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

# TDOWG Meeting 50

## 18 June 2024

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

# Agenda

| | |
|---|---|
| 9.30am | Welcome and overview |
| 9.35am | Aggregated Demand Side Programmes |
| 10.20am | Connection Point / Metering Point proposed changes |
| 10.30am | Contingency Reserve Raise Cost Allocation |
| 10.50am | Other Proposed Amendments |
| 11.20am | Next Steps |

# 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@dmirs.wa.gov.au after the meeting.
- If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video.

# Overview

Energy Policy WA has published the [Exposure Draft of WEM Amending Rules (Miscellaneous Amendments No. 3)].

**The draft contains three types of WEM Amending Rules:**

1. **Second round of consultation on amendments:**

a. Amendments already consulted to implement the outcomes of the Demand Side Response Review (e.g. dynamic baseline methodology)

b. Amendments regarding the registration of separate facilities behind network connection point(s)

c. Some of the amendments to implement the outcomes of the Cost Allocation Review (amendments to the Contingency Raise cost allocation method) have already been consulted

2. **Further amendments resulting from the reforms of the WEM implemented under the Energy Transformation Strategy**

3. **Error corrections and enhancements across all the WEM Rules**

# Aggregated Demand Side Programme Rules

# Changes to aggregated Demand Side Programmes (DSPs) participation in the RCM

**The following amendments are proposed to enable aggregations of smaller loads to participate in the RCM:**

1. Allow proponents to seek certification of DSPs without providing a TNI, as the relevant TNIs are unknown at the time of certification, with subsequent registration restrictions to manage Power System Security and Reliability (PSSR).
2. Allow Associated Loads of DSPs to inject (rather than withdraw) on average to meet their Reserve Capacity obligations.

# Certification of aggregated DSPs

## Three key changes:

1. Extend transitional arrangements for aggregated DSPs seeking certification without providing their TNIs to the 2025 Reserve Capacity Cycle.
    - Transitional Rule 4.10.1B[1] (which allows aggregated DSPs to be certified without identifying the relevant TNIs if expected Certified Reserve Capacity of each Associated Load in the DSPs < 5MW) extended to cover both 2024 and 2025 Reserve Capacity Cycles.
2. Require these DSPs to register and associate all loads three months prior to the relevant Capacity Year commencing.
3. Require above DSPs to only locate at "uncongested TNIs".

## Changes 2 and 3 are discussed on the following slides.

Note:

- Changes 2 & 3 will commence not earlier than the commencement of 2026 Reserve Capacity Cycle to give AEMO sufficient implementation time.
- Changes 1, 2 & 3 only apply to aggregated DSPs seeking certification at unknown multiple TNIs.
    - Rules governing larger DSPs that are included in the NAQ model will not change.

1 - Wholesale Electricity Market Amendment (Cost Allocation) Rules 2024

# Multi-TNI certification of aggregated DSPs

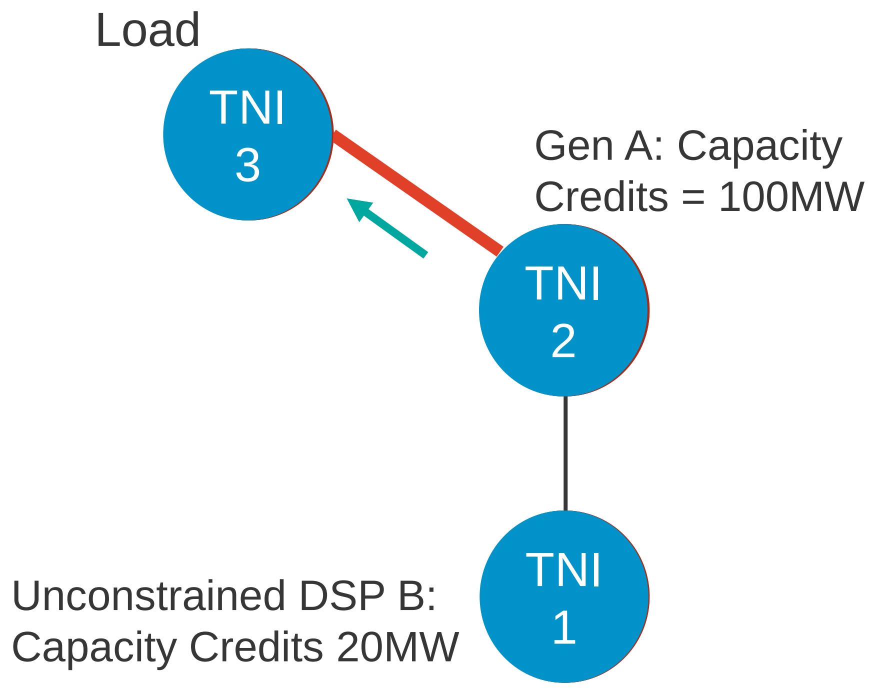
## Require aggregated DSPs to only locate at “uncongested TNIs”

**Aggregated DSPs, certified without an identified TNI, will be treated as unconstrained in the NAQ model.**

- Issue: Allowing such DSPs to locate anywhere may result in generators being curtailed below their Capacity Credits when these DSPs are dispatched.
- Therefore, we need to know where such congestion and curtailment may occur and restrict Associated Load locations to uncongested areas.

