Department of Energy, Mines, Industry Regulation and Safety
Energy Policy WA
GOVERNMENT OF WESTERN AUSTRALIA

Transformation Design and Operation Working Group meeting 53

Electricity System and Market Amendment (Tranche 8) Rules - Exposure Draft

10 April 2025

Working together for a **brighter** energy future.

Welcome

Please place your microphone on mute, unless you are asking a question or making a comment.

- **Please keep questions relevant to the agenda item being discussed.**
- **If there is no break in discussion and you would like to say something, you can ‘raise your hand’ by typing ‘question’ or ‘comment’ in the meeting chat. Questions and comments can also be emailed to energymarkets@demirs.wa.gov.au after the meeting.**
- **If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video.**

Agenda

10.00am	Welcome and overview
10.05am	New method to determine the Availability Duration Gap
10.50am	RCS Uplift Payments
11.00am	Changes affecting DER participation in the WEM
11.10pm	Other Tranche 8 changes
11.25pm	Next steps
11:30pm	Improving visibility for operational forecasting in the WEM

New method to determine the Availability Duration Gap

EPWA's review of the Availability Duration Gap method 1

The problem – ADG method:

- Preliminary analysis by AEMO in late 2024 suggested that the Availability Duration Gap (ADG) would extend the ESR Obligation Duration (ESROD) drastically (past the 14-hour fuel requirement for fossil-fuelled generators) if the method is not amended.
- This analysis was based on the method at the time which considered the days with a peak demand with the 90th percentile.
- EPWA introduced a quick fix in the *WEM Amendment (Miscellaneous Amendment No. 3) Rules 2024* determine the ADG based on the single highest peak demand day in the load scenario, however, considered a fulsome review of the method necessary.

The problem – ESROD protection:

- Facilities are currently protected for 5 years from changes in the ESROD.
- This means if an ADG is published, these facilities will not be derated to meet the obligations of the new ESROD.
- If this happens, there will be gap between the actual capacity available to meet the Reserve Capacity Target and the capacity which is assigned Capacity Credits. This may lead to potential shortfalls in available capacity to meet the 1-in-10 year peak.

EPWA's review of the Availability Duration Gap method 2

High level outcomes of the review:

1. **Implement a new method for determining the ADG.**
2. **Introduce a method to add 'missing' capacity to the Reserve Capacity Target due to the ESROD protection (ESR Duration Requirement Uplift).**
3. **Increase the ESROD protection from 5 years to 10 years to increase investment certainty.**

Review criteria

Criteria for new ADG method
Appropriately acknowledges ESR’s contribution to reliability
Investment certainty – high predictability and low volatility of ESROD
Appropriate sensitivity to “flat” demand shapes
Appropriate sensitivity to step change in ESR capacity
Ease of implementation and rollout across 10 years

Review outcome 1: Implement a new method to determine the ADG

The proposed method is based on the current method, but changed to find the ‘optimal’ ADG by increasing the ESROD until there is no capacity shortfall anymore.

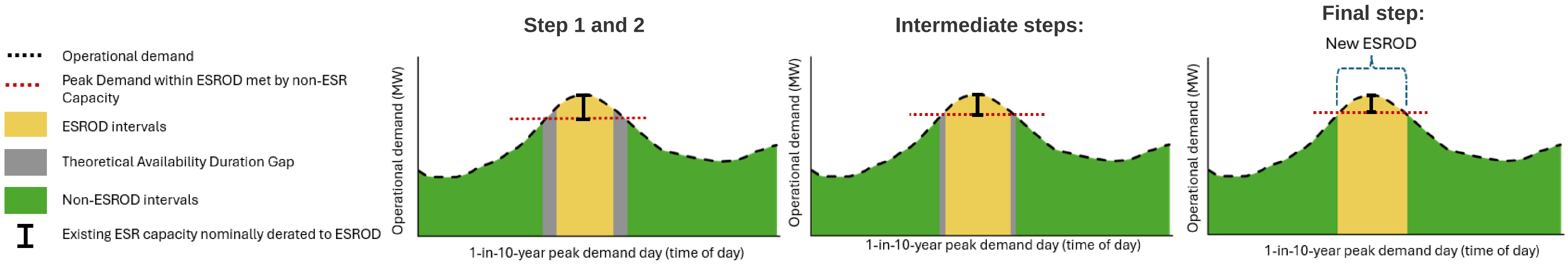
A reference ADG is determined for each reference year used by AEMO in determining the Limb B assessment of the Planning Criterion using the below method – the ADG is set as the median of the outcome for all reference years.

Step 1: subtract the total capacity of the ESR fleet from the operational demand of the peak interval (Residual Demand).

