ESOO and Reliability Forecast Methodology Document

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AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Important notice

Purpose

AEMO publishes the National Electricity Market Electricity Statement of Opportunities (ESOO) under clause 3.13.3A of the National Electricity Rules (NER). The purpose of this report is to provide information about the market modelling approach used in the development of the ESOO and the methodology used to determine the reliability forecast to meet the requirements of the Reliability Forecast Guidelines.

This publication has been prepared by AEMO using information available at 30 June 2022.

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Version control

Version	Release date	Changes
1	16/10/2017	Initial publication covering 2017 ESOO methodology
2	17/4/2019	Draft update reflected methodology to be applied in the 2019 ESOO
3	22/8/2019	Methodology applied in 2019 ESOO
4	19/12/2019	Added reliability forecast methodology section
5	25/8/2020	Updated to include improvements relevant to the 2020 ESOO
6	26/2/2021	Updated Sections 1,2, 4.4 and 6.1.3 following consultation on Reliability Forecast Guidelines
7	25/8/2021	Updated to include improvements and clarifications relevant to the 2021 ESOO: as consulted on through the forecast improvement program; the Inputs Assumptions and Scenarios Report; and the ISP Methodology
8	31/8/2022	Updated to include improvements and clarifications relevant to the 2022 ESOO: as consulted on consistent with the Reliability Forecast Guidelines

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1 Introduction

1.1 Electricity Statement of Opportunities and Reliability Forecasts

AEMO is required to publish an *Electricity Statement of Opportunities* (ESOO) for the National Electricity Market (NEM) annually under clause 3.13.3A of the National Electricity Rules (NER). The ESOO provides information that can help stakeholders plan their operations, investments and divestment over a 10-year outlook period, including information about the future supply-demand balance.

The ESOO also indicates when generation or demand side participation (DSP) capacity or augmentation of the power system is required to meet the reliability standard.

The reliability standard is defined in clause 3.9.3C(a) of the NER as "a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year".[1]

The implementation of the Retailer Reliability Obligation (RRO) was agreed at the Council of Australian Governments (COAG) Energy Council meeting on 26 October 2018. The necessary legislative and NER changes took effect on 1 July 2019.

A key component of the RRO is the calculation of a five-year reliability forecast and five-year indicative reliability forecast (covering years 6-10 in the ESOO horizon) for each NEM region, to be published in AEMO's annual ESOO.

The method adopted for calculating the expected USE is the same for both the ESOO and RRO and is outlined at a high level in the *Reliability Standard Implementation Guidelines* (RSIG)[2]. Expected USE is determined through probabilistic, time-sequential modelling at the interval level[3] using Monte-Carlo simulations of security-constrained optimal dispatch. AEMO compares the probability-weighted USE assessment against the reliability standard and identifies the potential for the reliability standard to be exceeded.

If the relevant reliability standard[4] is projected to be exceeded in any region, various parameters need to be calculated for that region as part of the reliability forecast, including a forecast reliability gap, forecast reliability gap period, and gap trading intervals, defined in rule 4A of the NER and the National Electricity Law.

1.2 Structure

The intent of this *ESOO and Reliability Forecast Methodology* document (**ESOO Methodology**) is to explain the key supply inputs and methodologies involved in determining the expected USE outcomes, for both the ESOO and the reliability forecast. It also explains how the forecast reliability gap and forecast reliability gap period are determined.

The process for producing a reliability forecast can be split into three overall components:

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[1] However, until 30 June 2025, the relevant reliability standard is deemed by the National Electricity Rules to be the interim reliability measure. The interim reliability measure requires "maximum expected unserved energy in a region of 0.0006% of the total energy demanded in that region for a given financial year".

[2] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Reliability-Standard-Implementation-Guidelines.

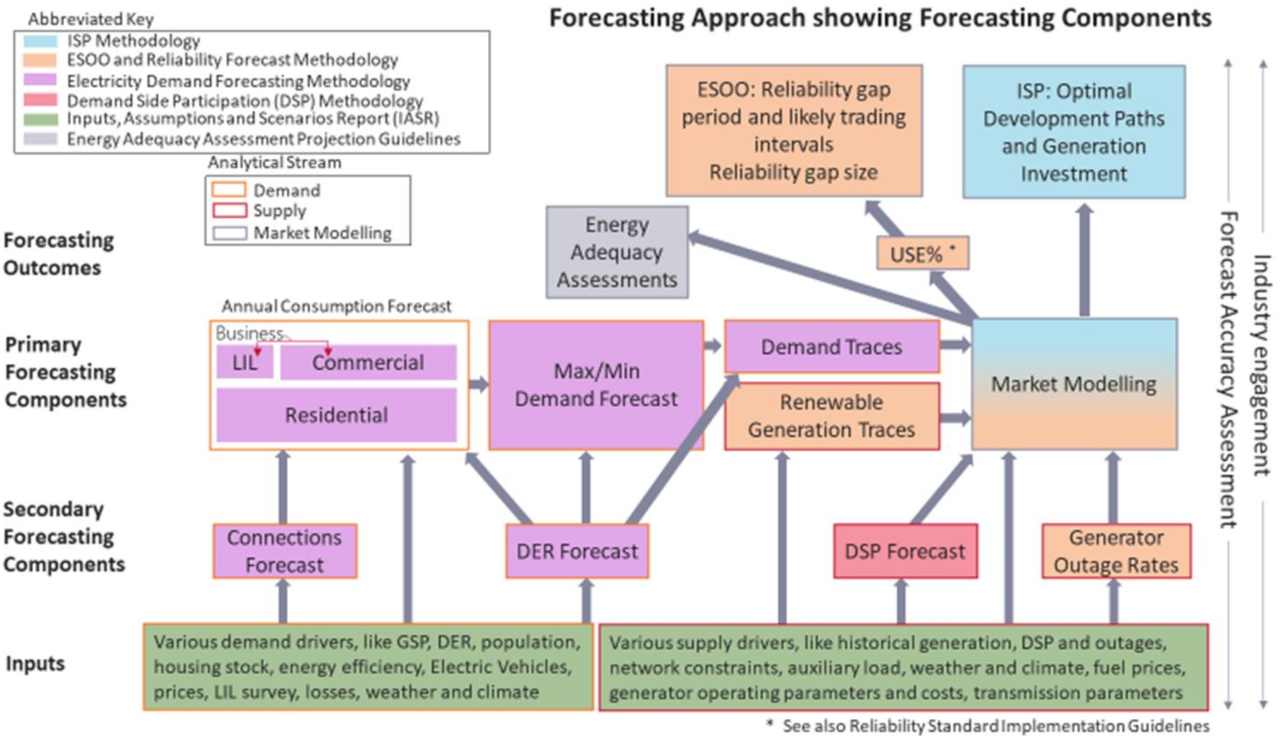
[3] AEMO currently models at the hourly level, but may change to half-hourly modelling in the future.

[4] For the purposes of the reliability forecast, the reliability standard is the interim reliability measure until 30 June 2025.

- Demand forecasts – the forecast load to be met for the NEM.
- Supply forecasts – the operational parameters applied for generators, demand side participation (DSP), large-scale storage, and transmission network elements.
- Reliability forecast – the assessment of the ability of available supply to meet demand.

Each of these comprises various components and needs different inputs. Figure 1 provides an overview of the end-to-end process.

Figure 1 End to end high-level overview of AEMO's Forecasting Approach



The figure also highlights the different methodology documents that explain the different processes and their inputs in more detail. Collectively, AEMO's detailed forecasting methodologies are known as the Forecasting Approach. The latest versions of the methodology documents are available on AEMO's Forecasting Approach web page[5].

