Department of
Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Meeting Agenda

Meeting Title:	Market Advisory Committee (MAC)
Date:	Thursday 30 July 2026
Time:	1:30 PM – 3:00 PM
Location:	Online via TEAMS

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest & Competition Law	Chair	Noting	2 min
2	Meeting Apologies/Attendance	Chair	Noting	1 min
3	Minutes of Meeting 2026_06_18 • Published 14 July 2026	Chair	Noting	1 min
4	Action Items • AEMO to provide verbal update on Action Item 1/2026	Chair	Noting	5 min
5	Update on the Australian Energy Market Commission (AEMC) upcoming work program	Chair	Discussion	15 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Noting	2 min
	(b) AEMO Major Projects Working Group	AEMO	Verbal Update	2 min
	(c) Power System Security and Reliability Standards Review Working Group	Working Group Chair	Verbal Update	2 min
	(d) WEM Investment Certainty (WIC) Review Working Group	Working Group Chair	Noting	5 min
	(e) Capability Class 2 Technology Review Working Group	Working Group Chair	Discussion	20 min
7	Coordinator's review of the Benchmark Technologies	Working Group Chair	Discussion	20 min
8	WEM Effectiveness Review – Progress Update	Chair/Secretariat	Noting	1 min
9	Market Development Forward Work Program	Chair/Secretariat	Noting	5 min
10	Overview of Rule Change Proposals	Chair/Secretariat	Noting	1 min
11	General Business	Chair	Discussion	5 min

Item	Item	Responsibility	Type	Duration
	Next meeting: 3 September 2026, 1:30pm to 3:30pm			

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the MAC (**Members**) note their obligations under the *Competition and Consumer Act 2010* (**CCA**).

If a Member has a concern regarding the competition law implications of any issue being discussed at any meeting, please bring the matter to the immediate attention of the Chairperson.

Part IV of the CCA (titled "Restrictive Trade Practices") contains several prohibitions (rules) targeting anti-competitive conduct. These include:

(a) **cartel conduct**: cartel conduct is an arrangement or understanding between competitors to fix prices; restrict the supply or acquisition of goods or services by parties to the arrangement; allocate customers or territories; and or rig bids.

(b) **concerted practices**: a concerted practice can be conceived of as involving cooperation between competitors which has the purpose, effect or likely effect of substantially lessening competition, in particular, sharing Competitively Sensitive Information with competitors such as future pricing intentions and this end:

- a concerted practice, according to the ACCC, involves a lower threshold between parties than a contract arrangement or understanding; and accordingly; and
- a forum like the MAC is capable being a place where such cooperation could occur.

(c) **anti-competitive contracts, arrangements understandings**: any contract, arrangement or understanding which has the purpose, effect or likely effect of substantially lessening competition.

(d) **anti-competitive conduct (market power)**: any conduct by a company with market power which has the purpose, effect or likely effect of substantially lessening competition.

(e) **collective boycotts**: where a group of competitors agree not to acquire goods or services from, or not to supply goods or services to, a business with whom the group is negotiating, unless the business accepts the terms and conditions offered by the group.

A contravention of the CCA could result in a significant fine (up to $500,000 for individuals and more than $10 million for companies). Cartel conduct may also result in criminal sanctions, including gaol terms for individuals.

Sensitive Information means and includes:

(a) commercially sensitive information belonging to a Member's organisation or business (in this document such bodies are referred to as an Industry Stakeholder); and

(b) information which, if disclosed, would breach an Industry Stakeholder's obligations of confidence to third parties, be against laws or regulations (including competition laws), would waive legal professional privilege, or cause unreasonable prejudice to the Coordinator of Energy or the State of Western Australia).

Guiding Principle – what not to discuss

In any circumstance in which Industry Stakeholders are or are likely to be in competition with one another a Member must not discuss or exchange with any of the other Members information that is not otherwise in the public domain about commercially sensitive matters, including without limitation the following:

(a) the rates or prices (including any discounts or rebates) for the goods produced or the services produced by the Industry Stakeholders that are paid by or offered to third parties;

(b) the confidential details regarding a customer or supplier of an Industry Stakeholder;

(c) any strategies employed by an Industry Stakeholder to further any business that is or is likely to be in competition with a business of another Industry Stakeholder, (including, without limitation, any strategy related to an Industry Stakeholder's approach to bilateral contracting or bidding in the energy or ancillary/essential system services markets);

(d) the prices paid or offered to be paid (including any aspects of a transaction) by an Industry Stakeholder to acquire goods or services from third parties; and

(e) the confidential particulars of a third party supplier of goods or services to an Industry Stakeholder, including any circumstances in which an Industry Stakeholder has refused to or would refuse to acquire goods or services from a third party supplier or class of third party supplier.

Compliance Procedures for Meetings

If any of the matters listed above is raised for discussion, or information is sought to be exchanged in relation to the matter, the relevant Member must object to the matter being discussed. If, despite the objection, discussion of the relevant matter continues, then the relevant Member should advise the Chairperson and cease participation in the meeting/discussion and the relevant events must be recorded in the minutes for the meeting, including the time at which the relevant Member ceased to participate.

Department of
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Agenda Item 4: MAC Action Items

Market Advisory Committee (MAC) Meeting 2026_07_30

Shaded	Shaded action items are actions that have been completed since the last MAC meeting. Updates from last MAC meeting provided for information in RED.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
1/2026	AEMO to provide regular updates on proposals 4 and 5 from the Essential System Services (ESS) Framework Review. **Proposal 4:** AEMO to implement a monitoring program over a twelve-month period to track the amount of headroom and footroom available from unaccredited Facilities or non-dispatched FCESS Facilities to better quantify mandatory Primary Frequency Response (MPFR) availability to assess the level of Contingency Reserve Raise and Lower that could be provided from the inclusion of MPFR.	AEMO	2026_02_11	**Open** Proposals 4 and 5 from ESS Review will be retained in the action log for AEMO to provide regular updates. AEMO provided an update on Proposal 5 under Agenda Item 5(d) at the 18 June 2026 MAC meeting. AEMO will provide a preliminary update to the MAC on Proposal 4 of the ESS Review at the 30 July 2026 MAC meeting. • AEMO will provide the next update at the first MAC meeting to be scheduled in 2027.

Item	Action	Responsibility	Meeting Arising	Status
	Proposal 5: AEMO to assess the suitability of Synthetic Inertia (RCS) from Battery Energy Storage Systems (BESS) in complementing synchronous Inertia from rotating machines, and consider potential barriers and suitable incentivisation for grid-forming BESS to provide such services.			
5/2026	MAC members to revisit the MAC schedule at the 18 June 2026 MAC meeting to decide whether an additional in person meeting will be held.	MAC members	2026_02_11	**Closed** The next two upcoming MAC meetings have been rescheduled to 3 September and 15 October 2026 respectively. The 3 December 2026 meeting will be a hybrid meeting.
9/2026	AEMO to provide MAC members with a list of the Wholesale Electricity Market (WEM) Procedures and the date by which they are scheduled to commence.	AEMO	2026_06_18	**Closed** List containing WEM Procedures and scheduled commencement dates emailed to MAC members 3 July 2026.
10/2026	EPWA to schedule a discussion for the December MAC meeting about the timing of commencing a review of the SESSM, considering any new information from the pre-operational deployment.	EPWA	2026_06_18	**Open**
11/2026	EPWA to re-circulate to MAC members the links to the WEM Investment Certainty Review (WIC) Working Group webpage and provide the	EPWA	2026_06_18	**Closed** 25 June 2026 WIC Review Working Group Meeting Papers emailed to MAC members on 18 June 2026

Item	Action	Responsibility	Meeting Arising	Status
	meeting papers for the meeting scheduled for 25 June 2026.			Links to the WIC Review and Working Group webpage emailed to MAC members on 15 July 2026
12/2026	EPWA to provide a list of upcoming planned consultations to MAC members.	EPWA	2026_06_18	**Closed** A list of upcoming planned consultations was emailed to MAC members on 15 July 2026.
13/2026	EPWA to circulate an email asking for MAC members' availability for a meeting on 3 September 2026, and whether their preferred in-person meeting is on 22 October 2026 or 3 December 2026.	EPWA	2026_06_18	**Closed** See status of Action Item 5/2026
14/2026	The Chair to present the AEMC's upcoming work program at the next MAC meeting on 30 July 2026.	The Chair	2026_06_18	**Closed** See Agenda Item 6

MARKET ADVISORY COMMITTEE MEETING, 30 July 2026

FOR DISCUSSION

SUBJECT: UPDATE ON AEMO'S WEM PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	26 March 2026	20 July 2026
WEM Procedures for discussion at APCWG	• Reserve Capacity Security • Certification of Reserve Capacity • Settlements	• Network Access Quantity Model • Rule Participant Registration Processes • Dispatch Algorithm Formulation • Consumption Deviation Applications

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as of 14 July 2026. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported, or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	Summary of changes	Status	Next steps	Indicative Date	Required Commence-ment Date
AEPC_2026_06 Network Access Quantity Model	The proposed changes to WEM Procedure: Network Access Quantity Model seek to resolve a potential issue with the methodology in paragraph 4.3 for the determination of the Possible Dispatch Range. Without this precautionary amendment, the methodology could potentially (in some edge cases) affect a reduction to the Network Access Quantity (NAQ) of a Scheduled Facility or a Semi-Scheduled Facility when the (relevant) Facility is not contributing to network congestion. (Note the edge case causing potential issue did not occur in previous cycles).	Consultation	Consultation closes	24 Jul 2026	1 Sep 2026
AEPC_2026_07 Dispatch Algorithm Formulation	AEMO has commenced the Procedure Change Process to propose amendments to the WEM Procedure: Dispatch Algorithm Formulation to reflect changes made to the Dispatch Algorithm in accordance with clause 7.2.3 and to undertake process improvements. Amendments have been made to reflect urgent changes undertaken under clause 7.2.3 to improve the operation of the Dispatch Algorithm, regarding the treatment of Facilities to respect relevant Frequency Co-optimised Essential System Services (FCESS) trapezia and address potential violations of safe limit and defined contingency constraints. Further proposed amendments have been informed by AEMO's operational experience and observed need for uplift to address emergent or potential issues in dispatch. AEMO has proposed the following amendments to the Procedure: • updating Constraint Violation Penalties following urgent changes implemented by AEMO in accordance with	Consultation	Consultation closes	10 Aug 2026	30 Sep 2026

ID	Summary of changes	Status	Next steps	Indicative Date	Required Commence-ment Date
	clause 7.2.3 on 30 October 2025, 5 November 2025, and 4 December 2025. • reducing RoCoF Control Service Requirement fluctuation when both costs of RoCoF and Contingency Raise services are zero. • aligning the schedule of a Non-Scheduled Facility where a negative Unconstrained Injection Forecast has been provided. • improving estimates of a Facility's potential Droop Response in the Essential System Service pre-processing calculation. • aligning the Procedure with current system functionality, with respect to relaxation of Enablement Limits for RoCoF Control Service in Pre-Dispatch Intervals in the Pre-Dispatch Schedule and Week-Ahead Schedule.				

4. INDICATIVE SCHEDULE OF AEMO PROCEDURE CHANGE PROPOSALS

AEMO has prepared an indicative schedule of its Procedure Change Proposals expected to commence shortly. Changes since the previous MAC meeting are in red text. Procedure Change Proposals that have commenced since the previous MAC meeting have been moved from Table 4 into Table 3 above. While every effort has been made to ensure the quality of the information contained in the indicative schedule, the content (including timeframes) may be subject to change (e.g. due to availability of staffing resources, unforeseen competing priorities etc).

WEM Procedure	Summary of changes	Status	Next steps	Indicative date of next step	Required Commence-ment Date
WEM Procedure: Facility Registration Processes	AEMO will be initiating this Procedure Change Proposal to accommodate changes resulting from WEM Reform and the Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 3) Rules 2024.	Drafting in progress	Consultation	TBD	1 Oct 2023

WEM Procedure: MT PASA	AEMO will be initiating this Procedure Change Proposal to update the WEM Procedure arising from WEM Reform. This WEM Procedure outlines the information AEMO requires and the process it will follow in conducting the Medium-Term Projected Assessment of System Adequacy.	Delayed	Consultation	TBD	1 Oct 2023
WEM Procedure: Forecast Unscheduled Operational Demand	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules from WEM Reform. This new WEM Procedure documents how AEMO will prepare the Forecast Unscheduled Operational Demand.	Drafting in progress	Consultation	Aug 2026	1 Oct 2023
WEM Procedure: Rule Participant Registration Processes	AEMO will be initiating this Procedure Change Proposal to update the WEM Procedure based on operational changes and to provide additional clarity on the process.	Drafting in progress	Consultation	Jul 2026	N/A
WEM Procedure: Consumption Deviation Applications	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM (Tranche 9) Rules 2025, Schedule 3. This WEM Procedure specifies the process Market Participants must follow for submitting Consumption Deviation Applications, and the process AEMO must follow for assessing Consumption Deviation Applications.	Drafting in progress	Consultation	Jul 2026	1 Oct 2026
WEM Procedure: Dispatch of Demand Side Programmes	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules from the RCM Review. This WEM Procedure provides an overview of how AEMO will determine the dispatch of Demand Side Programmes.	Drafting in progress	Consultation	Jul 2026	1 Oct 2026
WEM Procedure: Capacity Credit Allocations	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules stemming from the RCM Review. This WEM Procedure provides an overview of the Capacity Credit Allocation process for AEMO and Market Participants.	Drafting in progress	Consultation	Aug 2026	1 Oct 2026
WEM Procedure: Reserve Capacity Testing	AEMO will be initiating this Procedure Change Proposal to accommodate amendments to the ESM Rules from the RCM Review and Tranche 9 changes. Updates will be made to the process for DSP testing and re-testing, and it will clarify the	Drafting in progress	Consultation	Jul 2026	1 Oct 2026

	consequences on a DSP or NGIS for failing a test or re-test (respectively).				
WEM Procedure: Reserve Capacity Security	AEMO will be initiating this Procedure Change Proposal to accommodate the amendments to the ESM Rules from the RCM Review and Tranche 9 changes. Updates will be made to reflect the changes to DSP testing and to clarify the arrangements for drawing on RC security and assessment for Commercial Operation.	Drafting in progress	Consultation	Jul 2026	1 Oct 2026
WEM Procedure: Dispatch Compliance	AEMO will be initiating this Procedure Change Proposal to accommodate changes to sub-clauses 2.13.7(b) and 4.11.1(c)(v), which commence on 1 October 2026. The changes require AEMO to monitor Market Participant compliance with clause 7.10.6B and document how it intends to do so in a WEM Procedure. Where a Market Participant does not comply with clause 7.10.6B, from 1 October 2026, changes to sub-clause 4.11.1(c)(v) prohibits AEMO from assigning Certified Reserve Capacity to the relevant Facility.	Drafting in progress	Consultation	Jul 2026	1 Oct 2026
WEM Procedure: WEM Submissions	AEMO will be initiating this Procedure Change Proposal to clarify process explanations and to reflect the removal of 'Withdrawal' from DSP Profile Submissions in line with changes resulting from the Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025, Schedule 3.	Drafting in progress	Consultation	Sep 2026	1 Oct 2026

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Agenda Item 6(d): Update on the Wholesale Electricity Market (WEM) Investment Certainty Review

Market Advisory Committee (MAC) Meeting 2026_07_30

1. Purpose

The Chair of the WEM Investment Certainty (WIC) Review Working Group (the Working Group) to provide an update on the WIC Review.

2. Recommendation

That the MAC notes that:

- Working Group meetings were held on 25 June 2026 and 23 July 2026; and
- further updates on the outcomes from Working Group meetings will be provided to the MAC once discussion focuses on potential proposals.

Background

The Coordinator of Energy (Coordinator) is conducting the WIC Review, in consultation with the MAC, under clause 2.2D.1 of the Electricity System and Market (ESM) Rules.

The MAC established the Working Group to support the WIC Review. The Terms of Reference, papers and minutes for the Working Group meetings are available on the relevant webpage. Further information on the WIC Review, including the Scope of Work is available on the Review webpage.

The WIC Review includes a package of WEM reform initiatives aimed at ensuring that the WEM and the ESM Rules provide sufficient incentives for new renewable generation capacity, while maintaining system security and reliability, and without unduly increasing the cost to consumers.

- Consultation with stakeholders on Initiatives 1 and 2 of the WIC Review concluded in late 2024.

The Working Group considered various mechanisms to provide revenue certainty for renewable generation projects but decided to cease the work in May 2024 until there was further clarity on the final design of the Capacity Investment Scheme (CIS).

Since then, issues impacting on investment certainty for renewable generation projects, mainly due to uncertainty around future energy prices, have continued to be raised by renewable energy projects proponents.

As indicated at the last MAC meeting, the Working Group has been re-convened to examine options for a Renewable Energy Mechanism (the Mechanism) to provide investment certainty to new renewable energy projects for further analysis and consultation.

In its first two meetings, the Working Group focused on refining the “problem statement” the Mechanism is aimed at addressing. The following refined problem statement was discussed at the second Working Group meeting:

- Storage capacity continues to grow in the SWIS. As load grows and fossil fueled facilities retire, significant volumes of renewable energy will be needed to fill the storage and meet annual demand.
- Renewable projects are not bankable without confidence in future revenues. Currently, this can come from capacity payments, Power Purchase Agreements (PPAs), or real time energy market payments. However:
- Capacity payments are not sufficient to cover the fixed cost of renewables.
- Real-time energy market prices will decrease as renewable penetration increases.
- There is currently a gap between what developers are willing to sell for and what customers are willing to pay, and significant risk that the gap will not close in time to avoid energy shortfalls.
- The Mechanism is intended to address this risk, by providing revenue confidence to renewable projects whose output is needed, but is not covered by an existing PPA at the time the Mechanism is implemented.
- This Mechanism is intended to apply to generation facilities entering from 2030, providing the minimum support required to reach Final Investment Decision (FID).
- Market customers appear unwilling to agree contracts at a higher cost than projected Real-Time Market prices after renewable entry.

3. Next Steps

- At its next meeting on 20 August 2026, the Working Group will focus on the high-level design of a preferred option(s) for the Mechanism for further analysis and consultation.
- A comprehensive update on the Working Group discussion at its 20 August meeting will be provided to the MAC for consideration at its next meeting on 3 September 2026.

Agenda Item 6(e): Update on the Capability Class 2 Technologies Review

Market Advisory Committee (MAC) Meeting 2026_07_30

1. Purpose

The Chair of the Capability Class 2 Technologies Review Working Group (the Working Group) to provide an update on the Capability Class 2 Technologies Review (the Review).

2. Recommendation

That the MAC:

- reviews the draft Consultation Paper (Attachment 1); and
- provides any additional comments on the Proposed Review Outcomes and Rationale (refer to page 9 of the draft Consultation Paper).

3. Background

In accordance with section 4.13B of the Electricity System and Market (ESM) Rules, the Coordinator of Energy (Coordinator) must review several provisions in the ESM Rules related to energy and availability limited resources. Under clause 4.13B.2 of the ESM Rules, the first review must be completed by 1 October 2026.

The MAC established a Working Group at its 24 July 2025 meeting to support the Review. The Terms of Reference, papers and minutes for the Working Group meetings are available on the relevant webpage.

Further information on the Review, including the Scope of Work, is available on the Review webpage.

4. Consultation Paper

The Consultation Paper has been drafted to reflect the analysis undertaken during the Review and considering feedback received from the Working Group and the MAC.

We request that the MAC reviews the draft Consultation Paper (Attachment 1) and provides any additional comments on the Proposed Review Outcomes and Rationale (refer to page 9 of the draft Consultation Paper).

To meet the statutory deadline of 1 October 2026, the Consultation Paper must be published as soon as practical to allow sufficient time for stakeholder consultation, and for Energy Policy WA to review and consider stakeholder submissions before finalising and publishing an Information Paper with the Final Review Outcomes.

5. Next Steps

The Consultation Paper will be released and open for consultation until 31 August 2026.

Attachment

Agenda Item 6(e) – Attachment 1 – Capability Class 2 Technologies Review – Draft Consultation Paper

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Capabilities Class 2 Technologies Review

Consultation Paper

Contents

Abbreviations

Term	Definition
AEMO	Australian Energy Market Operator
ADG	Availability Duration Gap
BD	Business Day
BRCP	Benchmark Reserve Capacity Price
BTM	Behind-the-meter
CC1	Capabilities Class 1
CC2	Capabilities Class 2
CC2T	Capabilities Class 2 Technologies
CC3	Capabilities Class 3
CRC	Certified Reserve Capacity
DSP	Demand Side Programme
DPV	Distributed Photovoltaics
EFC	Effective Firm Capacity
ELCC	Effective Load Carrying Capability
ERA	Economic Regulation Authority
ESM	Electricity System and Market
ESR	Electric Storage Resource
ESRDR	Electric Storage Resource Duration Requirement
ESROD	Electric Storage Resource Obligation Duration
ESROI	Electric Storage Resource Obligation Interval
ESS	Essential System Services
EUE	Expected Unserved Energy

FCESS	Frequency Co-optimised Essential System Services
GW	Gigawatt
ISO-NE	ISO – New England
KW	Kilowatt
LDM	Linearly Derating Method
LOR	Lack of Reserve
LOLE	Loss of Load Expectation
LRC	Low Reserve Condition
LT PASA	Long Term Projected Assessment of System Adequacy
MAC	Market Advisory Committee
MW	Megawatt
MWh	Megawatt - Hour
NAFF	Network Augmentation Funding Facility
NAQ	Network Access Quantity
NBD	Non-Business Day
NCESS	Non-Co-optimised Essential System Services
PJM	Pennsylvania - New Jersey – Maryland
POE	Probability of Exceedance
PSSR	Power System Security and Reliability
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RCP	Reserve Capacity Price
RLM	Relevant Level Method
RoCoF	Rate of Change of Frequency

RTM	Real-Time Market
SC	Supplementary Capacity
SEO	State Electricity Objective
SOC	State of Charge
SSE	System Stress Event
ST-PASA	Short Term Projected Assessment of System Adequacy
SWIS	South West Interconnected System
TNI	Transmission Node Identifier
WEM	Wholesale Electricity Market

Executive summary/Overview

Capability Class 2 Technologies Review

The Coordinator of Energy (Coordinator) is required to review the Electricity System and Market (ESM) Rules related to Capability Class 2 Technologies (i.e. Electric Storage Resources (ESRs) and Demand Side Programmes (DSPs)), in accordance with section 4.13B of the ESM Rules at least once every five years.

In its transition to a decarbonised future, the South-West Interconnected System (SWIS) is facing some challenges regarding ESRs and DSPs, including:

- the SWIS has experienced significant growth in ESR penetration as existing thermal generation retires, and decarbonisation efforts ramp up. The quantity of Capacity Credits allocated to ESRs under the Reserve Capacity Mechanism (RCM) has also increased in recent years. However, an ESR Facility's ability to meet its Reserve Capacity Obligation Quantity (RCOQ), which applies at the time of system peak demand, is dependent on its State of Charge (SOC).
- DSPs are dispatched when there is a heightened risk of unserved energy. As peak demand periods in the SWIS change, DSP availability obligation intervals should align with power system needs. Behind-the-meter (BTM) storage can also contribute to system reliability via DSP participation. However, BTM storage assets are duration-limited and are unlikely to meet long-duration availability obligations.

It is critical that the ESM Rules include:

- mechanisms to ensure that ESR Facilities have sufficient charge to meet their RCOQ when they are most needed by the system; and
- DSP availability obligation intervals that capture intervals where system stress can credibly occur, while accounting for the duration-limited nature of the duration-limited nature of BTM storage.

The Capability Class 2 Technologies (CC2T) Review was initiated to work closely with stakeholders, including the Market Advisory Committee (MAC), the CC2T Working Group (Working Group) and the Australian Energy Market Operator (AEMO), to review the ESM Rules related to Capability Class 2 Technologies.

This paper sets out the outcomes and proposed changes to regarding CC2T, including:

- ESR derating methodology;
- The setting of ESR Obligation Intervals (ESROIs);
- ESR Reserve Capacity testing;
- ESR State of Charge obligations and compliance; and
- DSP availability obligation intervals.

The proposed changes outlined in this paper are required to maintain Power System Security and Reliability (PSSR), and to reduce barriers for ESRs and DSPs within the RCM.

Call for Submissions

Stakeholder feedback is invited on the Review proposed outcomes outlined in this Consultation Paper. Submissions can be emailed to: energymarkets@deed.wa.gov.au. Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at **5:00pm (AWST) on 31 August 2026**. Late submissions may not be considered.

Summary of Proposed Review Outcomes and Rationale

Table 1 summarises the proposed review outcomes from the quantitative and qualitative analysis, and stakeholder feedback, with the rationale for each proposal.

Table 1: Proposed Outcomes and Rationale

Proposed Outcomes	Rationale
Proposal 1 Amend the ESM Rules (clause 4.22.2E(a)) to allow AEMO to measure the total energy delivered for assessing ESR performance in a Reserve Capacity Test.	The current rules create a mismatch between how test performance is measured under the ESM Rules and the operational realities of testing an ESR. This proposal aims to change the way AEMO determines the Reserve Capacity Test performance of an ESR, so that total output (including ramping) is measured, thereby preventing ESRs from being oversized solely to meet testing requirements. Further information can be found in Chapter 3.
Proposal 2a Amend the ESM Rules to change DSP availability obligation intervals to 8:00am to 12:00pm (noon) and 2:00pm to 10:00pm on all Business Days. Stakeholder feedback is sought on whether there is justification for a 4:00am to 8:00am morning interval instead of the 8:00am to 12:00pm (noon).	This proposal aims to align DSP availability with system requirements while seeking to minimise implementation costs. Concerns have also been raised regarding the period before 8:00am. Stakeholder feedback is therefore requested on whether the morning window should be changed to 4:00am to 8:00am, while still maintaining the requirement that availability occurs within a single Trading Day and retains the 12-hour obligation.

<table>
<tr><th>Proposed Outcomes</th><th>Rationale</th></tr>
<tr><td></td><td>Further information can be found in Chapter 0.</td></tr>
<tr><td>Proposal 2b
Amend the ESM Rules to:
allow a DSP participant to choose only the 2:00pm to 10:00pm window option and receive the Reserve Capacity Price derated by 8/12 to reflect the reduction of the DSP availability.
require that any DSP participant that chooses only the 2:00pm to 10:00pm option trades its Capacity Credits through AEMO.</td><td>Some large loads cannot restart quickly enough between the morning and evening availability obligation windows. To facilitate their participation as a DSP, this proposal allows participants to opt into the evening availability obligation window only, in exchange for a lower Reserve Capacity Price.

Since DSPs that opt only for the evening obligation window provide reduced reliability, their Capacity Credits are not equivalent to standard Capacity Credits and must be traded directly through AEMO.

Further information can be found in Chapter 0.</td></tr>
<tr><td>Proposal 2c
Amend the ESM Rules to:
remove the option for DSPs to offer availability outside the availability obligation intervals.
allow a DSP to associate different loads within its portfolio to the morning and the evening availability obligation intervals (for every Trading Day) no later than 3 weeks before the effective date.
empower AEMO to conduct Reserve Capacity Tests in the availability windows selected by the DSP.</td><td>To make DSP participation easier:
the application process will be simplified by removing the option for DSPs to offer availability outside of the standard availability obligation windows.
DSP providers can change which Associated Loads they plan to use to provide greater portfolio flexibility, provided this is done sufficiently in advance.
Further Reserve Capacity testing changes are needed to verify that DSPs can provide their RCOQ in the window or windows they have selected.

Further information can be found in Chapter 0.</td></tr>
<tr><td>Proposal 3
Amend the ESM Rules to allow a DSP participant to have its Capacity Credits reduced and a corresponding portion of its Reserve Capacity Security returned, provided that:
an Associated Load greater than 5 megawatt (MW) ceases operations permanently or for the entirety of a</td><td>This proposal aims to:
reduce the risk that a DSP provider will be less likely to participate in the RCM where factors outside of its control cause an Associated Load to cease operations, but its Reserve Capacity obligations persist; and
recognise that the Reserve Capacity Requirement will be reduced if a significant DSP Associated Load exits the system before the relevant Capacity Year.</td></tr>
</table>

Proposed Outcomes	Rationale
Capacity Year in which the relevant DSP has Reserve Capacity obligations; • the DSP participant notifies AEMO no later than 1 April in Year 3 of the Reserve Capacity Cycle; and • the relevant Market Participant provides sufficient evidence that the load has ceased operations.	Further information can be found in Chapter 5.
Proposal 4a Amend the ESM Rules to: • update clause 3.17.11 (the head of power for the Low Reserve Condition (LRC) WEM Procedure) to empower AEMO to incorporate a Lack of Reserve – State of Charge (LOR-SOC) condition into the Low Reserve Condition Framework, as follows: – the declaration of an LOR-SOC condition triggers the imposition of a State of Charge (SOC) obligation on the ESR fleet comprising ESRs with a Peak Reserve Capacity Obligation Quantity; – the LRC WEM Procedure will also be amended to outline: o the system conditions under which the LOR-SOC obligations will apply; and o the methodology AEMO will use to determine the SOC obligation level. • allow AEMO to withdraw a LOR-SOC condition and SOC obligations if it determines they are no longer necessary; • specify the notification timings for AEMO when declaring a LOR-SOC condition: – AEMO must use best endeavours to declare the LOR-SOC condition and SOC obligations by 8:00pm on the Scheduling Day; and – AEMO must declare the LOR-SOC condition and SOC obligations no later than 8:00am on the Trading Day.	Analysis shows that system stress events requiring ESRs to have higher charge levels are infrequent but have the potential to impact PSSR. The infrequent nature of these events does not justify a redesign of the market. Targeted AEMO intervention when these events arise provides a more effective and simpler approach to implementation. This proposal aims to empower AEMO during these infrequent periods when appropriate ESR SOC levels are required to meet the upcoming evening peak obligation, and AEMO determines that ESR discharge is necessary to prevent the risk of unserved energy. The ESM Rules will define the information that must be included in the WEM Procedure. This proposal ensures full transparency for Market Participants regarding how and when the new LOR-SOC obligation will be applied. Further information can be found in Chapter 0.

Proposed Outcomes	Rationale
• specify that the LOR-SOC obligation will be for a uniform charge level applicable to all ESR Facilities with Reserve Capacity obligations, and that these Facilities must be at that level at the start of their relevant ESROIs; • specify the information that must be made available to relevant Market Participants to provide a reasonable level of certainty about the event occurring; and • specify that the SOC obligation applies to an ESR Facility's remaining available capacity to account for outages.	
Proposal 4b Stakeholder feedback is sought on the following two options aimed at assisting ESR operators in complying with an LOR-SOC obligation that applies and avoid non-compliance with other obligations. **Option 1:** Amend the ESM Rules to provide that, on a Trading Day when an LOR-SOC condition is in effect, AEMO must: • apply Constraint Equations to prevent ESRs from being dispatched for Injection before their relevant ESROIs, unless they are instructed by AEMO to provide FCESS or to maintain PSSR; and • apply Constraint Equations to prevent ESRs from being dispatched for withdrawal during their ESROIs and during the ESROIs of other ESRs, unless they are instructed by AEMO to provide FCESS or to maintain PSSR. **Option 2:** • allow ESR operators to make zero quantity offers for energy injections and zero withdrawal bids outside their ESROIs on a Trading Day when a LOR-SOC condition is in effect; and • introduce an obligation preventing ESRs from charging during their ESROIs and during the ESROIs of other ESRs on a	To facilitate compliance with the proposed LOR-SOC, it is proposed to amend the ESM Rules to provide Market Participants with an option that allows compliance with the LOR-SOC obligation without risking non-compliance with their offer requirements. Both options are expected to achieve the same outcome but differ in the level of effort required from different stakeholders: • Under Option 1, Market Participants will continue to comply with the relevant obligations when submitting offer quantities. This provides AEMO with greater visibility of the operational capability of ESR facilities. As a result, AEMO would need to perform less manual work if intervention for PSSR purposes is required. • Option 2 offers ESR operators a simpler and more straightforward method for operating under a LOR-SOC obligation. However, this simplicity shifts additional burden to AEMO, which may need to undertake more manual work if it needs to intervene. Further information can be found in Chapter 0.

Proposed Outcomes	Rationale
Trading Day when a LOR-SOC condition is in effect, except where AEMO instructs them to provide FCESS or to maintain PSSR.	
Proposal 5 It is proposed to amend the ESM Rules to introduce an addition to the current refund mechanism for ESRs when an LOR-SOC mandate applies.	An addition to the current refund mechanism will be introduced to incentivise appropriate behaviour and ensure that other technology types are not adversely affected. The proposed change is designed to minimise implementation costs while providing a simple enhancement to the financial incentives for ESRs to comply with the LOR-SOC obligation. Further information can be found in Chapter 7.

1. Introduction

The Coordinator of Energy (Coordinator) is required to review the Electricity System and Market (ESM) Rules related to Capability Class 2 Technologies (i.e. Electric Storage Resources and Demand Side Programmes), in accordance with section 4.13B of the ESM Rules at least once every five years.

The Coordinator has undertaken this review in consultation with the Market Advisory Committee (MAC), Capability Class 2 Technologies Review Working Group (Working Group). and the Australian Energy Market Operator (AEMO).

This paper sets out the outcomes of the Capability Class 2 Technologies Review (the Review) and the proposed changes arising from the Review.

1.1. Regulatory context

The Review was originally added to the ESM Rules in November 2021 and was subsequently amended in January 2025 to implement the outcomes of the Reserve Capacity Mechanism (RCM) Review, including amendments related to ESRs and DSPs.

The scope of the Review under section 4.13B of the ESM Rules, both before and after January 2025, is summarised below:

Table 2: Scope of the Review required under ESM Rule 4.13B (prior to 15 January 2025)

ESM Rule clause	Review requirement
4.13B.1	The Coordinator must review the effectiveness of the approach to certification of Reserve Capacity for ESR
4.13.B.3(a)	The Coordinator must review the methodology for rating the capacity of ESRs for Certified Reserve Capacity (CRC)
4.13.B.3(b)	The Coordinator must review the approach to setting the ESR Obligation Duration (ESROD)
4.13.B.3(c)	The Coordinator must review the approach for setting the ESR Obligation Intervals (ESROIs)
4.13.B.3(d)	The Coordinator must review the ESROI methodology and processes used by AEMO

Table 3: Scope of the Review required under ESM Rule 4.13B (after 15 January 2025)

ESM Rule clause	Review requirement
4.13B.1	The Coordinator must review the effectiveness of the approach to certifying ESRs and other energy limited resources, collectively Capability Class 2, in accordance with section 4.13B and against the State Electricity Objective (SEO)
4.13.B.1(a)	The Coordinator must review the methodology for rating the capacity of ERSs and DSPs for CRC
4.13.B.1(b)	The Coordinator must review the Reserve Capacity Obligation Quantity (RCOQ) determination for ESRs and DSPs
4.13.B.1(c)	The Coordinator must review the effectiveness of Reserve Capacity refunds for ESRs and DSPs
4.13.B.1(d)	The Coordinator must review the operation of clause 4.5.12 to ensure adequacy with clause 4.5.9(b) (reliability limb)
4.13B.3(a)	The Coordinator must review the capacity rating methodology for CRC for all Capability Class 2 technologies
4.13B.3(b)	The Coordinator must review the dynamic ESR Obligation Duration (ESROD) and the Availability Duration Gap (ADG) calculations
4.13B.3(d)	The Coordinator must review the AEMO method for setting the Mid-Peak ESR Obligation Interval (ESROI)
4.13B.3(f)	The Coordinator must review the year to year ADG trends and impact on certification
4.13B.3(g)	The Coordinator must review the methodology for Peak and Flexible DSP Dispatch Requirements

The Amending Rules introduced on 15 January 2025 have only been in place for a short period and, therefore, the Coordinator considers that it is too soon to conduct a review of these provisions. The Coordinator considers that it is appropriate to undertake a review of the provisions that will have been in operation for five years at the completion of the review, in line with the intent of the relevant ESM Rules.

The subject of clause 4.13B.3(b) – the ADG calculations, was recently reviewed, with changes implemented through the Tranche 8 ESM Amending Rules. Consequently, this item will not be considered as part of this Review.

Given the above, the Coordinator has set the following scope for the Review:

Table 4: Scope of Review

Issue in scope	Map to ESM Rule 4.13B
Issue 1: Review whether current ESR certification methodology (Linearly Derating Method) is still aligned with SEO See Chapter 2.1	4.13.B.1(a), 4.13B.3(a) (ESRs only)
Issue 2: Review Reserve Capacity Refunds regime and evaluate the potential to sharpen availability incentives See Chapter 0	4.13B.1(c) (ESRs only)
Issue 3: Review the DSP availability obligations against the SEO See Chapter 0	4.13.B.1(a), 4.13.B.1(b)
Issue 4: Identify policy options to improve ESR availability (based on Technical Analysis) See Chapter 0	4.13.B.1(a), 4.13.B.1(b), 4.13.B.3(d)
Issue 5: Assess whether the existing Capability Classes approach (under clause 4.5.12) enables compliance with the reliability limb of the Planning Criterion See Chapter 2.3	4.13B.1(d)

1.2. Subsequent review

The review required by section 4.13B, which includes assessing CC2T, must be conducted at least once every five years. Given the dynamic nature of the energy transition, this Review focuses on the next five years rather than a longer timeframe, over which forecasts are likely to be less accurate.

