It is apparent that the first step of Participant C's STEM Offer is fully scheduled, being used to offset the energy reduction caused by accepting all of Participant A's STEM Bids and some of Participant B's STEM Bids.

The point where the curves cross defines the market clearing STEM solution. The STEM clearing price is shown. All offers to sell with lower offer prices and all bids to buy with higher bid prices are deemed scheduled in the STEM. The STEM is designed to match supply with demand while supplying the maximum possible quantity of energy at the lowest possible price in all situations. Bids and offers with prices equal to the STEM price will be subject to additional tie breaking rules. Note that the STEM price can be negative.

The example illustrated above shows that the STEM clearing price would have a reasonable value even if no Portfolio Demand Curve were submitted to the STEM Auction. This is because, as shown in Exhibit 9-1, the supply curves for generators for levels below their Net Bilateral Position will be converted to STEM Bids. Even if no energy was scheduled in the STEM, the price would still have to be between the cost of the highest priced STEM Bid and the lowest priced STEM Offer, and this difference will normally only be a small amount (e.g. a few cents per MWh). The STEM auction process will select the lowest price.

Those scheduled in the STEM will be required to settle the amount they are scheduled for with the IMO at the STEM clearing price. That is, net suppliers will be paid the STEM price and net consumers must pay the STEM price.

Once the STEM has been solved, each Market Participant will have a Net Contract Position equal to its Net Bilateral Position as modified by its net purchase or sale in the STEM.

9.4 The Balancing Market

Outline

The Balancing Market accounts for differences between day-ahead Net Contract Positions, established after the STEM process, and actual outcomes. This is achieved through:

- Price-based dispatch of Facilities to match supply to demand; and
- Settling participant' differences from their Net Contract Positions at a common Balancing Price.

Only participants that deviate from their Net Contract Position are exposed to the Balancing Price. Deviations can occur for physical reasons (higher or lower than expected demand, generator outages etc) or for market reasons (lower priced generation being dispatched in preference to higher priced generation).

Participation in the Balancing Market

Participation via price-based dispatch in the Balancing Market is mandatory for generating Facilities with a sent out capacity of 10 MW or more. These Facilities must meet certain technical and communication criteria regarding their ability to receive, confirm and respond to electronic Dispatch Instructions from System Management. The IMO may impose conditions on Facilities that do not meet these requirements, including smaller Facilities, regarding their participation in the Balancing Market. For example, requiring that quantity in the Facility's Balancing Submissions must be priced at the Price Caps¹⁷. Note also that a Facility with a sent out capacity of 10 MW or more that does not comply with the Balancing Facility requirements is ineligible to receive Capacity Credits.

Resource Plans

The first step in the operation of the Balancing Market is the submission of Resource Plans. Resource Plans must be submitted to the IMO by 12:50 PM on the Scheduling Day. The Market Rules also provide for standing Resource Plans.

IPPs must prepare Resource Plans indicating for each Trading Interval of the Trading Day how they expect to operate each of their Scheduled Generator Facilities to match their Net Contract Position plus any self-supplied load less any known shortfall relative to their Net Contract Position. Resource Plans must also indicate intended synchronisation and de-synchronisation times. Resource Plans must also be submitted for Dispatchable Load Facilities.

Verve Energy is also required to submit Resource Plans for any Scheduled Generator Facilities which it elects to operate on a standalone basis outside its Balancing Portfolio. If Verve Energy does elect to operate a Facility on a standalone basis¹⁸, then for balancing purposes that Facility is treated as though it were an IPP Facility.

A Resource Plan specifies for each Trading Interval a target MW level and, if that is different to the MW target at the end of the previous interval, the rate at which the Facility will ramp to the target level.

The IMO provides Resource Plans to System Management.

Resource Plans enable System Management, along with forecasts of intermittent generation and system demand, to prepare an initial Dispatch Plan for the Verve Energy Portfolio and to assess any potential system security implications. The IMO also provides participant Fuel Declarations to System Management at 1:30 PM each Scheduling Day.

¹⁷ The Minimum STEM Price or the Alternative Maximum STEM Price.

¹⁸ The Rules provide for Verve Energy conduct one 1 month trial of a Facility on a standalone basis before deciding whether to permanently operate the Facility on a standalone basis (subject to System Management and IMO agreement).

Verve Energy Dispatch Plan

The Verve Energy Dispatch Plan covers how Facilities within the Verve Energy Portfolio will be scheduled to meet expected generation requirements not covered by Resource Plans and Ancillary Services requirements. In preparing the Verve Dispatch Plan, System Management uses dispatch guidelines supplied by Verve Energy including daily energy/fuel constraints, the order in which Facilities within the Portfolio are to be scheduled, including commitment/de-commitment, and plant technical capabilities and constraints. System Management must provide the initial Dispatch Plan for a Trading Day to Verve Energy by 4:00 PM on the Scheduling Day (2 hours before Verve Energy is required to make its first Balancing Submission for the following Trading Day).

Balancing Submissions

By 6:00 PM on the Scheduling Day, Market Generators must present Balancing Submissions to the IMO representing the available capacity of each of their Facilities (or, for Verve Energy, its Portfolio). A Balancing Submission is a series of Price-Quantity Pairs for a Trading Interval representing quantities the participant is prepared to have a Facility dispatched in the interval if the Balancing Price exceeds the level specified by the participant subject to the Ramp Rate Limit for the Facility (or the Verve Energy Portfolio). Non-Scheduled Generators must submit a single price at which they are prepared to have the Facility dispatched downwards.

The prices which participants specify in Balancing Submissions must:

- Not be less than the Minimum STEM Price or greater than the Maximum (or Alternative Maximum) STEM Price.
- Not exceed their reasonable expectation of the Facility's short run marginal cost of generating the associated quantity when such behaviour relates to market power.

Balancing Merit Order and Balancing Forecast

The IMO then prepares a Forecast Balancing Merit Order by loss factor adjusting prices in Balancing Submissions to a reference location (Muja)¹⁹ and stacking all of the quantities from Balancing Submissions in their loss factor adjusted price order.

The IMO then prepares Balancing Forecasts along the lines indicated in Exhibit 9-4 using demand and Non-Scheduled generation (e.g. wind) forecasts²⁰ provided by System Management and the Forecast Balancing Merit Order²¹. The figure shows in stylised form how the forecast Balancing Price and quantities are determined with reference to the intersection of forecast overall generation requirements and the Forecast Balancing Merit Order. The quantities in Balancing Submissions which are expected to be dispatched are shown as shaded blocks. Multiple blocks can relate to the same

¹⁹ Verve Energy Portfolio submission prices are already expressed at the reference node.

