AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

ESOO Methodology Document

2019 Electricity Statement of Opportunities

August 2019

Important notice

PURPOSE

AEMO publishes the National Electricity Market Electricity Statement of Opportunities (ESOO) under clause 3.13.3A of the National Electricity Rules. The purpose of this report is to provide information about the market modelling approach used in the development of the ESOO to evaluate the market against the reliability standard.

This publication has been prepared by AEMO using information available at 1 August 2019.

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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

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1. Introduction

1.1 Electricity Statement of Opportunities

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 set by the Reliability Panel and is currently defined as a maximum expected unserved energy (USE) in a region of 0.002% of total energy demanded in that region for a given financial year. Following the introduction of Retailer Reliability Obligation (RRO), the ESOO also has to include a Reliability Forecast as set out in the Reliability Forecasting Methodology Final Report[1]

AEMO uses probabilistic modelling to determine the expected USE by NEM region. This is done through time-sequential modelling at the interval level[2] using Monte-Carlo simulations of security-constrained optimal dispatch. AEMO compares the probability-weighted USE assessment against the reliability standard and identifies potential for the reliability standard to be exceeded.

1.2 Structure

AEMO follows the methodology outlined at a high level in the Reliability Standard Implementation Guidelines (RSIG)[3].

The intent of this ESOO Methodology document is to explain the key supply inputs and methodologies involved in producing the ESOO outcomes in more detail. For more information about the process used in creating the demand projections used in the ESOO, please see the Electricity Demand Forecasting Methodology Information paper[4].

This document is structured into the following sections:

- Generation and storage (Section 2).
- Network (Section 3).
- Traces (Section 4).
- Market modelling (Section 5).
- List of data sources (Appendix A1).

[1] 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.

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

[3] Available at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/Electricity_Consultations/2018/RSIG-Final/Reliability-Standard-Implementation-Guidelines-June-2018.pdf.

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

2. Generation and storage

2.1 Existing generation

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[5]. 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 summer and winter available capacity over the 10-year modelling horizon. These capacities represent the expected capability of the units during temperatures consistent with a 10% probability of exceedance (POE)[6] demand outcome in each region, and reflect the capability of the generator assuming everything is in service.

Participants also provide AEMO with closure timings of existing generators through the Generator Information process, and these retirements are included in the modelling.

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[7].

2.2 Dispatchable generator availability

Dispatchable generators are assumed to be available at their summer or winter capacity unless they experience an unplanned 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 would occur, and therefore not impact USE outcomes.

AEMO collects information from all generators on the timing, duration, and severity of unplanned forced outages, via an annual survey process. This data is used to calculate the probability of full and partial forced outages, which are then applied randomly to each unit in the 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 values

Outage rates, de-ratings, and mean times to repair for both full forced outages and partial forced outages are inputs into the ESOO model.

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

- Conduct generator survey to collect availability data for the most recent year.
- Calculate the sum of forced outage hours, partial outage hours, and total hours in all regions for each unit. This is used to get a forced and partial outage percentage for each year and each unit:

[5] For a full definition of AEMO's demand definitions, see http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Policy_and_Process/Demand-terms-in-EMMS-Data-Model.pdf.

[6] 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.

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

- Full Forced outage rate (FOR) = 'sum of FOR hours'/'total hours in all states'.
- Partial Forced outage rate (PFOR) = 'sum of PFOR hours'/'total hours in all states'.
- Mean time to repair for full outages = 'Sum of FOR hour'/'number of transitions from unavailable to available'.
- Mean time to repair for partial outages = 'Sum of PFOR hour'/'number of transitions from partially available to available'.
- Partial outage derating = 'Lost Energy'/'Energy during partial outages'. This represents the % that the unit is de-rated from its current rating.

- Aggregate the forced outage information. Station level aggregations are used for all power stations except small peaking generators (with unit capacity below 150 megawatts [MW]) and hydro generators. For each station and technology aggregation, calculate the outage statistics described above in each of the past four rolling 12-month periods (defined as April to March).
- Apply each of the four yearly outage statistics across all stations and any technology aggregations with equal likelihood.
- Calculate outage parameters for a number of technology aggregations for the published model to avoid exposing confidential information.

After calculating generator outage statistics, station owners are provided 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.

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 take into account auxiliary load based on generator dispatch in each modelling interval. AEMO currently sources per unit auxiliary rate assumptions from GHD's 2018 AEMO costs and technical parameter review[8], as summarised in AEMO's 2019 Inputs and Assumptions Workbook[9].