This document focuses on the areas highlighted in orange in the figure and is structured into the following sections:

- Generation and storage (Section 2).
- Network (Section 3).
- Traces (Section 4).
- Unserved energy calculation (Section 5).
- Reliability forecast (Section 6).

[5] Available from https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-approach.

2 Generation and storage

When assessing the supply-demand balance, AEMO uses the 'Operational – sent out' demand definition, reflecting the demand for generation supplied by scheduled, semi-scheduled, and significant non-scheduled generators in the NEM[6]. For that reason, on the supply side all 'Operational' generator units are modelled.

AEMO models the capabilities of dispatchable generation capacity by applying inputs sourced from market participants. The maximum capacity of each generating unit is provided by market participants through the Generation Information survey process, in which each participant provides expected extreme heat summer, typical summer, and winter available capacity over the 10-year modelling horizon. For the extreme heat summer, and winter, these capacities represent the expected capability of the units during temperatures consistent with a 10% probability of exceedance (POE)[7] demand outcome in each region, while the typical summer capacity reflects a slightly more modest summer temperature as specified on the Generation Information page. All reflect the capability of the generator assuming everything is in service.

Participants also provide information on closure timing for existing generators through the Generator Information process, and these retirements are included in the modelling. Precise closure dates are required under the three-year notice of closure rule, but precise closure dates have not been provided to AEMO beyond the three-year period. For the purpose of the ESOO, closure dates beyond the three-year period are assumed to be on 31 December of the stipulated expected closure year.

Hydro generation is modelled with consideration to water limitations related to inflows and storage level management. Water allocation is optimised so that, to the extent possible, water will be available for use by hydro generation at times of high demand and/or tight supply-demand balance. Water usage is optimised for each individual forecast year and cannot be stored from one year to consume in subsequent years.

For details on generator capabilities and retirements, refer to AEMO's *Generation Information Page*[8].

2.1 Generator rated capacity

Maximum generation output for thermal generators at any time is subject to many factors including maintenance and condition of the plant, and the environmental conditions (particularly temperature) in which it needs to operate. AEMO collects information on expected generator performance from each operator, balancing the need for fidelity in representing generator performance and costs incurred by participants in providing information.

AEMO collects three capacity values to represent varying performance in response to temperature. This includes expected capacity under the following conditions:

- The rating representative of 10% POE demand conditions (summer peak capacity).
- The rating under typical summer conditions (typical summer capacity).
- The rating under winter conditions (winter capacity).

[6] For a full definition of AEMO's demand definitions, see https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/dispatch/policy_and_process/2020/demand-terms-in-emms-data-model.pdf.

[7] POE is the likelihood a maximum or minimum demand forecast will be met or exceeded. A 10% POE maximum demand forecast, for example, is expected to be exceeded, on average, one year in 10, while a 90% POE maximum demand forecast is expected to be exceeded nine years in 10.

[8] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

The typical summer capacity is used to represent the capacity that would be available under regular summer conditions whereas the summer peak capacity represents capacity available at times of very high temperature where annual maximum demand is more likely to occur. In the ESOO modelling, the typical summer capacity is applied throughout summer except for a subset of days where the summer peak capacity is applied.

The typical summer temperature is new for generator ratings used in the 2020 ESOO and is calculated as the 85th percentile of observed maximum daily temperatures for all reference years for periods between December and March (inclusive).

The summer 10% POE demand and winter temperatures are associated with the types of conditions conducive to 10% POE demand events. However, there is not a single temperature threshold or weather pattern that drives 10% POE demand events. The response of generator capacities to temperature is also complex, with potential dependencies on other variables such as humidity, temperatures in the hours preceding a period, or even weather conditions the day before. The winter and summer 10% POE demand reference temperatures are therefore considered a reasonable approximation of conditions associated with 10% POE demand events.

Table 1 lists the reference temperatures AEMO applies for each region when requesting generator ratings.

Table 1 Common reference temperature and summer typical temperature

Region	Summer peak reference temperature	Winter reference temperature	Summer typical temperature
Queensland	37	15	32
New South Wales	42	9	32
Victoria	41	8	32
South Australia	43	11	35
Tasmania	7.7	1.2	n/a[9]

AEMO applies the ratings to the ESOO model as per the following schedule:

- Summer peak capacity:
  - Applies to both 50% and 10% POE demand simulations for all mainland regions.
  - Applies to the top five days of daily maximum temperature within each reference year as mapped to forecast year.
  - To capture years with many days of extreme temperature, the rating also applies to any additional days with daily maximum temperatures that are within two degrees Celsius of the summer 10% POE demand reference temperature.
- Typical summer capacity:
  - Applies to all remaining summer periods for all regions, where summer is defined as November to March inclusive for mainland regions and December to February inclusive for Tasmania.
- Winter capacity:
  - Applies to all remaining periods.

[9] Tasmania summer ratings are based on peak demand periods driven by cold weather. AEMO only uses the 10% POE demand reference temperature for Tasmanian summer ratings.

2.2 Dispatchable generator outage rates

Dispatchable generators are assumed to be available at their peak summer, typical summer, or winter capacity unless they experience an unplanned (forced) outage.

Planned outages are currently not modelled in the ESOO, because these are assumed to be planned in lower demand periods or to shift if low reserve conditions were to occur, and therefore not impact USE outcomes.

AEMO collects information from all generators on the timing, duration, and severity of actual unplanned forced outages, and projections of future unplanned outage rates via an annual survey process. This data is used to calculate and forecast the probability of high impact low probability (HILP), full, and partial forced outages, which are then applied randomly to each unit in ESOO modelling. To protect the confidentiality of this data, AEMO may publish calculated outage parameters for a number of technology aggregations.

2.2.1 Calculating random outage parameters

Outage parameters for forced outages, including outage rates, de-ratings, and mean times to repair, vary between facilities and over time for a variety of reasons. Some reasons include generator behaviour, equipment age, and maintenance regimes. These variables are modelled as three categories of outage for input into the ESOO model:

1. Long duration outages, defined as a full forced outage greater than five months.
2. Full forced outages, being less than or equal to five months, and
3. Partial forced outages, where a unit has an unplanned reduction in capacity.

AEMO differentiates long durationoutages from regular forced outage rates. Long duration outages that extend greater than five months are very unlikely, and could result in an overestimation if not considered in a longer-term context.

AEMO uses the following approach for determining the forced outage rates used for each power station:

- Conduct the generator survey to collect availability data for the past year, supplementing historical data collected in prior years. The data collected are:
  - Full and partial forced outage data for the most recent year (capacity available and outage duration).
  - Participants' projections on outage data for coal-fired and closed-cycle gas turbine (CCGT) generators over the next 10 years, or until retirement.
- Calculate the outage parameters of each category for each unit across all regions.
  - Remove any full outages that are more than five months (HILP forced outages) from the historical base data. Calculate the Full Forced Outage Rate (FOR), Partial Forced Outage Rate (PFOR), average Partial Outage Derating Factor and respective Mean Time to Repair.

$$FOR = \frac{\sum Full\ outage\ hours}{\sum Hours\ in\ all\ states}$$

$$PFOR = \frac{\sum Partial\ outage\ hours}{\sum Hours\ in\ all\ states}$$

$$MTTR\ (FOR) = \frac{\sum Full\ outage\ hours}{\sum Transitions\ from\ unavailable\ to\ available}$$

$$MTTR\ (PFOR) = \frac{\sum Full\ outage\ hours}{\sum Transitions\ from\ partially\ available\ to\ available}$$

$$Partial\ Derating\ Factor\ (PFOR) = \frac{\sum Lost\ Energy\ \ during\ partial\ outages}{\sum Energy\ that\ would\ \ otherwise\ have\ been\ available\ without\ partial\ outage}$$