As the system evolves and conditions change, the next review in 2031 will address any new issues and challenges that arise in the interim and cannot currently be foreseen.

The next review will also re-examine the matters covered in this review and evaluate whether the proposals, if implemented, are operating as intended.

1.3. Background

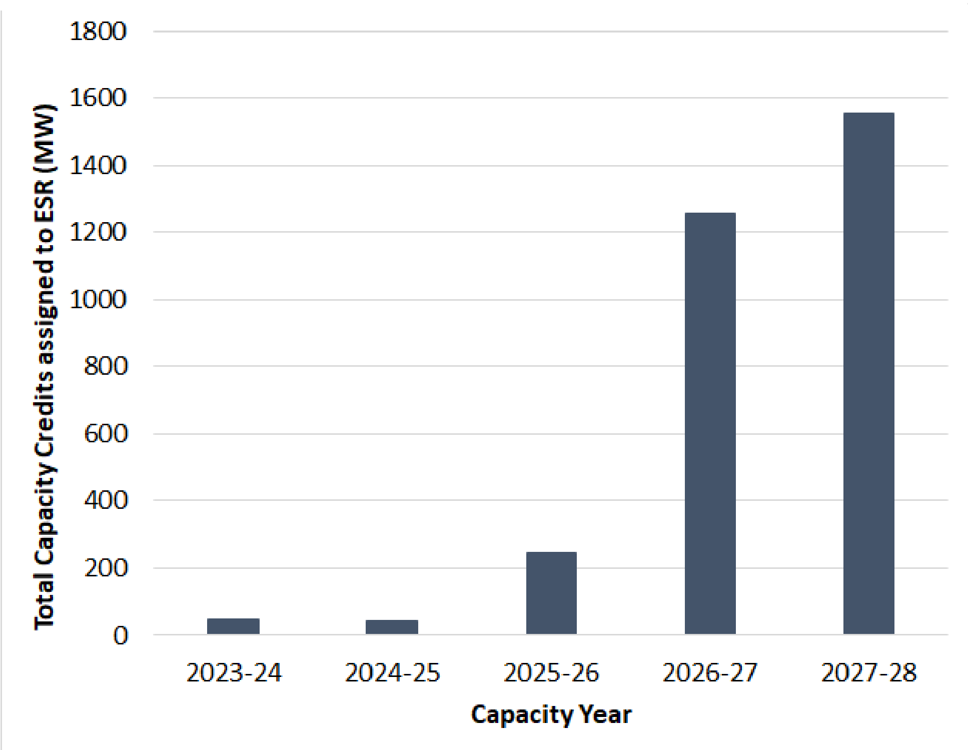
The increase of ESR capacity in the WEM presents opportunities and challenges

The SWIS has experienced significant growth in ESR penetration as existing thermal generation retires and other decarbonisation efforts ramp up.

The quantity of ESRs receiving Capacity Credits in the RCM has increased significantly in recent years, from 46.25 megawatts (MWs) of capacity assigned in the 2023-24 Reserve Capacity Cycle to 1,557 MW of Peak Capacity Credits assigned in the 2025-26 Reserve Capacity Cycle (see Figure 1). This increase has been driven, at least in part, by:

- High Reserve Capacity Prices, associated with changes to Benchmark Technology that is used to set the Benchmark Reserve Capacity Price (BRCP). The BRCP for the 2028-29 Reserve Capacity Cycle was determined by the Economic Regulation Authority (ERA) to be $488,500/MW/Year.[1]
- Grandfathering arrangements have been implemented to provide investor certainty by allowing ESRs to retain their original ESR Duration Requirement (ESRDR) for up to ten years, so that increases in the ADG do not reduce the Capacity Credits assigned to incumbent ESRs.

Figure 1: Peak Capacity Credits assigned to ESR Facilities since 2023-24



Source: AEMO (excludes Capacity Credits assigned to ESRs certifying as Non-Scheduled Facilities)

[1] See 2026 Benchmark Reserve Capacity Prices for the 2028-29 capacity year: Final Determination.

ESR availability obligations must be aligned with power system needs

The increase in ESR penetration presents both opportunities and challenges. As intermittent weather-dependent resources continue to grow and existing thermal generation retires, CC2T (particularly ESR) will become increasingly critical to maintaining system reliability. It is therefore important for the durational obligations placed on ESR to be aligned with system needs.

The ESM Rules must place effective and sufficient incentives on ESRs to be available

The ability of ESRs to respond to the reliability needs of the system is heavily dependent on how they charge:

- The Wholesale Electricity Market (WEM) does not have multi-period optimisation or unit commitment; this means that AEMO is not empowered to commit ESRs or schedule their charging.[2]
- As WEM participants self-schedule and are duration limited, they are responsible for ensuring that they have sufficient charge to meet their RCM and Real Time Market (RTM) obligations.

Unlike thermal Scheduled Facilities, for which AEMO has assurance that sufficient fuel is available through the certification process, AEMO does not have the same level of assurance that an ESR Facility will maintain sufficient SOC to comply with its RCOQ.

Thermal Scheduled Facilities have their fuel arrangements rigorously tested to ensure they have daily access to 14 hours of fuel to generate during the Capability Class 1 Assessment Intervals (8am to 10pm on Business Days). Accordingly, AEMO can reasonably assume that, unless a thermal generator suffers an unexpected contingency, it will have sufficient fuel to generate during these intervals. By contrast, an ESR Facility's ability to ensure daily access to energy, and therefore an appropriate SOC, cannot be likewise assessed.

For these reasons, it is critical that the ESM Rules include mechanisms to incentivise ESR Facilities to charge in a manner that enables them to meet their Reserve Capacity obligations when required.

DSP availability rules should be aligned to system need and enable new technologies to participate

DSP availability obligations must be aligned with power system needs

DSPs are assigned Capability Class 2 and are subject to more restrictions on their availability than ESR. DSPs are treated as a last resort and are dispatched when there is a heightened risk of unserved energy.

[2] clause 7.5.10 enables a Market Participant to request AEMO to include Constraint Equations for their ESR Facility to ensure their energy and Frequency Co-optimised Essential System Services (FCESS) dispatch targets are achievable given their charge levels. While all registered ESR Facilities currently have storage constraints, these constraints rarely bind in practice.

As power system operations become more volatile, DSPs may be required more frequently to reduce Unscheduled Operational Demand. It is therefore important to ensure that DSP obligations capture intervals during which system stress can credibly occur

Recently, there have been occasions where supplementary capacity services have been procured by AEMO to mitigate the risk of unserved energy occurring outside DSP availability obligation intervals. For example:

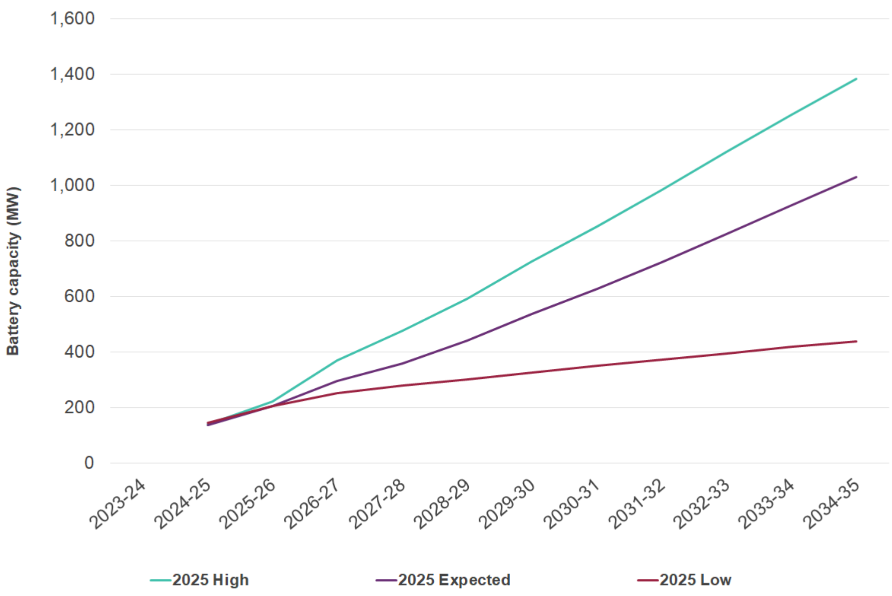
- In the 2025 ESOO, AEMO forecast that unserved energy may occur between 8 pm and 10 pm during the Hot Season, when DSPs are unavailable and ESRs are largely depleted. Consequently, AEMO identified a requirement to procure an additional 50 MW of capacity through Supplementary Capacity (SC)
- In response to heat conditions on 20 January 2025, AEMO activated a total of 20 MW of DSP response, along with 85 MW procured through the SC and NCESS mechanisms.

As existing thermal generation retires from the system, maintaining reliability during extreme weather conditions will require increasing reliance on ESRs and DSPs. It is therefore critical that DSP availability obligation intervals are aligned with system needs to minimise reliance on more costly ad hoc procurement

DSP availability obligations should enable the participation of Behind-the-Meter (BTM) storage

The residential battery schemes have resulted in a large uptake of BTM storage with AEMO forecasting an increasing trend in uptake – see Figure 2.

Figure 2: Forecast residential battery capacity (MW)



Source: 2025 WEM ESOO

BTM storage can contribute to system reliability via DSPs. While residential storage capacity is forecasted to increase significantly, commercial and industrial BTM storage can also contribute to system reliability. Further, residential, commercial, and industrial BTM storage can operate together within an aggregated DSP portfolio. However, as BTM storage is duration limited, it is unlikely to meet a continuous 12-hour availability obligation.

This Review assessed alternative availability obligations to enable BTM storage to participate in the RCM.

1.4. Approach to the Review

Consultation

The Coordinator has undertaken the Review in consultation with the MAC, the Working Group and AEMO.

The MAC established the Working Group to support the Review.

Further information on the Review is available from Energy Policy Western Australia's website, including the Scope of Work, the Terms of References for the Working Group, and papers and minutes of the Working Group.[3,4]

Review methodology

The review methodology comprised qualitative and quantitative technical analysis.

Qualitative Analysis

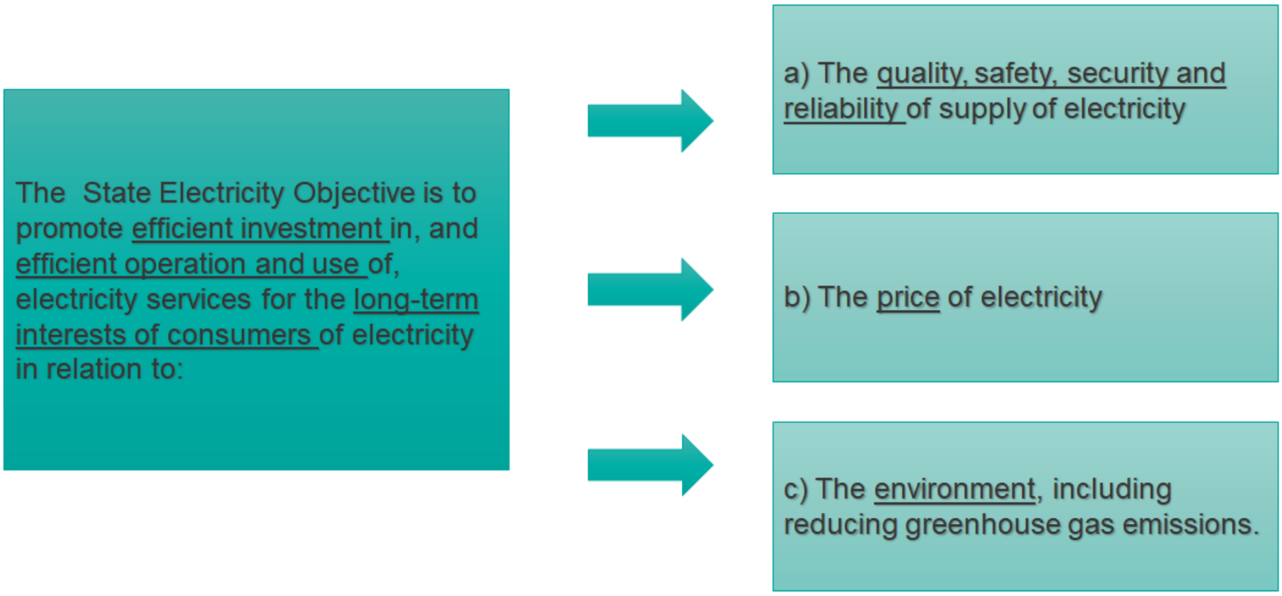
Policy options developed during the review were assessed against the SEO using multi-criteria analysis.

Evaluation criteria that mapped to the three limbs of the SEO were developed to assess different policy options. The three limbs of the SEO are shown in the figure below.

[3] Capability Class 2 Technologies Review

[4] Capability Class 2 Technologies Review Working Group

Figure 3: The three limbs of the SEO



The evaluation criteria that were developed for assessing different policy options is detailed in Appendix C.1 and E.1.

Policy options were evaluated to see how well they met the criteria as shown in the table below:

Figure 4: Rating scale for policy options evaluation

○	None of the criteria are met
◔	Some criteria met partially
◑	Some criteria met substantially or most met partially
◕	Most criteria met substantially
●	All criteria met substantially

Technical Analysis

The Review also conducted Technical Analysis to understand:

- The nature of historical power system incidents in which the availability of CC2T was critical to maintaining PSSR, examined through a Current State Analysis.

- The circumstances under which ESRs and DSPs are likely to be needed in the future to avoid unserved energy, examined through a Future State Analysis.

Current State Analysis

Historical System Stress Events (SSEs) between October 2023 and August 2025 were examined to understand the characteristics and drivers of SWIS stress incidents.

- Policy recommendations were informed by SSEs occurring after November 2024, as this is after the implantation of ESM Amending Rules arising from the Frequency Co-optimised Essential System Services (FCESS) Cost Review, which addressed previous market effectiveness issues.

SSEs were defined by identifying:[5]

- Market Advisories with Low Reserve Conditions and/or energy and ancillary services shortfall; and.
- manual (non-network) constraints applied by AEMO.

This resulted in 26 SSEs being selected for investigation, including analysis of:

- the underlying causes, timing and duration of the SSEs;
- ESR charging behaviour during the SSEs; and
- the relationship (if any) between FCESS enablement and charge levels.

In addition to reviewing historical SSEs, DSP activation events between October 2023 and February 2025 were examined to analyse the timing and duration of DSP dispatch events.

The detailed methodology is included in Appendix D.1. The results of the Current State Analysis are presented in the body of this report (see Chapters 2.2, 4.2, and 0) and in Appendix D.1.

Future State Analysis

AEMO conducted modelling to forecast when ESR dispatch is required to avoid unserved energy for Capacity Year 2026-27 through to 2030-31 (inclusive).

AEMO's model is a probabilistic Monte Carlo simulation model that uses nine reference (historical) load years to represent variation in weather conditions and five forced outage scenarios to represent random outages. This results in 180 iterations per Trading Intervals, capturing system conditions, available capacity, and demand under different weather and outage conditions.

The model further assumes that ESRs are at the top of the merit order (but behind DSPs), such that it is only dispatched to avoid unserved energy. Consequently. ESROIs are not considered, and ESR dispatch is determined by the need to avoid unserved energy.

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[5] See Appendix D.1.1 for a more detailed definition of SSEs.

The detailed methodology is included in Appendix D.2. The results of the Future State Analysis are presented in the body of this report (see Chapters 2.2 and 0) and in Appendix D.2.

1.5. Structure of this paper

This document is structured as follows:

- Chapter 2 summarises outcomes for review items that have not resulted in amendment. This includes the approach for:
    - derating ESR methodology;
    - the setting of ESR Obligation Intervals (ESROIs); and
    - prioritising technology within Capability Class 2 in the Network Access Quantity (NAQ) Model.
- Chapters 3 to 5 set out the review outcomes where amendments to the ESM Rules are proposed. These include:
    - amendments to the ESR Reserve Capacity Test rules to allow test performance to include energy produced when ramping up or down during a test;
    - amendments to DSP availability obligations intervals;
    - amendments to allow the return of a DSP security deposit;
    - the introduction of an SOC mandate that empowers AEMO to set a Peak Certified ESR fleet charge level during Low Reserve Conditions. This establishes the minimum SOC for an ESR facility before it enters its applicable ESROIs; and
    - amendments to the Reserve Capacity refund regime to introduce higher refunds (applicable only to ESR) during the ESROIs in which a SOC mandate applies.
- The appendices contain additional detail, including:
    - a jurisdictional review of ESR derating approaches;
    - a jurisdictional review of Demand Side approaches;
    - details of policy options evaluation against the SEO; and
    - Technical Analysis methodology and results.

1.6. Stakeholder Consultation

Stakeholder feedback is invited on the Review outcomes and proposed changes as outlined in this Consultation Paper.

Submissions can be emailed to: energymarkets@deed.wa.gov.au.

Any submissions received will be made publicly available on www.energy.wa.gov.au, unless requested otherwise.

The consultation period closes at 5:00pm (AWST) on **31 August 2026**. Late submissions may not be considered.

2. Items Assessed – No Amendments Proposed

2.1. Electric Storage Resources derating approach

ESRs are duration limited technologies, which means that their capacity contribution must be assessed to reflect their contribution to system reliability.

In the WEM, ESRs are assessed and, where necessary, derated using the Linearly Derating Methodology (LDM). Under this approach, the Peak CRC assigned to an ESR is calculated as its maximum discharge capability (MW) in Year 4 of a Reserve Capacity Cycle (the relevant Capacity Year) divided by the applicable ESR Duration Requirement (ESRDR) for that Capacity Year.[6]

This review has examined:

- the approach to derating ESRs in other markets. (See Appendix A for the jurisdictional analysis);
- whether the LDM is consistent with the SEO; and
- alternative derating options to determine whether the existing approach should be changed.

Summary of international review

The ESR derating approaches were reviewed across five jurisdictions with capacity markets. Key market statistics and derating approaches are summarised in the tables below.

All reviewed jurisdictions (except Ontario) have implemented variants of the Effective Load Carrying Capability (ELCC) or Effective Firm Capacity approach (EFC) approach.[7]

[6] Refer to Chapter 2.2 for details on how the ESRDR is calculated.

[7] The WEM has implemented the Last-In Fleet ELCC approach to derate CC3 technologies.

Table 5: Summary statistics by jurisdiction reviewed

	WEM[8]	Great Britain (GB)	PJM (USA)	ISO New England (ISO-NE) (USA)	Ireland (Northern Ireland and Ireland)	Ontario (Canada)
Storage Capacity	1.325 GW	6.87 GW	5.17 GW	330 MW	1.11 GW	264 MW
% Storage relative to total system capacity	18.5%	9.6%	2.6%	1.1%	7.4%	0.007%
Approach	LDM	Last-in EFC	Last-in ELCC	Last-in ELCC	Last-in ELCC with least-worst regrets analysis	Derating based on historical performance

WEM and Great Britain data is for 2024.
PJM, ISO-NE, Ireland and Ontario data is for 2023.

The ELCC and EFC approaches involve complex, iterative probabilistic simulation algorithms that model the impact of a marginal unit of capacity (from a particular technology) on the system reliability standard. While these models more accurately approximate the marginal reliability contribution of a given technology, international experience indicates that they are complex to implement and likely result in volatile capacity allocations from year to year. The issues encountered in these markets are set out in Appendix A.1.

Alternative options assessed

The WEM uses the LDM to certify the ESR Reserve Capacity, as follows:

- The certified capacity for an ESR is equal to its degraded maximum charge capability divided by its ESROD;
- New ESRs receive an ESROD based on the ADG calculation (conducted under Appendix 11 of the ESM Rules), assess whether non-ESR capacity can meet demand in intervals adjacent to the previous cycle's ESRDR;
- incumbent ESRs retain their original ESROD for ten years; and
- any over-allocation of capacity to incumbent ESRs is added back into the Planning Criterion.

[8] AEMO | Market data

The LDM's performance against the SEO is compared to three variants of the ELCC approach, as follows:

- Option 1: Incorporate ESRs into the amended Relevant Level Method (RLM) for Capability Class 3 (CC3) technologies.
  - Under this option, ESRs would be included in Appendix 9 of the ESM Rules and have capacity allocated based on the Last-in Fleet ELCC approach.
  - The output of incumbent ESRs would be based on historical generation, while the output of new ESRs would be determined using a peak or unserved energy minimisation heuristic (as ESR output cannot be forecast in the same way as wind and solar technologies).
  - As with the amended RLM, Distributed Photovoltaic (DPV)-corrected reference load profiles would be developed assuming a 10% Probability of Exceedance (POE) peak and expected demand growth, using historical load curves from the previous four year.
  - The Fleet ELCC would be calculated as the lower of
    (i) whole period fleet ELCC; and
    (ii) average of individual year fleet ELCC.
  - The Fleet ELCC would then be allocated:
    (i) to incumbent ESR, in proportion to their performance during Peak Individual Reserve Capacity Intervals; and
    (ii) to new ESR, in proportion to their estimated output, modelled using either a peak or unserved energy minimisation heuristic.
- Option 2: Implement Individual ELCCs.
  - This option is similar to Option 1, but instead of using a Last-in Fleet ELCC approach, individual ELCCs would be calculated for CC3 technologies and ESR
- Option 3: Last-in Fleet ELCC with Least Worst Regrets.
  - This option is similar to Option 1 but incorporates Least-Worst-Regrets analysis to address forecast uncertainty.
  - Instead, of modelling a single four-year ELCC period, multiple POE peak demand and expected demand assumptions are combined with different load shape assumptions to create multiple load trace scenarios.
  - Under this approach:
    (i) a Fleet ELCC is calculated for each scenario;
    (ii) regret costs are calculated for each scenario to assess the cost of unserved energy or excess capacity if a different demand outcome occurs;
    (iii) the Fleet ELCC associated with the lowest regret cost is selected and allocated to ESRs using the same approach as in Option 1.

Conclusion

The LDM status quo performs best against the SEO due to its simplicity, transparency and predictability.

Options 1 and 3 outperform the status quo in terms of accurately approximating reliability contribution, as these options involve sophisticated probabilistic simulation models.

Option 2 performs worse than Options 1 and 3 in this respect due to the implementation of individual ELCCs:

- Under a Last-in individual ELCC approach, ESR technologies added later to the model may be assigned lower reliability contributions than ESRs added earlier.
- Consequently, the sum of the individual ELCCs will not necessarily equal to the Fleet ELCC.

While Options 1 and 3 perform well in estimating reliability contribution, there are several drawbacks, including:

- Implementation is likely to be highly complex and costly. These options would require replacing dynamic ESROD and ESROIs with availability requirements across all Trading Intervals (albeit with a lower level of assigned capacity, as ELCC reflects marginal reliability impact).
- Both options may result in volatility in year-on-year capacity allocations (although less than under Option 2). Experience in PJM indicates that volatile allocations to intermittent generation can create investor uncertainty and increase reliance on firm generation, contributing to higher capacity prices.
- The resulting capacity derating factors are unlikely to be easily predictable for investors and existing Market Participants due to the complexity of the methodology, increasing investment risk for ESR.

When presented with these options, Working Group and MAC members supported retaining the LDM due to concerns regarding uncertainty in capacity allocation and high implementation costs under the alternative approaches.

Given the complexity and cost of the alternatives, and the views expressed by the Working Group and MAC members, the proposed Review outcome is to retain the existing LDM approach for derating ESR capacity for the purposes of CRC.

Table 6: Evaluation of ESR derating options against the SEO

	Status Quo (LDM & ESROD)	Option 1: Fleet ELCC	Option 2: Individual ELCC	Option 3: Fleet ELCC with least worst regrets
Overall performance	Most criteria met substantially ◕	Some criteria met substantially/ most partially ◐	No criteria met substantially ○	Some criteria met partially ◔
Provides value for money by reasonably approximating contribution of batteries to reliability	Met partially	Met substantially	Met partially	Fully met
Method is transparent and predictable	Met substantially	Not met	Not met	Not met
Method does not result in volatile allocation from year to year	Met substantially	Met partially	Not met	Met partially
Cost and complexity of implementation is reasonable	Fully met	Met partially	Not met	Not met

The detailed evaluation of the options above against the SEO is provided in B.1.3.

2.2. The method for determining the ESROIs

ESRs that have been assigned Capacity Credits are required to be continuously available during their ESROD, which comprises contiguous Trading Intervals (ESROI) centred on the Mid-Peak ESROI.

The ESROD (and corresponding ESROIs) are recalculated for new ESR Facilities and Separately Certified Components, with incumbent ESR Facilities retaining their ESROD for ten years under grandfathering arrangements.

AEMO determines the ESROD to apply to new ESRs by identifying the Availability Duration Gap (ADG) as part of the annual Long-Term Projected Assessment of System Adequacy (LT PASA) process. The ADG enables AEMO to determine the ESR Duration Requirement (ESRDR) and, subsequently, the Trading Periods (ESROIs) in which there is insufficient Capability Class 1 (CC1) and CC3 capacity to meet operational demand without CC2 technologies.

New ESRs are assigned an ESROD and ESROIs covering the ESRDR (including the ADG), while incumbent ESRs retain their previously determined ESROD. These grandfathering arrangements create a misalignment between the actual capacity required to meet demand during the amended ESROIs and the physical capacity of the ESR fleet to meet demand during that period. To address this, an ESR Duration Requirement Uplift is added to Limb A of the WEM Planning Criterion to maintain reliability.[9]

The most recently determined ESRDR and ESROIs for the 2025-26, 2026-27 and 2027-28 Capacity Years are summarised below.

Table 7: Summary of Peak ESROI/ESROD determination for the 2025-26 to 2027-28 Capacity Years

Capacity Year	Season	ESRDR (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
2025-26	**Summer**	8	16:00-19:30	17:30	**19:00 (amended)**	**17:30-21:00 (amended)**
	Shoulder	8	16:00-19:30	17:30	**19:00 (amended)**	**17:30-21:00 (amended)**
	Winter	8	17:00-20:30	18:30	**19:00 (amended)**	**17:30-21:00 (amended)**
2026-27	**Summer**	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30-20:00
	Winter	8	17:00-20:30	18:30	19:00/18:30	17:30-21:00 / 17:00-20:30
2027-28 (incumbent ESR)	**Summer**	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30-20:00
	Shoulder	8	16:00-19:30	17:30	19:00/18:00	17:30-21:00 / 16:30-20:00

[9] Clause 4.5.9(a) requires the Planning Criterion to include the calculated ESROD Uplift in determining the amount of reserve capacity needed for the system to meet its annual forecasted peak demand while maintaining SWIS frequency.

Capacity Year	Season	ESRDR (number of Trading Intervals)	Peak Demand Period	Indicative Mid Peak ESROI	Mid Peak ESROI (business days / non-business days)	Peak ESROD (business days / non-business days)
	Winter	8	17:00-20:30	18:30	19:00/18:30	17:30-21:00 / 17:00-20:30
2027-28 (new ESR)	**Summer**	12	15:00 – 20:30	17:30	19:00/18:00	16:30-22:00/15:30-21:00
	Shoulder	12	15:00 – 20:30	17:30	19:00/18:00	16:30-22:00/15:30-21:00
	Winter	12	16:00-21:30	18:30	19:00/18:30	16:30-22:00/16:00-21:30

Source: Values for the 2025-26 Capacity Year are sourced from AEMO's Amendment to the Mid Peak ESROI for the 2025-26 Capacity Year .
Values for the 2026-27 and 2027-28 Capacity Years are sourced from the 2025-26 WEM Electricity Statement of Opportunities.

Technical analysis – ESR availability assessment

To assess whether the existing availability obligations for ESRs remain aligned with the SEO, technical analysis was conducted to answer the following questions:

1. When have ESRs historically been required to respond to SSEs?
2. When will ESRs be needed in the future to avoid unserved energy?

The first question was addressed through a "Current-State Analysis" focusing on historical SSEs.[10]

The second question was addressed through a "Future-State Analysis," in which ESR dispatch was modelled from 2026 to 2030 to assess when it will be required to avoid unserved energy.[11]

[10] The approach to identifying SSEs is detailed in **Error! Reference source not found.**. SSEs were identified using Market Advisories issued by AEMO between October 2023 and August 2025 (including the 25 August 2025 event). Market Advisories relating to energy and ancillary services shortfalls were considered to represent SSEs. Additionally, instances in which manual (non-network) constraints were applied (with no Market Advisory issued) were also considered to be SSEs.

[11] The future-state modelling was conducted by AEMO. Details of AEMO's modelling approach is provided in Appendix B.2.

The methodology used to conduct this analysis, and the detailed results are provided Appendix D.

Current State Analysis – Summary

26 SSEs were identified between October 2023 and August 2025:

- 20 events occurred during summer months (December to March).
- 22 out of the 26 events occurred on Business Days.
- 23 events were triggered by extreme temperatures:
    - 20 of these events occurred during summer months
    - Low wind availability can also occur in summer, which can exacerbate system conditions during hot days.
- Most events were 3 to 4 hours in duration. Three longer duration events (6 to 10 hours) were also observed, all of which occurred during the summer months.
- 19 events started before 16:30 (the first ESROI for new ESRs assigned Capacity Credits for the 2027-28 Capacity Year). Of these, 9 started at 16:00, and the remaining 10 started before 16:00.
    - 4 of the remaining 10 events started before 16:00 when the system had less than 50 MW of ESR capacity credits available.
    - 6 of the remaining 10 events occurred before 16:00, when there was significant ESR capacity on the system.
        (i) These events occurred after the FCESS Cost Review ESM Rule Changes.
- 25 out of the 26 events ended by or before 21:00 (within the Peak ESROIs for business days for both incumbent and new ESRs).

The six SSEs that occurred after November 2024, following the FCESS Cost Review amendments to the ESM Rules, are more likely to be genuine Low Operating Reserve conditions rather than false positives arising from Market Participants not updating their offers to place capacity “in service.”

- All six events occurred during the summer months (December to March).

The six events that occurred before 16:30 (and after the FCESS Cost Review ESM Rule changes) were further analysed to assess whether ESRs were required outside their ESROIs to avoid unserved energy.

The table below summarises the start and end-times of the six events along with the time that peak demand occurred on each date and the time at which the capacity margin was the tightest.

Table 8: Analysis of six SSEs commencing prior to 16:30

SSE date	Start	End	Peak demand time	Highest stress time
10/12/2024	15:00	20:30	18:35	18:35
11/12/2024	15:00	20:30	18:35	18:35
20/01/2025	15:00	20:30	18:35	18:35
21/01/2025	11:25	20:30	18:00	17:50
23/01/2025	13:00	20:30	18:45	18:50
6/03/2025	15:00	22:00	18:00	18:20

Source: AEMO analysis

The table above indicates that both peak demand and the period of highest stress time occurred just prior to the Mid-Peak ESROI. As ESRs are duration limited, dispatching them earlier in the day would have reduced their available charge, leaving insufficient capacity when it was needed most. Accordingly, the Peak ESROIs were aligned with the timing of the SSEs identified above.

Future State Analysis

AEMO has modelled ESR dispatch for the 2026-27 to 2030-31 Capacity Years. The model and results are described in Appendix D.2.

In brief, AEMO conducted Monte Carlo modelling using nine reference weather years (or load shapes) and 20 forced outage scenarios per Trading Interval. This means that each Trading Interval in a Capacity Year produces 180 distinct outcomes based on variations in weather and load patterns, as well as randomised outages.

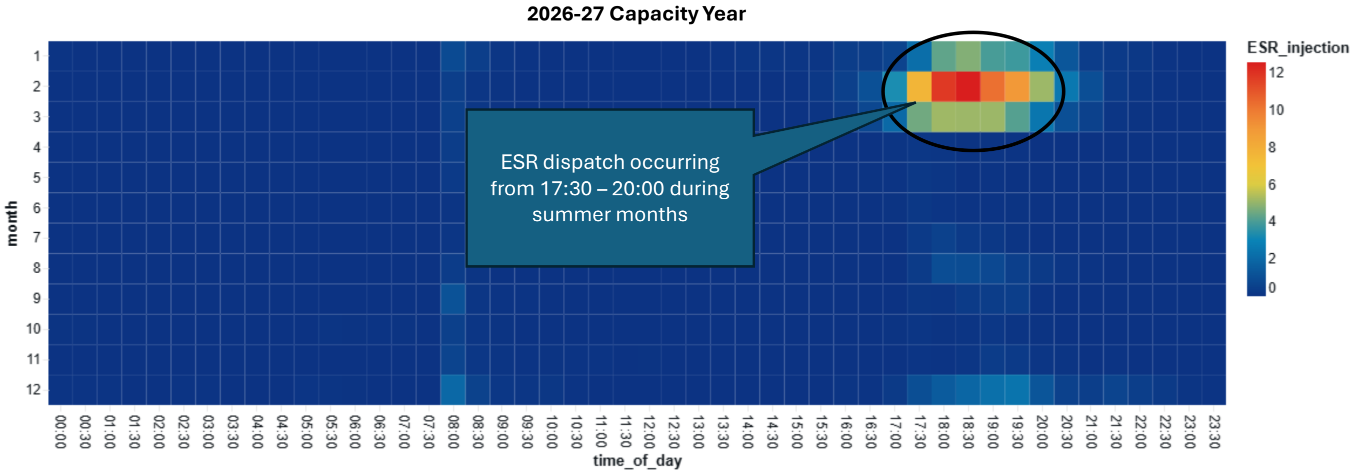
The modelling assumes that ESRs are at the top of the merit order stack (but behind DSPs), such that ESRs are dispatched to avoid unserved energy. In other words, Trading Intervals in which ESRs are dispatched would otherwise have resulted in unserved energy.

For later Capacity Years, the model assumed capacity stays flat while demand keeps rising, which artificially creates large amounts of unserved energy. This reflects a modelling limitation rather than a plausible market outcome. In practice, it is likely that the RCM would drive new capacity, so this outcome is not realistic.

The heat maps below illustrate the results for the 2026-27, 2028-29 and 2030-31 Capacity Years. The calendar month is shown on the y-axis, while Trading Intervals are shown on the x-axis. Shaded cells indicate the degree of ESR dispatch (measured in average MW injection) for each combination of calendar month and time of day.

With nine reference years and 20 iterations, each trading interval is simulated 180 times. Consequently, light blue shading in the charts reflects only a very small number of occurrences and is not sufficient to indicate a credible trend.

Figure 5: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2026-27

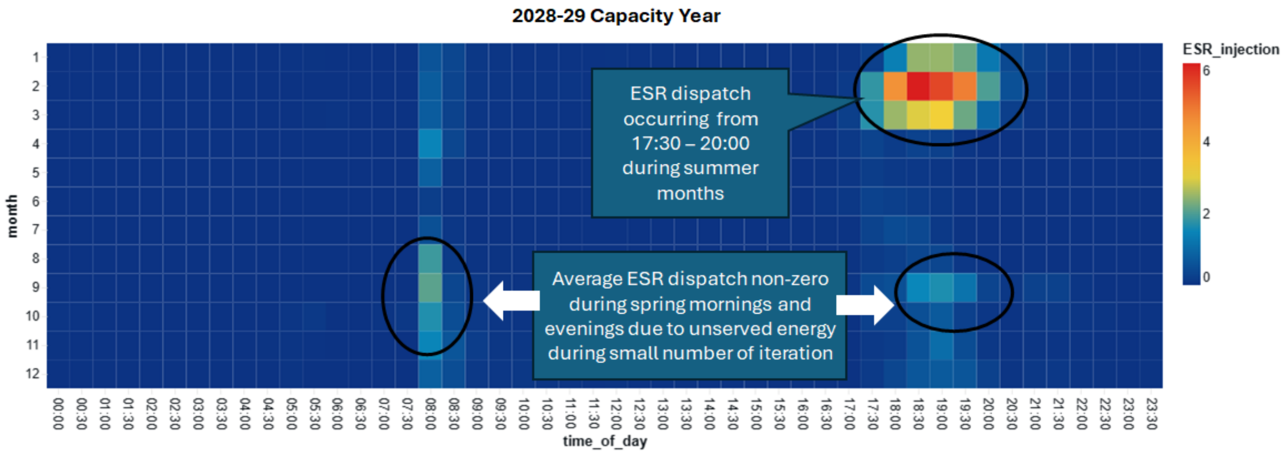


Source: AEMO modelling

As ESRs are treated as a last resort in the model, the average MW quantity of ESR dispatched represents the volume required to avoid unserved energy after all other Facilities (except DSPs) have been dispatched.

The 2026-27 results indicate that ESR dispatch to avoid unserved energy is aligned with the ESROIs for both existing and new ESRs, with discharge occurring between 17:30 and 20:00 during the January to March period.