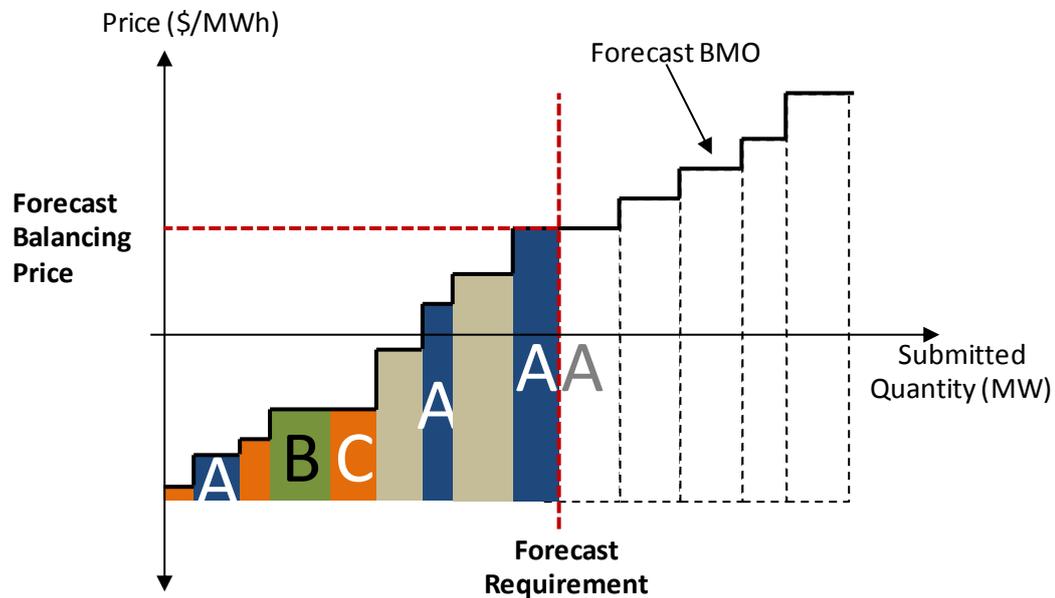
²⁰ For unscheduled generation quantities in the Forecast Balancing Merit Order, the IMO inserts the Facility's forecast quantity at the price submitted by the participant.

²¹ Being a forecast, this process ignores plant Ramp Rate Constraints.

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Facility as illustrated, for example, by the four shaded blocks labelled A in Exhibit 9-4 relating to submissions for the same Facility. The sum of the widths of each of the *shaded* A blocks indicates the amount which Facility A is forecast to generate in the Trading Interval.

Exhibit 9-4: Balancing Forecast Principles



As illustrated in Exhibit 9-4, for quantities B and C, it is possible for submission prices to be tied in the Balancing Merit Order. To determine the order of these quantities in the Balancing Merit Order, the IMO assigns a random number each day to each Balancing Facility, i.e. a tie-break mechanism.

The IMO then publishes to each Market Participant the quantity which each of its Facilities (and for Verve Energy, its Portfolio) are expected to generate in each Trading Interval along with the forecast Balancing Price.

The IMO also provides the Forecast Balancing Merit Order, but without prices, to System Management. This enables System Management to plan for dispatch, including reviewing the quantities the Verve Portfolio is expected to generate, assessing overall system security implications and if need be, as discussed later, issuing Dispatch Advisories.

Iterative Process

Market Participants are able to review and revise their Balancing Submissions in light of market forecasts. All submissions must reflect genuine intentions and not be designed to mislead other participants. In this regard, participants are subject to civil penalty provisions.

The forecasting process outlined iterates forward for all future Trading Intervals in the Balancing Horizon. Until 6:00 PM on the Scheduling Day, the Balancing Horizon includes intervals prior to 8:00 AM the next day (the end of the current Trading Day). After 6:00 PM on the Scheduling Day, the Balancing Horizon extends by 48 intervals (the end of the next Trading Day). However, participants

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are not permitted to revise Balancing Submissions for a Trading Interval once Gate Closure has occurred for that Trading Interval except in certain circumstances (for example if a Forced Outage occurs). Submissions for IPPs, and for Verve Energy Standalone Facilities, are subject to a rolling Gate Closure of between 2 and 6 hours as determined by the IMO in accordance with the Market Rules (initially set at 6 hours with a view to reducing to 2 hours).

The Market Rules provide Verve Energy fewer opportunities to revise its Balancing Portfolio Submissions and these submissions are locked in ahead of the Facility Gate Closure period. This reflects the additional flexibility Verve Energy has in managing its Portfolio, compared to managing individual Facilities through simple price and quantity submissions, and its dominant position in the market.

As discussed later, the Market Rules ensure that participants are able to update their Balancing Submissions to take account of any Load Following they are cleared to provide in the LFAS market.

Dispatch Process

System Management is responsible for dispatching the power system, which subject to maintaining system security requirements must be in accordance with the Balancing Merit Order.

In addition to information described previously, including Resource Plans and Fuel Declarations, Verve Energy Dispatch Guidelines, Network Control Service Contracts, and the Balancing Merit Order, System Management relies on a range of other information including:

- Network and generator outage information.
- Load and Non-Scheduled Generation forecasts.
- Non-Balancing Dispatch Merit Orders (described later) for Demand Side Programmes and Dispatchable Load Facilities.
- Ancillary Service Contracts (and, as discussed later, the LFAS Market).
- Systems for monitoring the state of the Power System in real time.
- Some Standing Data.

In dispatching the Power System, System Management's instructions to participants take various forms including:

- **Dispatch Orders** are issued to generating Facilities in the Verve Energy Balancing Portfolio
- **Dispatch Instructions** are issued to resources in:
 - the Balancing Merit Order (IPP Generator Facilities and Verve Energy Standalone Facilities) (Dispatch Instructions to the Verve Energy Balancing Portfolio are in effect given through Dispatch Orders); and

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- the Non-Balancing Merit Orders (Demand Side Programs and Dispatchable Loads).
- **Operating Instructions** are issued to Network Control Services, Commissioning or Reserve Capacity Tests, Back-up LFAS and Ancillary Services other than LFAS, and Supplementary Capacity Contracts.

System Management is required to monitor the compliance of Market Participants with instructions and advise the IMO of any non-compliance. It also provides to the IMO all instructions it has issued. The IMO is responsible for investigating any non-compliance and deciding what if any action is to be taken.

The IMO monitors the performance of System Management.

Dispatch of Balancing Facilities

For dispatch purposes System Management uses the most recent Balancing Merit Order received from the IMO. Under normal circumstances, System Management issues instructions to Facilities leading into each Trading Interval in accordance with the prevailing Balancing Merit Order. However, System Management may deviate from the Balancing Merit Order in order to ensure that system security requirements can be maintained. The Market Rules and PSOPs set out the protocols System Management must follow in this regard, including issuing Dispatch Advisories (discussed later) to provide opportunities for Market Participants to respond when there is time to do so.

In formulating instructions, System Management follows a similar process to that outlined in relation to Balancing Market forecasts. However, System Management's process must take account of some physical requirements, such as Facility Ramp Rate Limits, the expected trend in overall generation requirements during the Trading Interval, network constraints etc. System Management issues instructions to IPP Facilities and Verve Standalone Facilities in accordance with the Balancing Merit Order (Dispatch Instructions under the Market Rules) and dispatches Facilities with the Verve Energy Portfolio (Dispatch Orders under the Market Rules) to meet the overall Portfolio quantity determined by the Balancing Merit Order.

System Management may only depart from the order in the Balancing Merit Order, and ultimately from the Balancing Merit Order itself, for system security purposes, and departures along with the reason for the departures must be published. There are also merit orders for demand side resources as discussed below.