**How?**

- Require AEMO to identify “congested” areas as part of RCM EOI process.
- Use NAQ model outcomes from previous cycle to identify TNIs at which dispatch of ‘unconstrained DSPs’ may result in:
  - Generators being curtailed below their capacity credits due to the DSPs being dispatched; and/or
  - ‘Unconstrained DSP’ dispatch being reduced below assigned Capacity Credits.
- **DSPs will not be allowed to locate Associated Loads at the ‘congested’ TNIs determined above.**




- *If TNI2 ->TNI3 is constrained, the constraint is alleviated when the load at TNI1 increases.*
- *If DSP loads at TNI1 are dispatched (i.e, TNI1 load reduces), Gen A will have to be constrained down below its 100MW Capacity Credits.*

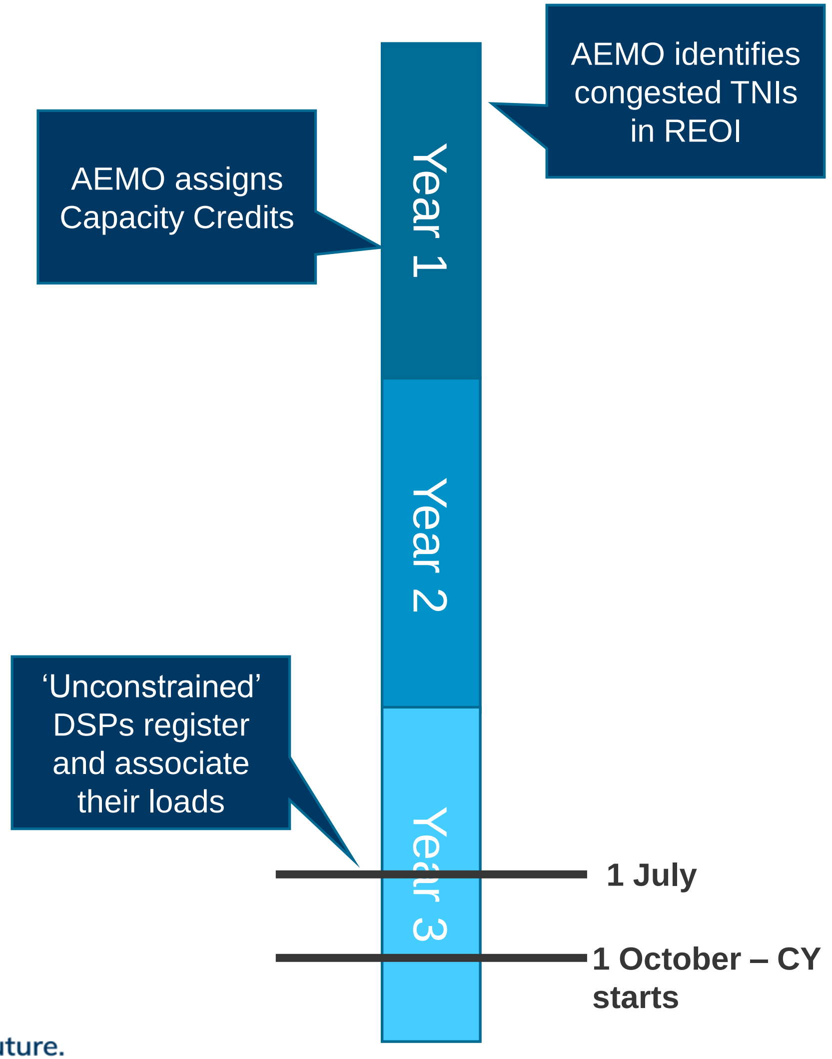
# Multi-TNI certification of DSPs

**Require aggregated DSPs to register and associate all loads three months prior to a Capacity Year commencing**

At least three months prior to Capacity Year starting:

- **‘Unconstrained DSPs’ must register their Facilities and associate their loads**
  - Must register DSP Facilities at each TNI with Associated Loads
    - Registration rules amended so  AEMO can set a single application fee
    - Retain requirement to register Facility at a single TNI
  - Capacity Credits of all the registered DSPs = Capacity Credits assigned at certification to the aggregated DSP
- **Failure to register and associate loads by above deadline will result in DSPs forfeiting Capacity Credits***
  - AEMO can draw down on Reserve Capacity Security
  - AEMO can initiate Supplementary Reserve Capacity process if needed

* This is a late addition, and not yet reflected in the Exposure Draft



# Allowing DSPs to inject

## Three key changes

1. **Introduce DSP Injection Cap that limits export behind a TNI**
2. **Changes to Metered Schedule and Reserve Capacity Deficit, Relevant Demand calculations to handle Injections**
3. **Changes to DSP submissions and Market Schedules to handle Injections.**

# Allowing DSPs to inject

## Introduce DSP Injection Cap

DSPs aggregating Associated Loads with storage behind the meter could inject into the SWIS when dispatched (i.e. reduce demand below 0MW).