– The long duration outage rates are modelled by AEMO, taking into consideration the historical data of at least the past 10 years.

$$FOR\ (long\ duration) = \frac{\sum Long\ duration\ outage\ hours}{\sum Hours\ in\ all\ states}$$

$$MTTR\ (long\ duration) = \frac{\sum Long\ duration\ outage\ hours}{\sum Long\ duration\ events}$$

- After calculating generator outage statistics, provide station owners the opportunity to propose evidence-based revisions to the parameters that are used in the ESOO modelling. AEMO takes any proposed revisions under consideration and may adjust the assumptions used in modelling.
- Commission consultants to provide forecasts of projected outage values for coal-fired generators[10].
- Compare participant-provided and consultant-derived projected outage rates for use in ESOO modelling. Rely on information provided by participants, using consultant forecasts where participant information does not provide a sufficiently detailed or suitable projection. (For example, a participant projection may not be considered suitable if has been developed on an inconsistent definition of a forced outage, or if the projection is inconsistent with the accompanying evidence provided on which the projection was based.)
- For generators without projections, apply each of the last four yearly outage statistics with equal likelihood to all forecast periods.
- For generators with projections, the last four yearly outage statistics are scaled up and down over time to ensure that the average outage rate in any given year matches the forecast.
- For long duration outages, apply an average rate derived from at least 10-yearly outage statistics to all forecast periods.

Note:

- Forced outage rates have been derived based on the most recent four years of data only. This approximates well the longer-term outage rates seen by most technologies, but also recognises the statistically significant deterioration in performance of some coal generators seen in recent years.
- AEMO calculates outage parameters for a number of technology aggregations for the published model to avoid exposing confidential information.

[10] For the 2020 ESOO, AEMO commissioned AEP Elical. Their report 'Assessment of Ageing Coal-Fired Generation Reliability' is at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.

2.3 Generator auxiliary usage

AEMO's demand forecasts are developed on a 'sent-out' basis representing electricity to be supplied to customers from the grid. However, AEMO's modelling of generator capacity is on an 'as-generated' basis and includes electricity consumed within the power plants themselves.

Rather than assume an annual auxiliary consumption and auxiliary demand at the time of peak, AEMO's models dynamically account for auxiliary load based on generator dispatch in each modelling interval. AEMO currently sources per-unit auxiliary rate assumptions from participants through the latest Generator Information surveys[11] which are published in aggregate form.

2.4 Variable renewable energy availability

Variable renewable energy (VRE) is modelled by considering at least 10 historical reference years, which reflect the weather conditions that drove demand and wind and solar production over that period. This approach preserves any correlation between VRE and demand, and between VRE in different locations.

Half-hourly trace development for VRE is discussed further in Section 4.3.

2.5 Grid-scale storage and virtual power plants

Grid-scale battery storage, pumped hydro generation, hydrogen elements, and the proportion of small-scale battery storage that is assumed to be aggregated (operating as a virtual power plant [VPP] or vehicle to grid [V2G]) is fully optimised in the supply dispatch modelling. Each storage or generator is modelled with regards to its maximum generation/discharge capacity, maximum load/charge capacity, storage capacity, and efficiency. Each hydrogen element is modelled with regards to its maximum load, minimum load and energy target. Within the modelling, each asset optimises its generation (or discharging), load (pumping or charging)in a way that will reduce the level of USE to the maximum extent possible given its operational constraints. The modelling assumes perfect foresight in optimising this behaviour.

The water reservoirs for hydro generation are modelled by using parameters such as maximum volume, initial storage volume, and the monthly reservoir inflow rates (reflecting historical inflows). Small reservoirs that do not allow large variations in storage and the generators using them are often called 'run of river'. These generators do not require long-term optimisation and will generally use all the available water.

Larger reservoirs, however, require optimisation across a longer timeframe to save water for periods with higher electricity demand and wholesale prices.

In the ESOO model, water use is optimised in the simulation, resource allocation is optimised for each financial year. The model also limits the storage volume by the end of each yearly step to be equal to the volume at the beginning of the step.

These optimised hydro generation trajectories are further allocated to represent optimal daily and half-hourly behaviour. This is achieved through the use of soft targets, allowing a simulated dispatch of higher than allocated output where advantageous, while ensuring long term volumes match dam inflows.

[11] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

This method also assumes "perfect foresight" in all modelling of hydro schemes. That means that the water use is optimised with absolute certainty what will be the future natural inflow, a situation no hydro generator operator experiences in practice. This is not a material risk to supply scarcity, as both operators (in practice) and the model ensure availability at time of maximum demand.

For hydro schemes that include pumped hydro units, the release and pumping decisions are not directly bound to the soft targets determined by the 10 one-year steps. Pumped hydro operation is fully optimised in the supply dispatch simulation.

2.6 New generator commitment

The ESOO includes only existing and new generation and battery storage projects that meet AEMO's commitment criteria. These criteria are used to consistently assess whether a project has made a formal commitment to construct.

The ESOO includes all generation that was existing or committed in the most recent generation information page published in accordance with clause 3.7F of the NER. AEMO include all new generators classified as 'Committed' based on criteria which can be found on the Generator Information page[12].

The ESOO also includes projects that are classified as Committed*. Committed* projects are those that meet all of AEMO's commitment criteria except for either the Contracts or Planning criteria, and have commenced construction. The commercial use date for all Committed* projects is the later of:

- The first day after the end of the "T-1 financial year" defined under the RRO[13], or
- The actual commercial use date submitted by the proponent.

For example, in the 2022 ESOO, Committed* projects commence operation no earlier than 1 July 2024.

The intent of this approach is to strike an appropriate balance between conservatism and optimism, by including projects that are likely to proceed without incorporating projects with a higher probability of not proceeding or being delayed beyond their announced completion date.

2.7 Application of DSP

AEMO incorporates a DSP forecast in the reliability forecast produced for the ESOO. DSP is modelled in the ESOO for each region in various quantities of firm capacity at different price bands.

The DSP forecast that is used in the ESOO highlights the risk of shortfalls to determine the need for RERT capacity, so the analysis excludes RERT it in the first instance, and is modelled as a last resource before a USE event occurs in the simulation.

Further information is available in AEMO's *Demand Side Participation Forecast Methodology*[14].

[12] Criteria for Committed and Committed* is specified on the Generation Information page, under the Background information tab.

[13] See Section 5.3 at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/Reliability-Forecasting-Methodology-Final-Report.pdf.

[14] See https://www.aemo.com.au/consultations/current-and-closed-consultations/demand-side-participation-forecast-methodology-consultation.

3 Network

3.1 Interconnectors

Existing transmission limits and interconnector capacities are generally applied assuming the interconnector limits currently in effect continue to apply. The limits on each line are modelled by applying dynamic power system constraints. AEMO reviews current conditions, constraints, and planned augmentations and includes these changes when appropriate.

3.2 Network constraints

The ESOO model applies a comprehensive set of network constraint equations that represent the thermal and stability limits that currently constrain dispatch in the NEM[15]. These constraint equations act at times to limit generation, but also frequently limit interconnector transfer capacity.

In general, the following constraint equations are included:

- Thermal – for managing the power flow on a transmission element so it does not exceed a rating (either continuous or short-term) under normal conditions or following a credible contingency.
- Voltage stability – for managing transmission voltages so they remain at acceptable levels after a credible contingency.
- Transient stability – for managing continued synchronism of all generators on the power system following a credible contingency.
- Oscillatory stability – for managing damping of power system oscillations following a credible contingency.
- Rate of change of frequency (RoCoF) constraints – for managing the rate of change of frequency following a credible contingency.

The effect of committed projects on the network is implemented as modifications to the network constraint equations that control flow. The methodology for formulating these constraints is in AEMO's *Constraint Formulation Guidelines*[16].