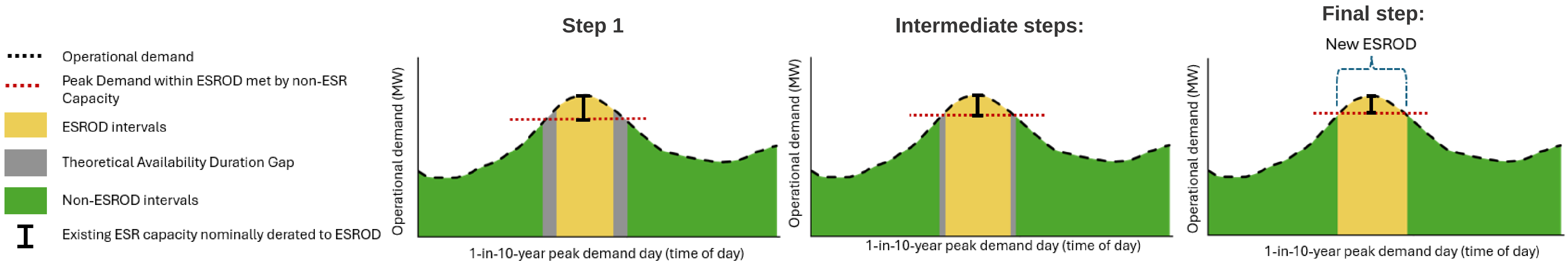
Step 2: determine whether ESROD adjacent intervals have operational demand > Residual Demand.

If yes, increase the ESROD by one interval, nominally derate the fleet to recalculate the Residual Demand and redo steps 1 and 2

Final step: if there are no ESROD adjacent intervals with operational demand > Residual Demand, the ADG = the ESROD in the final step subtract the ESROD from the current RCC.



Review outcome 1: Implement a new method to determine the ADG



EPWA considers that this method:

- allows investors to reasonably predict future ESRODs
- delivers lower volatility year-on-year than other methods assessed
- can be easily implemented by AEMO as it leverages forecasts already calculated during the Long Term Projected Assessment of System Adequacy study
- does not require AEMO to make any assumptions regarding entry of new future capacity

Review outcome 1: Implement a new method to determine the ADG

Proposed changes:

- **The method for determining the ADG is now outlined in Appendix 11 (Part B)**
- **Clause 4.5.12(d) and definition of Availability Duration Gap has been updated to reflect the move of the method to Appendix 11**
- **Note: 4.5.12(d) will be returned to original drafting with minor change: definition changed in error**

4.5.12. For the third Capacity Year of the Long Term PASA Study Horizon, AEMO must determine the following information:
…

As written in Exposure Draft:

(d) the ~~forecast~~ ESR Duration Requirement, ~~which is~~ the Availability Duration Gap and the ESR Duration Requirement Uplift ~~for the relevant Capacity Year~~, as calculated in accordance with Appendix 11~~plus the ESR Duration Requirement for the previous Reserve Capacity Cycle~~;

Proposed drafting:

(d) the ~~forecast~~ ESR Duration Requirement, which is the Availability Duration Gap for the relevant Capacity Year plus the ESR Duration Requirement for the previous Reserve Capacity Cycle;
(e) the Availability Duration Gap and ESR Duration Requirement Uplift as calculated in accordance with Appendix 11;

Review outcome 2: Introduce a method to add ‘missing’ capacity to the RCT due to the ESROD protection (ESR Duration Requirement Uplift).

The problem:

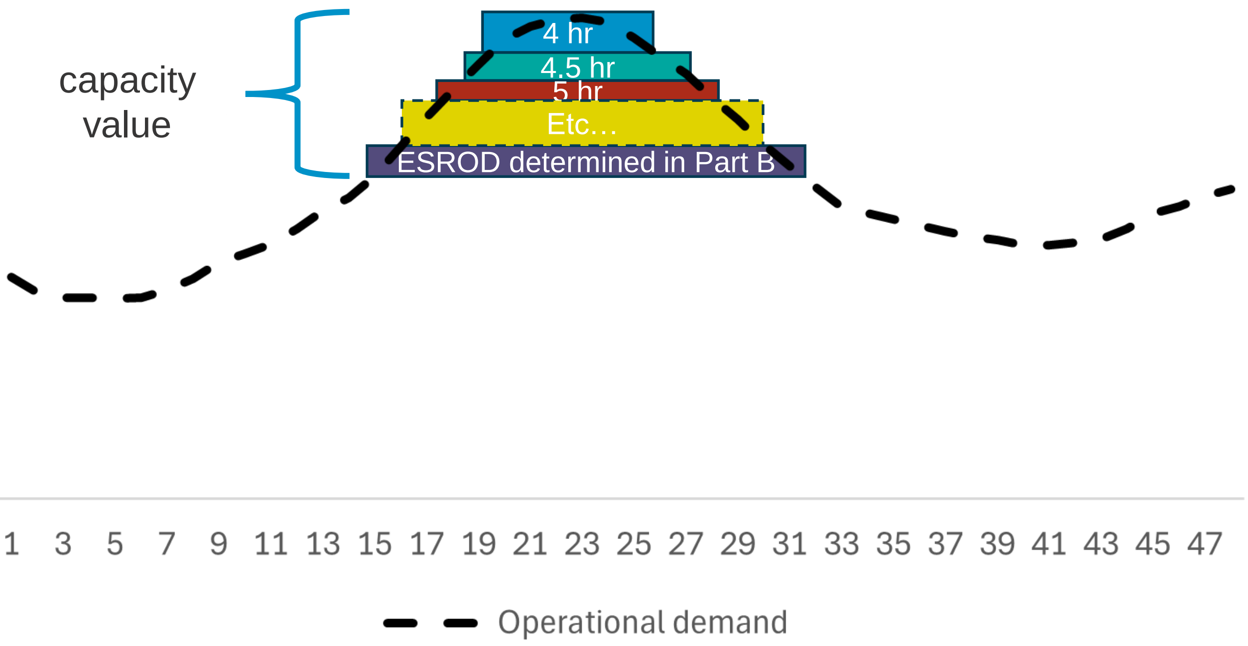
- **Facilities currently receive a 5-year protection against changes in the ESROD**
- **When an ADG arises, the ESROD protection will create a gap between the actual capacity available to meet the Reserve Capacity Target and the capacity which is assigned Capacity Credits**