Non-Balancing Dispatch merit Order

Market Participants with Dispatchable Loads or Demand Side Programmes must include (and update) in Standing Data their Facility peak and off-peak²² prices for being dispatched down from their Resource Plan or otherwise prevailing level. Consumption increase prices must also be submitted in

²² Off Peak Trading Intervals occurring between 10:00 PM and 8:00 AM.

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respect of Dispatchable Load Facilities. The IMO uses these prices to prepare Non-Balancing Dispatch Merit Orders²³ which it provides to System Management by 1:30 PM each Scheduling Day.

If System Management needs to dispatch down a Demand Side Programme or Dispatchable Load it will follow the Non-Balancing Dispatch Merit Order to the extent practicable and the Facility will receive its submitted price (pay-as-bid) for the MWh reduction²⁴. System Management may only dispatch Demand Side Programmes or Dispatchable Loads for system security purposes and only then if resources in the Balancing Merit Order, including out of merit options, are insufficient.

Dispatch Advisories

System Management must inform Market Participants and Network Operators of impending or current situations that could have security ramifications for Market Participants and Network Operators. It does this by issuing Dispatch Advisories when there has been, or is likely to be, an event that will require dispatch of Facilities out of merit or will restrict communication between System Management and any of the Market Participants, Network Operators, or the IMO.

System Management must issue a Dispatch Advisory if any of the following has or is expected to occur:

- Emergency load shedding.
- Committed generation exceeding forecast load.
- Ancillary Service requirements not being met.
- Significant outages of generation, transmission or customer equipment.
- Significant fuel supply restrictions.
- Unavailability of scheduling or communication systems required for dispatch
- Out of merit dispatch including the overall Verve Energy Balancing Portfolio.
- Deviation from the LFAS Merit Order (discussed later).
- A High Risk Operating State or an Emergency Operating State.

A Dispatch Advisory includes a statement of the operating state (Normal, High-Risk, or Emergency) during the period to which the advisory relates and information on how Market Participants should respond to the situation. The Market Rules recognise that sometimes System Management will have to react so quickly to a situation that it will not be able to issue a Dispatch Advisory until after the event.

²³ Peak and off peak consumption increase and consumption decrease merit orders.

²⁴ If System Management were to dispatch a Dispatchable Load upwards, the Facility would pay its submitted price.

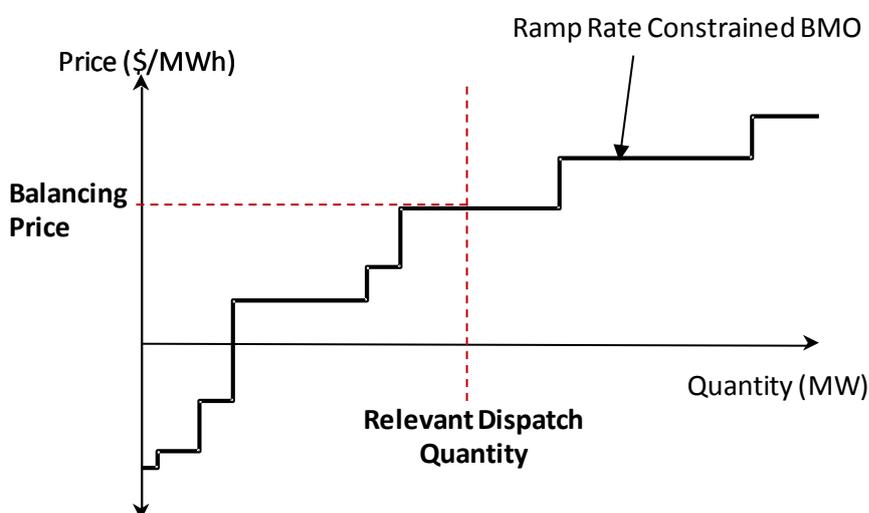
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Market Participants are obliged to keep System Management informed of any circumstances that they become aware of that might result in System Management issuing a Dispatch Advisory.

Balancing Prices

After each Trading Day, the IMO establishes the Balancing Price for each Trading Interval from the final Balancing Merit Order, adjusted to take Facility and Portfolio Ramp Rate Limits into account, and the actual end of interval MW generation requirement (called the Relevant Dispatch Quantity). This process is summarised in Exhibit 9-5. It is similar to that outlined in Exhibit 9-4 except that the available Balancing Submission quantities are adjusted to reflect the actual generation at the start of the Trading Interval and Ramp Rate Limits for IPP and Verve Standalone Facilities and for the Verve Energy Balancing Portfolio.

Exhibit 9-5: Determining the Balancing Price



Under normal circumstances the IMO publishes Provisional Balancing Prices on the next Trading Day and Final Balancing Prices on the next Business Day after that.

9.5 The LFAS Market

The LFAS Market operates in parallel with the Balancing Market. To be eligible to participate in the LFAS Market, a Facility must meet certain requirements which are set out in the PSOPs²⁵. There are separate Upwards LFAS and Downwards LFAS markets.

The first step in the LFAS Market cycle is the provision by 12:00 PM each Scheduling Day by System Management to the IMO of forecast LFAS requirements for each Trading Interval of the following Trading Day.

²⁵ For example, minimum acceptable ramp rates, ability to interface with and be controlled by AGC to regulate system frequency, dead-band etc.

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The next step is the presentation of LFAS Submissions by eligible participants. An LFAS Submission is a series of Price-Quantity Pairs relating to a Facility or the Verve Energy Portfolio for a Trading Interval. The MW quantity in each pair plus the sum of any lower priced quantities represents the MW range which the participant is prepared to reserve for a Facility (or Portfolio) to provide LFAS duty relative to its balancing dispatch point at the price specified in that pair.

Verve Energy must, and other participants may, make LFAS Submissions for Trading Intervals in the Balancing Horizon. As the default Ancillary Service provider, Verve Energy must:

- Present sufficient LFAS Submissions for its Portfolio, and any Standalone Facilities, to cover the entire amounts of Upwards LFAS and Downwards LFAS specified by System Management for each Trading Interval.
- Submit a price per MW for providing any Upwards or Downwards Back-Up LFAS which System Management may need to draw on (for example, should an LFAS Facility fail).

The first LFAS Submissions for a Trading Day are therefore made by 6:00 PM on the Scheduling Day, when the Balancing Horizon is extended through the next Trading Day and initial Balancing Submissions are made.