A set of network constraints is produced and applied for every scenario modelled. This set may reflect:

- Extracted constraints from the AEMO Market Management Systems (MMS).
- Network augmentations appropriate for the scenario.
- Adjustments to reflect the impact of new generation capacities.
- Other adjustments to reflect assumptions of system operating conditions.

[15] Further information is available at AEMO's Congestion Information Resource at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information.

[16] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2016/Constraint_Formulation_Guidelines_v10_1.pdf.

Operationally, AEMO also uses other types of constraint equations that are invoked as required depending on system conditions. These may include:

- Outage constraint equations.
- Frequency control ancillary service (FCAS) constraint equations.
- Condition-specific constraint equations such as RoCoF and network support agreements.

These constraint equation types are commonly excluded from the market simulations, although key outage constraints are included (See Section 3.4).

3.3 Losses

Intra-regional losses are included in AEMO's operational demand forecasts. As such, generator and load marginal loss factors (MLFs) are not a relevant input to the ESOO modelling, because all intra-regional losses are already accounted for in the demand.

Losses on interconnectors are modelled explicitly using the MLF equations defined in the *List of Regional Boundaries and Marginal Loss Factors report*[17]. For most interconnectors, these are defined as a function of regional load and flow.

AEMO uses proportioning factors to assign losses on interconnectors to regions. Operationally, this is used to determine settlement surplus. In ESOO modelling, proportioning factors are used to allocate losses to demand in each region. Proportioning factors are given in the annual *List of Regional Boundaries and Marginal Loss Factors report*.

The losses allocated to each region effectively add to the total load that needs to be supplied in that region. As a result, interconnector losses are removed from the demand inputs used in the model as these losses are then added back in each period depending on the allocation of losses associated with the interconnector flow outcomes.

3.4 Transmission outages

AEMO includes the impact of unplanned outages on key transmission lines that materially contribute to inter-regional transfer capability. Annually, in preparation for the ESOO publication, AEMO assesses the materiality of outages observed on each line to determine which lines should be considered using the following process:

1. Identify all transmission elements that form an inter-regional flow path from Regional Reference Node (RRN) to RRN.
2. From the transmission elements identified in step 1, exclude all transmission elements that connect each RRN with significant remote intra-regional generation output.
3. With the reduced subset of transmission elements remaining following step 2, exclude any other elements in the interregional flow path, that if unavailable, would not materially increase reliability risk.

[17] AEMO. *Loss Factors and Regional Boundaries*, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

In calculating the unplanned outage rate, AEMO considers both single credible contingency events, and reclassification events.

To calculate the forecast rate of unplanned outages driven by single credible contingencies, AEMO:

- Requests historical data on the occurrence of single credible contingencies from Network Service Providers (NSPs) over at least 10 years where possible.
- In the absence of NSP data provision, AEMO will use best endeavours to create a 10-year dataset based on publicly available information.
- Requests 10-year projected outage rates or expected performance insights from NSPs.
- Calculates forecast unplanned outage rates for the forecast horizon by applying the historical observed rate, unless NSP insight suggests an alternate projection.

To calculate the forecast rate of unplanned outages driven by reclassification events, AEMO:

- Collates historical data as derived from AEMO's reclassification database[18].
- Uses reasonable judgement to exclude reclassification events that occurred in response to a multiple or non-credible contingency event.
- Calculates a historical rate then applies the historical rate over the 10-year forecast horizon.

Long duration outages observed in the history receive no special treatment, and are included in the calculated outage rate unless the NSP provides insight that suggests they are more or less likely in future periods. The unplanned outage mean time to repair is derived from observed events.

AEMO will implement weather variable outage rates where either single credible contingencies, or reclassifications are observed to be predominantly driven by, and are correlated with measurable weather. Such an implementation will match the annual rate, but better allocate the risk to the relevant time interval by the use of reference year traces. The transmission forced outage rates may be further adjusted with consideration for climate change trends where a weather driven failure mode is observed. In the absence of a causal relationship with weather, static annual unplanned outage rates will be implemented.

The impact of the outage is simulated through the use of power system constraints. AEMO:

- Uses a constraint set that applies during a single credible contingency event on the transmission segment most representative of the flow path's interconnector.
  - For example, the constraint set that would apply during a single credible contingency event on Dumaresq – Bulli Creek would be used to simulate the impact of all outages on the Queensland – New South Wales Interconnector (QNI) flow path.
- Uses the constraints to reduce inter-regional transfer limits during simulated unplanned outages to:
  - 0 MW, for single circuit lines
  - a non-zero value consistent with operational constraints, for all other lines
- Where possible, updates constraint sets to reflect committed transmission investments.

[18] https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-events-and-reports/power-system-reclassification-events

These will be treated similarly to dispatchable generation forced outages in the modelling, through Monte Carlo simulations as explained in Section 2.2.1.

3.5 Augmentations

Network upgrades that have passed a regulatory investment test for transmission (RIT-T)[19] are considered committed and are included in the modelling. Other minor augmentations not subject to RIT-Ts may be included if they are also judged to be committed.

[19] Further RIT-T information is at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Victorian-transmission-network-service-provider-role/Regulatory-investment-tests-for-transmission.

4 Traces

4.1 Traces

The operational demand, VRE availability, and transmission line ratings are inputs into the model on an interval level. Trace development relies on historical reference years to provide guidance on the typical daily and weekly demand shapes, variations from interval to interval, and correlations with other regions.

4.2 Reference years

Demand, VRE, and line rating traces are developed based on multiple historical reference years according to the RSIG. This is to capture year-on-year variations in demand correlations across regions and VRE contributions during high demand periods. This approach preserves any correlation between VRE and demand, and VRE in different locations. The choice of reference years and the number of those modelled may change as more reference years with good data become available.

Demand traces are explained in the *Electricity Demand Forecasting Methodology Information Paper*[20].

4.3 Creating reference years trace for VRE

Where appropriate, AEMO uses at least 10 years of actual generation performance from a generation site to create VRE traces for Monte Carlo simulations, assuming similar weather conditions are repeated in future. Where this data is unavailable or unsuitable, AEMO uses historical meteorological data for the site, and a resource to power model based on the generator technology, to develop a generation forecast.

For wind generators, AEMO has developed a resource to power model using an empirical machine learning approach. This model is fitted per site to capture the specific power curve for each wind farm incorporating both high wind and high temperature effects. Participant information on generator capabilities during summer peak demand temperatures are overlayed on top of these resource to power models.

For large-scale solar generators, AEMO uses the System Advisor Model (SAM) from the National Renewable Energy Laboratory[21] considering site-based technology parameters where relevant. In the case of large-scale solar traces, for which little actual generation is historically available, AEMO uses historical meteorological data and an energy conversion model for all trace time-periods.

Where committed renewable generation will be located at new sites, the ESOO modelling incorporates generation traces entirely derived from meteorological data using a resource to power model representative of expected technological performance, or renewable energy zone (REZ) forecasts from AEMO's *Integrated System Plan* (ISP), which are also derived from meteorological data.

[20] At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

[21] See https://sam.nrel.gov/.

4.4 Transmission line rating traces

Where available, AEMO will apply transmission line ratings traces to better account for the transfer capability on transmission lines, particularly during high demand periods. These transmission line rating traces are developed based on historical line rating traces and take into account inputs such as ambient temperature, wind speed and solar heating in conjunction with probable flow on the line conductor. Where available, the input data utilises locally measured weather observations in modelling the line rating trace. The model also analyses the limitation of various plants in the terminal station that would impact the transmission line ratings. Subsequently, modelling results using actual weather observations are benchmarked against actual line ratings to ensure accuracy.

