System Control I-NTEM Dispatch & Pricing Procedure

DRAFT FOR CONSULTATION

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PowerWater

Contents

1 Purpose of Procedure

This procedure is provided for information purposes only. It describes the principles and processes used in determining the pre-dispatch ahead of the *trading day*, performing the real-time dispatch, and determining *market prices* in the *I-NTEM*. The document is intended to provide *Generators* and *Market Customers* with an understanding of the inputs, processes, and outputs from the pre-dispatch, commitment, dispatch and market pricing processes, including:

- How the *Power System Controller* interprets and processes *generator offers* submitted by *Generators*, and other information, to formulate the indicative pre-dispatch.
- How the *Power System Controller* makes real-time commitment and dispatch decisions for operations of *self-committed generating units* and *fast-start generating units*.
- How the *Power System Controller* determines, for each *trading period*, which *generating units*, if any, are eligible to set the *market price*.
- How the *market price* is set for each eligible *trading interval*, and how *market prices* are set when there is no eligible *generating unit*.

2 Scope

This procedure only applies in the *I-NTEM.*

The *market price* setting aspects of this procedure are prepared under the authority of clause 4.8(c) of the System Control Technical Code ("the Code").

The formal operational functions and obligations of the *Power System Controller*, as the System Control Licence holder, are set out in Section 38 of the *Electricity Reform Act* and the Code.

This procedure should be read in conjunction with other procedures, particularly the Generator Offer Procedure and the Generator Tie Break Procedure.

3 Definitions

The terms shown in italic in this document are either terms defined in the Code or are terms defined specific to this procedure which are described briefly below.

Definitions		
No.	**Term**	**Meaning**
1	*Band 1*	*Band 1* for each *generating unit* comprises a quantity and a price. The *band 1* quantity is to reflect the *minimum stable load* recorded in the Generator Registration standing data of the *I-NTEM* or such increased amount where the increase has been notified to the *Power System Controller* via a formal OTR submission. The *band 1* price is to be zero for a *self-committed generating unit* and is to be not less than zero for a *fast-start generating unit*.
2	*Band 2*	*Band 2* for each *generating unit* comprises a quantity and a price. *Band 2* can only be scheduled if *band 1* is fully scheduled.

		The *band 2* incremental quantity (beyond the *band 1* quantity) is to reflect the nominal dispatchable range of the *generating unit*. Any output that can only be dispatched as a result of an additional manual action is not part *of band 2.* For a synchronous *generating unit* the quantity provided from *band 1* and *band 2* combined must be equal to or greater than the *Base Maximum Capacity* recorded in the Generator Registration standing data of the *generating unit*, or such reduced amount where the reduction has been notified to the *Power System Controller* via a formal OTR submission. The *band 2* price is not to be less than the *band 1* price, except for *fast-start generating unit* in which case the *band 2* price is to equal the *band 1* price.
3	*Band 2 Long Run Price*	The offer price applicable to *band 2* when a *fast-start generating unit* is run for more than 4 hours. This offer price is used in the *Long Run Commitment Merit Order*.
4	*Band 2 Short Run Price*	The offer price applicable to *band 2* when a *fast-start generating unit* is run for 4 hours or less. This offer price is used in the *Short Run Commitment Merit Order*.
5	*Band 3*	*Band 3* for each *generating unit* comprises a quantity and a price. *Band 3* can only be scheduled if *band 2* is fully scheduled. The *band 3* quantity is only to be used to reflect the incremental increase in the *generating unit's* dispatchable range as a result of an additional manual action such as activation of wet mode or sprint capacity. The *band 3* price is not to be less than the *band 2* price.
6	*Base Maximum Capacity*	The lowest maximum capacity of a *generating unit* when environmental operating conditions are most unfavourable. Any output above the capacity recorded through Generation Registration standing data is regarded as a real time extension of the *band 3* offer. Refer to Secure System Guidelines Section 4 Determining Base Capacity.
7	*Decommitment Order*	The order in which a *Generator* nominates to have its *fast-start generating units* come off-line after 18:00 on a given *trading day*. If there are any other on-line *generating units* belonging to the same *Generator* identified in the decommitment order, then the *generating unit* with the lowest decommitment order that is not required to remain on for security reasons is to be decommitted. The order is applied until all the *generating units* identified have been decommitted (or prevented from being taken off-line by security requirements), with any *generating units* with no number specified being decommitted based on normal bid prices. Notes: This feature effectively moves these *generating units* to the top (what would normally be the highest price end) of the merit order for units to come off.

		Where a *generating unit* would, if not for the application of the decommitment order, be decommitted, that unit will not be able to set price. Normal scheduling and tie-break logic operates without regard for this order and will identify the next *generating unit* that would normally be taken off-line.
8	*Decommitment Merit Order*	A merit order that describes the order in which the online *generating units* are to be decommitted.
9	*Energy and tie break merit order*	A merit order guiding the scheduling of energy from non-regulating *generating units* that are on-line.
10	*First off decommitment merit order*	A merit order that modifies the decommitment of *fast-start generating units* after 18:00 hours on each *trading day*. This merit order is constructed using the *decommitment order* nominated by the *Generator* in their *Generator Offers*.
11	*Gate closure*	1230 hours on the last business day before the nominated *trading day*.
12	*Generator offer*	The information recorded on the Generator Offer template by a *Generator* for any one day of its proposed operation in the *I-NTEM*. For any one *trading day*, prior to *gate closure*, the *Generator* may progressively submit one of more versions of the Generator Offer to correct a previous version. The last version prior to *gate closure* is the active Generator Offer.
13	*Market exclusion*	When a *generating unit* is online, but for a given *trading interval* falls under one of the market exclusion criteria it is not allowed to set the *market price*.
14	*Market floor price*	The minimum allowed *market price,* currently $0/MWh.
15	*Minimum stable load*	The lowest MW output at which a *generating unit* freely operates before it is taken off-line. This is to be based on installed technology / plant performance characteristics, and is not to be adjusted to optimise a *generator unit's* dispatch in the market offer process.
16	*OOM*	Out of Merit, refers to a *generating unit* that is dispatched differently from an economic merit order.
17	*OTR*	Outage and test request. Definition as per Outage Procedure (still under development).
18	*Pre-dispatch instruction*	A set on instructions created to guide the *real-time dispatch* during the relevant trading day which is produced by the *Power System Controller* on the business day prior to that *trading day*.
19	*Real-time dispatch*	The process of determining the dispatch of *generating units* in the *I-NTEM* in real-time.
20	*Risk notification*	A notification of an outage submitted in accordance with the System Control Plant Outage Procedure.

21	*Self-committed commitment merit order*	A merit order guiding the commitment order of self-scheduled *generating units*
22	*Short run commitment merit order*	A merit order guiding the commitment order of *fast-start generating units* when run for less than 4-hours.

4 General Approach

This section provides a high-level overview of the concepts relevant to this procedure.

4.1 Key Obligations on the Power System Controller

The *Power System Controller* is obligated by Section 4.7(c) of the Code to conduct *generating unit* commitment and dispatch processes in the *I-NTEM*. The *Power System Controller* must assess the need for increasing the output of *self-committed generating units* or committing and dispatching *fast-start generating units* to meet total demand based on the primary principle of *Security Constrained Economic Dispatch*. This principle requires the dispatch of *generating units* to meet total demand while minimising costs as defined by *generating offers* and having regard to the *Dispatch Principles* and the *Dispatch Criteria,* as set out in clauses 4.3(a) and 4.3(c) of the Code.

