Department of
Energy and Economic
Diversification

GOVERNMENT OF
WESTERN AUSTRALIA

Energy
Policy WA

Meeting Agenda

Meeting Title:	Capability Class 2 Technologies (CC2T) Review Working Group
Date:	Thursday 5 February 2026
Time:	9:30 AM – 11:30 AM
Location:	Online

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda • Conflicts of interest • Competition Law	Chair	Noting	1 min
2	Meeting Apologies/Attendance	Chair	Noting	1 min
3	Minutes of Meeting 2025_12_04 Approved out of session Published 28 January 2026	Chair	Noting	1 min
4	Action Items	Chair	Noting	1 min
5	DSP Availability Options	RBP	Discussion	50 min
6	Current State Analysis	RBP	Discussion	65 min
7	General Business	Chair	Discussion	1 min

Please note, this meeting will be recorded.

Competition and Consumer Law Obligations

Members of the Working Group (**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.

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Agenda Item 4: Action Items

CC2TRWG Meeting 2026_02_05

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
1/2025	AEMO to clarify how ESR capacity is considered in the spare capacity calculation	AEMO	2025_12_04	**Open**
2/2025	AEMO to advise the CC2TWG the date that the technical analysis is expected to be completed	EPWA	2025_12_04	**Open** AEMO has provided the data to EPWA. Analysis results will be presented at future Working Group meetings. A historical stress analysis is provided in these papers.

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Energy Policy WA

Capability Class 2 Technologies (CC2T) Review

Review of Demand Side Programme (DSP) availability obligations and Historical System Stress analysis

5 February 2026

Working together for a
brighter energy future.

Title: Agenda

Demand Side Participation in Capacity Markets

International comparison

International Scan

Demand Side Programs in different jurisdictions

Market	Participation Mode	Capacity allocation approach	Capacity market availability obligations
Great Britain (GB)*	• Balancing Market - Demand Flexibility Services • Capacity Market • Ancillary services	Participant nominates capacity which is derated by availability factor (79% in 2024 auction) [1].	• Provider must activate loads four hours after notification. • No curtailment duration specified - no minimum limit
PJM*	• Energy market – as dispatchable load • Capacity market – loads can provide only capacity like WA DSPs[2] • Ancillary Services	ELCC	• Summer only resources available from June to October • Other resources, throughout the year. • No curtailment duration specified
ISO-NE*		ELCC (Marginal Reliability Impact)	• On-peak resources reduce electricity during summer peak hours (4 hours, Jun-Aug) and winter peak (2 hours, Dec/Jan) • Seasonal resources reduce electricity from Jun-Aug and Dec-Jan if hourly load forecast >=90% of seasonal peak
Ireland		ELCC (with Least Worst Regrets)	• Large industrial customers - curtail on notice • Aggregated generating unit - maintain on-site consumption (no changes) on notification • Resources must respond one hour after notification • Short duration (2-6 hours) resources allowed; long duration resources (6+ hours) also participate
Ontario	• Capacity Market • Industrial Conservation Initiative	Participant nominates capacity	• Summer (May-Oct) from 12pm-9pm • Winter (Nov-Apr) from 4pm -9pm • Loads typically activated for 4 consecutive hours.

1. OFGEM considering whether demand side should be incorporated into an EFC approach
2. Loads do not curtail - they reduce consumption through energy efficiency measures - hence no explicit curtail duration or notification requirements.

* Residential aggregations can participate

International Scan

Demand Side Programs in different jurisdictions

- Capacity markets all have a DSP type construct to enable demand-side participation in capacity without having to provide energy or meet a dispatch target.
- GB, PJM, ISO-NE and Ireland have multiple modes of participation in capacity market depending on the capability of loads:
  - Loads that can meet dispatch target can participate in energy, capacity and ancillary services markets;
  - Otherwise, they only participate in capacity market with less onerous dispatch obligations.
- Some capacity markets allow loads to participate with different durational capabilities:
  - Loads can participate with year-round availability required or during specific windows of time;
  - These markets (except Ontario), assign capacity to demand-side resources using ELCC/EFC so that loads with lower availability requirements have less impact on reliability and get less capacity.
- Ontario's approach is the closest to WA in terms of nominating capacity and requiring availability between specific windows of time:
  - Summer resources must be available for 9 hours and winter resources for 5 hours;
  - However, the curtailment duration is usually shorter.

Demand Side Programmes

A quick recap of availability obligations and recent changes

Demand-side integrated into WEM through DSP construct

DSPs can comprise single or aggregated loads (Associated Loads) whose purpose is to reduce Operational Demand during times of system stress

Availability requirements

- Must be available from 8am to 8pm on Business Days at a minimum (ESMR 4.10.1(f)(vi)
- Must be available for at least 24 Trading Intervals (ESMR 4.10.1(iii)).
  - DSPs must be available to curtail continuously for a maximum of 12 hours (within the 8am to 8pm window).
  - Requirement is analogous to 14-hour fuel requirement applied to Capability Class 1 technologies
- Minimum number of Trading Intervals for which DSP is available must equal the Peak DSP Dispatch Requirement

Capacity Year	Peak DSP Dispatch Requirement (Hours/Trading Intervals) [2025 WEM ESOO]
2025-26	200 / 400
2026-27	50 / 100
2027-28	23.75 / 47.5*

* Under the current methodology, this number will grow as more DSPs enter the RCM. However, concerns have been raised that the repeated SC procurements by AEMO have created a barrier for DSP aggregation

Miscellaneous 3 & Tranche 9 changes

- DSPs allowed to inject into the SWIS (reflected through changes to Relevant Demand and DSP submission rules).
- DSPs do not pay capacity refunds for not having sufficient capacity relative to their Minimum Consumption.
- DSPs are subject to testing if they fail to deliver and continue to pay refunds until they have passed a test.
- DSPs allowed to be certified without providing a location for their Associated Loads:
  - Must associate all loads no later than 1 December of Capacity Year - refunds payable on shortfalls between Oct – Dec
  - Cannot locate loads in constrained areas as identified by AEMO using previous cycle's NAQ model.

Upcoming DSP obligation changes

ESMR Tranche 8 changes

The ESMR rules for the new DSP obligation duration are approval by the Minister for Energy and come into operation at a time specified by the Minister in a notice published in the Gazette.

- Schedule 9 of the *Electricity System and Market Amendment (Tranche 8) Rules 2025*

The new DSP obligation duration applies on all Business Days during the periods:

- 6:00AM to 10:00AM; and
- 2:00PM to 10:00PM.

This has not commenced but it is expected to apply from the 2026 Reserve Capacity Cycle.

Demand Side Programmes

Policy context

Policy objectives

Dual objectives at play

- **Objective 1: Ensure DSP availability rules align with system need**
- **Objective 2: Identify amendments so that residential batteries can be utilised during system stress events**

Objective 1: Align DSP availability with system need

Current DSP obligations may be insufficient

In 2025, WEM ESOO, AEMO forecasted that EUE is forecast to occur between 8:00pm and 10:30pm during the 2025-26 hot season when DSP is no longer available and ESR is largely exhausted.

- Currently under the ESMR, DSP is not required to be available after 8:00pm.
- AEMO indicated that this would require procuring an additional 50MW of capacity through Supplementary Capacity (SC).

As thermal generation exits the system without replacement, maintaining reliability during extreme weather will require greater reliance on ESR and DSP.

In response to the extreme conditions on 20 January 2025, AEMO activated a total of 126 MW of additional capacity through DSP and capacity procured under the SC and NCESS mechanisms.

- This comprised 20 MW of DSP, 11.5 MW of Supplementary Capacity, and 94.5 MW of NCESS.

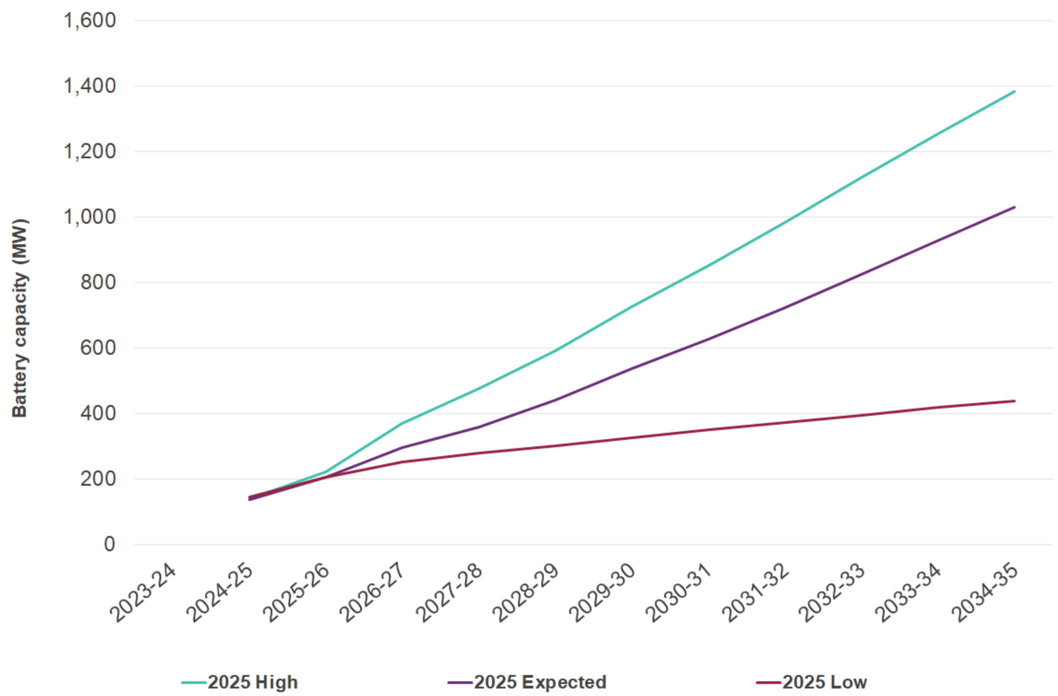
Without changes to DSP obligations, it may increase the reliance on SC and NCESS mechanisms.