The actual weather observations from the reference years will then be processed through this model to develop forward-looking line traces for each reference year, which is then further adjusted to reflect the impact of increasing temperatures over the forecast horizon on line ratings. The climate change factor implemented aligns with the scenario specified where relevant. The line ratings are used as an input into the right-hand-side (RHS) of the constraint equations calculated and described in Section 3.2. Lines with static line ratings utilise constraints that are not influenced by time-varying traces.

4.5 Photovoltaic (PV) traces

Rooftop PV and PV non-scheduled generation (PVNSG) reduce the electricity consumption and demand that needs to be met by the NEM. The extent of this contribution depends on the generation profile of these systems.

Capacity factors are a measure of power output relative to nameplate capacity at any given time. For fixed solar PV installations, capacity factors generally follow a parabolic arch, peaking at midday, when solar irradiance is highest. Figure 2 shows an example of historical average capacity factor curves by state, for the NEM, for February.

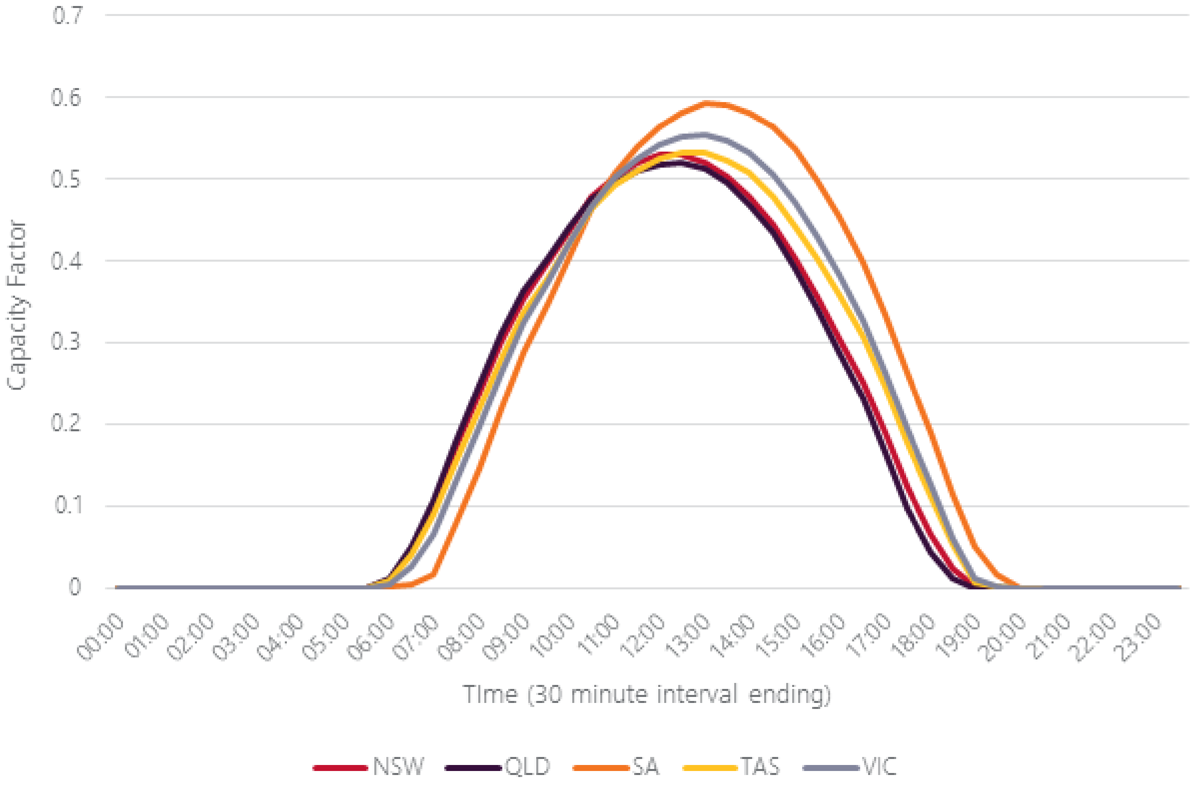
Capacity factor curves are influenced by a number of factors including:

- The latitude of the panels.
- Localised weather conditions (such as temperature and cloud cover).
- Panel inclination and azimuth[22].

Capacity factors are derived for each NEM region at all reference year periods (half-hourly resolution). The capacity factors are derived from external provider Solcast, whereby satellite-derived solar irradiance is coupled to models that account for the spatial distribution of installed capacity. The capacity factors used to estimate the forecast contribution of rooftop PV and PVNSG to consumption and demand were calculated based on these historical values.

[22] Inclination refers to the angle of the panel relative to horizontal and azimuth refers to the direction that the panel faces, with North facing panels generally having higher overall capacity factors. Western facing panels have higher capacity factors in the afternoon, and Eastern facing panels have higher capacity factors in the morning.

Figure 2 Estimated average historical rooftop PV capacity factors for February



4.6 Time-slice trace

As described in Section 2.1, AEMO determine the periods for three different ratings based on the historical temperature data for each reference year and region. The '10% POE summer', 'typical summer', and 'winter' capacity periods are formatted as time-slice traces for each reference year.

5 Unserved energy calculation

5.1 Simulation approach

AEMO's reliability assessments are based on a full time-sequential model that simulates each interval of the modelling horizon. This model replicates the NEM dispatch engine (NEMDE) to the extent possible by minimising cost of dispatch per interval subject to a number of physical constraints. AEMO currently uses the PLEXOS modelling tool for this.

The key assumptions that drive this model include:

- Interval level demand.
- Interval level wind and solar availability for each VRE generator.
- The seasonal capacity of each scheduled generating unit.
- Forced outage parameters used to account for unplanned generator outages.
- Transmission limitations, represented by transmission line ratings, interconnector limits and a detailed set of transmission constraint equations.
- The level of DSP in each region.

AEMO assesses reliability in the medium to long term by determining a statistical expectation of USE. This modelling takes into account uncertainty by using the following methods:

- Uncertainty in maximum demand – the modelling accounts for this uncertainty by modelling multiple maximum demand cases, defined by the POE of the maximum demand value. The outcomes of these different scenarios are then weighted as described in Section 5.2.2.
- Uncertainty in demand and VRE patterns – reliability outcomes are influenced by the pattern of demand and the available generation from VRE at the time of high demand. AEMO uses multiple historical reference years of demand, wind generation, solar generation, and transmission line ratings. This approach captures the diversity in demand and VRE patterns while maintaining correlation between these variables and across different geographical locations. It also ensures that effects of heatwaves, and other weather events observed in history, are captured in the simulations.
- Uncertainty in unplanned generation outages – AEMO uses a Monte Carlo simulation approach to capture the range of availability provided by scheduled generation. Within each simulation, the timing and duration of full and partial outages of each generating unit are independently determined, based on the forced outage parameters applied in the model. Each simulation therefore has a unique set of generator outage patterns. Simulating many outage patterns ensures the modelling captures a range of availability outcomes due to unplanned outages.

The Monte Carlo simulation approach is applied to each maximum demand and reference year, creating statistically robust results which capture the impact of uncertainties around key parameters.

The ESOO assesses different scenarios that vary with respect to the pace of change in the NEM. Differences in underlying demand growth, distributed energy resources (DER) uptake, and timing of coal-fired generation closures are observed across the scenarios. The approach above is repeated for each of those, to present USE for each of the scenarios separately.

5.2 USE outcomes

5.2.1 Definition (what does USE mean in modelling terms)

The key outcome of AEMO's reliability assessment is the expected level of USE in each region. USE refers to energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of customer supply), as a result of insufficient levels of generation capacity, demand response, or network capability, to meet demand.