Proposed changes:

- Introduce a new defined term, ESR Duration Requirement Uplift, which represents this ‘missing’ capacity
- Introduce Appendix 11 (Part C) to calculate the ESR Duration Requirement Uplift
- Include the ESR Duration Requirement Uplift when calculating the Reserve Capacity Target via Limb A of the Planning Criterion
- Remove the ADG Load Scenario as it is only proposed to be used in clause 4.5.12. Clause 4.5.12 has been amended to include the definition of ADG Load Scenario instead of the defined term

Review outcome 2: Introduce a method to add 'missing' capacity to the RCT due to the ESROD protection (ESR Duration Requirement Uplift).

- The proposed method calculates the contribution to system reliability subject to ESROD protection.
- The protected capacity is nominally derated in tranches and the size is set by determining how much of each tranche is needed to address the peak.
- The tranches start with the lowest ESROD of the fleet, currently 4 hours, and increasing this by 30 mins for each tranche.
- When the tranche ESROD = the ESROD calculated for the upcoming RCY. All left over capacity is derated at that ESROD.
- The difference between the capacity value and the total CC of the ESR under ESROD protection will equal the ESR Duration Requirement Uplift.



Review outcome 2: Introduce a method to add ‘missing’ capacity to the RCT due to the ESROD protection (ESR Duration Requirement Uplift).

Other changes

- Clause 4.5.9(a) amended to add the ESR Duration Requirement Uplift to the number determined by limb A of the Planning Criterion

4.5.9. The Planning Criterion to be used by AEMO in undertaking a Long Term PASA study is that there should be sufficient available capacity in each Capacity Year during the Long Term PASA Study Horizon to:

(a) meet the forecast peak demand (including transmission losses and allowing for Intermittent Loads) supplied through the SWIS plus:

i. ~~plus~~ a reserve margin equal to the greater of:

1. ~~i.~~ the forecast peak demand (including transmission losses and allowing for Intermittent Loads) multiplied by the proportion of Capacity Credits expected to be unavailable at the time of peak demand due to Forced Outages based on Forced Outage rates calculated in accordance with the WEM Procedure specified in clause 4.9.10, excluding Forced Outages of Facilities to which clause 4.11.1A applies; and

2. ~~ii.~~ the size, in MW, of the largest contingency relating to loss of supply (related to any Facility, including a Network) expected at the time of forecast peak demand (including transmission losses and allowing for Intermittent Loads), and

ii. the ESR Duration Requirement Uplift calculated in Part C of Appendix 11,

Review outcome 3: Increase the ESROD protection from 5 years to 10 years to increase investment certainty.

Overview

Peak Electric Storage Resource Obligation Duration: For an Electric Storage Resource and a Trading Day, the contiguous Trading Intervals ~~which have the Mid-Peak Electric Storage Resource Obligation Interval in the middle~~ published by AEMO in accordance with clause 4.11.3A, where:

(a) the number of Trading Intervals is equal to:

i. if the Electric Storage Resource first received Capacity Credits within any of the ~~four~~ nine previous Capacity Years, and does not include a Facility upgrade that first received Capacity Credits in a later Capacity Year, the ESR Duration Requirement for the Capacity Year in which ~~it~~ the Electric Storage Resource first received Capacity Credits; and

ii. otherwise the ESR Duration Requirement for the current Capacity Year; and

- **The ESROD protection is proposed to be increased from 5 years to 10 years.**
- **This is to provide investment certainty to ESR proponents.**
- **A facility will lose its protection if it is upgraded.**

Review outcome 3: Increase the ESROD protection from 5 years to 10 years to increase investment certainty.