To enable DSPs to inject without compromising PSSR a DSP Injection Cap is introduced:

- DSP Injection Cap is set at 10MW at each TNI:
    - A DSP cannot export at or above the cap at a given TNI – aligned to default System Size threshold for Scheduled Facility and Semi-Scheduled Facility
- AEMO may lower the cap at a TNI if it deems it necessary to maintain PSSR:
    - Aligned with ability to lower threshold for Non-Scheduled Facility class registration at congested TNIs.
- AEMO to publish DSP Injection Caps in Request for EOI so that Market Participants have visibility of whether caps have changed at a TNI.

# Allowing DSPs to inject

## Changes to Settlement calculations

Three changes:

1. DSP Metered Schedule definition (clause 9.5.4)
   - Positive indicates Withdrawal (existing)
   - Negative indicates Injection (new)
2. Reserve Capacity Deficit calculations (clauses 4.26.1A(a)(ii)(5) and 4.26.4(a)(ii)(4))
   - Requirement to hold sufficient capacity
3. Relevant Demand calculations (Appendix 10)
   - Adjustment formula amended to handle Injections
   - Adjustment floor introduced

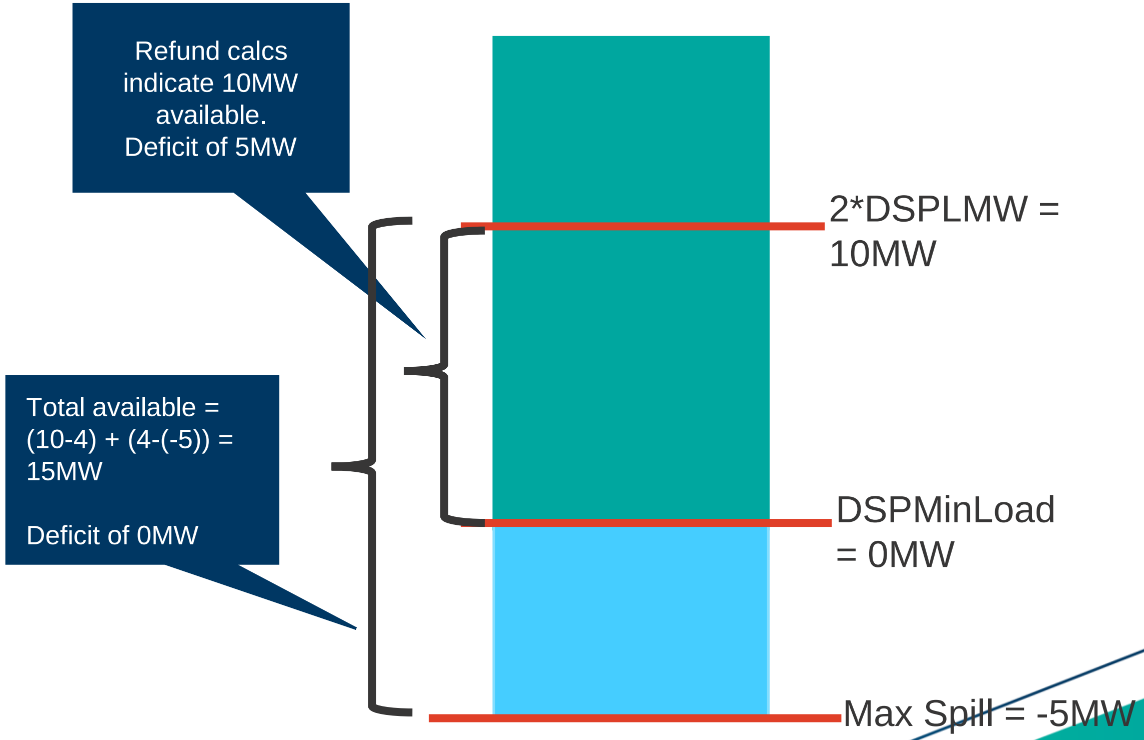
Changes 2 and 3 are discussed further in the following slides.

# Allowing aggregated DSPs to inject

## Changes to Settlement calculations: (2) Reserve Capacity Deficit calculations

**Two types of refunds:**

- **Capacity Shortfalls (clauses 4.26.2D & 4.26.14) –** only non-zero if there is a Dispatch Event and DSP is non-compliant with dispatch (*no change*)
- **Reserve Capacity Deficits (clauses 4.26.1A and 4.26.4) (RCD) –** calculated everyday. Non-zero if DSP does not have sufficient capacity to meet RCOQ
  - RCD = RCOQ  - Max(0, 2*DSPLMW – (DSPMinLoad + Test Shortfall)) [simplified]
- **Formula works for injecting aggregated DSPs if DSPMinLoad is allowed to be negative**
  - DSPMinLoad (Minimum Consumption) highly dynamic for residential loads
  - Cannot be easily verified
  - Can result in too many refunds or set to avoid refunds



# Allowing aggregated DSPs to inject

## Changes to Settlement calculations: (2) Reserve Capacity Deficit calculations cont'd…

**The following changes are proposed:**

- **Reserve Capacity Deficits (clauses 4.26.1A and 4.26.4) calculations changed**
  - Deficits only occur if DSP fails Reserve Capacity Test or fails to deliver Dispatch Instruction quantity
  - New quantities introduced to measure dispatch shortfall: Peak Delivery Shortfall (4.26.1AA [new]) and Flexible Delivery Shortfall (4.26.4A [new])
- **Reserve Capacity Testing (clauses 4.25.2B(d) [new] and 4.25.2BA(d) [new]) rules amended to enable AEMO to trigger test if DSP fails to deliver Dispatch Instruction Quantity**
  - If DSP passes test -> no refunds
  - If DSP fails test -> continue paying refunds till another test is passed.