In AEMO's reliability forecasting models, USE occurs in a region when there is no additional supply option available that is able to meet demand in that region. When USE is occurring in the model, it means the following set of conditions must be true:

- All DSP available in that region is fully utilised.
- All interconnectors are flowing into that region at their export/import (based on NEM convention) limits, except if the neighbouring region is also experiencing USE or has no surplus supply (including DSP).
- Any generator in the region that is not generating at its available capacity (after accounting for unplanned outages) is due to the impact of transmission constraint equations, whereby any additional generation from these generators would result in a reduction in generation or interconnector flow elsewhere in a way that would increase or have no impact on total USE.
- All dispatchable energy storage units (including VPPs) are running at their available capacity unless restricted by transmission constraint equations (as above) or having fully exhausted their energy storage capacity in other periods where there was USE or would otherwise have been USE if not for the batteries' discharge.

Within each Monte Carlo simulation that has been performed, the model will produce the level of USE in each region in each interval. The level of USE can then be summed across the year to determine the total volume of USE in each region in each financial year.

5.2.2 Determining the USE weightings

AEMO has historically calculated expected annual USE by using different levels of maximum demand outcomes, reflecting different underlying weather conditions that can drive extreme peak consumption. Assessments of USE consider the availability of supply to meet an uncertain demand, with many simulations conducted to account for potential generator outages.

Simulations, accounting for randomised generator outages, are generally limited to 10% POE and 50% POE maximum demand forecasts only, and the average of these simulations is weighted to account for the statistical spread of the spectrum of peak demands. As the risk of USE under 90% POE peak demand conditions is generally very low, simulations are avoided, and it is assumed that the USE under these conditions is zero. Therefore, 10% POE and 50% POE outcomes are weighted at 30.4% and 39.2% respectively, with the remaining 30.4% weighting assigned to 90% POE outcomes with zero USE assumed.

The weightings have been derived using a mathematical approach. Expected USE was approximated using a Taylor series expansion. From three points – such as 10% POE, 50% POE, and 90% POE – the weighting for these can be derived perfectly when:

- Maximum demand POE outcomes are normally distributed.
- USE outcomes as a function of maximum demand can be approximated by a second order (or lower) polynomial.

Statistical tests show that maximum demand outcomes are not normally distributed although are considered sufficiently close. As part of the 2018 ESOO23, AEMO further validated the weightings against a much more detailed approximation of USE in a particular year using a wider variety of sampled POEs. It was found that the mathematical approximation derived from the Taylor series expansion worked well across analysis of different regions and different years.

Using this mathematical approach, the three points – 10% POE, 50% POE, and 90% POE – have weightings of 30.4%, 39. 2%, and 30.4% respectively.

The approach is therefore to:

- Determine the average USE in each region and financial year for each demand POE level, equally weighting all reference years and all simulations of unplanned outages.
- Assume the USE is zero in the 90% POE case.
- Weight the average USE across the three POE cases to determine the expected USE value.

[23] See Appendix A3 of the 2018 ESOO at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/2018-Electricity-Statement-of-Opportunities.pdf.

6 Reliability forecast

6.1 Reliability forecast and indicative reliability forecast

The reliability forecast covers the first five years of the ESOO time horizon while the indicative reliability forecast covers the remaining five years of the 10-year ESOO outlook.

6.1.1 Existence of a forecast reliability gap and triggering reliability instrument requests

AEMO's methodology for calculating expected USE is explained in detail in the previous section.

As per NER clause 4A.A.2, a forecast reliability gap exists for a region if the expected USE exceeds the reliability standard.

In November 2020, the NER were amended by the National Electricity Amendment (Retailer Reliability Obligation trigger) Rule 2020, which temporarily changed AEMO's reporting obligations for reliability forecasts. The rule change requires AEMO to report on whether the IRM (0.0006% USE in a financial year) would be exceeded in financial years up until 30 June 2025, after which the reporting obligation reverts to the previous position under the NER: that AEMO must report on whether the reliability standard would be exceeded in any financial year.

While AEMO may assess the reliability gap under a range of scenarios, the forecast reliability gap that triggers a reliability instrument request will be based on the scenario AEMO considers most likely to eventuate, that is, a neutral or central scenario.

6.1.2 Reliability gap period and likely trading intervals

In the event that a forecast reliability gap is identified for either T-1 or T-3[24], AEMO determines the forecast reliability gap period and likely gap trading intervals based on the interval USE outcomes observed in the market simulations.

AEMO uses thresholds on the probability of lost load to determine the forecast reliability gap period and set of likely gap trading intervals where a forecast reliability gap has been identified. This methodology and the thresholds have been adopted to eliminate the impact of outlier events influencing simulation results, and to instead focus on likely periods which would cover the majority of load shedding events in simulations, when annual USE is forecast to exceed the reliability standard.

To provide greater decision-making support, AEMO will provide additional information that illustrates the distribution of USE events observed in the simulations with respect to month, day-of-the-week, and time-of-day, to help inform Registered Participants of the characteristics of the resources that could close the forecast reliability gap.

[24] T-3 and T-1 refer to reliability assessments three years out and one year out respectively. For example, for a reliability assessment conducted in August 2020, the T-1 period refers to the 2021-22 financial year.

The following approach is applied where AEMO has identified a reliability gap in relation to a region in a financial year, in determining the forecast reliability gap period and the likely gap trading intervals for the purposes of clause 4A.B.2:

- Monthly – a forecast reliability gap is declared to exist in a month if the probability of lost load in that month exceeds 10%[25]. The months identified are then used to determine the start and end date of the forecast reliability gap period. AEMO applies a 'sense test' that could tighten the start and end dates of the forecast reliability gap period within the month, if all the risk in the simulations occurs in, say, the first or last week of the month.
- Day-of-the-week – within each month that meets the lost load threshold, weekdays are declared as being within the forecast reliability gap period. The weekends are declared as being within the forecast reliability gap period if the probability of lost load on weekends exceeds 10%[26]. The day-of-the-week classification is used to describe the likely trading intervals of a shortfall.
- Time-of-day – a consistent time-of-day is applied across all month/day-of-the-week periods within a forecast reliability gap period. The range of trading intervals is identified by determining the earliest and latest time-of-day where the probability of lost load exceeds 10%[27]. All periods between these trading intervals are included.
- Excluded periods – consideration is given to whether there is a period of time within the forecast reliability gap period that should be excluded, such as the Christmas/New Year period, or discrete months where likelihood of supply shortfalls is low, as discussed below.

The forecast reliability gap period may contain months which do not meet the lost load thresholds described above. AEMO applies the following treatment in issuing reliability instrument requests:

- Where there is no consecutive two-month period that does not meet the threshold (for example, November, January, and March are above the lost load threshold but December and February are not), a single reliability instrument request is made which includes the month/s which did not meet the threshold. However, these month/s are explicitly excluded from the likely gap trading intervals.
- Where there is a consecutive period of two or more months that does not meet the threshold, two reliability instrument requests are submitted with different forecast reliability gap period specifications. For the purpose of calculating the megawatt size of the forecast reliability gap, the two or more forecast reliability gap periods are considered together, due to the need to assess the additional megawatts required to meet the annual reliability standard.

As indicated above, if there is a single month or another period (for example, the weeks over the holiday period) where the risks of load shedding are observed to be low in the simulations, this period is explicitly excluded from the likely gap trading intervals. This removes the possible need for contracting cover during periods where the risk of load shedding is low while maintaining the administrative simplicity of a single reliability instrument request in most cases.

This attempts to balance the cost of contracting for longer forecast reliability gap periods against the risk of confusion and administrative burden if multiple reliability instrument requests are requested in the same financial year.

[25] Subject to adjustment if, and only if, the forecast reliability gap is incalculable – see Section 6.1.3 for details.