Example:

ESROD increase (2025) *ESROD increase* (2029) *ESROD increase* (2033)

Reserve Capacity Cycle	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Yearly ESROD	**4**	**4**	**X**	**X**	**X**	**X**	**Y**	**Y**	**Y**	**Y**	**Z**	**Z**
ESR #1	-	4	4	4	4	4	4	4	4	4	4	Z
ESR #2	-	4	4	X	X	X	Y	Y	Y	Y	Z	Z
ESR #3	-	-	X	X	X	X	X	X	X	X	X	X

ESR #1 & #2 enter RCM

ESR #3 enters RCM

Facility 2 upgrade (loses protection, exposed to changes in ESROD)

Facility 1 protection ends after 10yrs

Addressing shortfalls in Capability Class 1 and 3

Prioritise new Capability Class 1 and Capability Class 3 facilities in the Network Access Quantity framework, if AEMO has determined that further Capability Class 1 and Capability Class 3 capacity would be required to make up a shortfall

- While the current WEM Rules require AEMO to determine under clause 4.5.12(i) if further Capability Class 1 and Capability Class 3 capacity would be required to make up a shortfall against the second limb of the Planning Criterion in clause 4.5.9(b), they do not specify a mechanism or an incentive to fill that shortfall.
- New clause 4.15.12A is proposed under which, if AEMO has determined that further Capability Class 1 and Capability Class 3 capacity would be required to make up a shortfall, any Capability Class 1 and Capability Class 3 Facility that has not been assigned a Network Access Quantity in any previous Reserve Capacity Cycle is to be deemed to be an "NAQ Facility" (as defined in Appendix 3).
- This would give them the same priority as existing Facilities (as they will be included in step 3A in Appendix 3).
- Not in the current drafting: To avoid the potential of new facilities reducing the NAQ of existing facilities, we are currently considering including them in step 4 in Appendix 3 instead, which will give them the same priority as the Network Augmentation Funding Facilities.

Other changes

NAQ priority for firm capacity

Proposed changes:

- **AEMO can determine they need firm capacity under clause 4.5.12(i).**
- **Clause 4.5.12A is introduced to give new capability class 1 and 3 facilities a higher priority in the NAQ process than typical new facilities.**

4.5.12. For the third Capacity Year of the Long Term PASA Study Horizon, AEMO must determine the following information:

then it would be possible to satisfy the Planning Criterion and the Outage Evaluation Criteria using, to the extent that the capacity is anticipated to provide Certified Reserve Capacity, the anticipated installed Capability Class 1 and Capability Class 3 capacity and to the extent that further Capability Class 1 and Capability Class 3 capacity would be required, an appropriate mix of Capability Class 1 and Capability Class 3 capacity to make up that shortfall; and

(j) any shortfall in Capability Class 1 and Capability Class 3 capacity, being the difference between the sum of all existing and committed Capability Class 1 and Capability Class 3 capacity and the minimum capacity determined under clause 4.5.12(i). For the avoidance of doubt, a negative shortfall should not be determined.

4.5.12A. If AEMO has determined under clause 4.5.12(i) that further Capability Class 1 and Capability Class 3 capacity would be required to make up a shortfall determined in accordance with clause 4.5.12(j), any Capability Class 1 and Capability Class 3 Facility that has not been assigned a Network Access Quantity in any previous Reserve Capacity Cycle is to be deemed to be an "NAQ Facility" (as defined in Appendix 3) for the purposes of Appendix 3.

- The definition of NAQ Facility within Appendix 3 has been expanded to include a NAQ Facility deemed under clause 4.5.12A

Other changes

- **This definition has been amended to consolidate wording**

Indicative Peak Electric Storage Resource Obligation Intervals: For a Trading Day in a Capacity Year, the set of contiguous Trading Intervals which includes ~~minimises~~ the daily peak demand Trading Intervals for that Trading Day ~~by discharging each Electric Storage Resource evenly across those Trading Intervals and for~~ and in which the number of Trading Intervals equals the ESR Duration Requirement for the previous Reserve Capacity Cycle.

RCS Uplift Payments

RCS Uplift Payments

Background

Wholesale Electricity Market Amendment (FCESS Cost Review) Rules 2024:

- **Removed FCESS Uplift Payments for RoCoF Control Service providers**
- **Created new clause 7.7.8A and amended clause 7.14.1 to make a Facility constrained on to provide RoCoF Control Service eligible for Energy Uplift Payments**
- **Short-term solution to meet 20 November 2024 deadline**
- **Using Energy Uplift Payments allocates costs to load instead of RoCoF Control Service 'causers'**

Directions to provide RoCoF Control Service more frequent than expected since 20 November 2024

Work on short-term enhancements and longer-term inertia provision options underway

RCS Uplift Payments

Proposed Tranche 8 changes

Schedule 7 includes amendments to

- Explicitly identify the Constraint Equations used by AEMO for directions to provide RoCoF Control Service (7.7.8A, 7.7.8B (new), “RCS Provision Constraint Equation” (new))
- Replace the Energy Uplift Payments made in these situations with “RCS Uplift Payments” – similar to Energy Uplift Payments but costs allocated to RoCoF Control Service causers (9.10.3, 9.10.3Q-9.10.3T (new), “RCS Uplift Payment” (new))
- Additional change to clause 9.10.3F to ensure a Facility constrained on under an NCESS Contract does not receive an FCESS Uplift Payment

Commencement date to be confirmed by AEMO but expect this year

Changes regarding DER participation in the WEM

Changes affecting DER participation in the WEM (1)

2.29.5AK. Synergy is the only Market Participant that may apply to AEMO to associate a Non-Dispatchable Load with a Demand Side Programme or an Interruptible Load under clause 2.29.5B, if that Non-Dispatchable Load is associated with a non-contestable customer as defined in the Metering Code.