Objective 2: Enable BTM battery participation

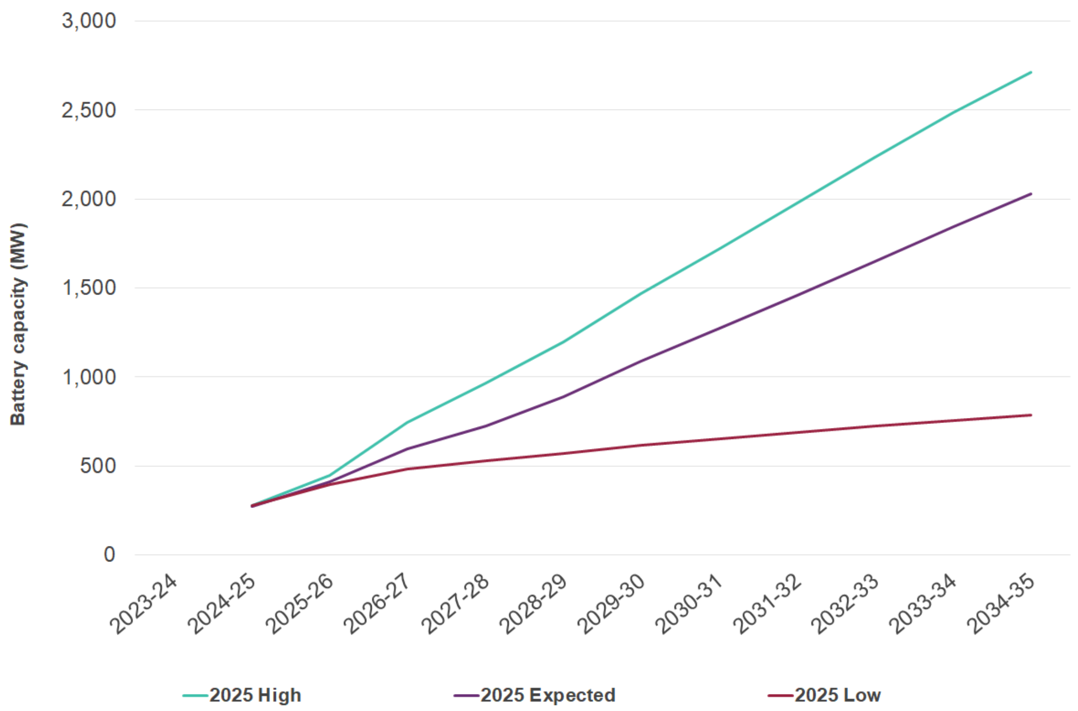
Residential Battery Scheme has resulted in large uptake of BTM batteries

- There is potential for these batteries to contribute to system reliability through RCM participation
- As batteries are duration limited (6.6kW/ 10-15kWh, 3kW/ 8.8kWh), they cannot meet the 12 hour requirement in ESMR 4.10.1(iii)
- How can the duration limited nature (requirement to charge) of BTM batteries be reflected in DSP availability obligations?

Forecast MW capacity, 2025 ESOO



Forecast MWh capacity, 2025 ESOO

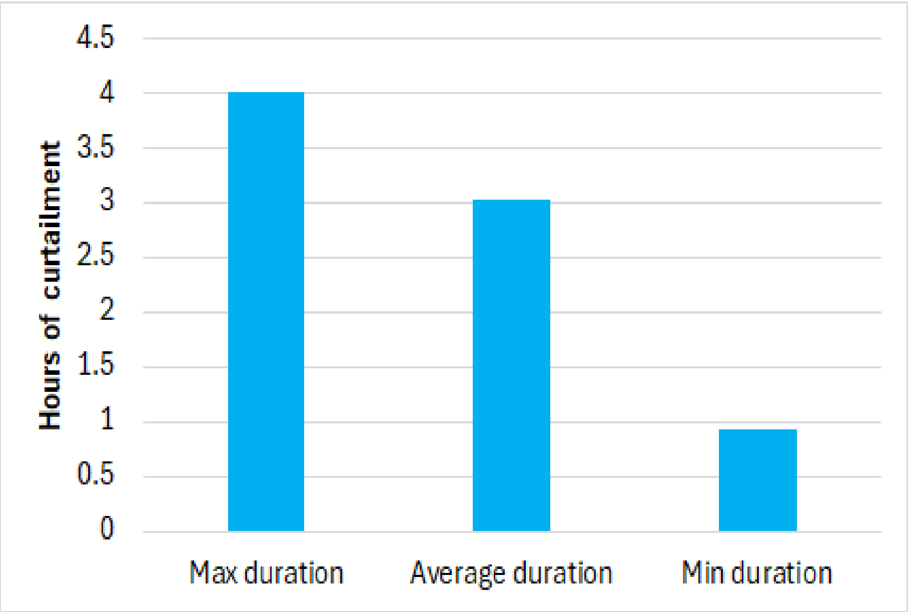


DSPs are treated as last resort

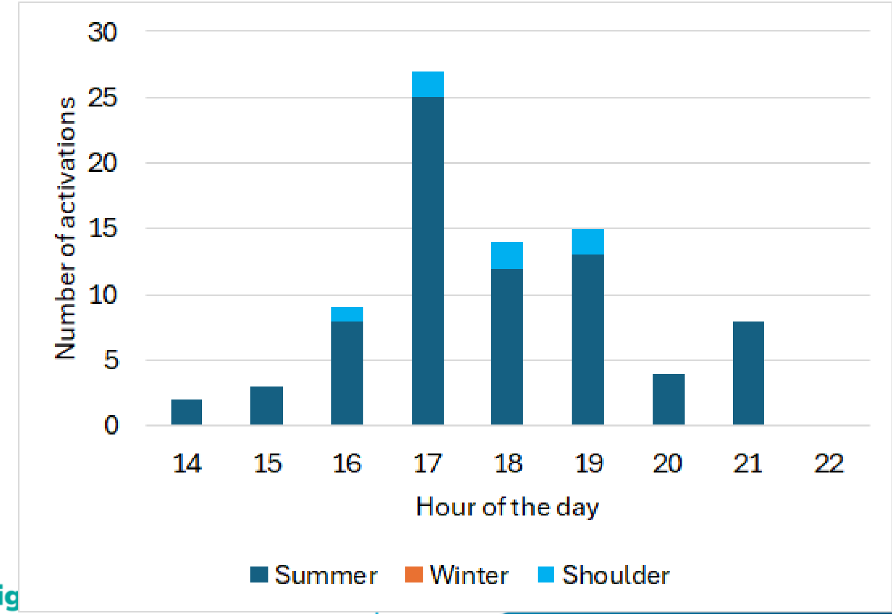
DSP are called during periods with high demand when all available facilities have already been dispatched

- Reviewed DSP activation and NCESS (Reliability Service) activation of Enel-X load reduction service since 1 Oct 2023 to assess when DSP dispatch events are likely to occur (AEMO Market Data site).
- 31 DSP/NCESS activation events since 1 Oct 2023:
  - 12 events pertain to Enel X's NCESS contract;
  - Graph counts whether DSP was curtailed during a specific hour;
    e.g. Out of the 31 events, 27 spanned 17:00-18:00 (Hour 17).
- Most events occurring between 16:00 – 20:00; however, later or earlier activations can occur with the latest one ending at 21:25.

Maximum, average and minimum curtailment duration



DSP/ NCESS (Enel-X) activations by hour: 1 Oct 2023 to 17 Feb 2025

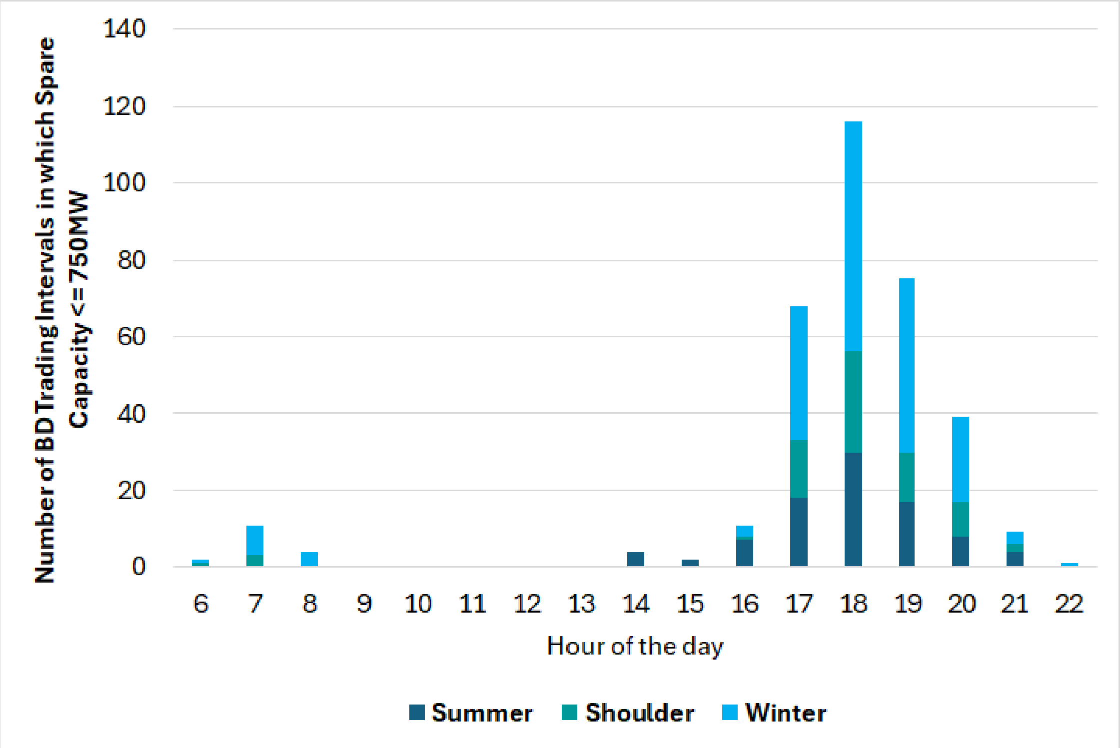


DSPs are treated as last resort

Historically called during afternoon/evening peak, but could be called when capacity margin is low

- Reviewed when low spare capacity (ESMR 4.26.1(e)) falls below 750MW
  - Dynamic refund factor cap of 6 binds at 750MW – at this level LOR declarations likely
- Spare capacity intervals overlap with intervals in which DSPs are likely to be called (as expected)
  - Evening low spare capacity events are most likely in winter: note DSPs not called in winter historically
  - As with DSP activation, low spare capacity intervals occur mostly between 16:00-20:00.
  - Small number of low spare capacity intervals occurring in the early morning during winter and shoulder months.
- Spare capacity intervals unlikely between 9am – 2pm.

Number of Business Day Trading Intervals from 1 Jan 2021 to 11 Oct 2025 in which Spare Capacity has fallen below 750MW



Source: RBP analysis of AEMO provided spare capacity data

How does this compare to the ESROD?

ESROD/ESROIs also overlap intervals in which DSPs are called

- ESROD has recently increased to 6 hours (12 Trading Intervals)
- ESROD extends beyond 8pm cut-off for DSPs
    - System stress events after 8pm may well become common in the future, particularly during winter months.
        - AEMO called for SC in 2026 because existing DSPs are exhausted by 8pm.
    - Enel-X NCESS contract called on 20 & 21 Jan 2025 to curtail between 17:30 – 21:25.
    - Extending DSP availability period beyond 8pm will capture late evening stress events
- Spare Capacity data indicates potential of low-capacity margins occurring in the early morning:
    - AEMO Technical Analysis will show whether this is a valid trend – could unserved energy occur in the early morning?
    - Is there an issue with extending the 8am DSP start time back to 6am?