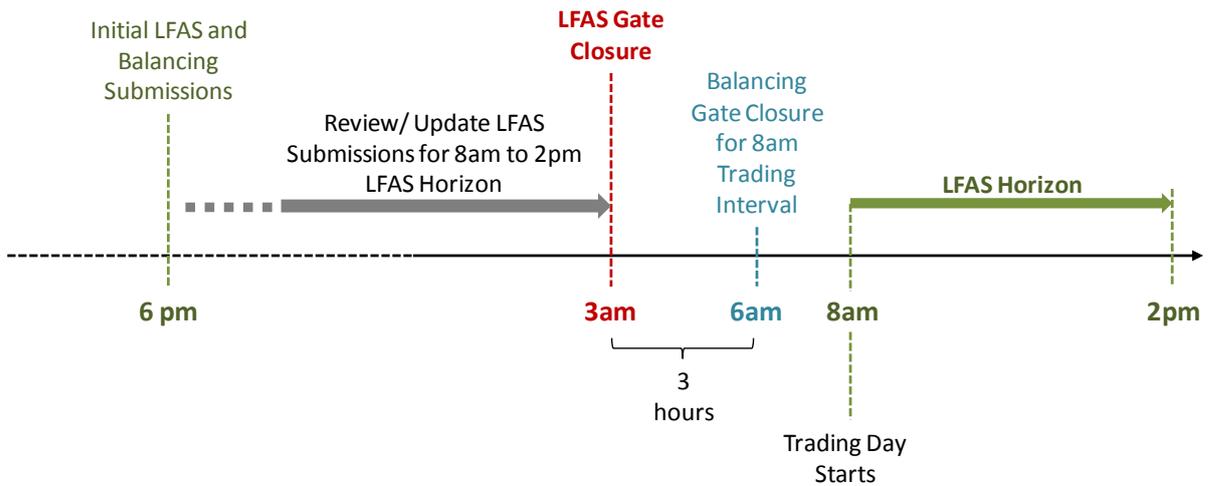
The IMO then creates Forecast Upwards and Downwards LFAS Merit Orders by stacking the quantities in respective Upwards and Downwards LFAS Submissions in price order.

The IMO then prepares Downwards and Upwards LFAS Forecasts from the intersection of each LFAS Merit Orders with the forecast LFAS requirement (following the principles illustrated previously in Exhibit 9-4 for the Balancing Forecasts). The IMO then provides the Forecast LFAS Merit Orders to System Management and provides to participants the forecast LFAS Price and any LFAS quantity they are forecast to provide for each Trading Interval of the Balancing Horizon.

Participants are then able to review their LFAS Submissions in light of Balancing and LFAS Forecasts. This process is iterative, as for Balancing Submissions, until LFAS Gate Closure.

LFAS is scheduled in 6-hour fixed windows (the LFAS Horizon) commencing at 8:00 AM, 2:00 PM, 8:00 PM and 2:00 AM. Gate Closure for LFAS Submissions occurs 3 hours prior to the Balancing Gate Closure corresponding to the first Trading Interval in the LFAS Horizon. Exhibit 9-6 shows these relationships for the first 6 hour LFAS Horizon on a Trading Day, which starts at 8:00 AM, assuming a 2 hour Balancing Gate Closure.

Exhibit 9-6: Sequencing LFAS Horizon and Gate Closure



Again assuming a 2 hour Balancing Gate Closure, Exhibit 9-7 shows the relationship between LFAS and Balancing Gate Closure times and each of the 6 hour LFAS Horizons.

Exhibit 9-7: LFAS Horizons and Gate Closure Times

LFAS Gate Closure	Balancing Gate Closure	LFAS Horizon Trading Intervals ²⁶	
		First	Last
3:00 AM	6:00 AM	8:00 AM	1:30 PM
9:00 AM	12:00 PM	2:00 PM	7:30 PM
3:00 PM	6:00 PM	8:00 PM	1:30 AM
9:00 PM	12:00 AM	2:00 AM	7:30 AM

This cycle ensures that participants have opportunities to adjust their Balancing Submissions to reflect any LFAS quantity they have been cleared to provide in the LFAS Market. Participants are responsible for managing any interactions between their Balancing and LFAS Submissions.

As noted previously, Verve Energy has fewer opportunities to adjust its Portfolio Balancing Submissions than for individual Facility based submissions. However, it has opportunities to adjust its Portfolio Balancing Submissions for some Trading Intervals within one hour after LFAS Gate Closure so that it can take account of any cleared (or un-cleared) LFAS quantities. For example, assuming a 2 hour Balancing Gate Closure, Verve Energy may update its Balancing Portfolio Submissions as shown in Exhibit 9-8. The 6:00 PM resubmission time coincides with the time when initial Balancing Submissions must be presented for the next day.

²⁶ Half-hour starting times

Exhibit 9-8: Verve Portfolio Balancing Re-Submissions and LFAS Horizons

LFAS Gate Closure	Balancing Gate Closure	Starting of 6 Hour LFAS Horizon	Balancing Portfolio Submissions	
			Re-submission Time	For Trading Intervals
3:00 AM	6:00 AM	8:00 AM	4:00 AM	8:00 AM +
9:00 AM	12:00 PM	2:00 PM	10:00 AM	2:00 PM+
3:00 PM	6:00 PM	8:00 PM	4:00 PM	8:00 PM+
			6:00 PM ²⁷	10:00 PM+
9:00 PM	12:00 AM	2:00 AM	10:00 PM	2:00 AM +

Once LFAS Gate Closure occurs, from each of the Upwards and Downwards Merit Orders the IMO determines the lowest priced selection of LFAS providers to meet LFAS requirements and determines the relevant LFAS price from the highest priced LFAS provider selected.

Operationally, System Management activates accepted LFAS Facilities and places them under AGC control for the Trading Interval. Where a shortfall in LFAS occurs following a reduction in LFAS capability, System Management is able to call on Verve Back-up LFAS (which can be provided from the Portfolio or Stand-alone Facilities).

9.6 Energy Market and LFAS Settlement

The IMO is responsible for settling the STEM, Balancing and LFAS markets.

STEM Settlement

The key components of the STEM settlement are:

- Those who buy energy in the STEM, whether by increasing consumption or decreasing supply, pay the IMO for that energy.
- Those who sell energy into the STEM, whether by decreasing consumption or increasing supply, are paid by the IMO for that energy.

Balancing

The IMO charges or pays Market Participants for any Balancing Quantity attributed to them. A participant's Balancing Quantity is the difference in a Trading Interval between the actual quantity it purchased or supplied (Loss Adjusted in either case) and its Net Contract Position.

²⁷ Initial Balancing submissions for next Trading Day.

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Balancing Settlements are as follows:

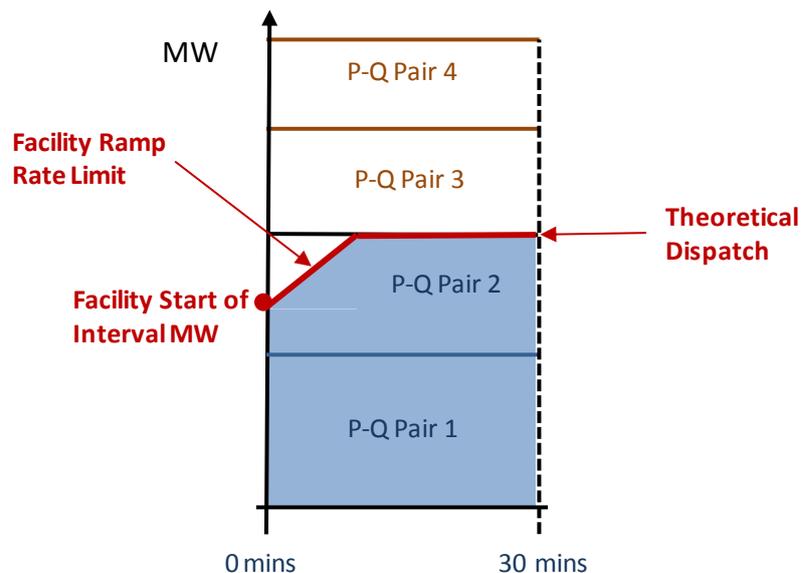
- Market Generators receive the Balancing Price for Balancing Quantity they supply to the market (i.e. in excess of their Net Contract Position) and pay the Balancing Price for Balancing Quantity they purchased from the market. They may also be entitled to Constrained On or Constrained Off compensation as described in the next section.
- Market Customers receive the Balancing Price for Balancing Quantity they sold back to the market (i.e. quantity less than their Net Contract Position) and pay the Balancing Price for Balancing Quantity they purchased from the Market. Market Customers are able to request reductions from their Demand Side Programmes to avoid exposure to high Balancing Prices.
- Demand Side Programmes and Dispatchable Loads dispatched by System Management receive the standing data (pay-as-bid) price specified by the relevant Market Participant. (Interruptible Loads are funded under Ancillary Service contracts).