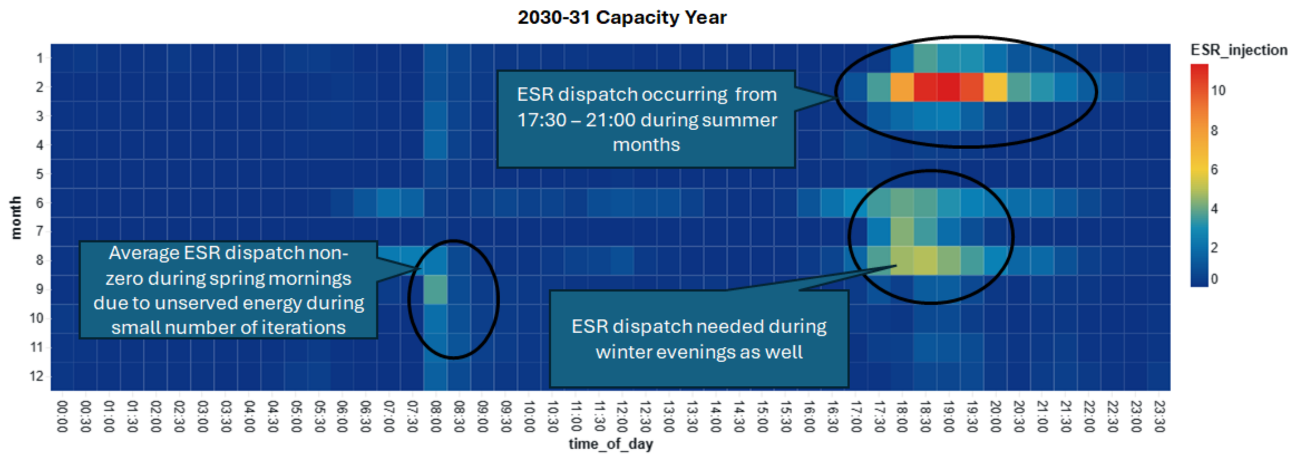
Figure 6: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2028-29



Source: AEMO modelling

In 2028-29, ESR dispatch to avoid unserved energy continues to align with ESROIs during the summer months. Some ESR dispatch is also forecasted during spring mornings and evenings. However, these very small average quantities are driven by unserved energy occurring in only a few Monte Carlo iterations. For example, if one of the 180 iterations required 300 MW of ESR injection in a Trading Interval to avoid unserved energy, this would appear in the results as an average of 1.667 MW. Accordingly, these low levels of forecasted ESR dispatch do indicate a statistically meaningful trend.

Figure 7: Forecast average ESR dispatch by month and Trading Interval for Capacity Year 2030-31



Source: AEMO modelling

By 2030-31, ESR dispatch to avoid unserved energy occurs during both summer and winter evenings, starting at 17:30. This is consistent with the retirement of existing coal facilities, resulting in ESRs filling the gap during winter evening peaks.

A small amount of ESR dispatch is forecasted during spring mornings, but these results are based on a limited number of iterations and therefore do not represent a meaningful trend.

Conclusions

The Technical Analysis yielded the following insights:

- Historically, ESRs have been required during their Peak ESROIs. While some SSEs have started before the Peak ESROIs, ESRs were best reserved for discharge during their ESROIs due to the timing of peak demand and periods of highest system stress (see Table 8).
- In the forecast period, ESRs will continue to be required during their ESROIs (17:30 to 21:00) in the summer months. As existing coal facilities retire, ESRs will also be increasingly required during winter evenings (17:30 to 20:30).
- There is insufficient evidence from the modelling to conclude that ESRs will also be required during the morning period.

The Technical Analysis, therefore, indicates that the existing approach to setting Peak ESROIs is fit for purpose and aligned with the SEO as:

- ESR duration and availability obligations are aligned with the periods in which ESR are required to avoid unserved energy, thereby satisfying the reliability limb of the SEO.
- The ADG ensures that the Peak ESRDR increases as CC1 capacity retires, thereby, increasing the number of contiguous intervals during which ESRs must be available. At the same time, the ESR Duration Requirement Uplift ensures that additional capacity is procured to account for grandfathered ESRs with lower Peak ESROD.
- The existing approach is transparent and predictable, as it is based on a known peak demand period.
- The alignment of ESROIs with system needs reduces the likelihood of AEMO needing to intervene to avoid unserved energy or procuring SC to meet demand during the summer peak demand periods.

Based on these findings, the Review outcome is to make no amendments to the existing approach for setting Peak ESROIs at this stage.

2.3. Capability Class 2 split for NAQ prioritisation

Capability classes are used as the first tie-break criterion (within the same step) of the NAQ method. That is, if the allocation of preliminary NAQ (within a step) results in the Peak Reserve Capacity Requirement being exceeded, AEMO must resolve the tie using the prescribed prioritisation order which prioritises the selection of CC1 facilities over CC3 facilities over CC2 facilities.

In this Review, an option was assessed to determine whether sub-classes should be created within CC2 for the purposes of resolving tie-breaks. The following prioritisation order for CC2 technologies was proposed:

- hybrid facilities are prioritised over ESR only facilities (to encourage greater entry of CC3 with firming capability);
- ESR only facilities are prioritised over DSPs (given the greater flexibility of ESR); and
- CC1 and CC3 facilities would still be prioritised over CC2.

Table 9: Proposed prioritisation order for Capability Class 2

Type	Description
Capability Class 2(a) – Hybrid	A Facility that includes Separately Certified Components that are over 50% Capability Class 2, with the remaining being: • Capability Class 1; or • Capability Class 3; or • A mix of Capability Class 1 and Capability Class 3.
Capability Class 2(b) –ESR only facilities	A Facility that only includes ESR and certified as ESR.
Capability Class 2(c) –DSPs	A Facility that is certified as DSP.

Conclusion

Information available to the Coordinator indicates that implementing the amended prioritisation order outlined above would not have changed previous NAQ outcomes. Accordingly, it is unclear whether the current NAQ prioritisation order for tie-breaking disincentivises hybrid entry.

Working Group members noted that, in the absence of a clearly identified problem, the expected material implementation costs of the proposal are unlikely to be justified by its benefits. However, some members expressed the view that DSPs should be prioritised above ESRs, as ESRs may be less effective in scenarios involving a shortfall in CC1 and CC3 capacity.

Given the associated costs and the absence of a demonstrated issue, the Coordinator has decided not to progress the proposal to create sub-classes within CC2. The Coordinator will revisit this matter if it emerges as a policy issue in the future.

2.4. Summary of items reviewed with no change proposed

It is proposed that:

- The Linearly Derated Method for assigning Certified Reserve Capacity for ESRs will be retained
- The current approach for determining Electric Storage Resource Obligation Intervals (ESROIs) will be retained.
- No changes will be introduced to tie-break different configurations of Capability Class 2 facilities within the Network Access Quantity (NAQ) prioritisation.

Consultation questions:

1. Do stakeholders disagree with any of the review outcomes outlined above? If yes, why?

3. Proposal 1 – Amend ESR Reserve Capacity Testing Performance measurement rules to account for ramping

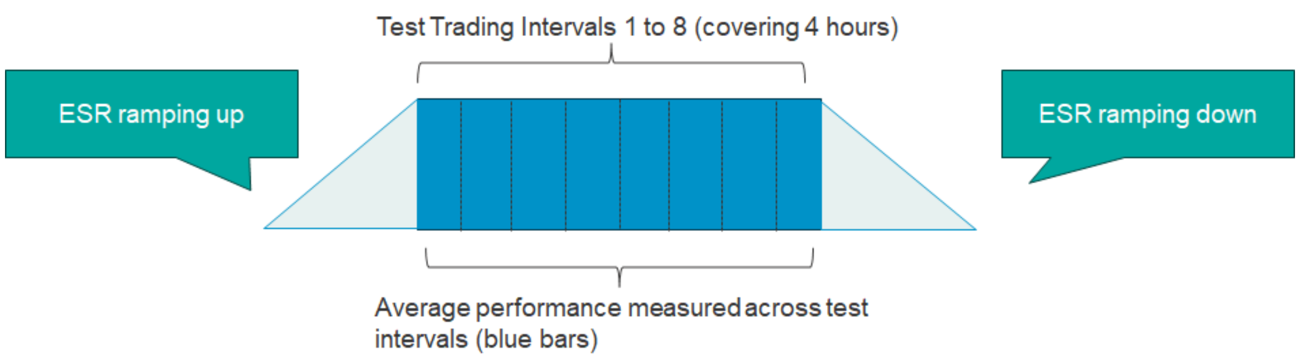
3.1. Issue with determining ESR Reserve Capacity test performance

During the Review, AEMO raised an issue with the approach to determining an ESR component's Reserve Capacity Test performance.

Clause 4.25.2E of the ESM Rules requires AEMO to assess the Reserve Capacity Test performance of an ESR as "*the average performance across its Peak Electric Storage Resource Obligation Duration based on the average performance across the Trading Intervals.*"

This clause results in a mismatch between how test performance is defined in the ESM Rules and the operational realities of testing an ESR. This is because an ESR consumes energy when ramping to its Required Level and again when ramping down to its minimum discharge depth. This is illustrated in Figure 8.

Figure 8: Example of ESR ramping up to RCOQ for Reserve Capacity Test and then ramping down



This means that, unless the ESR is oversized (i.e. able to deliver more than its RCOQ), performance during the test intervals will be lower than the ESR's average Required Level.

However, the area under the trapezium more accurately reflects the ESR's performance capability, as it measures the total energy delivered and therefore its maximum discharge capability.

It is proposed to address this issue by amending clause 4.25.2E(a) to allow AEMO to assess ESR test performance by measuring the total energy delivered (i.e. the area under the trapezium).

The Working Group and MAC supported the proposal, as it reduces the need for ESRS to be oversized solely to pass a testing requirement that does not accurately reflect their capability.

3.2. Proposal summary

The Coordinator proposes to amend the ESM Rules (including clause 4.25.2E(a)) to revise the method in which AEMO determines the Reserve Capacity Test performance of ESRs, so that total output (including ramping) is measured and ESRs are not required to be oversized to pass testing requirements.

Proposal 1

Amend the ESM Rules (including clause 4.22.2E(a)) to allow AEMO to measure the total energy delivered for assessing ESR performance during Reserve Capacity Tests.

Consultation questions:

1. Do stakeholders support amending the ESM Rules to account for ESR ramping during Reserve Capacity Tests?

4. Proposal 2 – Align DSP Availability Obligations to power system needs

Demand-side response is incorporated into the WEM via the concept of DSPs. DSPs are a specific Facility Class comprising one or more Non-Dispatchable Loads (located at the same Transmission Node Identifier (TNI)) with the capability to reduce their withdrawal or increase their injection in response to an instruction from AEMO.

DSPs inherently have lower availability than CC1, CC3 facilities, as well as ESR capacity, as service provision depends on the flexibility of the associated loads. To account for these availability limitations, the ESM Rules include specific provisions prescribing when DSPs must be available, as follows:

- At the time of publication, DSPs must be available from 8:00am to 8:00pm on Business Days (clause 4.10.1(f)(vi)).
    - ESM Amending Rules to change the DSP availability obligation intervals to 6:00am to 10:00am and 2:00pm to 10:00pm have been made and will take effect upon publication of a notice in the Government Gazette.
- The maximum number of Trading Intervals during which a DSP must be available within a Trading Day must be at least 24 (i.e. 12 hours) (clause 4.10.1(iii)). This means that DSPs must be available continuously for a maximum of 12 hours (currently, within the 8:00am to 8:00pm window) if required.[12]
- DSPs must be available for a specified number of Trading Intervals within a Capacity Year. This is referred to as the Peak Demand Side Programme Dispatch Requirement. The requirement over the years is shown in the table below.

Table 10: Peak DSP Dispatch Requirement for Capacity Years 2025-26, 2026-27 and 2027-28

Capacity year	Peak DSP Dispatch Requirement (hours)	Peak DSP Dispatch Requirement (# Trading Intervals)
2025/26	200	400
2026/27	50	100
2027/28	23.75	47.5

[12] This requirement is analogous to CC1 technologies having a 14 hour fuel-requirement to ensure they can generate continuously during CC1 Availability Assessment Intervals (8am to 10pm)

4.1. Availability obligations in other jurisdictions

Five jurisdictions were reviewed to compare obligations placed on demand-side resources. The review is summarised briefly below.

Table 11: Capacity availability obligations in different jurisdictions (indicates residential aggregations can participate)*

<table>
<tr><th>Market</th><th>Participation Mode</th><th>Capacity allocation approach</th></tr>
<tr><td>Great Britain*</td><td>• Balancing Market - Demand Flexibility Services
• Capacity Market
• Ancillary services</td><td>Participant nominates capacity which is derated by availability factor (79% in 2024 auction).[13]</td></tr>
<tr><td>PJM* (USA)</td><td rowspan="3">• Energy market – as dispatchable load
• Capacity market – loads can provide only capacity like WA DSPs[14]
• Ancillary Services</td><td>ELCC</td></tr>
<tr><td>ISO-NE* (USA)</td><td>ELCC (Marginal Reliability Impact)</td></tr>
<tr><td>Ireland (Ireland and Northern Ireland)</td><td>ELCC (with Least Worst Regrets)</td></tr>
<tr><td>Ontario (Canada)</td><td>• Capacity Market
• Industrial Conservation Initiative</td><td>Participant nominates capacity</td></tr>
</table>

The capacity markets reviewed all have a DSP type construct to enable demand-side participation without requiring participants to provide energy or meet a dispatch target.

In Great Britain, PJM, ISO-NE and Ireland, there are multiple modes of participation in the capacity market, depending on the capability of the loads:

- loads that can meet dispatch targets can participate in the energy, capacity and ancillary services markets.
- otherwise, loads only participate in the capacity market with less onerous dispatch obligations.

In terms of duration and availability obligations, markets that have adopted the ELCC or EFC approach tend to require year around availability, with no specified upper limit on

[13] The British regulator (OFGEM) is considering whether demand side should be incorporated into the EFC approach used to allocate capacity to ESRs and intermittent resources.

[14] Loads do not curtail - they reduce consumption through energy efficiency measures - hence no explicit curtail duration or notification requirements.

duration. However, some markets provide tailored availability windows for loads that cannot commit to year-round availability. For example:

- Ontario's approach is the closest to that of WA, in that participants nominate their available capacity and are required to be available within specific time windows. Summer resources must be available for nine hours and winter resources for five hours within defined availability windows. However, in practice, loads are typically activated for around four hours.
- ISO-NE allows some loads to participate on a seasonal basis within specified windows. Alternatively, loads can demonstrate demand reduction through energy efficiency measures during peak summer and winter periods.

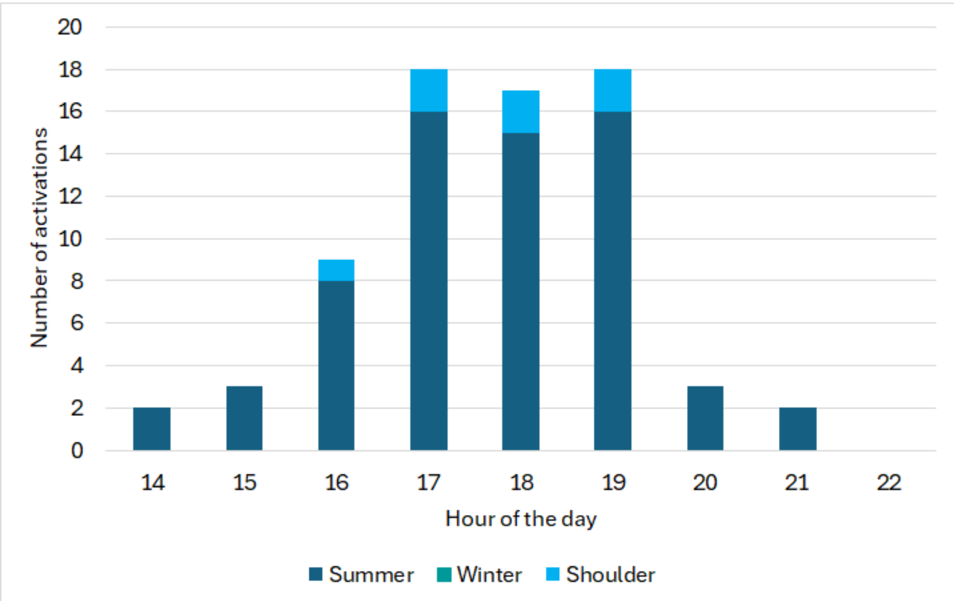
4.2. Technical analysis – DSP availability assessment

DSPs are dispatched as last-resort resources to avoid unserved energy. DSP activation events between October 2023 and February 2025 were analysed to assess the timing and duration of DSP dispatch events.

During this period, there were a total of 22 activation events, three of which include the activation of the Enel X's NCESS contract for Reliability Services.[15]

The graph below summarises the number of activations by hour of the day between October 2023 and February 2025. It counts whether DSPs were activated during a given hour. For example, of the 22 events, six spanned the 17:00 to 18:00 (hour 17).

Figure 9: DSP activation events by hour of day (October 2023 - February 2025)



Source: [AEMO Market Data Site]()

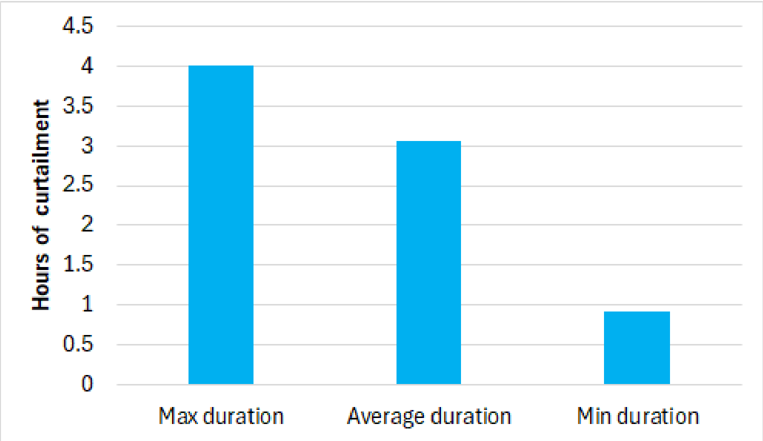
[15]The 22 activations pertain to four contracts: the Griffin DSP and three Enel X NCESS Reliability Service contracts.

Of the 22 events, 20 occurred during the summer months and two occurred during the shoulder months. The shoulder activations relate to two DSP dispatch events on 22 November 2023 and 23 November 2023. Historically, no DSP activations have occurred during winter months.

Most events occurred between 4:00pm and 8:00pm. However, three dispatch events occurred after 8:00pm, all of which involved the dispatch of Enel X's NCESS Reliability Service contract.

Figure 10 summarises the maximum, average, and minimum duration of the DSP dispatch events described above. Dispatch events lasted an average of three hours, with a maximum duration of four hours and a minimum duration of one hour (all significantly below the 12-hour requirement).

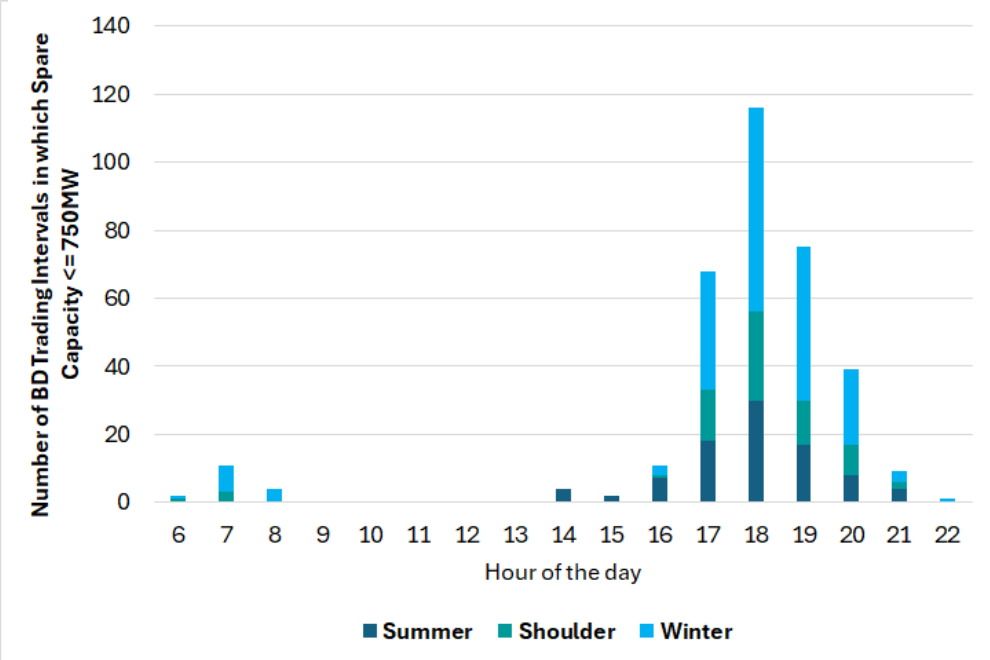
Figure 10: Duration of DSP dispatch events



Source: AEMO Market Data Site

As DSPs are dispatched when the capacity margin is low, the seasonal and time-of-day distribution of spare capacity was also examined. In the graph below, spare capacity is defined in accordance with clause 4.26.1(e) of the ESM Rules (as an input to the Dynamic Refund Factor (DRF) calculation). The bars show the number of Trading Intervals in which spare capacity fell below 750 MW between 1 January 2021 and 11 October 2025. A threshold of 750 MW represents the point at which the DRF cap binds and indicates a level at which a Low Operating Reserve declaration may be triggered.

Figure 11: Frequency of spare capacity falling below 750MW by hour of the day (January 2021 - October 2025)



Source: Analysis of AEMO provided data

The vast majority of low spare capacity intervals have occurred between 5:00pm and 9:00pm. A small number such intervals are also observed between 9:00pm and 10:00pm.

A limited number of low spare capacity intervals occur between 6:00am to 9:00am. However, the spare capacity calculation does not include ESR capacity during these periods (as they fall outside the ESROIs), meaning the actual capacity margin is likely higher.

The analysis shows that:

- DSP dispatch could credibly be required between 8:00pm and 10:00pm. Hence, the existing 8:00pm cut-off is no longer appropriate.
- Historically, there have been no DSP dispatch events prior to 2:00pm.
    - While there have been no DSP dispatch events or low spare capacity intervals between 9:00am and 2:00pm, one Low Reserve Condition was declared on 21 January 2025, commencing at 11:25am.
- While low spare capacity intervals have occurred during winter mornings, their prevalence is low. Further, ESRs are incentivised to discharge during such periods, as energy prices are likely to be high.

4.3. DSP availability obligation intervals - options assessed

Four options were assessed against the SEO:

Table 12: DSP availability obligation intervals options assessed against the SEO

Option	Description
Option 1: Split availability window (Tranche 8)	DSPs must be available as follows: • Available between 6:00am to 10:00am (4 hours) • Available between 2:00pm to 10:00pm (8 hours) • BTM Storage in DSPs have four hours to charge if activated in the morning (10:00am to 2:00pm)
Option 2: Split availability window (derated version)	DSPs must be available as follows: • Available between 8:00am to 12:00pm (4 hours) • Available between 2:00pm to 10:00pm (8 hours) • BTM Storage in DSPs have two hours to charge if activated in the morning (12:00pm to 2:00pm) Market Participants can choose to participate in both obligation windows or only the evening obligation (2:00pm to 10:00pm) availability window. Participants choosing the evening window receive a derated (8/12) Reserve Capacity Price.
Option 3: Include DSPs in ESRDR calculation	DSPs rolled into ESRDR calculation: • AEMO calculates availability requirement based on which intervals have insufficient non-CC2 capacity to meet demand • No grandfathering for DSPs • DSPs must meet Peak DSP Dispatch Requirement
Option 4: DSP availability obligation intervals based on Peak DSP dispatch requirement	DSP availability obligation intervals determined annually by comparing the reference demand profile developed for CC3 ELCC calculations to the 50% POE/median growth load profile and identifying which Trading Intervals (or periods of time) DSPs should be available for

Option 2 was considered following feedback from the MAC and Working Group that the period between the morning and evening obligation windows provides insufficient time for large, single loads to restart their operations. Consequently, if these loads were dispatched in the morning, they would need to shut down for up to 16 hours to meet the requirement.

4.4. Conclusion

Options 3 and 4 would significantly dilute the reliability value of DSPs to customers, as they would result in materially lower availability obligations than the existing 12-hour requirement.

- Under Option 3, new ESRs and DSPs would be subject to the same availability requirement during a Business Day. However, while ESRs must be available on all Trading Days throughout the Capacity Year, DSPs would only be required to meet the Peak DSP Dispatch Requirement.
- Under Option 4, AEMO would model the Trading Intervals in which demand in the reference demand profile (used in CC3 ELCC calculations) is likely to exceed peak demand under a 50% POE peak/median growth scenario (adjusted for DSP dispatch and capacity). This would enable AEMO to set specific windows during which DSPs would be required (e.g. Hot Season from 3:00pm to 9:00pm). As noted above, this would likely result in materially lower availability obligations than the current 12-hour requirement and introduce year-on-year volatility for DSP participants
- Additionally, both approaches would involve moderate to high implementation complexity.

Options 1 and 2 perform similarly against the SEO. Option 1 was implemented as part of the ESM Amending (Tranche 8) Rules and will commence on a date specified by the Minister in a notice published in the Government Gazette. While Option 1 performs better than Options 3 and 4 in terms of customer value (as it retains the 12-hour requirement), several issues have been identified:

- AEMO has advised that, as the morning window obligation (6:00am to 10:00am) spans two Trading Days, this is likely to increase implementation complexity and cost;
- Working Group members noted that BTM storage is likely to be depleted at the start of the morning window obligation (having discharged the previous evening) and would therefore be unable to participate; and
- large loads have load restart limitations, meaning they may be unable to operate between the two windows, effectively requiring them to be offline for 14 to 16 hours.

Option 2 addresses the issues with Option 1 by:

- shifting the morning obligation window to 8:00am to 12:00pm so that it does not span two Trading Days, thereby reducing implementation complexity and cost;
- allowing DSP participants to choose whether to participate in both obligation windows or only in the evening obligation window. This enables the participation of large loads with restart limitations; and
- DSP participants that opt to participate only in the evening obligation window will receive a Reserve Capacity Price that is derated by 8/12 of the full price, reflecting the

lower availability requirements. This derated price will flow through to the DSP's Reserve Capacity Security, reducing the security obligations proportionately.[16]

MAC and Working Group members expressed support for Option 2 on the basis that it:

- supports the participation of large, single loads within the DSP framework through the availability of a derated price; and
- minimises implementation costs by avoiding the need for availability windows that span two Trading Days.

MAC members have expressed concern that the morning window obligation does not include the period before 8:00am, as reliability shortfalls are more likely to occur during this time (relative to after 8:00am), due to lower rooftop solar output and the possibility that ESRs may not be fully charged. It is noted that there are currently no obligations for ESRs to be available before 8:00am.

As noted above, AEMO faces significant complexity and costs in implementing a morning window obligation that spans two Trading Days. Specifically, implementing a window that overlaps Trading Days would require substantial changes to AEMO's systems and processes to accommodate any split of the DSP availability hours into distinct windows. Allowing a window to cross the Trading Day boundary would break core system assumptions, resulting in increased implementation and ongoing maintenance complexity, as well as higher costs.

It is acknowledged that system stress is more likely to manifest before 8:00am (versus after 8:00am), but notes that no such events have been observed historically. The only SSE identified in the Technical Analysis that commenced before 12:00pm began at 11:25am, which falls within the 8:00am to 12:00pm window proposed under Option 2.

To maintain the 12-hour requirement, an alternative to Option 2 would be to shift the morning window obligation to 4:00am to 8:00am. Additionally, any proposal to shorten the morning window obligation would need to be offset by an equivalent extension to the evening window obligation, which may introduce different challenges.

[16] An alternative option to derate Capacity Credits was not pursued due to implementation complexities arising from the mismatch between the quantity of response needed from the DSP and the Capacity Credits assigned.

Table 13: Summary of evaluation of DSP availability obligation intervals against the SEO

	Option 1: Split window (Tranche 8)	Option 2: Split window with derating options	Option 3: Include DSPs in ESROD	Option 4: DSP availability linked to Peak DSP Dispatch Requirement
Overall performance	Most criteria met substantially	Most criteria met substantially	Some criteria met substantially/ most partially	Some criteria met partially
Availability obligations aligned with power system needs	Fully met	Met substantially	Met substantially	Not met
Availability obligations provide value for money	Fully met	Fully met	Met partially	Not met
Availability obligations enable value to be extracted from BTM batteries	Met substantially	Fully met	Fully met	Fully met
Approach is flexible enough to change as power system needs evolve and change	Met substantially	Met Partially	Met substantially	Met Partially
Approach is transparent and predictable	Fully met	Fully met	Met Partially	Met Partially
Cost and complexity of implementation is reasonable	Met Partially	Fully met	Met Partially	Met Partially

The detailed evaluation against the SEO is provided in Appendix E.

The proposed review outcome is to implement Option 2, as it performed best when assessed against the SEO.

Stakeholder feedback is sought on whether there is justification for the morning window obligation in Option 2 to be shifted to 4:00am to 8:00am (instead of 8:00am to 12:00pm) such that:

- the period prior to 8:00am is captured;
- the overall 12-hour availability obligation is maintained; and
- implementation complexity is reduced, as the morning window obligation would not span two Trading Days.

Consequential amendments

To facilitate DSP participation under Option 2 and simplify the certification process, the following ESM Rule amendments are proposed:

- DSPs will be allowed to associate different loads for the morning and evening windows. This will enable DSPs to form diverse portfolios of loads to meet availability obligations in both obligation windows.
- DSPs must associate loads at least three weeks prior to their proposed effective date. This is to ensure that a DSP cannot game the Relevant Demand methodology, which

uses the most recent 10 Business Days or 5 non-Business Days (in which there were no DSP dispatch events) to calculate the baseline.

    - A DSP is expected to nominate its loads and, if it needs to make any changes, it may submit an updated nomination at any time before the deadline.

- DSPs that have selected one or both windows will be required to undergo Reserve Capacity Tests assessing their performance in the relevant windows.
    - For example, if a DSP selects the 8:00am to 12:00pm window, its Reserve Capacity Test should take place in that window. Similarly, if the DSP selects both windows, Reserve Capacity Tests should be conducted in both the morning and evening window.
    - Section 4.25 will require amendments to reflect this.
- DSPs will not be allowed to offer availability outside of the standard availability windows prescribed in the ESM Rules, to simplify the certification process.
    - AEMO has raised that the ESM Rules currently allow DSPs to offer availability outside the windows specified in section 4.10 of the ESM Rules. However, to date, no Market Participant has offered availability outside the required period. AEMO advised that if a participant were to offer availability outside the required window, this would add complexity and cost to the certification process.
    - To simplify the certification process, the Coordinator proposes an amendment to restrict DSP availability to the windows defined in the ESM Rules.
- Some concerns were raised by Working Group members about treating the Capacity Credits with the Derated Price as equivalent to other Capacity Credits due to them offering reduced reliability. Therefore, it is proposed that Capacity Credits allocated to DSPs who choose only the 2:00pm to 10:00pm window obligation must be traded through AEMO.
    - This proposal reflects the fact that these DSPs provide a reduced level of reliability. Therefore, these Capacity Credits should not be treated as equivalent to other Capacity Credits, particularly regarding a participant's ability to bilaterally trade them or use them to reduce Individual Reserve Capacity Requirement (IRCR) exposure.

4.5. Proposal summary

The proposed Review outcome is to amend the ESM Rules to change the DSP availability obligation intervals in accordance with Option 2, to better align these with system reliability needs while minimising implementation costs.

However, to address MAC concerns about capturing the period before 8:00am, the Coordinator also seeks feedback on whether there is justification for Option 2 to be varied so that the morning window obligation is 4:00am to 8:00am (instead of 8:00am to 12:00pm).

Further proposed Review outcomes include amending the ESM Rules to facilitate DSP participation by:

- allowing DSPs the option to participate only in the evening window, to facilitate participation by large loads with restart limitations that may not be able to comply with split-window arrangements.
    - this would help maintain system reliability during periods of highest system stress, while reducing costs to consumers to reflect the DSP's reduced reliability contribution.
    - introducing corresponding ESM Rule amendments to reflect that DSP participants that opt for the evening-only window are not providing an equivalent service to other Capacity Credit holders.
- allowing DSP aggregators to associate different loads to the two sets of availability obligation intervals (for every Trading Day) to allow for greater portfolio flexibility.
- requiring Reserve Capacity Testing for DSPs to assess their performance within the applicable window.
- simplifying the certification process by specifying that DSPs are only required to be available during the availability obligation intervals specified in the ESM Rules.

Proposal 2a

The proposed Review outcome is that the ESM Rules are amended to change DSP availability obligation intervals to 8:00am to 12:00pm (noon) and 2:00pm to 10:00pm on all Business Days.

However, stakeholder feedback will be sought on whether the morning window obligation should be change to 4:00am to 8:00am.

Proposal 2b

The proposed Review outcome is that the ESM Rules are amended to:

- allow a DSP participant to choose only the 2:00pm to 10:00pm obligation window and receive the Reserve Capacity Price derated by 8/12 to reflect the reduced reliability availability; and
- require any DSP participant that chooses only the 2:00pm to 10:00pm obligation window must trade its Capacity Credits through AEMO.

Proposal 2c

The proposed Review outcome is that the ESM Rules are amended to:

- remove the option for DSPs to offer availability outside of the availability obligation intervals specified in the ESM Rules;
- allow a DSP to associate different loads within its portfolio to the morning and the evening sets of obligation intervals (for every Trading Day) at least 3 weeks before the associated loads effective date; and
- empower AEMO to conduct Reserve Capacity Tests in the availability obligation windows selected by the DSP.

Consultation questions:

1. Do stakeholders support the proposals for the changes associated with the DSP availability obligation intervals outlined above?
2. Is there justification for the 4:00am to 8:00am (rather than 8:00am to 12:00pm (noon)) morning availability obligation and if yes, what is the justification?

5. Proposal 3 – Return of DSP Reserve Capacity Security if a large load ceases

5.1. The policy issue

During the Review, Working Group members raised an issue regarding circumstances in which a large (equal to or greater than 5 MW) Associated Load ceases operations or enters extended care and maintenance during the Capacity Year in which the related DSP has Reserve Capacity obligations.

Under the ESM Rules, the DSP would be required to associate another load at the same TNI that can provide an equivalent response. However, securing a large load that is both capable of and willing to curtail consumption at short notice at a specific TNI can be challenging and is unlikely to be successful.

Two options were considered to address this concern.

5.2. Options assessed

Option 1: Allow the DSP to recruit and associate another load at a TNI that AEMO has deemed to be unconstrained under clause 4.15.16A

Clause 4.15.16A requires AEMO to publish a list of unconstrained TNIs at which DSPs with aggregated loads (certified without a specific location under clause 4.10.1B) may locate their Associated Loads.

AEMO uses the NAQ model from the previous Reserve Capacity Cycle to identify TNIs with sufficient spare capacity to accommodate DSPs without adversely affecting the ability of other Facilities (including Energy Producing Systems) to be dispatched.

AEMO advised that, if DSPs were allowed to associate additional loads (5 MW or higher) at these unconstrained locations, then the NAQ originally assigned to those loads during certification may not accurately reflect their contribution to meeting peak demand requirements at the new location. This is because NAQ is location-specific, and a load may receive different NAQ values depending on its location.

Working Group and MAC members also expressed concern about the potential impacts on NAQ allocations for other Market Participants.

Given the risk of adversely affecting other facilities, this option was not progressed.

Option 2: Return the Reserve Capacity Security as no replacement capacity is needed

A large load that ceases operations permanently or for an extended period (e.g., entering care and maintenance) will reduce unscheduled operational demand, as it no longer consumes electricity from the SWIS.

Given this reduction in demand, if a large Associated Load were to cease operations for an entire Capacity Year, AEMO would not be required to procure replacement capacity through the Supplementary Capacity mechanism. Accordingly, where a large load ceases operations due to factors outside the DSP participant's control, an application to AEMO to cancel the associated Capacity Credits would not be expected to adversely affect system reliability.

An alternative option, therefore, is for the DSP participant to request a reduction in its Capacity Credits, with a corresponding portion of its Reserve Capacity Security refunded, as the security would no longer be required to cover the cost of replacement capacity.

This option is relatively simple to implement and does not have adverse impacts on system reliability provided it has the following conditions in place:

- The affected DSP would be required to notify AEMO of the cessation of its Associated Load no later than 1 April in Year 3 of the relevant Reserve Capacity Cycle. This would ensure that AEMO can model the impact of the load cessation on the Reserve Capacity Requirement for the upcoming Capacity Year;
- AEMO would need to be satisfied that the cessation of operations is bona fide and will persist for the duration of the Capacity Year. Appropriate evidence would be required to support this assessment, with the evidentiary requirements set out in the relevant Reserve Capacity Security WEM Procedure;
- Associated Loads that declare cessation of operations would be ineligible to participate in Supplementary Capacity procurement for the relevant Capacity Year; and
- The policy would apply only to Associated Loads of 5 MW or greater (i.e. DSPs not subject to clause 4.10.1B), as loads must be of a material size to influence the Reserve Capacity Requirement.

MAC and Working Group members expressed concerns about treating DSPs differently from other capacity providers that are required to provide Reserve Capacity Security and are similarly subject to external factors that may affect their viability. However, when new supply-side capacity exits or fails to commence operations before the relevant Capacity Year, it results in an undersupply. Conversely, when a large load that is a DSP ceases operations before the relevant Capacity Year, it is likely to result in an oversupply.

AEMO cannot procure additional capacity without a justifiable reason. Where a new supply-side facility exits before the relevant Capacity Year, resulting in a market undersupply, AEMO would likely use the Reserve Capacity Security to procure replacement capacity and maintain system reliability.

