

TRANCHE 10: EXPOSURE DRAFT

PROPOSED ELECTRICITY SYSTEM AND MARKET (ESM) AMENDING RULES

Explanatory Note for Exposure Draft of the Tranche 10 Proposed ESM Amending Rules:

This exposure draft contains proposed Amending Rules to:

- amend the timeline for the first independent audit of the rule change process under clause 2.16.13F;
- require Western Power, in consultation with AEMO, to conduct a review of methods for estimating “DPV Shake-Off” and “Load Shake-Off” MW quantities arising from Contingency Events at least once every two years;
- extend the existing exemption for Flexible Capacity obligations for the 2025 Reserve Capacity Cycle to future Reserve Capacity Cycles in which the Flexible Reserve Capacity Price is less than or equal to the Peak Reserve Capacity Price;
- enable AEMO to direct a Market Participant to operate a Facility using Liquid Fuel if the Facility is certified to operate on Liquid Fuel and AEMO has issued a Low Reserve Condition Declaration;
- refine the provisions around determination of Market Participant Excess Amounts and Market Participant Deficit Amounts by the Economic Regulation Authority (ERA) after a suspension of the Real-Time Market, to ensure the provisions are meeting their policy intent;
- ensure correct settlement outcomes where the Separately Certified Components of a Scheduled Facility or Semi-Scheduled Facility have different capacity prices;
- bring forward the implementation of daily capacity prices from 1 October 2027 to 1 October 2026;
- prevent the aggregation of Facilities that contain Electric Storage Resources with different Peak Electric Storage Resource Obligation Durations;
- correct errors in the calculation of available capacity in clause 4.26.1(e), which can cause the available capacity to be overstated when Scheduled Facilities or Semi-Scheduled Facilities are Withdrawing in a Trading Interval, or when a Demand Side Programme fails to meet its dispatch target;
- re-implement a change to clause 4.26.4D that was included in the Tranche 9 ESM Amending Rules but failed due to an error in the Ministerial Instrument;
- reorder the options for determining a replacement Market Schedule for a missing or Affected Dispatch Interval, so that AEMO can use the preferred option (a re-run of the Dispatch Algorithm with corrected inputs) if the necessary data is available;
- reduce the minimum notice period for a return to normal operations after a Real-Time Market suspension from two hours to one hour;
- correct errors and clarify calculation details in Appendix 10 (Relevant Demand Determination);
- allow AEMO to override inappropriate Energy Uplift Payments and RCS Uplift Payments arising from missing or manifestly incorrect Constraint Equations in the Dispatch Algorithm;
- replace the settlement calculations that allocate costs to Market Participants according to their share of total Injection and/or Withdrawal with alternative calculations in Trading Intervals with very low or zero total Injection; and
- prevent unwarranted Energy Uplift Payments during Real-Time Market suspensions that arise from the use of End of Interval (EOI) MW SCADA quantities instead of Dispatch Targets to calculate the marginal offer price for the Facility.

This exposure draft is divided into four schedules:

1. Amending Rules to commence on gazettal;
2. Amending Rules to commence on 1 October 2026, directly after the commencement of Schedule 3 of the *Electricity System and Market Amendment (Tranche 9) Rules 2025* (Tranche 9 Amendments);

3. Amending Rules to commence on 1 October 2027, directly after the commencement of Schedule 4 of the Tranche 9 Amendments; and
4. Amending Rules to commence on a date to be confirmed by AEMO and Gazetted by the Minister.

Following industry consultation, the proposed Amending Rules in this exposure draft will be submitted to the Minister for Energy and Decarbonisation for making and gazettal.

The Department of Energy and Economic Diversification (DEED) is seeking stakeholder feedback on this exposure draft by **5:00 PM (WST) on 24 June 2026**. Feedback can be sent to energymarkets@deed.wa.gov.au.

Mark-up Colour guide:

Text in black	Text in black Rules assumed to be in force at the time the Amending Rules in the relevant schedule are proposed to commence (based on confirmed commencement dates for Amending Rules made by the Minister and the Amending Rules in prior schedules of this exposure draft)
Text in red - <u>underlined</u> and strikethrough	Amendments proposed under Tranche 10

Schedule 1: Amending Rules to commence on gazettal

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2.16. Monitoring the Effectiveness of the Market

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Explanatory Note

Currently, the ESM Rules require the Coordinator to arrange an independent audit of the effectiveness of the rule change process and the Procedure Change Process no less than every three years.

The first three-year period is proposed to commence on 1 October 2027 to align with the expiry of the Minister for Energy's temporary rule making power under regulation 7(4) of the *Electricity Industry (Electricity System and Market) Regulations 2004*. This change is consistent with minimising unnecessary costs to consumers in line with the State Electricity Objective.

Clause 2.16.13F is amended to commence the first three-year period on 1 October 2027.

2.16.13F. The Coordinator must ensure that an independent person carries out an audit of the effectiveness of the ESM Rule change process and Procedure Change Process no less than every three years, with the first such audit completed by 1 October 2030. The independent person must provide the Coordinator with a report, and the Coordinator must within 30 Business Days of receiving the report either:

- (a) accept the report and any recommendations contained in it; or
- (b) prepare a separate report setting out the matters raised in the independent person's report which the Coordinator accepts and those which it does not accept and setting out Coordinator's reasons for that view; and
- (c) publish the independent person's report and any report it prepared under clause 2.16.13F(b) within 30 Business Days of receiving the independent person's report.

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Explanatory Note

Voltage and frequency disturbances during network faults can lead to the disconnection of distributed photovoltaic (DPV) generation (“DPV shake-off”) and electrical loads (“load shake-off”), increasing the size of a Credible Contingency Event. AEMO needs to account for the impacts of DPV shake-off and load shake-off when determining Frequency Co-optimised Essential System Service (FCESS) requirements, to ensure that FCESS enablement quantities are sufficient to maintain Power System Security.

In 2022, Energy Policy WA, AEMO and Western Power conducted a joint investigation into Power System Security risks associated with low electricity demand in the SWIS (the Low Load Project). As part of this project, Western Power conducted extensive modelling and analysis of the impacts of DPV shake-off and load shake-off on the size of Contingency Events. A report setting out the findings of the Low Load Project is available on the Coordinator’s Website ([Energy Policy WA Low Load Project Stage 1 Report](#)).

AEMO has incorporated the statistical models developed by Western Power for the Low Load Project into the methods it uses to determine Largest Credible Supply Contingencies, Largest Credible Load Contingencies and FCESS requirements in the Real-Time Market. Details of these methods are available in the relevant WEM Procedures and the “Contingency Reserve Requirements in the WEM” and “Estimating Voltage-dependent DPV and Load Loss During Network Faults” fact sheets published by AEMO on the WEM Website ([AEMO | Contingency Reserve Quantities](#)).

The impact of DPV shake-off in the SWIS is expected to reduce over time, due to the introduction of updated inverter standards to improve the ride through capability of DPV during system disturbances. However, the current impact on Contingency Reserve Raise requirements, and therefore costs, is material.

The modelling and analysis conducted by Western Power for the Low Load Project has not been revisited since 2022. Given the material cost implications and the rate and extent of change in the SWIS, DEED, AEMO and Western Power have agreed that a regular review of the impact of DPV shake-off and load shake-off on Contingency Events and the methods used by AEMO to account for their impact is warranted.

New section 3.8B requires Western Power to conduct such a review at least once every two years. The reviews will be conducted in consultation with AEMO and include public consultation on a draft report and the publication of a final report.

It is expected that AEMO will continue to account for the impacts of DPV shake-off and load shake-off using the methods developed by Western Power, as refined through the section 3.8B review process. However, AEMO will have the option to vary the methods, provided it publishes its reasons for doing so on the WEM Website.

The proposed amendments will benefit the State Electricity Objective by helping to improve the accuracy of AEMO’s estimation of DPV and Load shake-off impacts when determining FCESS requirements. This reduces the likelihood of FCESS Requirements that are either:

- unnecessarily conservative, which imposes unwarranted costs on Market Participants; or
- insufficient to ensure Power System Security during a Contingency Event.

The deadline for the first review is intended to be around six months after the gazettal of these Amending Rules.

3.8B. Review of DPV Shake-Off and Load Shake-Off Impact on Contingency Events

3.8B.1. Western Power must, in accordance with this section 3.8B, conduct a review of the methods for estimating DPV Shake-Off and Load Shake-Off MW quantities arising from Contingency Events in the SWIS at least once in every two years. Western Power must:

- (a) publish the final report for its first review by 1 February 2027; and
 - (b) publish the final report for each subsequent review no later than two years after the publication date of the final report for the previous review.
- 3.8B.2. In conducting a review under clause 3.8B.1, Western Power must, in consultation with AEMO:
 - (a) undertake modelling and analysis using available records of previous Contingency Events to estimate the MW quantities of DPV Shake-Off and Load Shake-Off associated with those events;
 - (b) undertake analysis of the factors that influence the MW quantities of DPV Shake-Off and Load Shake-Off arising from Credible Contingency Events in the SWIS; and
 - (c) develop or refine, as applicable, methods for estimating DPV Shake-Off and Load Shake-Off MW quantities to be used by AEMO when determining:
 - i. the Largest Credible Supply Contingency and Largest Credible Load Contingency for each Dispatch Interval and Pre-Dispatch Interval; and
 - ii. Frequency Co-optimised Essential System Service requirements for each Dispatch Interval and Pre-Dispatch Interval.
- 3.8B.3. In conducting a review under clause 3.8B.1, Western Power must publish:
 - (a) a draft report containing a draft of the information required under clauses 3.8B.5(a), 3.8B.5(b), 3.8B.5(c), 3.8B.5(d) and 3.8B.5(g);
 - (b) a request for submissions on the draft report; and
 - (c) the closing date for submissions, which must be at least 20 Business Days after the date of publication of the draft report.
- 3.8B.4. Western Power must publish any submissions it receives in response to a draft report published under clause 3.8B.3 on its website, and take those submissions into account when preparing its final report under clause 3.8B.5.
- 3.8B.5. Following the closing date for submissions on a report published under clause 3.8B.3, Western Power must publish a final report containing:
 - (a) details of the modelling and analysis undertaken and the outcomes of the modelling and analysis;
 - (b) details of the methods developed or refined under clause 3.8B.2(c);
 - (c) details of the input parameters required by the methods specified under clause 3.8B.2(c), including the sources of input parameters, initial values, and details of mechanisms for the review and update of parameters where appropriate;

- (d) an assessment of any limitations on the accuracy of the proposed methods and potential options to address those limitations;
- (e) a summary of submissions received by Western Power on the draft report;
- (f) Western Power's response to the issues raised in submissions; and
- (g) any other matters Western Power considers relevant to the review.

3.8B.6. Western Power must provide to AEMO any information Western Power holds that is reasonably required by AEMO to implement the methods specified by Western Power in a final report under clause 3.8B.5(b).

3.8B.7. If AEMO decides to vary the methods it uses for the purposes described in clause 3.8B.2(c) from the methods specified by Western Power in the most recent final report published under clause 3.8B.5, then AEMO must publish the reasons for its decision on the WEM Website.

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4.1. The Reserve Capacity Cycle

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Explanatory Note

Flexible Capacity was first assigned in the 2025 Reserve Capacity Cycle for the 2027/28 Capacity Year.

Facilities only receive payments for Flexible Capacity Credits if the Flexible Reserve Capacity Price is higher than the Peak Reserve Capacity Price.

Market Participants will not be paid for Flexible Capacity for the 2025 Reserve Capacity Cycle due to excess of Flexible Capacity. Therefore, the ESM Rules exempt AEMO from implementing the relevant obligations for the 2027/28 Capacity Year, to avoid unnecessary implementation costs and use of AEMO resources.

The 2025 WEM Electricity Statement of Opportunities (WEM ESOO) forecast that under the expected scenario, Flexible Capacity would not be required until after 2035. A similar outcome is expected for the 2026 WEM ESOO.

To avoid the significant costs associated with implementing Flexible Capacity obligations, clause 4.1.27, which is currently blank, is amended to apply the current exemption for Flexible Capacity obligations to every Reserve Capacity Cycle for which the Flexible Reserve Capacity Price is equal to or less than the Peak Reserve Capacity Price.

The drafting of the new clause is based on the existing transitional clause 1.63.10. In line with the approach for clause 1.63.10, the clause will contain some initially blank sub-clauses, which will be filled in by the Amending Rules in Schedule 3 of this exposure draft on 1 October 2027. This is to reflect that some obligations related to Flexible Capacity will not exist in the ESM Rules before 1 October 2027.

The change supports the State Electricity Objective by reducing the burden on Market Participants to actively meet capacity obligations (e.g. Flexible Reserve Capacity Testing) during any years in which there will be no financial remuneration for the service. It would also delay AEMO's implementation effort and allow it to focus on other implementation priorities.

~~4.1.27. [Blank]~~

- 4.1.27. For a Reserve Capacity Cycle from the 2026 Reserve Capacity Cycle onwards, if the Flexible Reserve Capacity Price is less than or equal to the Peak Reserve Capacity Price then in respect of the relevant Capacity Year:
- (a) Market Participants are not required to fulfil any further obligations relating to Flexible Capacity Credits;
 - (b) AEMO must not procure supplementary Flexible Capacity under section 4.24;
 - (c) AEMO must not procure Non-Co-optimised Essential System Services relating to Flexible Capacity;
 - (d) AEMO must not consider Flexible Capacity Outage Capabilities or the availability of Flexible Capacity when conducting Outage Evaluations under section 3.18E;
 - (e) subject to clause 4.1.27(g), AEMO is not required to determine or publish:
 - i. [Blank]
 - ii. [Blank]
 - iii. [Blank]
 - iv. Entity Daily Flexible Reserve Capacity Prices under clause 4.29.1E and the Floating Daily Flexible Reserve Capacity Price under clause 4.29.1F;
 - v. [Blank]
 - vi. [Blank]
 - vii. [Blank]
 - viii. the Transitional Daily Flexible Reserve Capacity Price under clause 4.29.1G and Fixed Daily Flexible Reserve Capacity Prices under clause 4.29.1H; and
 - ix. the values described in clauses 4.20.5A(b)(iiiA) and 4.20.5A(b)(v);
 - (f) a standard form Supplementary Capacity Contract is not required to specify aspects relating to supplementary Flexible Capacity outlined under clauses 4.24.13(g) and 4.24.13(h)(i)(2); and
 - (g) AEMO must determine and publish:
 - i. [Blank]
 - ii. the Flexible Reserve Capacity Price under clause 4.29.1(b)(ii).

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4.20. Capacity Credits

Explanatory Note

Clauses 4.20.5A(b)(iiiA) and 4.20.5A(b)(v) are amended to reference new clause 4.1.27, because AEMO is not required to publish these values when clause 4.1.27(e)(ix) applies.

4.20.5A. AEMO must:

- (a) subject to clause 4.20.5C, assign a quantity of Peak Capacity Credits and a quantity of Flexible Capacity Credits to each Facility where the quantities are determined in accordance with clauses 4.20.5B and 4.20.5BA for the relevant Facility;
- (b) publish, by the date and time specified in clause 4.1.16A:
 - i. for each Facility assigned Capacity Credits under clause 4.20.5A(a):
 - 1. the quantity of Peak Capacity Credits assigned; and
 - 2. the quantity of Flexible Capacity Credits assigned; and
 - 3. the Facility Class;
 - ii. the Peak Reserve Capacity Price for the Reserve Capacity Cycle;
 - iiA. the Flexible Reserve Capacity Price for the Reserve Capacity Cycle;
 - iii. if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Transitional Daily Peak Reserve Capacity Price for the Reserve Capacity Cycle multiplied by the number of Trading Days in the relevant Capacity Year for the Reserve Capacity Cycle;
 - iiiA. subject to ~~clause 1.63.10(e)(ix)~~ clauses 1.63.10(e)(ix) and 4.1.27(e)(ix), if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Transitional Daily Flexible Reserve Capacity Price for the Reserve Capacity Cycle multiplied by the number of Trading Days in the relevant Capacity Year for the Reserve Capacity Cycle;
 - iv. each Fixed Daily Peak Reserve Capacity Price for each Facility and Separately Certified Component that is a Fixed Price Facility or Fixed Price Component for that Reserve Capacity Cycle multiplied by the number of Trading Days in the relevant Capacity Year for the Reserve Capacity Cycle; and
 - v. subject to ~~clause 1.63.10(e)(ix)~~ clauses 1.63.10(e)(ix) and 4.1.27(e)(ix), each Fixed Daily Flexible Reserve Capacity Price for each Facility and Separately Certified Component that is a Fixed Price Facility or Fixed Price Component for that Reserve Capacity Cycle multiplied by the number of Trading Days in the relevant Capacity Year for the Reserve Capacity Cycle.

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7.7. Scarcity and Intervention

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Explanatory Note

On 25 August 2025, AEMO issued multiple directions and implemented intervention constraints to secure sufficient generation capacity for the evening peak demand period in response to gas supply limitations.

AEMO's analysis of this event, and of other high gas-demand days during 2025, found that requiring dual-fuel Registered Facilities that are certified to operate on diesel but normally operate on gas to switch to diesel would significantly reduce the risk of maximum hourly gas peaking quantities exceeding network limits.

New clause 7.7.5A enables AEMO to direct a Market Participant to operate a Registered Facility using the Liquid Fuel nominated in accordance with its Certification of Reserve Capacity if a Low Reserve Condition Declaration has been issued.

Clause 7.7.14 is amended to require AEMO to document, in a WEM Procedure, the processes it will use to determine which Registered Facility may be directed under new clause 7.7.5A. This will promote transparency and provide Market Participants with greater clarity regarding how AEMO will exercise this power.

This proposal will improve Power System Reliability by reducing the risk of energy shortfalls and supports the achievement of the State Electricity Objective.

7.7.5A. If AEMO has issued a Low Reserve Condition Declaration and the Short Term PASA or the Available Capacity Scenario for the Pre-Dispatch Schedule projects that a Registered Facility will be needed to provide energy, AEMO may direct the relevant Market Participant to use the Liquid Fuel nominated under clause 4.10.1(e)(v) in the relevant application for Certified Reserve Capacity for the Registered Facility.

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7.7.14. AEMO must document in a WEM Procedure the processes it will use to determine which Registered Facility to direct:

- (a) under clauses 7.7.3, 7.7.4, ~~or 7.7.5~~ or 7.7.5A; or
- (b) to synchronise to provide a RoCoF Control Service under clause 3.4.4(d).

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Explanatory Note:

Section 7.12 includes provisions that apply after a suspension of the Real-Time Market by AEMO under clause 7.11D.1(c), i.e. "when AEMO determines, in its reasonable opinion, that actions undertaken to maintain Power System Security and Power System Reliability are significantly impacting market settlement in accordance with the provisions of these ESM Rules due to:

- failure of its IT systems;
- loss of communications or control systems required to maintain Power System Security; or
- any other reason as identified in the WEM Procedure published under clause 7.11D.4."

Section 7.12 requires the ERA to assess the “net settlement amounts” received by each Market Participant during a suspension period against the ERA’s best estimate of the variable costs incurred by the Market Participant that relate only to those net settlement amounts.

The ERA may notify AEMO of a “Market Participant Excess Amount” for a Market Participant if it determines the Market Participant’s net settlement amounts exceeded its variable costs. AEMO will then recover the Market Participant Excess Amount from the Market Participant and distribute it back to the market in accordance with section 9.11A.

Section 7.12 also allows a Market Participant to apply to the ERA if the Market Participant considers any net settlement amounts it received during the suspension period are lower than the net settlement amounts the Market Participant would have received if the Real-Time Market was not suspended.

If the ERA determines that the Market Participant is correct, then the ERA must determine whether any of the Market Participant’s net settlement amounts are lower than the ERA’s best estimate of its variable costs (a “Market Participant Deficit”). If the ERA determines a Market Participant Deficit, it must notify AEMO of the Market Participant Deficit Amount to be recovered from the market and paid to the Market Participant in accordance with section 9.11A.

Amendments are proposed to section 7.12 to address several issues identified by the ERA Secretariat and DEED that prevent the section from achieving its policy intent. The main issues addressed by the amendments are as follows:

- The term “net settlement amount” is not defined, making it unclear what amounts the ERA needs to compare with its estimate of the Market Participant’s costs. Clause 7.12.1 is amended and clauses 7.12.1A and 7.12.1B inserted to provide an explicit definition of the amounts to be compared (i.e. the Deemed Real-Time Payment and the Deemed Real-Time Cost).
- The assessment criteria do not clearly acknowledge that it is normal and reasonable for Market Participants to earn inframarginal rent from the Real-Time Market. For example, under the current drafting, it could be concluded that a wind farm has a Market Participant Excess Amount for a suspension period because the Reference Trading Prices are higher than its efficient variable costs.

The ERA Secretariat has advised, and DEED agrees, that it is not feasible for it to review the Market Clearing Prices for a suspension period to determine whether they should have been higher or lower. However, if the ERA’s assessment process is to take the final Market Clearing Prices determined by AEMO under clause 7.11E.3 as a given, then DEED considers that the total Market Participant Excess Amount recovered from a Market Participant for a suspension period should not exceed the total Energy Uplift Payments received by the Market Participant for the suspension period. This is because all the other relevant payments to the Market Participant are either based on the Market Clearing Prices or pre-contracted amounts unaffected by the suspension. The Energy Uplift Payment limit has been reflected into the Market Participant Excess Amount calculation in new clause 7.12.2A.

- The ERA is currently required to assess the net settlement amounts and costs of every Market Participant after a Real-Time Market suspension under clause 7.11D.1(c). Given the decision to restrict any recovery to a maximum of the total Energy Uplift Payments received by the Market Participant for the suspension period, a requirement to assess every Market Participant would place an unnecessary administrative burden on the ERA. To address this concern, new clause 7.12.1C only requires the ERA to assess a Market Participant’s amounts if it considers that the Market Participant has received a material and irregular level of Energy Uplift Payments over the suspension period.
- Currently section 7.12 does not account for the possibility that when the ERA checks for a Market Participant Deficit in response to a request from a Market Participant it may instead find a Market Participant Excess. Clause 7.12.7 is amended to require the ERA to follow the same process when it determines a Market Participant Excess regardless of whether the trigger for the determination was a Market Participant request under clause 7.12.3 or its own post-suspension period review under clause 7.12.1C.

- The current drafting does not clearly specify the basis for the ERA's comparisons, e.g. whether the assessment is to be undertaken for each Trading Interval individually or for the suspension period as a whole. This is problematic because a Market Participant could have a Market Participant Excess in some Trading Intervals in a suspension period and a Market Participant Deficit in others. The relevant clauses have been amended to require the assessment to be carried out over the suspension period as a whole.
- The current drafting is unclear about how Market Participant Deficit Amounts and Market Participant Excess Amounts are to be allocated across the Trading Intervals in the suspension period. The way in which the total amounts for a suspension period are allocated to Trading Intervals determines how these amounts are distributed to or recovered from Market Participants under section 9.11A.

