Energy Transformation Taskforce

Essential System Services

Scheduling and Dispatch

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Energy Transformation Taskforce

David Malcolm Justice Centre
28 Barrack Street
Perth WA 6000
Locked Bag 11 Cloisters Square WA 6850

Main Switchboard: 08 6551 4600

www.energy.wa.gov.au

Enquiries about this report should be directed to:

Aditi Varma, Assistant Director- Future Market Design and Operations

Telephone: 0865514756
Email: aditi.varma@energy.wa.gov.au

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1. Introduction

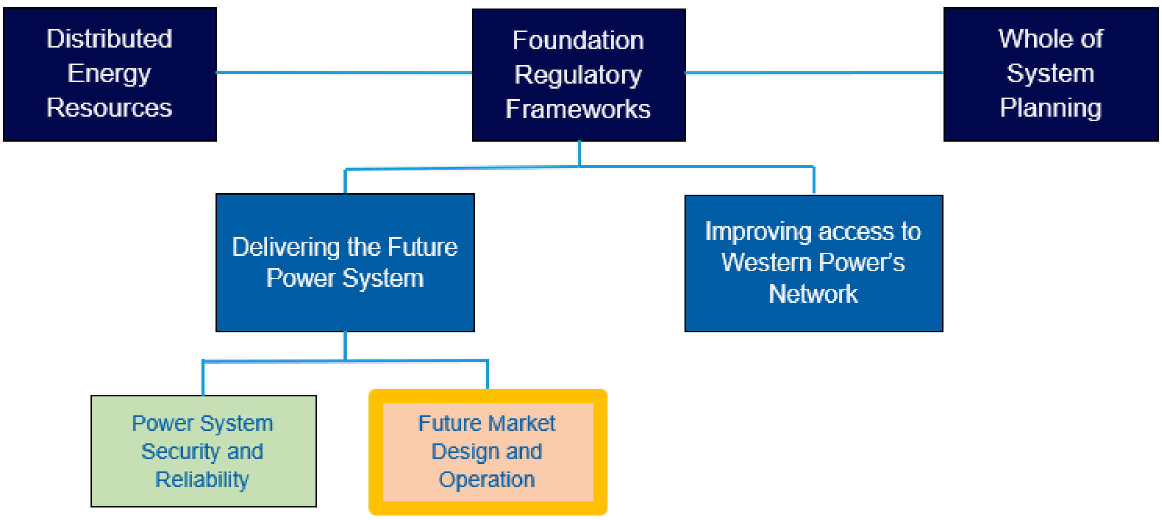
1.1 The Energy Transformation Strategy

This paper forms part of the work to deliver the Energy Transformation Strategy. This is the Western Australian Government's strategy to respond to the energy transformation underway and to plan for the future of our power system. The delivery of the Energy Transformation Strategy is being overseen by the Energy Transformation Taskforce (Taskforce), which was established on 20 May 2019. The Taskforce is being supported by the Energy Transformation Implementation Unit (ETIU), a dedicated unit within Energy Policy WA.

More information on the Energy Transformation Strategy, the Taskforce, and ETIU can be found on the Energy Transformation website at: www.energy.wa.gov.au.

This paper is prepared as part of the *Future Market Design and Operation* project (highlighted in Figure 1) within the Foundation Regulatory Frameworks work stream of the Energy Transformation Strategy.

Figure 1: Energy Transformation Strategy work streams



The Future Market Design and Operation project is undertaking improvements to the design and functioning of the Wholesale Electricity Market (WEM):

- modernising WEM arrangements to implement a security-constrained economic dispatch (SCED) market design that optimises the benefits of the introduction of constrained network access for Western Power's network; and
- implementing a new framework for acquiring and providing Essential System Services (ESS).

1.2 The purpose of this paper

This paper is one of a series covering design decisions for the new SCED market model endorsed by the Taskforce. These changes are critical to support the continuing security of the power system and the efficient operation of the WEM in an environment of rapidly changing technology and consumer demand.

This paper focuses on scheduling and dispatch of ESS under the SCED market model, building on the design decisions provided in the previous Taskforce papers:[1]

- *Foundation Market Parameters*, which described the fundamental characteristics that underpin the design of the new WEM;
- *Scheduling and Dispatch – Energy*, which set out issues and design proposals relating to scheduling and dispatch of energy under the SCED market model;
- *ESS – Acquisition, Cost Recovery and Governance*, which covers the overall case for change to ESS acquisition arrangements and the Taskforce's high-level design decisions; and
- *ESS – Frequency Control Technical Arrangements*, which describes the classes of Frequency Control ESS required by the new WEM.

[1] All papers are accessible through the Energy Transformation Strategy section of the Energy Policy WA website at http://www.wa.gov.au/organisation/energy-policy-wa.

2. Background

This chapter provides a brief overview of the design of the ESS framework previously endorsed by the Taskforce, on which the Taskforce design decisions contained in the remainder of the paper build.

2.1 Overview of ESS Framework

The new market will have five ESS which are co-optimised with energy in the SCED market model:

- *Regulation* x 2 (raise and lower)

A facility providing Regulation ESS will respond to Automatic Generation Control (AGC) signals to correct for small movements in frequency during a dispatch interval. Its energy dispatch must reflect sufficient ‘headroom’ or ‘footroom’ (remaining capacity for the facility to move up, or ability to move down, to provide the Regulation service).

- *Contingency Reserve* x 2 (raise and lower)

A facility providing Contingency Reserve will respond automatically to locally-detected frequency deviations, to help restore frequency to an acceptable level in case of a contingency event (the loss of a large generator or load). The facility’s energy dispatch must reflect sufficient headroom or footroom to respond to a contingency.

- Rate of Change of Frequency (RoCoF) Control

A facility providing RoCoF Control will provide synchronous or synthetic inertia which slows down the rate of change of electrical frequency on the power system.

Where necessary, other ESS may be procured under bilateral contracts with either AEMO or Western Power. These services will be reflected in the market dispatch processes but will not be co-optimised in the same way as the five real-time market services. Taskforce decisions on the procurement, dispatch and settlement of these other ESS are scheduled for the first quarter of 2020.

2.2 Structure of this document

This paper describes how the new ESS framework will work in practice, providing information on how the high-level design decisions will be implemented. Where relevant, the paper describes:

- current market arrangements;
- factors and considerations informing market design, including changes to market conditions (both past and projected); and
- the new market design, as endorsed by the Taskforce.

The remainder of this document is set out as follows:

- Chapter 3 sets-out design elements relating to ESS offers;
- Chapter 4 sets-out design elements relating to ESS dispatch; and
- Chapter 5 sets-out design elements for treatment of facilities other than traditional scheduled generators, including energy storage and demand-side resources.

3. ESS offers

Many of the fundamental characteristics that underpin the design of the new WEM as described in the Taskforce *Information Paper: Foundation Market Parameters* are relevant to the operation of the real-time ESS markets. Under the SCED market model endorsed by the Taskforce:

- all participants submit individual offers for each facility;
- energy and Frequency Control ESS are co-optimised (cleared in the market at the same time);
- there is a single, system-wide ex-ante price for each co-optimised ESS;
- the ex-ante market prices used for ESS dispatch are also used in settlement;
- dispatch instructions are given for each five-minute interval; and
- Synergy will be required to offer in ESS markets.

This chapter will describe the consequential operational processes resulting from these foundational parameters for:

- facility accreditation;
- offer characteristics;
- mandatory offer rules; and
- gate closure.

3.1 Facility accreditation

In order to provide ESS, facilities will have to go through a process over and above general registration for energy provision. As part of accreditation, facilities will need to prove their capability to provide the relevant ESS.

Facilities will be able to seek accreditation as part of the commissioning process, or at any time thereafter. Accreditation will be reassessed:

- on participant request, where at least 12 months has elapsed since the previous accreditation; and
- at AEMO discretion, where less than 12 months has elapsed since the previous accreditation, and there is reason to believe accredited parameters no longer accurately reflect facility capability.

Detail of the accreditation processes will be contained in a market procedure. Key aspects of the process for each ESS are discussed below.

3.1.1 Regulation

Facilities providing Regulation ESS will be required to:

- be capable of operating in AGC mode using set-points determined and sent by AEMO;
- maintain and provide real-time data from required SCADA points to AEMO;
- provide standing 'enablement' limits:
  - a lower limit which is the energy dispatch level below which no Regulation service can be provided (this may be zero); and
  - an upper limit which is the energy dispatch level above which no Regulation service can be provided (this may be the maximum generation capacity); and

- carry out tests to demonstrate response.

The PJM electricity market (in the eastern United States) determines performance factors reflecting accuracy and speed of response to AGC signals, in order to balance performance across two separate classes of regulation-type service with different performance definitions, delivered over different timeframes.[2] In the South West Interconnected System (SWIS), the variation in facility regulation is not expected to be significant enough to drive changes in the quantum of Regulation ESS required, so performance factors will not be implemented as part of SCED implementation. However, they may be considered as part of future market evolution.

3.1.2 RoCoF Control

Facilities providing RoCoF Control will be required to:

- provide evidence demonstrating the quantity of synchronous inertia (in megawatt-seconds) provided by the facility when it is synchronised to the power system;
- identify any conditions under which the facility would provide different quantities of inertia (e.g. by running different numbers of generating units, or starting a synchronous condenser); and
- provide a standing lower enablement limit which is the energy dispatch level below which no RoCoF Control service can be provided (this may be zero).

3.1.3 Contingency Reserve

Facilities providing Contingency Reserve will be required to:

- provide standing enablement limits:
  - a lower limit which is the energy dispatch level below which no Contingency Reserve service can be provided (this may be zero); and
  - an upper limit which is the energy dispatch level above which no Contingency Reserve service can be provided (this may be the maximum generation capacity);
- identify the expected time delay between detecting and responding to a frequency excursion;
- carry out tests to prove response; and
- provide access to high-speed performance data following a contingency event.

In the current WEM Ancillary Service framework, test results are used to measure facility response at defined time intervals (6 and 60 seconds). In the new ESS framework, test results will be used to determine a ‘speed factor’ which reflects the characteristics of facility response to frequency deviation, and the profile in time with which its response is provided.

A facility’s speed factor will form part of standing data and will be incorporated into the dispatch process to reflect the fact that slower-responding facilities may contribute less to the provision of an ESS, in some system conditions, than others.

Figure 2 shows an example of how speed factors (expressed as a Tau [τ] factor) may be calculated from response curves, using the equation $PFR \times (1 - e^{-t/\tau})$.[3]

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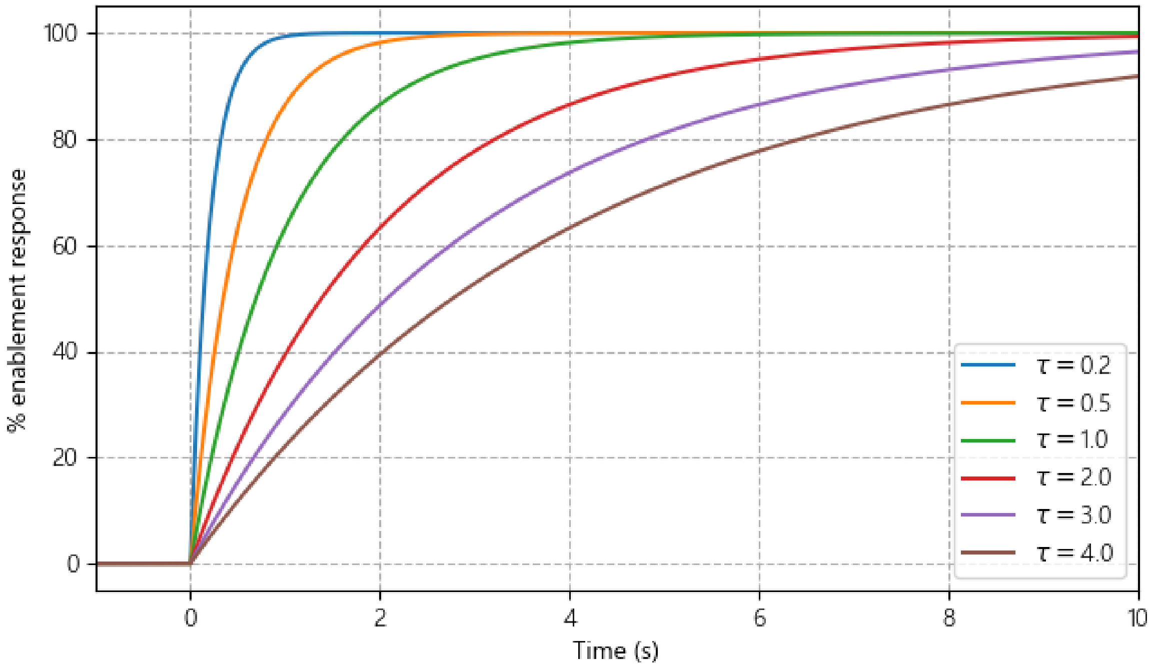
[2] https://www.pjm.com/-/media/markets-ops/ancillary/regulation-market-concepts-benefits-factor-calculation.ashx?la=en

[3] Where PFR is the MW headroom available on the facility or the number that clears in the dispatch engine for the Contingency Reserve, e represents the exponential function, t is the point in time at which a facility’s response is measured and τ is the speed factor that describes how quickly the facility reaches its target MW.

Figure 2: Example translation of response curves to speed factors



A facility which can provide full response within a fraction of a second might have a $\tau = 0.2$, while a facility that takes several seconds to fully respond might have a $\tau = 4$ (that is, the lower the τ factor, the higher the speed factor).

Figure 3 and Figure 4 show examples of how specific facility response in a generation loss contingency can translate to a given speed factor. The red dotted line is the point in time where the frequency reaches its lowest point (the frequency 'nadir'). Response before this time is more important than response after it.

Figure 3 shows a gas turbine which closely follows the $\tau = 2$ curve in the period before the frequency nadir. Figure 4 shows a steam turbine which has an initial volatile response, then settles down to approximately the $\tau = 6$ curve at the frequency nadir. The early response is valuable and will be accounted for in the accreditation process.