By contrast, where a load exits, AEMO would only procure replacement capacity if the reduction in demand does not materially reduce the Reserve Capacity Requirement. A strict threshold (greater than 5 MW) is therefore required to ensure that Reserve Capacity Security is only returned where the associated reduction in demand is sufficiently large that the capacity is no longer needed to support system reliability.

The proposed Review outcome is to progress this option, subject to the conditions outlined above.

5.3. Proposal summary

Due to the NAQ implications for other Market Participants, the option for DSPs to associate a load of 5 MW or greater at another unconstrained TNI will not be progressed.

The proposed Review outcome is to allow a DSP participant to have its Capacity Credits reduced, with a corresponding portion its Reserve Capacity Security to be refunded, where sufficient evidence is provided to AEMO that an Associate Load greater than 5 MW will cease operations for the relevant Capacity Year.

For avoidance of doubt, this policy will not apply to DSPs certified under clause 4.10.1B.

This proposal would:

- reduce the risk that a DSP provider may be disincentivised from participating in the RCM due to factors outside its control causing an Associated Load to cease operations; and
- account for any reduction in the Reserve Capacity Requirement arising from a DSP Associated Load exiting the system prior to a Capacity Year.

This proposal should be progressed, subject to appropriate conditions being applied.

Proposal 3

The proposed Review outcome is to amend the ESM Rules to allow a DSP participant (whose Facility was <u>not</u> certified under clause 4.10.1B) to have its Capacity Credits reduced and a corresponding portion of its Reserve Capacity Security returned if:

- an Associated Load greater than 5 MW ceases operations permanently or for the entirety of a Capacity Year in which the relevant DSP has Reserve Capacity obligations;
- the DSP participant notifies AEMO no later than 1 April in Year 3 of the Reserve Capacity Cycle, so that the impact of the load exit on system demand can be factored into the upcoming ESOO; and
- the relevant participant provides sufficient evidence, to be specified in the relevant WEM Procedure, that the Associated Load has ceased operations or will be offline during the relevant Capacity Year.

The ESM Rules are also proposed to be amended to prevent the Associate Load that ceased operations permanently, or on an extended basis, from participating in Supplementary Capacity for the upcoming Capacity Year.

Consultation questions:

1. Do stakeholders support the proposals to allow a DSP participant to request a reduction in its Capacity Credits and a corresponding portion of its Reserve Capacity Security returned under the above conditions?

6. Proposal 4 – Introduce State-of-Charge obligations to apply during Low Reserve Conditions

One of the issues examined by the Review was whether the RCM provides adequate incentives for an ESR to be sufficiently charged to meet the Peak RCOQs.

Chapter 2.2 of this paper sets out the Technical Analysis conducted to determine the characteristics of SSEs and when ESRs are most likely to be needed to avoid unserved energy.

The Current-State Technical Analysis also reviewed ESR charge levels for a small sample of five SSEs, in which large ESR Facilities entered their ESROIs with low SOC.

These five SSEs represent periods after the implementation of the FCESS Cost Amending ESM Rules in November 2024, which addressed previous market effectiveness problems.[17]

Table 14: SOC levels of selected ESR Facilities entering their ESROIs on SSE days

#	SSE Date	SSE Start Time	SSE End Time	ESR Charge Level at SSE start	ESR Charge Level at ESROI start	ESROI Start
1	13/01/2024	16:00	20:00	KWINANA_ESR1: 35%	KWINANA_ESR1: 50%	16:30
2	10/12/2024	15:00	20:30	KWINANA_ESR1: 42%	KWINANA_ESR1: 62%	16:30
3	23/01/2025	13:00	20:30	COLLIE_ESR1: 44%	COLLIE_ESR1: 64%	17:30
4	25/08/2025	17:45	23:40	COLLIE_ESR1: 17%	COLLIE_ESR1: 22%	17:30
5	11/12/2024	15:00	20:30	KWINANA_ESR1: 70%	KWINANA_ESR1: 32%	17:30

Source: SCADA Case Data

The charge/discharge profile of the above ESRs and the WEM energy prices during the 48 hours leading to the SSE, as well as the ESROIs on the relevant day, are illustrated in Appendix D.1.3.

[17] Wholesale Electricity Market Amendment (FCESS Cost Review) Rules 2024

Key observations include:

- Low SOC when entering SSEs or ESROIs coincide with high energy prices earlier in the day. High prices earlier in the day result in ESRs being dispatched and may prevent full recharging prior to the ESROIs.
    - For the 25 August 2025 Significant Incident, high prices were also observed, which likely contributed to the low SOC on the day.
- For all five SSEs analysed, confidential WEM refund data indicated that estimated revenue earned from discharging earlier in the day was greater than the refund paid during the ESROIs on the same day. As a result, ESRs experience a net gain after paying refunds during the ESROIs.
- As this behaviour is economically rational, it suggests that the refund mechanism may not provide a strong enough incentive for ESRs to enter their ESROIs with adequate charge levels.
    - Proposals to address the refund mechanism for ESRs are discussed in Chapter 7.
- It was also observed that dispatched FCESS quantities do not provide a clear explanation for the low ESR charge levels at the start of the SSE or the ESROIs, indicating that low charge levels do not appear to be related to FCESS dispatch.

It should be noted that the analysis identified only a small number of occurrences of this low SOC issue. However, while infrequent, such events create a PSSR risk when they occur. Therefore, it is proposed to introduce a SOC mandate within the Low Reserve Condition framework, enabling AEMO to issue a Lack of Reserve (LOR) SOC declaration that sets a mandatory charge level for the Peak Certified ESR fleet at the start of each ESROIs.

6.1. Proposed SOC Obligation Framework

The proposed Review outcome is to empower AEMO to mandate SOC for ESRs as follows:

- a SOC obligation will be included within the existing LOR framework;
- AEMO will be empowered to mandate SOC for the Peak Certified ESR fleet when it makes a LOR declaration;
- the SOC obligation will not require 100% SOC by default. Instead, the SOC required to maintain PSSR will be determined by AEMO based on prevailing system conditions and may be set at any level (e.g. 40% or 60%);
- the SOC level declared in the LOR will represent the minimum SOC level to be achieved by an ESR at the start of its ESROIs;
- the principles governing the SOC framework will be specified in the ESM Rules; and

- the ESM Rules will provide the heads of power for a WEM Procedure that sets out the details of how the SOC mandate will be operationalised.

MAC and Working Group members have expressed support for the LOR-SOC mandate but noted some concerns regarding how it interacts with FCESS and other requirements. These concerns are addressed through consequential amendments discuss later.

SOC Obligation Trigger

There are three types of LOR declarations that AEMO can currently make under the Low Reserve Condition framework (empowered by clause 3.17.11). These are summarised in Table 15.

Table 15: Description of LOR conditions

Type	Trigger conditions	Description

LOR1	Forecast Available Capacity is greater than:
	• the Forecast Operational Demand plus 70% of the Largest Supply Contingency,
	• but less than the Forecast Operational Demand plus
	  – 100% of the Largest Supply Contingency plus
	  – 70% of the Second Largest Supply Contingency
		Probability of load shedding low, but risk of ESS shortfalls is elevated

LOR2	Forecast Available Capacity is greater than: • the Forecast Operational Demand plus Operational Reserve Margin, • but less than the Forecast Operational Demand plus 70% of the Largest Supply Contingency	Probability of load shedding is elevated and there is insufficient ESS
LOR3	Forecast Available Capacity is less than: • the Forecast Operational Demand plus • the Operational Reserve Margin	Insufficient capacity to avoid load shedding and meet ESS requirements

LOR2 and LOR3 conditions reflect actual or elevated risks of unserved energy occurring. The LOR conditions, at time of publication, indicate risks to the SWIS arising from unplanned contingencies (e.g. a network or generator trip, uncertainty in weather patterns, etc.). When AEMO uses pre-dispatch schedules to issue LOR declaration, it assumes that all available capacity that is offered will remain available.

There may be power system conditions where no LOR declarations are anticipated, assuming the ESR fleet is at a certain level of charge when entering their respective ESROIs. However, if the ESR fleet charge is below this level, there may be a credible risk to PSSR.

Therefore, it is proposed that AEMO will develop a new LOR-SOC condition that indicates a heightened risk for unserved energy if the Peak Certified ESR fleet is not at a certain level of charge at the start of the relevant ESROIs:

- The new LOR-SOC condition will apply when there is a risk that LOR2 or LOR3 conditions may arise due to insufficient ESR fleet charge.
  - It is expected that LOR-SOC conditions will be declared by AEMO before LOR 2 or 3 declarations, indicating that LOR-SOC is applied as a preventative mechanism to avoid other LOR declarations.
  - It is also expected that, in the event AEMO has not declared a LOR-SOC but subsequently declares an LOR2 or LOR3 condition, an LOR-SOC will be declared.

These changes will require amendments to clause 3.17.11 of the ESM Rules, which provides the head of power for the Low Reserve Conditions WEM Procedure, so that AEMO is empowered to amend the LRC framework to capture the LOR-SOC condition.

Approach to determining SOC obligation levels

AEMO currently uses different modelling approaches for different purposes (e.g., probabilistic modelling for Unscheduled Operational Demand). As LOR-SOC is a preventative measure and based on AEMO advice, it is expected that the SOC obligation will be based on the LOR2 framework, with a calculated charge margin to prevent an LOR2 event.

To ensure implementation remains simple and to provide flexibility for AEMO, it is proposed that AEMO uses its existing modelling approaches to:

- Forecast the Peak Certified ESR fleet SOC level required to prevent an LOR2 condition. For avoidance of doubt:
  - A single uniform SOC level will apply across the entire peak capacity ESR fleet;
  - For ESR facilities on a partial planned outage, the SOC obligation will apply to their remaining available capacity;
  - Each ESR facility’s SOC obligation will apply at the beginning of its ESROIs; and
  - As noted previously, the SOC mandate may be less than 100% and will depend on prevailing system conditions.

It is proposed that the ESM Rules do not prescribe the methodology that AEMO must use to determine the SOC obligation level. However, to provide transparency to Market Participants it is proposed that the ESM Rules require AEMO to publish its methodology in the Low Reserve Condition WEM Procedure.

In developing the methodology, it is expected that AEMO ensures that it:

- is as simple as practicable, while providing adequate certainty to Market Participants, to support transparency and cost-effective implementation;

- minimises the risk of disruption to, or intervention in, normal market processes;
- clearly shows how the required charge level is calculated and whether a tolerance range applies.

AEMO has advised that a 100% SOC would indicate that the SWIS is under severe stress, and this is unlikely to occur in practice. Therefore, a charge level below 100% should be expected. Given that this represents the minimum charge level an ESR facility must achieve, an ESR facility may have some capacity to participate in the RTM and FCESS in advance of its ESROIs.

Notification Period and withdrawal

When AEMO makes LOR-SOC declaration and issues a SOC obligation, Market Participants with ESR Facilities will require:

- sufficient notice to allow adequate time to charge and adjust their operating profiles; and
- assurance that the SOC declaration is used only under genuine conditions of system stress.

The closer a declaration is made to real time, the more accurate the shortfall forecast is likely to be. However, this also reduces the time available for ESR operators to respond.

Scarcity and intervention rules allow AEMO to intervene (i.e. direct) to address actual or projected energy shortfalls forecast up to one week ahead of real-time (see clause7.7.4(b)). However, forecasts made a week in advance are subject to considerable uncertainty and may not provide ESR operators with the level of confidence needed to justify operational decisions.

To balance the lead-time required for ESR operators to respond with the forecast lead-time needed to prepare sufficiently accurate forecasts, the following is proposed:

- AEMO must use best endeavours to declare the SOC obligation by 8:00pm on the Scheduling Day. This will provide longer-duration ESR facilities with sufficient time to charge.
    - This does not prevent AEMO from declaring the SOC obligation earlier. However, it is important to note that the longer the forecast lead-time, the greater the forecast error is likely to be.
- If AEMO is unable the meet above requirement despite using best endeavours, it must declare the SOC obligation no later than 8:00am on the Trading Day.
- AEMO will withdraw the SOC obligation if it determines that the LOR-SOC condition is no longer likely to apply.

Consequential amendments to Energy and FCESS offer rules

Amendments to enable ESRs to participate in RTM while ensuring compliance with SOC obligations

Issue 1: The ESM Rules currently require Market Participants to submit their capability in the quantity part of their energy and FCESS offers (where the relevant Registered Facility is accredited). This requirement is set out in clause 7.4.2(a)(i).

- Working Group and MAC members have expressed concern that ESR Facilities subject to a SOC mandate may not be able to comply with both the SOC mandate and other offer and bidding requirements.

Issue 2: ESR Facilities may have different ESRDR and Peak ESROIs, depending on when they were first assigned Capacity Credits. This means that newer ESR Facilities will enter their ESROIs before grandfathered ESR Facilities (which have a lower ESRDR).

- When a SOC obligation applies, there is a risk that incumbent ESR Facilities may begin charging while newer ESR Facilities are discharging. This could exacerbate system conditions, as the discharge from newer ESR Facilities may be used to charge other ESR Facilities instead of meeting peak demand.

Two options are proposed to address the issues outlined above.

Option 1: Amend the ESM Rules to empower AEMO to apply Constraint Equations to:

- constrain Peak Certified ESR facilities from being dispatched for injection before their ESROIs, unless required to provide FCESS or other services necessary to maintain PSSR on a Trading Day when an LOR-SOC condition is in effect; and
- constrain Peak Certified ESR facilities from being dispatched for withdrawal during their ESROIs and during the ESROIs of any other ESR facility, unless required to provide FCESS or other services necessary to maintain PSSR on a Trading Day when an LOR-SOC condition is in effect.

Under this option, AEMO would be allowed to violate the Constraint Equations where necessary to provide FCESS or other services required to maintain PSSR in the period before the ESR facility's ESROIs. Where this occurs, it would be taken to constitute a direction by AEMO under clause 7.7.5, thereby satisfying the requirements of clause 4.12.5(g).

Consequently, AEMO would set the RCOQ for the relevant facility to zero for the remainder of the Trading Day, preventing refunds from being calculated where a facility is unable to meet its obligations for the full ESROI.

Option 2: Amend the ESM Rules to:

- enable Peak Certified ESR facilities to offer zero energy Injection and Withdrawal quantities during Dispatch Intervals outside their Peak ESROI on a Trading Day when an LOR-SOC condition is in effect;

- prohibit ESR Facilities from charging during the Peak ESROIs of any other ESR facilities on a Trading Day when an LOR-SOC condition is in effect, except when instructed by AEMO; and
- allow an exemption where ESR facilities are instructed by AEMO for FCESS or other reliability purposes (e.g. relieving network congestion), as these actions support the maintenance of PSSR.

While Option 2 is simpler from an implementation perspective, it reduces AEMO's visibility of an ESR facility's capabilities. This, in turn, increases AEMO's reliance on manual intervention to dispatch ESR facilities in response to unexpected contingencies or for other actions required to maintain PSSR. AEMO also advised that this issue remains even if Market Participants used the "Available" flag in their market submissions under Option 2.

Under Option 1, further additions are required, including:

- AEMO would need to develop a set of Constraint Equations to prevent:
    - Injection by peak capacity ESR facilities prior to their ESROIs where this would result in the facility's SOC level falling below the level prescribed by the LOR-SOC declaration; and
    - Withdrawal by ESR facilities during the peak ESROI period of any other peak capacity ESR facility, to prevent charge 'cannibalisation' between ESR facilities to ensure that PSSR is not compromised.
- AEMO would be required to document the methodology used to determine and apply these Constraint Equations in a WEM Procedure.

AEMO's expectation is that this approach can be incorporated into its operational processes.

Both options are expected to achieve the same outcome. However, given that the options have different implementation impacts, stakeholder feedback is sought on the preferred approach.

Interaction with ERA guidelines

Some MAC and Working Group members have raised that ESR energy and FCESS offers may not align with ERA guidelines, if they must comply with a SOC mandate.

As discuss earlier in this chapter, it is proposed to amend the ESM Rules to provide ESR operators greater clarity regarding how they are expected to behave and remain compliant with ERA guidelines when a SOC-obligation is imposed.

However, it is noted that, under clause 2.16D.2, that the ERA may amend its guidelines at any time, subject to section 2.16D.

It is recommended that Market Participants seek advice from the ERA on whether their offers are likely to breach the ERA guidelines when a SOC mandate applies.

6.2. Proposal summary

The analysis shows that the system stress events that coincided with ESR facilities having a low SOC, while currently infrequent, have the potential to impact PSSR. The infrequent nature of these events does not justify a redesign of the market. Instead, targeted AEMO intervention when such events arise provides a more effective and simpler approach to implementation. As a result, it is proposed to implement a SOC mandate condition for Peak Certified ESRs within the Low Reserve Condition framework within the ESM Rules.

This new LOR-SOC obligation is expected to reduce the likelihood of the SWIS entering higher Lack of Reserve conditions. Based on current AEMO advice, the LOR-SOC is likely to be linked to the LOR-2 framework, with the SOC level reflecting what is required to prevent an LOR2 event. The SOC level will be set at a Peak Certified ESR fleet level, with every ESR with peak ERSOIs expected to be at the mandated SOC level upon entering its respective ESROIs.

It was considered inappropriate to introduce an additional payment structure for ESRs when a LOR-SOC is declared, as these ESR facilities are already compensated through the Reserve Capacity Mechanism to make their Reserve Capacity Obligation Quantity available during their ESROIs. Providing an additional payment would result in ESRs being compensated twice for the same service.

To facilitate compliance with the proposed LOR-SOC, it is proposed to amend the ESM Rules to provide Market Participants with sufficient time and information.

To assist Market Participants in complying with the LOR-SOC and other market submission requirements, one of the discussed options in this chapter will be implemented. Both options are expected to achieve the same outcome but differ in their implementation impacts. Stakeholder feedback is sough on which option they prefer.

Proposal 4a

It is proposed to amend the ESM Rules to:

- update clause 3.17.11 (the head of power for the LRC WEM Procedure) to empower AEMO to incorporate a Lack of Reserve – State of Charge (LOR-SOC) condition into the Low Reserve Condition Framework that applies to Peak Certified ESR;
  - the LOR-SOC condition declaration is the trigger for imposing a State of Charge (SOC) obligation on the ESR fleet certified for Peak Certified Reserve Capacity.
  - The LRC WEM Procedure will also be amended to outline:
    - under what system conditions the LOR-SOC obligations will apply; and
    - the methodology AEMO will use to determine the SOC obligation level.
- allow AEMO to withdraw a LOR-SOC condition if it determines they are no longer necessary;
- specify the notification times for AEMO when declaring a LOR-SOC condition:
  - AEMO must use best endeavours to declare the LOR-SOC condition and SOC obligations by 8:00pm on the Scheduling Day; and

  - AEMO must declare the LOR-SOC condition and SOC obligations no later than 8:00am on the Trading Day,
- specify that the LOR-SOC obligation will be a uniform charge level applicable to all Peak Certified ESR Facilities, and that all ESR Facilities must be at that level at the start of their relevant ESROIs;
- specify the information that must be provided to ESR participants to provide them a reasonable level of certainty regarding the event; and
- specify that the obligation applies to the remaining available capacity of ESRs, taking outages into account.

Proposal 4b

The ESM Rules are also proposed to be amended to implement one of the following options.

Option 1:

- Amend the ESM Rules to empower AEMO to apply Constraint Equations to:
  - constrain ESRs from being dispatched for injection before its peak ESROIs, unless required to provide FCESS or other services to maintain PSSR on a Trading Day when a LOR-SOC is in effect;
  - to constrain ESRs from being dispatched for withdrawal during their peak ESROIs and during the peak ESROIs of any other ESRs, unless required to provide FCESS or other services to maintain PSSR on a Trading Day when a LOR-SOC is in effect;

Option 2:

- prevent ESRs from charging during their peak ESROIs and during the peak ESROIs of any other ESRs on a Trading Day when a LOR-SOC is in effect, except when AEMO instructs them for FCESS or system reliability purposes; and
- allow ESR facilities to make zero quantity offers for energy Injections and bids for zero Withdrawal outside of their peak ESROIs on a Trading Day when a LOR-SOC Charge is in effect.

Consultation questions:

1. Do stakeholders support the proposals to introduce a State of Charge mandate through the introduction of new Low Reserve Condition – Lack of Reserve-State of Charge (LOC-SOC)?
2. Which option - Option 1 or Option 2, do stakeholders support to assist ESR operators in complying with a LOR-SOC obligation?

7. Proposal 5 – New Charge Shortfall Refund to support SOC Obligation compliance

As noted in Chapter 6, the five SSEs with low ESR SOC that were further analysed showed that refunds were lower than the estimated revenue earned from discharging earlier in the day. This suggests that the current refund mechanism may not sufficiently incentivise availability during these stress periods.

The proposed SOC mandate scheme will be effective in ensuring system reliability during system stress events only if the Peak Certified ESR facilities comply with the LOR-SOC condition. It is therefore important to embed incentives for compliance within the proposed LOR-SOC condition.

Compliance with the SOC obligation will be made a Civil Penalty provision. However, as potential breaches of Civil Penalty provisions are investigated and penalties are typically imposed ex post, often sometime after the event, it may be beneficial to adopt a "compliance by design" approach. This would help ensure there are no adverse impacts on PSSR at the time the system is entering, or is within, a stress period.

As the existing refund mechanism does not always provide sufficiently strong financial incentives for ESRs to be available during their peak ESROIs, changes to this mechanism were considered. However, amending the existing refund mechanism would affect all other facility types, even though the SOC obligation would only apply to ESR.

Therefore, it is proposed to introduce an addition to the current refund mechanism that applies only to ESR facilities when a SOC mandate is in effect. This approach is intended to avoid unnecessary adverse impacts on other technology types.

It is proposed to introduce a new feature into the existing refund scheme:

- ESR facilities will face higher refunds amounts if they fail to comply with the SOC mandate; and
- these higher refunds will only apply where AEMO has made an LOR-SOC declaration.

Working Group members have expressed concern that a new refund regime may entail high implementation costs. To address these concerns, and to minimise implementation complexity and cost. The following is proposed:

- refund amounts for ESR facilities will be multiplied by two when a SOC mandate is in effect. This means an ESR facility would pay twice the refund amount for failing to deliver its RCOQ compared to an ordinary Trading Day.

As this is a minor adjustment to the current refund mechanism, AEMO has advised that it would be simple to implement.

7.1. Proposal summary

A “compliance by design” framework, in addition to a civil penalty provision, is proposed to ensure that behavioural changes are embedded within the SOC mandate, recognising that these events represent periods of system stress.

An addition to the current refund mechanism for Peak Certified ESR facilities when an LOR-SOC condition is in effect is proposed to incentivise appropriate behaviour while ensuring that other technology types are not adversely affected.

The proposed refund mechanism is designed to minimise implementation costs while providing strong financial incentives for ESR facilities to comply with an LOR-SOC declaration.

Proposal 5

It is proposed to amend the ESM Rules to introduce an addition to the current refund mechanism for ESRs when a LOR-SOC mandate applies.

- The refund will apply only to ESR Facilities and only when a LOR-SOC condition has been declared by AEMO.
- ESR Facilities will pay twice the amount of refunds they usually pay for failing to offer their RCOQ when a SOC obligation applies.

Consultation questions:

1. Do stakeholders support the proposals to introduce an addition to the current refund mechanism to apply only when a LOR-SOC is in effect?

Appendices

Appendix A. Jurisdictional Analysis of ESR derating approaches

This appendix sets out the approach to derating ESRs participating in capacity markets across five jurisdictions: Great Britain, PJM (USA), ISO New England (USA), Ireland (including Northern Ireland), and Ontario (Canada).

Key insights from the review are summarised first, followed by detailed descriptions of the ESR derating approaches used in each jurisdiction.

A.1 Key points of interest

A.1.1 ELCC/EFC approaches are the method of choice but have resulted in unexpected complexities

Distinction between EFC and ELCC

While the EFC and ELCC approaches to derating appear similar, there are subtly differences between them.

Both approaches use probabilistic modelling to simulate system reliability and measure a non-firm resource's reliability contribution by adding an increment of that non-firm resource and determining the resulting change in system adequacy. However:

- Under the EFC approach, the non-firm resource's contribution is measured by adding an *equivalent quantity of firm capacity to get the same change in system adequacy* that was observed when the non-firm resource was added. The derating factor here is given by the quantity of additional firm capacity added divided by the quantity of non-firm capacity added.
- Under the ELCC approach, the non-firm resource's contribution can be measured one of two ways:
    - By adding the *same quantity firm capacity as the non-firm resource* and comparing the change in system adequacy (relative to the base case) with the change in system adequacy when the non-firm resource is added. The derating factor equals the change in system adequacy when the non-firm is added compared to when the firm resource is added; or
    - By adding *increments of demand* to the base case until the relevant reliability standard binds. The derating factor here is given by the quantity of demand added back by the quantity of non-firm resource that was added.

Great Britain uses the EFC approach to quantify the reliability contribution of storage and intermittent generation resources (jointly referred to as non-firm resources). By contrast, PJM, ISO-NE and Ireland all use variants of the ELCC approach.

First-in vs Last-in variants

One of the issues with both the EFC and ELCC approaches is that derating factors can differ depending on whether the non-firm resources are added first, or added last:

- Under a first-in approach, system adequacy is first measured with only an increment of non-firm capacity added. The remainder of the fleet is then added, and the resulting change in system adequacy is measured.
- Under a last-in approach, system adequacy is first measured using the entire fleet (excluding the non-firm resource). The non-firm resource is then added, and the resulting change in system adequacy is measured.

If new non-firm resources have generation profiles that are correlated with those of existing non-firm resources (e.g. wind farms located in the same area), the last-in approach will result in lower derating factors than would otherwise apply to the new non-firm resource fleet. This is because the new resource's contribution to reliability coincides with the same periods during which the existing non-firm fleet contributes to reliability. By contrast, if the generation profile of the new resource is negatively correlated with that of the existing fleet, it will receive a higher derating factor because it can contribute to system reliability during periods when the existing fleet cannot.

The converse applies under the first-in approach: adding correlated new resources first results in those resources receiving higher derating factors than would otherwise apply, and vice versa.

All applicable jurisdictions reviewed in this report use the last-in EFC or ELCC approach. Interestingly, Ireland attempted to address the underestimation of new storage derating factors arising from the last-in approach by introducing a scaling factor that could be applied to the ELCC derating factor to ensure that new storage resources were appropriately compensated. However, this resulted in new storage resources being overcompensated. Consequently, the storage adjustment factor was removed.

Jurisdictions using the ELCC/EFC approach have modified (or plan to modify) initial implementations as bedding-in issues have been discovered

One of the key issues with EFC/ELCC approaches is the considerable complexity associated with these methodologies. Most of the markets reviewed have identified issues that have required changes to modify the existing approach:

- In Great Britain, two issues have been identified with the existing EFC approach:
    - The existing approach results in a misalignment between the aggregate contribution of all storage resources to system reliability and the sum of the modelled individual storage contributions. This is a consequence of the issues discussed previously.
    - The existing approach has also resulted in steep increases in EFC values for long-duration storage resources. This, combined with the ability of storage providers to self-declare capacity in the auction, has resulted in some

participants to declare durations that exceed their nameplate duration to receive a higher capacity allocation.

- To address the issues identified, Great Britain is moving to a scaled approach under which EFCs are calculated for both individual storage facilities and the storage fleet as a whole. The individual EFCs are then scaled proportionally so that their sum equals the EFC calculated when the storage fleet is modelled as a single resource.
  - However, a drawback of this approach is that it no longer results in the economically efficient level of storage being procured. Under the unscaled first-in EFC approach, the EFC reflects the marginal value of adding storage to the system.
  - In economic theory, this marginal value also corresponds to the profit-maximising price signal facing a producer. Therefore, provided the current EFC methodology values the marginal contribution of storage at the point where supply meets demand (i.e. the market-clearing point of the Capacity Market auction), the resulting incremental EFC should reflect an economically efficient market outcome.
- In PJM, the application of ELCC has resulted in two issues.
  - First, the approach has resulted in volatile allocations of capacity due to ELCCs changing materially from one capacity cycle to the next.[18]
  - Second, the use of ELCC has resulted in intermittent generation and storage resources receiving lower capacity allocations than would have been the case under a simpler methodology.
- At the time of publication, PJM was facing a supply crunch due to generator retirements and forecasts of higher demand. The lower capacity contributions assigned to intermittent generation and storage resources meant that additional capacity needed to be procured to satisfy the reliability standard. The resulting supply shortage contributed to capacity price spikes in the July 2024 auction. PJM is currently facing legal challenges from market participants in relation to these issues.
- Ireland has made two changes to its ELCC approach.
  - The first is the removal of the storage adjustment factor discussed previously.
  - The second is a shift from gross demand forecasting to net demand forecasting when applying the ELCC, to better maintain the correlation between weather and demand. This issue is discussed later.

ELCC/EFC approaches do not require durational availability obligations to be defined

The WEM uses the linearly derating approach to derate storage resources. The derating factor is a function of the storage resource’s charge level degradation and the length of the

[18] This issue has been addressed in the WEM (with respect to the future implementation of ELCC to replace the Relevant Level Method) by calculating a fleet ELCC (instead of calculating ELCCs for each individual resource) and then allocating that ELCC across intermittent resources to reduce year-on-year volatility.

ESROD. This means that AEMO must model these durational requirements to determine the intervals during which storage must be available for (i.e. the ESROIs).

By contrast, ELCC and EFC approaches quantify a resource's contribution to overall system reliability. Hence, there is no need to model durational requirements explicitly (i.e. identify the intervals during which storage resource must be available). Therefore, while the ELCC and EFC approaches are significantly more complex than the LDM approach, adopting either approach would eliminate the need for separate duration modelling.

A.1.2 Forecasting capacity requirements is becoming increasingly challenging leading to capacity market changes in some jurisdictions

Historically, system reliability was largely driven by discrete outage events of short duration. Power systems also had low levels of intermittent generation and high levels of dispatchable firm generation. This made determining capacity requirements to meet a reliability standard relatively simple.

As the penetration of intermittent generation and storage increases, system reliability is becoming more influenced by weather conditions than by discrete outage events. In a decarbonised system, periods of low solar and wind availability may result in insufficient energy being available to charge storage resources, leading to potential energy shortages that can last from hours to days.

The increasing complexity of forecasting capacity requirements has led to changes in two of the reviewed markets:

- ISO-NE is moving from its three-year-ahead Forward Capacity Market to short-term Prompt Auctions. These auctions will occur twice a year (summer and winter) and will occur one to two months before the relevant delivery period.
    - This represents a significant change, as capacity auctions have traditionally been conducted several years ahead of delivery to allow sufficient time for new facilities to be developed and constructed. This change appears to have been driven by a desire to improve the accuracy of capacity requirement forecasts.
- Ireland has changed its approach to demand forecasting as part of its ELCC modelling. The Irish Transmission System Operator (TSO) develops demand forecast scenarios based on alternative assumptions regarding peak demand, energy demand, and load shapes. Previously, the TSO used gross demand forecasts (which did not exclude intermittent generation) and modelled the existing intermittent generation fleet on the supply side when constructing the base case for the ELCC methodology.
    - As a result, the correlation between demand and weather-driven intermittent generation was not fully captured. To address this issue, the TSO is moving to a net-demand modelling approach, under which historical intermittent generation is removed from demand forecasts before load shapes are developed.
    - The ELCC methodology is then applied by adding increments of intermittent generation to the base case and measuring the resulting change in system

adequacy. This approach preserves the correlation between demand and weather-driven generation

A.1.3 Additional incentives and penalties are an option to incentivise performance during extreme stress events

PJM has a strong financial incentives and penalties designed to promote performance during periods of system stress. The rewards and penalties under this framework only apply during Performance Assessment Intervals (PAIs). PJM determines these intervals retrospectively, after low-reserve conditions or emergency system conditions have been declared.

- Resources that fail to deliver their obligation quantities during the PAIs are charged a penalty that is a function of their shortfall, and the Cost of New Entry (CONE) used to set the capacity price.
- Load serving entities that failed to procure sufficient capacity during the PAIs are also charged a penalty.
- Resources that over-deliver relative to their obligation are rewarded with a bonus payment funded by the penalties collected from the offending entities described above.

PJM operates the above scheme in addition to a capacity refund mechanism similar to that used in the WEM. As a result, capacity providers not only have a financial incentive to meet their capacity obligations throughout the year but also face additional incentives to perform during emergency conditions.

By contrast, the WEM's incentive structure for Demand Side Programmes (DSPs) is significantly stronger than that applying to equivalent Non-Retail Behind-the-Meter Generation (NRBTMG) units in PJM. NRBTMG units do not face direct financial penalties for non-availability. Instead, their future capacity allocations are reduced by a proportion of their under-delivery in the subsequent capacity cycle.

The effect of these weaker incentives was evident during Winter Storm Elliott in 2022, when more than 300 NRBTMG units failed to deliver 1,524.1 MW of the capacity for which they had received accreditation.[19]

A.1.4 Power system challenges associated with storage does not appear to be an issue yet

None of the jurisdictions reviewed have identified any storage-specific power system security challenges.

The two main issues identified are:

- Challenges in ensuring that capacity contribution methodologies accurately quantify the reliability contribution of storage in a manner that results in the economically efficient deployment of storage resources that, in combination with the rest of the fleet, can deliver the required reliability standard.

[19] 1,524.1 MW is the sum of the two-day shortfall (888.8 MW on Dec 23 and 635.3 MW on Dec 24), as reported in the Winter Storm Elliott Recommendations and Analysis Report

- Ensuring that weather driven impacts (such as dunkelflaute[20]) are appropriately captured when modelling capacity requirements.

It is worth noting that PJM, ISO New England (ISO-NE), and Ontario all operate day-ahead and real-time security-constrained unit commitment and dispatch algorithms that perform multi-period optimisation. This enables storage charging and discharging to be optimised based on the system operator's expectations of future system conditions. Consequently, storage coordination is likely to be less of an issue than in the WEM, which relies on self-commitment and single-period optimisation.

A.2 Great Britain

Great Britain's energy system is experiencing rapid growth in energy storage penetration, with 6.872 GW of operational capacity currently installed (representing approximately 9.6% of the total installed capacity of 71.7 GW) and a further 19 GW under construction. Around 90 GW of approved battery storage projects have yet to commence construction, while approximately 61 GW of proposed projects are awaiting planning decisions. In total, Great Britain's energy storage pipeline could result in up to 170 GW of battery storage capacity being connected to the grid.

A.2.1 Key Issues

The rapid increase in storage facilities connected to the grid has raised several concerns regarding Capacity Market (CM), particularly:

- The ability of storage to self-declare their capacity and duration, combined with existing performance testing requirements, may be resulting in the under-declaration of capacity to pass testing requirements.
    - This can lead to inefficient outcomes, as the contribution of storage to system reliability may be underestimated, requiring more capacity to be procured than would otherwise be necessary if storage operators accurately declared their capabilities.
    - To mitigate the risk of under-declaration, the British Government has proposed allowing storage units to transfer all or a part of its Capacity Obligations to another party in situations they deem necessary, including to reduce their testing requirements. [21]
- The existing EFC approach to allocating capacity results in the total contribution of the entire storage being misaligned with the sum of the individual contributions of each facility. Additionally, the derating factors sharply increase for long-duration storage facilities, incentivising over-declaration of duration to get a higher derating factor.

[20] Dunkelflaute (or dark doldrums or dark lull) is a German term for a meteorological phenomenon where there is little to no wind or sunlight at the same time, leading to a significant drop in renewable energy generation from wind and solar power.

[21] This Secondary Trading is still part of the Capacity Market. Units can either trade before stress event or reallocating the obligation volume after a stress event.

These issues are described in further detail below, together with the proposed solution, which involves moving to a scaled EFC approach.

A.2.2 Capacity Contribution Measurement

Great Britain measures system adequacy using the Loss of Load Expectation (LOLE) metric, with capacity procured to meet a reliability standard of three hours of LOLE per year. As the penetration of renewable generation and battery storage increase, system stress events are expected to occur less frequently but persist for longer duration, particularly during periods of prolonged low wind and solar generation ("dunkelflaute"[22]), combined with the energy-limited nature of battery storage

Recognising that no technology is available at all times, all capacity participating in the UK Capacity Market is assigned a derating factor. Intermittent generation and storage resources are assessed using the EFC framework, which estimates the quantity of firm generation required to provide an equivalent contribution to system reliability.

Great Britain currently applies an Incremental Last-In EFC methodology, which was introduced in 2017 when storage penetration was relatively low. This approach estimates the quantity of firm capacity required to provide the same reliability contribution as an incremental unit of non-firm capacity while maintaining the reliability standard. Incremental Last-In EFC values are calculated separately for each storage duration, with storage resources exceeding nine hours automatically treated as fully firm and assigned an EFC of 100%.

However, as the storage fleet has grown, this approach has become increasingly misaligned with the contribution of storage to overall system reliability. In particular, it has resulted in inconsistencies between the sum of individual EFC values and the expected contribution of the storage fleet as a whole. It has also led to steep increases in EFC values as storage duration approaches the nine-hour threshold.