[26] Subject to adjustment if, and only if, the forecast reliability gap is incalculable – see Section 6.1.3 for details.

[27] Subject to adjustment if, and only if, the forecast reliability gap is incalculable – see Section 6.1.3 for details.

Example

The figures below (Figures 3 to 5) show probabilities of lost load for a simulation at monthly, weekday/weekend, and time-of-day level. Based on the criteria above, the forecast reliability gap period and trading intervals for T-3 would be defined as follows:

- Start date: 1 January.
- End date: 28/29 February.
- Weekends are excluded in both months.
- Trading intervals: 1.00 pm – 8.00 pm.

Figure 3 Monthly probability of lost load assessment

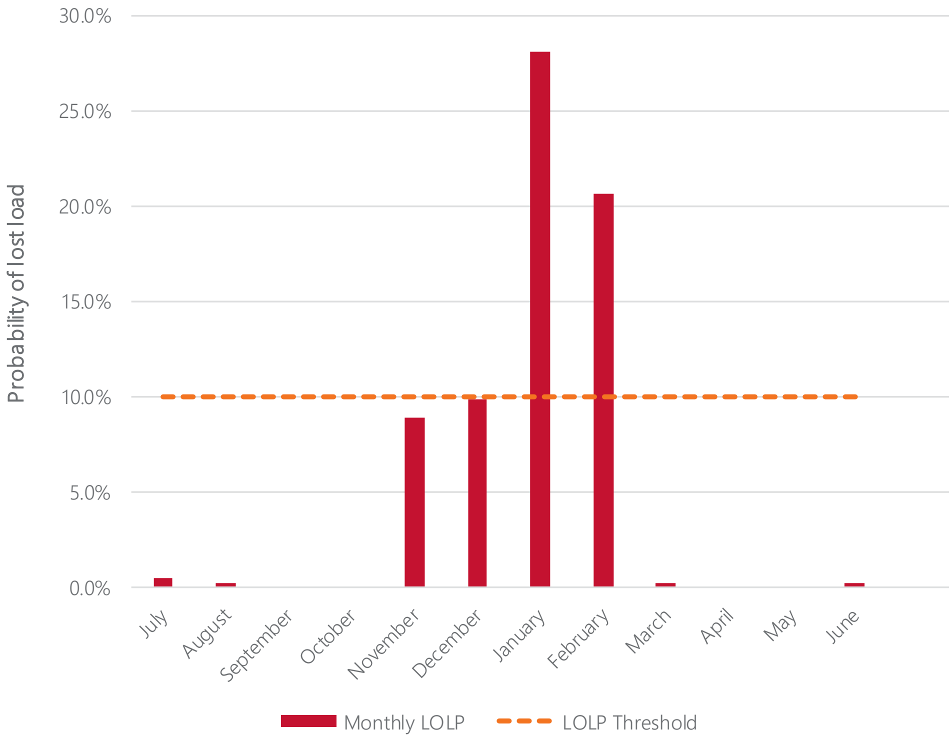


Figure 4 Weekday/weekend probability of lost load assessment

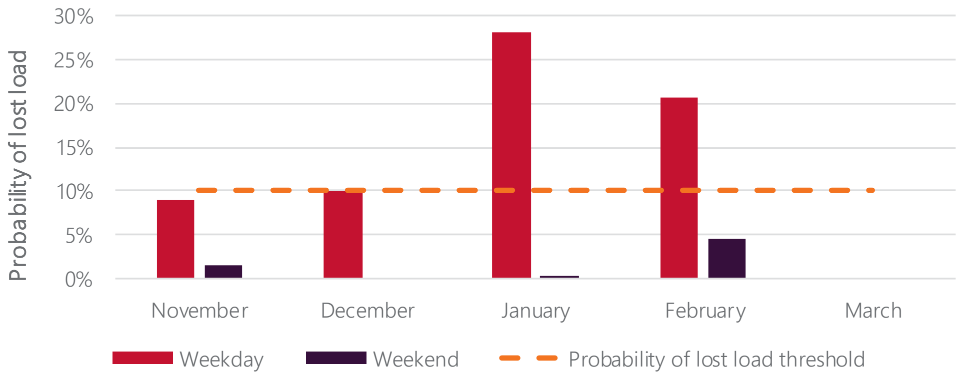
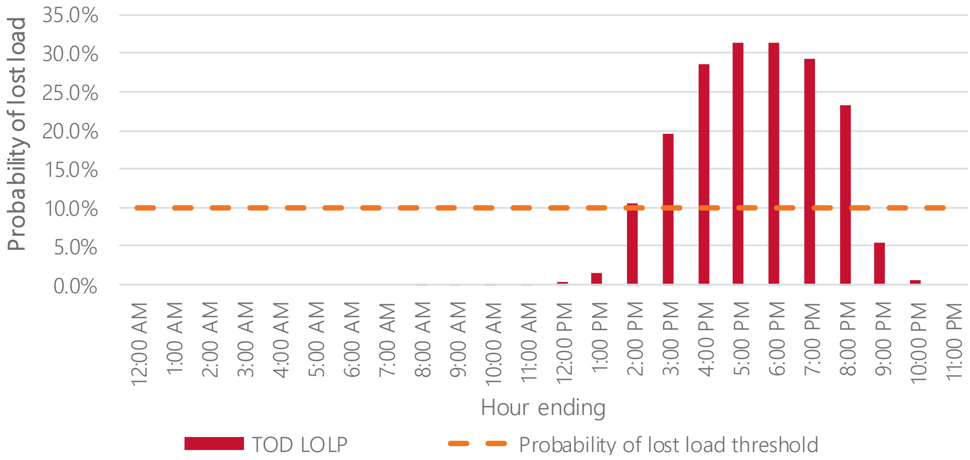


Figure 5 Time of day probability of lost load assessment (all months)



For T-1 reliability instrument requests, the forecast reliability gap period and trading intervals are determined using the same approach, but are equal to, or further confined to, a subset of the T-3 reliability instrument request forecast reliability gap period and trading intervals.

6.1.3 Arrangements for circumstances where the forecast reliability gap is incalculable

In rare cases, it may be mathematically impossible to calculate a forecast reliability gap using the substantive methodology. This is due to the *forecast reliability gap period* (where the probability of lost load exceeds 10%) being too narrow to capture enough unserved energy events for inclusion in the *forecast reliability gap* calculation. The outcome is that no forecast reliability gap can be determined that would reduce expected USE to the reliability standard. AEMO describes such a case as incalculable.

Should the calculation of the *forecast reliability gap* be incalculable, the calculation of the *forecast reliability gap period* (see Section 6.1.2) is progressively widened to include periods where the probability of lost load is less than 10%. The probability of lost load threshold will be iteratively reduced in 2% increments until the *forecast reliability gap* becomes calculable.