Figure 3: Facility capability example - gas turbine

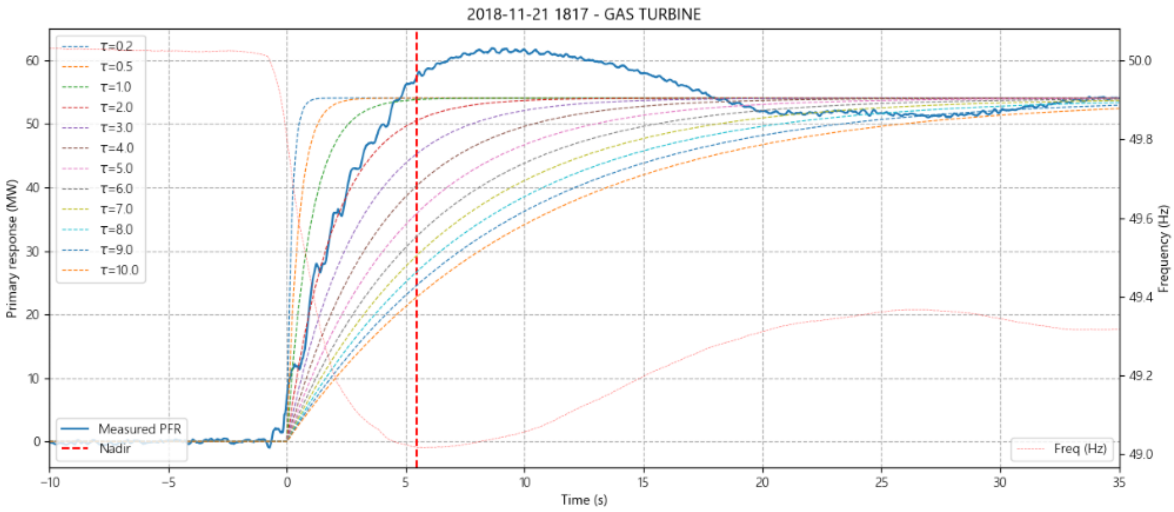
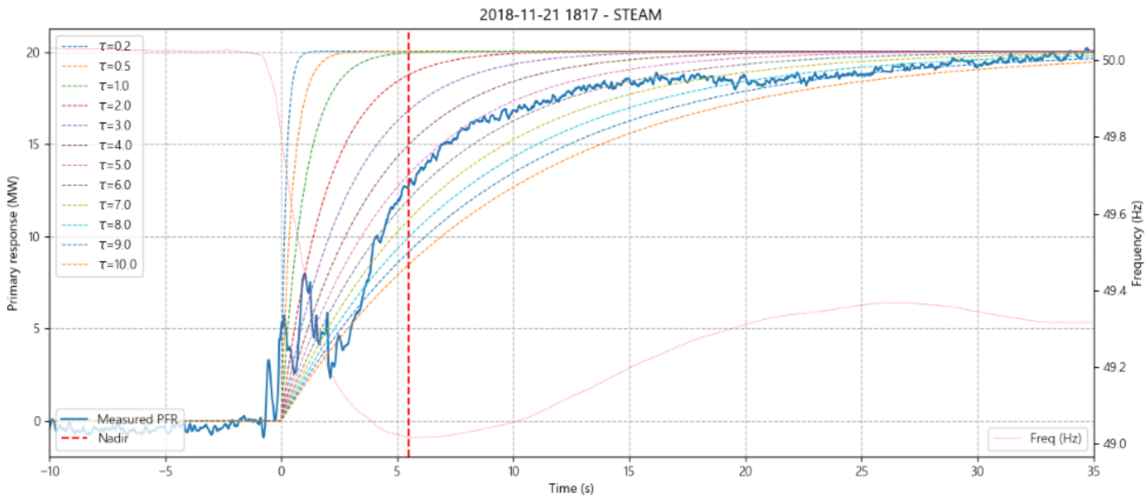


Figure 4: Facility capability example - steam turbine



All else being equal, a lower τ factor will result in larger payments for holding the same quantity of headroom. Although the speed of response is notionally constant for a given facility, it may be possible to improve a facility's τ factor (for example through machine upgrades, governor retuning, or change of operating mode). As noted in section 3.1, participants will be able to request reassessment of accreditation parameters, including where they have made changes to improve a facility's speed of response.

The Taskforce has endorsed the following design decision:

- Facilities will be accredited to provide ESS based on the facility's characteristics and the requirements for the specific ESS.

3.2 Offer characteristics

3.2.1 Precision and minimum quantities

In the current WEM, offers in the Short Term Energy Market (STEM) must be expressed to a precision of 0.001 megawatt hour (MWh) and $0.01. Precision of offers in the existing Balancing and Load Following Ancillary Services (LFAS) Markets is not defined in the rules, but in practice the same level of precision is used.

LFAS offers from an individual facility must total at least the Minimum LFAS Quantity in order to participate in the LFAS market. The Minimum LFAS Quantity is set in the Power System Operation Procedure: Ancillary Services. It is currently set at 10 megawatts (MW). Other than the Minimum LFAS quantity, no restrictions are placed on the granularity of offers.

Precision and minimum ESS quantities will continue to be set in a market procedure, with specific minimum quantities for each of Regulation, Contingency Reserve, and RoCoF Control service.

3.2.2 Offer components

ESS offers may contain up to 10 price-quantity pairs, which must have monotonically increasing offer prices with the increase in available MW or MW seconds (MWs) (that is, prices that only increase as the available MW or MWs increases in each price/quantity pair).[4] Co-optimisation means that in most cases, ESS offers do not need to account for the opportunity cost of energy dispatch.[5] Offer prices should reflect short-run marginal cost of retaining headroom or footroom for the facility.

Offers must also specify facility technical characteristics for providing ESS:

- Enablement limits – the level of generation (or load) above or below which no response can be provided by the facility[6]
- Response breakpoints – the levels of generation (or load) between which the facility can deliver its maximum ESS capability

Ramp rates will be submitted with energy offers, not ESS offers.

Where AGC settings are more restrictive than offered enablement limits or quantities, AEMO will use the tighter of the two. The methodology for doing so will be set out in a market procedure.[7]

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[4] The fundamental optimisation mechanism of the market clearing engine is to minimise total overall cost of supply. This means it will seek to clear the lowest priced energy and ESS offer tranches first, regardless of which portion of the generator's capacity it relates to. This approach is common to all SCED models, as using non-monotonically increasing supply curves requires introduction of integer variables which significantly affects the complexity of the solution process.

[5] The marginal opportunity cost of providing ESS instead of energy is reflected in the ESS price. However, energy up to the enablement minimum is not available for providing ESS, so there is no trade-off for this quantity, and any difference between the offer price of this energy and the energy price will not be reflected in ESS revenues by market clearing processes. Where a participant has a facility with a large enablement minimum, a small ESS dispatch, and expects the market price to be significantly lower than its energy offer, it may wish to increase ESS offers to reflect the foregone revenue.

[6] Although standing enablement limits are provided in accreditation, the dispatch process will use the values provided in offers. Participants may be asked to provide justification for deviations from standing data values.

[7] An example of such a market procedure is AEMO's FCAS Model in NEMDE, May 2017, Section 4, available at: www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2017/FCAS-Model-in-NEMDE.pdf

Indicative offer formats are provided in 0.

While submission of enablement limits allows participants to reflect facility operating characteristics, they can have the effect of restricting dispatch of a facility in undesirable ways for short periods as discussed below in section 3.2.3. In these cases, participants may need to adjust offers, and will indicate this by providing a value in the 'offer change reason flag' field of their respective ESS offer.

3.2.3 Accounting for minimum and maximum enablement limits

There is a trade-off between the quantity of energy and ESS provided by a single facility. Enablement for Regulation and Contingency Reserve affects the quantity of energy that a facility can provide in the energy market. If a facility is generating at maximum capacity, it cannot respond to raise the system frequency. If a facility is generating at minimum stable load, it cannot respond to lower the system frequency. The approach to co-optimisation of Regulation and Contingency Reserve ESS is well-understood, and implemented in many markets around the world, including the National Electricity Market Dispatch Engine (NEMDE), that will form the basis of the new WEM Dispatch Engine (WEMDE).

In general, the relationship can be modelled in the market clearing engine using 'joint capacity' constraints of the form shown in Equation 1 and Equation 2.

Equation 1 – joint energy capacity constraint (raise)

$$energyDispatch_f + regulationRaiseDispatch_f + contingencyReserveRaiseDispatch_f \leq maxCapacity_f$$

Equation 2 – joint energy capacity constraint (lower)

$$energyDispatch_f - regulationLowerDispatch_f - contingencyReserveLowerDispatch_f \geq 0$$

That is, the joint energy capacity constraint for Regulation raise and Contingency Reserve raise is the sum of the quantity for energy dispatch and Regulation and Contingency ESS (raise), where this is equal to or less than the maximum capacity of the facility. The joint capacity constraint for Regulation and Contingency Reserve (lower) is the quantity for energy dispatch minus the quantities for Regulation and Contingency Reserve ESS (lower), where this is equal to or more than zero.

This ensures that a facility providing ESS has enough room to move to provide the services it is dispatched for. An example visualisation of the constraint is shown in Figure 5. Any point below the line is a feasible solution. If the facility has a maximum capability for reserve provision, this can also be incorporated, as shown in Figure 6.

Figure 5: Basic form of joint capacity constraint

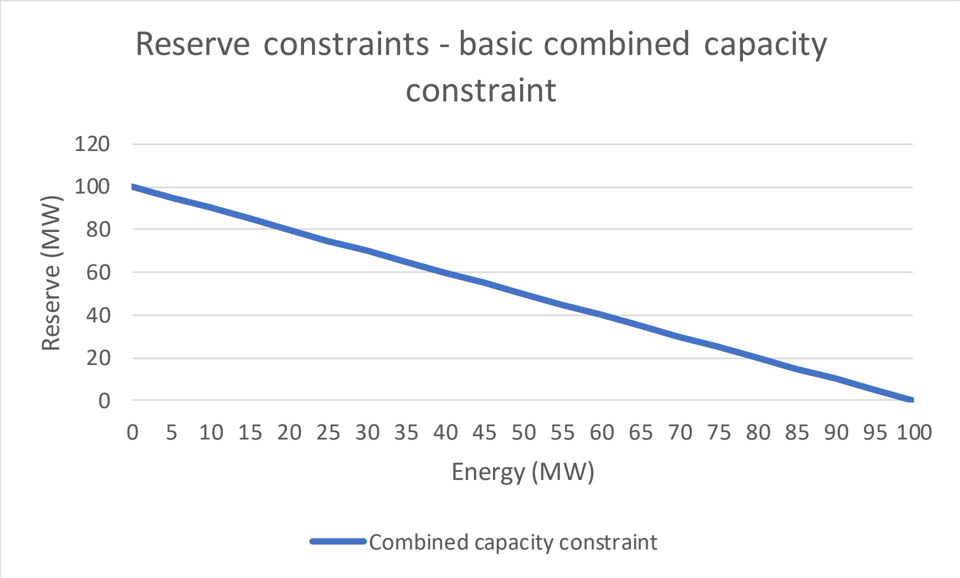
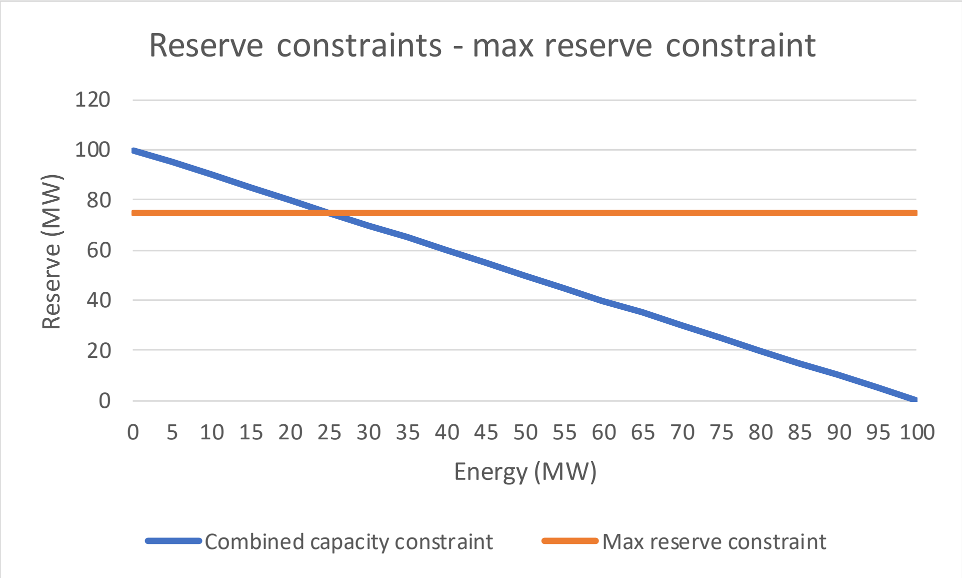


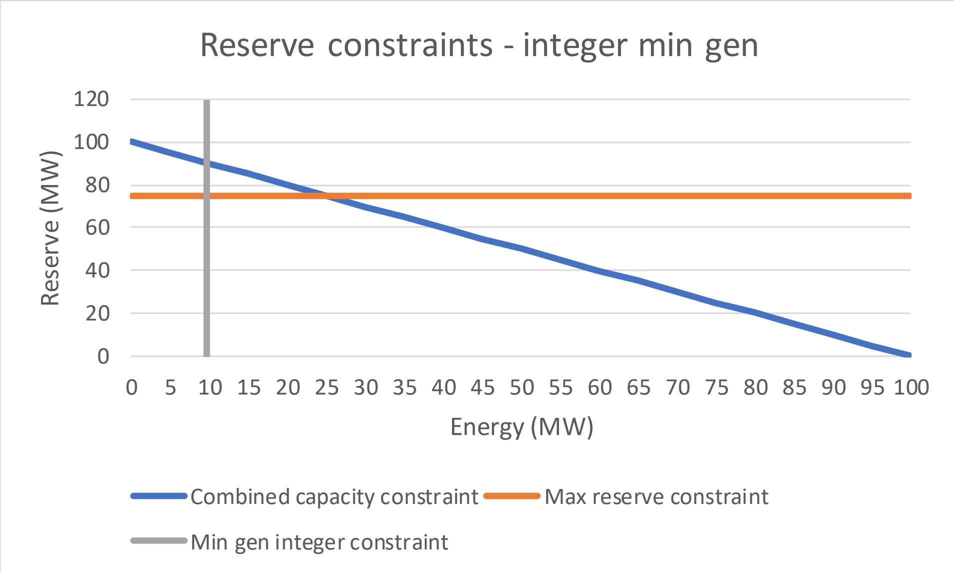
Figure 6: Joint capacity and maximum reserve constraints



The main consideration around co-optimisation of these services is whether the clearing process will account for the minimum stable generation. If it does not, facilities may be dispatched to an energy position which they cannot physically meet.