Constrained on and off compensation

A Balancing Facility, including the Verve Energy Balancing Portfolio that was dispatched out of merit by System Management is eligible for Constrained On or Constrained Off Compensation, subject to certain criteria. A Constrained On situation occurs if more energy has been dispatched from a Facility (or the Verve Energy Balancing Portfolio) than its Balancing Submission indicated when compared to the Balancing Price. A Constrained Off situation occurs if more energy could have been dispatched from a Facility (or the Verve Energy Balancing Portfolio) when its Balancing Submission is compared to the Balancing Price.

The IMO determines Constrained On and Constrained Off quantities by comparing the actual energy generated by a Facility (or the Verve Energy Balancing Portfolio) to the theoretical amount, called the Theoretical Energy Schedule that should have been dispatched given its Balancing Submission and the Balancing Price. For example, Exhibit 9-9 illustrates the Theoretical Energy Schedule for a Facility with a Balancing Submission comprising 4 Price-Quantity Pairs, of which 1 and 2 are priced below the Balancing Price and 3 and 4 are priced above the Balancing Price. Price-Quantity Pairs 1 and 2 should therefore have been dispatched to the maximum extent practical as indicated by the red line showing the Facility ramping up at its Ramp Rate Limit from its actual MW level at the start of the interval to the top of Price-Quantity Pair 2. The area shaded in blue is thus the Theoretical Energy Schedule. Any MWh generated above that level is Upwards Out of Merit Generation.

Exhibit 9-9: Theoretical Energy Schedule Example



Similarly if actual MWh generated by a Facility is less than its Theoretical Energy Schedule, the difference is Downwards Out of Merit Generation. Maximum and Minimum Theoretical Energy Schedules are calculated for assessing Upwards and Downwards Out of Merit Generation respectively. These are the same except when the Balancing Price equals the price (Loss Adjusted) in a Price-Quantity Pair. When that occurs, the Minimum Theoretical Energy Schedule is the maximum energy that could have been dispatched from all of the Facility's Price-Quantity Pairs with a Loss Factor Adjusted price less than the Balancing Price whereas the Maximum Theoretical Energy Schedule is the maximum energy that could have been dispatched from Price-Quantity Pairs with a Loss Factor Adjusted price less than or equal to the Balancing Price²⁸.

If any Upwards or Downwards out of Merit Generation has occurred, the IMO deducts any non-qualifying quantity associated with the provision of LFAS²⁹ and, if in excess of the Settlement Tolerance, attributes any remaining Upward or Downward Out of Merit Generation to individual Price-Quantity Pairs within the Facility's Balancing Submission. This process takes account of Ramp Rate Limits and the maximum energy which could have been dispatched up or down from each Price-Quantity Pair given the Facility's actual MW level at the start of the Trading Interval.

The IMO compensates the Facility (or Verve Energy Balancing Portfolio):

- For any energy Constrained On from each Price-Quantity Pair at the submitted price less the Balancing Price.

²⁸ Outages are also taken into account.

²⁹ If an IPP or Verve Energy Standalone Facility provides Ancillary Services other than LFAS or is dispatched to provide a Network Control Service, it is ineligible for compensation. In the case of the Verve Energy Balancing Portfolio, any out of merit generation associated with Spinning Reserve or Load Rejection Reserve that was triggered is ineligible for Constrained On or Off compensation.

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- For any energy Constrained Off from each Price-Quantity Pair at the Balancing Price less the submitted price).

Non-Scheduled Generation is eligible for Constrained On Compensation if the Balancing Price was less than its Balancing Submission price³⁰ and the Facility was not dispatched down by System Management. Similarly, it is eligible for Constrained Off Compensation if the Facility was dispatched down by System Management but its Balancing Submission price was less than the Balancing Price.

Reconciliation

Since Loss Factors are based on averaged marginal losses, and marginal losses tend to exceed average losses, the application of loss factors tends to mean that consumers pay more than is required to fund losses. Some market revenue will therefore typically need to be refunded to Market Customers each month as a non-STEM settlement payment called “reconciliation”. While this is expected to be a payment to Market Customers, there may be some exceptions where additional payments must be made by Market Customers.

Constrained On and Constrained Off payments to Market Generators are funded by Market Customers, prorated according to their monthly energy.

LFAS Settlement

LFAS Facilities activated by System Management receive the relevant LFAS Price determined by the IMO as described previously. Verve Energy is paid the relevant Back-up LFAS Price if System Management calls on this service.

9.7 Market Advisories

The IMO must inform Market Participants of impending situations that could impact market outcomes. It will do this by issuing market advisories in the following situations:

- Market system outages, whereby aspects of the market cannot run normally due to systems failures; and
- Notification of suspension of any aspect of the market.

These advisories will include information on how Market Participants should respond to the situation. Note that advisories related to dispatch are called Dispatch Advisories, and are issued by System Management, as discussed in section 9.4.

³⁰ Non-Scheduled Generators submit a single price for downwards dispatch from their current level.

10. Metering

Most of the metering processes are described outside of the Wholesale Market Rules. This is because the metering processes must address the requirements of wholesale, retailers and access metering. Hence the Market Rules focus on who must provide metering data, the process for submitting that data and the interface between the requirements of the market and the general metering regime.

A Metering Data Agent is required to maintain a registry of which meter corresponds to each Market Participant and must read meters and provide the data to the IMO for settlement purposes. Meter registry data must be provided to the IMO as required to support Facility registration.

Each Network Operator has the option to be the Metering Data Agent for its own network, but if it does not take up this option then Western Power will fill this role.

The Metering Data Agent must provide meter data to the IMO on a monthly basis (though may submit data more frequently) where this data includes meter data for the previous Trading Month, and any updates to metering data previously submitted to the IMO. The Metering Data Agent must support the IMO in matters such as providing any additional data required in setting Individual Reserve Capacity Requirements for individual Market Customers.

Each Metering Data Agent must operate to a Metering Protocol. This is a generic term that means any arrangement between the Metering Data Agent and the wholesale/retail Market Participants it provides the service to. This generic term is used because some Metering Data Agents may be covered by the Access Code, while others may not be.

Any metering disputes arising in the wholesale market must be translated by the Metering Data Agent into an equivalent dispute under the Metering Protocol.

While a Metering Data Agent may have other metering duties under its Metering Protocol, these are not subject to the Market Rules.