- The *Dispatch Principles* give priority, within the overarching principle of *Security Constrained Economic Dispatch,* to a number of system reliability and system security considerations. Implicit to these principles is the concept that, during normal operation, if practicable, scheduling *ancillary services* from *generating units* operated by *Generators* (other than Territory Generation) that pay for *ancillary services* should result in an equivalent or increased *dispatch* level where practical.[1]
- The *Dispatch Criteria* include *power system security*, *frequency* control and dispatch of *ancillary services*, energy market dispatch, unplanned generation and network outages, overall efficiency of energy production, minimum/maximum load limits of individual *generating units*, rate of fast pick-up of individual *generating units*, and voltage support.

A feature of these obligations is that since the *band 1* price of *self-committed generating units* is $0/MWh, once lowered to *minimum stable load*, are not to be decommitted while any *fast-start generating units* are online, unless this is required for a security reason.

At all times, the *Power System Controller*, while performing the management of committing, decommitting, and dispatching *generating unit*s, is required to prioritise its obligations for the management of system security.

[1] While Territory Generation is the sole *Generator* paid for the provision of *ancillary services*, other *generating units* can be required to respond automatically to increase output following contingency events with this reflected as increased energy market output.

4.2 Treatment of Ancillary Services

In the *I-NTEM*, *ancillary services* funded through the market are provided by Territory Generation. The *Power System Controller* commits Territory Generation *generating units* to satisfy system security requirements specified in the Code and the System Security Guidelines (SSG). In relation to dispatch, these are the services required for frequency control and voltage control. The current spinning reserve policy approximates Contingency Frequency Control Ancillary Services, this approximation will be replaced with a more dynamic calculation as part of Frequency Control Ancillary Service (FCAS) calculations due to be implemented in early 2021.

Ancillary services have no impact on the pre-dispatch process but are accounted for in real-time dispatch. Territory Generation *generating units* are operated in real time differently from other *generating unit*s. Although they are committed based on the same commitment logic that applies for all other *generating units*, once committed, they are not scheduled for energy based on prices in *generator offers*. Instead, they are run under Automatic Generation Control (AGC). Once started, AGC controls the output of these *generating units* to provide automatic adjustment to provide frequency control services reflecting relative energy costs according to preset incremental heat rate curves. This treatment of Territory Generation means that its *generating units* do not appear in the tie break energy merit order or play a direct role in energy tie-breaking in real-time dispatch (though are committed based on *generator offers* in pre-dispatch).

All non-Territory Generation *generating units* effectively follow the schedule specified by dispatch instructions, which will often put them at constant output unless ramping to another level. When a non-Territory Generator starts or stops, the transition from zero to *minimum stable load* or from *minimum stable load* back to zero will be absorbed by the Territory Generation portfolio. Once committed, non-Territory Generation *generating units* will change output according to:

- Changes in system load (typically by 5 MW incremental blocks for energy tie or as the marginal unit)
- Congestion arising from transmission constraints in 5 MW blocks according to tie break principles.
- System security management, including but not limited to:
  - Scheduling the unit out-of-merit to ensure the risk of credible contingencies are managed.
  - Scheduling the unit, by dispatch instruction or AGC, as required during the 30-minutes after a contingency event to restore a *secure operating state* (as defined in the Code). Most *generating units* have AGC configurations that will automatically change their output post-contingency once system frequency moves beyond the threshold normally managed by Territory Generation.
- During an islanding event, where the power system divides into two or more isolated regions, whether planned or resulting from an outage.

4.3 Limitations

The market design has general rules to handle a diverse array of situations that could arise. However, a number of less likely situations have not been considered in this procedure.

The broader market design as reflected in the Code and other procedures provides guidance as to how such situations not considered in this procedure would be handled if they were to occur.

For example, there is a strong incentive for *Generator*s, other than Territory Generation, to offer their portfolios as *self-committed generating units* rather than *fast-start generating units.* This is because of the higher dispatch priority of *self-committed generating units*. A consequence of these incentives is that the methodology described in this procedure excludes consideration of some scenarios that are possible in theory, but are unlikely to occur in practice.

This procedure assumes that the *band 2 short run price* of *fast-start generating units* will be significantly greater than any *band 2* prices of *self-committed generating units* or *band 2* long run prices of other *fast-start generating units* such that there is no need consider ties between such *generating units*.

If Market Participants anticipate circumstances where their offers may trigger such scenarios not considered in this procedure, they are encouraged to contact the Market Operator who will issue a notice of interpretation to all Market Participants until such time as this Procedure is updated and consulted upon.

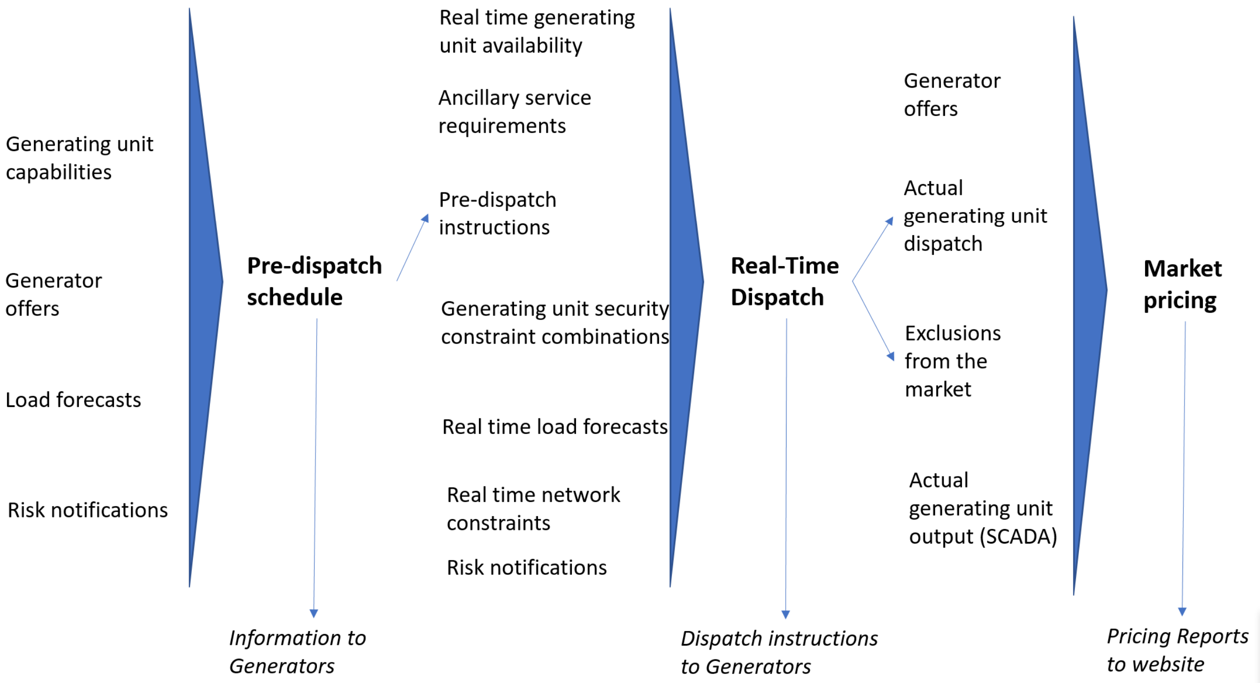
4.2 Market Pricing

The *market price* for energy in each *trading interval* is determined in accordance with the Market Price Principle set out in clause 4.8(b) of the Code. This principle requires that for each *trading interval*, the *market price* represents the marginal value of supply to balance supply and demand that arises from the dispatch.