Generators are provided the opportunity to propose that alternate auxiliary assumptions should be used in the ESOO modelling. Where these have been provided, AEMO has used this information.

2.4 Intermittent generation availability

Intermittent generation is modelled by considering nine historical reference years, which reflect the weather conditions that drove demand and wind and solar production between 2010-11 and 2018-19[10]. This approach preserves any correlation between intermittent generation and demand, and between intermittent generators in different locations.

Where possible, AEMO uses actual generation performance from a generation site, or a site nearby. Where this data is unavailable or unsuitable, AEMO uses historical meteorological data for the site, and an energy conversion model based on the generator technology, to develop a generation forecast.

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[8] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/9110715-REP-A-Cost-and-Technical-Parameter-Review---Rev-4-Final.pdf.

[9] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/2019-Input-and-Assumptions-workbook.xlsx

[10] The 2018 ESOO modelled eight reference years: 2010-11 to 2017-18.

Where committed renewable generation will be located at new sites, the ESOO modelling incorporates renewable energy zone forecasts for AEMO's Integrated System Plan (ISP), including solar production using the System Advisor Model (SAM) and Bureau of Meteorology solar insolation data, or wind production data developed by DNV-GL.

2.5 Grid-scale storage and virtual power plants

Grid-scale battery storage, pumped hydro generation, and the proportion of small-scale battery storage that is assumed to be aggregated (operating as a virtual power plant [VPP]) 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 round-trip efficiency. Within the modelling, each asset optimises its generation and pumping/discharging and 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.

2.6 New generator commitment

The ESOO includes only existing and new generation 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 update. AEMO include all new generators classified as 'Committed' based on criteria which can be found on the Generator Information page[11].

The ESOO also includes projects that are classified as Committed*. Committed* projects are those classified as 'Advanced' and have commenced construction. Advanced projects meet all of AEMO's commitment criteria except for either the Components or Planning criteria. Committed* projects are assumed to commence operation after the end of the "T-1 financial year" under the RRO as discussed in the Reliability Forecasting Methodology Final Report[12]. For example, in the 2019 ESOO, Committed* projects commence operation from 1 July 2021.

[11] Criteria for Committed and Committed* are in each regional spreadsheet on the Generation Information page, under the Background information tab.

[12] 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.

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[13]. 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[14].

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.

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.

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[13] 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.

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

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 using the MLF equations defined in the List of Regional Boundaries and Marginal Loss Factors report[15]. 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.

3.4 Transmission outages

AEMO may include the impact of a number of key unplanned transmission line outages or deratings which affect inter-regional transfer capability. AEMO assesses the probability of these outages using historical data to determine which outages will be included and the severity of the outage assumed.

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)[16] are considered committed and are included in the modelling. Other minor augmentations not subject to RIT-T's may be included if they are also judged to be committed.

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

[16] Further RIT-T information can be found 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, intermittent generation 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, intermittent generation, 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 intermittent generation contributions during high demand periods. This approach preserves any correlation between intermittent generation and demand, and between intermittent generators 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[17].

4.3 Creating reference years trace for intermittent generation

As described in Section 2.4, where possible AEMO uses actual generation performance from a generation site, or nearby. Where this data is unavailable or unsuitable, AEMO uses historical meteorological data for the site, and an energy conversion model based on the generator technology, to develop a generation forecast. Where an actual generator site is far away, wind production data developed to model new entrant wind farms in new locations may be used as an alternative.

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 by building a regression between weather observations at location along the transmission line and the measured line rating in historical data. The actual weather observations from the reference years will then be processed through this regression to develop forward-looking line traces for each reference year. The line ratings are used as an input into the RHS of constraint equations.

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 average capacity factor 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.