11. Settlement

11.1 Settlement Process

Settlements involve three main processes:

- STEM transactions are settled on a weekly basis.
- Non-STEM transactions are settled on a monthly basis.
- Any adjustments to settlement are made at least once every three months via a settlement adjustment process that corrects both STEM and Non-STEM settlements.

The STEM is a forward market and no meter data is required for its settlement. For this reason the STEM market can be settled on a different timeframe from other transactions. A Trading Week is a period of seven days starting at 8:00 AM. on Thursday and STEM transactions for that Trading Week will be summarised in daily STEM Settlement Statements and a weekly STEM Invoice. The STEM is settled on the third business day following the completion of the Trading Week.

All transactions other than STEM settlement are included in the Non-STEM Settlement Statements issued by the IMO following each Trading Month and after meter data has been received.

Each settlement statement includes data in sufficient detail for the Market Participants to verify the accuracy of the statement.

The settlement adjustment process calculates the change in settlement position of all Rule Participants after accounting for all changes to settlement data stemming from updated data and resolutions of Notices of Disagreement and Disputes. A Notice of Disagreement is a relatively straightforward way for a Rule Participant to notify the IMO of any aspect of their settlement statements that it disagrees with. Upon receipt of such a notice, the IMO will investigate the issue itself if it relates to data developed by the IMO, or it will forward it on to the relevant Metering Data Agent or System Management. The IMO has three months to report back to a Market Participant as to whether it believes the original settlement statement was wrong. Payment of the originally invoiced amount must be made in the interim.

If the IMO issues an Adjusted Settlement Statement, a Market Participant can also issue a Notice of Disagreement up until nine months have elapsed since the original Settlement Statement was issued. This feature is included because the Market Rules do not require the IMO to retain old versions of settlement software in an operable fashion for more than 12 months (because of the cost of maintaining licenses etc).

If the IMO does not address an issue to the satisfaction of the Rule Participant through the disagreement process, the Rule Participant can dispute the matter. If the dispute is not resolved to the satisfaction of the Rule Participant, it has the option of taking the IMO to court.

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11.2 Settlement Timelines

Exhibit 11-1 presents a summary of the Market Settlement timetable. In this table:

- “D” denotes the Trading Day.
- “W” denotes the Trading Week, starting on a Thursday, in which the Trading Day occurs. Trading Weeks relate to the settlement of the STEM.
- “M” denotes the Trading Month, comprising all Trading Days that commence within a calendar month, in which the Trading Day occurs. Trading Months are used for the settlement of non-STEM transactions.
- “BD” denotes a business day. Where a range of dates is presented, the IMO has discretion to choose a single date within that range, but must publish the actual dates prior to the start of each financial year.
- “SA” denotes the date on which a Settlement Adjustment process commences.

Exhibit 11-1: The Settlement Timetable

Day	Event
D	Trading Day ends.
1 st BD after a Trading Week	The IMO issues a STEM Settlement Statement for each day and a STEM invoice for the preceding Trading Week in which day D occurs.
2 nd BD after release of STEM Settlement Statement	Settlement date for STEM Invoice.
20 th BD after release of STEM Settlement Statement	Deadline for notifying IMO of disagreement with STEM settlement statement. Any resolution of disagreements will be reflected in an Adjusted Settlement Statement (see below).
1 st BD of month M+2	Generator and contestable customer meter data submitted to IMO by Metering Data Agents.
Not less than 10 BDs and not more than 5 BDs prior to non-STEM Settlement Statement issuance.	Submission of Capacity Credit transfers for the Trading Month. Prior to the Non-STEM Settlement Statement issuance date the IMO will go through a process to ensure that the Capacity Credit transfers are not inconsistent with the Capacity Credits held by generators and the Reserve Capacity Requirements of the Market Customers to whom they are transferred.
6 th BD of month M+2	Non-STEM Settlement Statements for trading day D are issued. These are based on actual meter data for generators (the operational meter data in the case of Verve Energy Facilities that are not metered) and contestable customers, and estimates of the aggregate non-interval meter load of

Day	Event
	Synergy.
6 th BD of month M+2	Invoice issued based on Non-STEM Settlement Statement for month M.
8 th BD of month M+2	Settlement date for Non-STEM Invoice.
20 th BD after issuance of Non-STEM Settlement Statement issued	Deadline for notifying the IMO of any disagreements with the Non-STEM Settlement Statement.
SA, a date set annually and occurring at least once every 3 months.	Commencement of Settlement Adjustment Process. All adjustments to settlement input data for STEM and Non-STEM transactions to be included must be provided to the IMO by this time. Changes in data will result from voluntary corrections of data by the issuing party or as a result of resolving disagreements and disputes. The issuing parties are, for metering data, the Metering Data Agents, for dispatch instruction related data, System Management, and for all other data the IMO.
By 20 th BD after SA	IMO must have rerun all settlement runs to which adjustments have been made and must have issued Adjusted Settlement Statements in respect of all STEM or Non-STEM Settlement Statements originally issued.
2 nd BD after issuance of Adjusted Settlement Statements	Invoice issued based on the Adjustment Settlement Statements issued as a result of the current settlement adjustment process.
2 nd BD after issuance of invoices for Adjusted Settlement Statements	Settlement date for Adjusted Settlement Statement Invoice.
20 th BD after issuance of invoices for Adjusted Settlement Statements	Deadline for notifying the IMO of any disagreements with an Adjusted Settlement Statement. Any adjustments will be addressed in a future adjustment process.

11.3 The Components of Settlement

Settlement Statements will include a variety of transactions. The key transactions are summarised in Exhibit 11-2.

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Exhibit 11-2: The Components of Settlement

Settlement Component	Who Funds It?	On What Basis?
STEM	STEM Participants	STEM Quantities Traded
<p>Targeted Reserve Capacity Cost.</p> <p>This is the cost incurred by the IMO in procuring just enough Capacity Credits (or Supplementary Capacity) to cover the difference between the Capacity Credits traded bilaterally and the total requirement of the market. Reserve Capacity security deposits drawn down by the IMO, if any, may offset any Supplementary Capacity cost.</p>	Market Customers	<p>The Market Customer's Individual Reserve Capacity Requirement less the number of Capacity Credits it holds.</p> <p>If the customer has fully met their capacity requirement by trading Capacity Credits bilaterally, they will pay nothing.</p>
<p>Shared Reserve Capacity Costs less the capacity component of Load Following costs.</p> <p>The Shared Reserve Capacity Costs are the costs of procuring Capacity Credits beyond the requirements of the market (to the extent this occurs) less any rebates and security deposits retained by the IMO as a result of non-compliance.</p> <p>The capacity component of Load Following is a rebate stemming from the fact that generators are fully funding these services despite consumers funding their capacity. i.e., both generators and Market Customers are paying for the capacity, so the generator payments are rebated to Market Customers.</p>	Market Customers	<p>In proportion to each Market Customer's Individual Reserve Capacity Requirement.</p> <p>Note that SRCC cannot be less than zero if the IMO has not had to exceed the Reserve Capacity Requirement when acquiring Capacity Credits.</p>
Spinning Reserve Cost (availability components)	Market Generators	Actual generation in each Trading Interval during a Trading Month.
Load Following Cost	Market Customers and Market Generators	Metered MWh during the month for all loads and for Non-Scheduled Generators (but not Scheduled Generators)
Load Rejection Reserve Cost, Constrained On and Constrained Off Compensation costs, Dispatch Instruction Payments to Demand Side Programmes or	Market Customers	In proportion to metered MWh during the month.