4.3 Process Overview

The key steps performed by the *Power System Controller* in conducting pre-dispatch, dispatch, and determining market pricing are summarised in the following diagram

Process overview diagram



The inputs into the dispatch process are described in Section 5. A subset of these inputs is used to determine the *pre-dispatch schedule*. Some information produced in the pre-dispatch process are provided for information to *Generators* while other information becomes an input to the *real-time dispatch*.

The pre-dispatch schedule is only an indicative set of *generating unit* schedules for the *trading* day. It is determined at least a day ahead of real-time based on the information available at that time. The pre-dispatch schedule is determined only on business days, and schedules for weekends are determined on the last business day of the week. The process for determining the pre-dispatch schedule is described in Section 6. It is expected that in the real-time commitment and dispatch decision making, factors will come into play such as emergency outages and security concerns that cause deviation from the *pre-dispatch instructions*.

Real-time dispatch is an ongoing process. The schedule is revised throughout the *trading day* in response to changing system load, *generating unit* availability, and network and security considerations. Real-time *generating unit* availability and load forecasts are updated dynamically in this time frame. Constraints, such as *network constraints*, which were not considered in the pre-dispatch schedule, are accounted for in the real-time dispatch process. The real-time dispatch process is described in Section 7.

The process to determine *market prices* is run on the first business day following the *trading day* and uses *generator offer* data, real-time dispatch information, and actual *generating unit* output information to determine the *market price* in each *trading interval* of the *trading day*. This process in described in Section 8.

5 Inputs into Pre-Dispatch and Real-Time Dispatch Processes

5.1 Generator Offers

Generators are obligated by clause 4.4B of the Code to make *generator offers* for each *trading day*. The information provided is described by the Generator Offer Procedure and includes classification of *generating unit*s as either *self-committed generating units* or *fast-start generating units*. For each *generating unit*, these submissions provide the offer prices, including both *band 2 short run price* and *band 2 long run price* for a *fast-start generating unit*. Submissions also contain the *Generators* preferences for how its portfolio of units are committed and decommitted.

5.2 Load Forecast

The *Power System Controller* is required by clause 5.11 of the Code to determine by 1600 hours on each *business day* and at least 72 hours ahead of the *trading day* a load forecast representing the total system load forecast for each half hour of the *trading day*. This load forecast is used in the pre-dispatch process. Load forecasts are only produced on business days.

In the operational time frame, the *Power System Controller* uses dynamic tools to update the total system load forecast at a five-minute resolution, which accounts for weather data, solar data, and historical patterns of behaviour.

5.3 Generating Unit Capacity Limits

Generating unit standing data captured in the Market Participant registration process, administered by the Market Operator is used to set the minimum and maximum capacity of each *generating unit* for the *trading day*.[2]

5.4 Risk Notifications

Risk notifications provide information on existing approved *OTRs*[3] and the generation or generic system *constraints*[4] that arise from them for the *trading day*. *Risk Notifications* record the impact of outages on *generating units* and any applicable limits on the operation of one or more *generating unit*s for one or more *trading intervals* during the *trading day*. Some of these constraints may specify, for example, a particular *generating unit* or a minimum or maximum number of *generating unit*s in a group of *generating units* to be committed or decommitted, and may place additional upper or lower energy output limits on *generating units*.

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[2] While the *Band 1* quantities and the *Band 2* or *Band 3* (if non-zero) quantities in *generator offers* respectively imply *minimum stable load* and maximum capacity the *Power System Controller* will still use standing data quantities, or adjusted values under an approved *OTR* reflected in a *Risk Notification*, if there is a conflict.

[3] For further information on OTR processes refer to the Plant Outage Procedure.

[4] Generic system *constraints*, which are defined in clause 3.9 of the Code, are applied by the *Power System Controller* where a system limitation exists as the result of a planned or unplanned network outage.

5.5 Network Constraints

Network constraints, which are defined in clause 3.9 of the Code, are applied by the *Power System Controller* if actions are required to maintain the power flow through a network element within limits. These actions include ensuring secure operation of the power system following a contingency event.

Network constraints are not applied in the *pre-dispatch schedule*, being only applied in the *real-time dispatch*.

In the *real-time dispatch* the *Power System Controller* will operationally endeavour to reconfigure the network via load shifting switching activities to manage both generic system *constraints* and *network constraints* as a priority. However, where it is not possible to manage by network switching alone, adjustments to *generating unit* dispatch will be applied. Much the same as generic system *constraints*, *network constraints* may specify a *generating unit* or a minimum or maximum number of *generating unit*s in a group of *generating units* to be committed and may place additional upper or lower energy output limits on *generating units* that are committed.

5.6 Ancillary Service Requirements

Ancillary service requirements are accounted for in the *real-time dispatch* only. The requirements for each of the services are translated into either a set of Territory Generation *generating units* that must be scheduled or an additional minimum capacity that must be available from the Territory Generation portfolio.

5.7 Real Time Generating Unit Availability

Real time generating unit availability information available to the *Power System Controller* indicating real-time limitations on generating units in the *real-time dispatch*. This information includes unplanned forced or performance issue outages, as well as generator firm offers and forecasting compliance monitoring.[5]

5.8 Pre-Dispatch Schedule Outputs

The process of determining the pre-dispatch schedule determines a number of inputs to the real-time dispatch process, including pre-dispatch instructions and feasible combinations of *generating units* to satisfy security considerations.

6 Pre-Dispatch Processes

6.1 Inputs used

The inputs used for a pre-dispatch for a *trading day* are:

- *Generator offers*
- *Generating unit* capabilities
- Load forecasts

[5] For further information refer to the Plant Outage Procedure and Generator Forecast Compliance Procedure.

- *Risk notifications*

6.2 Preparation of Commitment and Dispatch Merit Orders

The *generator offers* include information that defines the order in which units should be committed or decommitted and the order in which energy output should be increased or decreased within the portfolio of units of an individual *Generator*. The merit orders described in this section use the *generator offer* data to define merit orders at the market level, across all *Generators*.

The merit orders described in this section are:

- *Self-committed commitment merit order*
- *Energy and tie break merit order*
- *Short run commitment merit order*
- *Decommitment merit order*
- *First-off decommitment merit order* (only applies after 1800 hours)

These merit orders are developed in the pre-dispatch process. These merit order are used to determine the pre-dispatch schedule, which is a single schedule determined once for the full *trading day*. Tie-breaking is applied in accordance with the Generating Unit Tie-Breaking Procedure.

These same merit orders inform the real-time dispatch process. However, the interpretation of some of the merit orders in real-time is more dynamic as the merit orders are applied to the prevailing dispatch conditions, including the mixture of units running, the order of commitment and decommitment of units from the past, and constraints that impact generation commitment and dispatch decisions.

The Generating Unit Tie Break Procedure considers two separate situations:

- Ties between *generating unit*s with the respect to their energy output above their *minimum stable loads*, requiring some combination of *generating units* to adjust energy output while remaining on.
- Ties between *generating units* with respect to commitment or decommitment when energy output is already at minimum stable load or the units are off.

The Generating Unit Tie Break Procedure applies ties in commitment and energy decisions using, depending on the situation, either a random period or random day selection process that allocates the order in which *generating units* will be selected to respond. In all cases, tie-breaking is conditioned by the requirement that the selected *generating unit*, taking whichever action is required, will not violate other constraints. In practice, it may be necessary to skip *generating units* in the merit order to satisfy these higher-level requirements.

6.2.1 *Self-committed* Commitment Merit Order

The *self-committed commitment merit order* is the order in which *self-committed generating units* are to be committed. In practice, a *self-committed generating unit* will be committed unless this is not possible for reasons of system security.