- **This change is made to implement government policy published in the DER Roadmap: DER Orchestration Roles & Responsibilities Information Paper**

2.29.5AL. A Market Participant intending to apply under clause 2.29.5B to associate a Non-Dispatchable Load with a Demand Side Programme or Interruptible Load must ensure that the Non-Dispatchable Load is equipped with a meter which complies with the requirements of clause 3.16 of the Metering Code.

EPWA intends to amend the Metering Code to allow Western Power to transition a non-contestable meter to an *interval* meter, following request from Synergy.

This will allow AEMO to access the meter data for use with baselining and service validation.

- **Clause 2.29.5AL is proposed to ensure that all meters proposed to be aggregated have the functionality to be transitioned to an *interval* meter under the Metering Code.**

Changes affecting DER participation in the WEM (2)

2.33.3. AEMO must prescribe a Facility registration application form that requires an applicant to provide the following:

(a) the relevant non-refundable Application Fee where this Application Fee:

i. may differ for different Facility Classes;~~ and~~

ii. must be a single Application Fee for multiple registered Demand Side Programmes being allocated Capacity Credits under clause 2.29.5AB(a); and

iii. must be a single Application Fee for multiple Small Aggregations being registered by the same Market Participant;

- **Clarification that the Application Fee for multiple Small Aggregations is a single fee per Market Participation.**
- **This change is to address a barrier to RCM participation by Small Aggregations.**

- **Proposal to split the daily DSP obligation period so to not cover the middle of the day period (DSP dispatch here is unlikely and would allow ESR To charge).**
- **The proposed obligation is 6am-10am and 2pm-10pm.**
- **This proposal seeks to remove barrier to entry for ESR participation as a DSP.**

vi. the periods when the Facility can be dispatched, which must include:~~ the period between 8:00 AM and 8:00 PM on all Business Days; and~~

1. for a Reserve Capacity Cycle up to and including the 2025 Reserve Capacity Cycle, the period between 8:00 AM and 8:00 PM on all Business Days; and

2. for a Reserve Capacity Cycle from the 2026 Reserve Capacity Cycle onwards, the periods between 6:00 AM and 10:00 AM and 2:00 PM and 10:00 PM on all Business Days;

Other Tranche 8 changes

Changes related to the publication of BRCPs

- Under clause 4.16.11, the Coordinator must determine the Benchmark Capacity Providers within six months of the revised ESR Duration Requirement being published in the ESOO, if the ESR Duration Requirement determined by AEMO under clause 4.5.12(d) is different from the ESR Duration Requirement for the previous Reserve Capacity Cycle.
- This may lead to a change to the Benchmark Capacity Providers.
- Under clause 4.16.1, the ERA must publish a Peak Benchmark Reserve Capacity Price (BRCP) and a Flexible BRCP prior to 15 January 2026.
- Under clause 4.16.3, the ERA must develop a WEM Procedure documenting the method it must use and the process it must follow in determining the BRCPs.
- Under clause 4.16.9, the ERA must review the WEM Procedure within one year of the Coordinator's review under clause 4.16.11, if that review determines a change to a Benchmark Capacity Provider.
- Two new transitional clauses are proposed to ensure that the ERA has sufficient time to review the relevant WEM Procedure, and develop and publish the BRCPs following the determination of the Benchmark Capacity Providers by the Coordinator.

Other Tranche 8 changes (1)

Electricity Industry (Distributed Energy Resources) Amendment Act 2024 changes

- ***Electricity Industry (Wholesale Electricity Market) Regulations 2004* (WEM Regulations) now *Electricity Industry (Electricity System and Market) Regulations 2004* (ESM Regulations)**
- **Changes took effect from 6 February 2025**
- **Wholesale Electricity Market Rules (WEM Rules) become Electricity System and Market Rules (ESM Rules)**
- **Wholesale Market Objectives replaced by State Electricity Objective**
- **'WEM Rules', 'WEM Regulations' and 'Wholesale Market Objectives' retained in Glossary during transition period**
- **Not all changes shown in the exposure draft**

Other Tranche 8 changes (2)

Other Schedule 2 changes

- Remove AEMO’s obligation to notify affected Rule Participants of conflicts between Outage Intention Plans (clause 3.19.8)
- Clarify that a Facility must pass its Required Level performance test in two Trading Intervals during the relevant Capacity Year to apply for release of Reserve Capacity Security (clause 4.13.13)
- Extend deadline for first review of effectiveness of certification of Reserve Capacity for energy and availability limited technologies to 1 October 2026 (clause 4.13B.2)
- Remove explicit obligation on AEMO to provide a Trading Day demand forecast on the Scheduling Day (clause 6.3A.2A)
- Clarify Real-Time Market Submission requirements for Inflexible Facilities (clause 7.6.31)

Other Tranche 8 changes (3)

Changes relating to clause 7.10.6B

- Bring forward the commencement of clause 7.10.6B and clarify AEMO's compliance monitoring obligations relating to clause 7.10.6B over time (Schedules 2, 3 and 4, clauses 2.13.7, 4.11.1, 7.10.6B)
- Additional change (not in published exposure draft) – amend clause 7.10.6B to clarify that it is not intended to apply to Demand Side Programmes

7.10.6B. If a Market Participant holds Capacity Credits associated with an Energy Producing System for a ~~Facility~~ Scheduled Facility, Semi-Scheduled Facility or Non-Scheduled Facility that also includes a Load, the Market Participant must not operate the Energy Producing System in a manner that results in, or has the effect of, reducing the Individual Reserve Capacity Requirement for the relevant Facility unless operating pursuant to a Dispatch Instruction or in accordance with a direction from AEMO.