In markets with centralised commitment, this consideration is managed by solving the 'integer problem' of 'lumpy generation' (generation with technical characteristics that results in a non-linear relationship between reserve and energy quantities) using three-part offers, which include facility start costs. The constraints in this case look like those shown in Figure 7.

Figure 7: Integer constraint for minimum generation



Integer problems are much harder to optimise than those involving linear variables only, as the solution space is not continuous – the clearing engine must either choose to dispatch the facility for 0 energy and 0 reserve, or for some point under the curve. As a result, solve times for integer problems are longer than linear problems, and can vary considerably depending on input parameters. A second (linear) run is required to determine prices.

In markets without centralised commitment, (including the current WEM, the NEM, New Zealand, and Singapore) there is no consideration of minimum stable load when dispatching for energy, and participants must manage their offers to effect self-commitment and avoid dispatch targets that cannot be achieved.

The Taskforce *Information Paper: Foundation Market Parameters*[8] identified that the WEM will continue to operate on the principle of facility self-commitment, for both energy and ESS.[9] Participants will be responsible for structuring their offers to make their own commitment decisions. The pre-dispatch schedule[10] forecasts what is expected to happen in real-time, giving participants a view of the expected dispatch, with enough time to adjust so that the forecast schedule converges to a stable state ahead of real-time.

Nevertheless, the clearing process for ESS will include two mechanisms which allow participants to reflect their minimum stable load, in order to reduce the incidence of dispatch instructions that cannot be physically implemented:

1. fast-start inflexibility profiles (FSIP); and
2. pre-processing to filter infeasible offers[11] and constrain-on capable facilities.

[8] Available at: www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Foundation-Market-Parameters.pdf

[9] Full centralised optimisation of commitment decisions (using ‘three part’ offers) is a consideration for future market evolution.

[10] Pre-dispatch schedules are outlined in the *Information Paper: Energy Scheduling and Dispatch* available at: www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Energy-scheduling-and-dispatch-paper.pdf

[11] An infeasible offer for ESS is when the offer is structured in a way that a continuous solution space bound by the minimum and maximum capacity constraints for the facility (i.e. a trapezium shape) cannot be identified.

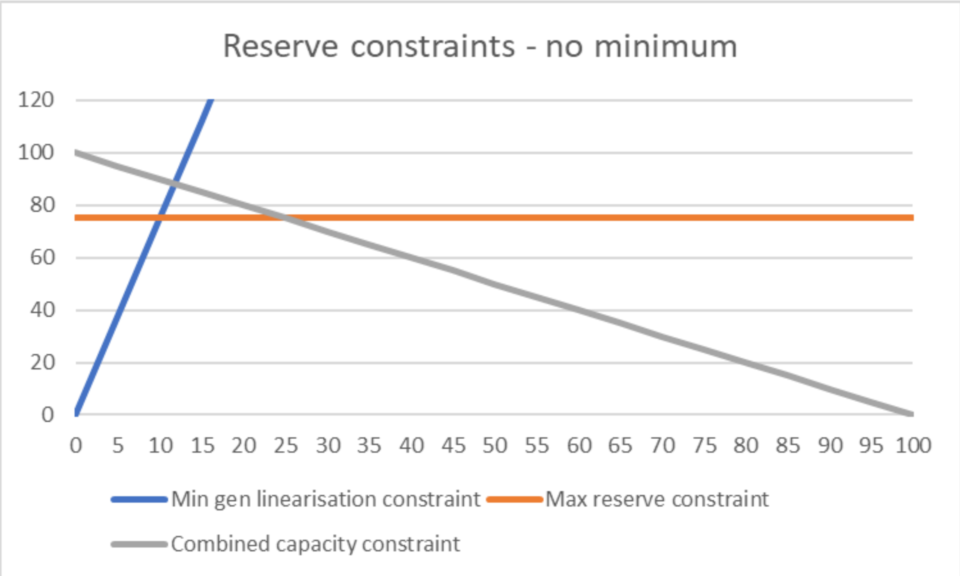
Fast-start inflexibility profiles

The clearing engine can respect facility start-up profiles by executing a second linear run with the output fixed. This approach is used in the NEM[12] and Singapore[13] for facilities which can start and reach minimum stable load within 30 minutes of a dispatch instruction. This approach will be adopted in the WEM as discussed in the *Information Paper: Scheduling and Dispatch – Energy*.[14]

Pre-processing to filter infeasible offers and constrain on capable facilities

In New Zealand and Singapore, managing minimum stable load constraints for reserve provision is also a participant responsibility. The clearing engine solves a linear approximation of the integer problem (as shown in Figure 8), where the solution space is a continuous, trapezium-shaped feasible operating zone. This can result in a facility being dispatched to provide reserve at an energy level below its minimum stable load.

Figure 8: Linear approximation of minimum generation constraint



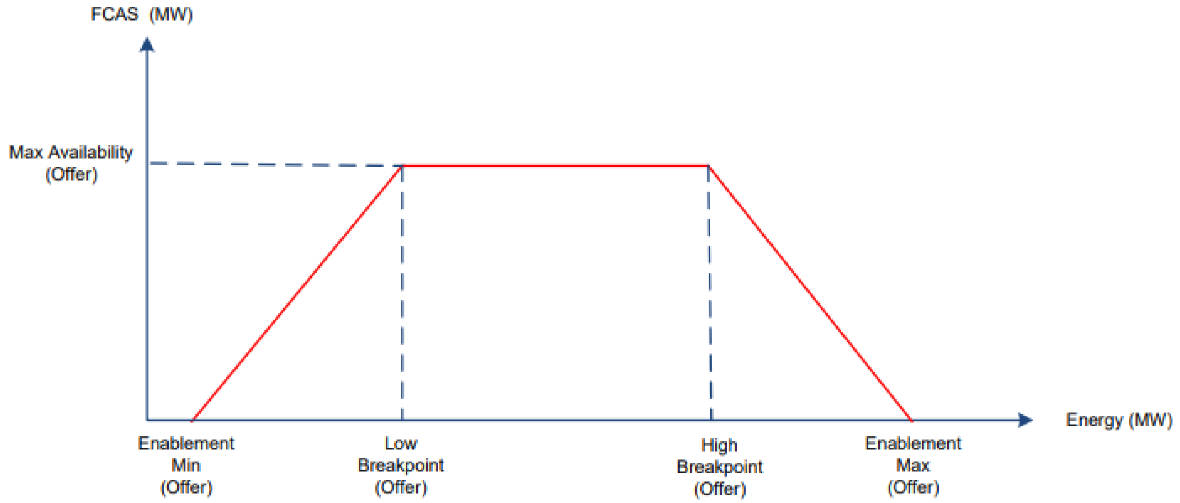
The NEM uses pre-processing to filter facility Frequency Control Ancillary Service (FCAS) offers for facilities not currently operating between minimum and maximum enablement limits, and these limits are used to further restrict the feasible operating zone (as shown in Figure 9).

[12]Available at: www.aemo.com.au/-/media/Files/PDF/Fast_Start_Unit_Inflexibility_Profile_Model_October_2014.pdf

[13] Available at: www.emcsg.com/f1239,103326/EMC320-EMA-LL-final.pdf

[14] Available at: www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Energy-scheduling-and-dispatch-paper.pdf

Figure 9: NEM FCAS offer trapezium - energy and FCAS capability relationship[15]



Because the enablement minimum is not at zero, a zero energy, zero FCAS dispatch is outside the continuous solution space. The NEM manages this by not allowing the clearing engine to consider:

- for any facility with a feasible contingency FCAS offer, an energy dispatch below the enablement minimum (or above the enablement maximum). To be dispatched off, the facility must adjust its offers so it is no longer in the feasible energy range for providing FCAS; and
- for any facility not already operating within the 'FCAS trapezium', a non-zero FCAS dispatch. Offers are filtered out in pre-processing and are not available to the market clearing engine for use in dispatch.

This allows a linear solution, but it means that, unlike for energy, the clearing engine can only schedule ESS provision from facilities which are already scheduled to be operating in the right range – it does not consider offers from other facilities, even if they could be dispatched to within the range.

Applying enablement limits means that to be dispatched for ESS, a facility must be producing energy between its enablement limits before it will even be considered for ESS by the clearing engine. With this in place, there is no need for approximation in the clearing engine.

This approach will be adopted for use in dispatch schedules, to provide certainty that calculated ESS dispatch will be physically feasible. Pre-dispatch schedules will include runs with and without enablement limits, to give participants an indication of the impact of their enablement limits, and whether they could be dispatched to provide ESS if offers were adjusted.

The dispatch schedule will not clear a facility for ESS if it is not already running to provide energy, so a facility which wishes to participate in ESS markets must first manage its energy offers so as to be dispatched for energy between its enablement limits. A facility which is 'trapped' in the trapezium and wishes to turn off will need to adjust its offers to set reserve availability to zero, or increase its enablement minimum.

[15] Source: AEMO (2017) FCAS Model in NEMDE, May 2017, p. 6 available at: www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/2017/FCAS-Model-in-NEMDE.pdf

3.2.4 Enablement limit examples

Enablement limits and response breakpoints are used to define the feasible operating zone for each service – an “ESS Trapezium”.

For raise services, the steepness of the upper slope is limited by the quantity of headroom remaining below the enablement maximum.

For lower services, the steepness of the lower slope is limited by the quantity of energy provided above the enablement minimum.

Table 1: Example facility characteristics – Contingency reserve raise

Maximum capacity	90
Maximum Contingency Reserve (raise) capability	60
Enablement minimum	10
Lower breakpoint	20
Upper breakpoint	30
Enablement maximum	90

Figure 10: Example feasible dispatch zone – Contingency reserve raise

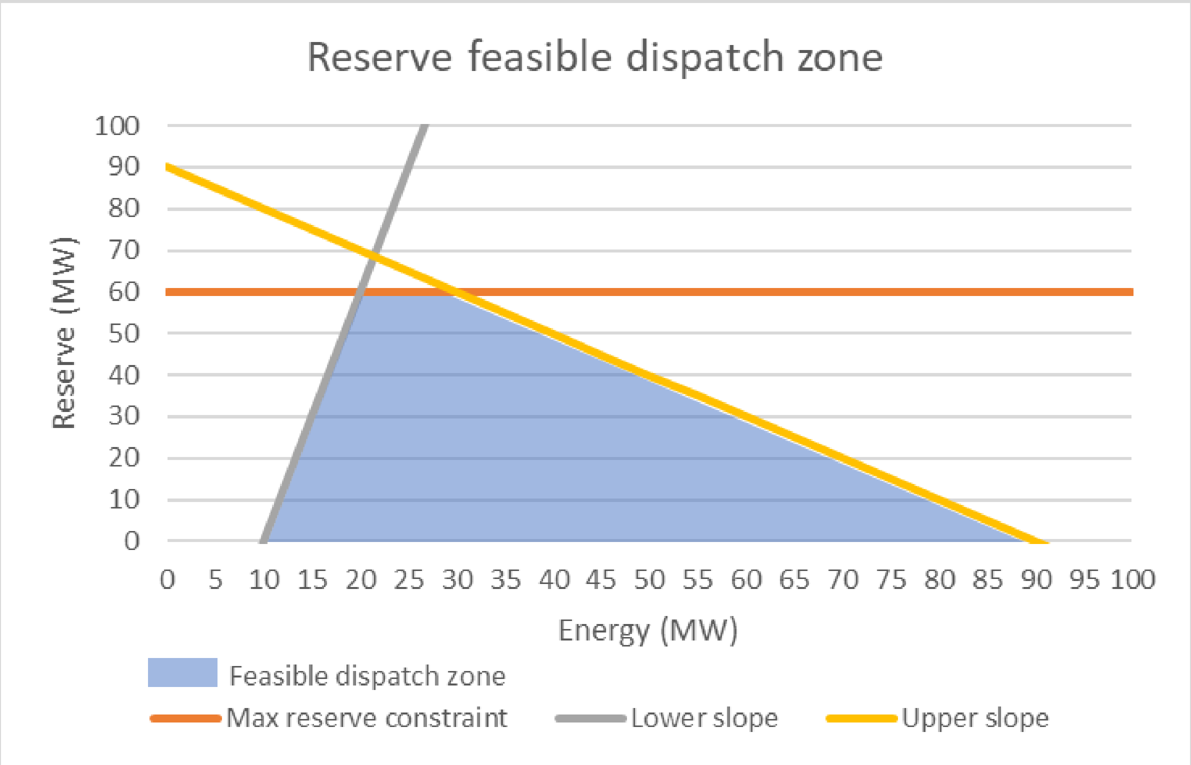
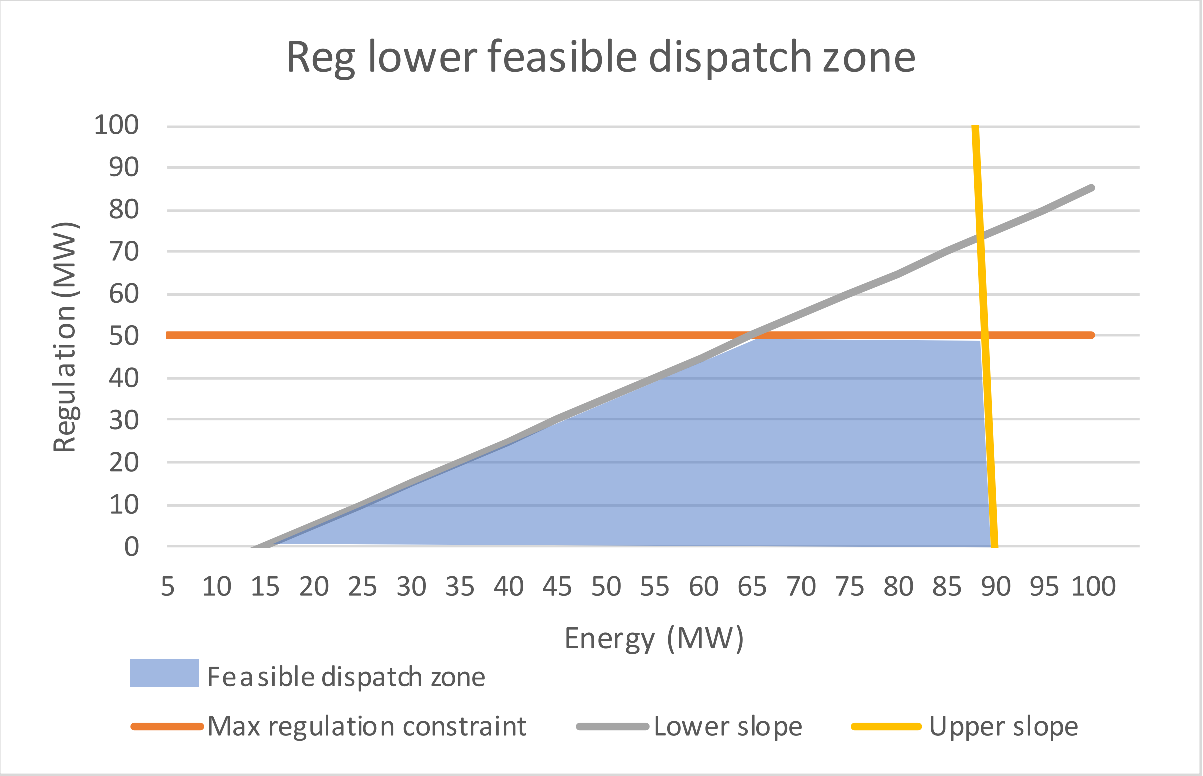