**4.26.1A(a)(ii)(5): Peak Reserve Capacity Deficit**

$$\cancel{\mathrm{Max}(0, \mathrm{PRCOQ} - \mathrm{Max}(0, 2 * \mathrm{DSPLoad} - \{\mathrm{DSPMinLoad} + \mathrm{Peak\ Test\ Shortfall}\})}$$

$$\mathrm{Max}(\mathrm{Peak\ Test\ Shortfall}, \mathrm{Peak\ Delivery\ Shortfall})$$

**4.26.4(a)(ii)(4): Flexible Reserve Capacity Deficit**

$$\cancel{\mathrm{Max}(0, \mathrm{Flex\ Test\ Shortfall}, \mathrm{FRCOQ} - \mathrm{Max}(0, 2 * \mathrm{DSPLoad} - \mathrm{DSPMinLoad})}$$

$$\mathrm{Max}(\mathrm{Flex\ Test\ Shortfall}, \mathrm{Flex\ Delivery\ Shortfall})$$

# Allowing DSPs to inject

## Changes to Settlement calculations: (3) Relevant Demand changes

**DSR Review proposed dynamic baseline method with on-the-day adjustment**

$$Baseline\ Adjustment = Min\left(20\%, \frac{AME\ - AUBE}{AUBE}\right)$$

$$Baseline\ Energy = UBE\ \times (1 + Baseline\ Adjustment)$$

**Two issues:**

- **Very large negative adjustments can occur if AUBE is close to zero**
  - Addressed by introducing a floor of -200%.
- **Adjustment occurs in the wrong direction if AUBE and UBE have different signs -> see example**
  - Addressed by multiplying adjustment by -1 if AUBE and UBE have different signs

**AME: Average Metered Energy, average actual consumption/production during Adjustment Window**

**UBE: Unadjusted Baseline Energy, average historical consumption/production over Selected Days**

**AUBE: Average Unadjusted Baseline Energy, average of Unadjusted Baseline Energy during Adjustment Window**

### Example

- AME = -0.45MWh, AUBE = -0.5MWh
- Baseline Adjustment = -10% (0.05/-0.5)

| UBE | Baseline Energy |
|---|---|
| -0.1 (spill) | -0.1 x (1 – 10%) = -0.09 ✓<br>Spill is reduced as AME indicates lower spill |
| 0.1 (consume) | 0.1 x (1 – 10%) = 0.09 X<br>Consumption incorrectly reduced -> lower spill (AME) equivalent to higher demand -> UBE should be increased<br>*Should be: 0.1 x (1+10%) = **1.1*** |

# Allowing DSPs to inject

## Changes to Settlement calculations: (3) Relevant Demand changes cont'd..

### Existing Formulation

$$\textit{Baseline Adjustment} = Min\left(20\%, \frac{AME - AUBE}{AUBE}\right)$$

### New Formulation

- If UBE and AUBE have the same sign

$$\textit{Baseline Adjustment} = Min\left(20\%, \mathbf{Max}\left\{\mathbf{-200\%}, \frac{AME - AUBE}{AUBE}\right\}\right)$$

- If UBE and AUBE have different signs

$$\textit{Baseline Adjustment} = \mathbf{-1} \times Min\left(20\%, \mathbf{Max}\left\{\mathbf{-200\%}, \frac{AME - AUBE}{AUBE}\right\}\right)$$

**In addition to changing the adjustment formulation, Appendix 10 is further amended to enable DSPs to choose between the Unadjusted Baseline Energy and Baseline Energy (adjusted) quantities to set their Relevant Demand.**

# Allowing aggregated DSPs to inject

## Changes to DSP submissions and Market Schedules to handle Injections

DSP market submissions and schedules assume Withdrawals only

- Clause 7.4A requires DSPs to submit DSP Withdrawal Profiles, which include their DSP Unconstrained Withdrawal Quantity and DSP Constrained Withdrawal Quantity
  - Addressed by requiring DSPs to instead submit a DSP Profile including a DSP Unconstrained Quantity and DSP Constrained Quantity (DSPCWQ) instead (positive submission = Withdrawal; negative submission = Injection)
- Clause 7.8A requires AEMO to publish DSP Pre-Dispatch Schedules including DSP Forecast Capacity (Clause 7.8A.3):
  - DSP Forecast Capacity = max(0, DSP Unconstrained ~~Withdrawal~~ Quantity – max(DSPMinLoad, Relevant Demand – RCOQ))
  - Appendix 10 amended to enable AEMO to estimate Relevant Demand using Unadjusted Baseline Energy of a DSP.
  - DSPMinLoad or **Minimum Consumption** is currently a static value collected during DSP Load Association.
    - Highly dynamic for residential loads and will vary seasonally and within the Trading Day.
    - Need mechanism for DSPs to provide more dynamic data to support Forecast Capacity calculation.
    - New unnumbered clauses added to require DSPs to provide dynamic data and keep it accurate.