Other Tranche 8 changes (4)

Other changes in Schedules 2-6 and 8

- **Changes to Observed Demand and Existing Facility Load for Scheduled Generation calculations to**
- account for reductions from operation of Supplementary Capacity and NCESS Contracts
- use the best estimate of DSP Reduction available at the time
- (Schedules 2, 3, 4 and 6, Appendix 7 and Appendix 9)
- **Correction of Ministerial Instrument errors in Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2024 (all schedules)**
- **Minor error corrections and enhancements (all schedules)**

Next steps

Next steps

- Consultation period for Tranche 8 exposure draft closes **5:00pm on 24 April 2025**
- Submissions should be sent to energymarkets@demirs.wa.gov.au
- We will not be able to accept late submissions
- Please provide your feedback as soon as practicable
- Happy to have 1:1 discussions if of benefit
- Amending Rules will be submitted to the Minister in May 2025

Improving visibility for operational forecasting in the WEM

EPWA and Frontier Economics

Improving visibility for operational forecasting in the WEM

EPWA / AEMO project

EPWA and AEMO are undertaking this project to investigate challenges to the accuracy of AEMO's operational forecasts, the impact of inaccuracy on WEM market outcomes and how other markets are addressing similar issues.

The project has three stages:

Stage 1

- **Assess materiality of error:** Identify periods of inefficiency in WEM market outcomes that could reasonably be attributed to operational forecasting error, and identify the material sources of these errors.
- **Inter-jurisdictional review:** Compare WEM operational forecasting methods to other jurisdictions to understand how they address similar challenges

Stage 2

- **Identify gaps:** Identify gaps in existing WEM operational forecasting sources of information or tools from Stage 1 analysis

Stage 3

- **Recommendations:** To improve operational forecasting inputs, tools or methods and supporting rule changes if required

Purpose of today

Share key insights and outcomes

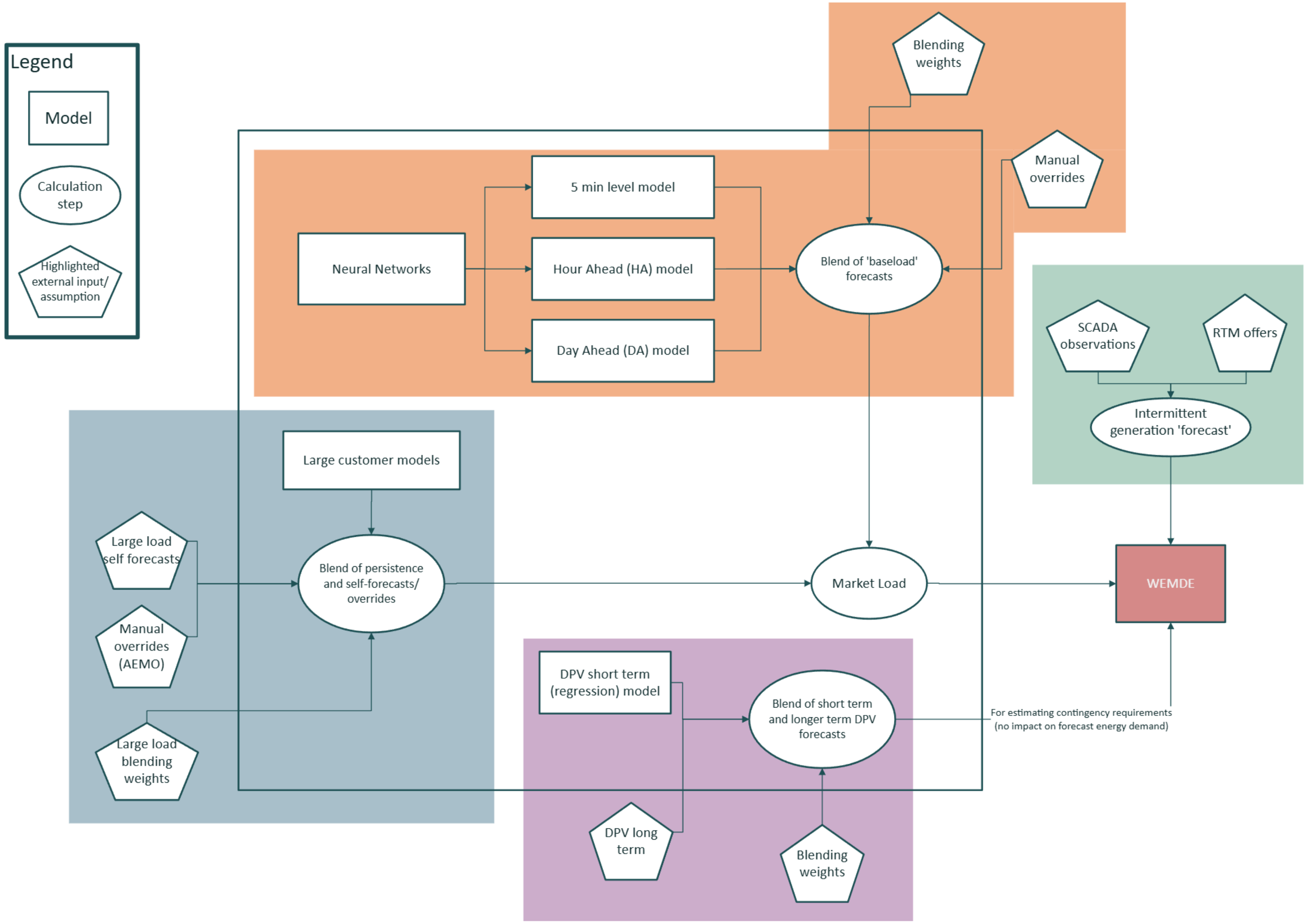
Stage 1 and 2 of the work program are complete – delivered by Frontier Economics, with inputs from AEMO and EPWA.