Table 2: Example facility characteristics – Regulation lower

Maximum capacity	90
Maximum Regulation (lower) capability	50
Enablement minimum	15
Lower breakpoint	65
Upper breakpoint	89
Enablement maximum	90

Figure 11: Example feasible dispatch zone – Regulation lower

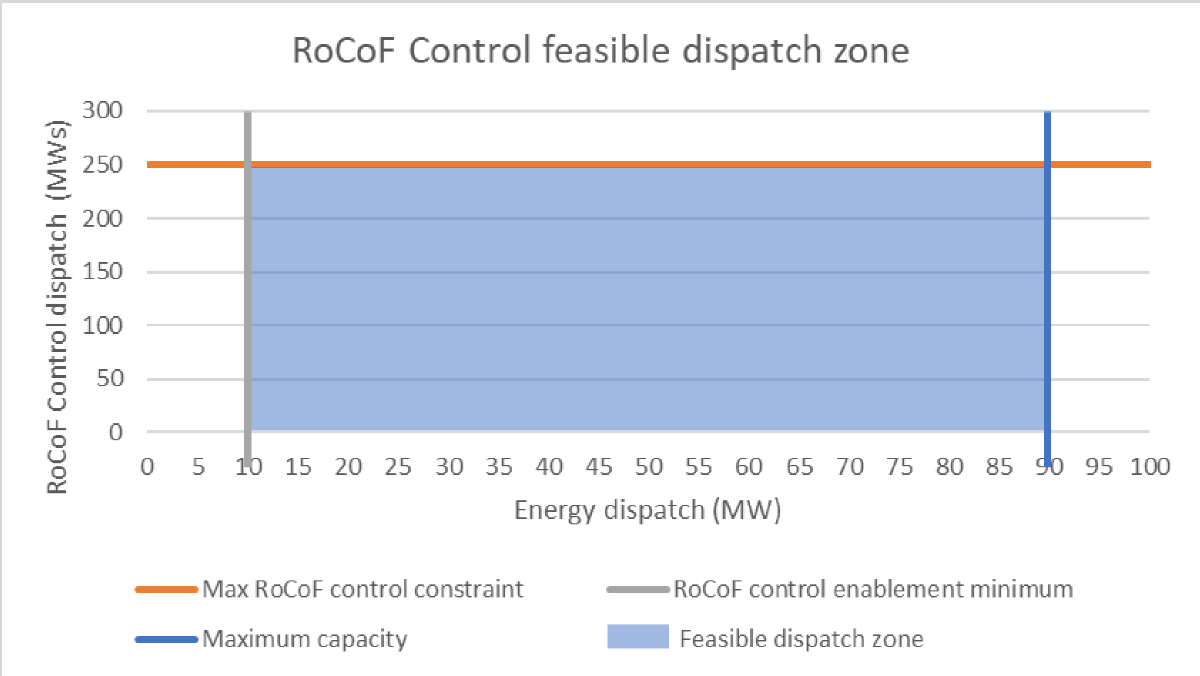


The capability of a facility to provide Contingency Reserve and Regulation is directly related to its energy output. Provision of RoCoF Control service is different. A synchronous machine which is generating above minimum stable load will provide the same quantity of inertia regardless of its generation level. The solution space is not limited at the upper end, as there is no trade-off with energy provision requiring a joint capacity constraint. An example of a RoCoF Control-providing facility and a feasible RoCoF Control dispatch zone are provided in Table 3 and Figure 12, respectively.

Table 3: Example facility characteristics – RoCoF Control

Maximum capacity	90
Maximum RoCoF Control capability	250MWs
Enablement minimum	10

Figure 12: Example feasible dispatch zone – RoCoF Control



0 shows example energy and ESS offers.

The Taskforce has endorsed the following design decision:

- Facility offers for ESS provision will include the facility's enablement limits and response breakpoints.
- Facilities will be required to self-manage their offers to avoid dispatch targets that cannot be achieved.

3.2.5 Offer price caps

It is currently expected that ESS offer price caps and floors will be set at the same level as energy offer price caps and floors.

Offer price caps and market price caps will be covered in future Taskforce decisions on market power mitigation.

3.3 Mandatory offer requirements

In the current WEM, provision of ESS is not linked to capacity credits. Synergy is required to offer into the LFAS market and to provide Spinning Reserve through portfolio dispatch, but participation of other facilities is voluntary. Mandatory participation in ESS markets could potentially support market liquidity and contribute to capacity capable of providing ESS being available in real-time.

For some scheduled facilities, participating in ESS markets would require additional expenditure on technology and equipment (e.g. AGC functions) and time and effort to become accredited. Demand Side Programmes (DSP) must be explicitly dispatched at least two hours ahead of time if they are to respond, and therefore cannot provide ESS. Intermittent generation can provide ESS, but provision of raise services rather than energy provision is unlikely to be economic in most situations. Requiring such facilities to become accredited and offer into ESS markets would impose costs for limited benefit. Facilities which do expect to get a return from participation in ESS markets will make their own commercial decision to invest in control systems and accreditation requirements.

In the short term, the current generation fleet has sufficient capacity capable of providing the required ESS. In the longer term, obligations on capacity credit holders (through the Reserve Capacity Mechanism (RCM)) to participate in ESS markets would not, by themselves, be sufficient to guarantee availability of the right kind of capacity required for ESS provision, nor would they manage the potential for market power exercise to result in inefficiently high prices. For that reason, the *Information Paper: ESS – Acquisition, Cost Recovery and Governance*[16] provided for a supplementary mechanism to manage market power and provide a response to forecast ESS scarcity, if deemed necessary.

Facilities that are successfully contracted through the supplementary mechanism will be required to offer into real-time ESS markets.

Facilities that are accredited to provide ESS may be required to offer in case of forecast shortfall if directed by AEMO (see section 4.4.3).

The Taskforce has endorsed the following design decision:

- Participation in real-time ESS markets will be voluntary, however a facility successfully contracted through the supplementary procurement mechanism will be required to offer its capacity into the real-time ESS markets.
- Facilities accredited to provide ESS may be directed by AEMO to offer in real-time ESS markets in case of a shortfall.

3.4 Gate closure

In the current WEM, the LFAS Market is cleared ahead of the energy market, and therefore has an earlier gate closure.

As discussed in the *Information Paper: Energy Scheduling and Dispatch*[17], gate closure for the new real-time energy market will be significantly reduced at market start (15 minutes) and reduced to zero after a bedding-in period.

Although ESS will in future be cleared at the same time as energy, ESS gate closure could still potentially be set earlier than energy. Doing so would require participants to lock-in ESS offers ahead of energy offers. However, optimal ESS dispatch (and associated ESS prices) would still change

[16] Available at: www.wa.gov.au/sites/default/files/2019-08/Information-paper-Frequency-Control-Essential-System-Services_1.pdf

[17] Available at: www.wa.gov.au/sites/default/files/2019-08/Information-Paper-Energy-scheduling-and-dispatch-paper.pdf

depending on changes to energy offers, so an advanced gate closure for co-optimised ESS would not provide any additional certainty of ESS market outcomes.

For these reasons, the gate closure for co-optimised ESS will be the same as the gate closure for energy.

The Taskforce has endorsed the following design decision:

> - The gate closure for co-optimised ESS will be the same as the gate closure for energy (15 minutes from 1 October 2022).

4. ESS dispatch

Under SCED, the market clearing engine becomes the key determinant of dispatch decisions. Previously manual activities will be systematised and automated, and discretion to depart from calculated outputs limited to extreme situations.

As far as possible, all dispatch will be in accordance with the output of the market clearing process[18]. To achieve this, the clearing engine must accurately represent operational constraints and physical properties of power system components.

4.1 Co-optimisation of energy and ESS

Economically efficient, least-cost dispatch of generation is a fundamental objective of the reforms to the wholesale energy and ESS markets. A facility can provide either energy, Regulation, or Contingency Reserve from the same capacity. This means that where dispatch decisions for ESS are made separately from energy, there will be loss of efficiency, particularly where ESS requirements depend on energy output. Co-optimising dispatch of energy and ESS provides the mechanism to deliver the lowest cost combination of dispatch from available facilities.

As is the case in the current market, participants will continue to make offers for their facilities to supply energy and one or more ESS. Each market represents the provision of a clearly defined set of services, each separate and distinct from the others, and participants can choose to offer into all, some or none of the markets. The market clearing process then solves all the markets at the same time, to arrive at the lowest cost secure solution, accounting for complex trade-offs:

- Each MW of capacity can only be allocated to one service at a time in each direction:
  - a MW providing energy cannot also be used for Regulation raise or Contingency Reserve raise;
  - a MW providing Regulation lower or Contingency Reserve lower must also be cleared for energy;
  - a facility's current production level will influence what ESS it can provide;
  - the energy dispatch can affect the total quantity of Contingency Reserve raise required, by changing the size of the largest risk (be it loss of a generator or network component)

Co-optimisation simplifies and de-risks the bidding process for market participants, allowing generators to offer their full capability simultaneously into energy and multiple ESS markets while being commercially indifferent as to which services they are dispatched to provide. Appendix C outlines examples of co-optimisation that result in commercial indifference for participants.

All five frequency control services (Regulation raise and lower, Contingency Reserve raise and lower and RoCoF Control) will be co-optimised with energy. This is achieved by defining an 'objective function', which describes the total cost of dispatch, and which the clearing engine seeks to minimise. A simplified objective function is shown in Equation 3.[19]

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[18] Rare occurrences of manual overrides of the dispatch algorithm may happen in emergency situations and/or when the dispatch outcome is infeasible.

[19] Where *f* is the set of all generation facilities, $[ESS]Dispatch_f$ is the quantity of service $[ESS]$ scheduled at facility *f*, and $[ESS]OfferPrice_f$ is the facility *f*'s offer price to provide an ESS service.

Equation 3 – simplified objective function

$$minimise\ TotalCost\ where$$

$$
\begin{aligned}
TotalCost = &\sum_f energyOfferPrice_f \times energyDispatch_f \\
&+ \sum_f contingencyReserveRaiseOfferPrice_f \times contingencyReserveRaiseDispatch_f \\
&+ \sum_f contingencyReserveLowerOfferPrice_f \\
&\times contingencyReserveLowerDispatch_f \\
&+ \sum_f RegulationRaiseOfferPrice_f \times RegulationRaiseDispatch_f \\
&+ \sum_f RegulationLowerOfferPrice_f \times RegulationLowerDispatch_f \\
&+ \sum_f RoCoFControlOfferPrice_f \times RoCoFControlDispatch_f
\end{aligned}
$$

Expected dispatch outcomes (prices and quantities) for energy and ESS will be signalled in pre-dispatch schedules, across a range of possible load and other scenarios.

4.2 Determining ESS quantities

ESS quantities are a critical part of the market clearing process. The quantity of ESS required directly drives market costs. Setting the required quantities too loosely risks insufficient response resulting in damage or loss of additional power system components, while setting them too conservatively will increase overall market costs.

For this reason, where the quantity required is directly dependent on dispatch outcomes, it is important to calculate them as part of the dispatch process, to automate and systemise optimisation of trade-offs. Where the quantity required is not dependent on dispatch outcomes, it can continue to be set exogenously.

Table 4 shows the approach to determining the required quantities for each ESS.

Table 4: Approach to determining ESS quantities

ESS type	Determinants of ESS quantities required	Treatment
Regulation (lower)	Expected forecast error	Set external to dispatch process, based on analysis of historic data (as set out in market procedure). May vary by time of day or based on system conditions.
Regulation (raise)	Expected volatility of generation and load within dispatch interval	
Contingency reserve (lower)	Largest credible load loss (including from loss of network components)	
Contingency reserve (raise)	Largest credible generation loss (including from loss of network components)	Co-optimised in dispatch process. Requirements can be reduced by reducing output of the risk-setting generator(s) or changing the balance between the two products.
RoCoF Control	System inertia Largest contingency Available Primary Frequency Response	

The methodologies for determining ESS quantities will be described in a market procedure.

4.2.1 Co-optimising the contingency reserve raise quantity

The Contingency Reserve raise quantity will be co-optimised as part of the dispatch process.[20] This means if the total cost is lowered by reducing the output of the largest generator rather than enabling additional reserve, the clearing engine can do so.

Specifically, the required quantity of contingency reserve raise will be determined by a set of equations of the form shown in Equation 4.