The *self-committed commitment merit order* is the reverse of the order of decommitment implied by off-load orders specified by Generator in their generator offers taking into account tie break rules. In particular:

- The off-load order for *self-committed generating unit* in the *generator offer* of a *Generator* defines the order which its *self-committed generating units* are to be decommitted. Different configurations of combined cycle units are also specified within these off-load orders.
- Commitment ties between *self-committed generating units* arise because non-zero *band 1* quantities are offered at a *band 1* price of zero. These *generating units* are to be decommitted according to the Generating Unit Tie Break Procedure as their *band 1* prices are always tied.

Where *self-committed generating units* have been decommitted earlier in the *trading day* (primarily in real-time), but it is now possible to recommit some of these *generating units*, the *Generator* for each *generating unit* has the right, but not an obligation, to have that *generating unit* committed in the same order in which it was decommitted (first off / first on). If all impacted *Generators* exercise this right for all impacted *generating units*, the merit order will remain the same. Where a Generator declines the option to be reinstated, that *generating unit* is moved down in the merit order.

6.2.2 Energy and tie break merit order

The energy and tie break order is constructed in two steps. Firstly, the *band 2 long run* and *self-committed band 2* prices will be arranged from the cheapest to the most expensive. Any energy price ties are then dealt with as follows. An energy tie exists where there are equal priced offers from *band 2* from two or more *self-committed* or *fast-start generating units*. The Generating Unit Tie Break Procedure determines the order in which to increase or decrease *generating unit* output. However, the tie-breaking process applies up to 5 MW increments of increase or decrease rather than the full capacity of the *band 2* offer. A cyclic approach is used. Each tied *band 2* offer is partitioned into 5 MW increments (or less where there is not enough remaining capacity in the band to support this), and the first increment of each tied *generating unit* is ordered in the merit order based on the tie-breaking order of the *generating unit.* This process is then repeated to order the next 5 MW increments from those same tied *generating units* within the remaining *band 2* capacity. This process repeats for all *generating units* until their *band 2* offer capacities are exhausted.

The *energy and tie break merit order* only considers the *band 2 long run price* of *fast-start generating units*. Further, if the *fast-start generating unit* is not currently committed it will be committed based on this merit order unless prevented forsecurity reasons.[6]

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[6] This will mean that the *band 1* quantity will be supplied automatically in making it possible for the *generating unit* to provide *band 2* energy.

The following example illustrates the process. Each of *generating units* A, B and C has offered their band *2* capacities at $30/MWh, with the tie-breaking logic indicating the order of selecting the units should be A, then B, then C.

As offered			
Generating Units	*Band 2* Offer Price ($/MWh)	*Band 2* Quantity (MW)	Base Tie Break Order
A	30	12	1
B	30	16	2
C	30	15	3

The table below shows the merit order with the *band 2* offer quantities partitioned into successive 5 MW quantities until only a residual amount is left. The merit order cycles through the *generating units* to the tie-breaking order they have been assigned for the *generating unit*.

Energy and tie break merit order		
Unit Name	Tie Break Order	Quantity (MW)
A	1	5
B	2	5
C	3	5
A	4	5
B	5	5
C	6	5
A	7	2
B	8	5
C	9	5
B	10	1

As with commitment ties, the tie-breaking procedure must be sensitive to system constraints.

6.2.3 Short Run Commitment Merit Order

When a *fast-start generating unit* is to be committed to run for a period of less than four hours, the choice of which *fast-start generating unit* to commit is based on the *short run commitment merit order*. *Generators* have the option to specify a short run price for each *fast-start generating unit band 2* quantity.

The *short run commitment merit order* is compiled by ordering the *band 2 short run* prices of *fast-start generating units* and the *band 3* prices from *fast-start generating units* from the cheapest to the most expensive.[7] The merit order does not distinguish between *band 2* and *band 3* offers so each compete directly. A tie occurs whenever two or more units have either the same *band 2* price, or *band 3* price for an available dispatchable quantity. In the event of a tie, the Generator Unit Tie Breaking Procedure is applied, subject to system constraints.

The following example shows the *band 2 short run* and *band 3* offers from several *fast-start generating units*. These have been ordered based on the *band 2 short run* prices rather than

[7] The nature of *band 3* quantities is that they are available for only a short period, so this procedure does not consider the situation of ties between *band 3* quantities and *band 2 long run prices*.

generating unit names to make it easier to follow. Note that for all *fast-start generating units*, the *band 1* price equals the *band 2* price, so it has no additional impact on unit ordering.

As Offered		
Unit Name	*Band 2* Short Run Price ($/MWh)	*Band 3* Short Run Price ($/MWh)
B1	25	48
B2	28	34
A1	30	
B4	35	
A2	45	55
B3	47	

The example below shows the integration of shaded *band 3* offers into the ordering of offers. For example, consider the *band 3* offer from unit B2. Given the other offers submitted, B2 will be selected as the second unit in the merit order based on its *band 2* quantity, and then again as the fourth unit, this time for its *band 3* quantity.

Short Run Commitment Merit Order			
Unit Name	Tie Break Order	Band	Price ($/MWh)
B1	1	2	25
B2	2	2	28
A1	3	2	30
B2	4	3	34
B4	5	2	35
A2	6	2	45
B3	7	2	47
B1	8	3	48
A2	9	3	55

6.2.4 Decommitment Merit Order

*Self-committed generating unit*s will only be decommitted after any operating *fast-start generating unit*s have been decommitted, unless security reasons prevent this.

If *fast-start generating units* are to be decommitted or *band 3* capacity is to be taken off-line, then, prior to 1800 hours, the *Power System Controller* must select the most expensive capacity to take offline first (except where prevented for security reasons). Where a tie exists, the Generator Unit Tie Breaking Procedure requires that the capacity is selected in the reverse of the order in which *Generators* were instructed to bring that tied capacity online (excepted where prevented for security reasons).

After 1800 hours on each *trading day*, and where the selected capacity is a *generating unit* to be decommitted, the *first off decommitment merit order* may modify the selected capacity, as described in Section 6.2.5.

The next capacity to be decommitted after the selected unit is determined by repeating the process with the remaining units.

Where *self-committed generating units* are to be decommitted, the Generator Unit Tie Breaking Procedure requires that the *Power System Controller* follows the order specified in the *Generator's generator offer* for the *trading day*. Where ties exist with *generating units* of other *Generators,* the *Power System Controller* follows in the reverse of the order in which the tied *Generators* were instructed to bring that capacity online, unless prevented from doing so for security reasons.

6.2.5 First Off Decommitment Merit Order (post 1800 hours)

The *first off decommitment merit order* modifies the *decommitment merit order* after 1800 hours each *trading day* when energy use typically begins to decrease. This provides flexibility to *Generators* to control which *fast-start generating units* are selected for decommitment. A *Generator* has the option, though is not required, to specify a *decommitment order* to apply post 1800 hours in its *generator offer* for the *trading day* as described in the Generator Offer Procedure. The *first off decommitment merit order* has no impact on the *self-committed* generating units in the *decommitment merit order*.

The *first off decommitment merit order* modifies the normal *decommitment merit order* by factoring in the information from the *decommitment order* that may be specified in *generator offers* by *Generators* for *fast-start generating units*.

When the process identifies a particular *fast-start generating unit* to be decommitted and the off-load order for that *Generator* has not been exhausted, the next online *fast-start generating unit* or units in the *Generator's decommitment order* will be taken offline first ahead of the initially selected *fast-start generating unit*. If a *fast-start generating unit* in the *decommitment order* was required to remain online for security reasons, then the next unit in *decommitment order* is selected instead.