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Settlement Component	Who Funds It?	On What Basis?
Dispatchable Loads, Outage Compensation costs, and Reconciliation (which may be negative)		
Balancing Settlement Amounts, including any Constrained On and Constrained Off Compensation and any	Market Customers and Market Generators	MWh deviation from NCP.
Market Fees These are used to fund the IMO, System Management and the Economic Regulation Authority)	Market Customers and Market Generators	Metered MWh during the month.
Default Levy (only following a default)	Market Customers and Market Generators	In the first instance, metered MWh during the month, but eventually adjusted to be relative to the metered MWh over a year.

11.4 Default

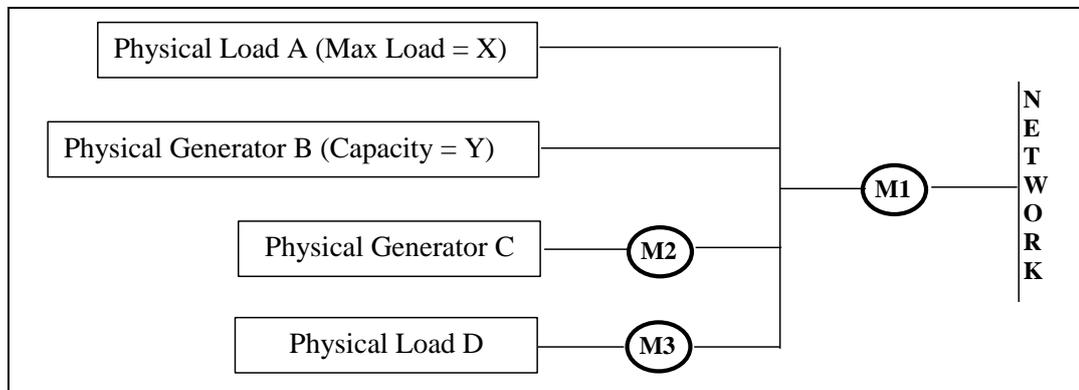
Default rules apply in the event of a Market Participant failing to meet its settlement obligations.

In the event of non-payment of bills the IMO will deem the Market Participant to be in default and may lay claim to credit support that it holds on behalf of the Market Participant. The Market Participant would be given at least 1 Business Day, and at the IMO's discretion, up to five Business Days to rectify the situation. In the event that the situation is not rectified, the Market Participant may, at the discretion of the IMO, be fully or partially suspended from participation in the market.

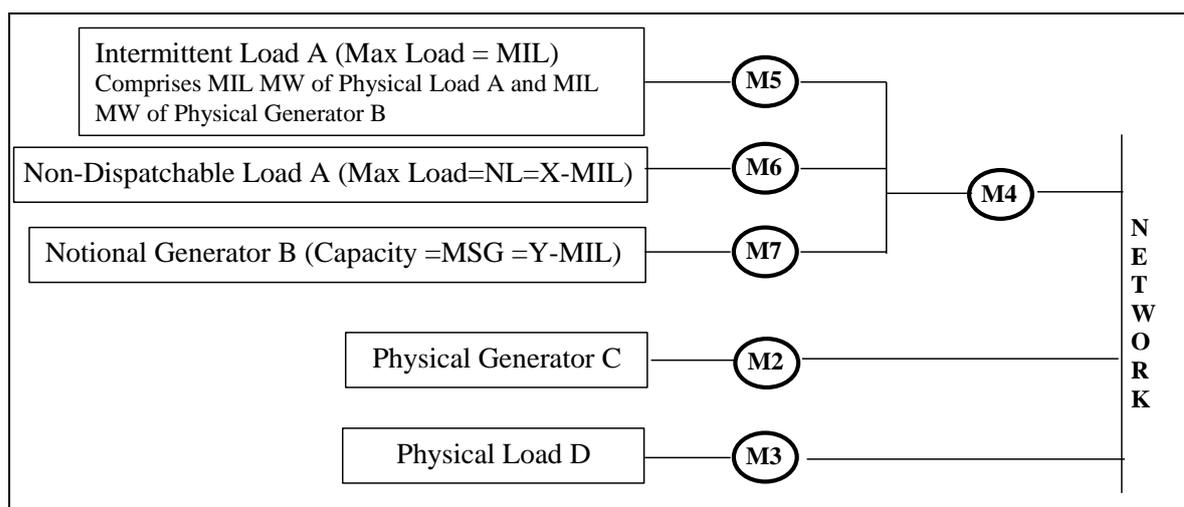
If following a default event the market lacks adequate funds to settle, then the shortfall will be funded by a levy on Market Participants. This levy will be collected a number of days after the default and will be allocated across all Market Participants based on their metered supply or consumption in the preceding month. The funds collected will be used to complete the settlement process. If the defaulting participant eventually pays its outstanding obligations, then the levy will be refunded. At the end of each financial year the default levy will be reallocated between Market Participants based on their metered supply or consumption over the year. This end of year adjustment ensures that participants do not avoid funding a default simply because they do not happen to be producing or consuming in the month in which the default occurred.

Appendix 1: Representing Intermittent Loads

This appendix describes how physical Facilities are represented when an Intermittent Load is registered in the market. The following diagram describes the physical layout of generators, loads and meters associated with an Intermittent Load.



The next diagram shows how this system is represented when an Intermittent Load is registered.



The maximum intermittent load is declared to be MIL (which must be not more than the maximum load). Intermittent Load A comprises MIL MW of load from Load A and the first MIL MW of supply from generator B. This intermittent load may be non-dispatchable or interruptible. Non-Dispatchable Load A is the remaining load of Physical Load A. Notional Generator B is the residual capacity of Physical Generator B. It will actually be registered like a normal generator except (a) it will be associated with the intermittent load and (b) its capacity figures (on each fuel) will reflect its residual capacity. Note that MSG may have a different value depending on which fuel is being used (but on each fuel the generator must have some residual capacity). Physical Generator C and Physical Load D are treated like normal generators and loads.

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Where Meter M1 existed in the physical world we replace this with Meter 4, which is just Meter 1 less the metered values of Meters 2 and 3. i.e. $M4 = M1 - M2 - M3$. Thus M4 measures the net output of the Facilities that are only metered by meter 1.

Under clause 2.30B.10 the IMO must allocate the measurement for Meter 4 between Meters 5, 6 and 7 (none of which actually exist in the real world). Effectively we are allocating the measured value at Meter 4 between the three notional Facilities.