Equation 4 - contingency reserve raise constraints

$$\sum_{f} contingencyReserveRaiseDispatch_f - energyDispatch_{FacilityA} \geq 0$$

$$\sum_{f} contingencyReserveRaiseDispatch_f - energyDispatch_{FacilityB} \geq 0$$

$$\sum_{f} contingencyReserveRaiseDispatch_f - energyDispatch_{FacilityC} \geq 0$$

...

[20] Only the Contingency Reserve raise quantity will be co-optimised as this value is dependent on the largest energy injection quantity, which the clearing engine can affect. The quantity of Contingency Reserve lower does not depend on energy dispatch and the algorithms in the clearing engine cannot affect this quantity.

And where occurrence of a credible network contingency would result in loss of output from multiple generators, for example Facility A and Facility B:

Equation 5 - contingency reserve raise constraint for a network contingency

$$\sum_f contingencyReserveRaise_f - (energyDispatch_{FacilityA} + energyDispatch_{FacilityB}) \geq 0$$

These equations together mean that the quantity of Contingency Reserve raise scheduled must be greater than or equal to the largest risk.

The risk calculation must include ESS enablement, to ensure that reserve scheduled is not lost at the same time as the energy it covers for. This can be illustrated by way of example. If only energy were used to set the risk, a 400MW facility could be scheduled for 200MW energy, and also be scheduled for the 200MW of Contingency Reserve required to cover the largest energy risk (itself). If this facility trips, it cannot respond to provide the reserve for itself. Including ESS dispatch in the market clearing engine constraints allows this dynamic to be managed to ensure that sufficient reserve is held on units other than the risk setter. This can be represented in the equations as follows:

Equation 6 - contingency reserve raise constraint including ESS variables

$$\sum_f contingencyReserveRaiseDispatch_f - (energyDispatch_{FacilityA} \\ + contingencyReserveRaiseDispatch_{FacilityA} + regulationRaiseDispatch_{FacilityA}) \\ \geq 0$$

...

4.2.2 Contingency factor

Response from facilities enabled for Contingency Reserve is not the only service restricting frequency excursion in the event of a contingency to within the 48Hz to 52Hz band. System inertia, load relief, and mandatory droop response from other facilities also contribute. This means that maintaining system security will not usually require Contingency Reserve to cover 100% of the largest risk.

The ‘contingency factor’ represents the ratio between the largest energy contingency and the Contingency Reserve quantity required to maintain frequency within safe bounds. This can be represented in equations as follows:

Equation 7 - contingency reserve raise constraint including ESS variables and contingency factor

$$\sum_f contingencyReserveRaiseDispatch_f - (ContingencyFactor \times energyDispatch_{FacilityA} \\ + contingencyReserveRaiseDispatch_{FacilityA} + regulationRaiseDispatch_{FacilityA}) \\ \geq 0$$

...

In the current WEM, the Spinning Reserve[21] standard is set at 70% of the output of the largest generating unit. In the future, where system conditions will be more varied, a dynamic determination of the Contingency Reserve quantity based on present system conditions will result in the optimal quantity being procured to ensure secure system operations at the lowest cost.

For these reasons, the Contingency Factor will be calculated dynamically in the dispatch process using a Dynamic Frequency Contingency Model (DFCM) which models the relationship between the various factors. The DFCM is being developed by AEMO with the methodology to be outlined in a market procedure.

4.2.3 Performance factors

Although the speed (τ) factor of a facility will not change regularly, the ability of facilities with different speed factors to contribute to meeting the Contingency Reserve requirement will differ depending on system conditions.

In intervals with high energy demand, where many facilities will be providing inertia as a by-product of their energy dispatch, the largest contingency will likely be a smaller proportion of the total generation, and the impact of a contingency on frequency will be lower and slower. In these situations, facilities with both high and low speed factors effectively make an equal contribution to meeting the reserve requirement.

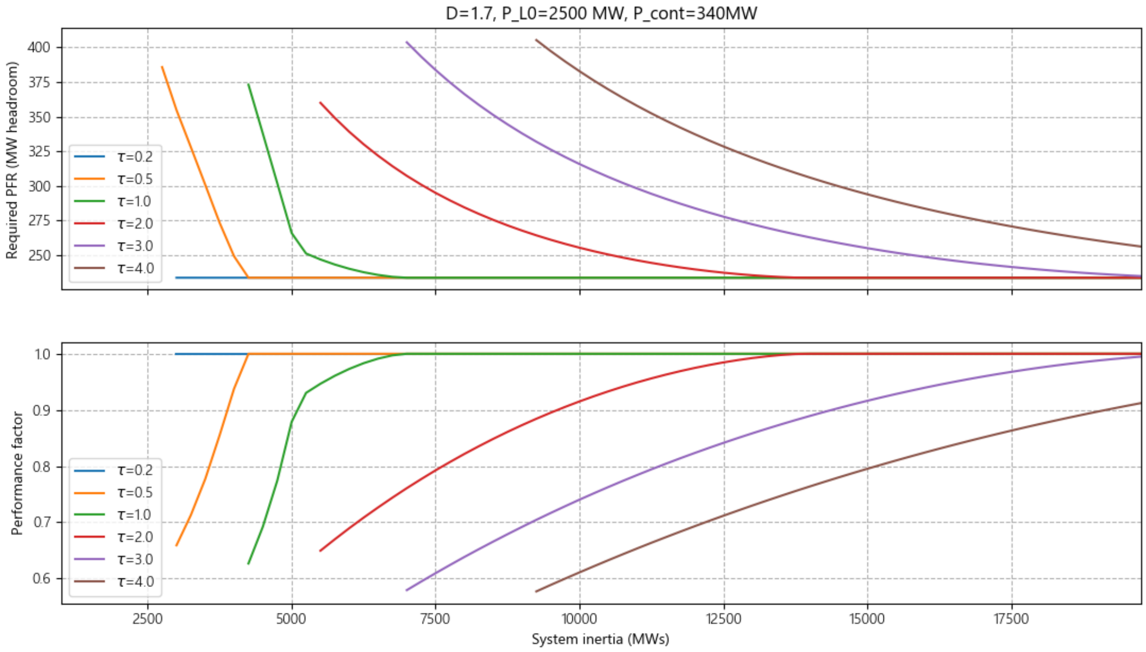
In intervals with low energy demand, there will be less system inertia, the largest contingency is likely to be a higher proportion of total generation, and the impact of a contingency on frequency will be greater and faster. In these situations, 1MW of headroom reserved on a fast-responding facility contributes more to meeting the reserve requirement than 1MW of headroom reserved on a slower responding facility.

The speed factor can be combined with system conditions to give a 'performance factor' for the facility, identifying its contribution to meeting the reserve requirement in those specific circumstances.

Figure 13 shows an example of how the DFCM could be used to generate performance factors for different speed factors.

[21] The current Spinning Reserve Ancillary Service will be replaced by the new Contingency Reserve raise service under new market arrangements.

Figure 13: Example translation of speed factors to performance factors for a 340MW contingency and a range of system inertia conditions



The top panel shows the system secure zone if all reserve were sourced from facilities with the same speed factor, for a range of speed factors. Traditionally, the WEM has been operated with an assumption of $\tau = 2$. With different speeds of connected facilities, the secure zone changes:

- Faster response means a larger secure zone (the system can be secure at lower inertia and with less reserve).
- There is a minimum level of reserve required regardless of how fast facilities respond[22].
- At high inertia, speed of response is less significant.

The lower panel shows the translation to performance factors, which are the ratio of the MW reserve required at that speed factor to the minimum level of reserve required (the 'reference requirement'). In this example, at 7,500MWs of system inertia, performance factors would be as shown in Table 5.

Table 5: Example performance factors

τ (s)	Reserve requirement (MW)	Performance factor
0.2	230	1.0
2	295	0.8
3	385	0.6

The dispatch process will include calculations of performance factors for current system conditions as determined in the DFCM.

Including performance factors in the clearing engine gives equations of the form:

[22] This reflects the need to maintain frequency within the operating band over the entire 15 minute response period – effectively the secondary frequency response requirement provides a floor on the quantity of Contingency Reserve to be provided.

Equation 8 - contingency reserve raise constraint including ESS variables, contingency factor and performance factors

$$\sum_{f} performanceFactor_f \times contingencyReserveRaiseDispatch_f - (ContingencyFactor \times energyDispatch_{FacilityA} + contingencyReserveRaiseDispatch_{FacilityA} + regulationRaiseDispatch_{FacilityA}) \geq 0$$

...

4.2.4 Determination of the RoCoF Control quantity

The required RoCoF Control quantity is also dependent on system conditions, the largest contingency, and the Contingency Reserve requirement. The relationship between these factors is difficult to represent in linear form for inclusion in the clearing engine, and it will be calculated dynamically as part of the dispatch process. This means that the quantity may change from interval to interval depending on system conditions.

4.3 Dispatch of co-optimised frequency control ESS

Currently, LFAS enablement is scheduled several hours ahead of real-time, according to a simple merit order. Spinning Reserve is dispatched through manual adjustment of generator output within the Balancing Portfolio by AEMO control room personnel.

In the new WEM, the quantity of each of the Frequency Control ESS to be delivered by each facility will be calculated by the co-optimised market clearing process. Participants awarded quantities via the ESS Supplementary Mechanism will be required to make certain quantities available in the real-time market, but the quantity of dispatch for each facility will be determined by the real-time process.

4.3.1 Accounting for non-linear factors

The DFCM will capture the relationship between total system inertia, contingency size, and reserve requirement. For any given contingency size and reserve response characteristics, the model can calculate a secure zone defined by the quantity of inertia on the system (which can be increased by dispatching additional RoCoF Control service) and the quantity of Contingency Reserve required.[23]

The primary purpose of the RoCoF Control service is to ensure the rate of change of frequency remains below the safe limit. In many intervals Contingency Reserve alone will be sufficient to meet that need, so the RoCoF Control service requirement could be set at zero, and system security maintained. However, even in these intervals, there is still a potential trade-off between RoCoF Control service and Contingency Reserve. Provisioning more of one means less of the other is required. This trade-off could theoretically be expressed in linear terms, but implementation along with linearization of pre-set performance factor surfaces would be particularly complex, resulting in unpredictable and volatile solve times.

Accounting for the trade-off will require iteration between the linear optimisation in the market clearing engine and the DFCM. 0 sets out an online iteration process which will be further investigated during implementation. If this approach is not feasible, an offline iteration process will

[23] This model was used to prepare Figure 2 and Figure 13.

be required, using the DFCM to calculate pre-set contingency factors, performance factors, and RoCoF Control requirements for defined system conditions, and not considering the potential trade-off between RoCoF Control and Contingency Reserve.

4.3.2 Post-contingency dispatch actions

When a contingency occurs, facilities enabled for ESS will respond, and some inputs to the dispatch process must be adjusted accordingly:

- For a network outage, the choice of active constraint equation set may change to reflect the network status.
- Where an interruptible load has activated in response to the contingency, the reduction must be reflected in the overall load forecast.
- If the contingency is a facility outage, the facility must be marked as unavailable, so it is not available for the clearing engine to dispatch
- Similarly, for facility dispatch non-compliance, the facility availability must be overridden so that actual performance is reflected in future dispatch.

These adjustments may be automated or implemented manually in accordance with a market procedure.

4.4 Dealing with energy and ESS shortfalls

Currently, AEMO has discretion to relax ESS requirements where it expects the shortfall will be for a period less than 30 minutes, to relax requirements completely to avoid load shedding (including in the event of a contingency), and broad discretion to dispatch facilities as required in case of system emergency.

AEMO will retain discretion to dispatch facilities as required in case of system emergency, but management of ESS requirements to avoid load shedding will be managed differently under SCED, as discussed below.

4.4.1 Real-time pre-contingent shortfalls

In situations where there is insufficient capacity available to meet real-time requirements for energy and ESS, a single contingency could result in involuntary load shedding.

The clearing engine must have rules that guide allocation of available capacity to energy, Regulation, or Contingency Reserve. These are set by using ‘slack variables’ to capture the quantity by which a requirement is not satisfied, and ‘constraint violation penalties’ (CVPs). This adds another term $contingencyReserveRaiseSlack$ to the reserve constraints as follows:

Equation 9 - contingency reserve raise constraint including ESS variables, contingency factor, performance factors and slack variable

$$\sum_f performanceFactor_f \times contingencyReserveRaise_f$$
$$- \left(ContingencyFactor \times energy_{FacilityA} + contingencyReserveRaise_{FacilityA} + regulationRaise_{FacilityA}\right) - contingencyReserveRaiseSlack \geq 0$$

Conceptually, slack variables and CVPs function as an extremely high-cost source of ESS, appearing in the objective function as follows:

Equation 10 - simplified objective function including slack variables and CVPs

$$minimise\ TotalCost\ where$$

$$\begin{aligned}
TotalCost = & \sum_f energyOfferPrice_f \times energyDispatch_f \\
& + \sum_f contingencyReserveRaiseOfferPrice_f \times contingencyReserveRaiseDispatch_f \\
& + \sum_f contingencyReserveLowerOfferPrice_f \\
& \times contingencyReserveLowerDispatch_f \\
& + \sum_f RegulationRaiseOfferPrice_f \times RegulationRaiseDispatch_f \\
& + \sum_f RegulationLowerOfferPrice_f \times RegulationLowerDispatch_f \\
& + \sum_f RoCoFControlOfferPrice_f \times RoCoFControlDispatch_f \\
& + contingencyReserveRaiseSlack \times contingencyReserveRaiseCVP \\
& + contingencyReserveLowerSlack \times contingencyReserveLowerCVP \\
& + regulationRaiseSlack \times regulationRaiseCVP \\
& + regulationLowerSlack \times regulationLowerCVP \\
& + RoCoFControlSlack \times RoCoFControlCVP
\end{aligned}$$

CVPs will be set to denote the relative preference for failing to satisfy requirements in each class:

- The CVP for energy will be set highest, to reflect the desire to avoid involuntary load shedding if at all possible.
- CVPs for Regulation and Contingency Reserve will be set lower than the CVP for energy. If they were set higher than the CVP for energy, then in the event of shortfall, the clearing engine would produce a dispatch that meets ESS quantities but requires load shedding to do so. Setting lower CVPs for ESS means that load shedding could be required if a contingency occurs but is not required ahead of the contingency.
- If there is sufficient capacity available to meet energy demand, but not enough to simultaneously meet Regulation and Contingency Reserve requirements, Regulation will be preferred to Contingency Reserve, as this service is able to actively respond following an AGC signal, to both regular fluctuations and to contingency events, while facilities enabled for Contingency Reserve respond only in proportion to locally detected frequency deviation.