It should be noted that this option does not allow a *Generator* to replace *fast-start generating units* in the order, only insert *fast-start generating units* to be decommitted prior to other units owned by the same *Generator*. This counters any gaming incentives as these will be lower cost units than the ones that would normally be decommitted.

Where *Generators* do not have, or they have exhausted preferences for the order of decommitting within their own portfolio, the decommitment merit order reverts to the standard *decommitment merit order*.

The following table illustrates the effect of *decommitment orders* on the *decommitment merit order* to produce the *first off decommitment merit order*. Units A1, A2, A3 and A4 are part of *Generator* A's portfolio, while B1, B2, B3 and B4 are part of *Generator* B's portfolio. For simplicity we will assume that all units are *fast-start generating units. Generator* A has specified A2 as the first unit in the *decommitment order* and A3 as the second unit (this order is denoted by the letters A and B in accordance with the *Generator* Offer Procedure). On the right is shown the *first off decommitment merit order*. All that has happened is that in the first position on the standard decommitment merit order that each *Generator* is required to decommit a *generating unit*, units from the off-load order are inserted.

Decommitment Merit Order	Decommitment Order
B2	
A3	B
A2	A
B1	
B4	
A1	
B3	A
A4	

First Off Decommitment Merit Order
B3
B2
A2
A3
B1
B4
A1
A4

This flexibility enables the *Generator* to efficiently manage resources, although it comes with pricing exclusion implications where the substituted *generating unit* is more expensive. In the example above, B2 would be a higher cost *generating unit* than B3, but B3 goes offline while B2 remains online.

The market pricing process excludes *generator units* from the same *Generator* that remain on because of this feature from setting the *market price* i.e. it is a *market exclusion* reason. This would apply for the remainder of the *trading day* or until the next time that unit is committed on in the same *trading day*, having subsequently gone offline. It follows that when B3 is decommitted instead of B2, then B2 is not allowed to set the *market price* for the remainder of the time that it is on during the *trading day*. The *market price* should therefore be nomore than it would otherwise be.

The *decommitment order* does not change the tie break logic. As an example, consider the case where unit B2 is tied with unit A3 and the normal tie breaking logic picks unit B2 to decommit. Because *Generator* B has specified that B3 is to come off before B2, then unit B3 would be taken off-line first (subject to system security constraints). That is, B3 is treated as being at the top of the merit order. The units involved in the tie break would then be taken off in the order that the tie break logic requires, namely B2 first, followed by A3. However, *Generator* A's off load order will have A2 take the place of A3.

In practice the *first off decommitment merit order* seen by the *Power System Controller* just lists the *generating units* compiled from all the *decommitment orders* across all *Generators*. And whenever the *Power System Controller* identifies a *fast-start generating unit* to decommit for a given *Generator,* it will instead call the first online *fast-start generating unit* for that *Generator* (if any) in the *first off decommitment merit order* unless prevented from doing so for security reasons.

6.3 Other Pre-Dispatch Data

6.3.1 Overnight Generating Units

This information is prepared for the *Power System Controller* use in real-time dispatch and based on the expected number of *generating units* required to be on overnight and the preferred order of decommitment specified by *Generators*. The list identifies specific *generating units* expected to be online based on the load forecast, with some *generating units* being required on due to specific security requirements that name that *generating unit*, with the rest determined based on commitment merit orders.

This information is provided as a reference point. The *Power System* Controller may run a different set of *generating units* where the situation changes, for instance, if a new security requirement arises.

One *trading day* ends at 0400 hours and a new *trading day* starts. The *generator offers* applicable to the new *trading day* take precedence over a *Generators* preference for how its *generating units* are decommitted for the first *trading day*. This means that if a *Generator* does not want some of its *generating units* decommitted at 0400 hours and different *generating units* committed it needs to ensure consistency of its preferred order of decommitment on the first *trading day* with prices and other data in its *generator offer* for the second *trading day.*

6.3.2 Frame 6 / FCAS Units

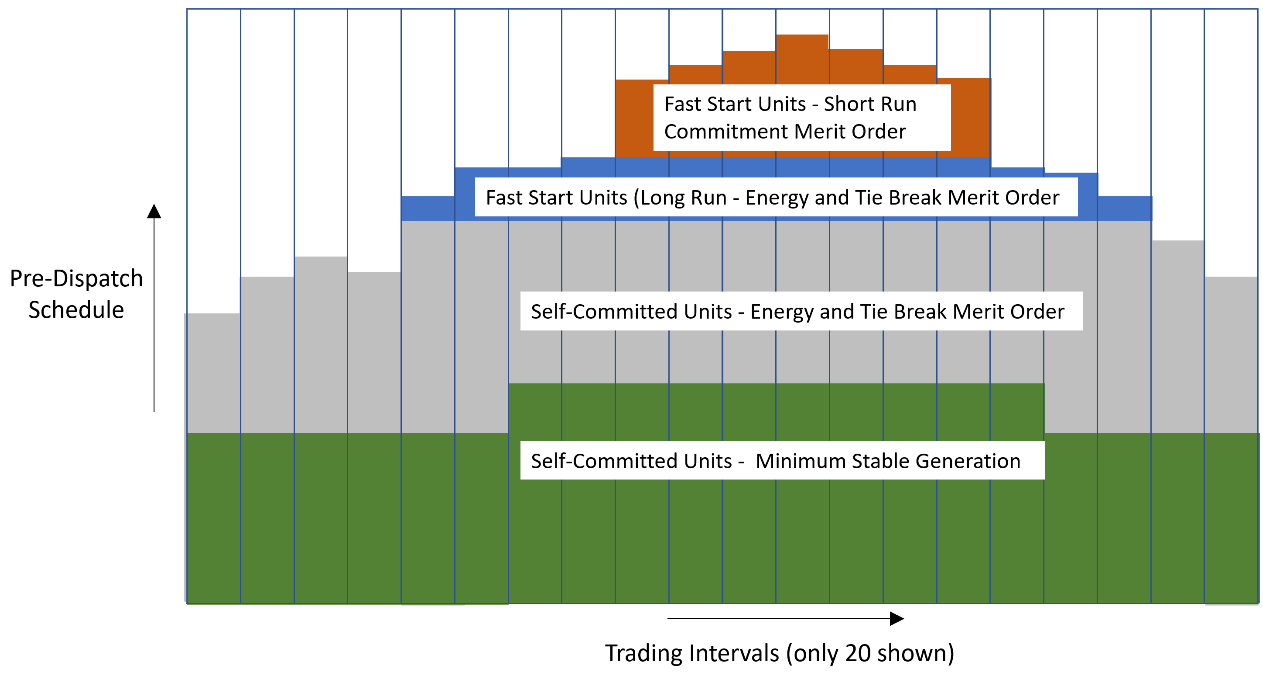
The *Power System Controller* is required to maintain a minimum number of frame 6 *generating units* online at different network locations. This information specifies the combinations of frame 6 *generating units* that can satisfy the security requirements. From this list of combinations, the controller must always select the cheapest two to be run.

While a fixed number of *generating units* has been used to date for this requirement, the number will become more dynamic from early 2021 with the introduction of FCAS.

6.4 Pre-dispatch Solution Process

The following diagram provides a conceptual view of the pre-dispatch solution process. The diagram covers 20 *trading intervals* (10 hours) rather than the full 48 *trading intervals* in the *trading day*. The example assumes the *band 2 long run* cost of all *fast-start generating units* exceeds the *band 2 long run* cost of all *self-committed generating units*, this being the normal case.