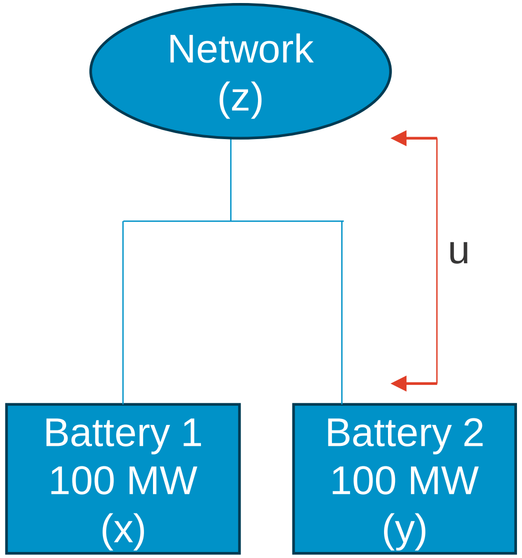
Clauses are unnumbered as implementation approach still under consideration:

1. Could require DSPs to submit as part of their DSP Profile submissions -> may result in system changes for participants
2. Could add to Standing Data -> Standing Data process does not enable dynamic changes due to lag between submission and AEMO approval

# Connection and Metering Points Arrangements

# Connection Arrangements and Metering Points

**This consultation and the proposed amending rules supersede the consultation on the WEM Amending Rules regarding the registration of Separately Certified components undertaken as a result of the Demand Side Response Review.**




**Under the current Wholesale Electricity Market (WEM) Rules, facility registration occurs at the connection point to the network.**

Why is this an issue?

Proposed Electric Storage Resources or "hybrids", for example, want to register their components as separate facilities (x and y).

Registering separate facilities behind a network connection point, or shared connection points, can also assist in reducing the largest contingency on the system.

If the components are separately registered, a new "orphaned" network (u) may be created between the metering points of the separate facilities (x and y) and the network connection point, or shared network connection points, (z).



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

# Connection Arrangements and Metering Points

## Proposed Solution

**Under most circumstances, metering points and connection points will be equivalent.**

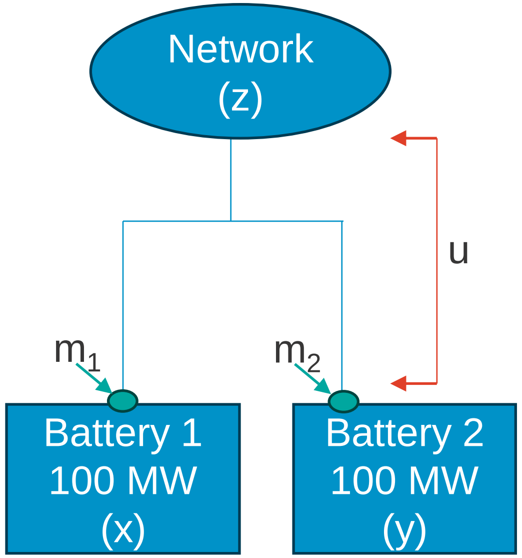
However, it is proposed that, when all proposed requirements are satisfied, the metering point can change ($m_1$ and $m_2$).

Therefore, the facilities can register separately (as x and y). It is proposed to apply this to all types of technology.

The equipment between the metering and connection point(s) (u) will be part of the Market Participant's equipment list.

The Market Participant must continue to comply with all WEM Rules obligations it would have had to comply with if a single facility was registered at the Network connection point.

.



# Connection Arrangements and Metering Points

**Amend the WEM Rules to refer to "metering points" that can differ from connection points in prescribed circumstances.**

Separate Facilities can be registered at their metering point and the same market participant is still responsible for all of the equipment up to the network connection point.

**Requirements:**

- The same market participants is responsible for all separate Facilities and all equipment behind the connection point(s).
- The separate Facilities are not electrically connected behind their Metering Points.
- All separate Facilities must be behind the same connection point(s) and there must be more than one Separate Facility.
- All energy producing systems or loads behind a connection point(s) are separately metered.
- Metering Points must have interval meters provided by the Network Operator.
- Loss factors are calculated by the Network Operator for the separate facilities (at x and y).
- SCADA is required for all the facilities and equipment (x, y & u).
- Facilities cannot become part of an intermittent load.

**Assumptions:**

- The connection point or shared connection points are unchanged
- This applies to scheduled, semi-scheduled and non-scheduled facilities.
- For Generator Performance Standards, as the connection point or shared connection points are unchanged, the facilities are still a single Transmission Connected Generating System.
- Cannot aggregate the facilities for registration or offers.