4.4.2 Real-time post-contingent shortfalls

When a contingency occurs, the system may no longer be in a secure operating state – that is, a second contingency could cause the power system to be operating outside the technical envelope, requiring activating load shedding schemes to maintain system security.

Correct ordering of CVPs ensures that energy will continue to be provided in preference to Contingency Reserve, and the maximum possible quantity of ESS will be scheduled after energy requirements have been satisfied.

Nevertheless, AEMO will retain the ability to explicitly relax Contingency Reserve requirements following a contingency without relying on the operation of CVPs. This discretion will be outlined in the WEM Rules. This provides an alternative mechanism to ensure the clearing engine will dispatch synchronised generators to provide energy as a priority. The ability to relax ESS requirements should only be required as a last resort in case of inexplicable clearing engine results, as doing so would depress the energy price in a shortfall situation.

4.4.3 Forecast shortfalls

Pre-dispatch schedules will include expected ESS dispatch. CVPs are also applied to these schedules, meaning that shortfalls in ESS and energy will be able to be forecast ahead of time more accurately than they can under the current market arrangements.

The WEM design has several features designed to minimise the likelihood of a shortfall situation occurring, including:

- The RCM, which ensures that there is sufficient capacity (albeit not necessarily ESS-capable capacity) available to meet energy and ESS requirements at 10% Probability of Exceedance (POE) peak demand.
- The ESS Supplementary Mechanism, for which one of the triggers will be the balance between long-term forecast ESS requirement and forecast ESS market participation.

In addition, the existing market design has several elements that can support resolution of forecast shortfall issues before real-time:

- Dispatch of DSP facilities – DSPs are designed to provide capacity in such a situation, and can be dispatched in response to a forecast shortfall.
- Facilities accredited for ESS provision but not offering can be instructed to offer ESS.
- Outages can be cancelled or recalled in anticipation of a shortfall, or approved under conditions of fast-recall capability.
- A facility holding capacity credits which is projected to be needed in real-time to provide energy can be directed to synchronise in accordance with the pre-dispatch schedule.

These options will continue to be available to AEMO to respond to forecast shortfall, but the ability to exercise them will be associated with a clear trigger.

In the NEM, an actual or forecast 'Lack of Reserve' (LOR) notice is issued "when AEMO determines, in accordance with the reserve level declaration guidelines, that the probability of involuntary load shedding is, or is forecast to be, more than remote."[24] LOR category definitions are set out in a guideline[25] (which AEMO must consult on) rather than market rules, and are currently as follows:

- LOR 1 means that if the two largest relevant contingencies were to occur at the same time, load shedding would be required (i.e. the power system is not operating at n-2 security)

[24] AEMO can also issue a 'Low Reserve Condition' (LRC) over longer timeframes, which parallels the triggers for the new WEM ESS Supplementary Mechanism.

[25] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Reserve-Level-Declaration-Guidelines.pdf

- LOR 2 means that load shedding would be required in the event of the largest contingency occurring (i.e. there is, or will be, an ESS shortfall)
- LOR 3 means load shedding is occurring, or is forecast to be required within the Short-Term Projected Assessment of System Adequacy (PASA) horizon if no response occurs (i.e. there is or will be an energy shortfall)

The new WEM design will also use market notices with different levels of severity to provide:

- clear mechanisms by which projected or actual scarcity can be signalled to the market; and
- clear triggers for powers of intervention in the market.

Details will be defined as part of developing new PASA processes and set out in a market procedure. Defined levels will cover shortfalls of both energy and ESS, including:

1. available capacity insufficient to meet demand if two largest contingencies were to occur (no shortfall);
2. available capacity sufficient to meet demand and ESS requirements if largest contingency was to occur, but insufficient ESS capable facilities offering (ESS shortfall);
3. available capacity sufficient to meet energy demand but not ESS requirements if largest contingency occurs (ESS shortfall); and
4. energy shortfall occurring or forecast within short-term PASA horizon (Energy and ESS shortfall).

4.4.4 Market pricing in case of shortfall

If a shortfall is predicted or is occurring, the ESS price must be sufficient to encourage participants to make additional capable capacity available. However, where there is shortfall of energy or ESS, at least one slack variable will be non-zero, and the CVP will flow through into the market price. If not adjusted, this would result in a market price in the millions of dollars per MWh, far in excess of offer caps and the true value of lost load. This occurrence is referred to as an 'overly-constrained dispatch' (OCD).

When an OCD occurs, a pricing rerun will be conducted to calculate market prices for use in settlement, by using a constraint relaxation process, ensuring that market prices reflect bids, offers and ESS market price caps, rather than artefacts of the solution process.[26] This process will be set out in a market procedure.

In some instances, ESS market prices may exceed offer price caps. Any market price cap for ESS must be at least the offer price cap plus the difference of the minimum and maximum energy prices. This will allow a facility with energy and ESS offered at the energy price cap to provide ESS when the energy price is at minimum. As noted in section 3.2.5, offer and price caps will be further considered as part of the market power mitigation workstream.

[26] Information on constraint relaxation procedures is available at: www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint-Relaxation-Procedure.pdf

4.5 Dispatch tiebreaking

If the contribution of two facilities to provision of a particular service (energy or ESS) is identical, and only one is needed to satisfy demand, there is no economic reason to prefer one to the other, and the market clearing process will be indifferent to which facility is dispatched.

In the current WEM, where network constraints are not modelled, if two facilities submit the same loss-factor-adjusted price, then a tie breaking process is used to determine which facility is cleared. The final tie breaker is a daily-assigned random number, which will see one facility preferred over another. This means that if two facilities both have 50 MW offers that are otherwise identical, Facility A will be dispatched entirely for that 50 MW before Facility B is considered (and on another day the random number assignment may result in the reverse).

In the new WEM, co-optimisation of ESS and inclusion of network constraints in the clearing process will result in fewer situations where facility offers are equivalent. However, potential for ties will still be present, especially where two facilities are at the same network location.

When an optimisation problem has more than one possible solution with the same objective function (i.e. the total cost can be minimised by dispatching facilities in more than one way) it is called a 'degenerate' solution. If such a situation were to persist over multiple intervals (two different facilities were co-marginal), the details of facility dispatch could change randomly from interval to interval.

Any rules for dealing with facility dispatch in such a situation would ideally be built into the optimisation process, so a heuristic like the existing random number generator cannot be applied in the same way. The market clearing engine will include a mechanism for dispatching price-tied bands for energy in proportion to their MW size, implemented using slack variables and (very small) CVPs. This mechanism already exists in the NEMDE solver. Similar ties in ESS offers are expected to occur infrequently, so it is not proposed to introduce an equivalent mechanism for managing ties in ESS dispatch at the start of the new market. The incidence of ESS ties will be monitored and if needed, a market procedure will be developed to address ESS ties.

4.6 Monitoring and treatment of dispatch compliance

In the current WEM, AEMO monitors facility performance, and may adjust ESS accreditation parameters (e.g. speed factor) accordingly.

AEMO will continue to monitor performance of facilities (including generators, loads and if relevant other devices) accredited and enabled for ESS, and participants will also be required to provide performance data following major contingencies.

If, in real time:

- a facility fails to respond to a dispatch instruction for energy or ESS enablement;
- a facility enabled for ESS fails to respond in the manner contemplated by ESS standards; or
- AEMO reasonably believes that the facility will not respond as required to future dispatch instructions or enablement;

AEMO will:

- identify the facility as non-compliant with dispatch;
- require that the relevant participant provides a reason for the non-compliance;

- require that the relevant participant updates its offers to reflect its actual capability (which may include ceasing to offer ESS);
- implement manual overrides (which may include introducing or adjusting constraint equations) to ensure the facility's capability is accurately reflected in dispatch calculations; and
- calculate and issue a new market dispatch reflecting the updated facility capability

If a facility fails to perform as accredited, it's accreditation settings will be adjusted, and it may face penalties under the Generator Performance Standards regime if non-compliance with the standards is apparent in performance. Financial implications of non-compliance will be developed in future Taskforce design decisions on monitoring and compliance, which are scheduled for early 2020.

5. Treatment of facilities other than scheduled generators

This chapter sets out the Taskforce design decisions for participation in ESS provision by facilities other than scheduled generators.

5.1 Provision of ESS by storage facilities

Storage facilities can theoretically provide ESS in the WEM[27], but there are no such facilities in the SWIS at present. In other markets, pumped-storage hydroelectric facilities have provided ESS alongside energy for many decades, and battery storage facilities have been providing ESS for several years, including the Hornsdale Power Reserve in the NEM (since 2017), and in PJM (since 2009).

Storage facilities differ from scheduled generation (and load) in that they are energy-limited as well as capacity-limited. Whereas a generator's output is limited by its generation capacity but it can keep injecting as long as it has fuel, a storage facility is also limited by energy: it can only inject until it runs out of stored energy (or withdraw until its storage is full). This means offer and dispatch of storage facilities must include consideration of the storage capacity and current storage level of the facility.

5.1.1 Storage accreditation

Storage facilities will have slightly different standing data requirements than generators, including provision of data regarding:

- storage capacity (MWh);
- maximum charge capability (MW);
- maximum discharge capability (MW); and
- round trip efficiency (%).

To be accredited for ESS, storage facilities must also provide additional information to AEMO:

- A real-time indication of current storage level. AEMO will use this data to validate offers and will constrain dispatched quantities if offers cannot be fully cleared at current storage levels.
- Information on any limitations on transition from charging to discharging or vice versa. Where a facility is not capable of providing services across this transition (or of transitioning within a time limit defined in a market procedure), offers into the relevant ESS products would be filtered out in pre-processing, or restricted in dispatch.
- Information on changes in response capability at different levels of charge (i.e. how does the MW charge/discharge capability differ at 0% charged vs 50% charged vs 100% charged).

[27] See Participation Guideline for Energy Storage Systems in the WEM.

5.1.2 Storage offer restrictions

The dispatch process will allow storage facilities to offer their maximum capability in energy and each ESS. Participants will not need to consider trade-offs themselves, because the clearing engine will dispatch to optimise use across the various services.

However, offers will need to be adjusted to ensure that the offered quantity for each service does not exceed the facility's capability to respond over the defined response time for that service. That is:

- the maximum offer quantity for Contingency Reserve (raise) will be the lower of:
  - the MW injection capability at the current charge state; and
  - the stored energy (MWh) divided by the response timeframe (15/60th of an hour)
- the maximum offer quantity for Contingency Reserve (lower) will be the lower of:
  - the MW withdrawal capacity; and
  - the available storage (MWh) divided by the response timeframe (15/60th of an hour)
- the maximum offer quantity for Regulation (raise) will be the lower of:
  - the MW injection capacity; and
  - the stored energy (MWh) divided by the response timeframe (5/60th of an hour)
- the maximum offer quantity for Regulation (lower) will be the lower of:
  - the MW withdrawal capacity; and
  - the available storage (MWh) divided by the response timeframe (5/60th of an hour)

Facility owners will not be able to implement these restrictions in pre-dispatch, so they will be applied as part of the real-time dispatch process via constraint equations.

5.1.3 Storage dispatch restrictions

In order to allow the trade-off between services, and ensure the offer restrictions in section 5.1.2 are respected, the clearing engine will include an energy constraint of the form:

$$\frac{5}{60} \times energyDispatch_f + \frac{5}{60} \times regulationRaiseDispatch_f + \frac{15}{60} \times contingencyReserveRaiseDispatch_f \leq storedEnergy_f$$

where energy, regulation and reserve are in MW, and stored energy is in MWh.

For pre-dispatch schedules, the stored energy parameter would be based on the previous interval's schedule.

5.2 Provision of ESS by intermittent generators

Intermittent generation cannot currently participate in WEM ESS provision. Intermittent generators are theoretically capable of providing ESS, but for some services this would require changes to operating practices.

Intermittent generation has low variable costs of production, so it usually operates at the maximum level possible given available fuel (wind and sun). When operating at maximum output, the facility will have no capacity to respond to raise the system frequency (Regulation raise or Contingency Reserve raise), but it can respond to lower the system frequency (Regulation lower or Contingency Reserve lower) by reducing output below what it would otherwise have produced.

An intermittent generator could provide Regulation raise or Contingency Reserve raise if it is 'pre-curtailed' from its expected output. Similarly, if it is constrained because of a network constraint, the headroom it has could be used for providing Contingency Reserve raise.

A proof-of-concept has been conducted in the NEM[28] to explore the conditions under which a wind generator would be able to provide ESS. Findings included the importance of accurate forecasting, guidance on the level of headroom required to assure performance can be relied upon, and accreditation requirements specific to wind farms. Providing 1MW of Regulation or Contingency Reserve will require reserving more than 1MW of headroom from the possible output level.[29]

Intermittent generators will be allowed to accredit for ESS in the new WEM, subject to meeting accreditation requirements. Accreditation requirements will be defined in a market procedure, and will include:

- existence of a facility 'unconstrained energy' data stream (provided by either AEMO or the participant), updated no less frequently than every 5 minutes, representing the maximum possible energy generation from available fuel in the absence of curtailment for network or ESS provision;
- analysis of forecast accuracy for use in setting headroom requirements; and
- setting a headroom factor for the facility.

When providing Regulation raise or lower, the facility would have to meet AGC set-point targets. When providing Contingency Reserve raise, the facility would have to maintain headroom (as dispatched) below its unconstrained energy quantity.

5.3 Provision of ESS by hybrid intermittent/storage facilities

Increasingly, generation developers are choosing to co-locate intermittent generation with storage capability. This combination of dispatchable and non-dispatchable capability in a single facility requires consideration. Registration status will depend on facility characteristics[30], but will fall into one of three configurations, all of which can be managed in the SCED process:

1. Each facility is registered separately – one intermittent generator, and one storage facility.
2. The combined facility is treated as an intermittent generator.[31]
3. The combined facility is treated as a fully dispatchable generator,[32] at least over the dispatch interval timeframe.