New clause 7.12.2A allocates a share of a total Market Participant Excess Amount for a suspension period to each Trading Interval according to the proportion of the total Energy Uplift Payment for the suspension period received in that Trading Interval. This approach should ensure that AEMO distributes a share of the Market Participant Excess Amount to each relevant Market Participant reflective of the share of the relevant Energy Uplift Payments originally recovered from that Market Participant.

New clause 7.12.8A allocates a total Market Participant Deficit Amount across the Trading Intervals in a suspension period according to the proportion of total Dispatch Intervals in the suspension period that fell in each Trading Interval (noting that a suspension period may start and/or end mid-Trading Interval). This allocates the amount as evenly as possible across the suspension period.

Other minor enhancements include:

- clarifying that the deadline for notifying AEMO of a Market Participant Deficit Amount or Market Participant Excess Amount is the Adjustment 3 date for the first Trading Week of the suspension period, to account for the unlikely but possible scenario of a suspension period spanning more than one Trading Week; and
- requiring the ERA to notify the Market Participant as well as AEMO about any Market Participant Deficit Amounts or Market Participant Excess Amounts it determines.

7.12. Market Suspension Compensation

~~7.12.1. If AEMO has suspended the Real-Time Market under clause 7.11D.1(c), the Economic Regulation Authority must assess the net settlement amounts received by Market Participants during the suspension period.~~

7.12.1. In this section 7.12:

Suspension Period: Means a continuous period in which AEMO has suspended the Real-Time Market under clause 7.11D.1(c).

Deemed Real-Time Payment: Has the meaning given in clause 7.12.1A.

Deemed Real-Time Cost: Has the meaning given in clause 7.12.1B.

Explanatory Note:

New clause 7.12.1A specifies the Deemed Real-Time Payment for a Market Participant for a suspension period. The payment comprises:

- any activation payments received for the suspension period under an NCESS Contract or Supplementary Capacity Contract;
- any payments received for FCESS provision (note that Market Participants do not receive FCESS Uplift Payments or RCS Uplift Payments during a suspension period); and
- a deemed energy payment that applies, for each Injecting Registered Facility and Dispatch Interval, the maximum of the Reference Trading Price and the Facility's Marginal Offer Price to the deemed Injection quantity used in Energy Uplift Payment calculations.

7.12.1A. The Deemed Real-Time Payment for Market Participant p in Suspension Period s is:

$$\begin{aligned}
 & \text{DeemedRTPayment}(p,s) \\
 &= \text{NCESS Activation Payment}(p,s) \\
 &+ \text{SC Activation Payment}(p,s) \\
 &+ \sum_{DI \in s} \sum_{f \in p} \left(\text{CR Payable}(f,DI) + \text{CL Payable}(f,DI) \right. \\
 &+ \text{RCS Payable}(f,DI) + \text{RR Payable}(f,DI) + \text{RL Payable}(f,DI) \\
 &+ \left. \left(\max(\text{MarginalOfferPrice}(f,DI), \text{ReferenceTradingPrice}(t)) \right) \right) \\
 &\times \text{EnergyUpliftQuantity}(f,DI)
 \end{aligned}$$

where:

- (a) NCESS Activation Payment(p,s) is the sum of any activation payments received by Market Participant p for Suspension Period s under a Non-Co-optimised Essential System Service Contract for a Registered Facility;
- (b) SC Activation Payment(p,s) is the sum of any activation payments received by Market Participant p for Suspension Period s under a Supplementary Capacity Contract for a Registered Facility;
- (c) DI ∈ s denotes all Dispatch Intervals DI in Suspension Period s;
- (d) f ∈ p denotes all Registered Facilities f registered to Market Participant p in Dispatch Interval DI;
- (e) CR Payable(f,DI) is the Contingency Reserve Raise amount payable for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 9.10.6;
- (f) CL Payable(f,DI) is the Contingency Reserve Lower amount payable for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 9.10.10;
- (g) RCS Payable(f,DI) is the RoCoF Control Service amount payable for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 9.10.14;

- (h) RR Payable(f,DI) is the Regulation Raise amount payable for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 9.10.22;
- (i) RL Payable(f,DI) is the Regulation Lower amount payable for Registered Facility f in Dispatch Interval DI as calculated in accordance with clause 9.10.23;
- (j) MarginalOfferPrice(f,DI) is the highest Loss Factor Adjusted Price associated with any cleared (or scheduled) Price-Quantity Pair for In-Service Capacity in respect of Market Participant p's Real-Time Market Offer for energy that was dispatched for Registered Facility f in Dispatch Interval DI;
- (k) ReferenceTradingPrice(t) is the Final Reference Trading Price for Trading Interval t containing Dispatch Interval DI; and
- (l) EnergyUpliftQuantity(f,DI) is the quantity determined for Registered Facility f in Dispatch Interval DI under clause 9.9.11.

7.12.1B. The Deemed Real-Time Cost for Market Participant p in Suspension Period s is the Economic Regulation Authority's best estimate of all the efficient variable costs incurred by Market Participant p in Suspension Period s that relate only to the provision of Market Services, Non-Co-optimised Essential System Services and supplementary capacity from Registered Facilities.

7.12.1C. If:

- (a) AEMO has suspended the Real-Time Market under clause 7.11D.1(c); and
- (b) the Economic Regulation Authority considers that a Market Participant has received a material and irregular level of Energy Uplift Payments over the Suspension Period,

then the Economic Regulation Authority must determine and compare the Market Participant's Deemed Real-Time Payment and Deemed Real-Time Cost for the Suspension Period.

~~7.12.2. If the Economic Regulation Authority determines under clause 7.12.1 that one or more net settlement amounts received by a Market Participant for one or more Trading Intervals during the suspension period exceed the Economic Regulation Authority's best estimate of all of the variable costs incurred by the Market Participant for those Trading Intervals that relate only to those net settlement amounts ("Market Participant Excess"), then:~~

- ~~(a) the Economic Regulation Authority may determine the value of the Market Participant Excess, being the difference between the net settlement amounts received by a Market Participant for the relevant Trading Intervals during the suspension period and the Economic Regulation Authority's best estimate of all of the variable costs incurred by the Market Participant~~

for those Trading Intervals that relate only to those net settlement amounts (“**Market Participant Excess Amount**”); and

- (b) ~~where the Economic Regulation Authority has determined a Market Participant Excess Amount under clause 7.12.2(a), the Economic Regulation Authority must, as soon as practicable, but before the commencement date corresponding to the Settlement Adjustment Date 3 of the Trading Week to which the Market Participant Excess Amount relates, notify AEMO of the Market Participant Excess Amount determined under clause 7.12.2(a) and the Trading Intervals to which the Market Participant Excess Amount relates.~~

7.12.2. If the Economic Regulation Authority determines under clauses 7.12.1C or 7.12.7(b) that a Market Participant’s Deemed Real-Time Payment for a Suspension Period exceeds its Deemed Real-Time Cost (“**Market Participant Excess**”), then:

- (a) the Economic Regulation Authority may determine a Market Participant Excess Amount for the Market Participant for each Trading Interval in the Suspension Period in accordance with clause 7.12.2A; and
- (b) if the Economic Regulation Authority determines a Market Participant Excess Amount for the Market Participant for each Trading Interval in the Suspension Period under clause 7.12.2(a), the Economic Regulation Authority must, as soon as practicable, but before the commencement date corresponding to the Settlement Adjustment Date 3 of the first Trading Week to which the Market Participant Excess Amounts relate, notify AEMO and the Market Participant of the Market Participant Excess Amounts and the Trading Intervals to which each Market Participant Excess Amount relates.

7.12.2A. The Economic Regulation Authority must determine a Market Participant Excess Amount for Market Participant p for Trading Interval t in Suspension Period s under clause 7.12.2(a) as:

$$MPEA(p, t) = \min(\text{EnergyUpliftPayment}(p, s), \frac{\text{DeemedRTPayment}(p, s) - \text{DeemedRTCOST}(p, s)}{\text{EnergyUpliftPayment}(p, s)} \times \text{EnergyUpliftPayment}(p, t))$$

where:

- (a) EnergyUpliftPayment(p,s) is the sum of all Energy Uplift Payments received by Market Participant p for Suspension Period s;
- (b) DeemedRTPayment(p,s) is the Deemed Real-Time Payment for Market Participant p for Suspension Period s, as determined by the Economic Regulation Authority in accordance with clause 7.12.1A;

- (c) DeemedRTCost(p,s) is the Deemed Real-Time Cost for Market Participant p for Suspension Period s, as determined by the Economic Regulation Authority in accordance with clause 7.12.1B; and
- (d) EnergyUpliftPayment(p,t) is the sum of Energy Uplift Payments received by Market Participant p for Dispatch Intervals in Trading Interval t that fall within Suspension Period s.
- 7.12.3. If AEMO has suspended the Real-Time Market under clause 7.11D.1(c) and a Market Participant considers that ~~one or more net settlement amounts received by the Market Participant in one or more Trading Intervals during the suspension period is lower than the net settlement amounts the Market Participant would have received~~ the Deemed Real-Time Payment for the Market Participant for the Suspension Period is lower than the corresponding payment would have been if the Real-Time Market was not suspended, the Market Participant may request the Economic Regulation Authority to determine if that is correct and, if so, ~~estimate the value of the net settlement amounts the Market Participant would have received if the Real-Time Market was not suspended~~ determine whether a Market Participant Deficit exists for the Market Participant for the Suspension Period in accordance with clause 7.12.7.
- 7.12.4. A request under clause 7.12.3 must:
- (a) be submitted to the Economic Regulation Authority within six weeks of the Settlement Statement Date for the Trading Week in which the Trading Interval the subject of the request under clause 7.12.3 occurred;
 - (b) contain information and justification that substantiates the request; and
 - (c) where a Compensation Guideline has been published by the Economic Regulation Authority under clause 7.12.9, comply with the Compensation Guideline.
- 7.12.5. The Economic Regulation Authority may request additional information or justification from a Market Participant that has submitted a request under clause 7.12.3 that substantiates the request. The Market Participant must provide the requested information or justification to the Economic Regulation Authority within ten Business Days of receiving the Economic Regulation Authority's request.
- 7.12.6. The Economic Regulation Authority may request AEMO to verify the information provided by a Market Participant to the Economic Regulation Authority under clauses 7.12.4(b) or 7.12.5, as applicable. AEMO must respond to the Economic Regulation Authority within ten Business Days of receiving the Economic Regulation Authority's request.
- 7.12.7. The Economic Regulation Authority must, following receipt of any further information under clause 7.12.5 or a response from AEMO under clause 7.12.6, if applicable, determine whether ~~one or more net settlement amounts received by the Market Participant for the Trading Intervals the subject of a request under~~

~~clause 7.12.3, are lower than the Economic Regulation Authority's best estimate of all of the variable costs incurred by the Market Participant for those Trading Intervals that relate only to those net settlement amounts ("Market Participant Deficit")~~;

- ~~(a) the Market Participant's Deemed Real-Time Cost for the Suspension Period exceeded its Deemed Real-Time Payment ("Market Participant Deficit"), in which case clause 7.12.8 applies; or~~
- ~~(b) the Market Participant's Deemed Real-Time Payment for the Suspension Period exceeded its Deemed Real-Time Cost, in which case clause 7.12.2 applies.~~

7.12.8. ~~Where~~ If the Economic Regulation Authority determines that there is a Market Participant Deficit under clause 7.12.7, the Economic Regulation Authority must:

- ~~(a) estimate the value of the Market Participant Deficit, being the difference between the net settlement amounts received by the Market Participant for the relevant Trading Intervals during the suspension period and the Economic Regulation Authority's best estimate of all of the variable costs incurred by the Market Participant for those Trading Intervals that relate only to those net settlement amounts ("Market Participant Deficit Amount"); and~~
- ~~(a) determine a Market Participant Deficit Amount for the Market Participant for each Trading Interval in the Suspension Period in accordance with clause 7.12.8A; and~~
- (b) as soon as practicable, but before the commencement date corresponding to the Settlement Adjustment Date 3 of the first Trading Week to which the Market Participant Deficit ~~Amount relates~~ Amounts relate, notify AEMO and the Market Participant of the Market Participant Deficit ~~Amount~~ Amounts determined under clause 7.12.8(a) and the Trading Intervals to which the Market Participant Deficit ~~Amount relates~~ Amounts relate.

7.12.8A. The Economic Regulation Authority must determine a Market Participant Deficit Amount for Market Participant p for Trading Interval t in Suspension Period s under clause 7.12.8(a) as:

$$MPDA(p,t) = (DeemedRTCos(p,s) - DeemedRTPayment(p,s)) \times \frac{NDI(t)}{NDI(s)}$$

where:

- (a) DeemedRTCos(p,s) is the Deemed Real-Time Cost for Market Participant p for Suspension Period s, as determined by the Economic Regulation Authority in accordance with clause 7.12.1B;
- (b) DeemedRTPayment(p,s) is the Deemed Real-Time Payment for Market Participant p for Suspension Period s, as determined by the Economic Regulation Authority in accordance with clause 7.12.1A;

(c) NDI(t) is the number of Dispatch Intervals in Trading Interval t that fall within Suspension Period s; and

(d) NDI(s) is the number of Dispatch Intervals in Suspension Period s.

7.12.9. The Economic Regulation Authority may publish on its website a guideline prescribing the processes to be followed and the information and justification to be provided by a Market Participant in making a request under clause 7.12.3 (**“Compensation Guideline”**). The Economic Regulation Authority may amend the Compensation Guideline from time to time and the amended guideline will take effect from the date the amended guideline is published on the Economic Regulation Authority's website.

7.12.10. A Notice of Disagreement cannot be issued under section 9.16 in respect to a Market Participant Excess Amount or a Market Participant Deficit Amount.

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Glossary

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DPV Shake-Off: The disconnection of distribution-connected photovoltaic energy producing units within Non-Dispatchable Loads caused by voltage and frequency disturbances during Credible Contingency Events in the SWIS.

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Load Shake-Off: The disconnection of Load within Non-Dispatchable Loads caused by voltage and frequency disturbances during Credible Contingency Events in the SWIS.

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Schedule 2: Amending Rules to commence on 1 October 2026

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Explanatory Note:

The *Wholesale Electricity Market Amendment (RCM Reviews Sequencing) Rules 2025* (RCM Sequencing Amendments) include provisions allowing a Market Participant that certifies a new component of an existing Scheduled Facility or Semi-Scheduled Facility (i.e. a new Facility Technology Type) to:

- not be subject to legacy transitional pricing arrangements for the new component; and
- apply for the component to be classified as a Fixed Price Component and receive a fixed capacity price for five or ten years.

The relevant changes to certification and Capacity Credit allocation took effect from the 2024 Reserve Capacity Cycle. However, due to an oversight, the settlement changes to support the payment of different capacity prices for different components of a Facility were not scheduled to commence until 1 October 2027.

Changes are proposed to bring forward the settlement provisions that support component-based pricing to 1 October 2026. These changes are essential to ensure that AEMO can determine and apply capacity prices to Scheduled Facilities and Semi-Scheduled Facilities over the 2026/2027 Capacity Year.

The RCM Sequencing Amendments include other changes to move from monthly-based to daily-based capacity prices from 1 October 2027. These changes, which have strong interconnections with the component-based pricing changes, will also be brought forward to 1 October 2026, to reduce AEMO's IT costs by allowing it to make both sets of changes at the same time.

The clauses affected include clauses 2.30.5(f), 4.1.29, 4.26.1(b), 4.28.1, 4.28.2, 4.28A.1A, 4.29.1A, 4.29.1B, 4.29.1D, 4.29.2B, 4.29.3, 4.29.5, 9.8.3, 9.8.3A and 9.8.3B, and the defined terms Excess Allocation Price and Facility Daily Peak Reserve Capacity Price.

Minor changes are also proposed to clause 4.29.1H to ensure consistent terminology throughout the relevant RCM settlement calculations.

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2.30. Facility Aggregation

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Explanatory Note

Clause 2.30.5(f) is amended to reflect the replacement of Facility Monthly Peak Reserve Capacity Prices with Entity Daily Peak Reserve Capacity Prices in settlement calculations from 1 October 2026.

New clause 2.30.5(j) prevents the aggregation of Facilities that contain Electric Storage Resources with different Peak Electric Storage Resource Obligation Durations. AEMO's IT systems do not support such aggregations, and it would be inappropriate to modify them to do so, as the current rules specifically remove the 10-years grandfathering for an existing Facility if a Market Participant seeks Capacity Credits for that Facility's upgrade. This amendment supports the State Electricity Objective by avoiding the unwarranted additional complexity and associated IT costs of permitting the aggregation of such Facilities.

- 2.30.5. AEMO must only allow the aggregation of Facilities pursuant to an application under clause 2.30.1 if, in its opinion, the proposed Aggregated Facility meets the following criteria:
- (a) the proposed Aggregated Facility will not adversely impact on AEMO's ability to ensure Power System Security and Power System Reliability are maintained;
 - (b) the Market Participant for the proposed Aggregated Facility provides Standing Data for:
 - i. each individual Facility that would be required to be provided if each Facility was registered separately; and
 - ii. the Aggregated Facility as a whole;
 - (c) adequate control and monitoring equipment exists for the proposed Aggregated Facility; and
 - (d) the Facilities within the proposed Aggregated Facility are at the same Electrical Location;
 - (e) [Blank]
 - (f) the ~~Facility Monthly Entity Daily~~ Peak Reserve Capacity Price applicable to each of the Facilities ~~and or~~ Separately Certified Components within the proposed Aggregated Facility is the same, and is expected to remain the same, from and including the current Reserve Capacity Cycle;
 - (g) either:
 - i. the System Size of the proposed Aggregated Facility as determined by AEMO will not affect the quantity of Frequency Co-optimised Essential Services required to be dispatched; or
 - ii. the Facility Contingency associated with the proposed Aggregated Facility affects each individual Facility in the proposed aggregation simultaneously;
 - (h) if the proposed Aggregated Facility intends to provide Frequency Co-optimised Essential System Services, the capability to simultaneously provide energy and Frequency Co-optimised Essential Services from the individual Facilities in the proposed aggregation can be adequately derived for the proposed Aggregated Facility; and
 - (i) the Aggregated Facility will be registered as a Scheduled Facility, Semi-Scheduled Facility or a Non-Scheduled Facility; and
 - (j) all the Separately Certified Components that are Electric Storage Resources within the proposed Aggregated Facility are expected to have the same Peak Electric Storage Resource Obligation Duration in any future Trading Day.

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4.1. The Reserve Capacity Cycle

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Explanatory Note

Clause 4.1.29 is amended to reflect the replacement of Facility Monthly Peak Reserve Capacity Prices with Entity Daily Peak Reserve Capacity Prices in settlement calculations from 1 October 2026.

- 4.1.29. The Peak Reserve Capacity Price, the Flexible Reserve Capacity Price, and each ~~Facility Monthly~~ Entity Daily Peak Reserve Capacity Price for a Reserve Capacity Cycle apply from the start of the Trading Day commencing on 1 October of Year 3 of the Reserve Capacity Cycle to the end of the Trading Day ending on 1 October of Year 4 of the Reserve Capacity Cycle.

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4.26. Financial Implications of Failure to Satisfy Reserve Capacity Obligations

- 4.26.1. If a Market Participant holding Capacity Credits associated with a Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to AEMO calculated in accordance with the following provisions.

- (a) The Trading Interval Refund Rate for a Facility f in the Trading Interval t is determined as follows:

$$\text{Trading Interval Refund Rate}(f,t) = \text{RF}(f,t) \times Y(f,t)$$

where:

- i. Trading Interval Refund Rate (f,t) is the Trading Interval Refund Rate for a Facility f in the Trading Interval t ;
- ii. $\text{RF}(f,t)$ is the refund factor for a Facility f in the Trading Interval t and is calculated in accordance with clause 4.26.1(c); and
- iii. $Y(f,t)$ is the per Trading Interval capacity price associated with a Facility f in the Trading Interval t and is determined in accordance with clause 4.26.1(b).

Explanatory Note

Clause 4.26.1(b) is amended to reflect the introduction of daily and component-based capacity prices in the capacity refund calculations from 1 October 2026.