ESROD/ESROIs for 2027-28 Capacity Year

Season	Peak ESROD – BD	Peak ESROD – NBD
Summer (Dec – Mar)	16:30 – 22:00	15:30 – 21:00
Winter (June – Aug)	16:30 – 22:00	15:30 – 21:00
Shoulder (Apr, May, Sep-Nov)	16:30 – 22:00	16:00 – 21:30

Source: 2025 WEM ESOO

Demand Side Programmes

Draft evaluation of policy options

Propose three options to evaluate

Option	Description
Option 1: Split DSP availability into two blocks (Tranche 8)	DSPs must be available as follows: • Available between 6am – 10am and available to curtail up to 4 hours • Available between 2pm – 10pm and available to curtail up to 8 hours • DSPs have four-hour block to charge (10am – 2pm)
Option 2: 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 3: 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.

Options assessed against the SEO

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 batteries	Aligning DSP obligations to enable BTM batteries 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 batteries) 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

DSP availability evaluation

Option 1: Split DSP availability into two blocks

DSPs are available as below

Availability Block 1	Charging block	Availability Block 2
6am -10am (curtail up to 4 hours)	10am – 2pm (4 hours)	2pm – 10pm (curtail up to 8 hours)

- 12 hour availability maintained across two blocks (4 + 8)
- Allows sufficient time to charge during peak solar hours
- Window covers late evening (addressing recent SC procurement concerns)
- DSPs must still be able to meet the Peak DSP Dispatch Requirement
- 6am availability requires BTM batteries to be charged beforehand – could this be an issue?

Requires changes to how Relevant Demand/settlement calculations are done to ensure DSPs with over-subscribed loads are not disadvantaged due to the behaviour of Associated Loads that are not activated during a particular event – covered in further detail later.

Criteria	Draft 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. Current 8am – 8pm window does not include the early morning, or late evening events and fails to recognise that additional capacity is unnecessary during the middle of the day. *Criteria met fully (only substantially if allowed to choose between split window or continuous 12-hour option)*
Availability obligations provide value for money	DSPs selecting 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 8pm, thereby reducing likelihood of costlier SC procurement. *Criteria met fully*
Availability obligations enable value to be extracted from BTM batteries	Option enables BTM batteries to charge in the middle of the day during peak solar output, thereby using renewable energy instead of curtailing it. *Criteria met fully*
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*
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	Simple to implement and will only require minor rule, process and system changes. *Criteria met fully*
Overall Performance	***All criteria met substantially***

DSP availability evaluation

Option 2: Include DSPs in ESROD calcs

- DSP availability intervals are dynamic and rolled into the ESROD calculations
- Appendix 11 updated to calculate ADG and ESROD by assessing whether there is sufficient non-CC2 capacity during Peak Demand Period.
- DSPs not grandfathered (unlike ESR)
- Will result in lower availability requirement:
  - 2027-28 ESROD of 6 hours would halve the existing 12 hour requirement
  - ESRs have lower requirement but must be available for all ESROIs during the year
  - DSPs only must be available to meet the Peak DSP Dispatch Requirement (23.75 hours in 2027-28)
- In theory, this option could be implemented with DSPs assessed under ELCC – more complex implementation and may stall DSP entry into RCM

Criteria	Draft evaluation
Availability obligations aligned with power system needs	Approach identifies Trading Intervals where non-CC2 capacity <= demand during peak demand period. Given ESROIs cover late afternoon to evening, DSPs will not be available for winter morning peaks. *Criteria met partially*
Availability obligations provide value for money	ESR & DSPs get same duration requirement, likely less than the 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. Option performs better if DSPs assessed under ELCC per US markets. DSPs will be available after 8pm thereby reducing likelihood of costlier SC procurement. *Criteria met partially*
Availability obligations enable value to be extracted from BTM batteries	See Option 1. ESROD starts after peak solar hours enabling batteries to charge. *Criteria met fully*
Approach is flexible enough to change as power system needs evolve and change	Availability obligations 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 partially***

DSP availability evaluation

Option 3: Calculate DSP availability requirements based on Peak DSP dispatch requirement

- DSP availability is dynamic and based on Peak DSP Dispatch Requirement.
- AEMO models which Trading Intervals the demand in the reference demand profile (used in ELCC calculations) is likely to be greater than the peak demand under a 50% POE peak/median growth scenario (adjusted for DSP dispatch and capacity). For example, winter mornings from 6am-9am and Hot Season from 3pm – 9pm.
- May result in smaller availability period than ESROD:
  - Could span smaller range of Trading Intervals than ESROD thereby diluting availability obligations further
  - Peak DSP Dispatch Requirement is 47.5 Trading Intervals for 2027-28.
- Similar approach is used in some US capacity markets, but these markets use ELCC to assign capacity to demand-side.

Criteria	Draft evaluation
Availability obligations aligned with power system needs	Approach incorrectly assumes DSPs only needed if reference demand profile peak > 50% POE peak (vs modelling ability of CC2 & non-CC2 capacity to meet peak demand). Unclear whether DSPs would be required to be available after 8pm 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 – to make this option perform better, DSPs would need to be assessed under an ELCC like approach (per US capacity markets). Unclear whether DSPs would be required to be available after 8pm 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 enable value to be extracted from BTM batteries	See Option 1. Peak solar hours unlikely to be included in Peak DSP dispatch requirement. *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 partially***

DSP availability evaluation

Summary

- Option 1 performs best against SEO:
  - Retains 12-hour requirement
  - Performs better against reliability limb if only split window option is available
  - Simple to implement.
- Option 2 and 3 will dilute value provided by DSPs.
- Options 1 and 2 likely reduces the need for SC procurement
- All three options enable BTM batteries to charge during peak solar hours but perform poorly against most other criteria

Option 1 requires changes to Relevant Demand related settlement rules to ensure DSPs with over-subscribed loads are not disadvantaged.

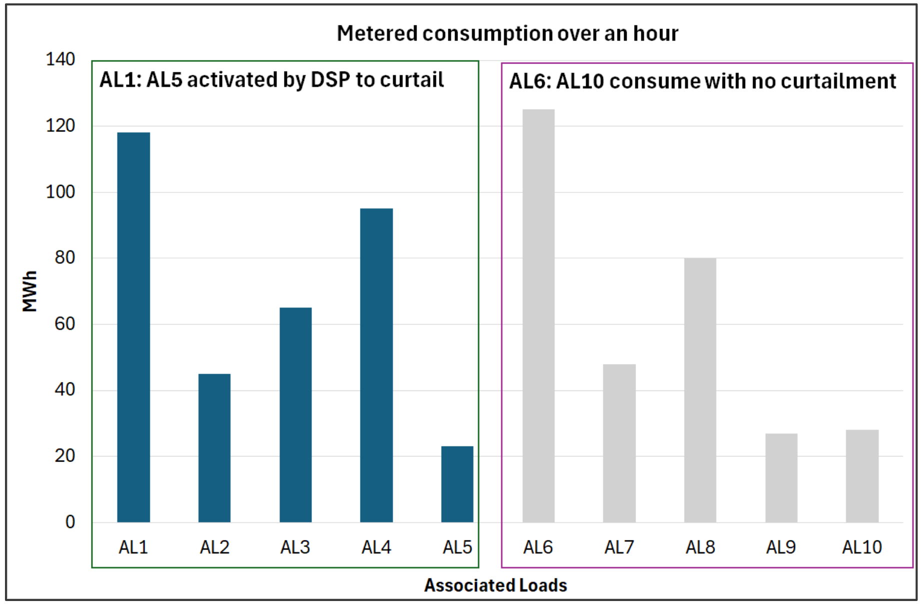
	Option 1: Two availability blocks	Option 2: DSPs rolled into ESROD	Option 3: DSP availability based on Peak DSP Dispatch Requirement
Overall performance	●	◔	◔
Availability obligations aligned with power system needs	Fully met (Only substantially met if allow to choose between split window or continuous 12-hour option)	Partially met	Not met
Availability obligations provide value for money	Fully met	Partially met	Not met
Availability obligations enable value to be extracted from BTM batteries	Fully met	Fully met	Fully met
Approach is flexible enough to change as power system needs evolve and change	Substantially met	Substantially met	Partially met
Approach is transparent and predictable	Fully met	Partially met	Partially met
Cost and complexity of implementation is reasonable	Fully met	Partially met	Partially met

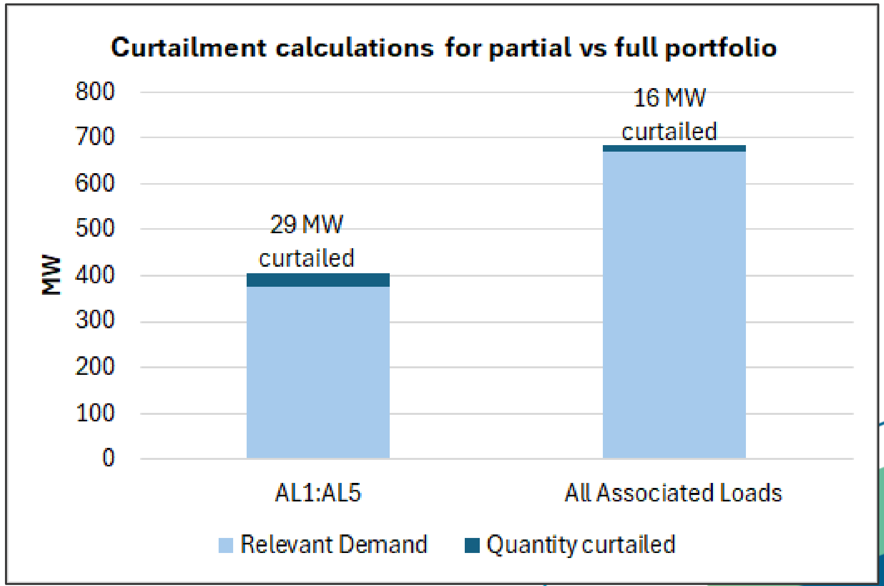
Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Example

- DSP with 10 Associated Loads has been assigned 25MW of Peak Capacity Credits (RCOQ = 25MW).
- DSP has over-subscribed, so that it only needs to activate part of its portfolio to meet its delivery obligations.
- During a DSP Dispatch Event, the DSP activates five of its Associated Loads to provide a response of 25MW
  - Remaining loads can do as they please.
- During settlement, compliance with RCOQ depends on whether only activated loads are included in Relevant Demand calculation or whether the entire portfolio is included – unused loads can end up cannibalising the response of other loads in the portfolio.





Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Amendments needed so that over-subscribed DSPs can specify which Associated Loads will be activated for a DSP Dispatch Event (and for Reserve Capacity Tests)

Specification of activated loads must occur ex-ante: For DSP dispatch event, need to strike balance between providing participant sufficient time to select loads to activate with mitigating any opportunity to game the baseline

- New Relevant Demand method uses most recent 10/50 or 5/50 non-DSP dispatch event days respectively for BD and NBD baselines
- Specifying loads within this window (~2 weeks of event) could result in participants cherry picking loads with the highest consumption
- Could require DSPs to associate/nominate loads for potential events at least 3 weeks ahead of time. Could work two ways:
    - DSPs can subscribe as many loads as they want but can only associate those loads that will be activated during an event:
        1. Association takes effect 3 weeks after application
        2. Does not enable a DSP to nominate different loads for the morning block vs evening block
        3. Are restrictions needed on how frequently loads can be disassociated and associated?
    - DSPs associate all subscribed loads but nominate activation status of each load to indicate whether load will be activated in the morning, evening or both:
        1. Any changes to activation status takes effect 3 weeks after application
        2. Enables DSPs to specify different loads for morning vs evening activations.
        3. As above, are restrictions needed on how frequently the activation status can be changed?
    - How would the above changes interact with the existing Reserve Capacity Testing process?

Changes to RCM settlement rules

Under Option 1, oversubscribed DSPs will be at a disadvantage if unused loads over-consume during a DSP dispatch event

Rule and system changes will be needed:

AEMO requires identification of which loads to include in Relevant Demand calculation:

- Amendments to existing load association/disassociation rules
- Appendix 9 (Relevant Demand) will require changes to ensure Relevant Demand is calculated over activated Associated Loads only
- Peak Capacity Shortfall (ESMR 4.26.2D) and related rules must be amended to measure response over activated loads only
- System changes needed to implement new association/nomination and settlement rules.

Timing of changes

- Above changes should occur at the same time that new Relevant Demand methodology and Misc 3 changes are implemented.

Technical Analysis

Historical review of system stress events

Introduction

Technical analysis comprises two components – current and future state analysis

- **Current state analysis focuses on historical system stress events:**
  - When do system stress events occur in terms of seasonality, time of day, type of day (business/non-business)?
  - What are the contributing factors to system stress?
  - What are ESR charge levels like entering into system stress events?
- **Future state analysis (to be provided in the future) :**
  - When are batteries likely to be needed in the future to avoid unserved energy?
  - What are the drivers of unserved energy and needing batteries in the future?
- **Technical analyses reviewed to identify potential triggers or scenarios in which mandatory charge obligations may be required**

The following slides are some of the findings from the current state analysis

- Further analysis on lower than expected charge levels is on-going.

What is a System Stress Event (SSE)?

Market Advisories and manual constraints used to identify SSEs occurring between November 2023 and August 2025

- Market advisories containing Low Reserve Condition declarations used to identify SSEs.
- Manual constraints applied by AEMO to capture additional events not captured by advisories.
- SSE start time based on the start-time specified in the most recent advisory relating to that event (so that any changes in event timing can be picked up).
- SSE end time based on the end-time specified in the most recent advisory relating to that event.
- **Note:**
    - SSE duration (SSE end time – SSE start time) does not necessarily indicate durational requirement for ESR
    - Insufficient information to assess when ESR would have been needed for entire duration of event

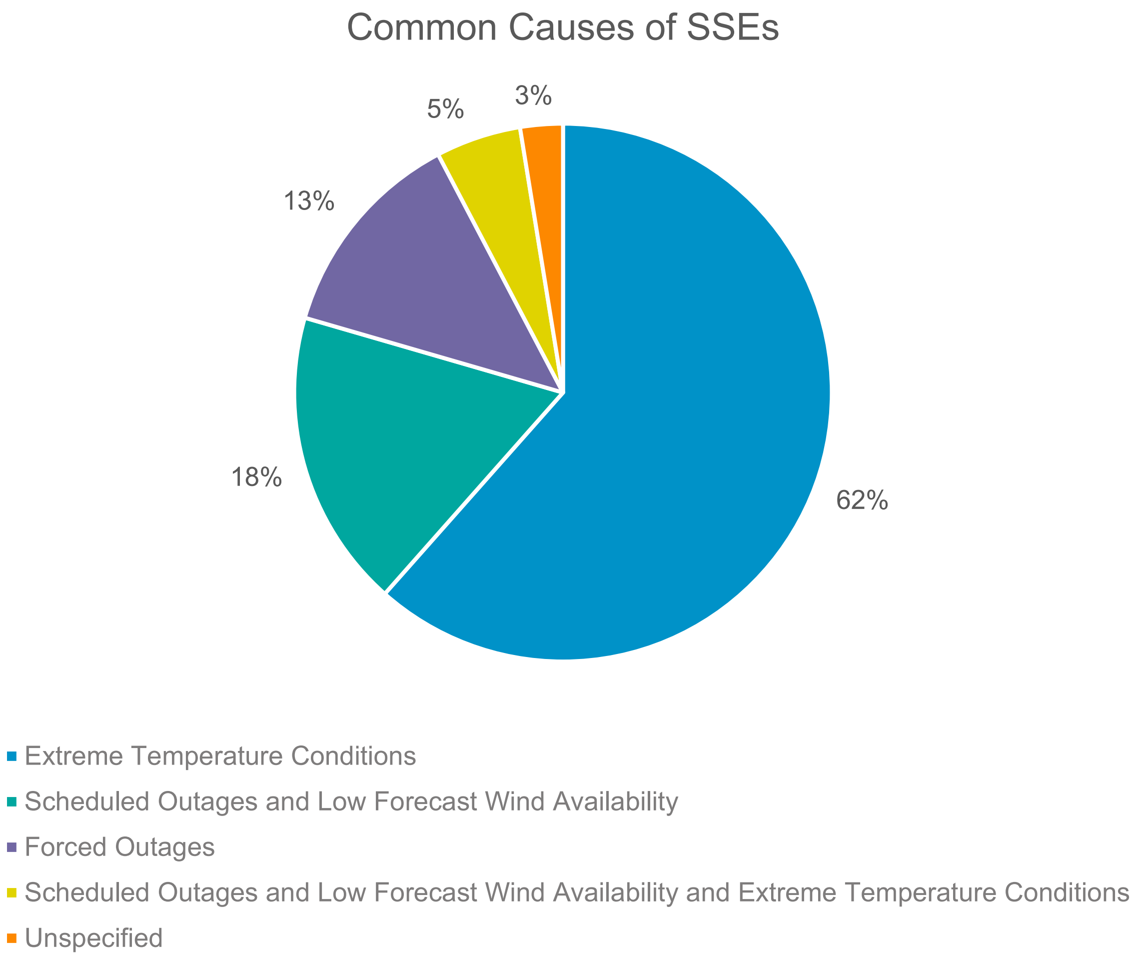
Dataset	Includes	Excludes
Market advisories 38 SSEs identified	Energy & ancillary services shortfalls	• Non-shortfall events (transmission or comms events) • Minor manual constraints • Ramp rate or RRS shortfalls • Emergency of High-Risk Operating State advisories due to system instability • Network 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

Historical System Stress Events (SSEs)

During the CC2 Current State Technical Analysis we have identified 39 historical SSEs

This pie chart shows the percentage breakdown of the main causes of the 39 identified SSEs:

- 62% were driven by extreme temperature conditions (both high and low).
    - 21 events occurred in summer, 2 in the shoulder season, and 1 in winter (the 25 August 2025 event)
- 18% were driven by scheduled outages combined with low forecast wind availability
    - **Only** occurred **in winter** and represented 7 events.
- 13% were driven by forced outages.
    - 4 events occurred in the shoulder season, 1 in winter and none in summer.
- 5% driven by a combination of scheduled outages, low forecast wind availability, and extreme temperature conditions
    - 2 events, and **only** occurred **in summer**.
- The remaining 3% of events were classified as unspecified (1 event)

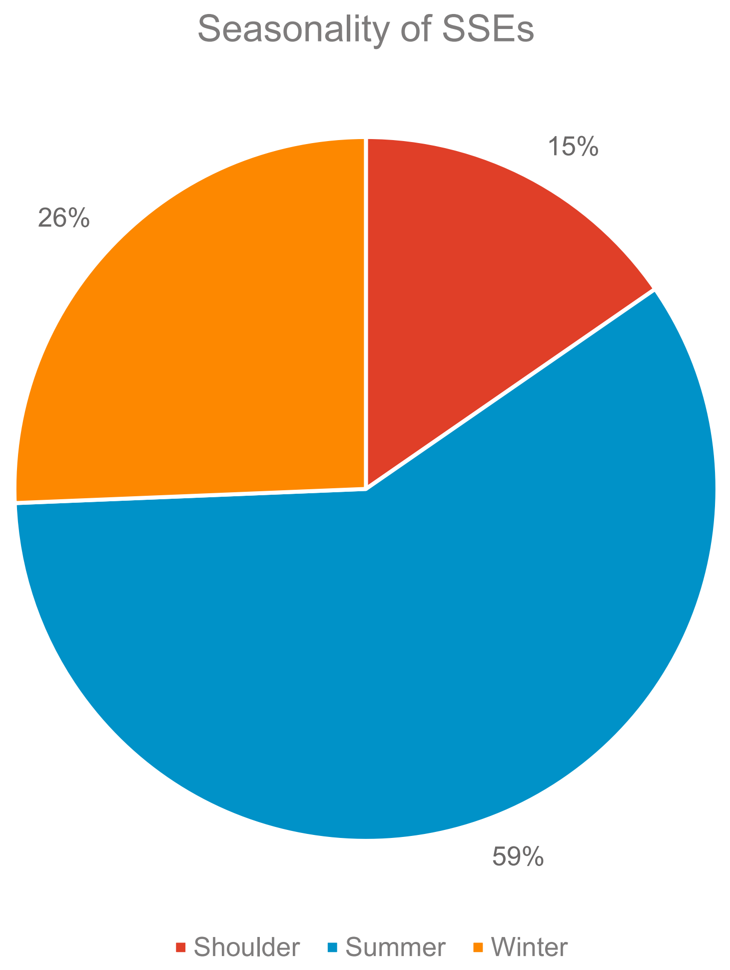


Historical System Stress Events (SSEs)

Seasonality of SSEs

This pie chart shows the percentage breakdown of the seasonality of the 39 identified SSEs:

- 15% of the SSEs (6 SSEs) occurred in the shoulder season (April, May, September)
- 59% of the SSEs (23 SSEs) occurred in summer (December – March)
- 26% of the SSEs (10 SSEs) occurred in winter (June – August)