# Contingency Reserve Raise (CRR) and Additional RoCoF Requirement Cost Allocation

# CRR and Additional RoCoF Cost Allocation

## Why are changes required? (1)

**Current cost allocation method in Appendix 2A not reflecting ‘causer pays’ principles where:**

- **a Registered Facility contains independently dispatchable energy producing units with separate network connections**
- **auxiliary loads mean facility risk > Dispatch Target/Forecast**
- **the sudden loss of part or all of one Registered Facility triggers**
- loss of output from Distributed Energy Resources (DER) from Non-Dispatchable Loads (NDLs)
- (very occasionally) loss of output from another Registered Facility
- **a Network Raise Contingency causes the loss of Injection from DER in NDLs**

# CRR and Additional RoCoF Cost Allocation

## Why are changes required? (2)

**Additionally:**

- **facility risks for Facilities with Intermittent Loads may not reflect actual risks (may be higher or lower)**
- **runway method inappropriate for allocating shares of Network Raise Risks**
- **terminology issues (e.g. current terminology tends to assume that all contingencies are raise contingencies)**

# CRR and Additional RoCoF Cost Allocation

## New/revised concepts (1)

**CR Facility**

- Scheduled Facility, Semi-Scheduled Facility, Non-Scheduled Facility
- NDL containing an Intermittent Load, if the Energy Producing System supplying the Intermittent Load is not also part of a Registered Facility

**Single Facility Raise Risk (MW)**

- AEMO will determine how to calculate for each CR Facility on a case by case basis
- for CR Facilities with Intermittent Loads AEMO must take into account the information in new clause 7.5.16
- for other CR Facilities usually Dispatch Target/Forecast, but may be higher (e.g. auxiliary loads) or lower (e.g. independently dispatchable energy producing units with separate network connections)
- determination details in WEM Procedure

# CRR and Additional RoCoF Cost Allocation

## New/revised concepts (2)

**Facility Raise Contingency**

- triggered by failure/loss of CR Facility
- Facility Raise Contingency Risk (MW)
- Secondary CR Facilities and Secondary Facility Raise Risks (MW)

**Network Raise Contingency**

- triggered by failure/loss of network equipment
- Network Raise Risk (MW)
- Network Facility Raise Risk (MW) – may not equal Single Facility Raise Risk for a CR Facility

**Determination details in WEM Procedure**

# CRR and Additional RoCoF Cost Allocation

## General cost allocation principles

- Single Facility Raise Risk should reflect real MW risk caused by the CR Facility
- All costs allocated using runway method based on Single Facility Raise Risk unless the Largest Credible Supply Contingency (LCSC) exceeds the largest Single Facility Raise Risk
- Costs associated with MW risk beyond the largest Single Facility Raise Risk allocated to causers on a pro-rata basis
- Risk associated with loss of output from DER of NDLs recognised and allocated to Synergy

# CRR and Additional RoCoF Cost Allocation

## Overview of revised cost allocation method (1)

Total cost divided into ‘runway’ and ‘non-runway’ components based on the relative size of

- RunwayComponentMW(DI): the largest Single Facility Raise Risk
- NonRunwayComponent(DI): the quantity by which the LCSC exceeds the largest Single Facility Raise Risk

Section 3 assigns shares of the runway component to CR Facilities with a Single Facility Raise Risk > 10 MW using the runway method

Section 4 assigns shares of the non-runway component (if it exists) to CR Facilities and Synergy’s NDLs on a pro-rata basis

Section 5 uses the values determined in sections 3 and 4 to calculate CR_Cost_Share(p,DI) for each Market Participant

# CRR and Additional RoCoF Cost Allocation

## Overview of revised cost allocation method (2) – allocation of non-runway component

**If LCSC > largest Single Facility Raise Risk (i.e. NonRunwayComponent(DI) > 0), then LCSC must be set by one or more Credible Contingencies that are either**

- **Facility Raise Contingencies for a CR Facility that involve the consequential loss of output from other Facilities; or**
- **Network Raise Contingencies**

**Section 4 identifies these contingencies and uses them to allocate shares of the non-runway component**

**For Facility Raise Contingencies**

- **a share is allocated to each Secondary CR Facility**
- **any remaining share is allocated to Synergy NDLs**
- **no share allocated to the initiating CR Facility (already accounted for)**

**For Network Raise Contingencies**

- **a share is allocated to each CR Facility affected by the contingency**
- **any remaining share is allocated to Synergy NDLs**

# Other Proposed Amendments

# Monitoring the Effectiveness of the Market

## Currently, AEMO is not required to report issues that negatively impact on the WEM effectiveness

### New clauses are proposed in section 2.16 of the WEM Rules to create disclosure obligations on AEMO

Clauses 2.16.3A to 2.16.3E will require AEMO to report issues that adversely affect the WEM or the achievement of the WEM Objectives.

AEMO must report an issue to the Coordinator and the ERA as soon as it becomes aware of it, and the Coordinator or ERA may request more information or data about the issue identified.

AEMO must comply with information requests made by the Coordinator or the ERA. However, they must consult with AEMO about the details and timing before making the request.