To address these issues, the National Energy System Operator (NESO) has proposed replacing the current methodology with a Scaled EFC approach. Under this approach, incremental EFC values are retained but scaled proportionally so that the aggregated individual EFC equals the EFC of the storage fleet as a whole. This results in a smoother and more proportional relationship between storage duration and EFC value.

Final capacity derating factors for storage are then calculated by multiplying EFC values by an assumed availability factor. This factor is determined by averaging the availability of pumped storage during winter peak periods over the previous seven years. NESO has recognised that relying on pumped-storage availability data is becoming increasingly outdated and is investigating the use of actual availability data from lithium-ion battery storage systems connected to the grid.

[22] Dunkelflaute (or dark doldrums or dark lull) is a German term for a meteorological phenomenon where there is little to no wind or sunlight at the same time, leading to a significant drop in renewable energy generation from wind and solar power.

A.3 PJM

The Federal Energy Regulatory Commission (FERC) issued Order 841, which enabled battery storage resources to participate in wholesale electricity markets from December 2019. Currently, PJM has more than 375.3 MW of nameplate battery storage capacity and 4,792 MW of hydro-pumped storage, representing approximately 2.6% of total installed capacity. PJM also hosts a range of other storage technologies that participate in the energy market, including:

- Flywheel storage
- Compressed Air Energy Storage
- Thermal Storage
- Electric Vehicles

Despite this, PJM considers itself to need significantly more energy storage capacity due to constrained supply, ongoing interconnection backlog issues, and high resource costs. PJM has more than 1 GW of storage projects awaiting connection, although the *PJM Energy Storage Outlook* report indicates that PJM will require at least 23 GW of energy storage capacity by 2040.[23]

A.3.1 Key issues

The PJM Capacity Market, which operates through a forward auction framework using the Reliability Pricing Model and locational pricing, has faced significant challenges, as highlighted by Winter Storm Elliott in December 2022 and subsequent market outcomes.

One major issue is the reliability risk posed by behind-the-meter generation, particularly non-retail behind-the-meter generation (NRBTMG), which failed to deliver over 1,316.1 MW during the storm. These resources are netted from load rather than directly dispatched and are subject only to reductions in future capacity allocation rather than financial penalties.

As a result, their underperformance increased system demand during critical periods and exposed a weakness in PJM's incentive framework when compared with demand-side resources, which face financial penalties for non-delivery.

A second key issue is capacity price volatility arising from supply inadequacy, most notably the sharp increase in clearing prices in the 2025/26 capacity auction, where prices rose to approximately ten times their level in the previous year's auction. This increase was driven by a combination of generator retirements, higher demand forecasts, and PJM's transition from the Equivalent Forced Outage Rate on Demand ($EFOR_d$) approach to the Marginal ELCC approach, which quantifies the contribution of individual resources to system reliability.[24]

[23] Outlook for Energy Storage in PJM

[24] PJM's Electric Capacity Market: Background and Current Issues (congress.gov)

However, this approach has introduced greater volatility in accredited capacity values and capacity revenues, increasing investor uncertainty at a time when substantial new investment is required.

Ongoing rule changes, litigation, and auction delays have further intensified stakeholder concerns that the current Capacity Market design may distort price signals and undermine resource adequacy during periods of greatest system stress.

A.3.2 Capacity Obligations and Incentives

PJM's Capacity Market operates under the Reliability Pricing Model, which includes a Performance-Based framework designed to incentivise reliable delivery during emergency system conditions. Capacity providers are assessed during declared PAIs, when system reliability is most at risk.

Resources that underperform relative to their committed capacity incur non-performance penalties calculated using the Net Cost of New Entry (i.e., Net CONE, the benchmark cost of adding new capacity to the system). Similarly, Load Serving Entities (LSEs) face deficiency charges if they fail to procure sufficient capacity. Conversely, resources that exceed their performance obligation receive bonus performance credits, which can offset penalties or generate additional revenue.

Following Winter Storm Elliott, PJM initiated a review of these arrangements, focusing on the adequacy of rewards and penalties framework, strengthening accreditation requirements through winterisation and fuel assurance measures, improving testing rules, and reassessing the participation model for non-retail behind-the-meter generation resources, whose poor performance highlighted weaknesses in the existing incentive structure.[25]

A.3.3 Capacity Contribution Measurement

As noted above, PJM measures the marginal contribution of storage and other non-thermal resources using a Last-In ELCC approach. Storage resources are grouped into specific ELCC classes based on thier duration and configuration, and their physical capability is expressed as the "Accredited UCAP (Unforced Capacity)".

The ELCC methodology uses a probabilistic risk model to assess the contribution of renewable generation and storage resources to system reliability relative to firm capacity. It does this by testing how small additions of "perfect" firm capacity and equivalent storage capacity affect Expected Unserved Energy (EUE) while maintaining the reliability standard of one day of LOLE in ten years. The resulting ratio is used to determine the ELCC Storage Class Rating.

In addition to the ELCC class rating, PJM applies a Resource Performance Adjustment factor to account for the performance of individual resources during high-risk weather

[25] Historically, capacity obligations related to summer seasons. However, changing weather and demand patterns means that system stress events can occur in winter as well (for extended periods of time). Winterisation of requirements ensures availability of capacity providers for both summer and winter events.

conditions and high-risk hours, based on historical data. This factor compares a resource's weighted availability against its class average. Together, the ELCC Class Rating and Resource Performance Adjustment are used to calculate a resource's Accredited Unforced Capacity (UCAP).

Although the Marginal ELCC approach improves the accuracy of valuing resources during periods of system stress, it has introduced greater volatility in accredited capacity values and capacity costs. PJM acknowledges that this may increase consumer costs in the short term but considers this to be justified by the longer-term reliability and efficiency benefits that the approach is intended to deliver.

A.4 ISO New England

Following FERC Order 841, ISO-NE was required to enable energy storage resources to participate in all wholesale electricity markets, including the Real-Time Energy Market, Day-Ahead Energy Market, and Forward Capacity Market.

In response, ISO-NE launched the Energy Storage Device (ESD) Project in 2019, introducing new participation models for storage, including continuous storage facilities (CSF), such as batteries, that can simultaneously provide energy, reserves, and regulation services. These reforms were supported by changes to market rules and tariffs and have contributed to rapid growth in storage participation, increasing grid-scale battery storage capacity from just 19 MW in 2018 to approximately 330 MW currently in operation.

A.4.1 Key Issues

ISO-NE's capacity market was initially designed to ensure reliability during periods of summer peak demand, on the assumption that this would also be sufficient to meet winter peak demand. However, modelling undertaken by ISO-NE and the External Market Monitor (EMM) has shown that winter reliability risks are increasing and are driven by prolonged cold-weather events lasting days or weeks, rather than a small number of peak-demand hours.

For storage resources, this creates challenges because batteries need to be charged during these cold periods, when renewable generation may be limited. To address these risks, ISO-NE has proposed replacing its three-year-ahead annual Forward Capacity Market (FCM) auction with separate prompt capacity auctions for the summer and winter seasons, with a lead time of only one to three months before the relevant delivery period.[26]

A.4.2 Capacity Contribution Measurement

Under the current Forward Capacity Market, capacity is accredited to meet a 1-in-10-year LOLE reliability standard, with storage resources receiving capacity credit based on their ability to discharge at full output for two hours. While simple, the current accreditation method for storage not adequately account for the duration limitations of energy storage

[26] See Capacity Market Reforms.

resources beyond two hours. As a result, it may overstate accredited capacity and increase the risk of insufficient capacity being available to meet the reliability standard.

The proposed methodology uses a last-in ELCC approach to calculate the Marginal Reliability Impact (MRI) of a resource in both summer and winter seasons (i.e. so ELCC is recalculated separately for the summer and winter auctions). Prompt Auctions will use the concept of Qualified Marginal Reliability Impact (QMRIC) to better reflect a resource's expected performance during the forecasted system risk periods. Separate formulas are used for summer and winter (or seasonal) QMRIC calculations. These seasonal QMRIC components represents the reliability contribution of the resource within the summer and winter season.

The seasonal Marginal Reliability Impact (MRI) of storage resources is calculated differently for existing and new resources.

- For existing storage resources, MRI is estimated by incrementally increasing storage capacity in the system model and measuring the resulting reduction in EUE during the summer and winter seasons, expressed relative to the change in qualified capacity (QC).
- For new storage resources, a proxy resource approach is used. A small quantity of representative storage is added to the model, the resulting seasonal reductions in EUE are calculated and allocated between the summer and winter seasons. This approach avoids distortions that may arise from the limited operational history of new resources.

The MRI methodology is designed to better capture seasonal reliability risks, particularly the growing challenge of ensuring winter resource adequacy.

A.5 Ireland

Since the first Battery Energy Storage System (BESS) was energised in 2018, Ireland's total installed storage capacity has grown substantially. According to *EirGrid and SONI's Ireland's Resource Adequacy Assessment 2025-2034*, there is now 1,110 MW (1.11 gigawatts) of operational storage capacity (about 7.4% of total capacity), comprising:[27,28]

- 440 MW with less than 1-hour storage duration;
- 290 MW with 1-2 hours of storage; and
- 380 MW with more than 2 hours of storage.

A.5.1 Key issues

Battery Storage units currently face several challenges within the Integrated Single Electricity Market (I-SEM) framework due to system and market design limitations. Existing market and system platforms do not fully accommodate the operational characteristics of battery storage, preventing the proper registration of battery facilities and the submission of negative physical notifications for charging. Batteries are also treated similarly to pumped storage under the Trading and Settlement Code, despite their greater flexibility and faster

[27] All-Island Resource Adequacy Assessment 2025-2034

[28] EirGrid operates and develops the electricity transmission system, while SONI plans the development of onshore electricity system

response capabilities. This misclassification leads to inefficiencies in scheduling, dispatch, and settlement, while existing technical data fields do not accurately reflect key battery parameters such as storage quantities, cycle efficiency and charging intent.

To address these issues, EirGrid and SONI proposed changes to the Trading and Settlement Code to enable the full and efficient participation of battery storage within the Balancing Market.[29] The Balancing Market reflects the actions taken by the Transmission System Operator's (TSO) to maintain the system balance and determines the imbalance settlement prices based on differences between scheduled and actual demand.[30]

A.5.2 Capacity Market, Obligations and Incentives

The I-SEM is the wholesale electricity market for Ireland and Northern Ireland, designed to align the all-island power system with European market frameworks. It comprises day-ahead, intraday, and balancing energy markets, alongside a Capacity Market that secures long-term system adequacy through competitive auctions held up to four years ahead of delivery, with additional auctions closer to real time. BESS can participate across the energy markets, the Capacity Market, and the DS3 System Services programme, which supports the secure operation of the power system at high levels of renewable generation.

Capacity providers that clear the auctions must meet strict capacity obligations, requiring them to be available and deliver energy through the day-ahead, intraday, and balancing markets. When market prices exceed a predefined strike price, intended to reflect the cost of the most expensive generator, providers must pay the difference between the market reference price and the strike price, known as the Difference Charge.[31]

This mechanism incentivises capacity providers to prioritise reliable availability over speculative profits during scarcity events, while shielding consumers from extreme price volatility by delivering stable capacity costs. To manage financial exposure, provider liabilities are capped through the "Annual and Billing Stop-Loss Limit Factors", balancing strong performance incentives with protections against excessive financial risk.

A.5.3 Capacity Contribution Measurement

Derating accounts for the fact that not all capacity is continuously available due to factors such as planned and unplanned outages, maintenance, operational constraints, and the variability of weather-dependent technologies such as wind and solar generation. Derating factors, determined by the TSO based on historical availability, size, and technology type, adjust the qualified capacity of each participant. Final auction outcomes are then determined by a Demand Curve established by the Regulatory Authorities, which incorporates locational

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29 SDP Stakeholder Presentation

30 In Ireland the TSO is EirGrid and SONI

31 Capacity-Market-A-Helicopter-Guide-to-Understanding-the-Capacity-Market.pdf and Capacity-Market-The-Quick-Guide-to-Understanding-Qualification.pdf

and reserve considerations for regions including Northern Ireland, Ireland, and the Greater Dublin Region.[32]

Ireland uses a combination of the last-in-ELCC method and a least-worst regrets approach to derive derating factors for all technologies (including storage), with the objective of minimising the maximum cost associated with either over procuring or under-procuring capacity.

The detailed process used by the TSO can be summarised as follows:

- Step 1 – Define net demand scenarios: The TSO develops multiple demand scenarios based on different combinations of peak demand forecasts, energy demand forecasts, and load shape assumptions.
- Step 2 – Define Capacity Adequate Portfolios (CAPs): For each demand scenario in DS, TSO models a range of potential generation portfolios capable of meeting the reliability standard of three hours of LOLE per year. These portfolios are generated using assumptions about the existing generation fleet and expected future capacity additions. Any portfolio resulting in a LOLE of three hours per year is deemed a "Capacity Adequate Portfolio" (CAP).
- Step 3 – Determine the reliability contribution: The TSO adds a specific technology and size of resource (e.g. a 100 MW, two-hour battery) to each Capacity Adequate Portfolio, then increases demand until the LOLE returns to three hours per year. The marginal derating factor is calculated as the ratio of the increase in demand to the additional capacity added, producing derating curves by technology and demand scenario.
- Step 4 – Calculate excess EUE and excess capacity: For each demand scenario, the TSO simulates its Capacity Adequate Portfolios under all other demand scenarios to estimate excess EUE and excess capacity. These outcomes are then monetising using the Value of Lost Load (VoLL) for unserved energy and CONE for excess capacity, allowing regret costs to be calculated.
- Step 5 – Select least-worst-regret outcome: This regret calculation is repeated for all demand scenarios, and the scenario with the lowest maximum regret cost is selected. The associated derating factors and derated capacity requirement are then applied in the capacity auction.

A.6 Ontario

As of September 2025, IESO reported 264 MW of storage capacity (representing less than 1% of their total installed capacity), mostly consisting of pumped storage. It is anticipated that Ontario's energy system will have 26 battery storage facilities with a combined capacity of 2,916 MW by year 2028.

[32] In Ireland the Regulatory Authorities consist of the Commission for Energy Regulation (CER)

A.6.1 Key issues

The *Effective Load Carrying Capacity of Energy Storage* paper investigated the capacity value of storage resources, and has stated the following issues: [33]

- Capacity Value, that is, the ability of storage resources to store energy and inject it into the system when needed. This is expected to decline as storage penetration increases, because duration-limited storage cannot sustain output during extended peak-demand periods.
- Short-duration storage can only respond to brief demand peaks. Consequently, system security and reliability may be at risk during prolonged periods of high demand.
- An increase in storage penetration may also increase competition for limited surplus energy available for charging, thereby increasing the risk that battery storage resources will not be fully charged when required.

A.6.2 Capacity Obligations

To participate in the Capacity Auction Market, an energy storage resource must be a non-committed, connected, and dispatchable facility that is registered prior to the obligation period. Capacity market participants are required to submit dispatch data and demonstrate their ability to meet capacity obligations through a Capacity Test.

For storage resources, this requires submitting offers and injecting energy at or above the greater of their cleared ICAP or minimum loading point for four consecutive hours. Successful performance is defined as delivering at least 95% of cleared ICAP on average. Failure to meet this requirement results in non-performance charges.

A.6.3 Capacity Qualification Calculation

The Unforced Capacity (UCAP) that a storage resource can offer is calculated by applying an availability derating factor and a performance adjustment factor to its Installed Capacity (ICAP). ICAP is defined as the lesser of the Energy Rating divided by a duration of four hours and the Full Power Operating Mode.

For storage resources, the availability derating factor is based on a fixed Equivalent Forced Outage Rate (EFORd) of 5%, while the performance adjustment factor reflects the resource's capacity test results and is subject to a minimum value of 0.75.

UCAP values are calculated and assigned by the system operator. However, the current methodology is under review to better reflect the diminishing marginal contribution and duration effects of increasing storage penetration.

[33] IESO Resource & Plan Assessment Technical Paper: Effective Load Carrying Capability of Energy Storage | August 2025

Appendix B. DSP Market Mechanisms and Obligations in other jurisdictions

This Appendix sets out the various market mechanisms that enable the participation of Demand Side Programmes, together with their respective obligations, across the five jurisdictions reviewed in Appendix A: Great Britain, PJM (USA), ISO New England (USA), Ireland (Ireland and Northern Ireland), and Ontario (Canada).

B.1 Great Britain

Demand Side Response (DSR) in Great Britain is defined as the ability of consumers to adjust their electricity consumption in response to price signals or incentive payments. Customers with either large-scale or small-scale assets may participate as DSR units, subject to the following conditions:

- Large-scale assets with the technical capability to meet NESO's metering, telemetry, and performance requirements may register directly in the market.
- Small-scale assets, such as domestic batteries, electric vehicles, or flexible commercial loads below 1 MW, must participate through an aggregator.

DSR units can provide any of the following services: Demand Flexibility Service (DFS), Capacity Market (CM) services, and Non-Balancing Mechanism services.

B.1.1 Demand Flexibility Services

Demand Flexibility Services (DFS) is a relatively new initiative that commenced during winter 2022/2023. DFS aims to incentivise homes and businesses to shift demand by reducing their electricity consumption or changing the times at which they use electricity.

Under this mechanism, the System Operator (NESO) assigns settlement periods during which a reduction in consumption is required, providing at least 48 hours' notice. Registered DFS participants can bid to reduce their electricity consumption during these periods, which typically have an average duration of (more or less) one hour.

DFS does not require complex telemetry systems or real-time control of the participating facility. Households with smart meters and businesses with half-hourly metering may voluntarily participate through their electricity retailers.

Currently, no penalties are incurred by customers who have signed up to provide DFS services but fail to reduce their consumption. Non-compliant customers are simply required to pay for their usual electricity consumption and do not face any additional financial consequences.

Between November 2022 and March 2023, 20 trial events and two live events were conducted, resulting in a total energy reduction of 3.3 gigawatt hours (GWh) across Great Britain. Approximately 2.6 million households and businesses were also able to earn revenue through this service during the winter of 2023/24.

B.1.2 Capacity Market

The Capacity Market in Great Britain conducts an annual auction for providers that undertake an obligation to deliver capacity when required by the system. DSR units are permitted to participate in the Capacity Market.

NESO publishes a Capacity Market Notice during a system stress event or when the capacity margin falls below 500 MW. Capacity Providers are expected to respond by delivering their committed capacity within four hours of the publication of the notice.

A key point to note for DSR units is that they are not derated using the existing EFC methodology applied in the Capacity Market. Instead, the historical availability of DSR providers participating in the Short-Term Operating Reserve (STOR) service is assessed to determine the required DSR volume. STOR is further discussed on Appendix B.1.3.

Around 677.3 MW of capacity was awarded to DSR units in the Capacity Auction for Delivery Year 2025/26. Despite this relatively high level of participation, the Government is continuing to develop reforms to the Capacity Market aimed at formally incorporating consumer-led flexibility through DSR technologies. Some of the key proposals include:

- Incorporating BTM technology classes to better quantify demand-side response
- Developing improved derating methodologies (e.g., incorporating DSR technologies into the EFC method)
- Reducing transaction costs for smaller capacity providers.

B.1.3 Non-Balancing Mechanism Services

Customers can offer to increase or decrease their electricity usage or generation depending on system needs. While DFS is technically a balancing service administered by NESO, this section focuses on Balancing Mechanism (BM) services that have more stringent technical and operational requirements, including communications systems and operational metering.

Frequency Response

Frequency Response Services require providers to respond within seconds of receiving a notice. DSR units can provide two types of frequency response: Fast Frequency Response (FFR) and Fast Reserve (FR).

- FFR service providers must respond within 2–30 seconds and sustain the response for up to 30 minutes.
- FR service providers must respond at a minimum rate of 25 MW per minute and sustain the response for 15 minutes. Consequently, the minimum capacity requirement is 25 MW.

Frequency Response Service providers are typically facilities equipped with battery storage, fast-ramping generators, or industrial processes capable of responding instantaneously to help stabilise system frequency.

Frequency Response services are typically procured through monthly tenders. However, some large generators provide mandatory frequency response through automatic changes in active power output.

In 2017, NESO procured 617 MW of DSR capacity for Frequency Response.

Short Term Operating Reserve (STOR) Services

STOR providers are required to respond within 20 minutes of receiving an instruction from the System Operator and sustain their response for up to four hours. A minimum capacity requirement of 3 MW applies to all participants, including DSR units, seeking to provide STOR services.

In 2017, NESO procured 1368 MW of DSR capacity for STOR services. In the 2024 auction, approximately 79% of STOR service contracts were awarded to DSR units.

B.2 PJM

Demand Response in PJM is defined as a consumer's ability to reduce electricity consumption when wholesale prices are high or when the system requires it for reliability purposes. However, this reduction in consumption must be measured against normal operating practices or behaviour. For example, a business that does not typically operate during holiday periods would not qualify as providing demand response during those periods.

Customers can participate in demand response programmes through a Curtailment Service Provider (CSP), which implements the necessary equipment, operational processes, and systems on the customer's behalf.

There are two different types of Demand Resources in PJM: Load Management Demand Resources (Emergency and Pre-Emergency) and Economic Demand Resources.

B.2.1 Load Management Demand Resources

Load Management Demand Resources are treated similarly to generators in the market and are expected to deliver capacity during periods of system reliability need. This category includes both Emergency and Pre-Emergency Demand Response resources.

Participants in this mechanism are subject to mandatory commitments and are required to respond to events that may occur on any day between June and May of the following year and may be of unlimited duration. Failure to comply with these obligations may result in a non-compliance penalty being imposed on the relevant participant.

PJM notifies the market when emergency demand response activation is required and then dispatches DR resources based on the most efficient combination of availability, location, dispatch price, and the quantity of load reduction required.

Load Management Demand Resources can participate in the following markets:

- Energy Market only (Emergency Loads only)
- Capacity Market only (DSP-like construct)
- Energy and Capacity Markets

CSPs are required to submit metering data to PJM to receive payment for participation. Participants receive compensation based on a combination of the applicable Reliability

Pricing Model (RPM) clearing price and their committed load reduction, together with an availability payment made monthly.

CSPs may also offer Summer-Only Resources in the auction. These resources are only required to be available from June to October and during May of the relevant delivery year.

In 2024, approximately 210.0 MW of demand response capability was registered to provide regulation services through load reduction. Of this capacity, 67.8 MW was provided by batteries, while 142.5 MW was provided by electric water heaters.

B.2.2 Economic Demand Resources

Energy Market

Economic Demand Response is a voluntary programme that is typically dispatched when wholesale energy prices exceed the monthly PJM Net Benefits Price (i.e., the price at which the benefits of reducing energy consumption exceed the costs of compensating Economic Demand Response resources).

DR units participating in the Energy Market are not subject to specific obligations regarding when they must respond or how long they must maintain their response to system needs.

Ancillary Market

An Economic Demand Response resource may also voluntarily participate in the Ancillary Services Market to provide the following services:

- Synchronised Reserves, which requires a response within 10 minutes of a PJM dispatch instruction;
- Day-ahead Scheduling Reserves, which require a response within 30 minutes of a PJM dispatch instruction; and
- Regulation services, which require resources to respond to frequency response signals.

However, once a DR resource has been certified to provide Ancillary Services, PJM expects the CSP to respond when dispatched to support system reliability. CSPs specify the hours during which each DR resource may be cleared or dispatched in the day-ahead and real-time markets.

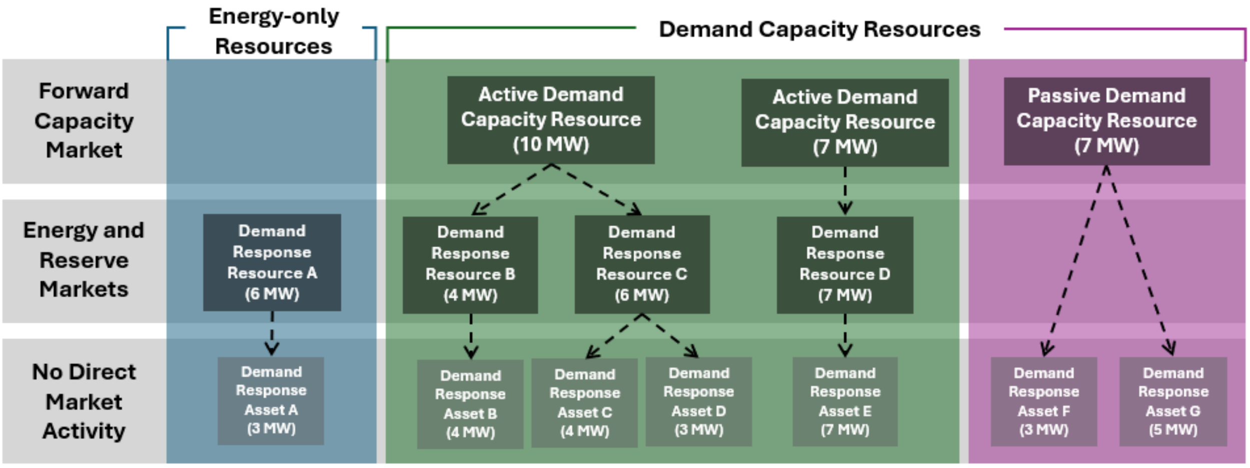
- In the Day-ahead market, a DR resource may offer load reductions in advance of real-time operations and receive payments based on the day-ahead Locational Marginal Price (LMP) for the quantity of load reduced.
- In the Real-time market, a DR resource may offer load reductions and receive payments based on the Real-Time LMP for the quantity of load reduced.

Compensation is based on the amount of load reduction provided. In addition, deviation charges may apply if PJM determines that the actual load reduction differs significantly from the reduction instructed or scheduled.

B.3 ISO New England

ISO New England defines demand resources as competitive assets that can reduce their electricity consumption to help ensure that the electricity supply remains sufficient, reliable, and cost-effective. There are various types of demand response that reflects a hierarchal structure, as displayed in Figure 12 and summarised below:

Figure 12: ISO-NE Market Structure for Demand Resources



Modified figure from source: [About Demand Resources (www.iso-ne.com)]

- Active Demand Capacity Resources (ADCRs) may consist of multiple Demand Response Resources.
  - ADCRs can participate in the Forward Capacity Market.
- Demand Response Resources (DRRs) may consist of multiple Demand Response Assets (DRAs).
  - DRRs can participate in the Day-Ahead and Real-Time Energy Markets, depending on their availability and the obligations of their associated ADCRs.
- DRAs are the physical assets or entities that provide the actual load reduction
  - DRAs are not allowed to directly participate in the energy, capacity, or ancillary services markets.
  - If a DRA has a capacity of 5 MW or greater, it cannot be aggregated and must be associated with its own DRR.
  - If a DRA has a capacity of less than 5 MW, it may be aggregated within a DRR. The aggregated DRR may exceed 5 MW in capacity.
- Passive Demand Capacity Resources do not curtail in response to dispatch notifications. Instead, they achieve load reductions through energy efficiency measures implemented during specified periods
- Passive Demand Capacity Resources can only participate in the Capacity Market. There are two types:
  - On-peak resources: may provide load reductions during summer peak periods (non-holiday weekdays from 1:00 PM to 5:00 PM in June, July, and August) and winter peak periods (non-holiday weekdays from 5:00 PM to 7:00 PM in December and January).
  - Seasonal-peak resources: may provide load reductions during June, July, August, December, and January when the real-time hourly load is equal to or greater than 90% of the system peak-load forecast for the relevant season.

DRRs in ISO New England are subject to seasonal audits during the capability demonstration year (April through November for the summer season, and December through March for the winter season). The purpose of these audits is to determine the resource's ability to perform through one of the following methods:

- Dispatching the resource between 8:00 AM to 10:00 PM for a duration of one hour (12 consecutive 5-minute intervals); or
- Assessing the historical performance of the resource when dispatched on a date and start time specified by the lead market participant, for the same duration of one hour (12 consecutive 5-minute intervals).

B.4 Ireland (Ireland and Northern Ireland)

The Demand Side Management allows customers to participate by reducing their electricity consumption during peak periods or by lowering their overall electricity usage. In addition to reducing their electricity bills, participating consumers may also receive financial incentives through tariff-based schemes.

Both Ireland and Northern Ireland have established demand side management mechanisms.

B.4.1 Demand Side Unit

Demand Side Units (DSUs) are third party companies that specialise in providing demand-side services by aggregating one or more Individual Demand Sites (IDSs). These sites are typically medium- to large-scale industrial facilities that can adjust their energy consumption by generating electricity on-site, shutting down plant operations, or using a combination of both approaches. DSUs must have a minimum capacity of 4 MW to register and participate in the Capacity Market and Ancillary Services markets.

There are two operating models for DSUs:

- Peaking types are price-responsive and are only required when energy market prices are high. They are activated relatively infrequently and are typically required for a limited number of periods.
- Long-run types are expected to continuously reduce their net electricity imports from the grid. This model is commonly used by businesses that have their own generating units to meet on-site demand.

Capacity Market

DSUs are awarded one-year Capacity Contracts based on the results of the Capacity Auction. In the 2023 Capacity Auction, 639 MW of DSU capacity in Ireland and 136 MW of DSU capacity in Northern Ireland were successful in the auction.

Ancillary Market

DSUs participating in the Ancillary Services Market are required to receive and respond to Dispatch Instructions issued by the Transmission System Operator (TSO). If a DSU is dispatched to provide Ancillary Services, it must respond within one hour of receiving the instruction and sustain its response until the next Dispatch Instruction is issued or until the DSU's Maximum Down Time has been reached.

DSUs are also required to maintain a Performance Monitoring Error (PME), defined as the difference between the baseline response and actual performance, of less than 0.25 MWh over a full quarter-hour period.

B.4.2 Aggregated Generating Unit

Aggregated Generating Units (AGUs) are currently specific to Northern Ireland and had a total registered capacity of 79 MW in 2023. AGUs consist of aggregations of small diesel and gas-fired generators, each with a capacity of less than 10 MW.

Similar to DSUs, AGUs are dispatched by instructing generation across multiple sites within the aggregation. However, AGUs are not considered a demand-side response service. Instead, they are treated in a manner similar to conventional generators, as they do not alter on-site electricity consumption.

B.4.3 Forthcoming Demand Side Mechanisms

There are several Demand Side Programmes that have either recently been introduced or are currently under development. Some of these include:

- The Dispatchable Consumption Unit mechanism aims to increase on-site electricity consumption in response to dispatch instructions and price signals from the energy market
- The Flexible Demand mechanism, which is specific to data centres in Ireland, enables EirGrid to instruct participating data centres to reduce their electricity demand when required.
- Mandatory Demand Curtailment applies to large industrial consumers connected to the transmission network at voltages of 100 kV or greater. Under this mechanism, participants may be required to reduce their demand to pre-agreed levels when the system enters an Emergency State. A reduction in consumption of up to 50% is expected within one hour of the instruction being issued.
- Other implicit demand side response initiatives are also under development in Ireland. These mechanisms rely on indirect signals and are expected to be enabled through technological advancements and policy measures that incentivise load shifting.

B.5 Ontario

Demand Response in Ontario enables customers to reduce their electricity consumption during periods of high demand. There are two main demand response mechanisms in Ontario: the Capacity Auction and the Industrial Conservation Initiative (ICI).

B.5.1 Capacity Auction

The Independent Electricity System Operator (IESO) previously operated a separate Demand Response Auction that functioned similarly to the Capacity Auction. However, this programme was discontinued, and demand response resources are now required to participate in the Capacity Auction alongside generation, energy storage, and import resources.

The capacity obligation applies over a six-month period, during which a demand response resource may be required to reduce its electricity consumption during either the summer period, the winter period, or both, for up to four consecutive hours. Demand response resources receive payments based on the auction clearing price in exchange for making their capacity available during the following periods:

- Summer period: 12:00 PM to 9:00 PM (May 1 to October 31); and/or
- Winter period: 4:00 PM to 9:00 PM (November 1 to April 30).

B.5.2 Industrial Conservation Initiative (ICI)

The ICI is intended for large industrial electricity consumers in Ontario. Participants in the ICI are compensated for shifting or reducing their electricity demand during periods of system stress. As a result, the ICI assesses a participant's average monthly maximum hourly demand, rather than its installed capability, to determine eligibility for participation in the initiative.

Participants must maintain their availability from May through April and are compensated based on their performance during the five highest system peak hours over the corresponding one-year period.

There are two classes of customers that may participate in the ICI:

- Class A (1 MW and above)
    - Customers with an average monthly demand of between 1 MW and 5 MW may opt into the ICI programme by 15 June of each year, provided they satisfy all other eligibility requirements.
    - Customers with an average monthly demand exceeding 5 MW are automatically enrolled in the ICI programme. If a participant wishes to be excluded from the initiative, it must opt out by 15 June of each year.
- Class B (500 kilowatts (kW) to 1 MW)
    - IESO has lowered the eligibility threshold by introducing a new class of customers with an average monthly maximum demand greater than 500 kW and less than 1 MW. These customers may opt into the ICI programme by 15 June of each year.
    - Customers with a maximum hourly demand greater than 5 MW that have opted out of the ICI programme will be treated as Class B customers. Similarly, current Class A customers that do not meet the eligibility threshold for the following year will be settled as Class B customers.

Appendix C. Evaluation for rating the capacity of Electric Storage Resources for the purposes of setting Certified Reserve Capacity

C.1 Evaluation criteria

ESR derating options were assessed against the following criteria and outcomes, each of which is aligned with one or more of the three limbs of the SEO.

Table 16: Evaluation criteria used to assess ESR derating options

Criteria/outcome sought	Map to SEO
Provides value for money by reasonably approximating contribution of ESRs to reliability	Over-estimating contribution can lead to under-procurement, adversely affecting the security & reliability limb. Under-estimating contribution can lead to over-procurement, adversely affecting the pricing limb.
Method is transparent and predictable	Complex opaque methods may deter investment in new batteries which could adversely affect the security & reliability, pricing and environment limbs of the SEO.
Method does not result in volatile allocation from year to year	Uncertainty and volatility of capacity revenue streams may deter investment in new batteries which could adversely affect the security & reliability, pricing and environment limbs of the SEO.
Approach does not distort RCM and RTM investment signals	The RCM and RTM provide scarcity pricing signals to investors. Policies involving frequent intervention or off-market procurement to provide the same service (e.g. getting energy/capacity through SC/NCESS) will erode investment signals in the WEM and could result in higher than otherwise long-term costs for the consumer therefore affecting the pricing limb of the SEO.
Cost and complexity of implementation is reasonable	Costly implementation will add to market participant costs (through increased market fees) which adversely affects the pricing limb of the SEO.

C.2 Options evaluated

The ESR derating options evaluated are summarised in the table below. See also Chapter 2.1.

Table 17: ESR derating policy options evaluated

Option	Description
Status Quo	Linearly Derating Methodology (degraded maximum charge capability by the relevant ESROD value) • Incumbent ESRs retain the original ESROD for ten years; and • Over-allocation of capacity to incumbent ESRs is added back into the Planning Criterion via ESROD Uplift.
Option 1: Incorporate storage into amended RLM	Incorporate ESRs into the amended Appendix 9 (Last-in Fleet ELCC) (adopting same approach as for CC3). • ESR output for facilities that have not been operational for the full RLM Reference Period is estimated via “perfect-foresight” heuristic that allocates ESR capacity to Trading Intervals to minimise peak demand or unserved energy. • Fleet ELCC is allocated to individual Facilities in proportion to their output during the 12 Peak SWIS Intervals.
Option 2: Implement individual ELCCs	Per Option 1, however, implement individual ELCCs for both ESRs and CC3. This would require replacing the amended Appendix 9 which uses Fleet ELCCs so that all intermittent generation and storage is allocated individual ELCCs
Option 3: Option 1 with least-worst regrets analysis	Same as Option 1 but replace demand scenarios with least worst regrets analysis. (This calculates ELCCs for multiple demand scenarios and capacity adequate portfolios and selecting the results of the demand scenario that minimises the worst regret cost)

C.3 Evaluation results

In this evaluation, the four options above are evaluated against the criteria summarised in Table 16.