Illustrative example of the formation of the pre-dispatch schedule



Step 1 – Schedule self-committed units to minimum stable load

The first step is to schedule all *self-committed generating units* to their *minimum stable load* (i.e. fully scheduled *band 1* capacity). Where there is not enough system load to support this, the *self-committed* commitment and decommitment orders will be used to guide commitment choices.

Step 2 – Schedule self-committed units to provide energy above minimum stable load

This step entails determining the energy output from *band 2* of each *self-committed generating unit* in each *trading interval* (allowing for system security and *ancillary service* requirements). The *generating units* are loaded based on the energy merit order subject to tie-breaking rules.

If system load is insufficient to require all *self-committed generating units* to have *band 2* fully scheduled (within the availability of the *generating unit* and generator or generic system *constraints*) in some *trading intervals*, then only the most economic *self-committed* units will be scheduled.

Step 3 – Schedule fast-start units

It can be seen from the diagram above that, at time, system load is at a level such that all *self-committed generating units* are running at capacity. To meet the remaining system load, it is necessary to schedule *fast-start generating units*.

There is a choice between committing *fast-start generating units* based either on the *short run price commitment merit order* or the *long run price commitment merit order*. The costs of committing and running *generating units* for the short run (≤ 4 hours) will be greater than for the long run. This is because *generating unit* offer prices are expected to be set to recover the *generating unit's* start-up costs, and there is less time to recover start-up costs for a *short run*, requiring higher offer prices.

It transpires that as there is enough system load over the 12 consecutive peak system load *trading intervals* (6 hours) to support the commitment of *fast-start generating units* based on the *long run price commitment merit order*. After committing these *generating units* and running them up to the point where they either serve the remaining load or reach their capacity, there is still additional system load over the peak seven *trading intervals* (3.5 hours).

Step 4 – Indicative pre-dispatch clearing prices

The highest priced offer cleared in each *trading interval* defines the indicative clearing price for that *trading interval*. The methodology used to set this price is conceptually the same as that used in determining *market prices* after the *trading day* but without the application of *market exclusions*.

Step 5 – Overlay known risk notification

At the time of solving, the risk notifications applicable to the trading day that are likely to be applied to alter generation dispatch are identified to inform likely generating unit availability and hence constrain the pre-dispatch solution.

Note about decommitment

When system load drops, it may be necessary to decommit units. This could happen in the middle of the day due to higher behind the meter solar generation or at the end of the day as actual consumer consumption declines.

Each *Generator* specifies its preferred order for decommitting its *generating units*, but for *fast-start generating units*, a *Generator* can also specify an alternative *first off decommitment merit order* to apply after 1800 hours. The logic described for these merit orders (above) will apply in each instance to determine the order in which *generating unit*s decommit, including changes in order due to tie-breaking and restrictions arising for security reasons.

Other points to note

Fast-start generating units have the same price for *band 1* and *band 2*. If the *band 2* price of a *fast-start* unit were to be less than the *band 2* price of a *self-committed generating unit*, then the *self-committed generating unit* would still be committed first as the *Power System Controller* is required to schedule *self-committed* units up to minimum load wherever system security constraints allow it to. In this situation, the *self-committed* unit would be scheduled to *minimum stable load*, then the *fast-start* unit would be committed to *minimum stable load*, then the units would increase output with increasing load based on their *band 2* prices, which would mean that the *fast-start* unit would be scheduled for energy ahead of the *self-committed* unit.

6.5 Indicative commitment and dispatch schedule

The *Power System Controller* must provide pre-dispatch targets (being expected outputs by *trading interval*) and the pre-dispatch indicative clearing prices to the Market Operator each business day for publication.

The *Power System Controller* will provide to each *Generator* via e-mail:

- The pre-dispatch schedule specific to that *Generator's generating units*
- The indicative clearing prices for each *trading interval* of the *trading day*
- For each *generating unit* participating in the pre-dispatch process, its minimum capacity, its maximum capacity, and the *trading intervals* it is available
- A list of security constraints and *ancillary service* requirements applied

The information provided to *Generators* is issued to provide guidance to the *Generators* as to how they can expect to be dispatched. The actual dispatch on the *trading day* may differ due to real-time considerations.

A set of *pre-dispatch instructions* are developed for use in real-time dispatch, by *Power System Controller* staff, though this information is described in the next section, so it is provided in the context of real-time dispatch inputs.

7 Real Time Dispatch

7.1 Context

Given the obligations on the *Power System Controller* described in Section 4.1, the practical summary of the process of dispatching the power system in (and leading up to) real-time is focused on simultaneously:

- matching energy generated with system load,
- ensuring that sufficient generation capacity with sufficient flexibility is online to give the power system the ability to react to changes in system load and contingency events while providing the required *ancillary services*,
- respecting constraints on how the system can be operated, and
- satisfying the economic and security requirements of a security constrained economic dispatch.

In managing the power system issues, the *Power System Controller* will first try and manage issues using the capabilities of the transmission and distribution network, and then will rely on *ancillary services* provided by Territory Generation. Only if further adjustment in needed at this point, will the *Power System Controller* resort to modifying the energy dispatch of other participants.

The *Power System Controller* can control the modes of operation of *generating unit*s via AGC. Generally:

- All Territory Generation *generating units* are generally under AGC control, with the settings related to regulating ranges set to allow the units to increase or decrease output within limits in controlled economic dispatch control mode to follow the changing load of the power system, as well as provide frequency error correction to the frequency set point and time error correction.

- By default, other dispatchable units are operated in base point control mode, meaning they are operated at a fixed output, unless system frequency requires drop control operation.
- Where required, units can be configured to produce or absorb reactive power in addition to producing active energy required by the market.

Note that the process described in this section is relaxed by the Code for the 30 minutes following a contingency event in recognition of the fact that some *ancillary service* requirements may not be satisfied after a contingency response and because *generating units* will be reacting, in many instances automatically, to the event rather than necessarily in response to specific dispatch instructions while the *Power System Controller* will be focused on taking actions, such as committing additional units, to restore more normal operations.

7.2 Inputs

The inputs used for real-time dispatch during a *trading day* are:

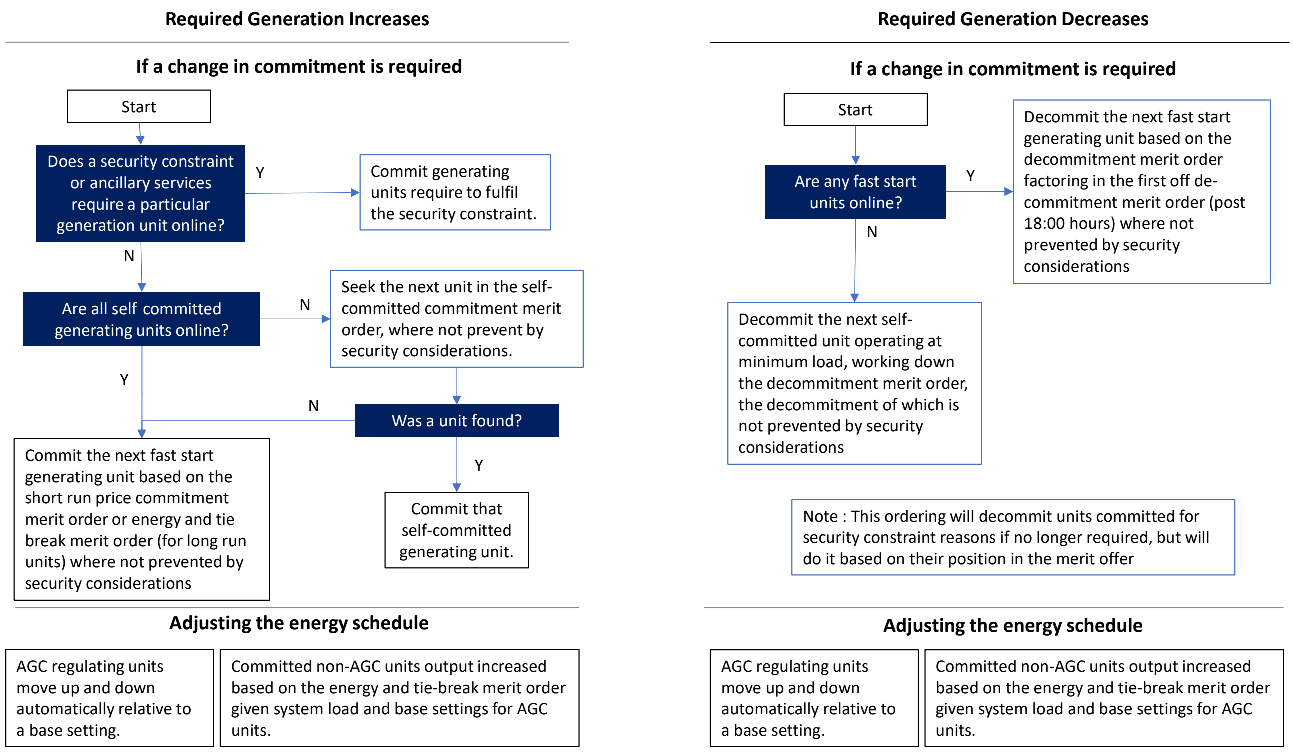
- A set of *pre-dispatch instructions* determined in the pre-dispatch process, which serve to provide information relevant to the dispatch process, including:
  - A graphical representation of the pre-dispatch solution
  - *Generating unit* capacities and availabilities
  - *Generator* aggregate capacities and availabilities
  - A pre-dispatch table providing a simpler ordering of *generating units* that covers system load plus covers other capacity requirements
  - Dispatch instructions showing various merit orders, tied units, and information on feasible combinations of the minimum set of units that must be run.
  - Standing notes and guidelines to provide additional information for system controllers
- Real-time *generating unit* availability.[8]
- Total system demand forecast
- Risk notifications
- *Network constraints*
- Real-time system configuration and system security considerations.

7.3 Process

The pre-dispatch schedule provided to *Generators* is indicative only. The *generating unit*s must instead operate in a manner consistent with the commitment and dispatch instructions issued by the *Power System Controller* in real-time. The instructions issued by the *Power System Controller* will deviate from the pre-dispatch schedule as required to respond to changing system load, changing *Generator* and network availability, and to reflect planned and real-time security constraints.

[8] For further information refer to the Plant Outage Procedure and Generator Forecast Compliance Procedure.

Illustration of the approach to real-time dispatch



7.3.1 Actions when the generation requirement for energy or capacity increases

Unit commitment

- *Priority 1 – Security Constraints*

  All *generating unit*s required to be online under any system security or *ancillary service* requirement are to be committed first. This will factor in both generic system *constraints* and *network constraints*. This scheduling provides protection against any credible contingency whether it involves the loss of generation or load by balancing out all the *ancillary service* requirements (voltage control and frequency control services including reserves associated with both) across more units. Where there is flexibility within a security constraint or *ancillary service* requirement to choose which *generating unit* or units to bring online, the *Power System Controller* will select the lowest price *generating unit* or units to commit as per the Economic Commitment and Dispatch Arrangements (see below), unless this would unnecessarily delay addressing the security constraints which may occur if there is a state of emergency within the system.

- *Priority 2 - Economic Commitment and Dispatch Arrangements*

  Self-committed *generating units*

  All *self-committed generating units* are to be committed as practicable, except where prevented by security reasons, prior to the commitment of any *fast-start generating units*. *Self-committed generating units* will always be committed at their *minimum stable load*, where practical, with the aim of committing all *self-committed* units at any given time in accordance with the *self-committed commitment merit order*.

The *self-committed generating units* online will be dispatched above their *band 1* quantities to match the load or in the case of Territory Generation units will provide regulation under AGC control (as described in Section 4).

Where a *self-committed generating unit* was previously decommitted on the same *trading day* and could be brought back online based on the *self-committed commitment merit order*, the *Generator* has the option to decline to commit the *generating unit* when requested by the *Power System Controller*.

Fast-start units

Fast-start generating units will be committed if and only if more capacity is required above that supplied by the *self-committed generating units* or if they are required for system security reasons. When there in a need to commit a *fast-start generating unit*, the *Power System Controller* will assess the likely duration for which the additional generation capacity is needed. If the assessment is that the additional capacity is likely required for not more than 4 hours, this will be considered a short run. If the assessment finds that the additional capacity is needed for more than 4 hours, this will be considered a long run.

- In the case where it is determined that a *fast-start generating unit* is required for a short run, the *Power System Controller* will start the next *generating unit* (or incremental *band 3* capacity if the associated unit is already online) from the *short run commitment merit order* that is not presently running.
- In the case where it is determined that a *fast-start generating unit* is required for a long run, the *Power System Controller* will start the next *generating unit* (or incremental *band 3* capacity if the associated unit is already online) from the *energy and tie break merit order* that is not presently running.

When committing from either of these merit orders the order will always be used regardless of the size of that quantity including in the circumstance where multiple *generating units* may be required to start at the same time. That is, small *generating units* (or *band 3* quantities) that are considered too small to likely cover the increase in load will not be skipped in favour of larger units.

Energy scheduling

- *Generation dispatch levels*

  Generating units providing regulating reserves will have their dispatch level determined by the *Power System Controller's* Automatic Generation Control (AGC) to meet their *ancillary service* obligations. Regulating reserve *generating units* may have their outputs increased or decreased to accommodate other changes.

  Other *generating units* will have their band *2* and/or band *3* dispatch level set by the *Power System Controller* based on the *energy and tie break merit order*. The *Power System Controller* will employ reasonable efforts to dispatch tied *generating units* in 5 MW blocks. That is each tied band is increased by 5 MW in turn in tie-breaking order. This feature exists to minimise the impact of tie-breaking on *Generators* and (in the case of solar farms) aids geographic diversity of supply by spreading the reductions across solar farms.

7.3.2 Actions when the generation requirement for energy or capacity decreases

Unit decommitment

- *Fast-start generating units*

The decommitment of *fast-start generating units* is undertaken prior to any decommitment of self-commitment *generating units* unless prevented by security considerations.

Prior to 1800 hours *fast-start generating units* will be decommitted, or *band 3* capacity removed from the schedule, based on the *decommitment merit order.*

After 1800 hours, the *first off decommitment merit order* is used in priority to the *decommitment merit order*.

- *Self-committed generating units*

  Once all *fast-start generating units* that can be decommitted have been decommitted, and as the load on the system decreases, all online *self-committed generating units* will have their outputs decreased to *minimum stable load* (plus any required reserve margins). Once all units are at their *minimum stable load* (allowing for any required reserve margins), the first online unit (or mode of operation with regards to combined cycle units) in the *decommitment merit order* will be decommitted unless prevented for security reasons.

Energy Scheduling

- *Generation dispatch levels:*

  This is an identical process to that presented for the load increasing case, but working down the *energy and tie break merit order* given the *generating units* committed rather than working up it. Regulating reserve *generating units* may have their outputs increased or decreased to accommodate other changes.

7.4 Participant communication

The *Power System Controller* must provide the actual dispatch schedules for the *trading day* to the *Market Operator* for *publication*.