~~(b) — For a Facility f , for which a Market Participant holds Capacity Credits, in the Trading Interval t , $Y(f,t)$ is determined as follows:~~

- ~~i. where Facility f is not a Registered Facility in Trading Interval t , $Y(f,t)$ equals the Facility Monthly Reserve Capacity Price for the~~

Facility divided by the number of Trading Intervals in the Trading Month in which Trading Interval t falls;

- ii. where AEMO has determined that in Trading Interval t Facility f is not in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility, $Y(f,t)$ equals the Facility Monthly Reserve Capacity Price for the Facility divided by the number of Trading Intervals in the Trading Month in which Trading Interval t falls;
- iii. if AEMO has determined that in Trading Interval t Facility f is in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility, $Y(f,t)$ is:

$$Y(f,t) = \frac{CCESR(f,t)}{CC(f,t)} \times \frac{FMRCP(f,t)}{8 \times TDTM(t)} + \frac{CC(f,t) - CCESR(f,t)}{CC(f,t)} \times \frac{FMRCP(f,t)}{TITM(t)}$$

where:

1. $CCESR(f,t)$ is the number of Capacity Credits held by Facility f associated with Separately Certified Components of Facility f which are Electric Storage Resources if Trading Interval t is within the Electric Storage Resource Obligation Intervals for the Trading Day, and 0 otherwise;
 2. $CC(f,t)$ is the total Capacity Credits held by Facility f in Trading Interval t;
 3. $FMRCP(f,t)$ is the Facility Monthly Peak Reserve Capacity Price for Facility f in Trading Interval t;
 4. $TDTM(t)$ is the number of Trading Days in the Trading Month in which Trading Interval t falls; and
 5. $TITM(t)$ is the number of Trading Intervals in the Trading Month in which Trading Interval t falls;
- iv. where Facility f is a Non-Scheduled Facility, $Y(f,t)$ equals the Facility Monthly Peak Reserve Capacity Price for the Facility divided by the number of Trading Intervals in the relevant Trading Month in which Trading Interval t falls; and
 - v. where Facility f is a Demand Side Programme, $Y(f,t)$ is:

$$\frac{PRCP}{DSP_MIN_AV_TI \times QTY_BD_CY}$$

where:

1. $PRCP$ is the Peak Reserve Capacity Price for Facility f for the Capacity Year;
2. $DSP_Min_AV_TI$ is the minimum number of Trading Intervals per Trading Day that a Demand Side Programme must nominate to be available to provide Peak Capacity if

~~issued a Dispatch Instruction in accordance with clause 4.10.1(f)(iii); and~~

~~3. QTY_BD_CY is the number of Business Days in the relevant Capacity Year.~~

(b) For a Facility f, for which a Market Participant holds Capacity Credits in Trading Interval t, Y(f,t) is determined as follows:

i. if Facility f is not a Registered Facility in Trading Interval t, Y(f,t) equals the Entity Daily Peak Reserve Capacity Price for the Facility in Trading Interval t divided by 48, or the highest Entity Daily Peak Reserve Capacity Price for any Separately Certified Component of the Facility in Trading Interval t divided by 48;

ii. if AEMO has determined that in Trading Interval t Facility f is not in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility:

$$Y(f, t) = \frac{\sum_{c \in f} CC(c, t)}{\sum_{c \in f} CC(f, t)} \times \frac{EDPRCP(c, t)}{48}$$

where:

1. c ∈ f denotes all Separately Certified Components c of Facility f;

2. CC(c,t) is the Capacity Credits associated with Separately Certified Component c in Trading Interval t;

3. CC(f,t) is the Capacity Credits associated with Facility f in Trading Interval t; and

4. EDPRCP(c,t) is the Entity Daily Peak Reserve Capacity Price for Separately Certified Component c in Trading Interval t;

iii. if AEMO has determined that in Trading Interval t Facility f is in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility:

$$Y(f, t) = \left(\frac{\sum_{c \in ESR(f, t)} \frac{PESROI(c, t) \times CC(c, t)}{CC(f, t)} \times \frac{EDPRCP(c, t)}{PESROD(c, t)}}{\sum_{c \in ESR(f, t)} \frac{PESROI(c, t) \times CC(c, t)}{CC(f, t)} \times \frac{EDPRCP(c, t)}{PESROD(c, t)}} \right) + \left(\frac{\sum_{c \in NonESR(f, t)} CC(c, t)}{\sum_{c \in NonESR(f, t)} CC(f, t)} \times \frac{EDPRCP(c, t)}{48} \right)$$

where:

1. c ∈ ESR(f,t) refers to all Separately Certified Components c of Facility f in Trading Interval t that are Electric Storage Resources;

2. PESROI(c,t) is 1 if Trading Interval t is a Peak Electric Storage Resource Obligation Interval for Separately Certified Component c and 0 otherwise;
 3. CC(c,t) is the Capacity Credits associated with Separately Certified Component c in Trading Interval t;
 4. CC(f,t) is the Capacity Credits associated with Facility f in Trading Interval t;
 5. EDPRCP(c,t) is the Entity Daily Peak Reserve Capacity Price for Separately Certified Component c in Trading Interval t;
 6. PESROD(c,t) is the number of Trading Intervals in the Peak Electric Storage Resource Obligation Duration for Separately Certified Component c in the Trading Day containing Trading Interval t; and
 7. c∈NonESR(f,t) refers to all Separately Certified Components c of Facility f in Trading Interval t that are not Electric Storage Resources;
- iv. if Facility f is a Non-Scheduled Facility, Y(f,t) equals the Entity Daily Peak Reserve Capacity Price for the Facility divided by 48; and
- v. if Facility f is a Demand Side Programme:

$$Y(f,t) = \frac{PRCP}{DSP_MIN_AV_TI \times QTY_BD_CY}$$

where:

1. PRCP is the Peak Reserve Capacity Price for the relevant Capacity Year;
 2. DSP MIN AV TI is the minimum number of Trading Intervals per Trading Day that a Demand Side Programme must nominate to be available to provide Peak Capacity if issued a Dispatch Instruction in accordance with clause 4.10.1(f)(iii); and
 3. QTY BD CY is the number of Business Days in the relevant Capacity Year.
- (c) The refund factor RF(f,t) for a Facility f in the Trading Interval t is the lesser of:
- i. six; and
 - ii. the greater of the dynamic refund factor RF dynamic(t) as determined under clause 4.26.1(d) and the minimum refund factor RFfloor(f,t) as determined under clauses 4.26.1(f) or 4.26.1(g) as appropriate.

- (d) The dynamic refund factor RF dynamic(t) in the Trading Interval t is determined as follows:

$$\text{RF dynamic}(t) = 11.75 - \left(\frac{5.75}{750} \right) \times \sum_{f \in F} \text{Spare}(f,t)$$

where:

- i. F is the set of all Registered Facilities for which Market Participants hold Capacity Credits in the Trading Interval t and f is a Facility within that set; and
- ii. Spare(f,t) is the available capacity related to the Registered Facility f, which is not dispatched in the Trading Interval t determined in accordance with clause 4.26.1(e).

Explanatory Note

Clause 4.26.1(e) is amended to correct errors in the calculation of Spare(f,t) for Scheduled Facilities, Semi-Scheduled Facilities and Demand Side Programmes.

Spare(f,t) is intended to represent the spare capacity available from a Facility in a Trading Interval. The total spare capacity across all Facilities is used in clause 4.26.1(d) to calculate the dynamic refund factor applicable to Facilities holding Capacity Credits. The lower the total spare capacity, the higher the dynamic refund factor, up to a maximum value of 6 (if the total spare capacity is 750 MW or less).

Spare(f,t) for a Scheduled Facility or Semi-Scheduled Facility is determined by subtracting the Sent Out Metered Schedule (converted to MW) and any Capacity Adjusted Forced Outage Quantity (CAFO) from the Facility's Reserve Capacity Obligation Quantity (RCOQ). However, as currently drafted, if the Facility contains a Load or Electric Storage Resource and is Withdrawing in the Trading Interval, the negative Sent Out Metered Schedule can cause the spare capacity to be over-estimated.

For example, consider a Scheduled Facility with a 130 MW Non-Intermittent Generating System and a 30 MW Load. If the Non-Intermittent Generating System has an RCOQ of 100 MW but is on full Forced Outage (CAFO = 100 MW) the spare capacity should be 0 MW. However, because the Sent Out Metered Schedule will be -15 MWh for the Trading Interval, Spare(f,t) will be set to 30 MW.

$$\begin{aligned}\text{Spare}(f,t) &= 100 (\text{RCOQ}) - 100 (\text{CAFO}) - (2 \times -15 \text{MWh}) (2 \times \text{SOMS}) \\ &= +30 \text{MW}\end{aligned}$$

These errors would lead to an overestimation of the total spare capacity available and the calculation of inappropriately low dynamic refund factors.

Clauses 4.26.1(e)(i) and 4.26.1(e)(iA) are amended to exclude any net Withdrawal quantities from the calculation of Spare(f,t) for Scheduled Facilities and Semi-Scheduled Facilities.

A similar issue exists for the calculation of Spare(f,t) for a Demand Side Programme under clause 4.26.1(e)(iii)(1). If a Demand Side Programme is dispatched and consumes above its Relevant Demand level, Spare(f,t) will exceed the Demand Side Programme's RCOQ for the Trading Interval. This is contrary to the policy intent that the spare capacity assumed for a Facility should not exceed its RCOQ.

The current drafting of clause 4.26.1(e)(iii)(1) also fails to account for a reduction in spare capacity that occurs while a Demand Side Programme is subject to a Reserve Capacity Test.

Clause 4.26.1(e)(iii)(1) is amended to correct these errors and simplify the calculation of Spare(f,t) for a Demand Side Programme. The new calculation sets the spare capacity of a Demand Side Programme that is subject to a non-zero Dispatch Instruction or a Reserve Capacity Test to its RCOQ less the MW quantity specified under clause 7.13.5 (i.e. the MW quantity by which the Demand Side Programme is requested to adjust its DSP Energy Level relative to its Relevant Demand). The change is consistent with clause 4.26.1(e)(iii)(2), which sets the spare capacity of a Demand Side Programme that is not subject to a non-zero Dispatch Instruction to its RCOQ.

The proposed change will benefit the State Electricity Objective by allowing AEMO to determine a more accurate assessment of the spare capacity of Facilities for each Trading Interval and determine dynamic refund factors that more accurately reflect the level of system stress.

(e) For Registered Facility f in the Trading Interval t , Spare(f,t) is determined as follows:

i. where Facility f is a Scheduled Facility, ~~the greater of zero and:~~

$$\underline{\max(0, \text{RCOQ}(f, t) - \text{CAFO}(f, t) - \max(0, 2 \times \text{SOMS}(f, t)))}$$

where:

1. RCOQ(f,t) is the Reserve Capacity Obligation Quantity determined for the Facility f in Trading Interval t; ~~less~~
 2. CAFO(f,t) is the Capacity Adjusted Forced Outage Quantity for Facility f in Trading Interval t calculated in 3.21.7B; ~~less and~~
 3. SOMS(f,t) is the Sent Out Metered Schedule for Facility f in Trading Interval t ~~multiplied by two so as to be a MW quantity;~~
- iA. where Facility f is a Semi-Scheduled Facility, ~~the greater of zero and:~~
- $$\max(0, RCOQ(f, t) - CAFO(f, t) - \max(0, 2 \times SOMS(f, t)))$$
- where:
1. RCOQ(f,t) is the Reserve Capacity Obligation Quantity determined for Facility f in Trading Interval t; ~~less~~
 2. CAFO(f,t) is the Capacity Adjusted Forced Outage Quantity for Facility f in Trading Interval t calculated in 3.21.7B; ~~less and~~
 3. SOMS(f,t) is the Sent Out Metered Schedule for Facility f in Trading Interval t ~~multiplied by two so as to be a MW quantity;~~
- ii. where Facility f is a Non-Scheduled Facility, zero; and
- ~~iii. if Facility f is a Demand Side Programme in the Trading Interval t, Spare(f,t) is equal to:~~
- ~~1. If Demand Side Programme f is subject to a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity determined under clause 7.13.5, then:~~
- $$\max\{0, RCOQ(f, t) - (RD(f, t) - 2 \times DSP \text{ Load}(f, t))\}$$
- ~~2. Otherwise, RCOQ(f,t),~~
- where:
- ~~3. RCOQ(f,t) is the Reserve Capacity Obligation for the Demand Side Programme f in the Trading Interval t;~~
 - ~~4. DSP Load(f,t) is the Demand Side Programme Load for the Demand Side Programme f in the Trading Interval t as determined under clause 9.5.4; and~~
 - ~~5. RD(f,t) is the Relevant Demand for Demand Side Programme f in Trading Interval t.~~
- iii. if Facility f is a Demand Side Programme:

1. if Demand Side Programme f is subject to a Reserve Capacity Test or a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity in Trading Interval t:

$$RCOQ(f, t) - DIMW(f, t)$$

2. otherwise:

$$RCOQ(f, t)$$

where:

3. RCOQ(f,t) is the Reserve Capacity Obligation Quantity for Demand Side Programme f in Trading Interval t; and

4. DIMW(f,t) is the quantity by which Demand Side Programme f was instructed by AEMO to amend its DSP Energy Level in Trading Interval t as specified by AEMO in accordance with clause 7.13.5.

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Explanatory Note

The change to the header paragraph of clause 4.26.2D(a) in Schedule 3, paragraph 4.12 of the Tranche 9 ESM Amending Rules cannot be implemented due to an error in the Ministerial Instrument. Clause 4.26.2D(a) is therefore amended to implement the intended change.

4.26.2D. AEMO must determine the shortfall in Peak Capacity (“Capacity Shortfall”) supplied by each Market Participant holding Peak Capacity Credits associated with a Demand Side Programme f in each Trading Interval t relative to its Reserve Capacity Obligation Quantity as:

(a) ~~if AEMO has issued a Dispatch Instruction with a non-zero MW quantity under section 7.6 to the Demand Side Programme f for the Trading Interval:~~ if Trading Interval t falls within a DSP Dispatch Event for Demand Side Programme f:

$$\max\left(0, \min(RCOQ(f, t), DIMW(f, t)) - \max(0, RD(f, t) - DSPLMW(f, t))\right)$$

where:

- i. RCOQ(f,t) is the Reserve Capacity Obligation Quantity of the Demand Side Programme f for Trading Interval t (in MW);
- ii. DIMW(f,t) is the quantity by which the Demand Side Programme f was instructed by AEMO to amend its DSP Energy Level in Trading Interval t as specified by AEMO in accordance with clause 7.13.5;
- iii. RD(f,t) is the Relevant Demand of the Demand Side Programme f for Trading Interval t, determined by AEMO in accordance with clause 4.26.2CA; and

- iv. DSPLMW(f,t) is the Demand Side Programme Load of the Demand Side Programme f in Trading Interval t, multiplied by two to convert to units of MW; and

- (b) zero, otherwise.

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4.28. Funding Reserve Capacity Purchased by AEMO

Explanatory Note

Clause 4.28.1(a)(ii) is amended to clarify the intent of the clause. The current wording is potentially misleading, firstly because Capacity Credits are now assigned to the components of a Scheduled Facility or Semi-Scheduled Facility and, secondly, because the number required is the number of Capacity Credits held by Market Participants on the relevant Trading Day, which may be lower than the number of Capacity Credits originally assigned for the Capacity Year.

4.28.1. AEMO must separate the total costs of Capacity Credits acquired by it for a Trading Day into the following two sets:

- (a) the cost of acquiring enough Capacity Credits to ensure, to the extent possible given the number of Capacity Credits AEMO has acquired, that the lesser of:
 - i. the Reserve Capacity Requirement applicable to that Trading Day; and
 - ii. total Capacity Credits ~~assigned to Facilities held by Market Participants for the Trading Day,~~

is just covered after allowing for Capacity Credits traded bilaterally (as defined in clause 4.14.2 and subject to clause 4.28.2(b)) in that Trading Day; and

- (b) the cost of other Capacity Credits acquired but not allocated to the set referred to in clause 4.28.1(a),

determined on the basis that the Capacity Credits acquired by AEMO are allocated to the set referred to in clause 4.28.1(a) in order of decreasing cost per Capacity Credit until the capacity requirements referred to in clause 4.28.1(a) are met, with the remaining Capacity Credits acquired by AEMO being allocated to the set referred to in clause 4.28.1(b).

Explanatory Note

Clause 4.28.2(d) is amended to reflect the implementation of component level capacity prices from 1 October 2026.

4.28.2. For the purposes of clause 4.28.1:

- (a) AEMO is taken to have acquired a Capacity Credit held by a Market Participant in respect of a Facility for a Trading Day if that Capacity Credit

has not been allocated by that Market Participant to another Market Participant for settlement purposes under sections 4.30 and 4.31;

- (b) any Capacity Credits that have been allocated to a Market Participant in excess of that Market Participant's Individual Reserve Capacity Requirement must be:
 - i. deemed to be Capacity Credits acquired by AEMO from the Market Participant; and
 - ii. not counted as Capacity Credits traded bilaterally;
- (c) [Blank]
- (cA) [Blank]
- (cB) the cost of a Capacity Credit deemed to be acquired by AEMO from a Market Participant under clause 4.28.2(b)(i) is equivalent to the Excess Allocation Price for that Market Participant in that Trading Day; and
- ~~(d) the cost of each other Capacity Credit acquired by AEMO from a Facility is equivalent to the Facility Daily Peak Reserve Capacity Price for that Facility in that Trading Day.~~
- (d) the cost of each other Capacity Credit acquired by AEMO from a Market Participant is the Entity Daily Peak Reserve Capacity Price for the relevant Facility or Separately Certified Component in that Trading Day.

...

4.28A. Intermittent Load Refunds

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Explanatory Note

Clause 4.28A.1A is amended to reflect the introduction of daily capacity prices in the capacity refund calculations from 1 October 2026.

4.28A.1A. The Trading Interval Refund Rate for an Intermittent Load f in the Trading Interval t is determined as follows:

$$\text{Trading Interval Refund Rate}(f,t) = \text{RF}(f,t) \times Y(f,t)$$

where:

- (a) Trading Interval Refund Rate (f,t) is the Trading Interval Refund Rate for Intermittent Load f in Trading Interval t ;
- (b) $\text{RF}(f,t)$ is the refund factor for Intermittent Load f in Trading Interval t , which is the lesser of:
 - i. six; and
 - ii. the greater of 1 and the dynamic refund factor $\text{RF dynamic}(t)$ as determined under clause 4.26.1(d); and

- (c) $Y(f,t)$ is the per Trading Interval capacity price associated with Intermittent Load f in Trading Interval t , which equals the ~~Reserve Capacity Price divided by 12 then divided by the number of Trading Intervals in the relevant Trading Month in which Trading Interval t falls~~ Floating Daily Peak Reserve Capacity Price for the relevant Reserve Capacity Cycle divided by 48.

...

4.29. Settlement Data

...

Explanatory Note

Clause 4.29.1A is amended to implement the calculation of daily capacity prices from the 2024 Reserve Capacity Cycle onwards.

4.29.1A. AEMO must set:

- (a) for a Reserve Capacity Cycle from the 2019 Reserve Capacity Cycle to the 2023 Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price for a Reserve Capacity Cycle to apply during the period specified in clause 4.1.29 for a Facility, which is equal to:
- i. [Blank]
 - ii. for a Transitional Facility during a Transitional Reserve Capacity Cycle, the value determined in accordance with clause 4.29.1B;
 - iii. for a Fixed Price Facility during a Fixed Price Reserve Capacity Cycle for that Fixed Price Facility, the value determined in accordance with clause 4.29.1D for that Fixed Price Facility; or
 - iv. for all other Facilities, the Reserve Capacity Price for the Reserve Capacity Cycle divided by 12; and
- ~~(b) for the 2024 Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price to apply during the period specified in clause 4.1.29 for a Facility or a Separately Certified Component, which is equal to:~~
- ~~i. for a Non-Scheduled Facility that is a Transitional Facility during a Transitional Reserve Capacity Cycle, the value determined in accordance with clause 4.29.1B;~~
 - ~~ii. for a Non-Scheduled Facility that is a Fixed Price Facility during a Peak Fixed Price Reserve Capacity Cycle for that Fixed Price Facility, the value determined in accordance with clause 4.29.1D for that Fixed Price Facility; or~~
 - ~~iii. for a Non-Scheduled Facility not covered by clause 4.29.1A(b)(i) or clause 4.29.1A(b)(ii), the Peak Reserve Capacity Price for the Reserve Capacity Cycle divided by 12;~~

- iv. ~~for a Transitional Component during a Transitional Reserve Capacity Cycle, the value determined in accordance with clause 4.29.1B;~~
- v. ~~for a Fixed Price Component during a Peak Fixed Price Reserve Capacity Cycle for that Fixed Price Component, the value determined in accordance with clause 4.29.1D for that Fixed Price Component;~~
- vi. ~~for a Separately Certified Component not covered by clause 4.29.1A(b)(iv) or clause 4.29.1A(b)(v), the Peak Reserve Capacity Price for the Reserve Capacity Cycle divided by 12;~~
- vii. ~~for all Demand Side Programmes, the Peak Reserve Capacity Price for the Reserve Capacity Cycle divided by 12;~~

(b) [Blank]

- (c) for a Reserve Capacity Cycle from the ~~2025~~ 2024 Reserve Capacity Cycle onwards, the Entity Daily Peak Reserve Capacity Price to apply during the period specified in clause 4.1.29 for a Facility or a Separately Certified Component, which is equal to:
 - i. for a Non-Scheduled Facility that is a Transitional Facility during a Transitional Reserve Capacity Cycle, the Transitional Daily Peak Reserve Capacity Price;
 - ii. for a Non-Scheduled Facility that is a Fixed Price Facility during a Peak Fixed Price Reserve Capacity Cycle for that Non-Scheduled Facility, the Fixed Daily Peak Reserve Capacity Price for that Facility;
 - iii. for a Non-Scheduled Facility not covered by clause 4.29.1A(c)(i) or clause 4.29.1A(c)(ii), the Floating Daily Peak Reserve Capacity Price;
 - iv. for a Transitional Component during a Transitional Reserve Capacity Cycle, the Transitional Daily Peak Reserve Capacity Price;
 - v. for a Fixed Price Component during a Peak Fixed Price Reserve Capacity Cycle for that Fixed Price Component, the Fixed Daily Peak Reserve Capacity Price for that Fixed Price Component;
 - vi. for a Separately Certified Component not covered by clause 4.29.1A(c)(iv) or clause 4.29.1A(c)(v), the Floating Daily Peak Reserve Capacity Price; and
 - vii. for all Demand Side Programmes, the Floating Daily Peak Reserve Capacity Price.

4.29.1AA. The Floating Daily Peak Reserve Capacity Price for a Reserve Capacity Cycle is the Peak Reserve Capacity Price divided by the number of Trading Days in the relevant Capacity Year for the Reserve Capacity Cycle.

Explanatory Note

Clause 4.29.1B is amended to implement the calculation of daily capacity prices from the 2024 Reserve Capacity Cycle onwards.

4.29.1B. AEMO must set:

- (a) for a Reserve Capacity Cycle from the 2019 Reserve Capacity Cycle to the 2023 Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price for a Transitional Facility, which is the value calculated using the formula below:

$$\text{TFMRCP}_{cy} = \frac{\min(\max(\text{PRCP}_{cy}, \text{Trans_Floor}_{cy}), \text{Trans_Ceiling}_{cy})}{12}$$

where:

- i. PRCP_{cy} is the Peak Reserve Capacity Price as determined in accordance with clause 4.29.1(a);
- ii. Trans_Ceiling_{cy} equals \$140,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(a); and
- iii. Trans_Floor_{cy} equals \$114,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(b); and

- ~~(b) for the 2024 Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price for a Transitional Facility or Transitional Component, which is the value calculated using the formula below:~~

~~$$\text{TFMRCP}_{ey} = \frac{\min(\max(\text{PRCP}_{ey}, \text{Trans_Floor}_{ey}), \text{Trans_Ceiling}_{ey})}{12}$$~~

~~where:~~

- ~~i. PRCP_{ey} is the Peak Reserve Capacity Price as determined in accordance with clause 4.29.1(a) for the Reserve Capacity Cycle;~~
- ~~ii. Trans_Ceiling_{ey} equals \$140,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(a); and~~
- ~~iii. Trans_Floor_{ey} equals \$114,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(b);~~

- ~~(b) [Blank]~~

- (c) for a Reserve Capacity Cycle from the ~~2025~~ 2024 Reserve Capacity Cycle onwards, the Transitional Daily Peak Reserve Capacity Price for a Transitional Facility or Transitional Component during a Transitional Reserve Capacity Cycle, which is the value calculated using the formula below:

$$\text{TDPRCP}_{cy} = \frac{\min(\max(\text{PRCP}_{cy}, \text{Trans_Floor}_{cy}), \text{Trans_Ceiling}_{cy})}{\text{TDCY}_{cy}}$$

where:

- i. PRCP_{cy} is the Peak Reserve Capacity Price as determined in accordance with clause 4.29.1(b)(i) for the Reserve Capacity Cycle;
- ii. $\text{Trans_Ceiling}_{cy}$ equals \$140,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(a);
- iii. Trans_Floor_{cy} equals \$114,000 for the 2019 Reserve Capacity Cycle and for each subsequent Transitional Reserve Capacity Cycle, the value as escalated in accordance with clause 4.29.1C(b); and
- iv. TDCY_{cy} is the number of Trading Days in the relevant Capacity Year.