C.3.1 Status quo

Table 18: Evaluation of the LDM against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability	Does a reasonable job approximating contribution to peak period reliability but does not represent contribution to overall reliability. Grandfathering arrangements mean that the capacity allocated to incumbent ESRs does not reflect the physical capacity needed to meet demand during the Peak Demand Period. Contribution to reducing peak demand will be over-estimated if participants do not reflect their minimum charge levels (or depth of discharge) correctly at time of certification. *Criteria met partially*
Method is transparent and predictable	The current system is reasonably simple and transparent. • The LDM component is very simple and transparent. • By contrast, the approach used to determine the ESROD is somewhat complex (but not as complex as implementing an ELCC approach). *Criteria met substantially*
Method does not result in uncertainty or volatile allocation from year to year	There should be no uncertainty in the LDM component as the participant will know their degradation profile ahead of time. There is an element of uncertainty for investors where the ESROD changes which would result in them receiving less capacity (than they would with a lower ESROD). However, the grandfathering arrangements address this concern. *Criteria met substantially*
Cost and complexity of implementation is reasonable	This approach is already implemented and therefore has no implementation costs associated with it. *Criteria met fully*
Overall Performance	Most criteria met substantially

C.3.2 Option 1: Incorporate ESRs into new RLM (Last-in Fleet ELCC)

Table 19: Evaluation of Option 1 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability	This approach results in a more accurate representation of the storage fleet's contribution to overall system reliability compared with the status quo. However, as the ELCC is calculated for the entire fleet and allocated afterwards, the

Criteria	Evaluation
	resulting RLM of each ESR does not reflect its individual marginal contribution to reliability. This approach also discourages charging and encourages high output during high demand periods. *Criteria met substantially*
Method is transparent and predictable	ELCC algorithms are complex, and it is unlikely that participants will be able to predict their ELCCs unless they have the required modelling infrastructure set up. *Criteria not met*
Method does not result in uncertainty or volatile allocation from year to year	This approach carries some risk of changes in ELCCs year-on-year. However, as previously noted, this risk is mitigated through the use of fleet ELCCs and by calculating the Fleet ELCC over the entire ELCC Reference Period and for each individual Capacity Year within the period and taking the average. Under this approach it is likely that the capacity associated with ESRs will change year on year, albeit not as drastically as it would under an individual ELCC approach. *Criteria met partially*

Cost and complexity of implementation is reasonable	As this option is already being implemented for CC3 technologies, the cost associated with this option relates to the additional implementation actions needed to incorporate storage. This would include:
	• ESM Rule amendments to assess ESRs under new Appendix 9
	• Changes to system implementation to include storage. This would include:
	  - Adding storage fleet calculations to the algorithm. Storage output should be anti-correlated with intermittent generation. As such, storage ELCCs can be calculated after the intermittent generation ELCCs have been calculated (for each of the Committed, Proposed, Early and Conditional categories)
	  - Implementing a heuristic to model the dispatch of new ESRs without historical output data.
	• Refund calculations for ESRs would need to be amended to apply over all Trading Intervals (not just ESROIs) with exemptions made for charging.
	Criteria met partially

Overall Performance	Some criteria met substantially or most met partially ◐

C.3.3 Option 2: Implement individual Last-in ELCC

Table 20: Evaluation of Option 2 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability	Like Option 1, this approach yields a more accurate estimate of the reliability contribution of individual ESRs than the status quo. However, the individual ELCC approach results in under-estimating the contribution of resources that are added later in the algorithm. This means that the sum of the individual ELCCs will not equal the ELCC of the fleet as a while. Hence, Option 1 outperforms Option 2 in terms of accuracy of fleet contribution. *Criteria met partially*
Method is transparent and predictable	See Option 1. *Criteria not met*
Method does not result in uncertainty or volatile allocation from year to year	This option has a high risk of allocations changing materially year on year as noted by the PJM experience. *Criteria not met*
Cost and complexity of implementation is reasonable	This option would involve replacing the amended Appendix 9 with the new approach. Given the new RLM was widely consulted on, replacing it is not a prudent approach. Moreover, this option would be more computationally intensive as AEMO would have to repeat the analysis for individual facilities (as opposed to calculating Fleet ELCCs). *Criteria not met*
Overall Performance	Most criteria not met ○

C.3.4 Option 3: Implement Option 1 with least worst-regrets analysis

Table 21: Evaluation of Option 3 against the SEO

Criteria	Evaluation
Provides value for money by reasonably approximating contribution of ESRs to reliability	The ELCC calculation approach under this option is similar to Option 1. The key difference is that the Fleet ELCCs are calculated for multiple demand scenarios, and regret costs are calculated to assess which demand scenario minimises the maximum regret cost. This method outperforms Option 1 as it has a more robust approach to incorporating the impacts of weather variation. *Criteria met fully*
Method is transparent and predictable	This approach is even more unclear than Option 1 due to the use of multiple demand scenarios and least-worst regrets analysis.

Criteria	Evaluation
	Criteria not met
Method does not result in uncertainty or volatile allocation from year to year	See Option 1 *Criteria met partially*
Cost and complexity of implementation is reasonable	As with Option 2, this option would involve replacing the amended Appendix 9 with the new approach which has already been consulted on. Like the individual ELCCs, implementation would be very complex as the Fleet ELCCs have to be recalculated for multiple demand scenarios. The least-worst regrets analysis involves another round of simulations in which capacity adequate portfolios developed with a specific demand scenario are run against all other demand scenarios to calculate the regret cost. A further problem with this approach is that the Planning Criterion and therefore the Reserve Capacity Requirement is linked to the 10% POE peak demand forecast (through the first limb of clause 4.5.9). Allocating ESR and CC3 capacity using different peak and energy assumption could result in misalignment between the Reserve Capacity Requirement and capacity allocations. This could be resolved by only using demand scenarios with a 10% POE peak forecast. *Criteria not met*
Overall Performance	Some criteria met partially

Appendix D. Technical Analysis

The Technical Analysis was conducted in two stages:

- A current state analysis focused on historical SSEs and the historical dispatch of DSPs;
- A future state analysis (using AEMO modelling) to forecast when ESRs will be required to avoid unserved energy in the near future.

The scope, methodology and detailed results are presented in this appendix.

D.1 Current State Analysis

The current-state technical analysis examined historical SSEs to understand the following:

- When do SSEs typically occur in terms of time of year and time of day?
- How long do SSES typically last?
- What were the charge levels of ESRs prior to entering their ESROD on SSE days?

D.1.1 What is a System Stress Event?

SSEs were identified by reviewing AEMO Market Advisories and Manual Constraints issued between November 2023 and August 2025 (including the Significant Incident of 25 August 2025), using the following approach:

- Market Advisories containing Low Reserve Condition declarations were used as the primary indicators of SSEs;
- Market Advisories relating to energy and ancillary services shortfalls were also considered indicative of SSEs;
- Manual (non-network) constraints applied by AEMO were reviewed to identify additional events not captured by Market Advisories;
- SSE start times were based on the start time specified in the most recent advisory relating to the event, allowing any changes in event timing to be captured;
- SSE end time were based on the end-time specified in the most recent advisory relating to that event;[34] and
- SSEs that were resolved without Directions or load shedding were excluded.

This process resulted in a final dataset comprising 26 confirmed SSEs.

Table 22 shows the types of Market Advisories and Manual Constraints that were included and excluded.

[34] Note that: SSE duration (end time - start time) doesn't necessarily reflect how long ESRs would be required.

Table 22: Inclusion and Exclusion of Market Advisories and Manual Constraints

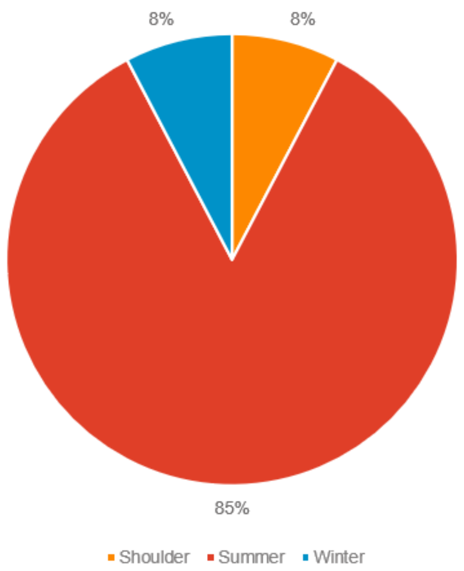
Dataset	Includes	Excludes
Market Advisories **25 SSEs identified**	Energy & ancillary services shortfalls	• Non-shortfall events (transmission or comms events) • Minor manual constraints • Ramp rate or RRS shortfalls • Emergency of High-Risk Operating State advisories due to system instability • Network and infrastructure failures
Manual constraints **1 SSE identified**	Non-network constraints applied outside the above SSE durations	• Constraints relating to above SSEs • Network constraints • RoCoF shortfalls • Muja 6 reserve mode

D.1.2 Characteristics of SSEs

Seasonality and causes of SSEs

While SSEs are often associated with summer conditions, the analysis showed that they were not exclusively a hot-season phenomenon, with 16% of events occurring during shoulder and winter months. Figure 13 shows the seasonality breakdown of the 26 identified SSEs.

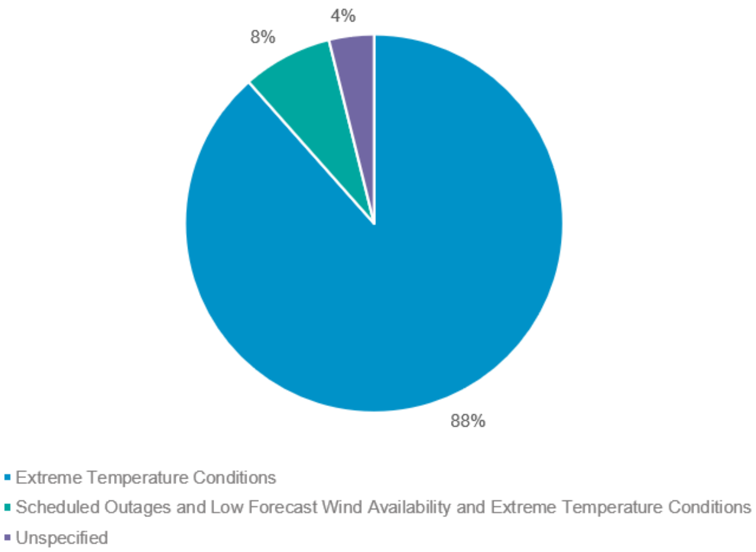
Figure 13: Seasonality of SSEs



The majority of SSEs also occurred on Business Day, with only 4 out 26 events occurring on non-Business Days.

The majority of events (88%) were triggered by extreme temperatures, most commonly high summer temperatures. While 8% were triggered by a combination of high temperatures, low wind availability and scheduled outages. Figure 14 shows the percentage breakdown of the main causes of the 26 SSEs

Figure 14: Common Causes of SSEs



Timing of SSEs

Figure 15 shows the number of SSEs on Business Days by Trading Interval, comparing their start and end times against the current 2025-2026 ESROI (applied to incumbent ESR) and the future 2027-2028 ESROI (to be applied to new ESRs).

Most SSEs on Business Days began earlier than 17:30 (the start of the first ESROI applicable to grandfathered ESRs).[35] The six-hour ESROD (commencing at 16:30) provides better coverage of these events; however, 19 of the 26 SSEs still commenced before 16:30.

As noted in Chapter 2.2, an SSE starting prior to the ESROD does not necessarily mean that AEMO would have required ESR dispatch to avoid unserved energy. Although many of these events began before the ESROD, peak demand and the tightest capacity margins generally occurred during the Mid-Peak ESROI, indicating that the existing ESROIs are broadly aligned with periods of system need.

[35] All four SSEs that occurred on Non-Business Days started before 16:30.

Figure 15: Start and End Times of SSEs that occurred on Business Days

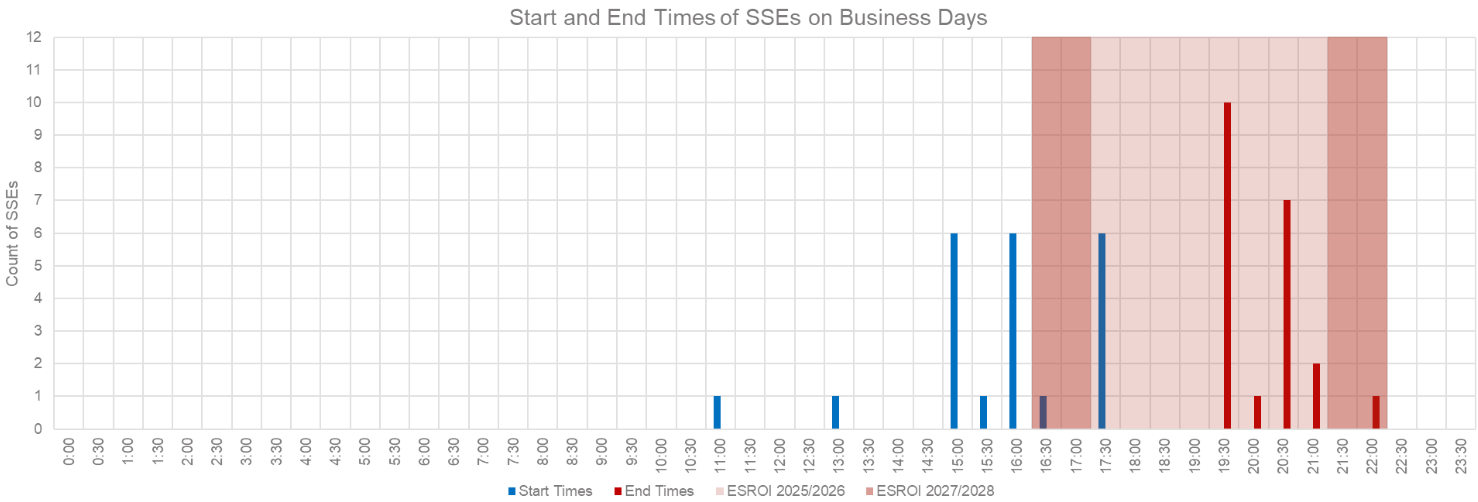
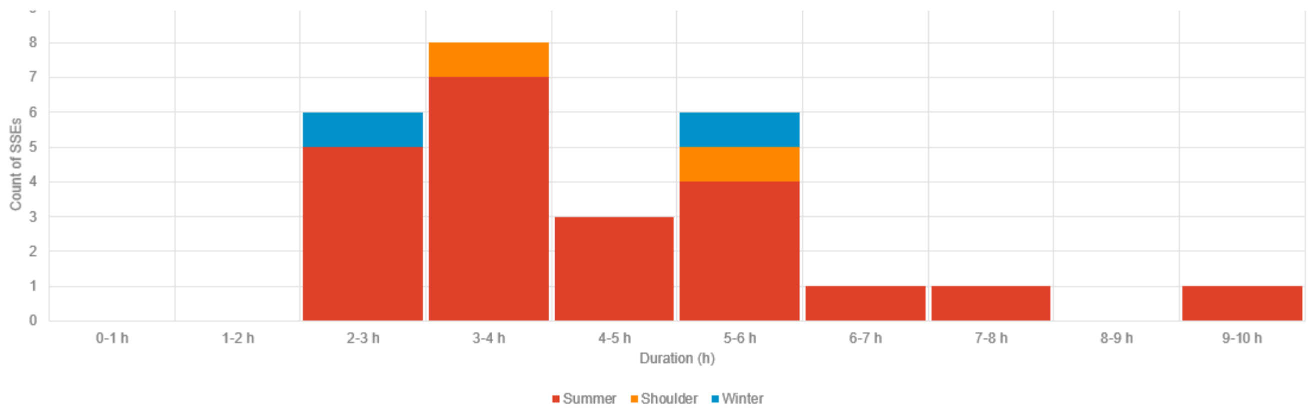


Figure 16 summarises the distribution of SSE duration. Most SSEs are relatively short, typically lasting three to four hours. Three longer duration events (6 to 10 hours) were also identified, all of which occurred during the summer months. While longer-lasting events do occur, they are considerably less common and are most likely to occur during summer.

Figure 16: SSE duration by season



D.1.3 Analysis of ESR behaviour in the 48 hours leading up to the SSE

FCESS, Energy dispatch, and WEM Energy price data was analysed to determine whether any trends in ESR charging and discharging behaviour could be identified. This analysis was undertaken to access ESR charging behaviour during their ESROIs on SSE days.

The data used to conduct this analysis is summarised in Table 23 below.

Table 23: Datasets used to conduct analysis

Data	Description	Source
SCADA Case Data	Details of the state of charge for each ESR	Market Surveillance Data Catalogue (MSDC) Database
Facility Energy Dispatch schedule quantity	Details of available capacity and energy dispatch by facility	MSDC Database
Facility Regulation Raise enablement quantity	Details of regulation raise dispatch by facility	MSDC Database
Facility Regulation Lower enablement quantity	Details of regulation lower dispatch by facility	MSDC Database
Facility Contingency Raise enablement quantity	Details of contingency raise dispatch by facility	MSDC Database
Facility Contingency Lower enablement quantity	Details of contingency lower dispatch by facility	MSDC Database
WEM Dispatch Solution Data	Only WEM energy prices data was analysed	AEMO market data website

The period analysed was 48 hours prior to the start of each SSE (across the 26 identified SSEs) until the end of each SSE. Five SSEs in the sample included instances where large ESR Facilities were at below 50% charge either at the start of the SSE or the first ESROI.

For the five SSEs selected for further analysis, Table 24 below shows the dates, start times, end times, and ESR charge levels. For the SSE that commenced after the start of the ESROI (28/08/2025), the charge level of COLLIE_ESR1 was below 50% both at event start and ESROI start.

Table 24: 5 SSEs with low ESR Charge Level

#	SSE Date	SSE Start Time	SSE End Time	ESR Charge Level at SSE start	ESR Charge Level at ESROI start	ESROI Start
1	13/01/2024	16:00	20:00	KWINANA_ESR1: 35%	KWINANA_ESR1: 50%	16:30

#	SSE Date	SSE Start Time	SSE End Time	ESR Charge Level at SSE start	ESR Charge Level at ESROI start	ESROI Start
2	10/12/2024	15:00	20:30	KWINANA_ESR1: 42%	KWINANA_ESR1: 62%	17:30
3	23/01/2025	13:00	20:30	COLLIE_ESR1: 44%	COLLIE_ESR1: 64%	17:30
4	25/08/2025	17:45	23:40	COLLIE_ESR1: 17%	COLLIE_ESR1: 22%	17:30
5	11/12/2024	15:00	20:30	KWINANA_ESR1: 70%	KWINANA_ESR1: 32%	17:30

To investigate the factors contributing to the low charge levels observed during the five SSEs identified above, FCESS enablement quantities and WEM energy prices over the preceding 48-hour period were analysed to identify any common drivers of charging and discharging behaviour.

Relationship between FCESS enablement and charge levels

Figures 17 to 19 show the relationship between FCESS enablement quantities and SSEs #2 to #4. These SSEs occurred after the implementation of the FCESS Cost Review ESM Rule Changes, and SSE #2 encompasses most of the 48-hour period preceding SSE #5.

To note about SSE #2:

- it occurred on 10/12/2024 from 15:00 to 20:30, with KWINANA_ESR1 having 42% charge level at event start; and
- SSE #2 was caused by extreme temperature conditions (heatwaves)

All figures should be interpreted in the same way. For example, Figure 17 illustrates FCESS enablement quantities compared with the charge level of KWINANA_ESR1 during SSE #2, where:

- the figure covers the period from 24 hours prior to the start of the SSE through to the end of the SSE;
- the orange shaded area indicates the duration of the ESROI
- the yellow shaded area indicates the portion of the SSE occurring before the ESROI; and
- the lines represent FCESS enablement quantities (Regulation Lower, Contingency Lower, Regulation Raise, and Contingency Raise), measured in MW.

A review of FCESS enablement and charge-level patterns across multiple SSEs showed no clear relationship between low charge levels and FCESS dispatch. This result is consistent with expectations, as an ESR charge level only needs to support FCESS dispatch for the subsequent five-minute interval. As a result, an ESR can be enabled to provide FCESS across a wide range of charge levels.

Figure 17: FCESS Quantities for SSE #2 on 10/12/2024 from 15:00 to 20:30: KWINANA_ESR1 had 42% charge level

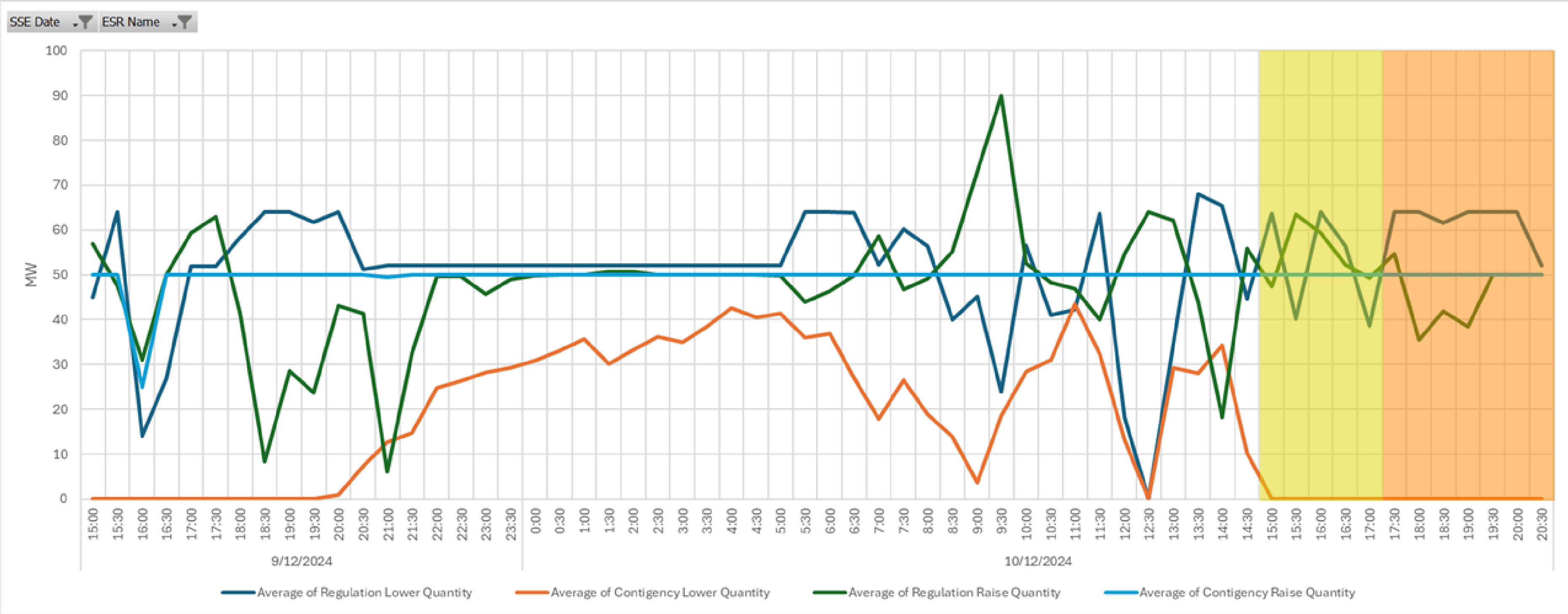


Figure 18: FCESS Quantities for SSE #3 on 23/1/2025 from 13:00 to 20:30: COLLIE_ESR1 had 44% charge level

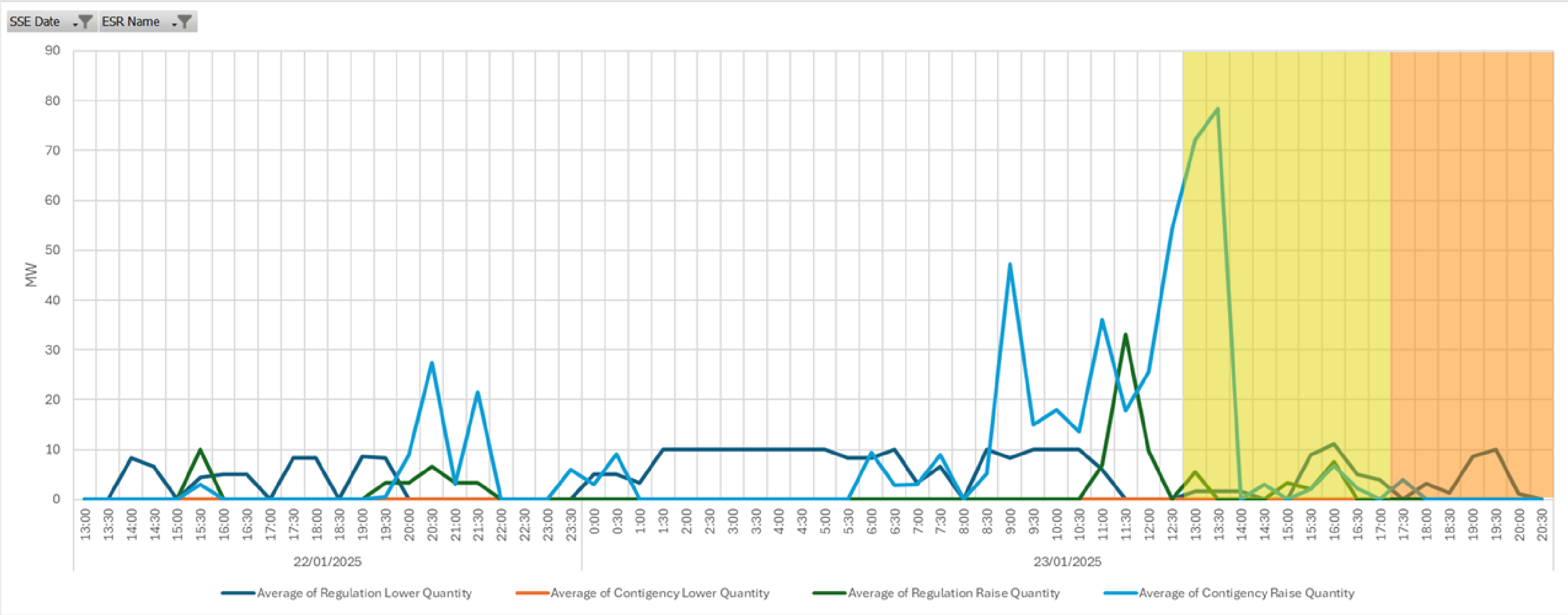
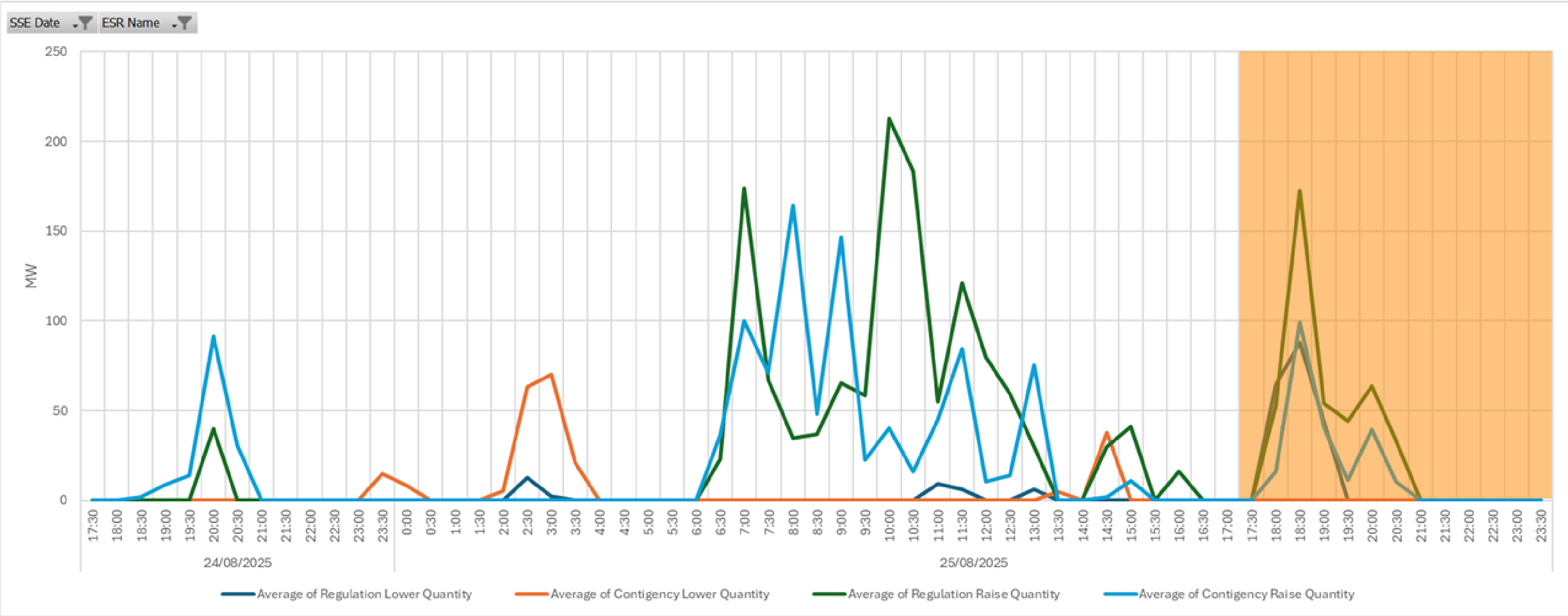


Figure 19: FCESS Quantities for SSE #4 on 25/8/2025 from 17:45 to 23:40: COLLIE_ESR1 had 17% charge level



Relationship between FCESS enablement and WEM Energy Prices

WEM energy price data was also analysed for the five SSEs and compared with individual ESR charge levels at the start of these events.

The following graphs compare ESR charge level with WEM energy prices for the five of the identified SSEs:

- each graph covers the period from 24 hours prior to the start of the SSE through to the end of the SSE;
- orange shaded areas indicate the duration of the ESROI;
- yellow shaded areas indicate the portion of the SSE occurring before the ESROI;
- pink lines represent WEM Energy Prices (AUD/MWh); and
- dark green lines represent the ESR charge level.

Figure 20: ESR Charge levels vs. WEM Energy Price for SSE #1 on 13/01/2024 from 16:00 to 20:00 KWINANA_ESR1 had 35% charge level at event start

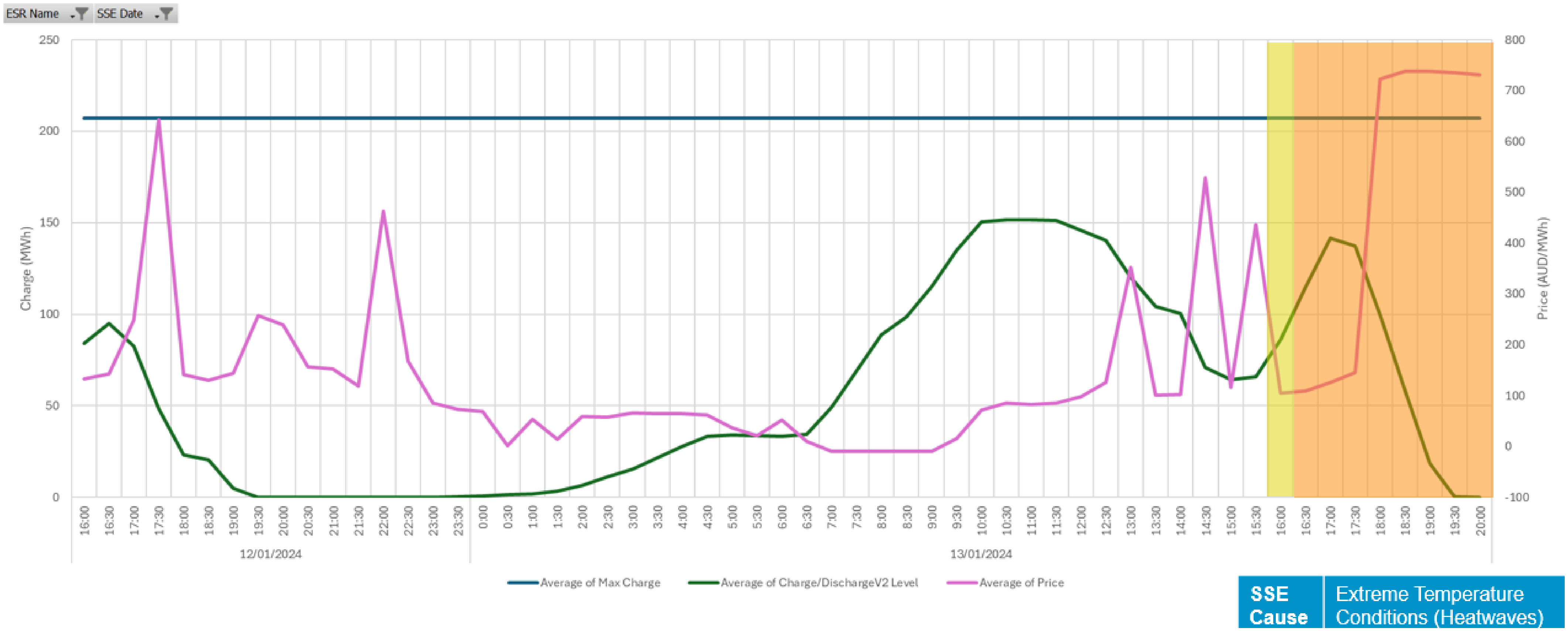


Figure 21: ESR Charge levels vs. WEM Energy Price for SSE #2 on 10/12/2024 from 15:00 to 20:30 KWINANA_ESR1 had 42% charge level at event start

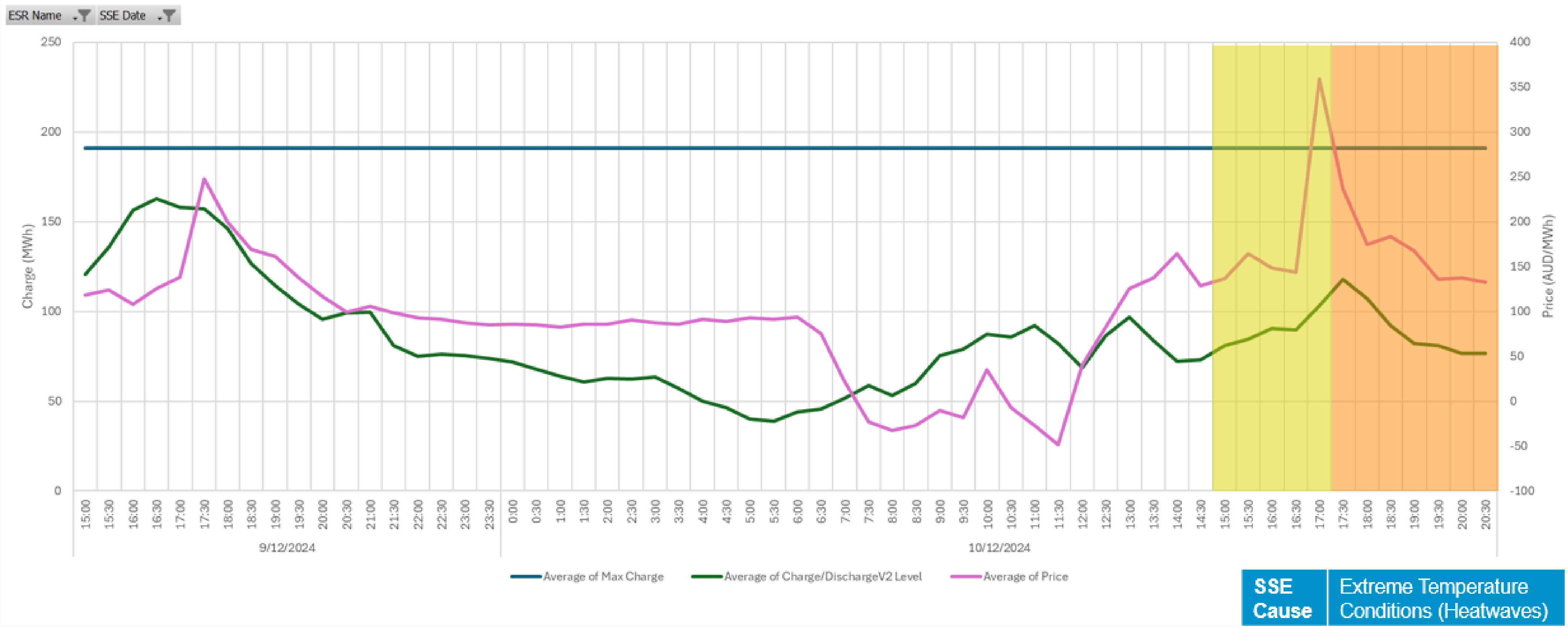


Figure 22: ESR Charge levels vs. WEM Energy Price for SSE #3 on 23/01/2025 from 13:00 to 20:30 COLLIE_ESR1 had 44% charge level at event start

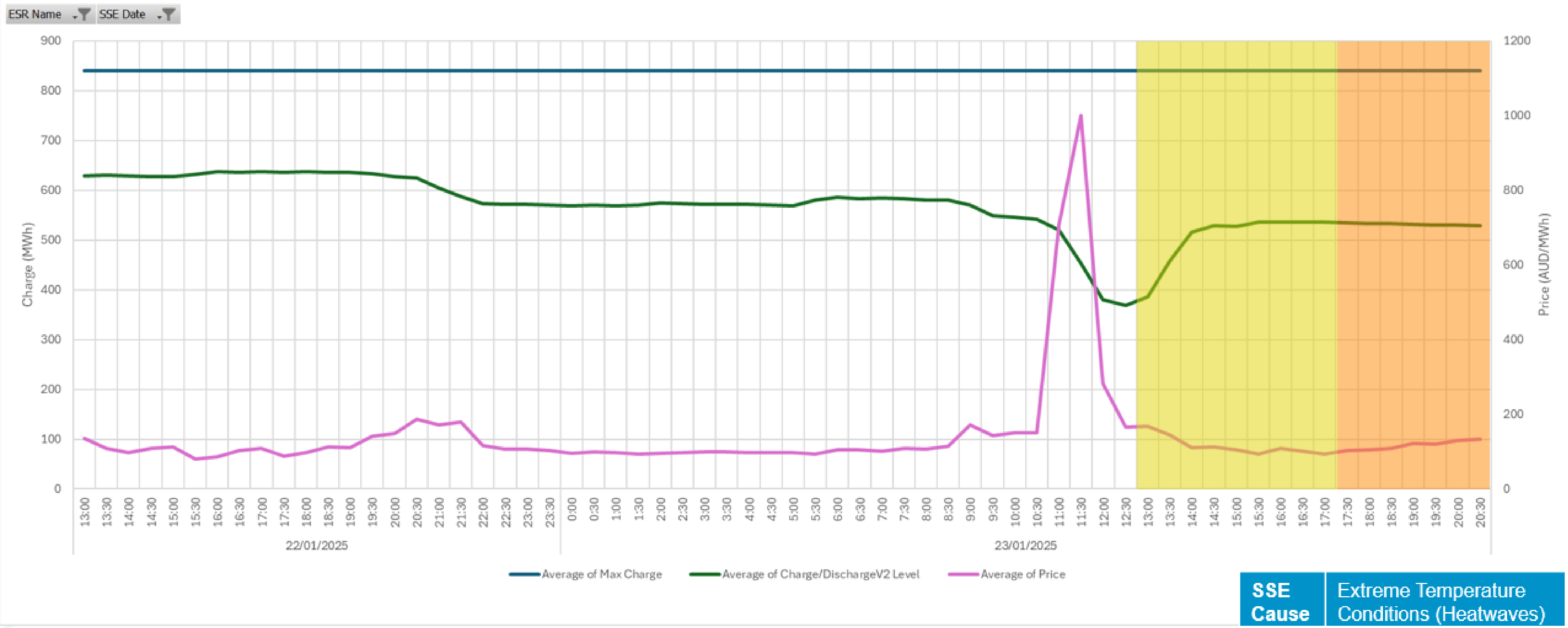


Figure 23: ESR Charge levels vs. WEM Energy Price for SSE #4 on 25/08/2025 from 17:45 to 23:40 COLLIE_ESR1 had 17% charge level at event start