[28] AEMO, Hornsdale Wind Farm 2 FCAS trial.

[29] The Hornsdale trial used a factor of two.

[30] Including whether they are separately metered, whether they share a common network connection, and whether they meet facility aggregation requirements.

[31] This will be the case only if, within a single five-minute dispatch interval, it cannot control its output within the tolerance ranges that would apply to a scheduled generator of the same rated capacity, due to factors beyond the control of its operator.

[32] This will be the required where the combined capability is such that facility output can be controlled over a single 5 minute dispatch interval.

In all cases:

- the full storage capacity would have to be associated with a single facility. It would not be possible to register a portion of the storage facility as part of the intermittent generator and the remaining portion as a separate storage facility (participants would effect operational decisions to dedicate storage capacity to specific uses by the way they structure their offers);
- to be accredited to provide ESS, the facility would have to provide storage capacity, and a real-time indication of storage level; and
- the facility would contribute to ESS cost recovery.

For a hybrid intermittent generator offering energy only:

- decisions and assumptions on the operation of the storage component would be fully in control of the relevant participant, and reflected in its energy offer quantities and prices, for example by adjusting the quantity of its single tranche offer, based on the unconstrained output forecast adjusted up or down for whether it wishes to charge or discharge the battery;
- the facility could offer negative energy (withdrawal); or
- the storage component must be used in the direction of aligning actual output with forecast output. Use of storage to increase deviation from facility energy output forecast would be prima facie evidence of market manipulation.

For a hybrid intermittent generator offering both energy and ESS:

- facility ESS accreditation would include any limitations the participant wished to place on use of the storage component in ESS provision;[33]
- data from feeds of real-time available stored energy and real-time ‘unconstrained energy’ indication would be summed to determine a ‘possible power’ quantity including both storage and fuel availability;
- participants could still reflect intentions for use of the storage component in offer construction (e.g. by not offering maximum capability for ESS);
- headroom required for ESS provision would still be based on the accuracy of the intermittent forecast, but would include an adjustment to reflect current storage levels available for ESS provision – this would allow the facility to provide ESS with a lower quantity of pre-curtailment from its cleared energy offer position; and
- actual operation of the storage component would have to be in line with ESS enablement – energy output could vary according to available fuel,[34] but the ESS quantities would need to be provided as enabled, as they would for any other type of facility:
  - For Regulation, the facility would have to meet absolute AGC targets (set relative to the facility’s cleared energy offer).

[33] For example, if the participant wished to permanently reserve a portion of the storage capacity solely for use in firming energy output, the facility may be accredited with a higher headroom requirement than if the full storage capacity were potentially to be committed to ESS provision.

[34] If the possible power feed is available more frequently than every 5 minutes, energy output could fluctuate to reflect intra-interval changes in fuel availability. If the feed was only available at 5-minute intervals, energy output would be fixed at the dispatched level to ensure the quantity of ESS is actually available.

– For Contingency Reserve raise, the facility would have to maintain a minimum headroom relative to the 'possible power'.
– For Contingency Reserve lower, the facility would have to maintain a minimum footroom relative to the remaining available storage capacity.

5.4 Provision of ESS by demand side resources

Demand side resources[35] (DSR) already provide ESS in the WEM. A single, large interruptible load provides spinning reserve. Aggregated distributed resources do not provide ESS in the current WEM, although the registration constructs would allow it. The current DSP construct could not provide ESS, as it allows for a 2-hour response time, while ESS response is required within seconds or milliseconds.

DSR (including both load response and distributed energy resources) are an important part of modern power systems and electricity markets. DSR can provide a significant contribution to power system security, often at lower cost than generation. For example, in New Zealand, interruptible load makes up 30-60% of the volume of reserve offers in any given trading interval.[36] As the energy transition continues, there will be more and more flexibility distributed around the power system, and the wholesale market design must provide a way to access this flexibility where it is cost-effective to do so.

5.4.1 Routes for DSR participation

DSR will be able to participate in ESS provision in several ways:

- Schedulable loads can be accredited to provide Regulation (raise and lower), Contingency Reserve (raise and lower), and RoCoF Control
- Interruptible (non-schedulable) loads can be accredited to provide Contingency Reserve raise only, either as an ESS-only provider or as part of their registration as a load
- Aggregated distributed schedulable resources (storage, load or behind the fence generation) can be accredited to provide Regulation (both directions) and Contingency Reserve (both directions), participating as:
  – a storage facility (if in a single electrical location, and controlled by the same participant responsible for settling the energy volumes for the associated National Meter Identifier (NMIs), or
  – an ESS-only provider, (if distributed across the network, or if a different participant is responsible for settling the energy volumes for the associated NMIs)

5.4.2 Treatment of interruptible loads

The DSP construct is primarily related to the RCM and will continue to be considered energy only in energy scheduling. A load associated with a DSP may also register as an interruptible load but must declare its alignment with a DSP. If the DSP is dispatched (two hours ahead of real-time), the interruptible load must change its ESS offers to offer zero quantities.

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[35] In the context of this paper, DSR are identified as schedulable loads, interruptible loads, as well as DER. DSP is an existing WEM construct where a number of associated loads form a portfolio that can be dispatched if certain requirements are met such as notice period.

[36] Source: EPWA analysis, based on data from https://www.emi.ea.govt.nz/Wholesale/Datasets/BidsAndOffers/Offers

Offer quantities from interruptible loads represent an on-or-off quantity: if a contingency occurs, the entire tranche will trip. Interruptible load tranches will be subject to a maximum size. Payment would still be only for the cleared quantity.

Accreditation for an interruptible load facility will include demonstrating response to frequency excursion, either by:

- providing an ongoing real-time data feed of its available interruptible quantity which can be used in place of offer quantities in the dispatch process; or
- recording and providing access to performance data that shows actual response to a contingency, where the facility can commit that its real-time response will not vary significantly from its offers. This approach is used in other markets to increase potential for participation.

To ensure security can be maintained in the dispatch interval after an interruptible load stops being dispatched, it may be required to maintain enablement for part of that subsequent dispatch interval.

Appendix A
Example offer structure

A.1 Scheduled generator – energy offer

This appendix provides example offer structures for a single trading interval for selected facility types. Offer structures and format will be finalised during implementation, including for bulk upload.

Field	Units	Example value	Note
Facility ID		TEST_GT_1	
Service		ENERGY	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
In-service capacity	MW	160	Synchronised capacity, or unsynchronised capacity with FSIP profile
Available capacity	MW	0	Unsynchronised capacity which would be available for dispatch if given notice in accordance with standing data start times
Fast Start Min Load	MW	20	Only populated if opting in to FSIP dispatch.
FS Time at Zero (T1)	Minutes	5	
FS Time to Min Load (T2)	Minutes	5	
FS Time at Min Load (T3)	Minutes	20	
FS Time to Zero (T4)	Minutes	5	
Ramp up rate	MW/minute	10	Doesn't have to match standing data, but if it doesn't, must be prepared to give a reason
Ramp down rate	MW/minute	10	
Tranche 1 price	$/MWh	-100	
Tranche 1 quantity	MW	20	
Tranche 2 price	$/MWh	20	Must be greater than previous tranche price
Tranche 2 quantity	MW	140	
…			
Tranche 10 price	$/MWh	100	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to sum of in-service + available capacity
Offer change reason flag		O	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS

			I = initial offer Status definitions to be finalised
Offer change reason description	Text		Optional
Standing offer flag		N	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp		Standing offers only

A.2 Scheduled generator – ESS offer

Field	Units	Example value	Note
Facility ID		TEST_GT_1	
Service		CONTRESRAISE	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
Max available	MW	100	
Enablement min	MW	20	
Low break point	MW	25	
High break point	MW	100	
Enablement max	MW	140	
Tranche 1 price	$/MW/h	3	
Tranche 1 quantity	MW	90	
Tranche 2 price	$/MW/h	20	Must be greater than previous tranche price
Tranche 2 quantity	MW	10	
…			
Tranche 10 price	$/MW/h	100	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to max available
Offer change reason flag		O	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Standing offer flag		N	If Y, will replace standing offers for same interval on other days

Effective date/time	Timestamp		Standing offers only

A.3 Intermittent generator – energy offer

Additional field for forecast unconstrained output.

Field	Units	Example value	Note
Facility ID		TEST_WIND_1	
Service		ENERGY	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
In-service capacity	MW	100	Synchronised capacity (at max output)
Available capacity	MW	0	Unsynchronised capacity which would be available for dispatch if given notice in accordance with standing data start times
Forecast unconstrained output	MW	74.5	Best estimate of output given available fuel
Fast Start Min Load	MW		Only populated if opting in to FSIP dispatch. Not available for intermittent generator
FS Time at Zero (T1)	Minutes		
FS Time to Min Load (T2)	Minutes		
FS Time at Min Load (T3)	Minutes		
FS Time to Zero (T4)	Minutes		
Ramp up rate	MW/minute	40	Doesn't have to match standing data, but if it doesn't, must be prepared to give a reason
Ramp down rate	MW/minute	40	
Tranche 1 price	$/MWh	-100	
Tranche 1 quantity	MW	74.5	
Tranche 2 price	$/MWh	20	Must be greater than previous tranche price
Tranche 2 quantity	MW	0	
…			
Tranche 10 price	$/MWh	100	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to forecast unconstrained output

Offer change reason flag		O	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Offer change reason description	Text		Optional
Standing offer flag		N	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp		Standing offers only

A.4 Scheduled load – energy bid

- tranches represent bids to purchase at that price, not offers to sell
- tranche prices must be monotonically *decreasing*
- tranche quantities must be negative

Field	Units	Example value	Note
Facility ID		TEST_SCHEDLOAD_1	
Service		ENERGY	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
In-service capacity	MW	100	Maximum consumption available to AEMO to call on
Ramp up rate	MW/minute	50	Doesn't have to match standing data, but if it doesn't, must be prepared to give a reason
Ramp down rate	MW/minute	50	
Tranche 1 price	$/MWh	500	tranches represent bids to purchase at that price, not offers to sell
Tranche 1 quantity	MW	-50	tranche quantities must be negative
Tranche 2 price	$/MWh	20	Must be less than previous tranche price
Tranche 2 quantity	MW	-40	
Tranche 3 price	$/MWh	-20	Must be less than previous tranche price
Tranche 3 quantity	MW	-10	
…			
Tranche 10 price	$/MWh	-1000	Must be less than previous tranche price

Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to in-service capacity
Offer change reason flag		I	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Offer change reason description	Text		Optional
Standing offer flag		Y	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp	2023 12 22 08:00:00	Standing offers only

A.5 Storage – energy offer

Tranche quantity can be positive or negative, but all negative quantities must be grouped at the bottom end, all positive quantities grouped at the top end.

Field	Units	Example value	Note
Facility ID		TEST_BATT_1	
Service		ENERGY	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
In-service capacity	MW	60	Synchronised capacity, or unsynchronised capacity with FSIP profile
Available capacity	MW	0	Unsynchronised capacity which would be available for dispatch if given notice in accordance with standing data start times
Ramp up rate	MW/minute	100	Doesn't have to match standing data, but if it doesn't, must be prepared to give a reason
Ramp down rate	MW/minute	100	
Tranche 1 price	$/MWh	-100	
Tranche 1 quantity	MW	-20	Sum of absolute values of negative tranche quantities must be less than or equal to sum of in-service + available capacity
Tranche 2 price	$/MWh	20	Must be greater than previous tranche price
Tranche 2 quantity	MW	-40	Sum of absolute values of negative tranche quantities must be less than or

			equal to sum of in-service + available capacity
Tranche 3 price	$/MWh	70	Must be greater than previous tranche price
Tranche 3 quantity	MW	35	Sum of positive tranche quantities must be less than or equal to sum of in-service + available capacity
Tranche 4 price	$/MWh	170	Must be greater than previous tranche price
Tranche 4 quantity	MW	25	
…			
Tranche 10 price	$/MWh	300	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	
Offer change reason flag		R	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Offer change reason description	Text		Optional
Standing offer flag		N	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp		Standing offers only

A.6 Storage – ESS offer

Field	Units	Example value	Note
Facility ID		TEST_BATT_1	
Service		CONTRESRAISE	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
Max available	MW	60	
Enablement min	MW	0	
Low break point	MW	0	
High break point	MW	60	
Enablement max	MW	60	
Tranche 1 price	$/MW/h	40	

Tranche 1 quantity	MW	35	
Tranche 2 price	$/MW/h	100	Must be greater than previous tranche price
Tranche 2 quantity	MW	25	
…			
Tranche 10 price	$/MW/h	200	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to max available
Offer change reason flag		O	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Standing offer flag		N	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp		Standing offers only

A.7 Interruptible load – ESS offer

Field	Units	Example value	Note
Facility ID		TEST_IRUPTLOAD_2	
Service		CONTRESRAISE	
Trading date		2023 12 22	
Dispatch interval	Integer	102	Between 1 and 288
Max available	MW	25	
Enablement min	MW	0	
Low break point	MW	0	
High break point	MW	25	
Enablement max	MW	25	
Tranche 1 price	$/MW/h	5	
Tranche 1 quantity	MW	10	
Tranche 2 price	$/MW/h	5.01	Must be greater than previous tranche price
Tranche 2 quantity	MW	10	
Tranche 3 price	$/MW/h	5.02	Must be greater than previous tranche price

Tranche 3 quantity	MW	5	
…			
Tranche 10 price	$/MW/h	200	Must be greater than previous tranche price
Tranche 10 quantity	MW	0	Sum of tranche quantities must be less than or equal to max available
Offer change reason flag		I	O = outage or partial outage start R = outage or partial outage return S = stranded for ESS T = trapped for ESS I = initial offer Status definitions to be finalised
Standing offer flag		N	If Y, will replace standing offers for same interval on other days
Effective date/time	Timestamp		Standing offers only

Appendix B
Iteration Approach

Figure 14 shows the expected process of iteration between the market clearing engine (MCE) and the DFCM. The approach will be confirmed and further detailed during implementation and captured in a market procedure.