4.29.1C. The escalation factors used in clause 4.29.1B are calculated as follows:

- (a) Trans_Ceiling in Capacity Year cy is:

$$\begin{aligned} \text{Trans_Ceiling}_{cy} &= \text{Trans_Ceiling}_{cy-1} \\ &\times (1 + \max(0, \text{ForecastCPI}_{cy}) + \max(0, \text{ActualCPI}_{cy-2}) \\ &\quad - \max(0, \text{ForecastCPI}_{cy-2})) \end{aligned}$$

- (b) Trans_Floor in Capacity Year cy is:

$$\begin{aligned} \text{Trans_Floor}_{cy} &= \text{Trans_Floor}_{cy-1} \\ &\times (1 + \max(0, \text{ForecastCPI}_{cy}) + \max(0, \text{ActualCPI}_{cy-2}) \\ &\quad - \max(0, \text{ForecastCPI}_{cy-2})) \end{aligned}$$

- (c) $\text{Trans_Ceiling}_{cy-1}$ is the value of Trans_Ceiling published for the previous Reserve Capacity Cycle;
- (d) $\text{Trans_Floor}_{cy-1}$ is the value of Trans_Floor published for the previous Transitional Reserve Capacity Cycle;
- (e) ForecastCPI_{cy} is the value determined under clause 4.29.2(a);
- (f) $\text{ForecastCPI}_{cy-2}$ is the value determined under clause 4.29.2(b); and
- (g) ActualCPI_{cy-2} is the value determined under clause 4.29.2(c).

4.29.1CA. AEMO must publish on the WEM Website:

- (a) the values determined for Trans_Ceiling and Trans_Floor in accordance with clause 4.29.1C;
- (b) the Peak Capacity values for Transitional Facilities or Transitional Components determined in clause 4.29.1B; and
- (c) the Flexible Capacity values for Transitional Facilities or Transitional Components determined in clause 4.29.1G.

Explanatory Note:

Clause 4.29.1D is amended to:

- implement the calculation of daily capacity prices from the 2024 Reserve Capacity Cycle onwards; and
- standardise the variable name used for the number of Trading Days in a Capacity Year (TDCY).

4.29.1D. AEMO must set:

- (a) for a Reserve Capacity Cycle from the 2019 Reserve Capacity Cycle to the 2023 Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price for a Fixed Price Facility during a Peak Fixed Price Reserve Capacity Cycle, which for the Fixed Price Facility is:
 - i. for the first Reserve Capacity Cycle for which a Facility is classified as a Fixed Price Facility, the Reserve Capacity Price divided by 12; and
 - ii. for each subsequent Fixed Price Reserve Capacity Cycle for the Fixed Price Facility, the value calculated in accordance with the following formula divided by 12:

$$FRCP = FRCP_{[previous]} \times \max(1, (1 + CPI))$$

where:

1. FRCP is the Facility Monthly Peak Reserve Capacity Price for the Fixed Price Facility in the current Peak Fixed Price Reserve Capacity Cycle for that Fixed Price Facility;
2. $FRCP_{[previous]}$ is the Facility Monthly Peak Reserve Capacity Price for the Fixed Price Facility in the previous Peak Fixed Price Reserve Capacity Cycle for that Fixed Price Facility; and
3. CPI is the latest decimal value of the published annual percentage change in the Reserve Bank of Australia's Statement of Monetary Policy for the Australian Consumer Price Index forecast for June of Year 3 of the relevant Fixed Price Reserve Capacity Cycle, or if that value is not available, the mid-point of the Reserve Bank of Australia's latest decimal value of the published target range of

inflation, at the time AEMO undertakes the calculation in clause 4.29.2A;

- (b) for the 2024 Reserve Capacity Cycle, the ~~Facility Monthly Peak Reserve Capacity Price Fixed Daily Peak Reserve Capacity Price~~ for a Fixed Price Facility or Fixed Price Component during a Peak Fixed Price Reserve Capacity Cycle for the Fixed Price Facility or Fixed Price Component, which is the ~~Peak Reserve Capacity Price divided by 12 Floating Daily Peak Reserve Capacity Price~~; and
- (c) for a Reserve Capacity Cycle from the 2025 Reserve Capacity Cycle onwards the Fixed Daily Peak Reserve Capacity Price for a Fixed Price Facility or a Fixed Price Component during a Peak Fixed Price Reserve Capacity Cycle for the Fixed Price Facility or Fixed Price Component, which is:
- i. for the first Reserve Capacity Cycle for which a Facility is classified as a Fixed Price Facility or a Separately Certified Component is classified as a Fixed Price Component, the Floating Daily Peak Reserve Capacity Price; and
 - ii. for the second and third Peak Fixed Price Reserve Capacity Cycles for the Fixed Price Facility or Fixed Price Component:

$$\text{FDPRCP}_{ey} = \frac{\text{FDPRCP}_{ey-1} \times \text{TDCM}_{ey-1}}{\text{TDCM}_{ey}} \times (1 + \max(0, \text{ForecastCPI}_{ey}))$$

$$\text{FDPRCP}_{cy} = \frac{\text{FDPRCP}_{cy-1} \times \text{TDCY}_{cy-1}}{\text{TDCY}_{cy}} \times (1 + \max(0, \text{ForecastCPI}_{cy}))$$

where:

1. FDPRCP_{cy-1} is Fixed Daily Peak Reserve Capacity Price for the Fixed Price Facility or Fixed Price Component in the previous Reserve Capacity Cycle;
 2. ~~TDCM_{ey-1}~~ ~~TDCY_{cy-1}~~ is the number of Trading Days in the relevant Capacity Year for the previous Reserve Capacity Cycle;
 3. ForecastCPI_{cy} is the value determined in accordance with clause 4.29.2(a); and
 4. ~~TDCM_{ey}~~ ~~TDCY_{cy}~~ is the number of Trading Days in the relevant Capacity Year for the current Reserve Capacity Cycle.
- iii. for each subsequent Peak Fixed Price Reserve Capacity Cycle for the Fixed Price Component:

$$\text{FDPRCP}_{ey} = \frac{\text{FDPRCP}_{ey-1} \times \text{TDCM}_{ey-1}}{\text{TDCM}_{ey}} \times (1 + \max(0, \text{ForecastCPI}_{ey}) + \max(0, \text{ActualCPI}_{ey-2}) - \max(0, \text{ForecastCPI}_{ey-2}))$$

$$\text{FDPRCP}_{cy} = \frac{\text{FDPRCP}_{cy-1} \times \text{TDCY}_{cy-1}}{\text{TDCY}_{cy}} \times (1 + \max(0, \text{ForecastCPI}_{cy}) + \max(0, \text{ActualCPI}_{cy-2}) - \max(0, \text{ForecastCPI}_{cy-2}))$$

where:

1. FDPRCP_{cy-1} is the Fixed Daily Peak Reserve Capacity Price for the Fixed Price Facility or Fixed Price Component in the previous Reserve Capacity Cycle;
2. TDCM_{cy-1} ~~TDCY_{cy-1}~~ is the number of Trading Days in the relevant Capacity Year for the previous Reserve Capacity Cycle;
3. ForecastCPI_{cy} is the value determined in accordance with clause 4.29.2(a);
4. ActualCPI_{cy-2} is the value determined in accordance with clause 4.29.2(c);
5. $\text{ForecastCPI}_{cy-2}$ is the value determined in accordance with clause 4.29.2(b); and
6. TDCM_{cy} ~~TDCY_{cy}~~ is the number of Trading Days in the relevant Capacity Year for the current Reserve Capacity Cycle.

...

Explanatory Note

Clause 4.29.1H is amended to standardise the variable name used for the number of Trading Days in a Capacity Year (TDCY).

4.29.1H. The Fixed Daily Flexible Reserve Capacity Price for a Fixed Price Component during a Flexible Fixed Price Reserve Capacity Cycle for the Fixed Price Component is:

- (a) for the first Reserve Capacity Cycle for which a Separately Certified Component is classified as a Fixed Price Component, the Floating Daily Flexible Reserve Capacity Price; and
- (b) for the second and third Flexible Fixed Price Reserve Capacity Cycles for the Fixed Price Component:

$$\text{FDFRCP}_{ey} = \frac{\text{FDFRCP}_{ey-1} \times \text{TDCM}_{ey-1}}{\text{TDCM}_{ey}} \times (1 + \max(0, \text{ForecastCPI}_{ey}))$$

$$\text{FDFRCP}_{cy} = \frac{\text{FDFRCP}_{cy-1} \times \text{TDCY}_{cy-1}}{\text{TDCY}_{cy}} \times (1 + \max(0, \text{ForecastCPI}_{cy}))$$

where:

- i. FDFRCP_{cy-1} is the Fixed Daily Flexible Reserve Capacity Price for the Fixed Price Component in the previous Reserve Capacity Cycle;
 - ii. ~~TDCM_{ey-1}~~-~~TDCY_{cy-1}~~ is the number of Trading Days in the relevant Capacity Year for the previous Reserve Capacity Cycle;
 - iii. ForecastCPI_{cy} is the consumer price index value determined in accordance with clause 4.29.2(a); and
 - iv. ~~TDCM_{ey}~~-~~TDCY_{cy}~~ is the number of Trading Days in the relevant Capacity Year for the current Reserve Capacity Cycle; and
- (c) for each subsequent Flexible Fixed Price Reserve Capacity Cycle for the Fixed Price Component:

$$\begin{aligned}
 \text{FDFRCP}_{cy} &= \frac{\text{FDFRCP}_{cy-1} \times \text{TDCM}_{cy-1}}{\text{TDCM}_{cy}} \times (1 + \max(0, \text{ForecastCPI}_{cy}) \\
 &\quad + \max(0, \text{ActualCPI}_{cy-2}) - \max(0, \text{ForecastCPI}_{cy-2})) \\
 \text{FDFRCP}_{cy} &= \frac{\text{FDFRCP}_{cy-1} \times \text{TDCY}_{cy-1}}{\text{TDCY}_{cy}} \times (1 + \max(0, \text{ForecastCPI}_{cy}) \\
 &\quad + \max(0, \text{ActualCPI}_{cy-2}) - \max(0, \text{ForecastCPI}_{cy-2}))
 \end{aligned}$$

where:

- i. FDFRCP_{cy-1} is the Fixed Daily Flexible Reserve Capacity Price for the Fixed Price Component in the previous Reserve Capacity Cycle;
- ii. ~~TDCM_{ey-1}~~-~~TDCY_{cy-1}~~ is the number of Trading Days in the relevant Capacity Year for the previous Reserve Capacity Cycle;
- iii. ForecastCPI_{cy} is the value determined in accordance with clause 4.29.2(a);
- iv. ActualCPI_{cy-2} is the value determined in accordance with clause 4.29.2(c);
- v. ForecastCPI_{cy-2} is the value determined in accordance with clause 4.29.2(b); and
- vi. ~~TDCM_{ey}~~-~~TDCY_{cy}~~ is the number of Trading Days in the relevant Capacity Year for the current Reserve Capacity Cycle.

...

Explanatory Note

Clause 4.29.2B is amended to implement the calculation of daily capacity prices from the 2024 Reserve Capacity Cycle onwards.

4.29.2B. For each Reserve Capacity Cycle AEMO must determine the following information in accordance with this section 4.29:

- (a) for a Reserve Capacity Cycle from the 2019 Reserve Capacity Cycle to the 2023 Reserve Capacity Cycle:
 - i. the Facility Monthly Peak Reserve Capacity Price for a Transitional Facility if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle;
 - ii. the Facility Monthly Peak Reserve Capacity Price for each Fixed Price Facility for which the Reserve Capacity Cycle is a Peak Fixed Price Reserve Capacity Cycle;
 - iii. the Facility Monthly Peak Reserve Capacity Price for all other Facilities;
- (b) for the 2024 Reserve Capacity Cycle:
 - i. ~~if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Facility Monthly Peak Reserve Capacity Price~~ the Entity Daily Peak Reserve Capacity Price for each Transitional Facility or Transitional Component;
 - ii. ~~the Facility Monthly Peak Reserve Capacity Price~~ Fixed Daily Peak Reserve Capacity Price for each Fixed Price Facility and each Fixed Price Component for which the Reserve Capacity Cycle is a Peak Fixed Price Reserve Capacity Cycle;
 - iii. ~~the Facility Monthly Peak Reserve Capacity Price~~ Entity Daily Peak Reserve Capacity Price for all other Facilities and Separately Certified Components;
- (c) for a Reserve Capacity Cycle from the 2025 Reserve Capacity Cycle onwards:
 - i. if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Entity Daily Peak Reserve Capacity Price for each Transitional Facility or Transitional Component;
 - ii. the Fixed Daily Peak Reserve Capacity Price for each Fixed Price Facility and each Fixed Price Component for which the Reserve Capacity Cycle is a Peak Fixed Price Reserve Capacity Cycle;
 - iii. the Entity Daily Peak Reserve Capacity Price for all other Facilities and Separately Certified Components;
 - iv. if the Reserve Capacity Cycle is a Transitional Reserve Capacity Cycle, the Entity Daily Flexible Reserve Capacity Price for each Transitional Component;
 - v. the Fixed Daily Flexible Reserve Capacity Price for each Fixed Price Component for which the Reserve Capacity Cycle is a Flexible Fixed Price Reserve Capacity Cycle;
 - vi. the Entity Daily Flexible Reserve Capacity Price for all other Separately Certified Components; and

- vii. the Entity Daily Flexible Reserve Capacity Price for all Demand Side Programmes.

Explanatory Note

Clause 4.29.3 is amended to implement the calculation of daily capacity prices from the 2024 Reserve Capacity Cycle onwards and make the references to the relevant Trading Day consistent.

- 4.29.3. AEMO must determine the following information in time for settlement of each Trading Day d:
- ~~(a) the Facility Monthly Peak Reserve Capacity Price for each for each Demand Side Programme, Non-Scheduled Facility, and Separately Certified Component applying during that Trading Month;~~
 - (a) the Entity Daily Peak Reserve Capacity Price for each Demand Side Programme, Non-Scheduled Facility, and Separately Certified Component applying during Trading Day d;
 - (aA) ~~[Blank]the Facility Daily Peak Reserve Capacity Price for each Demand Side Programme, Non-Scheduled Facility, and Separately Certified Component applying during that Trading Day;~~
 - (b) the Targeted Reserve Capacity Cost for ~~that Trading Day~~ Trading Day d as defined in clause 4.28.3;
 - (c) the Shared Reserve Capacity Cost for ~~that Trading Day~~ Trading Day d as defined in clause 4.28.4;
 - (cB) the Reserve Capacity Security Compensation Amount for ~~that Trading Day~~ Trading Day d as defined in clause 4.28.4D;
 - (d) for each Market Participant p and for Trading Day d:
 - i. the quantity of Peak Capacity Credits (including Peak Capacity Credits from Facilities subject to NCESS Contracts) for each Facility acquired by AEMO;
 - ia. the quantity of Peak Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Separately Certified Component acquired by AEMO;
 - ii. the quantity of Peak Capacity Credits for each Demand Side Programme ~~for Trading Day d~~;
 - iii. [Blank]
 - iv. the quantity of Peak Capacity Credits for each Facility traded bilaterally in accordance with section 4.30;
 - ivA. the quantity of Peak Capacity Credits for each Separately Certified Component traded bilaterally in accordance with section 4.30;
 - v. the Individual Reserve Capacity Requirement for each Market Participant for that Trading Month in which Trading Day d falls; and

- vi. the total Capacity Cost Refund to be paid by the Market Participant to AEMO for all Trading Intervals in Trading Day d;
- (dA) for each Market Participant, the sum over all of Market Participant p's Intermittent Loads, deemed to be Intermittent Loads under clause 1.48.2, of the Intermittent Load Refund payable to AEMO by Market Participant p in respect of each of its Intermittent Loads for Trading Day d; and
- (e) for each Supplementary Capacity Contract:
 - i. the net payment to be made by AEMO under that contract for the Trading Day d; and
 - ii. to whom the payment is to be made.

4.29.4. [Blank]

Explanatory Note

Clause 4.29.5 is amended to implement the calculation of daily capacity prices.

- 4.29.5. Where a Facility first enters service prior to 1 October of Year 3 of a Reserve Capacity Cycle and Reserve Capacity Obligations apply to the Facility in accordance with clause 4.1.26, then for the period between commencement of the Reserve Capacity Obligations for the Facility and up to the start of the Trading Day on 1 October of Year 3 of that Reserve Capacity Cycle, ~~the Facility Monthly Peak Reserve Capacity Price for the Facility or Separately Certified Component for that period is equal to the Reserve Capacity Price for the Capacity Year immediately preceding 1 October of Year 3 of that Reserve Capacity Cycle divided by 12~~ the Entity Daily Peak Reserve Capacity Price for the Facility or a Separately Certified Component of the Facility for that period is equal to the Floating Daily Peak Reserve Capacity Price for the Capacity Year immediately preceding 1 October of Year 3 of the Reserve Capacity Cycle.

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7.11B. Determination of Market Clearing Prices

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Explanatory Note:

Clause 7.11B.1B is amended to reorder the options for determining a replacement Market Schedule when:

- the Dispatch Algorithm has failed to determine an outcome for a Dispatch Interval; or
- AEMO has determined that a Dispatch Interval is an Affected Dispatch Interval.

AEMO has found that often these issues are caused by erroneous or failed data for which replacement or backup data can be sourced. If suitable replacement data is available, a re-run of the Dispatch Algorithm with corrected inputs will produce a replacement Market Schedule that best reflects the market conditions in effect at the time of dispatch and so will provide the most efficient prices for settlement. However, currently clause 7.11B.1B only allows AEMO to use this option if it cannot identify an earlier 'forecast' Market Schedule that does not include manifestly incorrect data.

The proposed change will enable AEMO to determine replacement Market Schedules with corrected inputs in preference to choosing historically calculated Market Schedules, which will often not have the relevant up to date information that is used by WEMDE for primary Dispatch Intervals.

The proposed change benefits the State Electricity Objective by allowing AEMO to determine more accurate replacement Market Schedules, with more efficient Market Clearing Prices, if re-running the Dispatch Algorithm with corrected inputs is a viable option.

Clause 7.11C.1 is amended to reflect the reordering of the options listed in clause 7.11B.1B.

7.11B.1B. For the purposes of clauses 7.11B.1A and 7.11C.2, AEMO must identify a replacement Market Schedule containing the Dispatch Interval as follows:

- ~~(a) — if the Dispatch Interval has been included in a previous Dispatch Schedule, then AEMO must identify the most recent Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data;~~
- ~~(b) — if AEMO is unable to identify a Dispatch Schedule in accordance with clause 7.11B.1B(a), then AEMO must identify the most recent Pre-Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data;~~
- ~~(bA) — if AEMO is unable to identify a Market Schedule under clauses 7.11B.1B(a) or 7.11B.1B(b), then AEMO must, if it has sufficient information, use the Dispatch Algorithm with corrected Dispatch Inputs to determine a replacement Market Schedule for the relevant Dispatch Interval that does not include manifestly incorrect data, in accordance with the WEM Procedure referred to in clause 7.11C.1; and~~
- ~~(c) — if AEMO is unable to identify a Market Schedule under clauses 7.11B.1B(a), 7.11B.1B(b) or 7.11B.1B(bA), then AEMO must identify the most recently determined Dispatch Schedule or Pre-Dispatch Schedule that contains the Dispatch Interval.~~
- (a) — if AEMO has sufficient information, it must use the Dispatch Algorithm with corrected Dispatch Inputs to determine and identify a Market Schedule for the relevant Dispatch Interval that does not include manifestly incorrect data, in accordance with the WEM Procedure referred to in clause 7.11C.1;

- (b) if AEMO is unable to identify a Market Schedule under clause 7.11B.1B(a), then AEMO must identify the most recent Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data;
- (c) if AEMO is unable to identify a Market Schedule under clauses 7.11B.1B(a) or 7.11B.1B(b), then AEMO must identify the most recent Pre-Dispatch Schedule, if available, that contains the Dispatch Interval and which AEMO reasonably considers does not include manifestly incorrect data; and
- (d) if AEMO is unable to identify a Market Schedule under clauses 7.11B.1B(a), 7.11B.1B(b) or 7.11B.1B(c), then AEMO must identify the most recently determined Dispatch Schedule or Pre-Dispatch Schedule that contains the Dispatch Interval.

...

7.11C. Corrections to Price Determinations and Intervention Pricing

7.11C.1. AEMO must develop procedures for the identification of Affected Dispatch Intervals within the timeframes contemplated under clause 7.11C.2, and must document in a WEM Procedure:

- (a) the conditions or circumstances that would identify a Dispatch Interval as an Affected Dispatch Interval;
- (b) the conditions and circumstances that would require AEMO to determine a replacement Market Schedule under ~~clause 7.11B.1B(bA)~~ clause 7.11B.1B(a); and
- (c) the process AEMO must follow to determine a replacement Market Schedule under ~~clause 7.11B.1B(bA)~~ clause 7.11B.1B(a).

...

7.11D. Real-Time Market Suspension

...

Explanatory Note

Following a recent Real-Time Market suspension, AEMO raised with DEED that a two-hour notice period before the return to normal market operation may be unnecessarily long for brief market suspensions. AEMO has suggested that a one-hour notice period may be more suitable.

Clause 7.11D.3(a)(i) is amended to reduce the minimum notice period for the lifting of a Real-Time Market suspension from two hours to one hour. This will provide AEMO with more flexibility and allow for a shorter notice period in situations where it may be more appropriate.

Providing for the Real-Time Market to return to normal as soon as practicable, would allow generators to be dispatched based on price and ensure that the price of energy and Essential System Services return to being cost-reflective, aligning with the State Electricity Objective.

DEED is seeking stakeholder feedback on whether a one-hour minimum notice period for lifting a Real-Time Market suspension is appropriate.

7.11D.3. Where AEMO determines, in its reasonable opinion, it is practicable to resume the operation of the Real-Time Market it must:

- (a) issue a Market Advisory which must include:
 - i. the time from which the Real-Time Market suspension will be lifted which must be the commencement of a Trading Interval and provide a notice period of not less than ~~two hours~~ one hour; and
 - ii. where applicable, any additional actions to those specified in the WEM Procedure under clause 7.11D.4 required of Market Participants leading up to the time of the suspension being lifted; and
- (b) where relevant, resume the use of the Dispatch Algorithm in the Central Dispatch Process from the time described in clause 7.11D.3(a)(i).

...

9.8. Settlement Calculations - Reserve Capacity

...