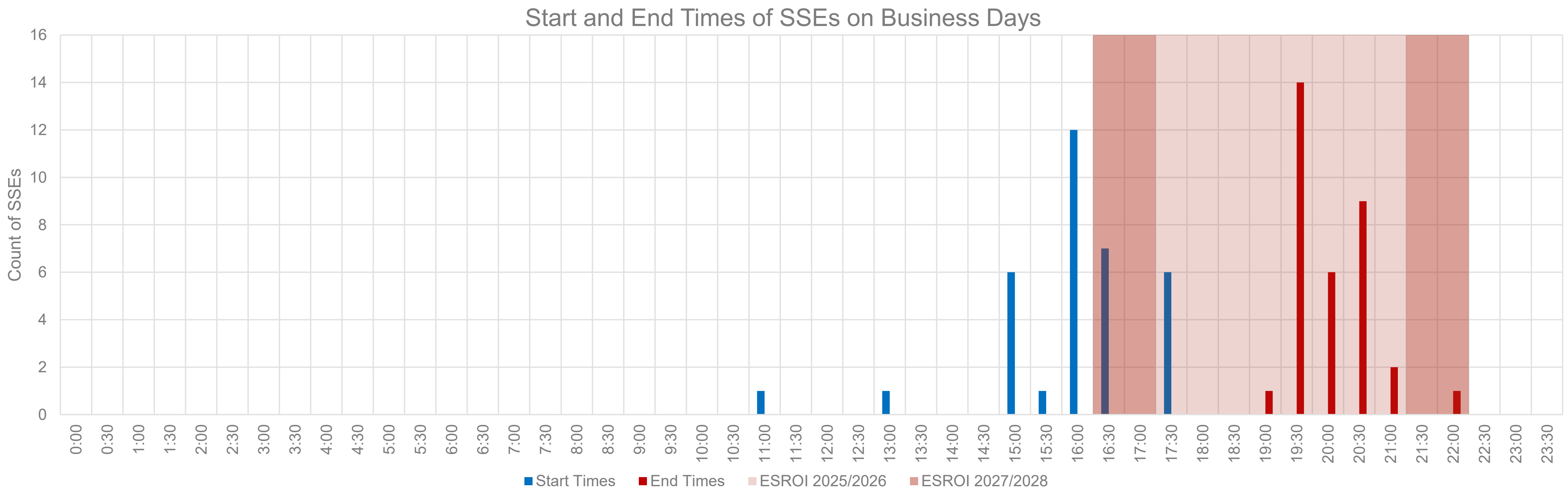


Historical System Stress Events (SSEs)

Timing of SSEs on Business Days

This chart shows the number of SSEs on business days by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

- 82% of business day SSEs started before the 2025-2026 ESROI, while 62% started before the 2027-2028 ESROI

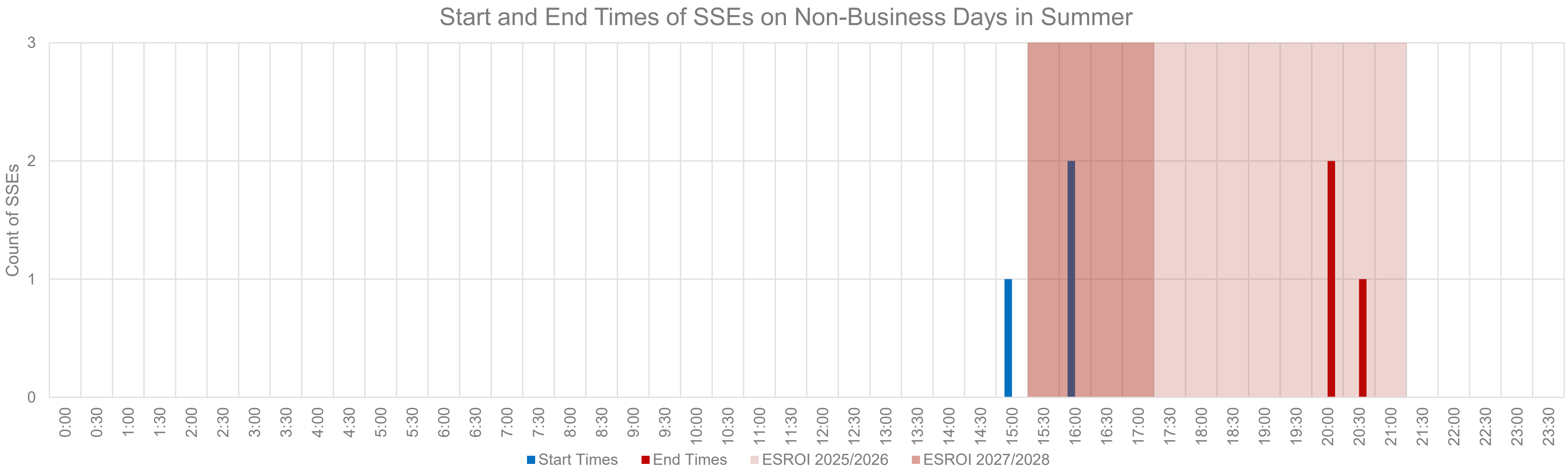


Historical System Stress Events (SSEs)

Timing of SSEs on Non-Business Days in Summer (Dec – Mar)

This chart shows the number of SSEs on non-business days in summer by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

All non-business day summer SSEs started before the 2025-2026 ESROI, while one started before the 2027-2028 ESROI. Note that there were no SSEs that occurred both on non-business days and shoulder season.

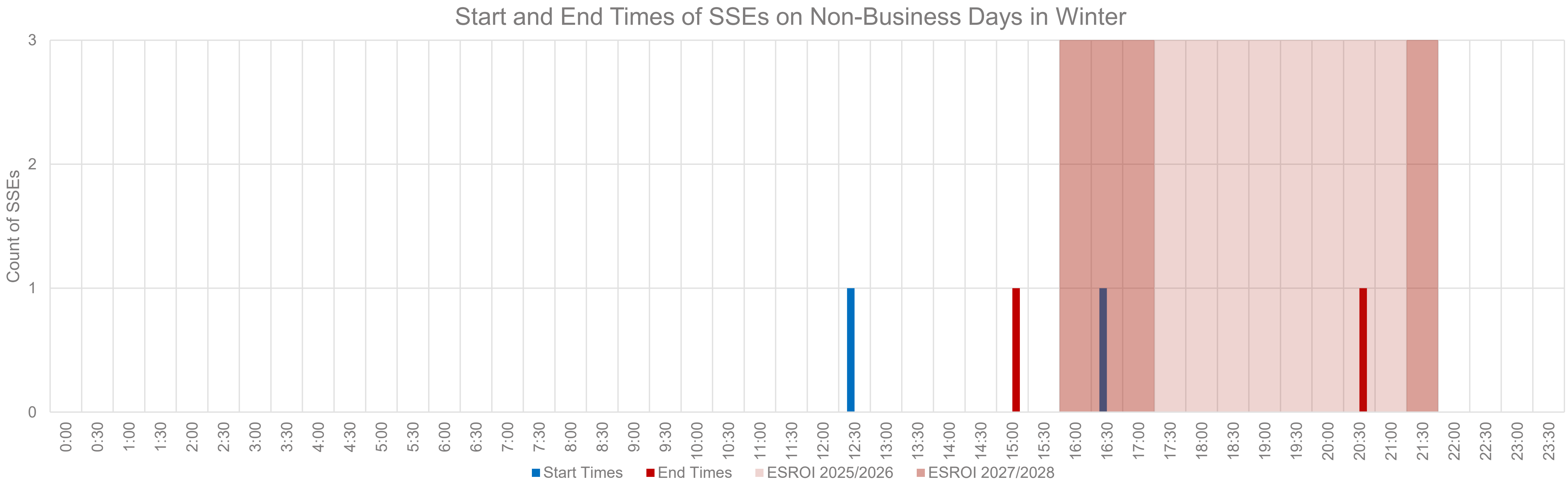


Historical System Stress Events (SSEs)

Timing of SSEs on Non-Business Days in Winter (Jun-Aug)

This chart shows the number of SSEs on non-business days in winter by trading interval, comparing their start and end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

All non-business day winter SSEs started before the 2025-2026 ESROI, while one started before the 2027-2028 ESROI.



Historical System Stress Events (SSEs)

SSEs Starting Before the 2025-2026 ESROIs

33 of the 39 historical SSEs identified started before the 2025-2026 ESROIs.

Common Characteristics of these 33 SSEs:

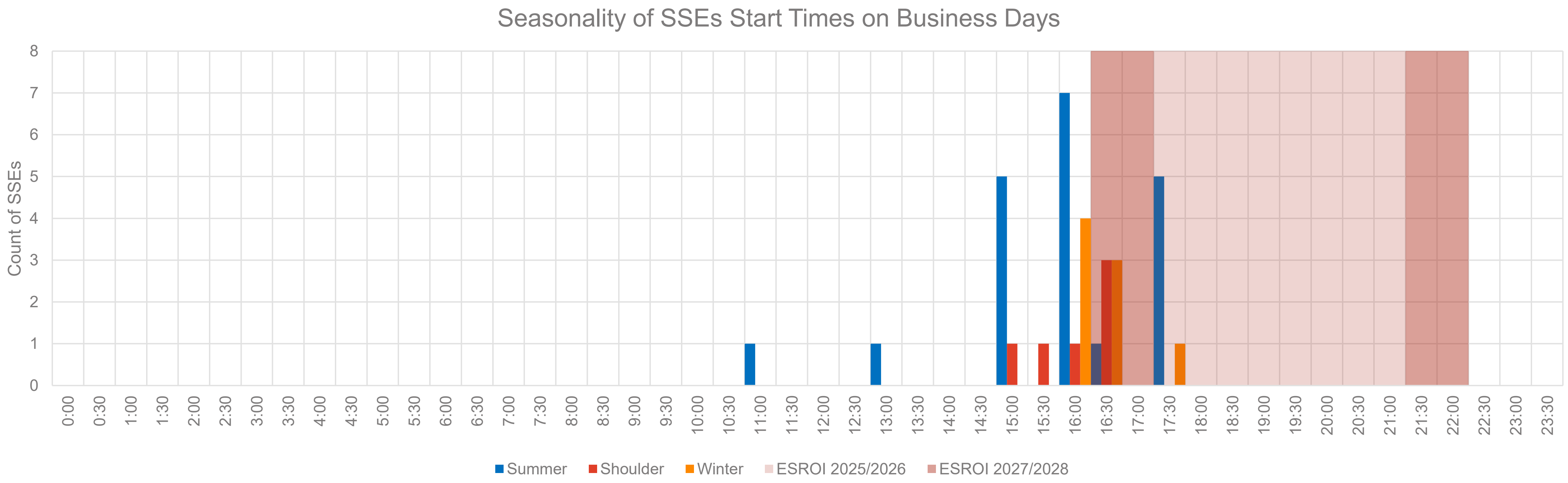
- **Timing:** The median start and end times were 16:00 and 20:00, with a median duration of 4 hours
- **Seasonality :** 18 events occurred in summer, 6 in the shoulder season and 9 in winter
- **Drivers:** Summer events were predominantly driven by heatwaves or higher than forecast temperatures, while winter events were driven by generation outages and low forecast wind availability
- **Severity:** Predominantly LOR1 or LOR2, with one event initially LOR2 and later upgraded to LOR3, and one event initially LOR1 and later upgraded to LOR2
- **Alignment with ESROIs:** Only one event extended beyond the end of the 2025-2026 ESROI
- **Day of the week:** Only 5 events were on Non-Business Days
- **ESRs Charge Levels:** Across all 39 SSEs, the median charge level at event start was 78%

Historical System Stress Events (SSEs)

Seasonality of SSEs Start Times on Business Days

This chart shows the number of SSEs on business days by trading interval in the summer, shoulder, and winter seasons, comparing their start times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

As shown in the chart, SSEs tend to start earlier in summer and shoulder seasons.