Stage 3 is in progress - Frontier Economics has developed proposals for reform which will be presented today.

The aim today is to share key insights/outcomes from Stage 1 and 2 and present reform proposals.

Input on reform proposals is being sought from TDOWG

Operational forecasting in the WEM



There are five key components to operational forecasting in the WEM

1. Metered 'baseload' demand represents the bulk of customer load; key inputs are recent trends and weather forecasts
2. Large load models represent significant loads; key inputs are recent trends and reported outages/activity
3. Intermittent generation forecasts indicate available unconstrained resource; based on persistence forecast blended with RTM offer
4. DPV forecasts:
   - Explicit forecast used for establishing contingency requirement
   - Impact of DPV forecast included in 'baseload' demand forecasts
5. WEMDE produces forecasts of market outcomes providing signals to the market

Working together for a **brighter** energy future.

Sources of forecast error

Forecast error may arise within each of these components listed on the previous slide, and be attributable to:

- **Input error:** e.g. the weather forecasts used in demand forecasts may be inaccurate.
- **Model misspecification:** e.g. irrelevant variables may be used, relevant variables may be omitted, or the functional form may be inappropriate.
- **Model implementation:** e.g. the model may be trained on out-of-date information, or trained on a very long horizon which masks recent trends.
- **Pre- and post-model calculations:** e.g. smoothing and blending processes may increase rather than decrease error.

Ultimately:

- **Given correct inputs, does the model accurately predict outcomes?**
- **Can the quality, frequency, and/or understanding of uncertainty of inputs be improved?**

Methodology to prioritise sources of error

Assessing inefficient market outcomes related to the sources of forecast error

Resource cost (observed) − Resource cost (counterfactual with accurate forecasts) = Inefficiency

This represents a complex task:

In a perfect world …

- For each component (and interactions), produce accurate forecasts; re-run WEMDE
- Induce counterfactual actions (RTM offers) from participants based on new forecasts
- Re-populate WEMDE with accurate forecasts and counterfactual actions
- Compare counterfactual resource cost with observed resource cost

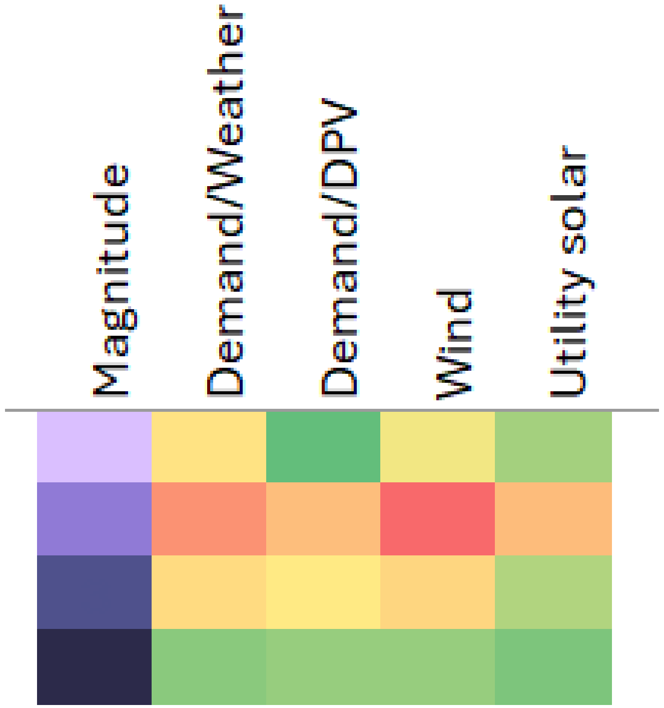
Our approach

- Produce detailed dashboard with daily market outcomes (forecasts, offers, dispatch, notices)
- Qualitatively identify periods of inefficiency
- Relate outcomes to source of forecast error, if possible
- Qualitatively assess counterfactual outcomes

We note this is far from perfect; however, the approach provided a reasonable direction forward

Key findings

Assessing inefficient market outcomes that can be attributed to forecasting error



Ranking of material error impacting on market outcomes:

- Market outcomes are graded from least impact (light purple) to most impact (dark purple).
- For each level of impact, the frequency of events attributable to a source of forecast error is indicated by a colour scale ranging from green (least frequent) to red (most frequent).