Explanatory Note

Clause 9.8.3. is amended, and clauses 9.8.3A and 9.8.3B inserted, to account for the introduction of daily and component-based capacity prices in settlement from 1 October 2026.

9.8.3. For the purposes of clause 9.8.2, Capacity_Provider_Payment(p,d) for Market Participant p for Trading Day d is:

$$\begin{aligned}
 \text{Capacity_Provider_Payment}(p, d) &= \text{Capacity_Payments}(p, d) - \text{Intermittent_Load_Refund}(p, d) \\
 &+ \text{Supplementary_Capacity_Payment}(p, d) \\
 &- \text{Capacity_Cost_Refund}(p, d) + \text{Over_Allocation_Payment}(p, d)
 \end{aligned}$$

where:

(a) [Blank]

(b) ~~$$\text{Capacity_Payments}(p, d) = \sum_{f \in F} ((CC(f, d) - \text{Facility_CCA}(f, d)) \times \text{FDRCP}(f, d))$$~~

~~where:~~

- ~~i. F is the set of all Facilities registered to Market Participant p in Trading Day d and f is a Facility within the set;~~
- ~~ii. CC(f,d) is the number of Capacity Credits assigned to the Facility f, registered to Market Participant p, for the Trading Day d;~~
- ~~iii. Facility_CCA(f,d) is the sum of the Capacity Credits associated with the Facility f, registered to Market Participant p, for the Trading Day d that have been allocated in a Capacity Credit Allocation; and~~

iv. ~~FDRCP(f,d) is the Facility Daily Peak Reserve Capacity Price associated with the Facility f in Trading Day d;~~

(b) Capacity Payments(p,d) is calculated in accordance with clause 9.8.3A;

(c) Intermittent_Load_Refund(p,d) is the total Intermittent Load Refund payable to AEMO by Market Participant p in respect of each of its Intermittent Loads, deemed to be an Intermittent Load under clause 1.48.2, for Trading Day d, as determined in accordance with clause 4.29.3(dA);

(d) Supplementary_Capacity_Payment(p,d) is the net payment to be made by AEMO under a Supplementary Capacity Contract to Market Participant p for Trading Day d, as specified by AEMO in accordance with clause 4.29.3(e)(i);

(e) Capacity_Cost_Refund(p,d) is the Capacity Cost Refund payable to AEMO by Market Participant p in respect of that Market Participant's Capacity Credits for Trading Day d, as specified in clause 4.29.3(d)(vi); and

~~(f) Over_Allocation_Payment(p,d) = max (0, Participant_CCA(p,d) – IRCR(p,d)) × Excess_Allocation_Price(p,d);~~

(f) Over Allocation Payment(p,d) is calculated in accordance with clause 9.8.3B.

~~(g) Participant_CCA(p,d) is the sum of Capacity Credits allocated to Market Participant p in Trading Day d in a Capacity Credit Allocation;~~

~~(h) IRCR(p,d) is the Individual Reserve Capacity Requirement for Market Participant p for the Trading Month in which the Trading Day d falls, expressed in units of MW;~~

~~(i) Excess_Allocation_Price(p,d) = 0, if Participant_CCA(p,d) = 0; and $\frac{\sum_{e \in C} (CCA(e,d) \times FDRCP(f,d))}{\sum_{e \in C} CCA(e)}$ otherwise;~~

~~(j) C is the set of Capacity Credit Allocations made to Market Participant p in Trading Day d and c is a Capacity Credit Allocation within the set; and~~

~~(k) CCA(c,d) is the number of Capacity Credits that have been allocated in a Capacity Credit Allocation associated with the Facility f to Market Participant p in the Trading Day d.~~

9.8.3A. For the purposes of clause 9.8.3, Capacity Payments(p,d) is calculated as:

$$\text{Capacity Payments}(p,d) = \sum_{e \in PCCEntities(p,d)} ((CC(e,d) - CCA(e,d)) \times EDPRCP(e,d))$$

where:

(a) e ∈ PCCEntities(p,d) denotes all:

- i. Separately Certified Components of Scheduled Facilities;
- ii. Separately Certified Components of Semi-Scheduled Facilities;
- iii. Non-Scheduled Facilities; and
- iv. Demand Side Programmes,

registered to Market Participant p on Trading Day d, and e is an entity in that set;

- (b) CC(e,d) is the number of Capacity Credits assigned to entity e for Trading Day d;
- (c) CCA(e,d) is the sum of the Capacity Credits associated with entity e for Trading Day d that have been allocated in Capacity Credit Allocations; and
- (d) EDPRCP(c,d) is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d.

9.8.3B. For the purposes of clause 9.8.3, Over Allocation Payment(p,d) is calculated as:

$$\begin{aligned} \text{Over Allocation Payment}(p, d) &= \max(0, \text{Participant CCA}(p, d) - \text{IRCR}(p, d)) \\ &\times \text{Excess Allocation Price}(p, d) \end{aligned}$$

where:

- (a) Participant CCA(p,d) is the sum of Capacity Credits allocated to Market Participant p in Trading Day d in Capacity Credit Allocations;
- (b) IRCR(p,d) is the Individual Reserve Capacity Requirement for Market Participant p for the Trading Month in which Trading Day d falls, expressed in units of MW; and
- (c) Excess Allocation Price(p,d) is zero if Participant CCA(p,d)=0, and otherwise:

$$\begin{aligned} \text{Excess Allocation Price}(p, d) &= \frac{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (CCA(c, e, p, d) \times EDPRCP(e, d)))}{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (CCA(c, e, p, d)))} \end{aligned}$$

where:

- i. C(p,d) is the set of Capacity Credit Allocations made to Market Participant p in Trading Day d and c is a Capacity Credit Allocation within the set;
- ii. e ∈ PCCEntities(d) denotes all registered:
 - 1. Separately Certified Components of Scheduled Facilities;
 - 2. Separately Certified Components of Semi-Scheduled Facilities;
 - 3. Non-Scheduled Facilities; and
 - 4. Demand Side Programmes,

on Trading Day d;

iii. CCA(c,e,p,d) is the number of Capacity Credits associated with entity e that have been allocated to Market Participant p in Capacity Credit Allocation c in Trading Day d; and

iv. EDPRCP(e,d) is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d.

...

11. Glossary

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Excess Allocation Price: For a Market Participant is as calculated in accordance with ~~clause 9.8.3(i)~~ clause 9.8.3B(c).

...

~~**Facility Daily Peak Reserve Capacity Price:** The Facility Monthly Peak Reserve Capacity Price for a Facility as determined in accordance with clause 4.29.1A, divided by the number of Trading Days in the relevant Trading Month.~~

...

Explanatory Note

Appendix 10 sets out the method for determining the Relevant Demand of a Demand Side Programme (DSP), which is the baseline level of Injection or Withdrawal for a Trading Interval against which the dispatch performance of the DSP is assessed. Several amendments to the appendix are proposed to correct errors and clarify the calculations. The amendments do not include any substantive changes to the intended method, but are needed to ensure that the calculations work correctly and the appendix can achieve its policy intent.

The main issues addressed by the amendments are as follows:

- The calculations of Unadjusted Baseline Energy in step 2.1 and Adjustment Window Energy in step 3.2 use the Demand Side Programme Load of the DSP for a set of Trading Intervals falling on days prior to the day of the dispatch event. However, Demand Side Programme Load should not be used for these calculations, because the Associated Loads of a DSP can vary over time. The baseline used to determine the Relevant Demand for a Trading Interval t should be based on the historical Sent Out Metered Schedules of the Non-Dispatchable Loads associated to the DSP in Trading Interval t, not a potentially different set of Non-Dispatchable Loads that were associated to the DSP in the past. The appendix is amended to use the correct set of Associated Loads in these calculations.
- The Adjustment Window(f,d), Adjustment Window Energy(f,d) and Average Unadjusted Baseline Energy(f,d) calculations all indicate that the values are determined for a DSP and an Event Day. However, while the Adjustment Window for a DSP will be the same for each Trading Interval in an Event Day, the other two values may differ across the Event Day, because they depend on the Associated Loads of the DSP (which can change at 8:00 AM on an Event Day when a new Trading Day begins). Steps 3.2 and 3.3 are redrafted to clarify that the values are determined for the specific DSP f and Trading Interval t, to ensure the correct Associated Loads are considered.

The amendments also address the following minor issues:

- The references to specific Trading Intervals in the appendix can be confusing and/or incorrect. For example, the reference in step 2.1 to “Trading Interval t of Selected Day i” is incorrect, because a Trading Interval is a specific half-hour period on a specific day, and Trading Interval t in this appendix is the Trading Interval for which the Relevant Demand is being calculated. The text is amended to reflect the intent, i.e. the Trading Interval on the Selected Day that commences at the same time of day as Trading Interval t.
- The Appendix requires AEMO to calculate a Baseline Adjustment even where AEMO is required to use the Unadjusted Baseline Method for a DSP. The appendix is amended to skip the Baseline Adjustment calculations in step 3 if they are not required to determine the Relevant Demand.
- Step 2.2 calculates the Unadjusted Baseline Energy for an Associated Load of a DSP. However, this step is not part of the process for determining the Relevant Demand of a DSP – it will be used from 1 October 2027 to determine an input to the Peak Individual Reserve Capacity Requirement calculations in Appendix 5. A Glossary definition of Unadjusted Baseline Energy is scheduled to commence on 1 October 2027.

The presence of this step in the middle of the steps used to calculate Relevant Demand is confusing, and the name “Unadjusted Baseline Energy” is very similar to the name of the DSP-level value calculated in step 2.1. To address these concerns, the proposed amendments:

- remove the step from the appendix until 1 October 2027 when it is first required;
 - reinsert the step at the end of the appendix on 1 October 2027, along with an explanation of how and when it is used; and
 - rename the value produced by the step to Associated Load Baseline Energy, to clarify its purpose and avoid confusion with the value produced in step 2.1.
- The references to clause 4.26.2CC(b) in steps 1.1 and 1.3 are amended to refer to the correct clause (4.26.2CD).

Other minor amendments include:

- additional text to clarify how AEMO is required to use the appendix;
- adding “subject to clause 4.26.2CD” to steps 1.5 and 1.7, because the option for a Market Participant to apply for a day to be excluded from its Relevant Demand calculations under clauses 4.26.2CB-4.26.2CD applies to both Business Days and Non-Business Days;
- ensuring that terms without Glossary definitions shown in title case have definitions in the introduction section (e.g. Selected Day and Adjustment Window);
- replacing the term “MQ” with the defined term Sent Out Metered Schedule; and
- renaming the variables Adjustment Window Energy (step 3.2) and Average Unadjusted Baseline Energy (step 3.3) to AdjustmentWindowActualEnergy(f,t) and AdjustmentWindowBaselineEnergy(f,t) respectively, to better reflect their purpose.

Consequential changes to the appendix, proposed to commence on 1 October 2027, are included in Schedule 3 of this exposure draft.

~~Appendix 10: Relevant Demand Determination~~

~~This Appendix sets out the method for determining the Relevant Demand for a Demand Side Programme f in a Trading Interval t where one of the following applies:~~

- ~~• The Demand Side Programme is subject to a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity determined under clause 7.13.5; or~~

- ~~The Demand Side Programme is undergoing a Reserve Capacity Test under section 4.25.~~

~~An “Event Day” for a Demand Side Programme is a day in which one or more DSP Dispatch Events occur for that Demand Side Programme.~~

~~The “Baseline Window” for a Demand Side Programme on an Event Day d is the 50 days from day d-50 to day d-1.~~

~~1. Determine Selected Days for a Demand Side Programme~~

~~Determine the “Selected Days” for a Demand Side Programme f for Event Day d using the following steps:~~

~~If Event Day d is a Business Day:~~

~~1.1 Subject to clause 4.26.2CC(b), select the ten most recent days in Demand Side Programme f’s Baseline Window for Event Day d, that are a Business Day and not a previous Event Day. If fewer than ten days are identified, then select as many days that are Business Days and not previous Event Days as possible.~~

~~1.2 If between five and ten days (inclusive) have been selected, go to step 1.4.~~

~~1.3 If fewer than five days have been selected in step 1.1, then subject to clause 4.26.2CC(b), keep adding the next most recent day(s) in the Baseline Window that is (or are) a Business Day and a previous Event Day until five days have been selected.~~

~~1.4 Days selected under steps 1.2 or 1.3, as applicable, are the Selected Days for Demand Side Programme f on Event Day d.~~

~~If Event Day d is a Non-Business Day:~~

~~1.5 Select the four most recent days in Demand Side Programme f’s Baseline Window for Event Day d that are Non-Business Days and not previous Event Days. If fewer than four days are identified, then select as many days that are Non-Business Days and not previous Event Days as possible.~~

~~1.6 If four days have been selected, go to step 1.8.~~

~~1.7 If fewer than four days have been selected in step 1.5, then keep adding the next most recent day(s) in the Baseline Window that is (or are) a Non-Business Day and an Event Day until a total of four days has been selected.~~

~~1.8 Days selected under steps 1.6 or 1.7, as applicable, are the Selected Days for Demand Side Programme f on Event Day d.~~

~~2. Determine Unadjusted Baseline Energy~~

~~2.1 Calculate the **Unadjusted Baseline Energy(f, t(d))** of Demand Side Programme f for Trading Interval t on Event Day d as:~~

$$\text{Unadjusted Baseline Energy}(f, t(d)) = \frac{1}{N(f, d)} \times \sum_{i \in \text{Selected Days}(f, d)} \text{DSPLoad}(f, t(i))$$

~~where:~~

- ~~(a) N(f, d) is the number of Selected Days for Demand Side Programme f on Event Day d that contains Trading Interval t as determined in step 1.4 or 1.8 as relevant;~~
- ~~(b) DSPLoad(f, t(i)) is the Demand Side Programme Load for Demand Side Programme f in Trading Interval t of Selected Day i, as determined under clause 9.5.4; and~~
- ~~(c) i ∈ Selected Days(f, d) denotes the Selected Days for Demand Side Programme f on Event Day d that contains Trading Interval t as determined in steps 1.4 or 1.8 as relevant.~~

~~2.2 Calculate the **Unadjusted Baseline Energy(l(f), t(d))** of Associated Load l of Demand Side Programme f for Trading Interval t on Event Day d as:~~

$$\text{Unadjusted Baseline Energy}(l(f), t(d)) = \frac{1}{N(f, d)} \times \sum_{i \in \text{Selected Days}(f, d)} \text{MQ}(l(f), t(i))$$

~~where:~~

- ~~(a) N(f, d) is the number of Selected Days for Demand Side Programme f on Event Day d that contains Trading Interval t as determined in step 1.4 or 1.8 as relevant;~~
- ~~(b) MQ(l(f), t(i)) denotes the non-loss adjusted metered Withdrawal or Injection (as relevant) of Associated Load l(f) in Trading Interval t as determined from Meter Data Submissions; and~~
- ~~(c) i ∈ Selected Days(f, d) denotes the Selected Days for Demand Side Programme f on Event Day d that contains Trading Interval t as determined in steps 1.4 or 1.8 as relevant.~~

~~3. Determine Adjustment~~

~~3.1 Determine the Adjustment Window(f, d) for Demand Side Programme f for Event Day d as the set of two Trading Intervals immediately preceding the Trading Interval in which AEMO either:~~

- ~~(a) issues the first Dispatch Instruction under clause 7.6.5A with a non-zero quantity to Demand Side Programme f; or~~
- ~~(b) notifies a Market Participant that Demand Side Programme f will be subject to a Reserve Capacity Test in accordance with clause 4.25.9(dA).~~

For avoidance of doubt, AEMO must determine a single Adjustment Window for a given Event Day for a given Demand Side Programme.

3.2 Calculate the **Adjustment Window Energy(f,d)** for Demand Side Programme f on Event Day d as the average energy consumption or production of the Demand Side Programme, during the Adjustment Window, determined as:

$$\text{Adjustment Window Energy}(f,d) = \frac{1}{2} \sum_{t \in \text{Adjustment Window}(f,d)} \text{DSPLoad}(f,t(d))$$

where:

- (a) $\text{DSPLoad}(f,t(d))$ is the Demand Side Programme Load of Demand Side Programme f on Trading Interval t on Event Day d as determined under clause 9.5.4; and
- (b) $t \in \text{Adjustment Window}(f,d)$ denotes the set of two Trading Intervals in the Adjustment Window for Demand Side Programme f on Event Day d as determined in step 3.1.

3.3 Calculate the **Average Unadjusted Baseline Energy(f,d)** for Demand Side Programme f on Event Day d as the average Unadjusted Baseline Energy of Demand Side Programme f, during the Adjustment Window, determined as:

$$\begin{aligned} &\text{Average Unadjusted Baseline Energy}(f,d) \\ &= \frac{1}{2} \sum_{t \in \text{Adjustment Window}(f,d)} \text{Unadjusted Baseline Energy}(f,t(d)) \end{aligned}$$

where:

- (a) $\text{Unadjusted Baseline Energy}(f,t(d))$ is the Unadjusted Baseline Energy of the Demand Side Programme f in Trading Interval t on Event Day d as determined step 2.1; and
- (b) $t \in \text{Adjustment Window}(f,d)$ denotes the set of two Trading Intervals in the Adjustment Window for Demand Side Programme f on Event Day d determined in step 3.1.

3.4 Calculate the **Baseline Adjustment(f,t(d))** for Demand Side Programme f in Trading Interval t on Event Day d as follows:

$$\begin{aligned} &\text{Baseline Adjustment}(f,t(d)) = \\ &\text{Min} \left(\frac{0.2 \times |\text{Average Unadjusted Baseline Energy}(f,d)|}{\text{Max} \left(\frac{-2 \times |\text{Average Unadjusted Baseline Energy}(f,d)|}{\text{Adjustment Window Energy}(f,d) - \text{Average Unadjusted Baseline Energy}(f,d)} \right)} \right) \end{aligned}$$

where:

- (a) $\text{Average Unadjusted Baseline Energy}(f,d)$ is the Average Unadjusted Baseline Energy for Demand Side Programme f on Event Day d as determined in step 3.3; and

(b) ~~Adjustment Window Energy(f,d) is the Adjustment Window Energy for Demand Side Programme f on Event Day d as determined in step 3.2.~~

3.5 ~~Calculate the **Baseline Energy(f,t(d))** for the Demand Side Programme f in Trading Interval t (on Event Day d) as:~~

$$\begin{aligned} \text{Baseline Energy}(f,t(d)) \\ = \text{Unadjusted Baseline Energy}(f,t(d)) + \text{Baseline Adjustment}(f,t(d)) \end{aligned}$$

where:

(a) ~~Unadjusted Baseline Energy(f,t(d)) is the Unadjusted Baseline Energy of the Demand Side Programme f in Trading Interval t on Event Day d as determined in step 2.1; and~~

(b) ~~Baseline Adjustment(f,t(d)) is the adjustment applied to Demand Side Programme f in Trading Interval t on Event Day d as determined in step 3.4.~~

~~4. Calculate Relevant Demand~~

4.1 ~~Calculate the **Relevant Demand(f,t(d))** for the Demand Side Programme f in Trading Interval t on Event Day d as follows:~~

(a) ~~the Baseline Energy(f, t(d)) calculated in step 3.5 multiplied by 2 to convert it to a MW quantity, if the relevant Market Participant nominated the Adjusted Baseline Method under clause 2.29.5AG(a); or~~

(b) ~~the Unadjusted Baseline Energy(f, t(d)) calculated in step 2.1 multiplied by 2 to convert it to a MW quantity, if the relevant Market Participant nominated the Unadjusted Baseline Method under clause 2.29.5AG(b).~~

Appendix 10: Relevant Demand Determination

This Appendix sets out the method for determining the Relevant Demand of a Demand Side Programme in a Trading Interval in which one of the following applies:

- the Demand Side Programme is subject to a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity determined under clause 7.13.5; or
- the Demand Side Programme is undergoing a Reserve Capacity Test under section 4.25.

In this Appendix:

- a reference to a step is to the process step so numbered in this Appendix;
- steps are to be performed sequentially unless otherwise stated;
- an “Event Day” for a Demand Side Programme is a day in which one or more DSP Dispatch Events occur for that Demand Side Programme;

- the “Baseline Window” for a Demand Side Programme on an Event Day d is the 50 days from day d-50 to day d-1;
- “Selected Day” has the meaning given in step 1; and
- “Adjustment Window” has the meaning given in step 3.1.

AEMO must perform steps 1 to 4 to determine the Relevant Demand of a Demand Side Programme f for a Trading Interval t that occurs on Event Day d.

Step 1. Determine Selected Days

Determine the “Selected Days” for Demand Side Programme f for Event Day d using the following steps:

If Event Day d is a Business Day:

- 1.1 Subject to clause 4.26.2CD, select the ten most recent days in Demand Side Programme f’s Baseline Window for Event Day d, that are a Business Day and not a previous Event Day. If fewer than ten days are identified, then select as many days that are Business Days and not previous Event Days as possible.
- 1.2 If between five and ten days (inclusive) have been selected, go to step 1.4.
- 1.3 If fewer than five days have been selected in step 1.1, then subject to clause 4.26.2CD, keep adding the next most recent day(s) in the Baseline Window that is (or are) a Business Day and a previous Event Day until five days have been selected.
- 1.4 Days selected under steps 1.2 or 1.3, as applicable, are the Selected Days for Demand Side Programme f on Event Day d.

If Event Day d is a Non-Business Day:

- 1.5 Subject to clause 4.26.2CD, select the four most recent days in Demand Side Programme f’s Baseline Window for Event Day d that are Non-Business Days and not previous Event Days. If fewer than four days are identified, then select as many days that are Non-Business Days and not previous Event Days as possible.
- 1.6 If four days have been selected, go to step 1.8.
- 1.7 If fewer than four days have been selected in step 1.5, then subject to clause 4.26.2CD, keep adding the next most recent day(s) in the Baseline Window that is (or are) a Non-Business Day and an Event Day until a total of four days has been selected.
- 1.8 Days selected under steps 1.6 or 1.7, as applicable, are the Selected Days for Demand Side Programme f on Event Day d.

Step 2. Determine Unadjusted Baseline Energy

2.1 Calculate UnadjustedBaselineEnergy(f,t) for Demand Side Programme f for Trading Interval t as:

$$\begin{aligned} & \text{UnadjustedBaselineEnergy}(f, t) \\ &= \frac{1}{N(f, d)} \\ & \times \sum_{s \in \text{SelectedDays}(f, d)} \left(-1 \times \sum_{l \in \text{AssocLoads}(f, t)} \text{SOMS}(l, \text{prevt}(s, t)) \right) \end{aligned}$$

where:

- (a) N(f,d) is the number of Selected Days for Demand Side Programme f on Event Day d as determined in step 1.4 or 1.8 as relevant;
- (b) s∈SelectedDays(f,d) denotes the Selected Days for Demand Side Programme f on Event Day d as determined in steps 1.4 or 1.8 as relevant;
- (c) l∈AssocLoads(f,t) denotes the Associated Loads of Demand Side Programme f in Trading Interval t;
- (d) prevt(s,t) is the Trading Interval in Selected Day s that commences at the same time of day as Trading Interval t; and
- (e) SOMS(l,prevt(s,t)) is the Sent Out Metered Schedule of Associated Load l in Trading Interval prevt(s,t).