All confidential information must be treated as confidential and cannot be published unless the identity of the Market Participant or Market Participants remains protected.

# AEMO’s next Allowable Revenue - Dates

New clause 2.22A.2C is introduced to extend the date by which AEMO is required to submit its seventh Allowable Revenue (AR7) period proposal to the ERA until 31 January 2025. This change is required to allow:

- consideration of a Rule Change Proposal to amend the framework for oversight of AEMO’s Allowable Revenue and Forecast Capital Expenditure, which may apply for the AR7 period; and
- AEMO adequate time to develop a submission that captures the full scope of its activities in the context of ongoing WEM reform and the energy transition, or undertake other activities required in accordance with any changes to the framework.

New clause 2.22A.7A is introduced to allow for AEMO to publish its budget after 30 June in the event that the ERA does not make a final determination before this time. This is required, as otherwise AEMO’s Budget would not reflect the Final Determination as required by clause 2.22A.7A and AEMO would have no mechanism to recover the correct Market Fees.

# Standing Data and ESS Accreditation Parameters

Clause 2.34.11 is replaced with a provision that establishes an obligation on AEMO to verify the accuracy of the Standing Data provided by a Rule Participant and amended to require (not just permit) AEMO to request a Rule Participant to provide updated Standing Data for any of its Facilities if AEMO considers the information to be inaccurate or no longer accurate.

Clause 2.34A.11 is amended to require (not just permit) AEMO to reassess the Frequency Co-optimised Essential System Service Accreditation Parameters if it becomes aware that the performance of a Facility has varied, is varying, or is likely to vary significantly from these parameters, or performance requirements.

# Significant Incident Reporting

**Section 3.8B is inserted to provide an obligation on AEMO to investigate and report on significant incidents in the SWIS**

It is proposed that AEMO investigates significant incidents that:

- endanger Power System Security or Power System Reliability to a significant extent; or
- causes significant disruption to the operation of the dispatch process; or
- which AEMO considers have had, or had the potential to have had, a significant impact on the effectiveness of the market.

AEMO may require the Rule Participants involved in the incident to provide a report on the incident within a reasonable time period specified by AEMO.

# NCESS Procurement and Publication Requirements

**Currently, there is inconsistency between 3.11B and section 5.2A regarding certain obligations and some uncertainty as to what should be published regarding the NCESS contracts**

**Amendments are proposed to section 3.11B of the WEM Rules to clarify NCESS obligations.**

Clause 3.11B.7(g) is proposed to be amended to clarify that, within an NCESS submission form, the information required for a technology that can be assigned Certified Reserve Capacity is for every Reserve Capacity Cycle that the facility is eligible to participate in over the NCESS contract.

Clause 3.11B.15(e) is proposed to be amended to clarify that the published payment structure and amounts specified in an NCESS contract include, if applicable:

- the price to make the facility available for enablement or dispatch and the nature of the availability obligations;
- the price that the facility or equipment will provide NCESS when enabled or dispatched; and
- any other payments the facility or equipment requires to provide NCESS.

# Long Term Projected Assessment of System Adequacy

Clause 4.5.12 is amended to allow the calculation of the Availability Duration Gap based on the 90th percentile peak days, rather than all Trading Days in a relevant Capacity Year, and to revise the Indicative Peak ESR Obligation Intervals to delink them from the Mid Peak ESR Obligation Intervals to minimise the daily peak demand for the Trading Day.

# Reserve Capacity Security

Clause 4.13.1B is amended to simplify and provide clarity around the circumstances in which the obligation to provide Reserve Capacity Security under clause 4.13.1 applies (i.e. if AEMO does not already hold security).

New clause 4.13.1D is introduced to ensure that AEMO continues to hold the benefit of a Reserve Capacity Security for a Facility in scenarios where:

- AEMO has already drawn down upon the Reserve Capacity Security of the Facility;
- the Market Participant has been assigned Capacity Credits for a subsequent Reserve Capacity Cycle; and
- the Facility is yet to enter Commercial Operation.

Clause 4.13.2B is amended to ensure that AEMO is required to return the Reserve Capacity Security to the Market Participant if the amount recalculated under clause 4.13.2(b) is zero.

# Reserve Capacity Testing

Clause 4.25.2(b) is amended to prevent a Demand Side Programme from being subjected to an unnecessary Reserve Capacity Test when it has successfully demonstrated its capability through the normal dispatch process.

Clause 4.25.4 is amended to allow AEMO to reduce the number of Capacity Credits held by a Facility, which has failed testing, to the greatest value obtained during testing.

# Finalisation of Forced Outage details

## Finalisation of Forced Outage details – clause 3.21.2(d)

- Propose to reduce the deadline for providing AEMO any final details of a Forced Outage from 15 days to 7 days after the relevant Trading Day
- Intent is to allow settlement calculations that rely on Outage details (e.g. for Supplementary Capacity and NCESS Contracts) to be performed earlier
- Question: will the earlier deadline prevent a Market Participant from collecting any specific information it needs to finalise its Forced Outage details?