The logic of allocating the M4 value is that:

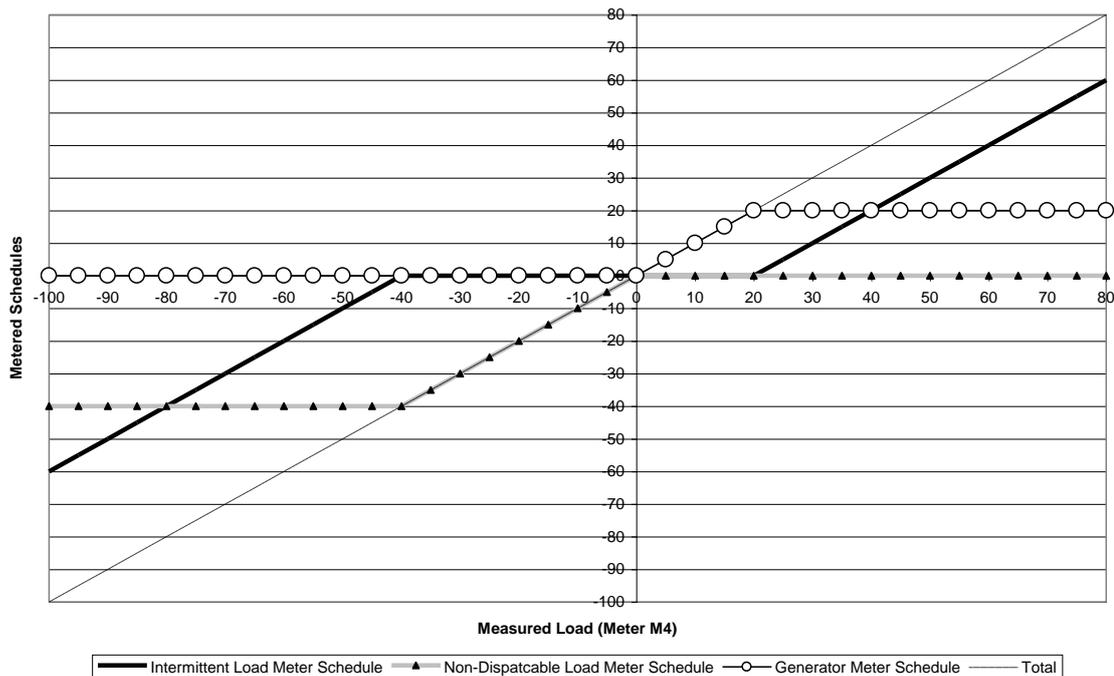
- Net supply is associated with Notional Generator B up to its capacity.
- Net consumption is associated with the Non-Dispatchable Load up to its capacity.³¹
- All other supply and consumption is associated with the Intermittent Load. This energy is settled at MCAP and Intermittent Load refunds only apply to net consumption.

Mathematically, the rules are:

- If $M4 > MSG$ then $M5 = M4 - MSG$, $M6 = 0$, $M7 = MSG$
- If $0 < M4 \leq MSG$ then $M5 = M6 = 0$, $M7 = M4$
- If $M4 = 0$ then $M5 = M6 = M7 = 0$
- If $0 > M4 \geq -NL$ then $M5 = 0$, $M6 = M4$, $M7 = 0$
- If $-NL > M4$ then $M5 = M4 + NL$, $M6 = -NL$, $M7 = 0$

Suppose the Physical Load A is 100 MWh ($X=100$), Physical Generator B can supply 80 MWh ($Y=80$), the Maximum Intermittent Load is 50 MWh (though this value is not actually used in the allocation), and there is no Physical Generator C or Physical Load D, we get the solutions in the following graph. The Intermittent Load Metered Schedule corresponds to meter M5, the Non-Dispatchable Load metered schedule corresponds to meter M6, and the generator Metered Schedule corresponds to meter M7.

³¹ Earlier versions of the rules incorrectly associated consumption with the Intermittent Load first. This was illogical as it would mean that any Non-Dispatchable Load consumption would be seen as net consumption by the Intermittent Load, causing an Intermittent Load Refund to be applied.



The IRCR for the Intermittent Load is simply its nominated maximum intermittent load (MIL) multiplied by the system reserve margin. So if the system reserve margin is 15% then the IRCR for the Intermittent Load is 0.15 MIL. This reflects the fact that generator is covering the Intermittent Load. However, whenever Intermittent Load has net consumption beyond 3% of MIL at a time when the first MIL MW of Physical Generator B is not on Planned Outage the Intermittent Load must pay intermittent load refunds (because this implies that the generator may be on an outage and would be exposed to refunds if it were a normal generator with Capacity Credits).

The Non-Dispatchable Load on meter M6 will have its IRCR determined in the normal fashion, with its IRCR typically being in the region of 115% of its peak summer load if the system reserve margin is 15%.

From an IRCR perspective a participant wants to maximise its intermittent load and minimise its Dispatchable Load. However it needs to trade off the risk of refunds if its generator is not reliable enough to cover the intermittent load.

The IMO will be monitoring registrations to ensure that the declared Non-Dispatchable Load NL value reflects a realistic representation of the actual peak non-Dispatchable Load which is not Intermittent Load.

Note that under special circumstances Physical Generator B may be at an entirely different node, but for the purpose of the above processes, it must be metered (M8) and is translated by the combination of its loss factor and the intermittent load nodes loss factor to be merged into the meter value for M1. i.e. $M1 = M4 - M2 - M3 - (M8 * LF_PGB / LF_IL)$ where LF_PGB is the loss factor for Physical Generator B's node and LF_IL is the loss factor for the Intermittent Load node. Consequently everything else works in the same way.

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Appendix 2: Summary of Market Activities

Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Verve Energy	Network Operators	Market Customers	Independent Market Generators
Rule Changes	x		x	x	x	x	x	x
Changes to PSOPs	x	x	x	x	x	x	x	x
Changes to Market Procedures.	x		x	x	x	x	x	x
Registering as Rule Participant	x				x	x	x	x
Facility Registration	x			x	x	x	x	x
Reserve Capacity Procurement	x				x		x	x
Capacity Supplying Intermittent Loads	x						x	x
Supplementary Reserve Capacity Procurement	x						x	x
Network Control Service		x (Western Power)				x	x	x

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Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Verve Energy	Network Operators	Market Customers	Independent Market Generators
Standing Data Submissions	x			x	x	x	x	x
Bilateral Contract Data Submission	x				x			x
Short Term Energy Market	x				x		x	x
Resource Plan Submission to IMO	x				x ³²			x
Scheduling of Verve Energy Portfolio		x			x			
Balancing & LFAS Submissions	x				x			x
Balancing and Merit Orders and Forecasts	x				x			x
Dispatch		x			x	x	x	x
Balancing Pricing	x			x	x		x	x

³² *In respect of Standalone Facilities*

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Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Verve Energy	Network Operators	Market Customers	Independent Market Generators
LFAS Pricing	x				x			x
Settlement	x				x		x	x
Prudential Requirements	x				x		x	x
Compliance Monitoring with respect to Security and Reliability		x			x	x	x	x
Compliance Monitoring other than for Security and Reliability.	x			x	x	x	x	x
Outage Planning		x	x		x	x	x	x
Commissioning Test Planning		x			x			x
10 Year Generation Planning (LT PASA)	x				x	x	x	x
10 Year Transmission Planning		x (Western Power)			x	x	x	x
3 Year Capacity Planning (MT PASA)		x			x	x	x	x

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Activity	Administrator of Activity		Parties to Activity					
	Independent Market Operator	System Management	Independent Market Operator	System Management	Verve Energy	Network Operators	Market Customers	Independent Market Generators
3 Week Capacity Planning (ST PASA)		x			x	x	x	x
Ancillary Service Requirements	x			x				
Procuring Ancillary Services		x			x		x	x