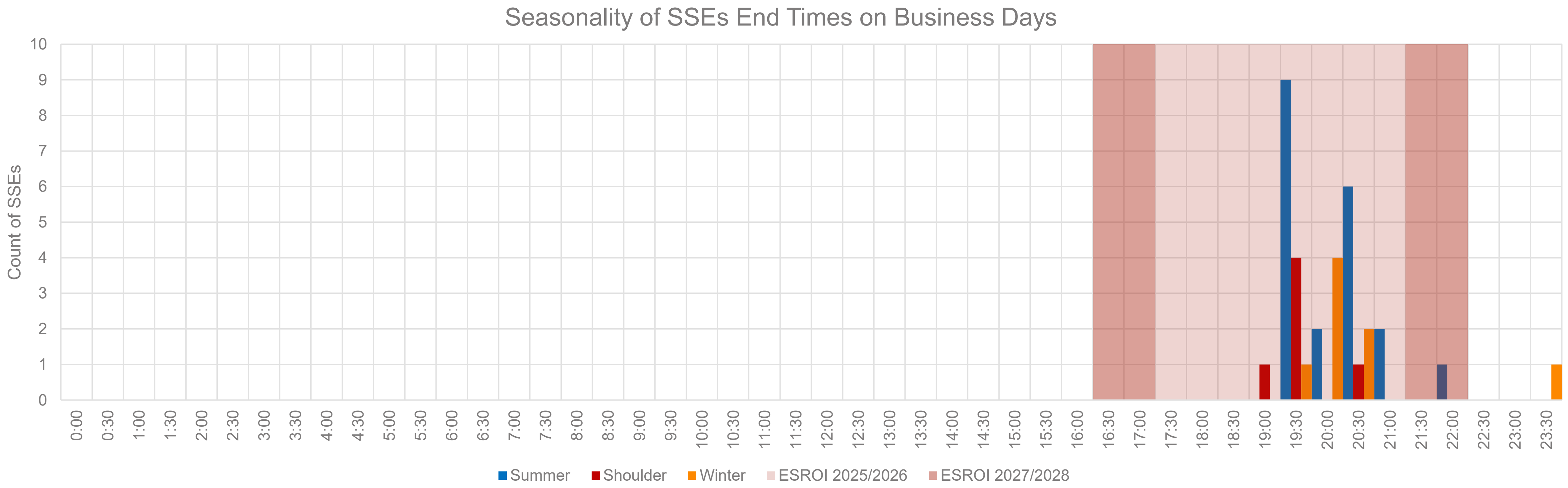


Historical System Stress Events (SSEs)

Seasonality of SSEs End Times on Business Days

This chart shows the number of SSEs on business days by trading interval in the summer, shoulder, and winter seasons, comparing their end times with the current 2025-2026 ESROI and the future 2027-2028 ESROIs.

As shown in the chart, only two SSEs ended after the 2025-2026 ESROI, one of which (the 25 August 2025 event) ended after the 2027-2028 ESROI.



Historical System Stress Event (SSEs)

Duration of SSEs by Season

The graph shows a scatter plot of SSEs durations across summer, shoulder and winter.

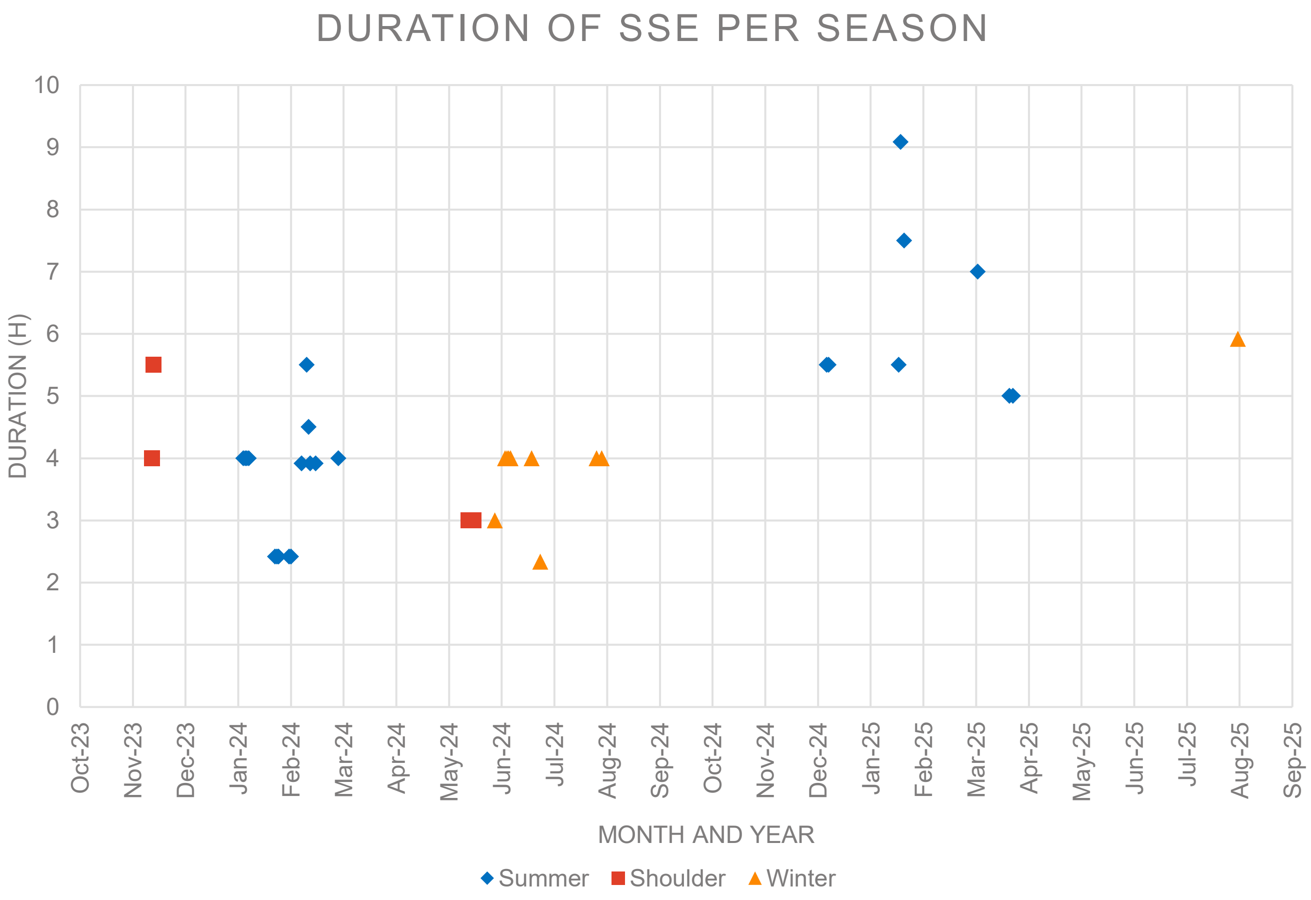
The three SSEs that had a duration greater than 6h occurred on:

- 21/01/2025 from 11:25 to 20:30
- 23/01/2025 from 13:00 to 20:30
- 6/03/2025 from 15:00 to 22:00

These SSEs had the following in common:

- They all occurred in Summer
- They started before the start of both the 2025-2026 ESROI and 2027-2028 ESROI
- They occurred on Business Days
- The 21/01/2025 and 6/03/2025 event had an average ESR charge level of 82% and 86% respectively, while the 23/01/2025 event had 54%.

As previously noted, SSE duration does <u>not</u> necessarily reflect durational requirement for ESR.

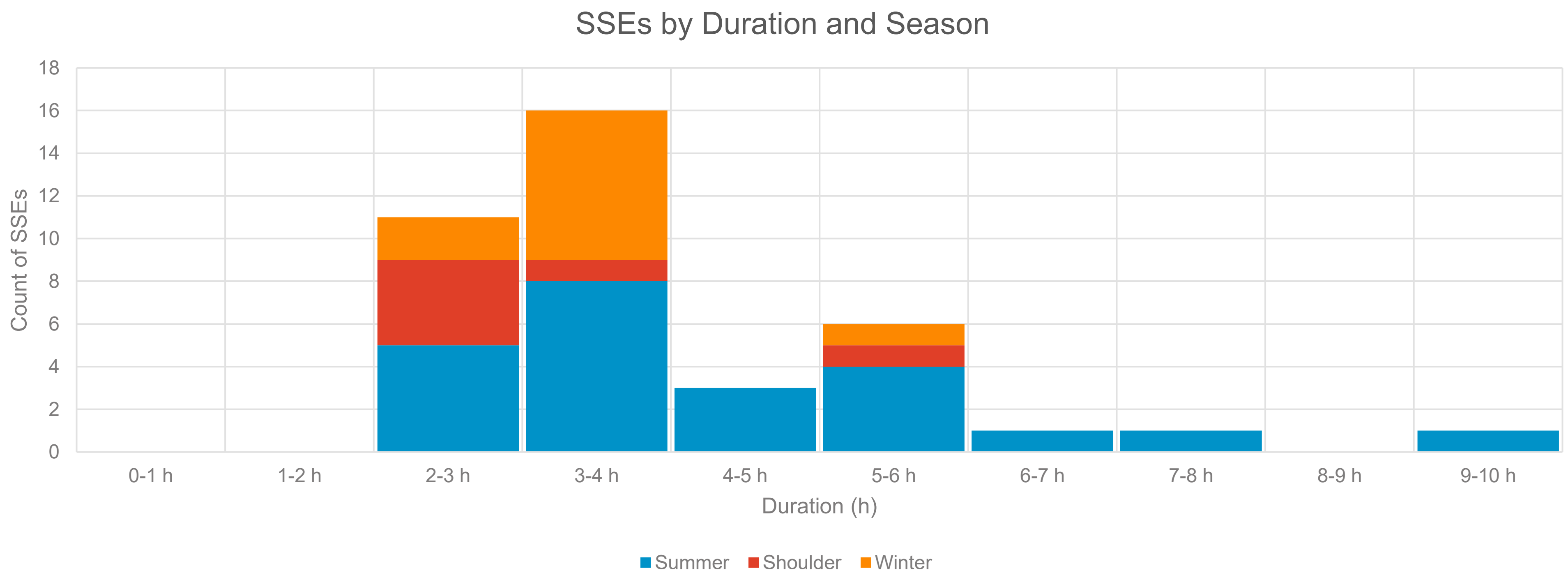


Historical System Stress Events (SSEs)

Number of SSEs by Duration and Season

This chart shows the number of SSEs by duration across summer, shoulder and winter.