2.2 If AEMO is required to use the Unadjusted Baseline Method for Demand Side Programme f for Trading Interval t under clause 2.29.5AH, then go to step 4.

Step 3. Determine Adjusted Baseline Energy

3.1 Determine the “Adjustment Window” for Demand Side Programme f for Event Day d as the set of two Trading Intervals immediately preceding the Trading Interval in which AEMO either:

- (a) issues the first Dispatch Instruction under clause 7.6.5A with a non-zero quantity to Demand Side Programme f; or
- (b) notifies a Market Participant that Demand Side Programme f will be subject to a Reserve Capacity Test in accordance with clause 4.25.9(dA).

For the avoidance of doubt, AEMO must determine a single Adjustment Window for a given Event Day for a given Demand Side Programme.

3.2 Calculate AdjustmentWindowActualEnergy(f,t) for Demand Side Programme f for Trading Interval t as:

$$\begin{aligned} & \text{AdjustmentWindowActualEnergy}(f, t) \\ &= \frac{1}{2} \times \sum_{\text{awt} \in \text{AdjustmentWindow}(f, d)} \left(-1 \times \sum_{l \in \text{AssocLoads}(f, t)} \text{SOMS}(l, \text{awt}) \right) \end{aligned}$$

where:

- (a) awt ∈ AdjustmentWindow(f,d) denotes the Trading Intervals in the Adjustment Window for Demand Side Programme f for Event Day d as determined in step 3.1;
- (b) l ∈ AssocLoads(f,t) denotes the Associated Loads of Demand Side Programme f in Trading Interval t; and
- (c) SOMS(l,awt) is the Sent Out Metered Schedule of Associated Load l in Trading Interval awt.

3.3 Calculate AdjustmentWindowBaselineEnergy(f,t) for Demand Side Programme f for Trading Interval t as:

$$\begin{aligned}
 & \text{AdjustmentWindowBaselineEnergy}(f, t) \\
 & \equiv \frac{1}{2} \\
 & \times \frac{\sum_{awt \in \text{AdjustmentWindow}(f,d)} \left(\frac{1}{N(f,d)} \right)}{\sum_{s \in \text{SelectedDays}(f,d)} \left(-1 \times \sum_{l \in \text{AssocLoads}(f,t)} \text{SOMS}(l, \text{prevt}(s, awt)) \right)}
 \end{aligned}$$

where:

- (a) awt ∈ AdjustmentWindow(f,d) denotes the Trading Intervals in the Adjustment Window for Demand Side Programme f for Event Day d as determined in step 3.1;
- (b) N(f,d) is the number of Selected Days for Demand Side Programme f on Event Day d as determined in steps 1.4 or 1.8 as relevant;
- (c) s ∈ SelectedDays(f,d) denotes the Selected Days for Demand Side Programme f on Event Day d as determined in steps 1.4 or 1.8 as relevant;
- (d) l ∈ AssocLoads(f,t) denotes the Associated Loads of Demand Side Programme f in Trading Interval t;
- (e) prevt(s,awt) is the Trading Interval in Selected Day s that commences at the same time of day as Trading Interval awt; and
- (f) SOMS(l,prev(s,awt)) is the Sent Out Metered Schedule of Associated Load l in the Trading Interval in Selected Day s that commences at the same time of day as Trading Interval awt.

3.4 Calculate BaselineAdjustment(f,t) for Demand Side Programme f for Trading Interval t as:

$$\begin{aligned}
 & \text{BaselineAdjustment}(f, t) \\
 & \equiv \text{Min} \left(\frac{0.2 \times |\text{AdjustmentWindowBaselineEnergy}(f, t)|,}{\text{Max} \left(\frac{-2 \times |\text{AdjustmentWindowBaselineEnergy}(f, t)|,}{\text{AdjustmentWindowActualEnergy}(f, t) - \text{AdjustmentWindowBaselineEnergy}(f, t)} \right)} \right)
 \end{aligned}$$

where:

- (a) AdjustmentWindowBaselineEnergy(f,t) is the quantity calculated for Demand Side Programme f for Trading Interval t in step 3.3; and
- (b) AdjustmentWindowActualEnergy(f,t) is the quantity calculated for Demand Side Programme f for Trading Interval t in step 3.2.

3.5 Calculate the AdjustedBaselineEnergy(f,t) for Demand Side Programme f for Trading Interval t as:

$$\begin{aligned} \text{AdjustedBaselineEnergy}(f, t) \\ = \text{UnadjustedBaselineEnergy}(f, t) + \text{BaselineAdjustment}(f, t) \end{aligned}$$

where:

- (a) UnadjustedBaselineEnergy(f,t) is the quantity calculated for Demand Side Programme f for Trading Interval t in step 2.1; and
- (b) BaselineAdjustment(f,t) is the quantity calculated for Demand Side Programme f for Trading Interval t in step 3.4.

Step 4. Calculate Relevant Demand

4.1 Calculate the Relevant Demand of Demand Side Programme f for Trading Interval t as:

- (a) the AdjustedBaselineEnergy(f,t) calculated in step 3.5 multiplied by 2 to convert it to a MW quantity, if AEMO is required to use the Adjusted Baseline Method under clause 2.29.5AH; or
- (b) the UnadjustedBaselineEnergy(f,t) calculated in step 2.1 multiplied by 2 to convert it to a MW quantity, if AEMO is required to use the Unadjusted Baseline Method for Demand Side Programme f in Trading Interval t under clause 2.29.5AH.

...

Schedule 3: Amending Rules to commence on 1 October 2027

...

4.1. The Reserve Capacity Cycle

...

Explanatory Note

Clause 4.1.27 is amended to extend the list of exempted Flexible Capacity obligations to include obligations that will be introduced to the ESM Rules on 1 October 2027. The amendments are consistent with corresponding amendments for the 2025 Reserve Capacity Cycle to clause 1.63.10, which are also scheduled to commence on 1 October 2027.

- 4.1.27. For a Reserve Capacity Cycle from the 2026 Reserve Capacity Cycle onwards, if the Flexible Reserve Capacity Price is less than or equal to the Peak Reserve Capacity Price then in respect of the relevant Capacity Year:
- (a) Market Participants are not required to fulfil any further obligations relating to Flexible Capacity Credits;
 - (b) AEMO must not procure supplementary Flexible Capacity under section 4.24;
 - (c) AEMO must not procure Non-Co-optimised Essential System Services relating to Flexible Capacity;
 - (d) AEMO must not consider Flexible Capacity Outage Capabilities or the availability of Flexible Capacity when conducting Outage Evaluations under section 3.18E;
 - (e) subject to clause 4.1.27(g), AEMO is not required to determine or publish:
 - i. ~~[Blank]~~Flexible Capacity Outage Quantities, Flexible Capacity Adjusted Forced Outage Quantities, and Flexible Capacity Adjusted Planned Outage Quantities under section 3.21;
 - ii. ~~[Blank]~~Flexible IRCR Intervals under clause 4.1.23AA;
 - iii. ~~[Blank]~~the 3 High-Ramp Trading Days under clause 4.1.23BA;
 - iv. Entity Daily Flexible Reserve Capacity Prices under clause 4.29.1E and the Floating Daily Flexible Reserve Capacity Price under clause 4.29.1F;
 - v. ~~[Blank]~~Indicative Flexible Individual Reserve Capacity Requirements under clause 4.1.23C(b);
 - vi. ~~[Blank]~~Flexible Individual Reserve Capacity Requirements under clauses 4.1.24(b) or 4.28.11B;
 - vii. ~~[Blank]~~Flexible Reserve Capacity Obligation Quantities under clauses 4.12.7, 4.12.8 and 4.12.9 and Flexible Reserve Capacity Obligation Quantity estimates under clause 6.3A.3(h);

- viii. the Transitional Daily Flexible Reserve Capacity Price under clause 4.29.1G and Fixed Daily Flexible Reserve Capacity Prices under clause 4.29.1H; ~~and~~
- ix. the values described in clauses 4.20.5A(b)(iiiA) and 4.20.5A(b)(v);
- x. the Flexible Facility Reserve Capacity Deficit Refund under clause 4.26.4;
- xi. the Flexible Targeted Reserve Capacity Cost or Flexible Shared Reserve Capacity Cost under clause 4.28.1A; and
- xii. the Flexible Capacity Provider Payment or Flexible Capacity Purchaser Payment under clause 9.8.2;
- (f) a standard form Supplementary Capacity Contract is not required to specify aspects relating to supplementary Flexible Capacity outlined under clauses 4.24.13(g) and 4.24.13(h)(i)(2); ~~and~~
- (g) AEMO must determine and publish:
 - i. ~~[Blank]~~the forecast highest Four-Hour Demand Increase as required by sections 7.3 and 3.16; and
 - ii. the Flexible Reserve Capacity Price under clause 4.29.1(b)(ii);
- (h) AEMO must not conduct Reserve Capacity Tests under clauses 4.25.1B or 4.25.2BA;
- (i) Market Participants must not apply to AEMO for a reduction in Flexible Capacity Credits under clause 4.25.4A;
- (j) Market Participants must not submit Capacity Credit Allocation Submissions in respect of Flexible Capacity Credits; and
- (k) AEMO must not issue Dispatch Instructions under 7.6.11(b)(ii).

...

4.26. Financial Implications of Failure to Satisfy Reserve Capacity Obligations

Explanatory Note

Several changes to clause 4.26.1 are scheduled to commence on 1 October 2027, some of which affect the proposed 1 October 2026 changes to clauses 4.26.1(b) and 4.26.1(e). Clauses 4.26.1(b) and 4.26.1(e) are therefore amended to restore the effect of the proposed 1 October 2026 changes in Schedule 2 of this exposure draft.

- 4.26.1. If a Market Participant holding Capacity Credits associated with a Facility fails to comply with its Reserve Capacity Obligations applicable to any given Trading Interval then the Market Participant must pay a refund to AEMO calculated in accordance with the following provisions.

...

(b) For a Facility f, for which a Market Participant holds Peak Capacity Credits, in the Trading Interval t, PY(f,t) is determined as follows:

- i. if Facility f is not a Registered Facility in Trading Interval t, PY(f,t) equals the Entity Daily Peak Reserve Capacity Price for the Facility in Trading Interval t divided by 48, or the highest Entity Daily Peak Reserve Capacity Price for any component Separately Certified Component of the Facility, in Trading Interval t divided by 48;
- ii. if AEMO has determined that in Trading Interval t Facility f is not in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility:

$$PY(f,t) = \frac{\sum_{c \in f} EDPRCP(c,t) \times PCC(c,t)}{PCC(f,t) \times 48}$$

$$PY(f,t) = \frac{\sum_{c \in f} PCC(c,t) \times \frac{EDPRCP(c,t)}{48}}{\sum_{c \in f} PCC(f,t)}$$

where:

1. ~~c ∈ f~~ denotes all Separately Certified Components c of Facility f;
2. ~~EDPRCP(c,t) is the Entity Daily Peak Reserve Capacity Price for Separately Certified Component c in Trading Interval t;~~
3. ~~PCC(c,t) is the Peak Capacity Credits associated with Separately Certified Component c in Trading Interval t; and~~
4. ~~PCC(f,t) is the Peak Capacity Credits associated with Facility f in Trading Interval t;~~
2. PCC(c,t) is the Peak Capacity Credits associated with Separately Certified Component c in Trading Interval t;
3. PCC(f,t) is the Peak Capacity Credits associated with Facility f in Trading Interval t; and
4. EDPRCP(c,t) is the Entity Daily Peak Reserve Capacity Price for Separately Certified Component c in Trading Interval t;
- iii. if AEMO has determined that in Trading Interval t Facility f is in Commercial Operation and is either a Scheduled Facility or Semi-Scheduled Facility, ~~PY(f,t) is:~~

$$PY(f,t) = \left(\sum_{c \in ESR(f,t)} \frac{PESROI(c,t) \times PCC(c,t)}{PCC(f,t)} \times \frac{EDPRCP(c,t)}{PESROD(c,t)} \right) + \left(\sum_{c \in NonESR(f,t)} \frac{PCC(c,t)}{PCC(f,t)} \times \frac{EDPRCP(c,t)}{48} \right)$$

where:

1. $c \in \text{ESR}(f,t)$ refers to all Separately Certified Components c of Facility f in Trading Interval t that are Electric Storage Resources;
 2. $\text{PESROI}(c,t)$ is 1 if Trading Interval t is a Peak Electric Storage Resource Obligation Interval for Separately Certified Component c and 0 otherwise;
 3. $\text{PCC}(c,t)$ is the Peak Capacity Credits associated with Separately Certified Component c in Trading Interval t ;
 4. $\text{PCC}(f,t)$ is the Peak Capacity Credits associated with Facility f in Trading Interval t ;
 5. $\text{EDPRCP}(c,t)$ is the Entity Daily Peak Reserve Capacity Price for Separately Certified Component c in Trading Interval t ;
 6. $\text{PESROD}(c,t)$ is the number of Trading Intervals in the Peak Electric Storage Resource Obligation Duration for Separately Certified Component c in the Trading Day containing Trading Interval t ; and
 7. $c \in \text{NonESR}(f,t)$ refers to all Separately Certified Components c of Facility f in Trading Interval t that are not Electric Storage Resources;
- iv. if Facility f is a Non-Scheduled Facility, $\text{PY}(f,t)$ equals the Entity Daily Peak Reserve Capacity Price for the Facility divided by 48; and

~~v. if Facility f is a Demand Side Programme:~~

~~$$\text{PY}(f,t) = \frac{\text{EDPRCP}(f,t)}{48} \times \frac{\text{TICY}(t)}{\text{DSPTICY}(f,t)}$$~~

~~where:~~

- ~~1. $\text{EDPRCP}(f,t)$ is the Entity Daily Peak Reserve Capacity Price for Facility f in Trading Interval t ; and~~
- ~~2. $\text{TICY}(t)$ is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls; and~~
- ~~3. $\text{DSPTICY}(f,t)$ is the number of Trading Intervals in the Capacity Year in which Trading Interval t falls which fall in the period specified under clause 4.10.1(f)(vi) for Demand Side Programme f .~~

v. if Facility f is a Demand Side Programme:

$$\text{PY}(f,t) = \frac{\text{PRCP}}{\text{DSP_MIN_AV_TI} \times \text{QTY_BD_CY}}$$

where:

1. PRCP is the Peak Reserve Capacity Price for the relevant Capacity Year;
2. DSP MIN AV TI is the minimum number of Trading Intervals per Trading Day that a Demand Side Programme must nominate to be available to provide Peak Capacity if issued a Dispatch Instruction in accordance with clause 4.10.1(f)(iii); and
3. QTY BD CY is the number of Business Days in the relevant Capacity Year.

...

(e) For Registered Facility f in the Trading Interval t , $Spare(f,t)$ is determined as follows:

i. if Facility f is a Scheduled Facility:

$$\max(0, RCOQ(f,t) - CAFO(f,t) - \max(0, 2 \times SOMS(f,t)))$$

$$\max(0, PRCOQ(f,t) - PCAFO(f,t) - \max(0, 2 \times SOMS(f,t)))$$

where:

1. ~~RCOQ(f,t)~~PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity determined for the Facility f in Trading Interval t ;
2. ~~CAFO(f,t)~~PCAFO(f,t) is the Peak Capacity Adjusted Forced Outage Quantity for Facility f in Trading Interval t calculated in 3.21.7B; and
3. $SOMS(f,t)$ is the Sent Out Metered Schedule for Facility f in Trading Interval t ;

iA. if Facility f is a Semi-Scheduled Facility:

$$\max(0, RCOQ(f,t) - CAFO(f,t) - \max(0, 2 \times SOMS(f,t)))$$

$$\max(0, PRCOQ(f,t) - PCAFO(f,t) - \max(0, 2 \times SOMS(f,t)))$$

where:

1. ~~RCOQ(f,t)~~PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity determined for Facility f in Trading Interval t ;
2. ~~CAFO(f,t)~~PCAFO(f,t) is the Peak Capacity Adjusted Forced Outage Quantity for Facility f in Trading Interval t calculated in 3.21.7B; and
3. $SOMS(f,t)$ is the Sent Out Metered Schedule for Facility f in Trading Interval t ;

ii. if Facility f is a Non-Scheduled Facility, zero; and

- iii. if Facility f is a Demand Side Programme:
 - 1. if Demand Side Programme f is subject to a Reserve Capacity Test or a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity in Trading Interval t:

$$PRCOQ(f, t) - DIMW(f, t)$$

- 2. otherwise:

$$PRCOQ(f, t)$$

where:

- 3. PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity for Demand Side Programme f in Trading Interval t; and
- 4. DIMW(f,t) is the quantity by which Demand Side Programme f was instructed by AEMO to amend its DSP Energy Level in Trading Interval t as specified by AEMO in accordance with clause 7.13.5.

...

...

Explanatory Note

Clause 4.26.3A is scheduled to be replaced on 1 October 2027 by the RCM Sequencing Amendments and the Tranche 8 Amendments. The clause is further amended to restore the changes made to the clause on 1 October 2026 by the Tranche 9 Amendments.

4.26.3A. The Peak Demand Side Programme Capacity Cost Refund for Trading Interval t for a Facility f with a Facility Class (or, for an unregistered Facility, an indicative Facility Class) of Demand Side Programme is equal to the lesser of:

- (a) the Maximum Peak Facility Refund for Facility f in the Capacity Year the Trading Interval t falls in, less all Peak Demand Side Programme Capacity Cost Refunds applicable to the Facility in previous Trading Intervals falling in the same Capacity Year; and

- (b) the sum of:

- i. either:

~~1. if Facility f is a Registered Facility:~~

~~$$PTIRR(f, t) \times PCS$$~~

~~where:~~

- ~~i. PCS is the Peak Capacity Shortfall in MW for Facility f in Trading Interval t determined in accordance with clause 4.26.2D, and~~

ii. ~~PTIRR(f,t) is the Peak Trading Interval Refund Rate for Facility f in Trading Interval t; or~~

1. if Facility f is a Registered Facility:

$PTIRR(f, t) \times \min(PDSPDS(f, t), PRCOQ(f, t))$

where:

i. PTIRR(f,t) is the Peak Trading Interval Refund Rate for Facility f in Trading Interval t;

ii. PDSPDS(f,t) is the Peak DSP Delivery Shortfall in MW determined in accordance with clause 4.26.1AA in Trading Interval t; and

iii. PRCOQ(f,t) is the Peak Reserve Capacity Obligation Quantity of the Demand Side Programme f for Trading Interval t (in MW); or

2. otherwise, zero; and

ii. the Peak Facility Reserve Capacity Deficit Refund for Trading Interval t for Facility f, determined in accordance with clause 4.26.1A.

...

4.28. Funding Reserve Capacity Purchased by AEMO

Explanatory Note

Clause 4.28.1(b)(ii) is amended to reapply the change proposed in Schedule 2 of this exposure draft following the replacement of the clause by Schedule 4 of the RCM Sequencing Amendments.

4.28.1. AEMO must separate the total costs of Peak Capacity Credits acquired by it for a Trading Day into the following two sets:

- (a) the Peak Targeted Reserve Capacity Cost, which is the cost of acquiring enough Peak Capacity Credits to ensure, to the extent possible given the number of Peak Capacity Credits AEMO has acquired, that the lesser of:
 - i. the Peak Reserve Capacity Requirement applicable to that Trading Day; and
 - ii. total Peak Capacity Credits ~~assigned to Facilities~~ held by Market Participants for the Trading Day,

is just covered after allowing for Capacity Credits traded bilaterally (as defined in clause 4.14.2 and subject to clause 4.28.2(b)) in that Trading Day; and

- (b) the Peak Shared Reserve Capacity Cost, calculated in accordance with clause 4.28.4, which is the cost of other Peak Capacity Credits acquired but not allocated to the set referred to in clause 4.28.1(a),

determined on the basis that the Peak Capacity Credits acquired by AEMO are allocated to the set referred to in clause 4.28.1(a) in order of decreasing cost per Peak Capacity Credit until the capacity requirements referred to in clause 4.28.1(a) are met, with the remaining Peak Capacity Credits acquired by AEMO being allocated to the set referred to in clause 4.28.1(b).

...

4.28A. Intermittent Load Refunds

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Explanatory Note

Clause 4.28A.1A(c) is amended to align with the wording proposed in Schedule 2 of this exposure draft following the replacement of the clause by Schedule 4 of the RCM Sequencing Amendments.

4.28A.1A. The IML Trading Interval Refund Rate for an Intermittent Load f in the Trading Interval t is determined as follows:

$$\text{IML Trading Interval Refund Rate}(f,t) = \text{RF}(f,t) \times Y(f,t)$$

where:

- (a) IML Trading Interval Refund Rate (f,t) is the IML Trading Interval Refund Rate for Intermittent Load f in Trading Interval t ;
- (b) $\text{RF}(f,t)$ is the refund factor for Intermittent Load f in Trading Interval t , which is the lesser of:
 - i. six; and
 - ii. the greater of 1 and the Peak Capacity dynamic refund factor $\text{RF dynamic}(t)$ as determined under clause 4.26.1(d); and
- (c) $Y(f,t)$ is the per Trading Interval Peak Capacity price associated with Intermittent Load f in Trading Interval t , which equals the Floating Daily Peak Reserve Capacity Price for the relevant Reserve Capacity Cycle divided by 48.

...

4.29. Settlement Data

...

Explanatory Note

Several changes to clause 4.29.3 are scheduled to commence on 1 October 2027, some of which duplicate or conflict with the proposed 1 October 2026 changes in Schedule 2 of this exposure draft. Clause 4.29.3 is therefore amended to restore the effect of the proposed 1 October 2026 changes and remove any duplications.