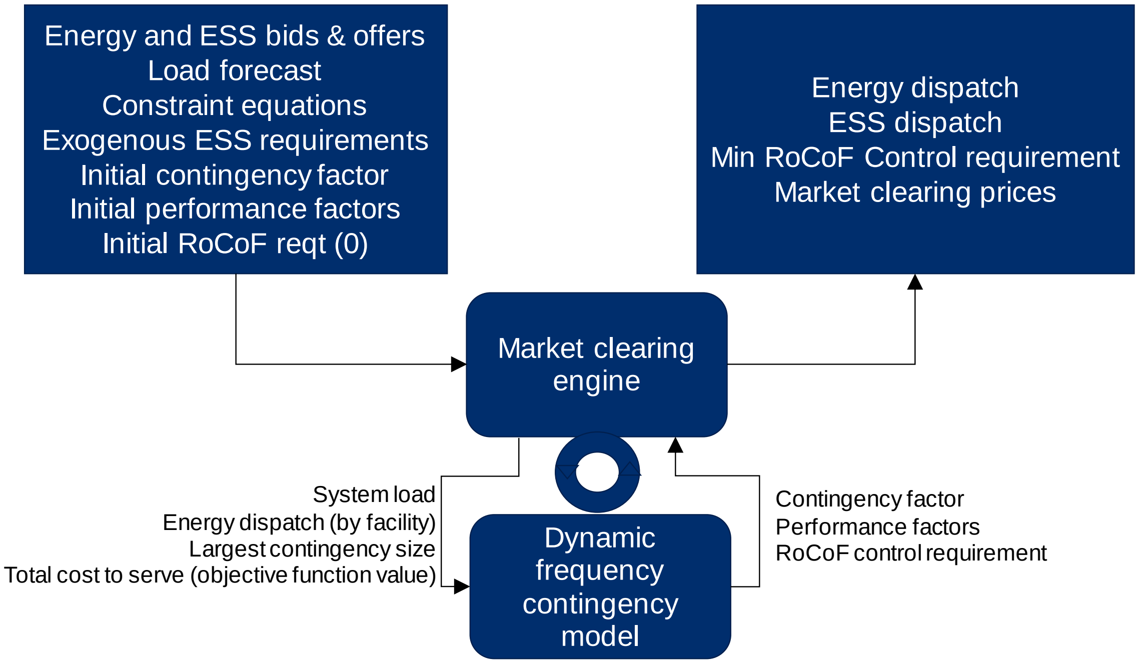
The DFCM will be used to adjust three MCE input parameters for each interval of each solve:

- The contingency factor (as discussed in section 4.2.2)
- Facility performance factors (as discussed in section 4.2.3)
- The RoCoF Control requirement (as discussed in section 4.2.4)

The dispatch will occur in three steps:

1. Apply correct factors
2. Set RoCoF Control requirement
3. Finalise dispatch

Figure 14: Market scheduling and dispatch process



A.8 Step 1: Apply correct factors

The MCE will run first, using:

- Energy and ESS bids and offers
- Facility MW max
- Marginal loss factors
- Load forecast
- Network constraint equations
- Exogenous ESS requirements
  - Regulation raise and lower
  - Contingency Reserve lower

- Initial settings for the DFCM provided parameters:
  - Final contingency factor used in the previous interval
  - Final participation factors used in the previous interval
  - An initial RoCoF Control requirement of zero.

Key items of output from the MCE to the DFCM are:

- System load
- Energy dispatch for previous interval (by facility)
- Calculated energy dispatch for current interval (by facility)
- Largest contingency size
- Total Contingency reserve offered (pre-performance factors)
- Total Contingency reserve offered (post-performance factors)
- Flag for energy/ESS shortfalls
- Total cost to serve (objective function value)

The DFCM will use that input to calculate:

- An updated contingency factor
- Updated performance factors

The two solvers will iterate until contingency and performance factors from subsequent DFCM solves remain consistent.

A.9 Step 2: Set RoCoF Control requirement

Once the correct performance factors have been applied, the RoCoF Control requirement will be calculated. This is achieved by gradually incrementing the RoCoF Control requirement (repeating step 1 each time) until two levels have been identified:

1. The minimum quantity of RoCoF Control required to maintain RoCoF within safe limits
2. The additional quantity of RoCoF Control that minimises overall costs by reducing reserve requirements.

If the dispatch at the end of step 1 is such that RoCoF would remain below the safe limits in the event of the largest contingency, then the RoCoF Control requirement level 1 is zero. Otherwise, the MCE will have identified a reserve shortfall, and potentially an energy shortfall. If the MCE has not identified an energy shortfall, keep incrementing the RoCoF requirement until either:

a. the DFCM identifies a secure solution; or
b. all available RoCoF Control service has been cleared; or
c. all facilities have performance factors of 1.

Cases b and c imply a no secure solution and confirm an ESS shortfall. In these cases (and if there is an energy shortfall), set the RoCoF Control requirement level 1 and 2 to that used in the previous interval, and go to step 3.

In case a, the quantity of RoCoF Control service required to provide a secure solution is RoCoF Control requirement level 1.

Continue incrementing the RoCoF requirement (if RoCoF Control service level 1 is zero, start from the quantity of inertia present in the MCE dispatch), until:

- the MCE objective function starts to increase; or
- (for dispatch runs and pre-dispatch runs with enablement limits) the RoCoF requirement is equal to the total inertia provided by facilities which are synchronised at the end of the previous trading interval.

This is the quantity of RoCoF Control service that minimises overall cost: RoCoF Control requirement level 2.

A.10 Step 3: Finalise dispatch

Steps 1 and 2 must be performed in the absence of enablement limits (i.e. where the MCE has ability to choose from any facility offering services and can move any unit to or from 0). In step 3, enablement limits will be reapplied, and the final dispatch calculated.

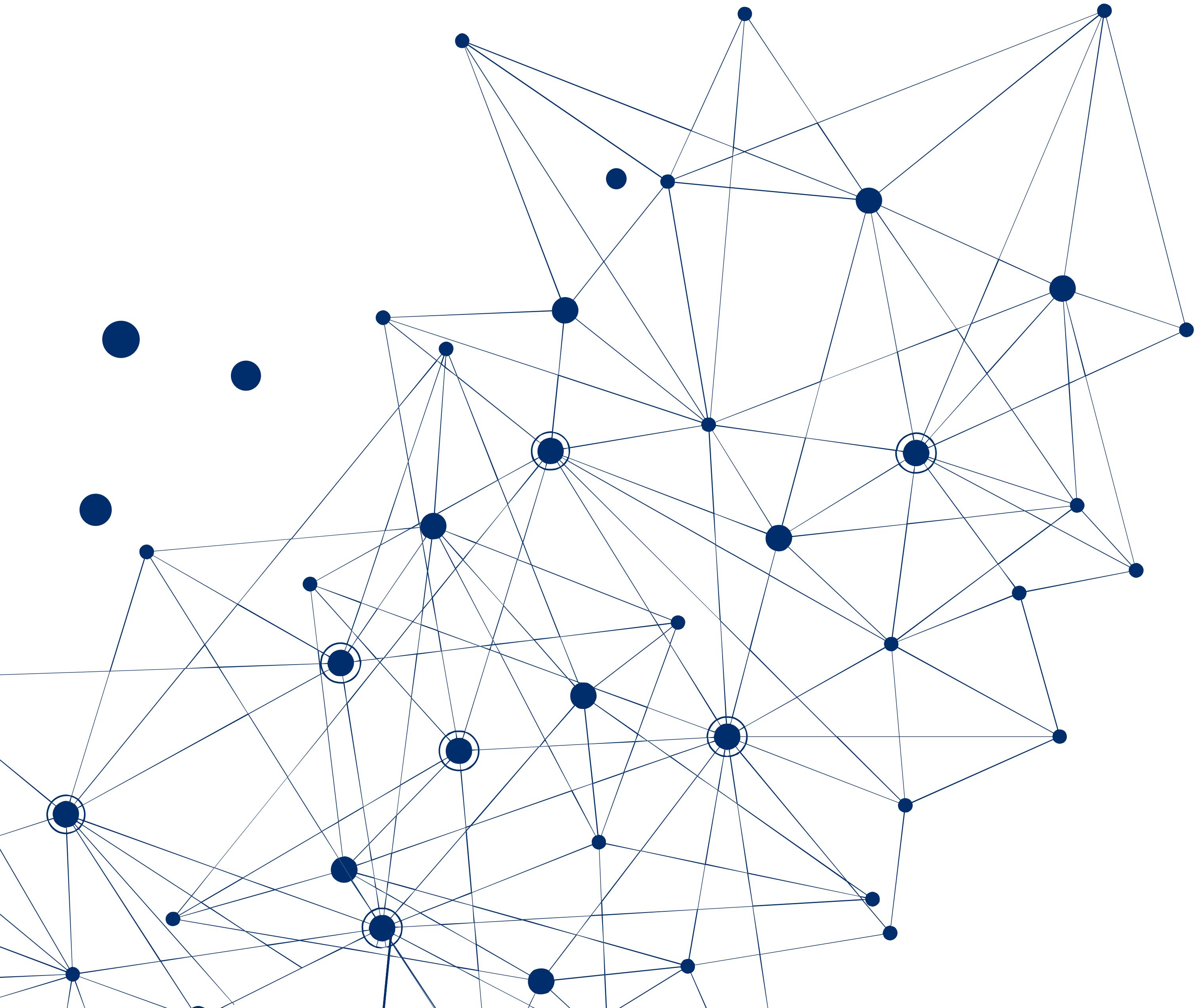
If enablement limits were included in steps 1 and 2, the RoCoF Control requirement could only ever be zero (because the clearing engine cannot turn off facilities capable of providing RoCoF Control) or the total RoCoF Control available at the end of the previous interval (because the engine cannot schedule more facilities than were already available). At dispatch time, there is not enough time to change the quantity of system inertia by committing more facilities, so it must be well-signalled in pre-dispatch, and the requirement must continue to be non-zero at real-time to ensure facilities are paid for their provision.

A.11 Implementation considerations

NEMDE has capability to iterate with input adjustment processing between solves but has not yet been iterated with a dynamic model. This approach (iteration between linear and dynamic models) is a common feature in SCED implementations, and though the specifics of the interaction proposed here is novel, the individual components are well-proven.

Depending on the time required to iterate between models, it may be necessary to run the iteration with the 30-minute pre-dispatch only, and use those outputs for the 5-minute dispatch schedules. This will be confirmed in implementation.

Appendix C
Examples of co-optimisation



This appendix outlines two examples of co-optimisation explaining how market participants can be commercially indifferent to whether their plant is dispatched for energy or for ESS.

Example 1

Inputs

Requirements

Energy demand: 100MW

ESS requirement: 25MW

Generator A

Size: 50MW

Energy offer: 50MW @ $100

ESS offer: 50MW @ $0

Generator B

Size: 100MW

Energy offer: 100MW @ $500

ESS offer: 0MW

Optimisation problem

Objective function: minimise TotalCost where

TotalCost = EnergyDispatch(GeneratorA)×EnergyOfferPrice(GeneratorA) + EnergyDispatch(GeneratorB)×EnergyOfferPrice(GeneratorB) + ESSDispatch(GeneratorA)× ESSOfferPrice(GeneratorA) + ESSDispatch(GeneratorB)× ESSOfferPrice(GeneratorB)

Subject to:

EnergyDispatch(GeneratorA) + EnergyDispatch(GeneratorB) >= EnergyDemand

ESSDispatch(GeneratorA) + ESSDispatch(GeneratorB) >= ESSRequirement

Outputs

Cost is minimised by dispatching Generator A for all the ESS, then as much of the energy as possible, then dispatching generator B for the remaining energy.

TotalCost = 25×100 + 75×500 + 25×0 + 0×0 = 40,000

Generator A (size 50 MW)

Energy dispatch: 25MW

ESS dispatch: 25MW

Generator B (size 100 MW)

Energy dispatch: 75MW

ESS dispatch: 0MW

Marginal prices

If energy demand is increased by 1MW (to 101MW), Generator B will be dispatched for one more MW:

TotalCost = 25×100 + 76×500 + 25×0 + 0×0 = 40,500

Marginal price of energy is $500, calculated as the delta in the total system cost required to serve the 1 MW marginal incremental energy demand.

If ESS requirement is increased by 1MW (to 26MW), Generator A must be backed off by 1MW energy to make room, and that MW provided by Generator B instead.

TotalCost = 24×100 + 76×500 + 26×0 + 0×0 = 40,400

Marginal price of ESS is $400, calculated as the delta in the total system cost required to serve the 1 MW marginal incremental ESS requirement.

Payments

Generator A: 25MW × $500 + 25MW × $400 = 22,500

Generator B: 75MW × $500 = 37,500

Result

Even though A offers $0 for reserve (because that is the facility's short run marginal cost of providing it), the facility is indifferent to whether it provided energy (at $500/MW, but with $100 fuel cost) or ESS (at $400/MW, with $0 fuel cost)

Example 2

Inputs

Requirements

Energy demand: 100MW

ESS requirement: 25MW

Generator A

Size: 50MW

Energy offer: 50MW @ $100

ESS offer: 50MW @ $0

Generator B

Size: 100MW

Energy offer: 100MW @ $500

ESS offer: 100MW @$0

Optimisation problem as above

Outputs

Cost is minimised by dispatching Generator A for as much of the energy as possible, then dispatching generator B for the remaining energy and the ESS

TotalCost = 50×100 + 50×500 + 0×0 + 25×0 = 30,000

Generator A (50MW)

Energy dispatch: 50MW

ESS dispatch: 0MW

Generator B (size 100MW)

Energy dispatch: 50MW

ESS dispatch: 25MW

Marginal prices

If energy demand is increased by 1MW (to 101MW), Generator B will be dispatched for one more MW:

TotalCost = 50×100 + 51×500 + 0×0 + 25×0 = 30,500

Marginal price of energy is $500, calculated as the delta in the total system cost required to serve the 1 MW marginal incremental energy demand.

If ESS requirement is increased by 1MW (to 26MW), it will be provided by generator B.

TotalCost = 50×100 + 50×500 + 0×0 + 26×0 = 30,000

Marginal price of ESS is $0.

Payments

Generator A: 50MW × $500 + 0MW ×$0 = 25,000

Generator B: 50MW ×$500 + 25MW ×$0 = 25,000

Result

Generator B would rather have provided more energy, but it can also provide extra ESS because it doesn’t cost the facility anything.