- The charts indicates that SSEs most frequently have durations between 3 and 4 hours.
- Events in summer tend to have a greater duration than in winter and shoulder.



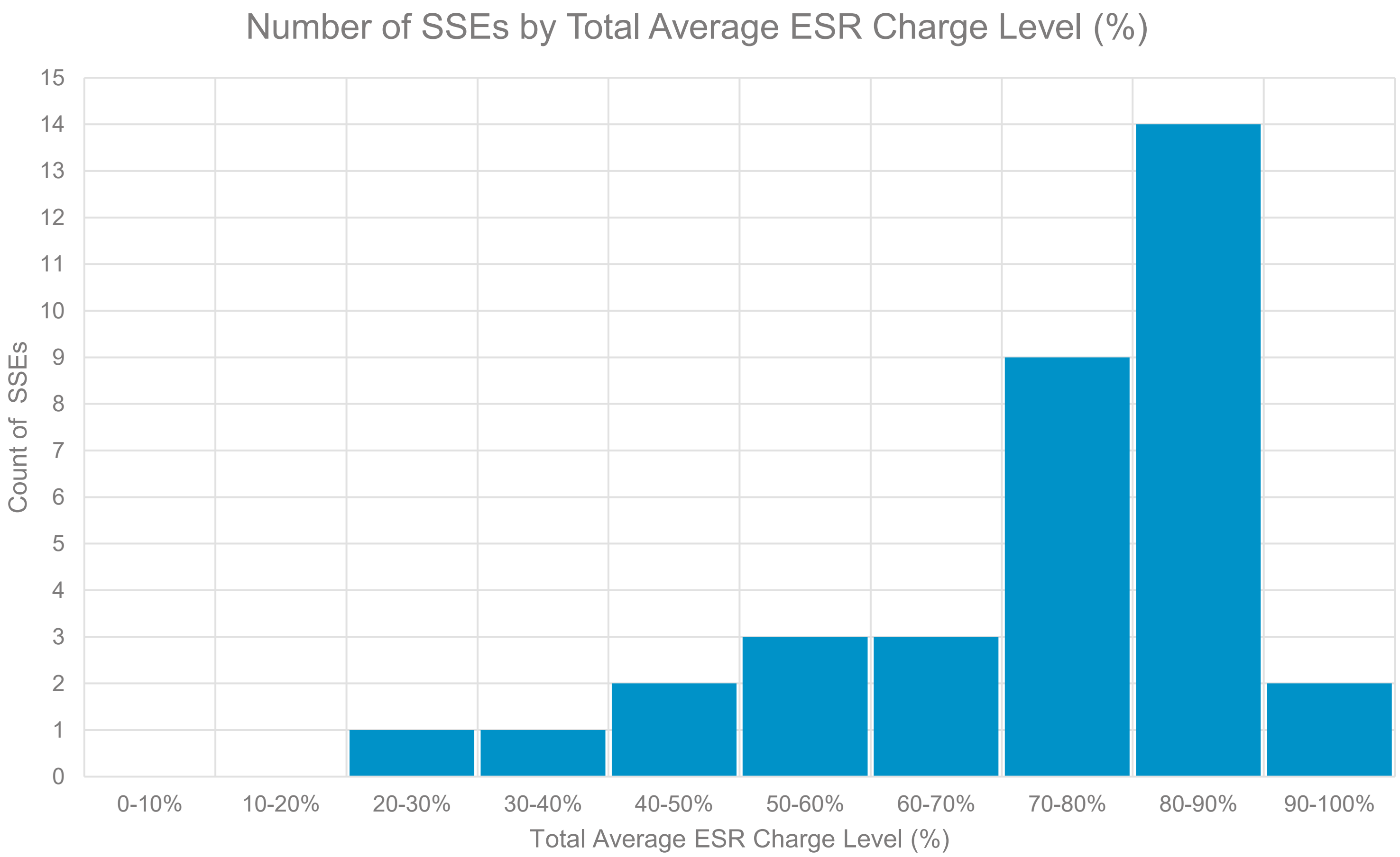
Historical System Stress Events (SSEs)

Number of SSEs by Average ESR Fleet Charge Level (%)*

This chart shows the number of SSEs by the average charge level (%) of the entire ESR fleet at the event start.

- 66% of SSEs had an average ESR charge level between 70% and 90%
- ESRs on outage (forced or planned) excluded from charge level calculation

*
1. Sourced from SCADA Case data.
2. Draft results – subject to change



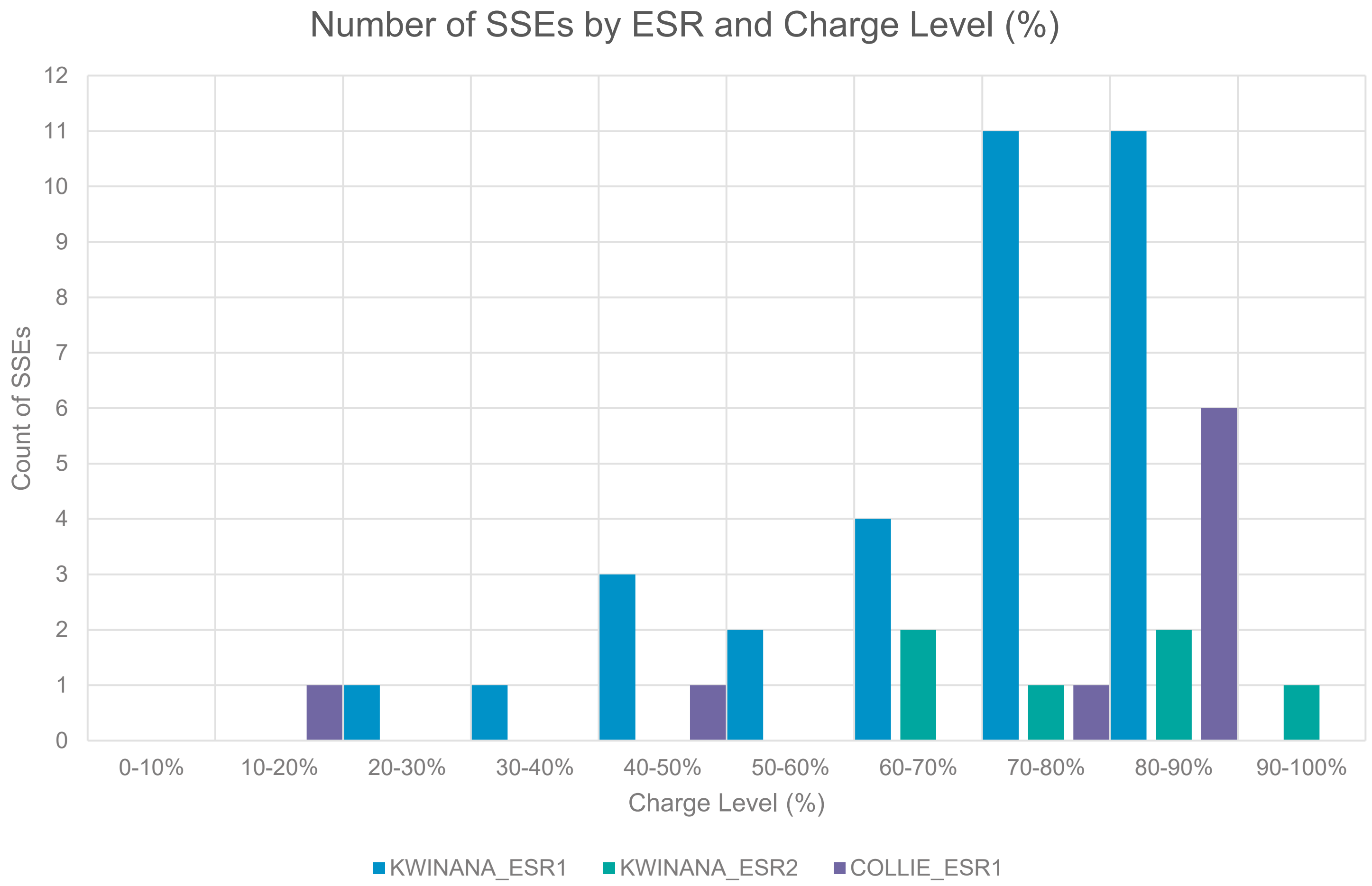
Historical System Stress Events (SSEs)

Number of SSEs by Average ESR Charge Level (%) of each ESR*

This chart shows the number of SSEs by the average charge level (%) of each ESR at event start.

- When available, COLLIE_ESR1 had charge levels of 80-90% for 67% of the events
- KWINANA_ESR2 maintained a minimum charge level of 60-70% across all events

*One KWINANA_ESR1's data point was excluded in this draft result pending further data validation analysis.



Historical System Stress Events (SSEs)

Analysis of charge levels

- **Ongoing work to analyse events during which batteries have depleted charge prematurely**
  - Will include analysis FCESS dispatch patterns during SSEs to understand impact of FCESS enablement on charging behaviour
- **Note:**
  - Regulation is enabled for 5-minutes – unlikely to have significant impact on charge levels
  - Contingency sustained for 15 minutes – as above, unlikely to have significant impact on charge level

Concluding Comments

Key observations

- **SSEs are not a “Hot Season” only phenomena**
  - 41% of events occurred in shoulder and winter months (mostly winter)
- **23 events (59% of total) were triggered by extreme temperatures**
  - Most of them (20) occurred in summer
  - Low wind availability tends to occur in winter – combination of scheduled outages and extreme (cold) temperatures can cause system stress
- **Most events started before grandfathered ESROIs (5:30pm)**
  - 6-hour ESROD captures events better, but there were still 23 of 39 events that occurred prior to 4:30pm
- **Most events are 3-4 hours in duration**
  - Longer duration events possible but most likely to occur in summer
- **Average ESR fleet charge level >=70% for over half the events**
  - Average fleet charge level<50% for 20% of events

Concluding Comments

Policy implications

- **Majority of SSEs starting before grandfathered ESROIs**
  - Will new ESR entry combined with the ESROD uplift ensure there is sufficient capacity at these times to avoid unserved energy?
  - Should CC2 be split into sub-classes (DSP, Pure ESR, ESR-hybrid)?
  - Are measures needed to restrict certain CC2 technologies if RCR is exceeded?
- **Combination of outages, low wind and cold temperatures are likely to cause stressed conditions in winter months:**
  - Could pre-dispatch processes be used to identify system margins under High Demand and Low Wind forecast scenarios?
  - Could ST-PASA be used to identify low system margins due to forecast extended periods of low-wind (dark doldrums)?
  - Could AEMO trigger charging obligations based on the above?
  - How would this work in practice?