# Publication of Capacity Credit information

## Publication of summary Capacity Credit information

AEMO currently required to publish by 30 September of Year 1

- the Reserve Capacity Prices and the aggregate MW of Capacity Credits assigned to Facilities and components at each price (clauses 4.1.18A, 4.20.5AA)
- whether the Reserve Capacity Requirement has been met or exceeded with Capacity Credits satisfying certain conditions (clauses 4.1.16A(b), 4.20.5AA(aA))

AEMO cannot determine this information until it has certainty around how Market Participants with multiple Separately Certified Components will allocate their Capacity Credits – information received around 30 October of Year 1 (clause 4.1.21A)

Proposing amendments to sections 4.1 and 4.20 to

- delay these publications until 5 Business Days after AEMO receives the required notifications
- retain the publication of relevant Reserve Capacity Prices (without associated Capacity Credit quantities) by around 30 September of Year 1

# Early Reserve Capacity payments

## Eligibility for early Reserve Capacity payments

**Changes proposed to clause 4.1.26 to**

- **rationalise provisions for previous Reserve Capacity Cycles**
- **clarify that a Facility upgrade may be eligible for early Reserve Capacity payments if it meets the relevant criteria**
- **clarify that when Reserve Capacity Security is required for only part of a Facility under section 4.13 (i.e. for a Facility upgrade) then the remaining capacity should contribute to the Reserve Capacity Requirement in the early Reserve Capacity payment test in clause 4.1.26(e)(i)**

# Scheduling Day demand forecasts

## Clause 6.3A.2A – Scheduling Day demand forecasts

- Original intent of clause 6.3A.2A was for AEMO to provide an up-to-date demand forecast to Market Participants for each Trading Day on the Scheduling Day, similar to the pre-NWCD Scheduling Day demand forecast
- AEMO has deemed this requirement to be met by the publication of a Pre-Dispatch Schedule or Week-Ahead Schedule that includes all the Trading Intervals in the Trading Day
- Current implementation does not guarantee the provision of an up-to-date forecast so not fulfilling any useful purpose
- Question: Is there still a requirement for a separate Scheduling Day demand forecast? If so, why and what specifically is required?

# Affected Dispatch Interval deadlines

## Clause 7.11C.2 – Affected Dispatch Interval deadlines

- Clause 7.11C.2 requires AEMO to publish replacement data for Affected Dispatch Intervals by noon on the Business Day following the Trading Day
- AEMO advises timeline is not always achievable and maybe extended under clause 7.13.1K
- AEMO has suggested amendments to require AEMO to just identify Affected Dispatch Intervals by the clause 7.11C.2 deadline, then provide replacement data by a later deadline (e.g. 1 week from the Trading Day)
- **Question: What are Market Participants' views on the trade-off between timeliness of replacement data for Affected Dispatch Intervals (e.g. to provide final price certainty) vs replacement data quality and cost of provision?**

# Submissions after Gate Closure

## Real-Time Market Submissions after Gate Closure (clause 7.4.35)

- It is proposed to amend clause 7.4.35 to allow Market Participants to make a Real-Time Market Submission after Gate Closure if the submission is being made to comply with a direction issued by AEMO
- Required to prevent Market Participants from breaching clause 7.4.35 when complying with a direction from AEMO
- Change does not affect existing requirements for AEMO directions or require a Market Participant to offer capacity that it cannot deliver in the relevant timeframes
- AEMO/EPWA are currently reviewing the use of directions, interventions and discretionary constraint equations in the WEM

# Allocation of cost for peak capacity procured through NCESS

It is proposed to modify the cost allocation and settlement rules to allocate the costs of NCESS Contracts for peak capacity as a shared Reserve Capacity cost, i.e. on the basis of IRCR.

Clauses 9.10.27D and 9.10.45 are amended to remove from the Essential System Service Settlements Calculations any NCESS contract amounts procured and recovered under the Reserve Capacity Mechanism, in accordance with the new clauses 4.28.4(aA) and 4.28.4A.

# Settlement Calculations - Essential System Services

Section 9.10 is amended because registration of a Facility is proposed to be defined at the Metering Point in clause 2.29.1B, as opposed to the connection point.

Clauses 9.10.3C(a)(v), 9.10.3D(a)(v), 9.10.3E(a)(v), 9.10.3F(a)(v), and 9.10.3G(a)(v) are updated to clarify that the Loss Factor Adjusted Price in the Price-Quantity Pair (LFAOP(f,DI)) is derived from the Enablement Minimum for the relevant Frequency Co-optimised Essential System Service as specified in the relevant Real-Time Market Submission, and not as updated by AEMO, if applicable, under clause 7.4.52.

# Managing disclosure of Confidential Information

The current framework under Chapter 10 does not explicitly enable AEMO to proactively share Market Information with EPWA or the ERA, unless it has received a formal request under clause 10.4.6 or it is included in the MSDC. This has led to delays in communicating information related to critical market effectiveness or compliance issues.

New clause 10.4.4A is inserted to enable AEMO to use its discretion to share information with the Coordinator or the ERA where necessary.

# Next Steps

We appreciate stakeholder feedback before 5:00pm 8 July 2024 (AWST).