Identifies the following priority areas in order:

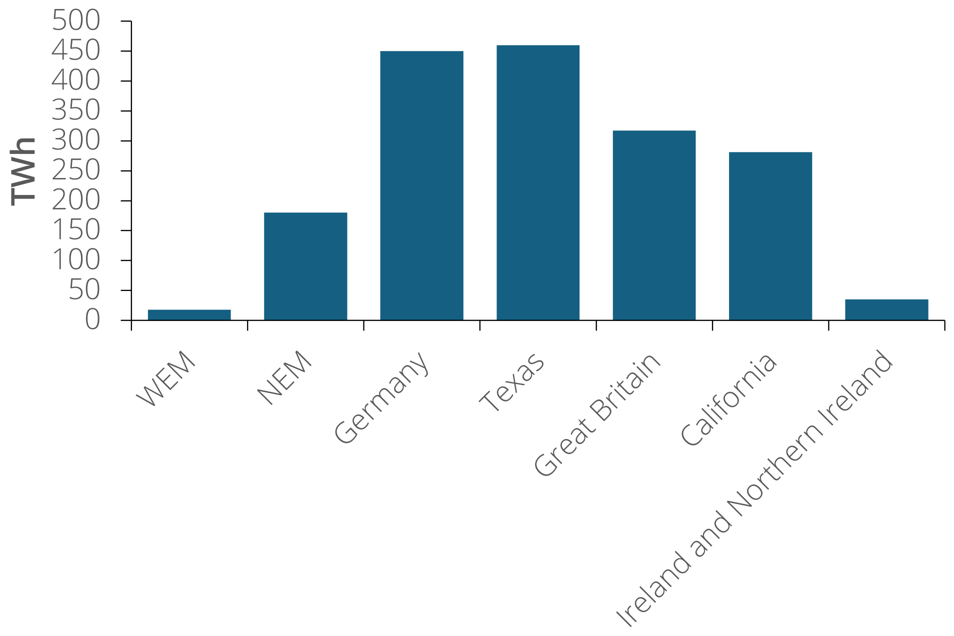
- Wind and solar* facility generation forecasts
- Weather inputs to demand forecasting
- DPV inputs to demand forecasting

* Solar has fewer events, but is grouped with wind as remedies are related

Inter-jurisdictional review

Key findings

Annual consumption TWh



The WEM was the smallest market in terms of annual energy consumption and an outlier in terms of DPV penetration

Intermittent generation

- Forecasting can be centralised (system or transmission operator) or de-centralised (participant).
- Where decentralised, there is typically a certification process for participants (e.g. California, NEM) and/or incentives in place for accurate forecasting (Germany)
- The WEM is partially decentralised, i.e. persistence forecasts blended with RTM offers with weak incentives for accurate forecasts
- Where DPV penetration is significant, forecasting cloud cover is a difficult and an ongoing issue
- Visibility of DPV and increasing DER is also an ongoing concern

How other jurisdictions are improving forecasts

- Focus on improving *input* forecasts – weather forecasting
- Partnering with meteorological services
- Development of input modelling approaches e.g. deep learning to augment or replace numerical weather prediction models

Key proposals

Proposals for change relate to implementation and process; some may require rule changes

Recommendation	Rationale	Rule change?
Reconsider blending parameters	Persistence forecasts and blending can lead to recurring forecast inaccuracies	
Address lack of incentive for accurate intermittent generation forecasts	Improve incentives for party responsible for forecasting intermittent generation (participants/AEMO) to provide accurate forecasts	✓
Investigate collaboration with weather providers regarding improving input forecasts	Quality, frequency and understanding of uncertainty should be a key focus for improving demand and intermittent generation forecasts	
Require AEMO publish operational forecasting accuracy metrics	Demonstrate models fit-for-purpose; provide stakeholder confidence; monitor impacts of developments (e.g. CER) on forecast accuracy; provide incentives to improve forecasts and address specific issues; provide evidence of need for change	✓
Formalise large load information provision	Large loads provide self-forecasts to AEMO on a voluntary basis; this is an unnecessary risk	✓

Stakeholder input and next steps

Questions

- Do stakeholder believe all significant sources of forecast errors been captured?
- Do stakeholders believe the impact of forecast errors is accurately reflected?
- Do stakeholders have any comment on the proposals, or any additional proposals for consideration?

Next steps

- Finalise the proposals – April/May 2025
- Consultation Paper with proposals for change and draft WEM Amending Rules – May 2025
- Public submission period – 4 weeks
- Information Paper and final WEM Amending Rules - TBC