Annex 1

International Scan

Demand Side Programs in different jurisdictions

Great Britian (GB)

Demand Side Response (DSR) can participate through multiple mechanisms

Market mechanism	Description	Durational obligations
Balancing Market – Demand Flexibility Services (DFS)	• Customers participate through retailer • NESO assigns settlement periods 48 hours in advance in which response will be needed • DFS can bid to reduce consumption in these period – voluntary with no penalties for non-performance	Customers must reduce consumption for (more or less) *one hour*

Capacity Market	• Residential customers can participate through aggregators
	• NESO issues notice to Capacity Market Units (CMUs) when capacity margin falls below 500MW
	• DSRs are not derated using EFC – instead derated using historical availability of DSRs that provide Short-Term Operating Reserves (STOR – see next slide) (79% in the 2024 Auction)
	• Work underway to:
	    • Incorporate BTM technology classes to better quantify response
	    • Develop better derating approaches (e.g. incorporation into EFC method)
	    • Lower transaction costs for smaller capacity providers
		Providers must be able to respond *four hours* after the notice publication

Non-Balancing Services	• Frequency response (Fast Frequency Response (FFR) and Fast Reserve (FR) • Short-term Operating Reserves (STOR)	• FFR: respond within 2-30s; sustain for up to 30 mins • FR: respond at minimum rate of 25MW/minute and sustain for 15 mins (min vol required is 25MW) • STOR respond within 20 mins; sustain for 4 hours.

Demand Side Programs in different jurisdictions

Pennsylvania–New Jersey–Maryland (PJM)

- Customers can participate through a Curtailment Service Provider (CSPs).
- There are two main types of Demand Resources in PJM that can participate across all PJM

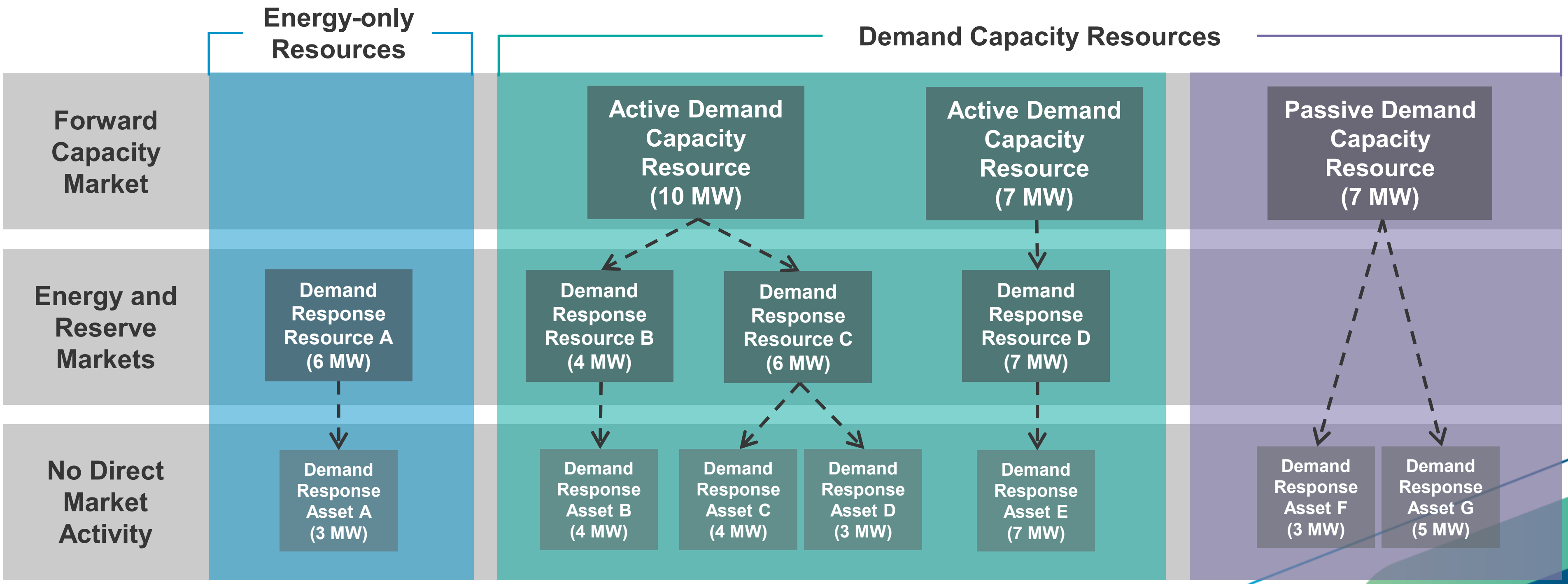
DR type	Markets that CSPs can participate in	Description	Durational obligations
Load Management Demand Resources (Emergency and Pre-Emergency)	Can participate in all markets: • Energy market only (Emergency Loads only) • Capacity Market only (DSP like construct) • Energy and Capacity market	Emergency Response – notified by SO that activation will be required; activated based on the most efficient combination of availability, location, dispatch price, and/or quantity of reduction.	• Must respond to events any day of the delivery year for (possibly) unlimited duration • Summer Only resources are only required to be available from June to October and then May of the following year.
Economic Demand Resources	• Energy Market • Ancillary Service (AS) Market	Price Response – voluntary commitment typically acquired when wholesale energy prices are higher than the monthly published PJM net benefits price.	No specified obligation for energy. CSPs providing AS are fully expected to respond for system reliability, depending on the type of service: • Synchronised reserves – within 10 min • Day-Ahead Scheduling Reserves - within 30 min • Regulation – respond to frequency response signal

Demand Side Programs in different jurisdictions

ISO New England

Demand Response comprises two types of resources can participate in all ISO-NE markets or off-market.

Demand Capacity Resources (can be active or passive) can comprise aggregated resources while each resource itself can be an aggregation of one or more assets (loads that do not participate directly in markets).



Demand Side Programs in different jurisdictions

ISO New England

- Active Demand Capacity Resources may consist of multiple Demand Response Resources. Demand Response Resources may consist of multiple Demand Response Assets.
- Passive demand resources are only allowed to participate in the capacity market. There are two types:
  - **On-peak resources** – may offer electricity reduction during summer peak hours (nonholiday weekdays, 1 PM to 5 PM in June, July, and August) and winter peak hours (nonholiday weekdays, 5 PM to 7PM in December and January).
  - **Seasonal-peak resources** – may offer electricity reduction in June, July, August, December, and January during periods that real-time hourly load is equal to or greater than 90% of the system peak-load forecast for the respective season.

  These loads do not curtail on notification; instead, they reduce consumption through energy efficiency measures during specific periods
- Demand Response Resources are subject to seasonal audits (Apr to Nov for summer and Dec to March for winter). Performance can be measured through:
  - Dispatching the Resource between 8AM and 10 PM for an audit duration of one hour (12 consecutive 5-minute intervals); or
  - Historical performance of the Resource when dispatched.

Demand Side Programs in different jurisdictions

Ireland (Ireland and Northern Ireland)

- Demand Side Units (DSU) are third party companies that specialise in providing demand side services by aggregating one or more Individual Demand Sites. They must have at least 4 MW of capacity to register.
- DSUs participate in the Capacity Market and Ancillary Service markets:

Operating Models	Participation	Ancillary Market Obligations
• **Peaking types** are Price Responsive – not as frequently activated and are only required for a small number of periods • **Long-run types** – Constantly expected to reduce their net demand import from the grid.	In the 2023 Capacity Market, • 639 MW for Ireland; and • 136 MW for Northern Ireland	When the Transmission Operator dispatches DSU to provide AS: • DSU must *respond within one hour* and sustain the response until the next Dispatch Instruction or until the Maximum Down Time of the DSU is done; and • DSU must ensure that the Performance Monitoring Error (baseline minus actual performance) is less than 0.25 MWh for a full quarter-hour period.

Demand Side Programs in different jurisdictions

Ireland (Ireland and Northern Ireland)

- Other Demand Side Programs are as follows:

Program	Participation	Type/Description	Obligation
Aggregated Generating Unit	Northern Ireland only; 79 MW in 2023	Activated generation across different sites in the aggregation	No change in on-site consumption (not similar to Demand Side Response)
Dispatchable Consumption Unit	Newly introduced	Price Response	Increasing on-site demand directly from dispatch and signals in the energy market
Flexible Demand	Newly introduced – for data centres	Price/Emergency Response	Follow dispatch instruction to lower their load
Mandatory Demand Curtailment	Newly introduced – for large industrial consumers	Emergency Response	Lower demand to pre-agreed levels of up to 50% consumption reduction at least one hour after the notice.
Other implicit demand side response programs	Still in the works	Mainly Price Response	Driven by indirect signals and achieved through technological advancements and policies to encourage load shifting.

Demand Side Programs in different jurisdictions

Ontario (Canada)

- IESO used to have a separate Demand Response Auction but was discontinued. Demand Side Response (DSR) units currently participate in the Capacity Market along with generation, energy storage, and import resources.

Program	Type/Description	Obligation
Capacity Auction	Emergency Response	Providers must be available for the capacity obligation period that runs for a six-month period: • Summer – May 1 to October 31, from 12 PM to 9PM • Winter – November 1 to April 30, from 4 PM to 9 PM The usual duration of energy reduction is 4 consecutive hours.
Industrial Conservation Initiative (ICI)	Emergency Response – shifting energy demands during system stress events	Participants must ensure availability from May through April and will be compensated based on their performance during the top five peak hours of the one-year period.

Annex 2

Abbreviations

Abbreviations not previously introduced

Term	Definition
ADG	Availability Duration Gap
BD	Business Day
BTM	Behind-the-meter
CC1	Capability Class 1
CC2	Capability Class 2
CC3	Capability Class 3
DSP	Demand Side Programme
DPV	Distributed Photovoltaics
EFC	Effective Firm Capacity
ELCC	Effective Load Carrying Capability
ESMR	Electricity System and Market Rules
ESR	Electric Storage Resource
ESROD	Electricity Storage Resource Obligation Duration
ESROI	Electricity Storage Resource Obligation Intervals
EUE	Expected Unserved Energy
FCESS	Frequency Co-optimised Essential System Services

Abbreviations not previously introduced

Term	Definition
IESO	Independent Electricity System Operator
ISO-NE	Independent System Operator – New England
LOR	Lack of Reserve
MW	Megawatt
NAQ	Network Access Quantity
NBD	Non-Business Day
NCESS	Non-Co-optimised Essential System Service
OFGEM	Office of Gas and Electricity Markets
PJM	Pennsylvania - New Jersey – Maryland
RCM	Reserve Capacity Mechanism
RCR	Reserve Capacity Requirement
SEO	State Electricity Objective
ST-PASA	Short Term Projected Assessment of System Adequacy
SWIS	South West Interconnected System
WA	Western Australia