- 4.29.3. AEMO must determine the following information in time for settlement of each Trading Day d:
- (a) the Entity Daily Peak Reserve Capacity Price for each Demand Side Programme, Non-Scheduled Facility, and Separately Certified Component applying during ~~that Trading Day~~ Trading Day d;
 - (aA) the Entity Daily Flexible Reserve Capacity Price for each Demand Side Programme and Separately Certified Component applying during ~~that Trading Day~~ Trading Day d;
 - (b) the Peak Targeted Reserve Capacity Cost for Trading Day d as defined in clause 4.28.3;
 - (bA) the Flexible Targeted Reserve Capacity Cost for ~~that Trading Day~~ Trading Day d as defined in clause 4.28.3A;
 - (c) the Peak Shared Reserve Capacity Cost for Trading Day d as defined in clause 4.28.4;
 - (cA) the Flexible Shared Reserve Capacity Cost for ~~that Trading Day~~ Trading Day d as defined in clause 4.28.4B;
 - (cB) the Reserve Capacity Security Compensation Amount for Trading Day d as defined in clause 4.28.4D;
 - (d) for each Market Participant p and for Trading Day d:
 - i. the quantity of Peak Capacity Credits (including Peak Capacity Credits from Facilities subject to NCESS Contracts) for each Facility acquired by AEMO;
 - iA. the quantity of Peak Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Separately Certified Component acquired by AEMO;
 - ~~iA. the quantity of Peak Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Separately Certified Component acquired by AEMO;~~
 - iB. the quantity of Flexible Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Facility acquired by AEMO;
 - iC. the quantity of Flexible Capacity Credits (including Capacity Credits from Facilities subject to NCESS Contracts) for each Separately Certified Component acquired by AEMO;

- ii. the quantity of Peak Capacity Credits for each Demand Side Programme;
 - iii. the quantity of Flexible Capacity Credits for each Demand Side Programme ~~for Trading Day d~~;
 - iv. the quantity of Peak Capacity Credits for each Facility traded bilaterally in accordance with section 4.30;
 - ivA. the quantity of Peak Capacity Credits for each Separately Certified Component traded bilaterally in accordance with section 4.30;
 - ~~ivA. the quantity of Peak Capacity Credits for each Separately Certified Component traded bilaterally in accordance with section 4.30;~~
 - ivB. the quantity of Flexible Capacity Credits for each Facility traded bilaterally in accordance with section 4.30;
 - ivC. the quantity of Flexible Capacity Credits for each Separately Certified Component traded bilaterally in accordance with section 4.30;
 - v. the Peak Individual Reserve Capacity Requirement for the Trading Month in which Trading Day d falls;
 - vA. the Flexible Individual Reserve Capacity Requirement for the Trading Month in which Trading Day d falls;
 - vi. the total Peak Capacity Cost Refund to be paid by Market Participant p to AEMO for all Trading Intervals in Trading Day d; and
 - vii. the total Flexible Capacity Cost Refund to be paid by Market Participant p to AEMO for all Trading Intervals in Trading Day d;
- (dA) for each Market Participant, the sum over all of Market Participant p's Intermittent Loads, deemed to be Intermittent Loads under clause 1.48.2, of the Intermittent Load Refund payable to AEMO by Market Participant p in respect of each of its Intermittent Loads for Trading Day d; and
- (e) for each Supplementary Capacity Contract:
- i. the net payment to be made by AEMO under that contract for the Trading Day d; and
 - ii. to whom the payment is to be made.

...

9.8. Settlement Calculations - Reserve Capacity

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Explanatory Note

The versions of clauses 9.8.3A and 9.8.3B that are proposed to be inserted on 1 October 2026 (in Schedule 2 of this exposure draft) are deleted, because they have been superseded by the new versions of the clauses inserted on 1 October 2027. The 1 October 2027 version of clause 9.8.3A is amended to correct a typographical error.

~~9.8.3A. For the purposes of clause 9.8.3, Capacity_Payments(p,d) is calculated as:~~

$$\begin{aligned} & \text{Capacity_Payments}(p,d) \\ &= \sum_{e \in \text{PCCEntities}(p,d)} ((CC(e,d) - CCA(e,d)) \times \text{EDPRCP}(e,d)) \end{aligned}$$

~~where:~~

- ~~(a) $e \in \text{PCCEntities}(p,d)$ denotes all:
 - ~~i. Separately Certified Components of Scheduled Facilities;~~
 - ~~ii. Separately Certified Components of Semi-Scheduled Facilities;~~
 - ~~iii. Non-Scheduled Facilities; and~~
 - ~~iv. Demand Side Programmes,~~registered to Market Participant p on Trading Day d, and e is an entity in that set;~~
- ~~(b) $CC(e,d)$ is the number of Capacity Credits assigned to entity e for Trading Day d;~~
- ~~(c) $CCA(e,d)$ is the sum of the Capacity Credits associated with entity e for Trading Day d that have been allocated in Capacity Credit Allocations; and~~
- ~~(d) $\text{EDPRCP}(e,d)$ is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d.~~

9.8.3A. For the purposes of clause 9.8.3, Peak_Capacity_Payments(p,d) is calculated as:

$$\begin{aligned} & \text{Peak_Capacity_Payments}(p,d) \\ &= \sum_{e \in \text{PCCEntities}(p,d)} ((PCC(e,d) - PCCA(e,d)) \times \text{EDPRCP}(e,d)) \end{aligned}$$

where:

- (a) $e \in \text{PCCEntities}(p,d)$ denotes all:
 - i. Separately Certified Components of Scheduled Facilities;
 - ii. Separately Certified Components of Semi-Scheduled Facilities;
 - iii. Non-Scheduled Facilities; and
 - iv. Demand Side Programmes,registered to Market Participant p on Trading Day d, and e is an entity in that set;

- (b) PCC(e,d) is the number of Peak Capacity Credits assigned to entity e for Trading Day d;
- (c) PCCA(e,d) is the sum of the Peak Capacity Credits associated with entity e for Trading Day d that have been allocated in Capacity Credit Allocations; and
- (d) EDPRCP(c,d) is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d;

~~9.8.3B. For the purposes of clause 9.8.3, $Over_Allocation_Payment(p,d)$ is calculated as:~~

$$\begin{aligned}
 & \text{Over_Allocation_Payment}(p,d) \\
 &= \max(0, \text{Participant_CCA}(p,d) - \text{IRCR}(p,d)) \\
 & \times \text{Excess_Allocation_Price}(p,d)
 \end{aligned}$$

~~where:~~

- (a) ~~Participant_CCA(p,d) is the sum of Capacity Credits allocated to Market Participant p in Trading Day d in Capacity Credit Allocations;~~
- (b) ~~IRCR(p,d) is the Individual Reserve Capacity Requirement for Market Participant p for the Trading Month in which Trading Day d falls, expressed in units of MW; and~~
- (c) ~~Excess_Allocation_Price(p,d) is zero if Participant_CCA(p,d)=0, and otherwise:~~

$$\begin{aligned}
 & \text{Excess_Allocation_Price}(p,d) \\
 &= \frac{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (CCA(c,e,p,d) \times EDPRCP(e,d)))}{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (CCA(c,e,p,d)))}
 \end{aligned}$$

~~where:~~

- i. ~~C(p,d) is the set of Capacity Credit Allocations made to Market Participant p in Trading Day d and c is a Capacity Credit Allocation within the set;~~
- ii. ~~e ∈ PCCEntities(d) denotes all registered:~~
 1. ~~Separately Certified Components of Scheduled Facilities;~~
 2. ~~Separately Certified Components of Semi-Scheduled Facilities;~~
 3. ~~Non-Scheduled Facilities; and~~
 4. ~~Demand Side Programmes,~~~~on Trading Day d;~~
- iii. ~~CCA(c,e,p,d) is the number of Capacity Credits associated with entity e that have been allocated to Market Participant p in Capacity Credit Allocation c in Trading Day d; and~~
- iv. ~~EDPRCP(e,d) is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d.~~

9.8.3B. For the purposes of clause 9.8.3, Peak_Over_Allocation_Payment(p,d) is calculated as:

$$\text{Peak_Over_Allocation_Payment}(p,d) = \max(0, \text{Participant_PCCA}(p,d) - \text{PIRCR}(p,d)) \times \text{Peak_Excess_Allocation_Price}(p,d);$$

where:

- (a) Participant_PCCA(p,d) is the sum of Peak Capacity Credits allocated to Market Participant p in Trading Day d in Capacity Credit Allocations;
- (b) PIRCR(p,d) is the Peak Individual Reserve Capacity Requirement for Market Participant p for the Trading Month in which Trading Day d falls, expressed in units of MW; and
- (c) Peak_Excess_Allocation_Price(p,d) is zero if Participant_PCCA(p,d)=0, and otherwise:

$$\text{Peak_Excess_Allocation_Price}(p,d) = \frac{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (PCCA(c,e,p,d) \times EDPRCP(e,d)))}{\sum_{c \in C(p,d)} (\sum_{e \in PCCEntities(d)} (PCCA(c,e,p,d)))}$$

where:

- i. C(p,d) is the set of Capacity Credit Allocations made to Market Participant p in Trading Day d and c is a Capacity Credit Allocation within the set;
- ii. e ∈ PCCEntities(d) denotes all registered:
 1. Separately Certified Components of Scheduled Facilities;
 2. Separately Certified Components of Semi-Scheduled Facilities;
 3. Non-Scheduled Facilities; and
 4. Demand Side Programmes,
 on Trading Day d;
- iii. PCCA(c,e,p,d) is the number of Peak Capacity Credits associated with entity e that have been allocated to Market Participant p in Capacity Credit Allocation c in Trading Day d; and
- iv. EDPRCP(e,d) is the Entity Daily Peak Reserve Capacity Price associated with entity e in Trading Day d.

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11. Glossary

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Explanatory Note

The defined term Unadjusted Baseline Energy is renamed Associated Load Baseline Energy and the reference to the Appendix 10 calculation step updated.

~~Associated Load Baseline Energy: For an Associated Load of a Demand Side Programme in a Trading Interval, the value in MWh determined in step 5.1 of Appendix 10.~~

...

~~Unadjusted Baseline Energy: For an Associated Load of a Demand Side Programme in a Trading Interval, the value in MWh determined in clause 2.2 of Appendix 10.~~

...

Explanatory Note

Appendix 5 is amended to use the updated name for the input to this appendix that is determined under Appendix 10.

Appendix 5: Peak Individual Reserve Capacity Requirements

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For the purpose of this Appendix:

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10. Metered energy for meter m , in Trading Interval t is:
 - (a) zero, if AEMO has issued a direction under clause 7.7.5 in respect of an Electric Storage Resource associated with m for a Dispatch Interval within Trading Interval t ;
 - (b) if meter m measures an Associated Load of a Demand Side Programme which was issued a Dispatch Instruction under clause 7.6.5A for a non-zero MW quantity in Trading Interval t :

$$-1 \times UBE$$

~~where UBE is the Unadjusted Baseline Energy for the Associated Load in Trading Interval t as calculated in step 2.2 of Appendix 10;~~

$$-1 \times ALBE(m, t)$$

where ALBE(m, t) is the Associated Load Baseline Energy of the Associated Load for Trading Interval t as calculated in step 5.1 of Appendix 10;

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Explanatory Note

Appendix 10 is amended to reinsert the step to calculate Associated Load Baseline Energy values for use in Appendix 5. 5 is amended to use the updated name for the input to this appendix that is determined under Appendix 10.

Appendix 10: Relevant Demand Determination

This Appendix sets out the ~~method~~ methods for determining the Relevant Demand of a Demand Side Programme and the Associated Load Baseline Energy of an Associated Load of a Demand Side Programme in a Trading Interval in which one of the following applies:

- the Demand Side Programme is subject to a Dispatch Instruction issued under clause 7.6.5A with a non-zero dispatch quantity determined under clause 7.13.5; or
- the Demand Side Programme is undergoing a Reserve Capacity Test under section 4.25.

In this Appendix:

- a reference to a step is to the process step so numbered in this Appendix;
- steps are to be performed sequentially unless otherwise stated;
- an “Event Day” for a Demand Side Programme is a day in which one or more DSP Dispatch Events occur for that Demand Side Programme;
- the “Baseline Window” for a Demand Side Programme on an Event Day d is the 50 days from day d-50 to day d-1;
- “Selected Day” has the meaning given in step 1; and
- “Adjustment Window” has the meaning given in step 3.1.

AEMO must perform steps 1 to 4 to determine the Relevant Demand of a Demand Side Programme f for a Trading Interval t that occurs on Event Day d.

AEMO must perform steps 1 and 5 as required to determine the Associated Load Baseline Energy of each Associated Load l of a Demand Side Programme f for a Trading Interval t that occurs on Event Day d.

Step 1. Determine Selected Days

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Step 4. Calculate Relevant Demand

4.1 Calculate the Relevant Demand of Demand Side Programme f for Trading Interval t as:

- (a) the AdjustedBaselineEnergy(f,t) calculated in step 3.5 multiplied by 2 to convert it to a MW quantity, if AEMO is required to use the Adjusted Baseline Method under clause 2.29.5AH; or
- (b) the UnadjustedBaselineEnergy(f,t) calculated in step 2.1 multiplied by 2 to convert it to a MW quantity, if AEMO is required to use the Unadjusted Baseline Method for Demand Side Programme f in Trading Interval t under clause 2.29.5AH.

Step 5. Determine Associated Load Baseline Energy

5.1 Calculate the Associated Load Baseline Energy of Associated Load l of Demand Side Programme f for Trading Interval t on Event Day d as:

$$\begin{aligned}
 & \text{AssociatedLoadBaselineEnergy}(l,t) \\
 & \equiv \frac{1}{N(f,d)} \times \sum_{s \in \text{SelectedDays}(f,d)} \text{SOMS}(l,\text{prevt}(s,t))
 \end{aligned}$$

where:

- (a) N(f, d) is the number of Selected Days for Demand Side Programme f on Event Day d as determined in step 1.4 or 1.8 as relevant;
- (b) s ∈ Selected Days(f,d) denotes the Selected Days for Demand Side Programme f on Event Day d as determined in steps 1.4 or 1.8 as relevant;
- (c) prevt(s,t) is the Trading Interval in Selected Day s that commences at the same time of day as Trading Interval t; and
- (d) SOMS(l,prevt(s,t)) is the Sent Out Metered Schedule of Associated Load l in Trading Interval prevt(s,t).

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Schedule 4: Commencement TBD

Explanatory Note

This schedule includes changes to:

- allow AEMO to override inappropriate Energy Uplift Payments and RCS Uplift Payments arising from missing or manifestly incorrect Constraint Equations in the Dispatch Algorithm (clauses 7.5.22 – 7.5.24, 9.9.9 and 9.10.3T, and defined terms Energy Uplift Override Flag and RCS Uplift Override Flag);
- replace the settlement calculations that allocate costs to Market Participants according to their share of total Injection and/or Withdrawal with alternative calculations in Trading Intervals with very low or zero total Injection (clauses 9.5.5A, 9.5.7, 9.10.32E and 9.10.38, and defined term Low Injection Flag); and
- prevent unwarranted Energy Uplift Payments during Real-Time Market suspensions that arise from the use of End of Interval (EOI) MW SCADA quantities instead of Dispatch Targets to calculate Energy Uplift Payments (clause 9.9.10).

AEMO intends to confirm the commencement date for these changes in time for that date to be included in the final Tranche 10 Amending Rules.

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7.5. Dispatch Algorithm

Explanatory Note

In December 2024, a Scheduled Facility was directed on to provide RoCoF Control Service, but due to AEMO including an incorrect Constraint Equation in the Dispatch Algorithm the Market Participant did not receive the Energy Uplift Payments that it should have received.

While AEMO acknowledged the error, it does not have any mechanism under the ESM Rules to appropriately compensate the Market Participant. AEMO has advised that Constraint Equation errors, while rare, may occur again in future, and that Constraint Equation errors can result in either the underpayment (as in the December 2024 event) or the overpayment of Energy Uplift Payments or (from 26 February 2026) RCS Uplift Payments.

The inclusion of a correction mechanism in the ESM Rules will support the State Electricity Objective by preventing inefficient market outcomes, improving confidence in the integrity of the WEM and potentially reducing costs to consumers.

New clauses 7.5.22 and 7.5.23 require AEMO to set two new flags, the Energy Uplift Override Flag and the RCS Uplift Override Flag, for each Registered Facility and Dispatch Interval. The flags will be used in settlement to override inappropriate Energy Uplift Payments and RCS Uplift Payments arising from missing or manifestly incorrect Constraint Equations in the Dispatch Algorithm.

Each flag has three possible values:

- minus 1, the default value that has no impact on the Energy Uplift Payment/RCS Uplift Payment calculations;
- one, which will force the mispricing trigger/RCS Uplift Payment eligibility flag (as applicable) for the Registered Facility to be one for the Dispatch Interval, making the Registered Facility eligible for an Energy Uplift Payment/RCS Uplift Payment; and
- zero, which will force the mispricing trigger/RCS Uplift Payment eligibility flag for the Registered Facility to be zero for the Dispatch Interval, making the Registered Facility ineligible for an Energy Uplift Payment/RCS Uplift Payment.

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Missing or manifestly incorrect Constraint Equations

7.5.22. AEMO must set the Energy Uplift Override Flag for a Registered Facility in a Dispatch Interval to:

- (a) one, if AEMO becomes aware that, due to a missing or manifestly incorrect Constraint Equation in the Dispatch Algorithm, the Registered Facility is ineligible for an Energy Uplift Payment for which it would have been eligible had the correct Constraint Equations been included;
- (b) zero, if AEMO becomes aware that, due to a missing or manifestly incorrect Constraint Equation in the Dispatch Algorithm, the Registered Facility is eligible for an Energy Uplift Payment for which it would not have been eligible had the correct Constraint Equations been included; and
- (c) minus one, otherwise.

7.5.23. AEMO must set the RCS Uplift Override Flag for a Registered Facility in a Dispatch Interval to:

- (a) one, if AEMO becomes aware that, due to a missing or manifestly incorrect Constraint Equation in the Dispatch Algorithm, the Registered Facility is ineligible for an RCS Uplift Payment for which it would have been eligible had the correct Constraint Equations been included;
- (b) zero, if AEMO becomes aware that, due to a missing or manifestly incorrect Constraint Equation in the Dispatch Algorithm, the Registered Facility is eligible for an RCS Uplift Payment for which it would not have been eligible had the correct Constraint Equations been included; and
- (c) minus one, otherwise.

Explanatory Note

New clause 7.5.24 requires AEMO to publish the relevant details when it sets an Energy Uplift Override Flag or RCS Uplift Override Flag to a non-default value, i.e. when it identifies a trigger to override an erroneous Energy Uplift Payment or RCS Uplift Payment caused by a missing or manifestly incorrect Constraint Equation.

7.5.24. If AEMO sets the Energy Uplift Override Flag or RCS Uplift Override Flag to zero or one for a Registered Facility in a Dispatch Interval, then AEMO must as soon as practicable publish the following details on the WEM Website:

- (a) the Registered Facility;
- (b) the Dispatch Interval;
- (c) the value of the Energy Uplift Override Flag or RCS Uplift Override Flag (as applicable); and
- (d) the reasons for AEMO's setting of the Energy Uplift Override Flag or RCS Uplift Override Flag, including details of the relevant missing or manifestly incorrect Constraint Equation.

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Explanatory Note:

During a system black event, there may be no Injection or Withdrawal in the SWIS for several Trading Intervals. Total Injection and Withdrawal may also be extremely limited over the recovery period following a system black event or other major supply disruption, as AEMO works its way through the recovery process.

The WEM settlement rules include several calculations that allocate costs to Market Participants according to their share of total Injection and/or Withdrawal in each Trading Interval. These settlement calculations:

- become unusable due to 'divide by zero' errors if there is no metered Injection or Withdrawal in a Trading Interval; and
- may produce perverse and unreasonable outcomes during a recovery period, because material costs could be allocated to a very few Market Participants whose Facilities happen to be the first reconnected.

The settlement calculations affected include:

- calculations that allocate Energy Uplift, System Restart, non-capacity related NCESS, Outage Compensation and Market Suspension Compensation costs to Market Participants based on their Consumption Contributing Quantities for a Trading Interval;
- the calculations that allocate Contingency Reserve Lower costs to Market Participants based on their CL_GL_Contributing_Quantity values for a Trading Interval; and
- the calculations that allocate Regulation costs to Market Participants based on their Regulation contributing quantities for a Trading Interval.

New clause 9.5.5A is inserted and clauses 9.5.7, 9.10.32E and 9.10.38 are amended to address these concerns by replacing the default calculations for Consumption Contributing Quantity, CL_GL_Contributing_Quantity and Regulation contributing quantity in a Trading Interval if the sum of the Metered Schedules of Injecting Facilities is less than 200 MWh. The 200 MWh threshold represents the minimum Injection level expected under 'normal' operating conditions.

The default quantities will be replaced with the average of the relevant quantities for the Market Participant for the corresponding day/time over the previous four Trading Weeks. Using an average of corresponding quantities for previous Trading Weeks avoids the divide by zero problem and ensures that no Market Participant will be subject to a share of these costs that is much larger than usual.

The proposed changes benefit the State Electricity Objective by:

- ensuring that the WEM settlement calculations remain valid if a system black event occurs;
- removing an unnecessary source of financial risk for Market Participants; and
- enhancing Power System Security by removing a potential disincentive for Market Participants to assist with the restoration of the SWIS after a system black event.

9.5. The Metered Schedule

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Explanatory Note

New clause 9.5.5A defines the value of the new Low Injection Flag for each Trading Interval. The Low Injection Flag is used to determine whether alternative settlement calculations should be used to allocate some costs because the usual calculations are inappropriate under abnormally low Injection conditions.

9.5.5A. The Low Injection Flag for Trading Interval t is:

$$LowInjectionFlag(t) = \begin{cases} 1, & \text{if } \sum_{f \in F} \max(0, MeteredSchedule(f, t)) < 200 \\ 0, & \text{otherwise} \end{cases}$$

where:

- (a) $f \in F$ denotes all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads (including Synergy's Notional Wholesale Meter); and
- (b) $MeteredSchedule(f, t)$ is the Metered Schedule for Facility f for Trading Interval t as calculated in accordance with clauses 9.5.2 and 9.5.3.

9.5.6. AEMO must calculate for each Market Participant the Consumption Share for a Trading Interval. The Consumption Share for Market Participant p in Trading Interval t is:

$$ConsumptionShare(p, t) = \frac{ConsumptionContributingQuantity(p, t)}{TotalConsumptionContributingQuantity(t)}$$

where:

- (a) $ConsumptionContributingQuantity(p, t)$ is the Consumption Contributing Quantity for Market Participant p in Trading Interval t as determined in clause 9.5.7; and
- (b) $TotalConsumptionContributingQuantity(t)$ is the total Consumption Contributing Quantity for all Market Participants in Trading Interval t as determined in clause 9.5.8.

Explanatory Note

Clause 9.5.7 is amended to use an alternative method to calculate Consumption Contributing Quantities for Market Participants when the Low Injection Flag for the Trading Interval equals one.