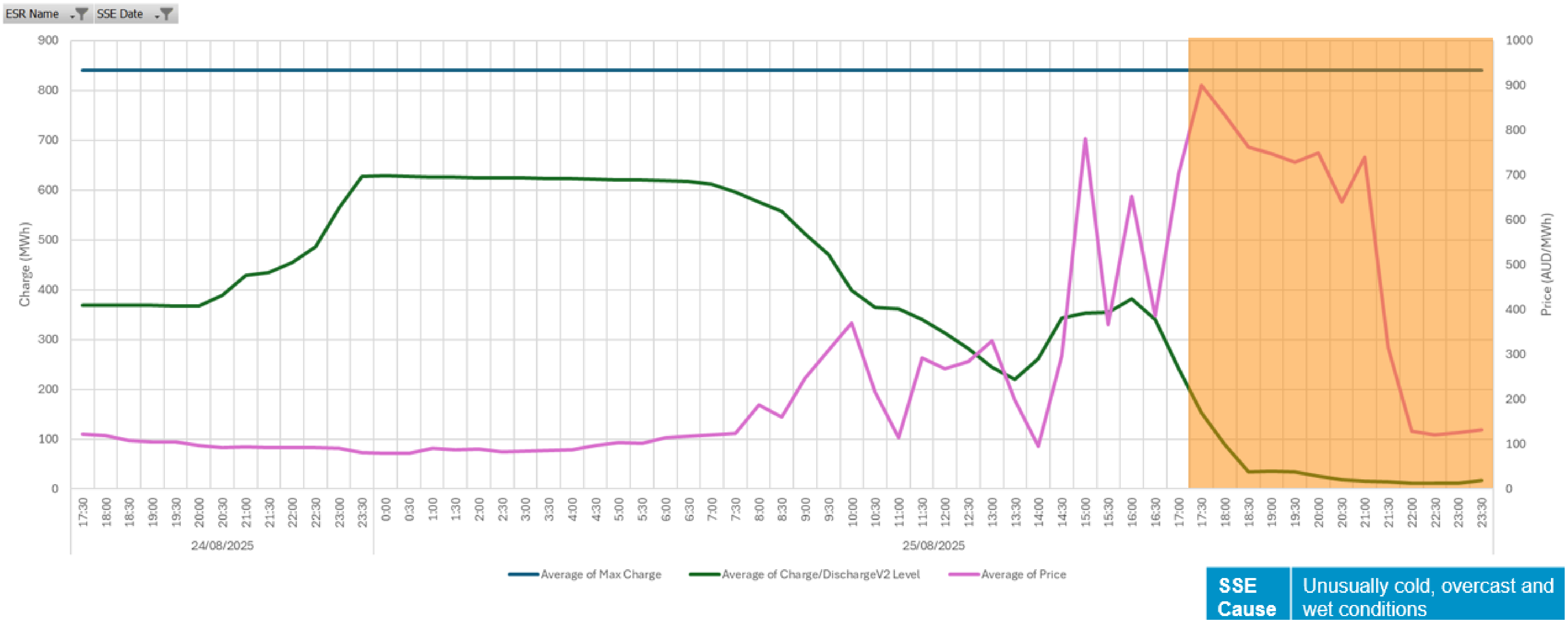


Figure 24: ESR Charge levels vs. WEM Energy Price for SSE #5 on 11/12/2024 from 15:00 to 20:30 KWINANA_ESR1 had 32% charge level at ESROI start (orange)

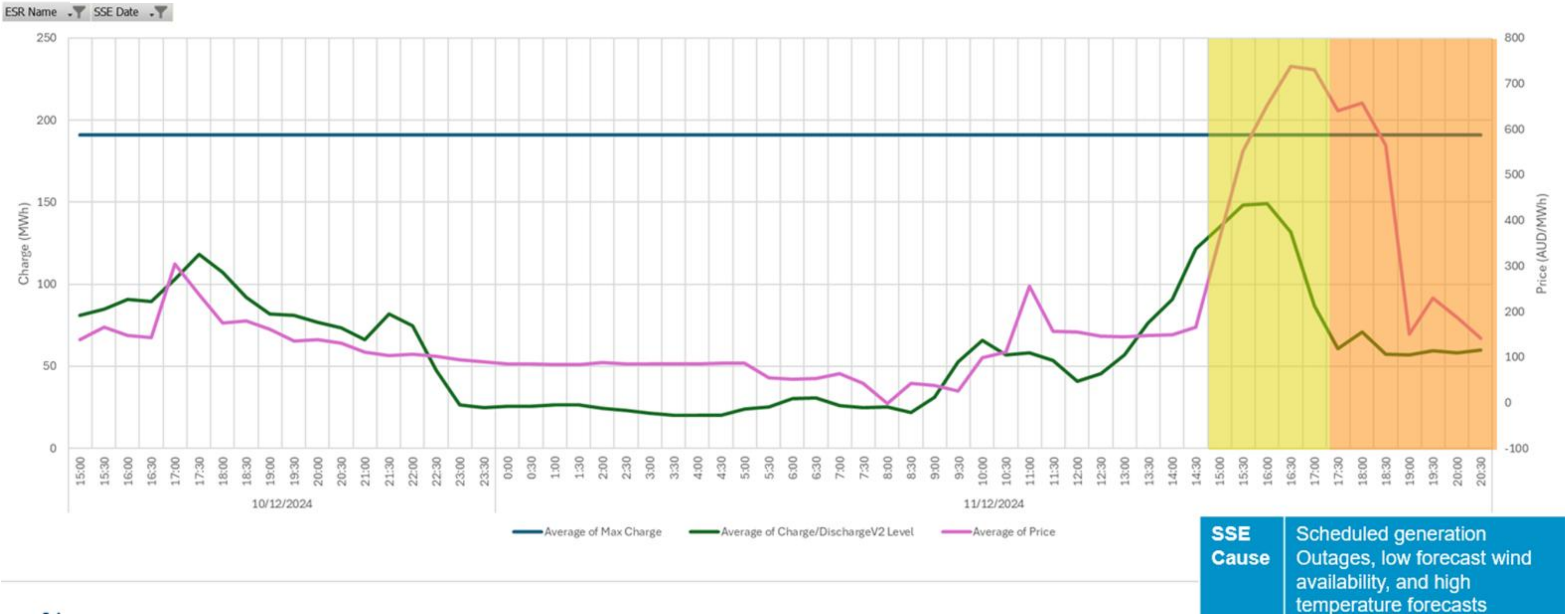


Figure 20 to Figure 24 indicate a potential relationship between high WEM Energy Prices earlier in the day and low ESR charge levels at the commencement of ESROIs. Across all five SSEs, ESRs were observed to discharge during periods of higher energy prices and commence charging as prices declined. This behaviour may result in ESRs not being sufficiently charged by the time their ESROIs commence.

The estimated energy revenue earned from discharging during periods of high energy prices was compared with the refund exposure of the relevant ESRs (KWINANA_ESR1 and COLLIE_ESR1) on the relevant SSE days.[36] Data available to the Coordinator indicate that, in each instance, the estimated energy revenue exceeded the corresponding refund amount for the ESR.

D.2 Future State Analysis

AEMO has conducted modelling to forecast the conditions under which ESR dispatch may be required over the next nine years. The AEMO model:

- considers five reference years of half hourly demand profiles and intermittent generation availability;
- models 20 outage scenarios to assess their impact on unserved energy;
- allows ESRs to be dispatched up to their Capacity Credits, with perfect foresight, to optimally avoid unserved energy (i.e., ESROIs are not considered); and
- places ESRs at the top of the merit order (but behind DSP) to ensure that they operate only during events that would otherwise result in unserved energy.

The modelled behaviour of ESRs will be analysed to better understand the conditions under which ESR dispatch is required.

Figure 25 illustrates the structure of the modelling framework, showing how inputs are processed through a reliability model to produce outputs. On the input side, the model uses demand forecasts, intermittent generation time series, facility assumptions, reserve requirements, historical data, outage data, and other modelling assumptions and constraints.

These inputs are processed by the reliability model to produce facility-level outputs (dispatch, outages, and reserve provision) and system-level outputs (Expected Unserved Energy), all at 30-minute intervals. The outputs are then aggregated into the formats required for analysis and reporting.

[36] Estimate Revenue from energy was calculated by multiplying energy sent-out (MWh) by WEM energy price ($AUD) for each dispatch interval on the same SSE day in which the ESRs were discharging. Refund values were provided by AEMO.

Figure 25: Structure of Inputs and Outputs of AEMO mode

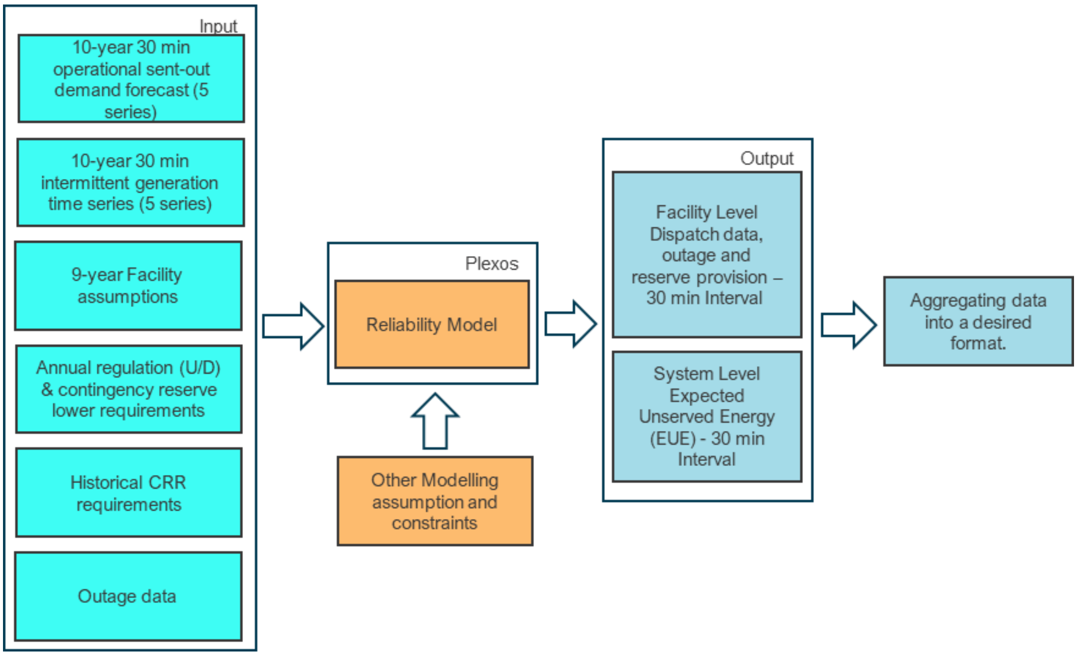
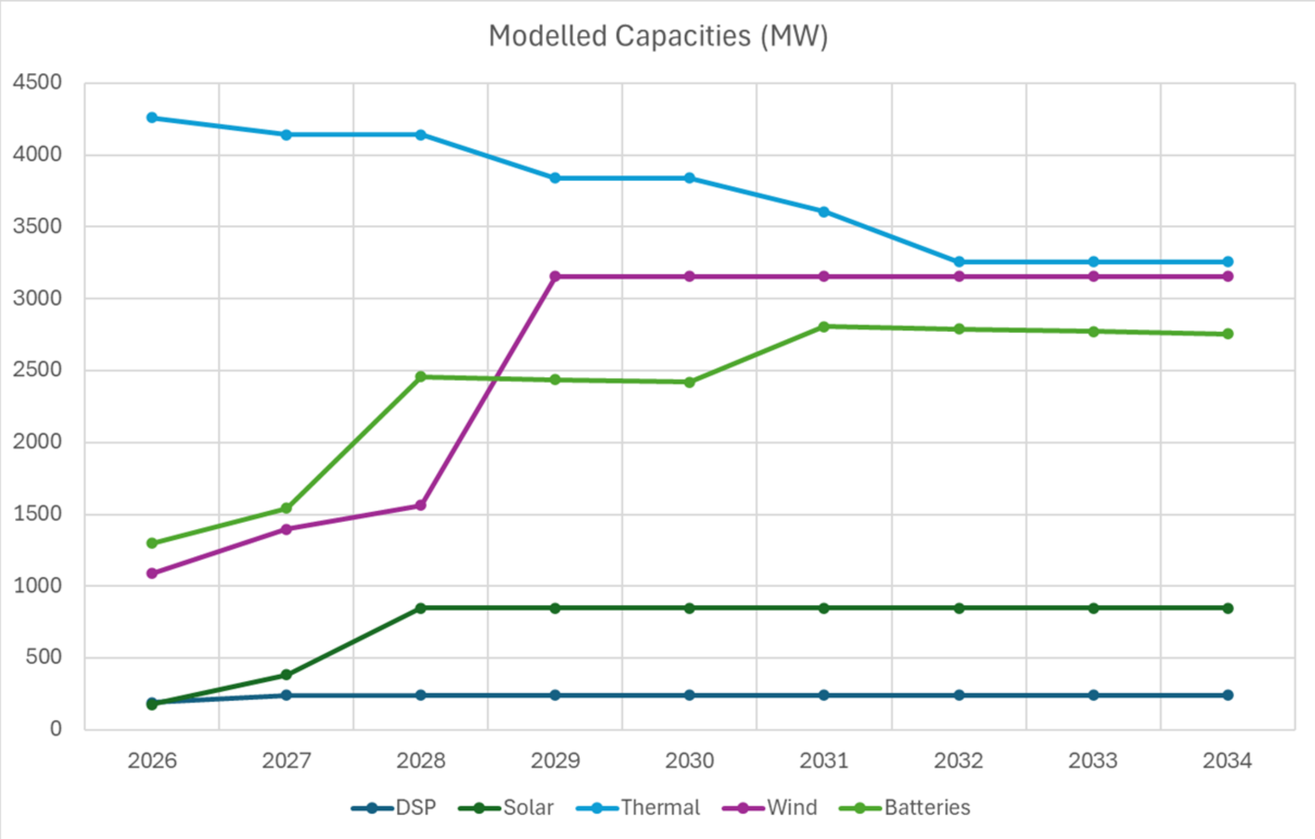


Figure 26 illustrates the capacity assumptions used in the model for the period from 2026 to 2034. The assumptions show a clear transition in the generation mix, with thermal capacity steadily declining, while wind capacity increases sharply to around 3,100 MW by 2029 before remaining relatively flat thereafter. Solar and battery capacities grow rapidly until 2028, with solar capacity stabilising in subsequent years and battery capacity increasing again in 2031 before stabilising. Demand-side participation capacity remains low and relatively constant throughout the modelling period.

Overall, the assumptions reflect a shift away from thermal generation towards greater reliance on wind, solar, and battery storage, with most new capacity added before 2030.

Figure 26: Capacity Assumptions



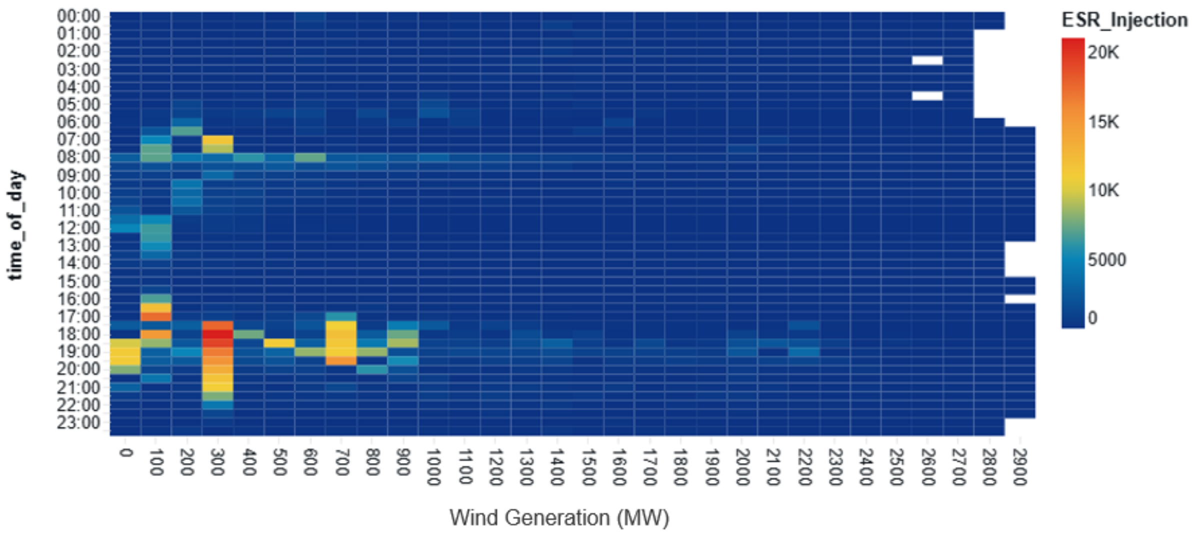
ESR injection requirements by month and time of day are presented in the main body of this report and illustrated in Figure 5, Figure 6 and Figure 7.

- Figure 5 presents the forecast average ESR dispatch by month and Trading Interval for Capacity Year 2026–27;
- Figure 6 presents the results for Capacity Year 2028–29; and
- Figure 7 presents the results for Capacity Year 2030–31.

The future-state analysis indicates that ESRs are predominantly required during summer evening periods, reflecting times of higher demand and increased system stress. While summer evenings remain the primary driver of ESR dispatch requirements, the results also suggest that winter evening periods will become increasingly important from 2028 onwards.

The relationship between ESR injection and wind generation was also analysed. As an example, Figure 27 presents a heat map in which the time of day is shown on the y-axis and wind generation (MW) is shown on the x-axis. The shaded cells indicate the average ESR dispatch (MW) for a given month, time of day, and level of wind generation.

Figure 27: Forecast average ESR dispatch vs. Wind Generation by time of the day for Capacity Year 2030-31



White patches indicate that the model did not produce any outputs for the corresponding combination of time of day and wind generation level.

The analysis shows that the need for ESR support is concentrated during periods of low wind generation, indicating a clear relationship between reduced wind availability and increased system stress. This finding suggests that ESR state-of-charge requirements could potentially be made conditional on low wind generation forecasts, provided that forecast accuracy is sufficiently reliable.

The relationship between ESR injection and solar generation was also examined. However, this relationship was found to be weaker and less consistent than that observed for wind generation, making solar output a less reliable indicator of the need for ESR support.

In summary, the future-state analysis concluded that the timing of ESR support requirements varies by season and is expected to change significantly as the system transitions to higher levels of intermittent generation. Consequently, ESROI periods will need to adapt accordingly.

The analysis also indicates that ESR requirements are closely linked to periods of low wind generation, suggesting that state-of-charge requirements will likely follow wind generation patterns, subject to sufficient forecast reliability.

Appendix E. Evaluation of DSP availability obligations

E.1 Evaluation criteria

DSP availability obligation options were assessed against the following criteria mapped to the SEO.

Table 25: Evaluation criteria used to assess DSP availability options

Criteria	Map to SEO
Availability obligations are aligned with power system needs	Failing to make ESR/DSPs available during intervals of system stress will adversely affect the security & reliability limb
Availability obligations provide value for money	Diluted availability obligations for DSPs who receive the full Reserve Capacity Price for every MW of capacity would mean customers are paying the same amount for less reliability. This will adversely affect the pricing limb.
Availability obligations enable value to be extracted from BTM storage	Aligning DSP obligations to enable BTM storage to charge during peak solar hours contributes positively to the environmental limb by more efficiently using stored renewable energy instead of curtailment.
Approach is flexible enough to change as power system needs evolve and change	Power system characteristics are evolving rapidly with more uncertainty due to the Energy Transition. Approaches to setting duration and availability obligations must be flexible enough to adapt to such changes so that the alignment with system need is maintained. Failure to do so would adversely affect the security & reliability limb
Approach is transparent and predictable	Opaque approaches to setting dynamic duration and availability obligations could deter DSP entry (and less efficient use of the BTM storage) if operators are unable to plan operations efficiently. This could adversely affect the security & reliability, pricing and environment limbs of the SEO.
Cost and complexity of implementation is reasonable	Costly implementation will add to market participant costs (through increased market fees) which adversely affects the pricing limb of the SEO

E.2 Options evaluated

The DSP availability options evaluated are summarised in the tables below.

Table 26: DSP availability options assessed against the SEO

Option	Description
Option 1: Split availability window (Tranche 8)	DSPs must be available as follows: • Available between 6:00 am to 10:00 am and available to curtail up to 4 hours • Available between 2:00 pm to 10:00 pm and available to curtail up to 8 hours • DSPs have a four-hour block to charge/restart (10:00am to 2:00 pm)
Option 2: Split availability window (derated version)	The availability windows are as follows: • Available between 8:00 am to 12:00 pm and available to curtail up to 4 hours • Available between 2:00 pm to 10:00 pm and available to curtail up to 8 hours • DSPs have a two-hour block to charge/restart (12:00 pm to 2:00 pm) Market Participants can choose to participate in both obligation windows or only the evening (2pm to 10pm) obligation window. Participants choosing the evening window only receive a derated Reserve Capacity Price.
Option 3: Include DSPs in ESROD calculation	DSPs rolled into ESROD calculation: • AEMO calculates availability requirement based on which intervals have insufficient non-CC2 capacity to meet demand • No grandfathering for DSPs • DSPs must meet Peak DSP Dispatch Requirement
Option 4: DSP availability intervals based on Peak DSP dispatch requirement	DSP availability intervals determined annually by comparing the reference demand profile developed for CC3 ELCC calculations to the 50% POE/median growth load profile and identifying which Trading Intervals (or periods of time) DSPs should be available for

E.3 Evaluation results

E.3.1 Option 1: Split availability window (Tranche 8)

Table 27: Evaluation of Option 1 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs	DSP dispatch and spare capacity levels indicate that split windows are aligned with times of system stress: • The current 8:00 am to 8:00 pm window does not capture late evening events and fails to recognise that additional capacity is unnecessary during the middle of the day. • Morning window covers early morning hours (6:00 am to 8:00 am) when rooftop solar output is low. • Technical analysis indicates SSEs could occur during later morning hours with one historical event commencing at 11:25 am. *Criteria met fully*
Availability obligations provide value for money	DSPs selecting the split window option must still curtail for a max of 12 hours per day. Availability obligations are not diluted. Requires DSPs to be available after 8:00 pm, thereby reducing the likelihood of costlier SC or NCESS procurement. *Criteria met fully*
Availability obligations enable value to be extracted from BTM storage	Option enables BTM storage to charge in the middle of the day during peak solar output, thereby using renewable energy instead of curtailing it. However, meeting the morning window may be challenging for residential aggregations, as their BTM storage will likely be depleted overnight. This option may also deter large loads with restart limitations from participating as the split window may not enable them to resume operations normally during 10:00 am to 2:00 pm break. To comply with both windows, such loads would need to ensure availability between 6:00 am to 10:00 pm. *Criteria met substantially*
Approach is flexible enough to change as power system needs evolve and change	The split availability blocks are static but span a large enough window likely to capture system stress events. The single block does not capture early morning or late evening peaks. *Criteria met substantially*

Criteria	Evaluation
Approach is transparent and predictable	The availability blocks are static so participants will know ahead of time when they will be needed *Criteria met fully*
Cost and complexity of implementation is reasonable	This change is moderately simple (relative to the other options) to implement and will only require minor rule, process and system changes. However, the morning window spans two Trading Days. AEMO has advised this will add to implementation complexity and cost. *Criteria met partially*
Overall Performance	Most criteria met substantially 

E.3.2 Option 2: Split availability window (derated version)

Table 28: Evaluation of Option 2 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs	This option performs slightly less well than Option 1 as the morning availability window does not include 6:00 am to 8:00 am. This morning window is more likely to encounter capacity shortages as rooftop solar output is low (particularly in winter) and demand is high due to the SWIS load shape. However, we note that no DSP dispatch events or SSEs have historically occurred during this period. *Criteria met substantially*
Availability obligations provide value for money	DSPs opting for reduced availability by participating only in the second window receive a derated Reserve Capacity Price. Hence, no customer value is diluted. *Criteria met fully*
Availability obligations enable value to be extracted from BTM storage	Even though the charging window for BTM storage under this option is reduced (from 10:00 am to 2:00 pm to 12:00 pm to 2:00 pm), DSPs should still be able to charge BTM storage in their portfolio during peak solar hours. Those with load restart limitations can participate in the evening window. *Criteria met fully*

Criteria	Evaluation
Approach is flexible enough to change as power system needs evolve and change	This option performs slightly less well than Option 1 on this criterion as it does not have the flexibility to include early morning intervals if in the future availability during early winter mornings becomes important. *Criteria met partially*
Approach is transparent and predictable	See Option 1. *Criteria met fully*
Cost and complexity of implementation is reasonable	This option will be simpler to implement than Option 1 due the 6:00 am to 8:00 am Trading Intervals from the previous Trading Day being excluded. *Criteria met fully*
Overall Performance	Most criteria met substantially

E.3.3 Option 3: Include DSPs in ESROD calculation

Table 29: Evaluation of Option 4 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs	Approach identifies Trading Intervals where non-CC2 capacity is insufficient to meet demand during the evening peak demand period. This means that evening reliability needs are well met under this approach. However, given ESROIs cover late afternoon to evening, DSPs will not be available for winter morning peaks. The Technical Analysis indicates DSP dispatch during the morning is possible but likely to be uncommon. *Criteria met substantially*
Availability obligations provide value for money	ESRs & DSPs will get same duration requirement under this approach. This is likely to be less than the current 12-hour requirement. ESRs must be available throughout the year but DSPs must only meet Peak DSP Dispatch Requirement. Hence, consumers will pay the same for less. DSPs will be available after 8:00 pm thereby reducing the likelihood of costlier Supplementary Capacity procurement *Criteria met partially*

Criteria	Evaluation
Availability obligations enable value to be extracted from BTM storage	See Option 1. ESROD starts after peak solar hours enabling BTM storage to charge. *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	Availability obligations under this approach will change annually based on AEMO's reliability modelling more accurately reflecting when CC2 technologies are likely to be required *Criteria met substantially*
Approach is transparent and predictable	Some uncertainty in availability requirements. Previous ESROD should give participants a starting off point for how long they may be required for. *Criteria met partially*
Cost and complexity of implementation is reasonable	Moderate changes to rules, processes and systems to incorporate DSPs into Appendix 11. *Criteria met partially*
Overall Performance	Some criteria met substantially or most met partially ◐

E.3.4 Option 4: DSP availability intervals based on Peak DSP dispatch requirement

Table 30: Evaluation of Option 4 against the SEO

Criteria	Evaluation
Availability obligations aligned with power system needs	This approach assumes that DSPs will only be needed at times when demand is likely to exceed the 50% POE peak forecast (vs modelling ability of CC2 & non-CC2 capacity to meet peak demand). This may not be true, as DSP and ESR need is driven by the level of non-CC2 capacity available. It is unclear whether DSPs would be required to be available after 8:00 pm as modelling is needed to assess which Trading Intervals are forecast to have demand greater than the 50% POE peak. *Criteria not met*
Availability obligations provide value for money	DSP availability obligations are likely to be significantly diluted under this approach. *Criteria not met*

Criteria	Evaluation
Availability obligations enable value to be extracted from BTM storage	Demand during peak solar hours is unlikely to be greater than the 50% POE peak. As such, DSP availability requirements during peak solar hours are unlikely to manifest under this approach. *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	Availability obligations will change annually reflecting changes in demand shape and level of DSP participation. However, it will not pick up changes due to changing generation patterns. *Criteria met partially*
Approach is transparent and predictable	See Option 2 *Criteria met partially*
Cost and complexity of implementation is reasonable	Moderate changes to rules, processes and systems to incorporate DSPs into Appendix 11. *Criteria met partially*
Overall Performance	Some criteria met substantially or most met partially ◐

Department of
Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 7: Update on the Coordinator of Energy's review of the Benchmark Technologies

Market Advisory Committee (MAC) Meeting 2026_07_30

1. Purpose

The Chair of the WEM Investment Certainty Review Working Group (the Working Group) to provide an update on the Coordinator of Energy (Coordinator) 2026 Benchmark Technology Review (Review).

2. Recommendation

That the MAC:

- notes that the slides from the 16 July Working Group meeting are provided as background information on progress to date and will be taken as read; and
- provides any additional views on the approach to determining the long and short list of Benchmark Technology candidates and/or the cost assessment methodology.

3. Background

The Coordinator is conducting a review, under clause 4.16.11 of the Electricity System and Market Rules, of the Benchmark Technologies, which are used to determine the Benchmark Reserve Capacity Prices (BRCPs).

The Coordinator must determine the Benchmark Technologies within six months of the Electricity Storage Resource Duration Requirement (ESRDR) being published in AEMO's Electricity Statement of Opportunities (ESOO), if the ESRDR is different from the ESRDR for the previous Reserve Capacity Cycle.

AEMO's 2026 ESOO was published on 23 June 2026 and included an ESRDR of 7 hours, an increase from the previous ESRDR of 6 hours.

- The increase in the ESRDR is driven by an increase in the Capacity Credits assigned to Electric Storage Resources (ESRs) in the 2025 Reserve Capacity Cycle.
- As ESRs are duration limited, the increase in the ESRDR ensures that the reliability contribution of ESRs applying for certification in the 2026 Reserve Capacity Cycle can be adequately assessed.

The Coordinator must complete its review by the end of October 2026 to allow sufficient time for the Economic Regulation Authority to amend and consult on its BRCP methodology and set the BRCPs for the 2029/30 Capacity Year by 15 March 2027.

The Benchmark Technology Review will include an assessment of both the Peak and Flexible Benchmark Technology to:

- determine the technology with the lowest fixed costs (capital and fixed Operating and Maintenance cost); and
- whether gross costs of new entry (CONE) or net CONE should apply.

Following the recent BRCP Determination by the ERA for the 2028/29 Capacity Year, DEED is working more closely with the ERA throughout this process so that both parties are aligned on the approach to the Review.

The Review is utilising publicly available data sources, including CSIRO's GenCost report and AEMO's Inputs Assumptions and Scenarios Report. Regional (WA) adjustments will be applied as appropriate, using public data sources to the maximum extent practicable.

4. Consultation

Due to the Review's compressed timeline, Energy Policy WA is consulting with the WIC Review Working Group on the Review, instead of forming a special MAC Working Group. At its 16 July 2026 meeting, discussion at the Working Group included:

- dual fuel gas unit configuration, as well as gas laterals and fuel storage;
- derating of battery energy storage systems previously assessed; and
- Regional (WA) adjustments, for example, for construction costs.

Terms of Reference, papers and minutes for the Working Group meetings are available on the WIC Review Working Group webpage. Information on the Review is available here

5. Next Steps

The next Working Group meeting to discuss the 2026 Benchmark Technology Review is scheduled for 6 August 2026. It is proposed that discussion will focus on:

- the shortlisted technologies' cost analysis; and
- the initial proposals for the Peak and Flexible Benchmark Technology; and
- the modelling results of the application of Gross or Net CONE.

DEED will provide a draft Consultation Paper to the MAC out-of-session before it is published for consultation, incorporating MAC feedback as appropriate. The table below shows the expected next steps:

Tasks/Milestones	Timing
(1) Initial Assessment	
(a) Initial assessment & WIC Review Working Group meetings on proposals	July & August 2026
(2) Consultation Paper	
(a) Publish Consultation Paper on proposals	August 2026
(b) Submissions on the Consultation Paper close	September 2026
(3) Further Assessment	
(a) Further assessment based on submissions received	September 2026
(4) Coordinator Determination	
(a) Publish the Coordinator's Determination	October 2026

Attachment

(1) Agenda Item 7 – Attachment 1 – WIC Review Working Group – Meeting 16 July 2026 – Papers

(2) Agenda Item 7 – Attachment 2 – WIC Review Working Group – Meeting 16 July 2026 – Draft Minutes

Department of
Energy and Economic
Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

WEM Investment Certainty Review (WIC Review) Minutes

Date:	16 July 2026
Time:	9:30am – 11:30am
Location:	Microsoft Teams

Attendees	Company	Comment
Dora Guzeleva	(Chair) Energy Policy WA	
Sreeparna Saha	AEMO	Proxy for Neetika Kapani
Matthew Fairclough	AEMO	Proxy for Mena Gilchrist
Oscar Carlberg	Alinta Energy	
Duc Tran	APA Group	Proxy for Lizzie O'Brien
Jordan Prainito	AuzVolt	
Daniel Kurz	Bluewaters Power 1 Pty Ltd	
Francis Ip	BLT Energy Pty Ltd	
Tom Frood	Bright Energy Investments	
Aaron Walker	Chamber of Minerals and Energy WA	
Jake Flynn	Collgar Renewables	
Liz Aitken	Empire Carbon and Energy	
Richard Cheng	ERA	
Noel Schubert	Expert Consumer Panel	
Luke Skinner	Expert Consumer Panel	
Warren King	Frontier Energy Ltd	
Max Collins	Neoen	
Wayne Trumble	Newmont	
Patrick Peake	Perth Energy	
Shane Cremin	Summit Southern Cross Power Pty Ltd	
Rhiannon Bedola	Synergy	
Ben Tan	Tesla Corp	
Peter Huxtable	Water Corporation	
Mark McKinnon	Western Power	
Other attendees	**From**	**Comment**
Christopher Wilson	AEMO	

Steven Mills	Chamber of Minerals and Energy WA	Observer
Rohan Zauner	Jacobs	Presenter
Richard Bowmaker	RBP	Presenter
Tessa Liddelow	Shell Energy	
Shelley Worthington	EPWA	
Rory Hannon	EPWA	
Lara Bradbury	EPWA	
Apologies	**From**	**Comment**
Mena Gilchrist	AEMO	
Neetika Kapani	AEMO	
Lizzie O'Brien	APA Group	
Graham Pearson	Australian Energy Council	
Rachael Smith	Australian Gas Infrastructure Group	
William Street	Entego Group Pty Ltd	
Timothy Edwards	Metro Power	
Paul Arias	Shell Energy	

1. WELCOME

The Chair opened the meeting with an Acknowledgement of Country and welcomed members.

2. MEETING APOLOGIES AND ATTENDANCE

The Chair noted the meeting attendance as listed above.

3. CONFLICTS OF INTEREST AND COMPETITION LAW

The Chair noted the obligations of the Working Group members under Australian Competition Law.

4. 2026 BENCHMARK TECHNOLOGY REVIEW

The Chair presented Slide 5 (scope). She noted that:

- as time to complete the 2026 Benchmark Technologies Review (the Review) is limited, the Working Group is being convened to facilitate industry consultation;
- once the Coordinator has consulted on and determined the technologies, the Economic Regulation Authority (ERA) must adjust its methodology, as required, consult on that and the Benchmark Reserve Capacity Prices (BRCPs) and determine the BRCPs for the 2027 Reserve Capacity Cycle;
- the Electricity System and Market (ESM) Rules require the Coordinator to determine the technologies with the least cost capital and fixed operating and maintenance costs. This may be different for Peak Capacity and Flexible Capacity; and
- there will be two meetings of this group and a short public consultation.

Mr Zauner noted that Jacobs is assisting RBP with the 2026 Benchmark Technologies Review, including items 1 – 6 on Slide 6 (Approach). He noted that the method and approach are the same as in the 2025 Review. However, this year there will be more transparency about the cost parameters so that others can complete their own calculations to interrogate the results.

Mr Zauner presented slides 8-9 (technology long-list). He noted that, with regard to lithium-ion batteries, several durations will be assessed to capture the change from one review to the next.

- Mr Fairclough asked why hybrid facilities are excluded from the longlist, noting that they may offer the most cost competitive solution.
- Ms Aitken noted that the Department of Energy and Economic Diversification (DEED) is currently running an Expression of Interest (EOI) for a 10-hour duration vanadium flow battery in Kalgoorlie. She asked if vanadium batteries should be included in the Review for the sake of consistency, as this facility has to be in place for the 2029 Capacity Year. She questioned how its competitiveness can be established without a proper assessment and noted that it may be competitive with the subsidy being offered.