6.1.4 Size of the gap

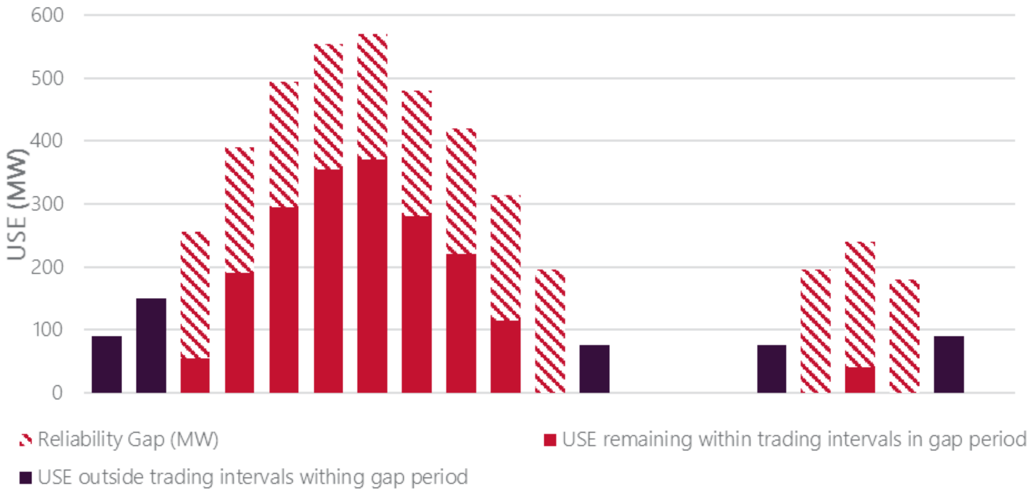
The size of the forecast reliability gap, expressed in megawatts, is determined by analysing the interval level USE across all simulations in each region where the USE exceeds the reliability standard. The size of the gap is calculated as the additional megawatts of capacity, assumed to be 100% available, during all identified trading intervals within the forecast reliability gap period only, that is required to reduce the annual expected USE to the reliability standard.

To better align with the actions available to liable entities under the RRO to ensure they have adequate contract coverage over the forecast reliability gap period, the size of the gap is determined based on the effective response that additional reserves could provide if only procured to cover the forecast reliability gap period and likely trading intervals identified. This means the gap (in megawatts) may be slightly larger than would otherwise be the case if those reserves were assumed to be available for the entire financial year.

The additional megawatts are assumed to be perfectly reliable and have no constraints such as a maximum hours of operation. Only a single megawatt value will be assessed per region for the entire forecast reliability gap period. Different megawatt values may apply for multiple reliability instrument requests within a financial year, although the objective is still to assess the additional reserves required to bring expected USE below the reliability standard.

A conceptual example is provided below in Figure 6. In this example, some of the USE periods are specified as falling outside the forecast reliability gap period. The figure shows the impact of 200 MW of additional capacity applied to USE periods that occur during the forecast reliability gap period and likely trading intervals identified.

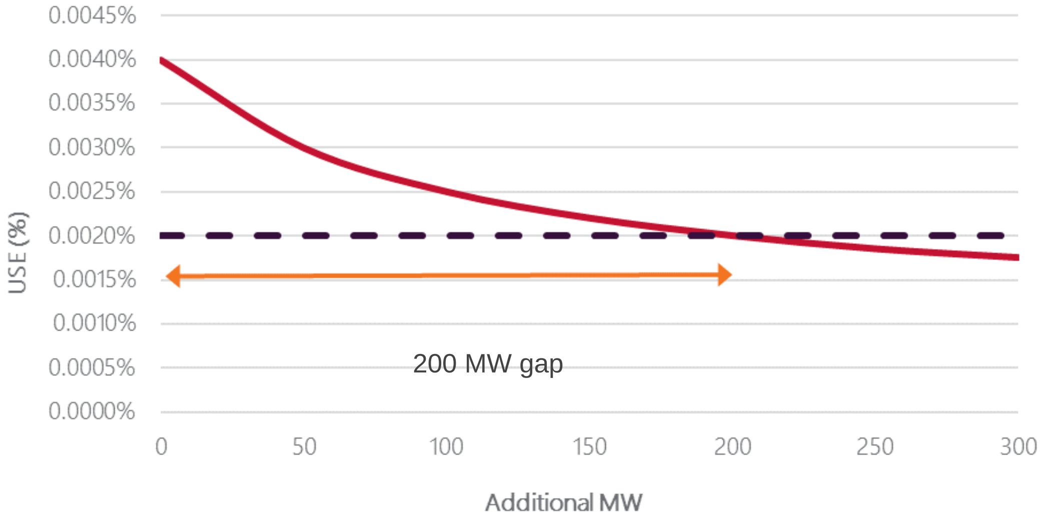
Figure 6 Conceptual example of the forecast reliability gap



Note the x axis here represents two conceptual days (not necessarily contiguous) with the intervening time where no USE occurred being removed for the purpose of illustration.

Figure 7 follows from the example above, and shows the impact on annual USE from the application of the 200 MW of additional capacity. Here the forecast reliability gap is calculated as 200 MW, the level of additional capacity required to bring USE to within the reliability standard when applied to USE in the relevant trading intervals within the forecast reliability gap period.

Figure 7 Conceptual example of the forecast reliability gap



6.1.5 Sharing additional reserves

As the forecast reliability gap is determined independently in each region where the level of USE exceeds the reliability standard, the methodology does not consider the impact additional resources in one region may have on the size or existence of a gap in another.

For example, tight supply-demand conditions in Victoria and South Australia are often highly correlated. As such, it is frequently observed that additional capacity in Victoria would reduce the level of USE in Victoria but also in South Australia, and vice versa.

By determining the size of the gap in each region independently, the combined gap in megawatts may be bigger than the level that would be required to have both regions meet the reliability standard when allowing for reserve sharing.

AEMO considers this is not an issue for the purpose of the forecast reliability gap calculation, because the relative size of the gap is used only for the allocation of any Procurer of Last Resort (POLR) cost to non-compliant parties between the two (or more) regions. The exclusion of reserve sharing in the assessment of the forecast reliability gap was contemplated in developing the formula for determining POLR cost. The calculation of the quantity of any Reliability and Emergency Reserve Trader (RERT) contracts procured (and therefore the total cost of RERT) will consider the effect of inter-regional reserve sharing.

Glossary

This document uses many terms that have meanings defined in the National Electricity Rules (NER). The NER meanings are adopted unless otherwise specified.

Term	Definition
committed projects	Generation that is considered to be proceeding under AEMO's commitment criteria (see Generation Information on AEMO's website, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information). AEMO categorises projects as: • Committed – satisfies all five of AEMO's criteria related to site acquisition, contracts for major plant components, planning and approvals, project financing, and scheduled operation commencement. • Committed* - projects that are classified as Advanced and have commenced construction or installation. Advanced projects meet AEMO's site, finance and date criteria but are required to meet only one of the components or planning criteria. Other projects may be listed as proposed, which includes advanced, maturing, emerging, or publicly announced project proposals.
DSP	Demand side participation
electrical energy	Average electrical power over a time period, multiplied by the length of the time period.
ESOO	Electricity Statement of Opportunities
forecast reliability gap	A forecast reliability gap represents the additional quantity of dispatchable capacity or equivalent, expressed in megawatts (MW), that AEMO projects will be needed to maintain reliability at levels that meet the reliability standard. The dispatchability of an energy resource can be considered as the extent to which its output can be relied on to 'follow a target', and incorporates how controllable the resources are, how much they can be relied upon, and how flexible they are. For more, see AEMO's Power System Technical Requirements, March 2018, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability.
generating capacity	Amount of capacity (in megawatts (MW)) available for generation.
generating unit	• Power stations may be broken down into separate components known as generating units, and may be considered separately in terms (for example) of dispatch, withdrawal, and maintenance.
installed capacity	The generating capacity (in megawatts (MW)) of the following (for example): • A single generating unit. • A number of generating units of a particular type or in a particular area. • All of the generating units in a region. Rooftop photovoltaic (PV) installed capacity is the total amount of cumulative rooftop PV capacity installed at any given time.
reliability standard	The reliability standard for generation and inter-regional transmission elements in the national electricity market is defined in NER 3.9.3C as a maximum expected unserved energy (USE) in a region of 0.002% of the total energy demanded in that region for a given financial year.
RSIG	Reliability Standard Implementation Guidelines. AEMO publishes the RSIG to set out how it will implement the reliability standard, including its approach and assumptions related to demand, generation reliability, VRE, energy constraints, network constraints, and treatment of extreme weather events.
USE	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). USE is calculated consistent with NER 3.9.3C.