8 Market prices

8.1 Introduction

The market pricing process, including processes to determine all after-the-event information about the dispatch, are only run on business days. In the event of an islanding situation, the market will continue to operate as normal, although it is expected that several generation units will need to be run out of merit for the duration of these events.

8.2 Inputs

The inputs used in determining the *market price* for each *trading interval* are:

- The offer applicable to each *generating unit*, including long run and short run offers, where applicable.
- The MWh quantity provided by each *generating unit* in each *trading interval*, where this information is based on real-time SCADA data or, in the event of a SCADA issue.[9]

[9] If SCADA data were unavailable for a *generating unit* (e.g. due to a communication failure) fall back strategies include holding the *generating unit* at constant output or decommitting it, while deducing any

- The set of dispatch instructions issued to each *generating unit*.
- List of criteria for excluding generating units from setting the *market price*, to be applied to the set of dispatch instructions. The *market exclusions* are set by the *Power System Controller* to reflect dispatch actions taken that are deemed to preclude the *generation unit* from contributing to marginal cost of serving system load. For example, a unit that is constrained to run out of merit order should not set the *market price*.

8.3 Method

The *market price* for a *trading interval* is representative of the marginal cost of supplying system loads for that *trading interval*.

The *market price* for each *trading interval* is taken to be the offer price of the most expensive *generating unit* running for that *trading interval* take from that the set of *generating units* that are running but which are not excluded from setting the *market price* for that *trading interval*.

Step 1: Process Generating Units to identify Excluded Units

This first step involves excluding *generating units* from setting *market price* for a *trading interval* as result of meeting criteria for such exclusions. The criteria broadly align with the following two areas:

- System Security, where a *generating unit* must be committed for security requirements in an order that does not align with the normal economic ordering. Examples of this include but are not limited to:
    - When a risk notice forces a generating unit to come online out of merit.
    - Where a performance issue is detected, and an *OTR* is requested.
    - Where *ancillary service* requirements force a generating unit to come online out of merit.
    - In post-contingent event management.
    - To support system voltage requirements.
    - To manage supply in islands.
    - When a *generating unit* that is not offered on a given *trading day* due to being subject to a planned outage, but is recalled from the outage by the *Power System Controller* in an emergency scenario to meet load or system security requirements.
- Out of Merit, where *generating units* are online in a manner inconsistent with security constrained economic dispatch. Examples of this include but are not limited to:
    - Unit changeovers at the change of *trading day*.
    - Unit changeovers when a lower cost *generating unit* becomes available.
    - Unit changeovers when *ancillary service* requirements change.
    - The application of the *first-off decommitment merit order.*
    - Other events that may cause a *generating unit* to become out of merit, such as an error on behalf of one or more parties.

missing data based on dispatch instructions which have verbal confirmation, data requested from and provided by the *Generator*, or from state-estimator data.

Step 2: Process the remaining generating units to identify the relevant price for each trading interval

This step is only performed if there is one or more *generating units* still able to set the *market price* for the *trading interval* after the completion of step 1.

It is first necessary to define which band a *generating unit* is deemed to be dispatched in for the *trading interval*. If the *generating unit* is operating in the same band for the entire *trading interval*, this is straightforward, and the band can be deduced from its MWh output. If the *generating unit* is operating within more than one band during the *trading interval,* then the relevant band is the highest priced band the *generating unit* operated in during the *trading interval* as deduced from the dispatch instructions.

The price associated with a *generating unit* for the purpose of setting the *market price* is determined by highest priced band that it was dispatched to at any point within a given *trading interval*, irrespective of the *generating unit's* output over that *trading interval*. If a *generating unit* was dispatched at *band 1* for the entire *trading interval*, then its price will be set to its *band 1* price. If a *generating unit* is dispatched as *band 2* during a *trading interval*, then its price will be set as either its *band 2 short run* price or *band 2 long run* price, depending on the duration for which the *generation unit* was run. If a *generating unit* is dispatched as *band 3* during a *trading interval*, then its *band 3* price will be used in favor of the *band 2* or *band 1* price.

The *band 2 short run price* will only be used in cases where the *generating unit* is brought online and taken offline within a 4 hour period. This does not include cases where the *generating unit* was already committed and operating at its *band 1* quantity, was then raised to *band 2* for not more than 4 hours, before having its output returned to its *band 1* quantity, where the entire duration of the commitment is greater than 4 hours.

Step 3: Setting market price for each trading interval

If all *generating units* were excluded in Step 1 from setting the *market price* for the *trading interval,* then the *market price* for that *trading interval* is the *market floor price* of $0/MWh.

If there is one or more *generating units* remaining that were not excluded in Step 1 from setting the *market price* for the *trading interval* then the *market price* for the *trading interval* is the greatest value of the relevant prices identified at Step 2 for these *generating units.*

8.4 Market Pricing Results

The Market Operator will post a report pertaining to the *market price* on the Market Operator website. This report contains system load, *generating unit* output and *market price* for each *trading interval* of the *trading day.*

These reports are available on-line at: https://www.powerwater.com.au/market-operator/daily-price-and-trading-data.

8.5 Generator Information

The following information is provided to *Generators* by the *Power System Controller* after each *trading day*

- Actual System Loads.
- Actual constraints on the dispatch and the *market exclusions* that they gave rise to.

- *Generator offers*.
- Chart of the *market price* for each *trading interval* over the *trading day*.
- The exact value of the *market price* for each *trading interval*.
- *Generator offer* file details:
  - *Generator* name.
  - Offer version.
  - Start Interval.
  - *Trading day*.
- The pre-dispatch table defined in Section 7.2.

This information is emailed to each *Generator*.

Where a System Participant wishes to query a *market price* for a given *trading interval*, they may contact the Market Operator via email at: SystemDispatch.PWC@powerwater.com.au

8.6 Pricing Reviews

The Market Operator in concert with the *Power System Controller* will review pricing results that appear anomalous and will categorise them as being due to either:

- Scheduling decisions that may not conform with expected practice;
- The application of a previously undocumented security constraint; or
- An error in application of the pricing methodology.

In any case, the Market Operator will issue a notice to Market Participants explaining the circumstances of the event and the outcome of the review within 10 business days following the relevant *trading day*.

9 Timetables

All timetables associated with release of pre-dispatch and pricing information are governed by Clauses 4.4B and 4.7 of the Code and summarised in detail in the Market Timetable Procedure (https://www.powerwater.com.au/__data/assets/pdf_file/0021/5817/Market-Timetable-Procedure-v1-approved.pdf).

10 References

#	Document	Date	Location
1	Generator Offer Procedure (V2)	04/09/2020	D2020/402571
2	Generator Tie-Break Procedure (V2)	04/09/2020	D2020/402608
3	Market Timetable Procedure (V1)	01/06/2016	
4	System Control Plant Outage Procedure	22/10/2020	D2020/497155
5	Generator Forecast Compliance Procedure	13/07/2020	D2020/172294
6	System Control Technical Code (V6)	30/03/2020	
7	System Security Guidelines (V4.2)	30/04/2020	D2020/197868

11 Records

This Guideline is to be stored in Power and Water's Records Management System (TRIM) in accordance with the Document and Record Control Procedure.

12 Review

This document should be reviewed from time to time at either the request of participating *Generators* or the Market Operator. The document should also be reviewed in the event of a significant change in circumstances such as to the *I-NTEM* with market reform, the System Control Technical Code or a change to market conditions such as the addition of new market participants.

13 Document History

Date of Issue	Version	Prepared By	Description of Changes
04/11/2020	Draft	Amelia Farmilo	Draft for consultation