The Chair responded that this Review looks for the least fixed cost technology, and that many existing or proposed technologies are not least fixed cost.

Mr Zauner added that subsidies cannot be included in the calculations, and the unsubsidised cost of a vanadium battery will be more than a lithium-ion battery. He offered to provide analysis to this effect, if required.

- Ms Aitken stated that there is nothing to stop a hybrid facility from setting the BRCP, per the ERA's WEM Procedure.

The Chair responded that this review is concerned with determining the technology with the lowest annualised fixed cost per MW.

- Mr Fairclough noted that Capacity Credits for wind and solar PV will increase with the new Relevant Level Method (RLM) which could make them more competitive.
- Mr Prainito asked if the total Capacity Credits for a hybrid facility was the sum of the Capacity Credits for its separately certified components or whether the total Capacity Credits for the facility are capped at the Declared Sent Out Capacity (DSOC).

The Chair confirmed that the number of Capacity Credits a hybrid facility receives is limited by the DSOC at the connection point and the Network Access Quantities (NAQs) for the facility.

- Ms Aitken noted that if a facility can set up as a hybrid to meet the duration requirement in a more cost-effective way than a standalone technology it should be considered the lowest cost for BRCP purposes.

The Chair reiterated that each component behind the connection point needs to be assessed separately against the requirements relevant to that technology. Then, if the Capacity Credits are capped by its DSOC or NAQ, the facility can choose which ones to reduce.

- Ms Aitken suggested a rule change may be necessary.

Mr Zauner noted that:

  - it is the fixed cost that is being assessed in the Review, not the levelized cost;
  - solar and wind components built in conjunction with a battery energy storage system (BESS) behind the same connection may have a lower dollars per MW hour lifecycle cost, but unless they have a lower annualised fixed capital cost relative to their Capacity Credit allocation, they're not competitive for the purposes of a BRCP calculation; and
  - many hybrid Facilities fall into this category, as the solar component reduces the lifetime cost of the energy produced but it can only add to the capital cost of the plant. On a fixed cost basis, a hybrid facility is likely to be higher cost than a stand-alone battery.

- Mr Schubert stated that the review should consider technologies that meet system needs over a longer timeframe, noting that the market bears the cost of the Reserve Capacity Target (RCT) uplift required when technologies that don't meet future needs have been chosen. He stated that the Review should compare technologies that will last for the duration the system is likely to need them.

The Chair noted that this would require a rule change, as the current ESM Rules require that the Review assess the benchmark technology based on the Electric Storage Resource Duration Requirement (ESRDR) in the Capacity Cycle for which the Review is undertaken.

- Mr Fairclough commented that there is a possibility that the ESRDR reduces in the future.

The Chair agreed this is unlikely but possible.

- Mr Schubert noted that the number of utility scale and behind the meter batteries being installed meant that the evening peak is likely to flatten further and increase the ESRDR. He stated that consideration of a rule change to ensure future system needs and the cost of the RCT uplift are considered was important.

The Chair noted this was outside the scope of the Review and that a rule change is needed to allow consideration of this.

- Mr Walker asked Mr Zauner if batteries with durations below 7 hours will be assessed in this Review.

Mr Zauner responded that 6, 7 and 8 hour durations are being assessed to allow for continuity in assessing cost changes between one review and the next. However, a 6 hour battery would not be eligible, and an 8 hour battery would only get seven eighths of its certified capacity for the purposes of the cost assessment.

- Mr Walker asked if the cost calculation takes into account the cost of the uplift in the RCT required to compensate for the fact that previously certified facilities are grandfathered from having to meet a higher ESRDR for 10 years, and that, as such, these facilities cannot necessarily meet the top of the demand curve.

The Chair responded that is not what the ESM Rules require.

- Ms Bedola agreed with Mr Schubert's comment on the uplift portion of the RCT and proposed that, given that the BRCP is also increasing, efforts should be made to understand the costs to customers and revenue to ESRs.

The Chair agreed that the additions to the RCT, that result from the grandfathering arrangements, lead to additional costs to consumers but noted that this is outside the scope of this Review.

- Mr Frood questioned whether under the ESM Rules, pre-existing Facilities that have less than 7-hours will still get the full, rather than a pro rata, Capacity Credits .

The Chair clarified that they are certified based on the ESRDR in their first year of certification. The consequence is they do get their full Capacity Credits even as the ESRDR increases.

- Mr Schubert suggested that the Review should assess the cost of the RCT uplift that is likely to be incurred in future and add that to the fixed costs.
- Mr Frood questioned what reliable sources could be used to determine the longer duration that may be required in the future.
- Mr Skinner agreed with Mr Frood, noting that the Capacity Year in question is already years in advance and any future projection beyond that is less likely to be accurate given the rate of change in energy systems across the board at the moment.

The Chair responded that the cost of the RCT uplift cannot be taken into account in the evaluation as this is outside the scope of the ESM Rules. The Chair reiterated that this review must assess the least fixed cost technology, that being capital and fixed operating and maintenance costs, and that accounting for any other variables would inflate the cost to consumers.

- Mr Schubert stated that he understood that this may cost more, but he is seeking a proper assessment of the appropriate technology that meets the system needs.
- Mr Schubert noted that one of the issues was with windfall gains, and that DEED was to work with the ERA to ensure alignment on certain assumptions.

The Chair confirmed that DEED is working with the ERA on these matters.

- Mr Cheng noted that the ERA will update its BRCP Procedure and the BRCP Determination will be based on the outcome of the Review.

Mr Zauner presented slide 10 (candidate configurations). He noted that the size chosen for each candidate (including BESS) reflects the least cost configuration that a prudent person would build.

- Mrs Bedola asked whether emissions were accounted for in these configurations, to understand how the State Electricity Objective (SEO) has been considered.

The Chair noted that previous assessments applied an emissions threshold of 550 kilograms of CO2 per megawatt hour, noting that this was in the context of a draft policy proposal to include this in the Reserve Capacity Mechanism (RCM) at the time. She noted that, while the target for emissions is net-zero by 2050, the 550kg Co2/MWh draft policy has not been progressed and as such cannot be taken into account.

- Mr Skinner commented that, while technologies cannot be excluded based on emissions if it's not in the ESM Rules, the Review should be transparent regarding any differences in emissions amongst the technologies. He suggested that the SEO requires this group to at least consider this.

The Chair noted that, given retirement plans for some of the gas fleet, any more efficient technology in terms of both emissions and round-trip efficiency will reduce emissions.

- Mr Fairclough noted that the candidate gas facilities assume dedicated gas laterals and onsite storage. He asked if shared fuel supply infrastructure has been considered.

The Chair confirmed that reservation costs for the pipeline have been considered.

- Mr Schubert stated that emissions should be considered, even if not prescribed in the ESM Rules.
- Mrs Bedola suggested that the change in emissions considerations should be included in DEED's Consultation Paper for public comment.
- Mr Carlberg asked if a return to a diesel fired Open Cycle Gas Turbine (OCGT) is likely.

The Chair responded that diesel fired only technologies are not being considered, but in recent cycles dual fuel facilities have been certified on diesel with gas being the preferred fuel for operation. Dual fuel facilities that certify on diesel but run on gas require some pipeline capacity reservation and a gas lateral will be examined.

- Mr Carlberg noted that the Coordinator's last determination assumed that gas-fired facilities costs should include the Dampier to Bunbury Natural Gas Pipeline (DBNGP) fixed haulage charges (sufficient to account for the 14-hour fuel requirement). He asked if that assumption is continuing.

The Chair responded that the last assessment of open cycle turbines considered a skinny lateral with diesel tank, and that this study also considers a fat lateral configuration, which is now present in WA, Queensland and NSW (Karikari).

Mr Zauner clarified that a fat lateral is a configuration that is certified on gas, on the basis that it can contain fuel sufficient for 14 hours of generation with (for this study) an allowance to be replenished over three days.

- Mr Tan noted that a diesel fuelled OCGT will be cheaper than dual fuel and asked if that option would be considered.

The Chair stated that this could be considered but it would not be justifiable on the basis of the SEO as, while there is not a formal emissions threshold being applied, diesel only facilities have significantly higher emissions than dual fuel facilities which typically run on gas.

- Mrs Bedola noted that even though a dual fuel facility can run on gas but be certified on diesel, if the participant does not secure sufficient pipeline transport, it will not be able to regularly run on gas.

The Chair responded that this hasn't been observed to date.

- Ms Aitken asked if the fuel requirement should be 7 hours rather than 14 hours in order for a BRCP assessment to be consistent.

The Chair responded that the ESM Rule requirement for gas facilities is 14 hours.

- Mr Collins asked if the 14 hours over 3 days (Karikari style gas turbine) will have a requirement to be fully charged at the start of its ESR Obligation Intervals each day.

The Chair clarified that the fat lateral needs to at any point in time have 14 hours of fuel and continue to be recharged with whatever reservation the facility has in the pipeline.

- Mr Collins noted that this is a problem in Karikari because the fat lateral takes 3 days to replenish.

Mr Zauner noted that he would discuss this with the Chair offline. The assumption for the DBNGP charge last year was that refilling was spread over three days. If that is not appropriate, a discussion about the Maximum Daily Quantity (MDQ) and a one-day refill should be had.

- Mr Walker commented that this Review is required to determine the lowest cost technology while also having some transparency about the trade-offs around emissions.

The Chair noted Mr Skinner's comment that technologies that will worsen emissions should not be considered, noting the support for this comment from other members.

- Mr Carlberg asked if the assumptions around the fat lateral are going to increase or decrease the fixed transport charge assumption compared to previous determinations.

Mr Zauner noted that gas lateral assumptions vary between technologies because different gas turbines have different usage rates and pressure requirements. Typically, 20 to 30 kilometres of 36 inch, 15 megapascal pipe to get 14-hours is required.

The Chair noted that the assessment will size these elements to meet the 14-hour fuel ESM Rule requirements, and this will impact on the cost.

Mr Zauner noted that the largest practical pipe buildable in Australia is a 36 inch 15 megapascals, and so it comes down to the length required to get an amount of fuel required. The calculation will determine the length required to get the required amount of storage.

- Mr Cremin noted that a diesel facility operating 100 hours a year to meet the peak has negligible overall emissions and low fixed costs. He commented that the market has drifted from its original design and making decisions on this matter based on emissions is leading to choosing technologies with higher fixed costs. He noted that incremental changes are leading to increased costs.

The Chair noted the market has changed due to the 20250 emissions target and the existence of the SEO. She noted that another consequence of selecting a diesel only technology would be increased energy costs in the Real-Time Market.

- Mrs Bedola asked if the requirement for 14-hour gas is necessary if this is for a least cost technology only intended to be there for peak periods and for contingency.

The Chair noted that this is an existing requirement and that current analysis suggests that gas facilities will need to run for 14 hours on certain days in the future.

- Mr Skinner noted the liquid fuel crisis in 2026 and the potential need to consider this from a reliability perspective.

Mr Zauner noted, with regard to slide 10, that the parameters are unchanged from last year except for the additional BESS duration option.

- Mr Prainito asked, regarding credible delivery for 2029, what order timeline and OEM slot availability is assumed for each gas option treated as credible in the list.

The Chair responded that this assessment assumes that facilities are participating in the RCM, are committed and have fulfilled all other requirements to be RCM ready.

Mr Zauner presented slide 12 (peak service requirements).

- Mr Fairclough asked if a 6-hour BESS could apply for certification as a 7-hour BESS and whether this would change the outcome.

Mr Zauner confirmed that, in theory, but this would be more expensive than a 7-hour BESS.

- Mr Carlberg asked where the single contingency limit comes from.

The Chair responded that that is based on the existing largest single contingency which cannot be exceeded for the purposes of this assessment.

Mr Zauner presented slide 13 (flex service requirements). He noted that the Closed Cycle Gas Turbine with bypass stacks is scaled up in costs as the steam turbine cannot meet the flex service requirements.

Mr Zauner presented slide 14 (proposed configuration shortlist), noting that there was an error in the slides and that there should be a cross against the 1xGE 9FA.04 1+1 ss in the 'peak service' row.

Mr Zauner presented the cost calculation methodology, noting that it is similar to the 2025 review. He presented other materials to indicate how construction cost multipliers in different areas of the South West Interconnected System will be calculated.

- Mrs Bedola asked if there is alignment between DEED and the ERA on what cost assumption sources will be used.

The Chair responded that DEED proposes to use only publicly available information to calculate costs and that she cannot make commitments on what the ERA will consider, but noted the submissions made on the ERA's previous BRCP determination expressed a preference for full transparency.

Mr Zauner added that the methodology presented today has been shared with the ERA.

Mr Zauner presented slide 17 (calculation basis).

- Mr Frood asked how the Review accounts for capacity factors.

The Chair responded that this Review does not account for capacity factors, as the objective of the Review is to assess $/MW fixed capital and fixed operating and maintenance costs. However, net vs. gross cost of new entry (CONE) will be assessed to determine if there is any over-recovery in the energy market.

Mr Zauner presented slides 18-19 (thermal plant configuration), noting that the configuration has been tailored according to Jacobs' expectations. The configurations can be shared to enable parties to reproduce the analysis and feedback is welcomed.

- Mrs Bedola asked if NAQs are taken into consideration.

The Chair confirmed this, noting that last year the Review found an unconstrained location, but that this will need to be examined again this year.

- Mr Peake asked to clarify the meaning of "soft ground" in the configuration options.

Mr Zauner responded that this is ground that doesn't require rock excavation for foundation build.

Mr Zauner presented slide 20 (additional costs).

- Ms Aitken noted the connection contribution charge of $100k per MW.

Mr Zauner noted that the network uplift is included.

Mr Zauner presented slide 21 (fixed operations and maintenance costs), noting that:

- these base costs are the fixed operations and maintenance costs for the relevant technology from the IASR. The listed factors are adjustments to those, where required; and
- the MDQ will be adjusted based on the discussion earlier in the meeting.

Mr Zauner presented slide 22 (other parameters).

- Mrs Bedola asked if there is consideration of the costs associated with community benefits investment, as in the Community Benefits Guideline.

The Chair noted that the team will review the ERA’s consideration of this.

- Mr Fairclough noted that the ERA's 2026 BRCP Final Determination used WACC of 10.85 per cent.

The Chair confirmed that this will be used.

- Mr Peake asked if an allowance to cover the early payment of deposits to secure equipment should be included.

Mr Zauner noted this is effectively interest during construction and the ERA have a fixed formula for this that will be used.

5. NEXT STEPS

The Chair noted the next steps of the Review as per slide 25.

6. GENERAL BUSINESS

No general business was discussed.

The meeting closed at 11.29am.

Department of Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 8: WEM Operation Effectiveness Report – Progress Update

Market Advisory Committee (MAC) Meeting 2026_07_30

1. Purpose

Energy Policy WA (EPWA) to update the MAC on the progress of implementing the recommendations from the Coordinator of Energy's (Coordinator's) inaugural Wholesale Electricity Market (WEM) Operation Effectiveness Report.

2. Recommendation

That the MAC notes:

- the update on the progress of implementing the recommendations from the first WEM Operation Effectiveness Report since the previous MAC meeting, which are shown in red in the Tables below.

3. Background

Under clause 2.16.13D of the Electricity System and Market (ESM) Rules, the Coordinator must provide the Minister of Energy (Minister) with a report dealing with the matters identified through its market monitoring activities at least once every three years, with the first such report due by 1 July 2025.

The Coordinator provided the first WEM Operation Effectiveness Report (the Report), that covered matters outlined in clauses 2.16.13A, 2.16.13B and 2.16.13E of the ESM Rules, to the Minister on 25 June 2025.

- After consultation with the Minister, the Coordinator published a version of the Report on 8 July 2025 on the Coordinator's website.
    - Any confidential and/or sensitive data was either aggregated or removed.
- The published report is to serve as a point of reference of further work required by AEMO, the ERA, EPWA and Western Power to improve market effectiveness, including through future ESM Amending Rules.

Table 1 – Recommendations relevant to all Market Bodies

Recommendation	Status	Update
Proactive reporting of Market Bodies on WEM design flaws and areas for improvement	Ongoing	EPWA, AEMO and the ERA have established fortnightly Market Surveillance meetings to discuss WEM design flaws and areas for improvement. Updates, as appropriate, will be provided to the MAC by EPWA or the AEMO at its relevant forums. Additionally, AEMO and EPWA have established regular meetings at Executive level and are working together to establish a new 'Market and Systems Issues Log' that will enable improved information sharing and tracking of solutions between the two agencies.
Improvement of accessibility across all market bodies' websites and published materials	Ongoing	On 17 September 2025, the ERA implemented a new website design, moving to a function-based structure and restructured its WEM section. Western Power's webpage 'The Wholesale Electricity Market and Market Information Management' lists its WEM Procedures, Guidelines and other market information. This new page is also easily discovered by search engines.

Table 2 – Recommendations relevant to AEMO

Recommendation	Status	Update
Provision of further detail on the cause of any direction/intervention by AEMO.	Ongoing	The ongoing Frequency Co-optimised Essential System Services (FCESS) Cost Review (Stage 2) is addressing this proposal.
Improvements in relation to operational forecasting.	Ongoing	The ongoing Operational Forecasting Review is addressing this proposal. In parallel to the Review, AEMO has progressed an internal Project to uplift AEMO's operational forecasting capabilities, which includes several initiatives aligned with EPWA's proposals. AEMO consulted on the draft Implementation Assessment for the uplift project through the Major Projects Working Group, which included a presentation at the 16 May 2026 meeting. The project involves upgrading AEMO's forecasting software platform, building better forecast models (using new data inputs) and improving data ingestion and establishing auditable input storage. It's currently in its execution phase and is expected to be completed around November 2026. Further information can be found on AEMO's website.

Recommendation	Status	Update
Completion and publication of WEM Procedures in a timely manner, including prompt updates when required.	Ongoing	The WEM Procedure Content Review will address some of the issues highlighted in the Report. As highlighted in the Report, there were still nine WEM Procedures outstanding from the date of the new WEM commencement. AEMO has since finalised and commenced six, two have had drafts completed and are expected to be published for consultation in the coming months (with MT PASA subject to more extended delay as previously explained to industry at the July 2025 AEMO Procedure Change Working Group and notified to MAC). AEMO has also implemented new internal processes to support the timely development of Procedures. This includes uplifted Procedure tracking and reporting tools (that enhances oversight by Managers and the Senior Leadership Team and highlights resourcing requirements and risks early).
Making complete and verified market data available through the publicly accessible web portal in easily accessed data formats.	Ongoing	AEMO's Data Uplift Project is a priority initiative for FY26 and will help address the findings from the Report around the availability of data through AEMO's website. Phase 1 of the project is underway, with the execution of WEM public data site improvements expected to be delivered on 20 July 2026. This includes the addition of new and existing data reports in new formats (incl. CSV format), consistent with user feedback. Phase 2 of the project, which includes updates to the WEM data dashboard is expected to be completed by May 2027. Information on the progress of the project will be advised through updates to the WEM Implementation Roadmap.

Table 3 – Recommendations relevant to the ERA

Recommendation	Status	Update
Provision of clearer information to Market Participants regarding the current priorities and focus of the ERA's surveillance and compliance activities, noting that confidential information must be protected.	Ongoing	EPWA is drafting ESM Amending Rule changes to introduce an obligation for the ERA to publish annual priorities.

Table 4 – Recommendations relevant to Western Power

Recommendation	Status	Update
Transformation of the Transmission System Plan, in the medium term, into a broader Networks Plan that includes a complete transmission and distribution development roadmap, to provide an informed view of investment opportunities. Supporting information should include constraint data, cost-benefit analyses and improved distribution level heat maps.	Starting	To be commenced.

Table 5 – Recommendations relevant to EPWA

Recommendation	Status	Update
The Coordinator will work with the Market Bodies and other stakeholders on how to integrate the State Electricity Objective more broadly within the ESM Rules and will monitor this in the next WEM Operation Effectiveness Report.	Starting	To be commenced.

Department of Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 9: Market Development Forward Work Program

Market Advisory Committee (MAC) Meeting 2026_07_30

1. Purpose

- To update the MAC on changes to the Market Development Forward Work Program since the previous MAC meeting, which are shown in red in the Tables below.
- Rows that are shaded grey are complete and will be removed for the next MAC meeting.

2. Recommendation

The MAC Secretariat recommends that the MAC:

- notes the updates in the paper; and
- reviews the consultation scheduled provided to members below.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@deed.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Current MAC Working Groups			
Working Group	**Established**	**Status**	**Next steps**
WEM Procedures Content Review	2 May 2024 MAC Meeting	Open	EPWA is currently reviewing Priority 1 WEM Procedures
Capability Class 2 Technologies Review	24 July 2025 MAC Meeting	Open	Drafting Consultation Paper
Essential Systems Services Framework Review	2 May 2024 MAC Meeting	Open	Publication of metrics for AEMO to assess the performance of the Frequency Co-optimised Essential System Services against the Frequency Operating Standards
AEMO Procedure Change	1 May 2017 MAC Meeting	Open	Ongoing Process
AEMO Major Projects	1 May 2025 MAC Meeting	Open	Ongoing Process
Power System Security and Reliability Standards	23 November 2023 MAC Meeting	Open	Preparing an Information Paper and an Exposure Draft outlining the final Review outcomes and implementing the reforms consistent with specific proposals from the June and December 2025 Consultation Papers.
Wholesale Electricity Market Investment Certainty Review	20 July 2023 MAC Meeting	Open	Working Group meetings recommenced on 25 June 2026.
Cost Allocation Review	14 December 2021 MAC Meeting	Finishing	Schedule 3 is the last schedule of the of the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 for which a commencement date is yet to be specified by the Minister.

<table>
<tr><th colspan="3">Table 2 – Market Development Forward Work Program</th></tr>
<tr><th>Review</th><th>Issues</th><th>Status and Next Steps</th></tr>
<tr><td>Cost Allocation Review (CAR)</td><td>A review of:
the allocation of Market Fees, including behind the meter (BTM) and Distributed Energy Resources (DER) issues;
cost allocation for Essential System Services; and
Issues 2, 16, 23 and 35 from the MAC Issues List.</td><td>The MAC established the Cost Allocation Review Working Group (CARWG). Information on the CARWG is available at Cost Allocation Review Working Group, including:
the Scope of Work for the review, as approved by the Coordinator;
the Terms of Reference for the CARWG, as approved by the MAC;
the list of CARWG members;
meeting papers and minutes from the CARWG meetings on 9 May 2022, 7 June 2022, 30 August 2022, 27 September 2022, 25 October 2022, 29 November 2022, 21 March 2023, 2 May 2023 and 29 August 2023.
The following papers have been released and are available on the CAR webpage at Cost Allocation Review:
the Consultation Paper;
the International Review;
submissions on the Consultation Paper;
the CAR Information Paper;
the Exposure Draft of the ESM Amending Rules implementing the outcomes of the CAR;
submissions on the CAR ESM Amending Rules Exposure Draft; and
response to submissions on the CAR ESM Amending Rules Exposure Draft.</td></tr>
</table>

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

		• the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 available at Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024.
		• Further changes to refine the cost allocation method for the Contingency Reserve Raise Service were presented at the 18 June 2024 TDOWG and consulted on within the Miscellaneous Amendments No. 3 Exposure Draft.
		• The last set of changes (to Contingency Reserve Raise cost allocation) implementing the outcomes of this Review were included in the Amending Rules made by the Minister on 2 October 2024.
		• AEMO to confirm implementation dates.
		• An Exposure Draft was released on 19 August 2025 on changes to Contingency Reserve Lower that affects Schedule 4 of the *Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024*.
		    • Consultation closed 2 September 2025.
		    • One stakeholder submission was received, which was published on 26 September 2025.
		• By gazettal on 26 September 2025, Schedules 2 and 4 of the *Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024* will commence on 30 October 2025.
		• Schedule 3 is the last schedule of the of the Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024 for which a commencement date is yet to be specified by the Minister.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

Review of the Power System Security and Reliability (PSSR) Standards	The scope of this review is to:
	• review the various PSSR related provisions in the instruments governing power system security and reliability in the SWIS;
	• assess whether the combination of existing standards is effective to ensure power system security and reliability can be maintained;
	• develop proposals for a single end-to-end PSSR standard and a centralised governance framework; and
	draft amending Rules and other regulatory changes, as necessary.
		• The MAC established the PSSR Standards Working Group (PSSRSWG). Information on the PSSRWG is available at Power System Security and Reliability (PSSR) Standards Working Group including:
		  ◦ the Terms of Reference for the PSSRSWG, as approved by the MAC;
		  ◦ the Scope of Work
		  ◦ the list of PSSRSWG members; and
		  ◦ meeting papers and minutes for the 14 December 2023, 1 February 2024, 29 February 2024, 18 April 2024, 25 July 2024, 10 October 2024 and 31 October 2024 PSSRSWG meetings.
		• The PSSR Consultation Paper was published on 19 June 2025 on the PSSR Standards Review webpage.
		  ◦ The consultation period for the Consultation Paper closed on 7 August 2025.
		  ◦ Stakeholder submissions were published on 14 November 2025 on the PSSR Standards Review webpage.
		• The consultation period for Proposal 20 included in the PSSR Consultation Paper - Adopting Western Power September 2023 Proposed Technical Rules Amendments was extended on 30 September 2025.
		  ◦ The consultation period closed on 11 November 2025.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
		- Stakeholder submissions were published on 13 August 2025. • A Western Power Consultation Paper – User Facility Standards for grid-forming and grid-following inverters was published on 22 December 2025 on the PSSR Standards Review webpage. - The consultation period for the Consultation Paper closes on 6 February 2026. • EPWA is currently progressing work on the following items, anticipated for publication in the first half of 2026: - assessing options to propose a System Strength incentive framework, to be issued for stakeholder consultation. - an Information Paper outlining the review outcomes covering interim GFM and GFL technical requirements and prescribed roles and responsibilities for system strength, together with an Exposure Draft of ESM Amending Rules.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
WEM Procedure Content Review	The scope of this review is to assess the content of selected existing WEM Procedures and their heads of power to determine, using the guiding principles, whether any matters identified require changes to improve the effectiveness of WEM Procedures, including, but not limited to: • the potential elevation of certain content to the ESM Rules; and/or • changes to a WEM Procedure heads of power.	• A revised Scope of Works and Terms of Reference was presented to the MAC at the 4 September 2025 Meeting to reflect the proposals from the 2025 WEM Operation Effectiveness Report. • On 11 September 2025, a MAC member provided EPWA with WEM Procedures that should be included in the review. • EPWA is currently reviewing Priority 1 WEM Procedures, as outlined in the Scope of Works.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Procedure Change Process (PCP) Review	A review of the PCP to address issues identified through Energy Policy WA's consultation on governance changes.	• The MAC discussed a draft Scope of Work for this review at its meeting on 11 October 2022. EPWA has updated the Scope of Works to reflect the MAC discussions. • The Scope of Work for the review, as approved by the Coordinator is available here Wholesale Electricity Market Procedure Change Process Review (www.wa.gov.au) • ACIL Allen has been appointed to assist with the PCP review. • ACIL Allen engaged with MAC members through a survey and one-on-one consultations between 12 March and 18 April 2024. There were 11 respondents to the PCP survey, out of 19 requests. • On 6 May 2024, the Consultation Paper was released for public consultation. Submissions closed 31 May 2024 with stakeholder submissions published on the Coordinator's website. • On 9 August 2024, the Coordinator finished stage 1 by publishing the ACIL Allen report and his response on the Coordinator's website. • EPWA is progressing stages 2 and 3 of the review and is revising a draft consultation paper to reflect the MAC's feedback from the 5 September 2024 MAC meeting.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Review of the Essential Systems Services (ESS) Framework	The Coordinator of Energy (Coordinator) is conducting a review of the ESS Framework (the Review), incorporating: • a review of the ESS Process and Standards under Section 3.15 of the ESM Rules; and • a review of the Supplementary Essential Systems Services Procurement Mechanism (SESSM) under clause 2.2D.1(h). The purpose of this Review is to assess whether the FCESS framework in the ESM Rules is operating efficiently to ensure power system security and reliability can be maintained at the lowest cost to consumer.	• The MAC approved the establishment of the ESS Framework Working Group (ESSFRWG) to support the ESS Framework Review. Information on the ESSFRWG is available at Essential System Services Framework Review Working Group including: • The Terms of Reference for the ESSFRWG, as approved by the MAC; • The list of ESSFRWG members; • Meeting papers and minutes for 6 November 2024, 26 February, 26 March and 24 July 2025 meetings. The following papers have been released and are available on the ESS Framework Review webpage: • The Scope of Work for the Review. • The Essential System Services Framework Review Consultation Paper. • An addendum (of proposed ESM Amending Rules) to the Essential System Services Framework Review – Consultation Paper • Stakeholder submissions to the Essential System Services Framework Review Consultation Paper and addendum. • The Amending Rules to relax the RoCoF Safe Limit were included in the Electricity System and Market Amendment (Tranche 9) Rules 2025 were approved by the Minister for Energy on 19 December 2025, published in the Government Gazette on 23 December 2025 and commenced on 26 February 2026.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
		The metrics for monitoring Frequency Co-optimised Essential System Services to be published once consultation with AEMO is finalised.

WEM Investment Certainty (WIC) Review	The WIC Review will consider, design and implement the following five reforms that have been announced by the Minister for Energy, which are aimed at providing further investment certainty to assist the decarbonisation of the WEM:
	(1) changing the Reserve Capacity Price (RCP) curve so it sends sharper signals for investment when demand for new capacity is stronger;
	(2) a 10-year RCP guarantee for new technologies, such as long-duration storage;
	(3) a wholesale energy price guarantee for renewable generators, to top up their energy revenues as WEM prices start to decline, in return for them firming up their capacity;
	(4) emission thresholds for existing and new high emission technologies in the WEM; and
	(5) a 10-year exemption from the emissions thresholds for existing flexible gas plants that qualify to provide the new flexibility service.
		• The MAC established the WIC Review Working Group (WICRWG). Information on the WICRWG is available at Wholesale Electricity Market Investment Certainty (WIC) Review Working Group including:
		  • the Terms of Reference for the WICRWG, as approved by the MAC;
		  • the list of WICRWG members;
		  • meeting papers and minutes from the 31 August 2023, 11 October 2023, 8 November 2023, 6 December 2023, 24 January 2024, 24 April 2024, 29 May 2024, 25 June 2026 WIC Review Working Group meetings.
		  • meeting papers from the 23 July 2026 WIC Review Working Group meeting.
		• The following papers have been released and are available on the WIC Review webpage, including:
		  • the Scope of Work for the review, as approved by the Coordinator;
		  • the WIC Review (Initiatives 1 and 2) Consultation Paper;
		  • the submissions received on the WIC Review (Initiatives 1 and 2) Consultation Paper;
		  • the WIC Review (Initiatives 1 and 2) Information Paper;
		  • The Exposure Draft of ESM Amending Rules to implement Initiatives 1 and 2;
		  • Submissions for the Exposure Draft of WEM Investment Certainty and RCM Review Amending Rules; and
		  • Response to Submissions for the Exposure Draft of WEM Investment Certainty and RCM Review Amending Rules.
		• The ESM Rules implementing the Review Outcomes for Initiatives 1 and 2 of the WIC Review are in Wholesale

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

		Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025. The Rules were approved by the Minister for Energy and published in the Government Gazette on 14 January 2025.
		• The WICRWG convened on 14 August 2025 and on 16 July 2026 to discuss the Coordinator's review of the Benchmark Capacity Providers.
		  • meeting papers and minutes for this meeting are available at Wholesale Electricity Market Investment Certainty (WIC) Review Working Group page.
		• The following papers for the 2025 Benchmark Capacity Provider Review have been released and are available on the webpage:
		  • Scope of Work
		  • Consultation Paper
		  • Stakeholder submissions
		  • The Coordinator's Determination, including responses to submissions
		• The following paper for the 2026 Benchmark Capacity Provider Review have been released and is available on the webpage:
		  • Scope of Work

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**

Capability Class 2 Technologies Review (CC2TR)	The Review will consider:
	• whether market design changes are required to maintain Power System Security and Reliability (PSSR) with the growing share of Electric Storage Resource (ESR) in the South West Interconnected System (SWIS);
	• whether the methodology for rating the capacity of ESR for the purposes of setting Certified Reserve Capacity remains consistent with the State Electricity Objective (SEO);
	• whether the Demand Side Programme (DSP) Obligation Duration remains consistent with the SEO; and
	• whether the ESR obligation intervals (ESROI), including the effectiveness of the method used by AEMO to determine the ESROI, is consistent with the SEO.
		• The MAC established the Capability Class 2 Technologies Review Working Group (CC2TRWG). Information on the CC2TRWG is available at Capability Class 2 Technologies Review Working Group, including:
		  ◦ the Terms of Reference for the CC2TRWG, as approved by the MAC;
		  ◦ the list of CC2TRWG members;
		  ◦ Meeting papers and minutes for the 23 October 2025, 4 December 2025, 5 February 2026, 26 March 2026, 2 April 2026 and 23 April 2026 meeting CC2TR Working Group meeting.
		• The following papers have been released and are available on the CC2TR webpage:
		  ◦ the Scope of Works.
		• EPWA is drafting a Consultation Paper for publication.

Forecast quality	Review of Issue 9 from the MAC Issues List.	• This review has been incorporated in the Operational Forecasting Review.
Network Access Quantity (NAQ) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• The timing for this review is to be determined.

Table 2 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Short Term Energy Market (STEM) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.

Table 3 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	EPWA has commenced work to improve AEMO's operational forecasting that will consider this issue. The following papers have been released and are available on the Operational Forecasting Review webpage: • The Scope of Works • The Operation Forecasting Review Consultation Paper • Stakeholder submissions EPWA is considering stakeholder feedback on the Consultation Paper and is preparing to release an Exposure Draft on proposed Amending Rules.

Upcoming Consultations 2026/2027	Indicative Timing for publication
Consultation Paper on the Capabilities Class 2 Technologies Review	July 2026
Consultation Paper on System Strength regulatory incentives framework and Technical Standards for hybrid systems (Power System Security and Reliability (PSSR) Standards Review)	August 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules to implement Technical Requirements for GFM/GFL (PSSR Standards Review)	August 2026
Consultation Paper - 2026-27 Benchmark Technologies Review	August 2026
Consultation on the Non-Co-optimised Essential System Service (NCESS) Framework Review Exposure Draft of Amending Rules	September 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules resulting from the Operational Forecasting Review	September 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules to implement System Strength regulatory incentives (PSSR Standards Review)	October 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules resulting from the Capabilities Class 2 Technologies Review	October 2026
Consultation on the Wholesale Electricity Market (WEM) Investment Certainty Review (Renewable Energy Mechanism)	November 2026
Consultation Paper on the WEM Operation Effectiveness (large loads)	November 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules to implement other System Strength changes (Proposal 20, PSSR Standards Review)	December 2026

Upcoming Consultations 2026/2027	Indicative Timing for publication
Consultation on the Exposure Draft of proposed ESM Amending Rules resulting from the WEM Investment Certainty Review (Renewable Energy Mechanism)	February 2027
Consultation on the Exposure Draft of proposed ESM Amending Rules (Tranche 11)	March 2026
Consultation Paper on the review of the Planning Criterion	March 2026
Consultation on the Exposure Draft of proposed ESM Amending Rules resulting from the review of the Planning Criterion	May 2026
Consultation Paper on the Procedure Content Review	June 2026

Department of
Energy and Economic Diversification

GOVERNMENT OF WESTERN AUSTRALIA

Energy Policy WA

Agenda Item 10: Overview of Rule Change Proposals (as of 23 July 2026)

Market Advisory Committee (MAC) Meeting 2026_07_30

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy or the Minister.

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

None

Rule Change Proposals Awaiting Commencement

None

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

None

Rule Change Proposals Awaiting Approval by the Minister

None

Formally Submitted Rule Change Proposal

None

Pre-Rule Change Proposals

None

Rule Changes Made by the Minister since Report presented at the 18 June 2026 MAC Meeting

None

Rule Change Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2023/165	12/12/2023	Wholesale Electricity Market Amendment (Reserve Capacity Reform) Rules 2023	• Schedules 2, 3 and 4 will commence at a time specified by the Minister in a notice published in the Gazette.
2024/66	7/06/2024	Wholesale Electricity Market Amendment (Cost Allocation Reform) Rules 2024	• Schedule 3 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/113	26/09/2025	Wholesale Electricity Market Amendment (Supplementary Capacity No. 3) Rules 2024	• Schedule 2 will commence on 1 October 2026.
2025/3	14/01/2025	Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025	• Schedule 3 will commence 1 October 2026. • Schedule 4 will commence 1 October 2027. • Schedule 6 will commence 1 October 2027. • Schedule 7 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/64	3/06/2025	Electricity System and Market Amendment (Tranche 8) Rules 2025	• Schedule 4 will commence 1 October 2026. • Schedule 5 will commence 1 October 2027. • Schedule 8 will commence 1

			October 2026. • Schedule 9 will commence at a time specified by the Minister in a notice published in the Gazette.
2025/155	23/12/2025	Electricity System and Market Amendment (Tranche 9) Rules 2025	• Schedule 3 will commence 1 October 2026 • Schedule 4 will commence 1 October 2027.