9.5.7. AEMO must calculate for each Market Participant the Consumption Contributing Quantity for a Trading Interval. The Consumption Contributing Quantity for Market Participant p in Trading Interval t is:

$$ConsumptionContributingQuantity(p, t) = \sum_{f \in P} \min(0, MeteredSchedule(f, t))$$

where:

- (a) $f \in P$ denotes all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads registered to or

~~associated with Market Participant p (including Synergy's Notional Wholesale Meter where Synergy is Market Participant p) in Trading Interval t; and~~

~~(b) MeteredSchedule(f,t) is the Metered Schedule for facility f for Trading Interval t as calculated in accordance with clause 9.5.2 and clause 9.5.3.~~

9.5.7. AEMO must calculate for each Market Participant the Consumption Contributing Quantity for a Trading Interval. The Consumption Contributing Quantity for Market Participant p in Trading Interval t is:

$$\begin{aligned} & \text{ConsumptionContributingQuantity}(p, t) \\ & \equiv \begin{cases} \text{PriorAverageCCQ}(p, t), & \text{if } \text{LowInjectionFlag}(t) = 1 \\ \sum_{f \in p} \min(0, \text{MeteredSchedule}(f, t)) & \text{otherwise} \end{cases} \end{aligned}$$

where:

(a) PriorAverageCCQ(p,t) is the average of the Consumption Contributing Quantities determined for Market Participant p under this clause 9.5.7 for Trading Intervals commencing at the same time of day on the same day of the week as Trading Interval t in the four Trading Weeks immediately prior to the Trading Week containing Trading Interval t;

(b) LowInjectionFlag(t) is the Low Injection Flag determined for Trading Interval t in accordance with clause 9.5.5A;

(c) f ∈ p denotes all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads registered to or associated with Market Participant p (including Synergy's Notional Wholesale Meter where Synergy is Market Participant p) in Trading Interval t; and

(d) MeteredSchedule(f,t) is the Metered Schedule for facility f for Trading Interval t as calculated in accordance with clause 9.5.2 and clause 9.5.3.

9.5.8. AEMO must calculate the total Consumption Contributing Quantity for all Market Participants for a Trading Interval. The TotalConsumptionContributingQuantity(t) for all Market Participants in Trading Interval t is:

$$\begin{aligned} & \text{TotalConsumptionContributingQuantity}(t) = \\ & \sum_{p \in P} \text{ConsumptionContributingQuantity}(p, t) \end{aligned}$$

where:

(a) ConsumptionContributingQuantity(p,t) is the Consumption Contributing Quantity for Market Participant p in Trading Interval t as determined in clause 9.5.7; and

(b) p ∈ P denotes all Market Participants.

...

9.9. Settlement Calculations – Real-Time Energy

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Explanatory Note

Clause 9.9.9 is amended to use the Energy Uplift Override Flag determined under new clause 7.5.22 to override the mispricing trigger as required to enable/prevent an Energy Uplift Payment.

9.9.9. The mispricing trigger for Registered Facility f in Dispatch Interval DI is:

$$\begin{aligned}
 \text{IsMisPriced}(f,DI) &= \begin{cases} 1, \text{ if } \text{RTMSuspFlag}(DI) = 1 \\ 1, \text{ if } \text{ClearedQuantity}(f,DI) > 0 \text{ and} \\ \text{and } \text{CongestionRental}(f,DI) > 0 \\ \text{MarginalOfferPrice}(f,DI) > \text{Energy_MCP}(DI) \\ \text{and } f \notin \text{FacilitiesInBindingDownRampRate}(DI) \\ \text{and } f \notin \text{FacilitiesInBindingESSEnablementMinimum}(DI) \\ \text{and } \forall c (f \notin \text{FacilitiesInBindingNCESS}(c,DI)) \\ 0, \text{ otherwise} \end{cases} \\
 \text{IsMisPriced}(f,DI) &= \begin{cases} \text{EnergyUpliftOverride, if } \text{EnergyUpliftOverride} \geq 0 \\ 1, \text{ if } \text{RTMSuspFlag}(DI) = 1 \\ 1, \text{ if } \text{ClearedQuantity}(f,DI) > 0 \\ \text{and } \text{CongestionRental}(f,DI) > 0 \\ \text{and } \text{MarginalOfferPrice}(f,DI) > \text{Energy_MCP}(DI) \\ \text{and } f \notin \text{FacilitiesInBindingDownRampRate}(DI) \\ \text{and } f \notin \text{FacilitiesInBindingESSEnablementMinimum}(DI) \\ \text{and } \forall c (f \notin \text{FacilitiesInBindingNCESS}(c,DI)) \\ 0, \text{ otherwise} \end{cases}
 \end{aligned}$$

where:

- (a) RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI;
- (aA) ClearedQuantity(f,DI) is the cleared energy quantity for Registered Facility f in Dispatch Interval DI as recorded in the relevant Dispatch Instruction (where this quantity can be a Dispatch Target, Dispatch Cap or Dispatch Forecast);
- (a) EnergyUpliftOverride is the Energy Uplift Override Flag for Registered Facility f in Dispatch Interval DI;
- (aA) RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI;
- (aB) ClearedQuantity(f,DI) is the cleared energy quantity for Registered Facility f in Dispatch Interval DI as recorded in the relevant Dispatch Instruction (where this quantity can be a Dispatch Target, Dispatch Cap or Dispatch Forecast);
- (b) CongestionRental(f,DI) is the Congestion Rental for Registered Facility f in Dispatch Interval DI in respect of a set of Network Constraints N as published under clause 7.13.1EA(b);
- (c) MarginalOfferPrice(f,DI) is the highest Loss Factor Adjusted Price associated with any cleared (or scheduled) Price-Quantity Pair for In-

Service Capacity in respect of a Market Participant's Real-Time Market Offer for energy that was dispatched for Registered Facility f in Dispatch Interval DI;

- (d) Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI;
- (e) FacilitiesInBindingDownRampRate(DI) is the set of Registered Facilities whose EOI Quantity is higher than it would otherwise be in Dispatch Interval DI as a result of a binding ramp rate constraint applied under clause 7.2.4(c);
- (f) FacilitiesInBindingESSEnablementMinimum(DI) is the set of Registered Facilities whose EOI Quantity is constrained to its Enablement Minimum value in Dispatch Interval DI, as a result of a binding Essential System Service Enablement Minimum Constraint applied under clause 7.8.5(b)(i) for a Frequency Co-optimised Essential System Service other than RoCoF Control Service; and
- (g) FacilitiesInBindingNCESS(c,DI) is the set of Registered Facilities provided under clause 5.9.1(b) for NCESS Contract c and Dispatch Interval DI.

Explanatory Note

The *Wholesale Electricity Market Amendment (Market Suspension) Rules 2023* amended clause 9.9.10(b) to calculate MarginalOfferPrice(f,DI) using End of Interval (EOI) MW values instead of Dispatch Targets during a Real-Time Market suspension. The MarginalOfferPrice(f,DI) is the Facility offer price used to calculate Energy Uplift Payments. The rules were made because AEMO had limited capacity to record details of manual Dispatch Instructions when the new market commenced on 1 October 2023.

However, during the 8 June 2025 Real-Time Market suspension, the use of EOI MW values in clause 9.9.10(b) led to several unwarranted Energy Uplift Payments. The payments appear to have been caused by Facilities straying above their actual Dispatch Target due to normal, in-tolerance variations and/or the provision of an FCESS. This resulted in some high MarginalOfferPrice(f,DI) values that did not reflect the Facility's Dispatch Instructions.

To prevent such unwarranted Energy Uplift Payments in future, clause 9.9.10 is amended to always use the actual quantity dispatched (i.e. the real Dispatch Target) when calculating MarginalOfferPrice(f,DI) values, including when the market is suspended and Dispatch Targets may be issued via manual Dispatch Instructions.

The amendment benefits the State Electricity Objective by ensuring energy consumers do not bear the costs of unwarranted Energy Uplift Payments.

9.9.10. The Energy Uplift Price for Registered Facility f in Dispatch Interval DI is:

$$\text{EnergyUpliftPrice}(f,DI) = \begin{cases} 0, & \text{if InServiceTrancheCount}=0 \\ \text{Max}\left(0, (\text{MarginalOfferPrice}(f,DI) - \text{ReferenceTradingPrice}(t))\right), & \text{otherwise} \end{cases}$$

where:

- (a) InServiceTrancheCount is the number of Price-Quantity Pairs for non-zero quantities of In-Service Capacity in the Real-Time Market Offer for energy for Registered Facility f in Dispatch Interval DI;

- (b) $\text{MarginalOfferPrice}(f,DI)$ is: the highest Loss Factor Adjusted Price associated with any cleared (or scheduled) Price-Quantity Pair for In-Service Capacity in respect of a Market Participant's Real-Time Market Offer for energy that was dispatched for Registered Facility f in Dispatch Interval DI; and
- i. ~~the highest Loss Factor Adjusted Price associated with any cleared (or scheduled) Price-Quantity Pair for In-Service Capacity in respect of a Market Participant's Real-Time Market Offer for energy that was dispatched for Registered Facility f in Dispatch Interval DI; or~~
 - ii. ~~if AEMO has suspended the Real-Time Market under clause 7.11D.1, the highest price Price-Quantity Pair in respect of a Market Participant's Real-Time Market Submission for energy associated with the MW Injection or Withdrawal of Registered Facility f for Dispatch Interval DI as monitored by AEMO's SCADA system as prepared under clause 7.13.1E(a)(vi); and~~
- (c) $\text{ReferenceTradingPrice}(t)$ is the Final Reference Trading Price for Trading Interval t containing Dispatch Interval DI.

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9.10. Settlement Calculations - Essential System Services

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Explanatory Note

Clause 9.10.3T is amended to use the RCS Uplift Override Flag to override the RCS Uplift Payment eligibility flag as required to enable/prevent an RCS Uplift Payment.

9.10.3T. The RCS Uplift Payment eligibility flag for Registered Facility f in Dispatch Interval DI is:

$$\text{RCSUpliftEligibleFlag}(f,DI) = \begin{cases} 1, & \text{if } \text{RTMSuspFlag}(DI)=0 \\ & \text{and } f \in \text{FacilitiesInBindingRCSProvision}(DI) \\ & \text{and } \text{IsMisPriced}(f,DI)=0 \\ & \text{and } \text{FCESUpliftEligibleFlag}=0 \\ & \text{and } \text{ClearedQuantity}(f,DI) > 0 \\ & \text{and } \forall c (f \notin \text{FacilitiesInBindingNCESS}(c,DI)) \\ & \text{and } \text{MarginalOfferPrice}(f,DI) > \text{Energy_MCP}(DI) \\ 0, & \text{otherwise} \end{cases}$$

$$\text{RCSUpliftEligibleFlag}(f,DI) = \begin{cases} \text{RCSUpliftOverride}, & \text{if } \text{RCSUpliftOverride} \geq 0 \\ & 1, \text{ if } \text{RTMSuspFlag}(DI)=0 \\ & \text{and } f \in \text{FacilitiesInBindingRCSProvision}(DI) \\ & \text{and } \text{IsMisPriced}(f,DI)=0 \\ & \text{and } \text{FCESSUpliftEligibleFlag}=0 \\ & \text{and } \text{ClearedQuantity}(f,DI)>0 \\ & \text{and } \forall c (f \notin \text{FacilitiesInBindingNCESS}(c,DI)) \\ & \text{and } \text{MarginalOfferPrice}(f,DI) > \text{Energy_MCP}(DI) \\ 0, & \text{otherwise} \end{cases}$$

where:

- (a) ~~RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI;~~
- (a) ~~RCSUpliftOverride is the RCS Uplift Override Flag for Registered Facility f in Dispatch Interval DI;~~
- (aA) ~~RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI;~~
- (b) FacilitiesInBindingRCSProvision(DI) is the set of Scheduled Facilities and Semi-Scheduled Facilities that are subject to a binding RCS Provision Constraint Equation in Dispatch Interval DI;
- (c) IsMisPriced(f,DI) is the mispricing trigger for Registered Facility f in Dispatch Interval DI, as calculated in accordance with clause 9.9.9;
- (d) FCESSUpliftEligibleFlag is the FCESS Uplift Payment eligibility flag for Registered Facility f in Dispatch Interval DI, as calculated in accordance with clause 9.10.3F;
- (e) ClearedQuantity(f,DI) is the cleared energy quantity for Registered Facility f in Dispatch Interval DI as recorded in the relevant Dispatch Instruction (where this quantity can be a Dispatch Target, Dispatch Cap or Dispatch Forecast);
- (f) FacilitiesInBindingNCESS(c,DI) is the set of Registered Facilities provided under clause 5.9.1(b) for NCESS Contract c and Dispatch Interval DI;
- (g) MarginalOfferPrice(f,DI) is the highest Loss Factor Adjusted Price associated with any cleared (or scheduled) Price-Quantity Pair for In-Service Capacity in respect of a Market Participant's Real-Time Market Offer for energy that was dispatched for Registered Facility f in Dispatch Interval DI; and
- (h) Energy_MCP(DI) is the Final Energy Market Clearing Price for Dispatch Interval DI.

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9.10.32D. Market Participant p's share of the cost of procuring Contingency Reserve Lower allocated to Generic Load in Trading Interval t is:

$$\text{CL_GL_Share}(p,t) = \frac{\text{CL_GL_Contributing_Quantity}(p,t)}{\text{CL_GL_Total_Contributing_Quantity}(t)}$$

where:

- (a) CL_GL_Contributing_Quantity(p,t) is the quantity calculated for Market Participant p in Trading Interval t in accordance with clause 9.10.32E; and
- (b) CL_GL_Total_Contributing_Quantity(t) is the quantity calculated for Trading Interval t in accordance with clause 9.10.32G.

Explanatory Note

Clause 9.10.32E is amended to use an alternative calculation to determine Market Participants' Contingency Reserve Lower Generic Load contributing quantities when the Low Injection Flag for the Trading Interval equals one.

~~9.10.32E. Market Participant p's Contingency Reserve Lower Generic Load contributing quantity in Trading Interval t is:~~

$$\begin{aligned}
 & \text{CL_GL_Contributing_Quantity}(p,t) \\
 = & \left\{ \begin{array}{l} |\min(0, \text{NWM_Metered_Schedule}(t))| + \\ \sum_{f \in p} |\min(0, \text{Metered_Schedule}(f,t))|, \text{ if } \sum_{DI \in t} \text{RTMSuspFlag}(DI) > 0 \\ \sum_{f \in p} |\min(0, \text{NWM_Metered_Schedule}(t))| + \\ \sum_{f \in p} |\min(0, \max(-1 \times \text{CL_Threshold} \times 0.5, \text{Metered_Schedule}(f,t)))|, \text{ otherwise} \end{array} \right.
 \end{aligned}$$

where:

- (a) ~~NWM_Metered_Schedule(t)~~ is:
 - i. ~~the Metered Schedule of the Notional Wholesale Meter in Trading Interval t, if Market Participant p is Synergy; and~~
 - ii. ~~zero, otherwise;~~
- (b) ~~fcp~~ denotes all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads (excluding Synergy's Notional Wholesale Meter) of Market Participant p in Trading Interval t;
- (c) ~~CL_Threshold~~ is the CL Threshold;
- (d) ~~Metered_Schedule(f,t)~~ is the Metered Schedule of Facility f in Trading Interval t;
- (e) ~~DI ∈ t~~ denotes all Dispatch Intervals DI in Trading Interval t; and
- (f) ~~RTMSuspFlag(DI)~~ is the RTM Suspension Flag for Dispatch Interval DI.

9.10.32E. Market Participant p's Contingency Reserve Lower Generic Load contributing quantity in Trading Interval t is:

$$\begin{aligned}
 & \text{CL_GL_Contributing_Quantity}(p,t) \\
 & \equiv \left\{ \begin{array}{l}
 \text{PriorAverageCLGLCQ}(p,t), \text{ if } \text{LowInjectionFlag}(t) = 1 \\
 \quad \left| \min(0, \text{NWM_Metered_Schedule}(t)) \right| + \\
 \quad \sum_{f \in p} \left| \min(0, \text{Metered_Schedule}(f,t)) \right|, \text{ if } \sum_{DI \in t} \text{RTMSuspFlag}(DI) > 0 \\
 \hline
 \quad \left| \min(0, \text{NWM_Metered_Schedule}(t)) \right| + \\
 \quad \sum_{f \in p} \left| \min(0, \max(-1 \times \text{CL_Threshold} \times 0.5, \text{Metered_Schedule}(f,t))) \right|, \text{ otherwise}
 \end{array} \right.
 \end{aligned}$$

where:

- (a) PriorAverageCLGLCQ(p,t) is the average of the Contingency Reserve Lower Generic Load contributing quantities determined for Market Participant p under this clause 9.10.32E for Trading Intervals commencing at the same time of day on the same day of the week as Trading Interval t in the four Trading Weeks immediately prior to the Trading Week containing Trading Interval t;
- (b) LowInjectionFlag(t) is the Low Injection Flag determined for Trading Interval t in accordance with clause 9.5.5A;
- (c) NWM Metered Schedule(t) is:
 - i. the Metered Schedule of the Notional Wholesale Meter in Trading Interval t, if Market Participant p is Synergy; and
 - ii. zero, otherwise;
- (d) f ∈ p denotes all Scheduled Facilities, Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads (excluding Synergy's Notional Wholesale Meter) of Market Participant p in Trading Interval t;
- (e) CL Threshold is the CL Threshold;
- (f) Metered Schedule(f,t) is the Metered Schedule of Facility f in Trading Interval t;
- (g) DI ∈ t denotes all Dispatch Intervals DI in Trading Interval t; and
- (h) RTMSuspFlag(DI) is the RTM Suspension Flag for Dispatch Interval DI.

9.10.32F. [Blank]

9.10.32G. The total Contingency Reserve Lower Generic Load contributing quantity across all Market Participants in Trading Interval t is:

$$\text{CL_GL_Total_Contributing_Quantity}(t) = \sum_{p \in P} \text{CL_GL_Contributing_Quantity}(p,t)$$

where:

- (a) CL_GL_Contributing_Quantity(p,t) is the quantity calculated for Market Participant p in Trading Interval t in accordance with clause 9.10.32E; and

(b) $p \in P$ denotes all Market Participants.

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9.10.37. Market Participant p 's share of the total cost of Regulation payable for Trading Interval t is:

$$\text{Regulation_Share}(p,t) = \frac{\text{RegulationContributingQuantity}(p,t)}{\text{RegulationContributingQuantity}(t)}$$

where:

- (a) $\text{RegulationContributingQuantity}(p,t)$ is the quantity calculated in accordance with clause 9.10.38; and
- (b) $\text{RegulationContributingQuantity}(t)$ is the quantity calculated in accordance with clause 9.10.39.

Explanatory Note

Clause 9.10.38 is amended to use an alternative calculation to determine Market Participants' Regulation contributing quantities when the Low Injection Flag for the Trading Interval equals one.

~~9.10.38. Market Participant p 's Regulation contributing quantity in Trading Interval t is:~~

$$\begin{aligned} & \text{RegulationContributingQuantity}(p,t) \\ = & \sum_{SSF \in p} |\text{MeteredSchedule}(SSF,t)| + \sum_{NSF \in p} |\text{MeteredSchedule}(NSF,t)| \\ & + \sum_{NDL \in p} |\text{MeteredSchedule}(NDL,t)| \end{aligned}$$

~~where:~~

- ~~(a) $\text{MeteredSchedule}(SSF,t)$ is the Metered Schedule of Semi-Scheduled Facility, SSF , in Trading Interval t ;~~
- ~~(b) $SSF \in p$ denotes all Semi-Scheduled Facilities, SSF , registered to Market Participant p ;~~
- ~~(c) $\text{MeteredSchedule}(NSF,t)$ is the Metered Schedule of Non-Scheduled Facility, NSF , in Trading Interval t ;~~
- ~~(d) $NSF \in p$ denotes all Non-Scheduled Facilities, NSF , registered to Market Participant p ;~~
- ~~(e) $\text{MeteredSchedule}(NDL,t)$ is the Metered Schedule of Non-Dispatchable Load, NDL , in Trading Interval t ; and~~
- ~~(f) $NDL \in p$ denotes all Non-Dispatchable Loads, NDL , associated with Market Participant p (including Synergy's Notional Wholesale Meter where Synergy is Market Participant p).~~

9.10.38. Market Participant p 's Regulation contributing quantity in Trading Interval t is:

$$\begin{aligned}
 & \text{RegulationContributingQuantity}(p, t) \\
 & \equiv \begin{cases} \text{PriorAverageRCQ}(p, t), & \text{if } \text{LowInjectionFlag}(t) = 1 \\ \sum_{SSF \in p} |\text{MeteredSchedule}(SSF, t)| + \\ \sum_{NSF \in p} |\text{MeteredSchedule}(NSF, t)| + \\ \sum_{NDL \in p} |\text{MeteredSchedule}(NDL, t)|, & \text{otherwise} \end{cases}
 \end{aligned}$$

where:

- (a) PriorAverageRCQ(p,t) is the average of the Regulation contributing quantities determined for Market Participant p under this clause 9.10.38 for Trading Intervals commencing at the same time of day on the same day of the week as Trading Interval t in the four Trading Weeks immediately prior to the Trading Week containing Trading Interval t;
- (b) LowInjectionFlag(t) is the Low Injection Flag determined for Trading Interval t in accordance with clause 9.5.5A;
- (c) MeteredSchedule(SSF,t) is the Metered Schedule of Semi-Scheduled Facility, SSF, in Trading Interval t;
- (d) SSF \in p denotes all Semi-Scheduled Facilities, SSF, registered to Market Participant p;
- (e) MeteredSchedule(NSF,t) is the Metered Schedule of Non-Scheduled Facility, NSF, in Trading Interval t;
- (f) NSF \in p denotes all Non-Scheduled Facilities, NSF, registered to Market Participant p;
- (g) MeteredSchedule(NDL,t) is the Metered Schedule of Non-Dispatchable Load, NDL, in Trading Interval t; and
- (h) NDL \in p denotes all Non-Dispatchable Loads, NDL, associated with Market Participant p (including Synergy's Notional Wholesale Meter where Synergy is Market Participant p).

9.10.39. The Regulation contributing quantity in Trading Interval t is:

$$\text{RegulationContributingQuantity}(t) = \sum_{p \in P} \text{RegulationContributingQuantity}(p, t)$$

where:

- (a) RegulationContributingQuantity(p,t) is Market Participant p's Regulation contributing quantity in Trading Interval t calculated in accordance with clause 9.10.38; and
- (b) p \in P denotes all Market Participants.

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Glossary

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Energy Uplift Override Flag: A flag set by AEMO under clause 7.5.22 and used to amend erroneous Energy Uplift Payments caused by missing or manifestly incorrect Constraint Equations.

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Low Injection Flag: A flag indicating whether the total level of Injection for the SWIS in a Trading Interval is sufficiently low to warrant the use of alternative calculations for the allocation of various costs normally allocated using Metered Schedules, determined in accordance with clause 9.5.5A.

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RCS Uplift Override Flag: A flag set by AEMO under clause 7.5.23 and used to amend erroneous RCS Uplift Payments caused by missing or manifestly incorrect Constraint Equations.

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