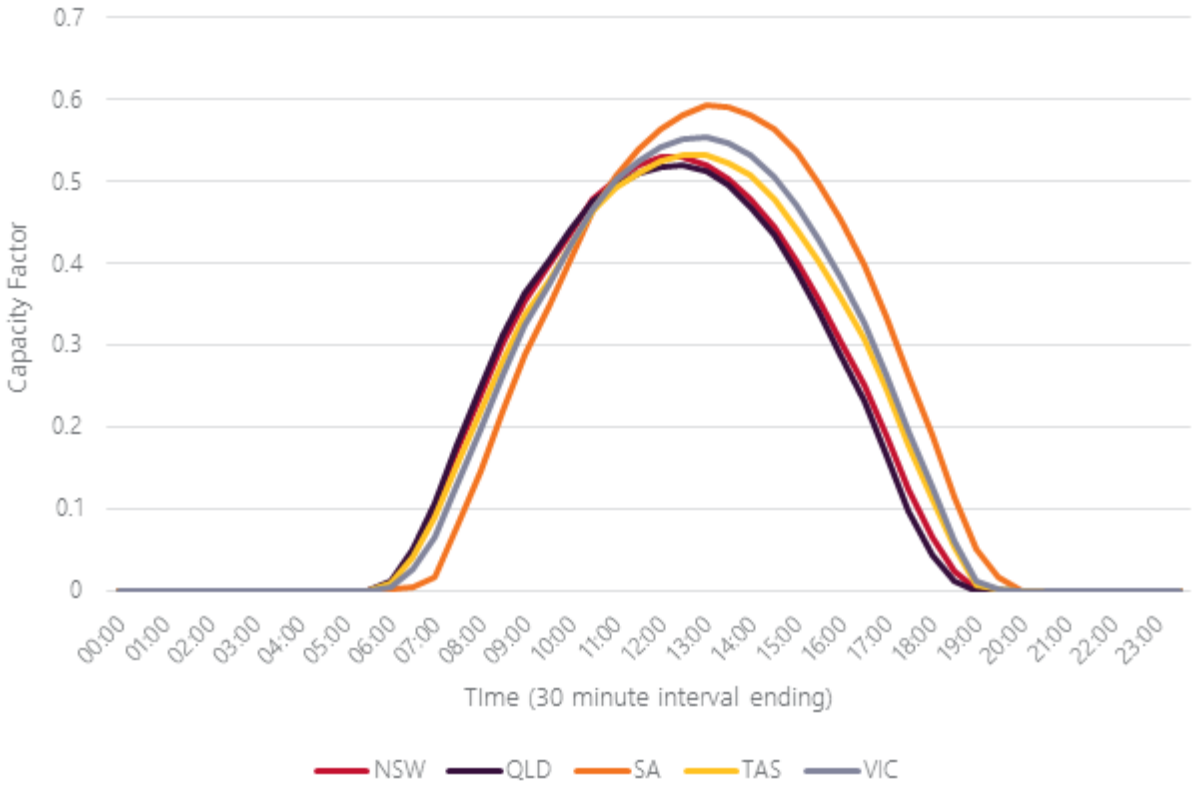
[17] Available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

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

- The latitude of the panels.
- Localised weather conditions (temperature, cloud cover, etc).
- Panel inclination and azimuth[18].

For the 2019 ESOO, AEMO has improved the method for calculating state level capacity factors, engaging SolCast to provide estimated capacity factors at half-hourly resolution for 19 years of history. 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. Figure 1 shows the historical average capacity factor curves by state, for the NEM, for February.

Figure 1 Estimated average historic rooftop PV capacity factors for February.



[18] 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.

5. Market modelling

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 intermittent 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 probability of exceedance (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 intermittent generation patterns** – reliability outcomes are influenced by the pattern of demand and the available generation from intermittent generators 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 intermittent generation patterns while maintaining correlation between these variables and across different geographical locations.
- **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 of demand growth. 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 energy storage units are running at their available capacity unless restricted by transmission constraint equations (as above) or having fully exhausted its energy storage capacity in other periods where there was USE or would otherwise have been USE if not for the battery's 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 though they were however found to be reasonably close to. To ensure the weightings were still valid, AEMO as part of the 2018 ESOO[19] undertook a comprehensive testing of the accuracy against a much more detailed approximation of USE in a particular year, that had used additional simulations for other POEs to make it more accurate. It was found the mathematical approximation worked well across different regions and different years analysis Additional points will allow a better fit for USE functions that are better approximated with higher order polynomials (of an order one lower than the number of maximum demand POEs used).

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

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.

A1. Appendix – data sources

Table 1 summarises relevant inputs and information used in producing ESOO runs.

Table 1 Key sources of input data for NEM ESOO model

Input	Source
Demand projections	AEMO demand forecast information for NEM ESOO, at http://forecasting.aemo.com.au.
Half-hourly demand profiles*	Half-hourly profiles are averaged to hourly profiles within the time-sequential model. At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.
Intermittent generation profiles	Half-hourly profiles are averaged to hourly profiles within the time-sequential model. At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.
Demand Side Participation (DSP)	DSP Forecast and methodology: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Demand-Side-Participation-Forecast-Methodology-2019.pdf.
Generator information	As provided by industry participants. At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.
Constraint ratings	Analysis by AEMO and other transmission network service providers (TNSPs). At http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities.
Market modelling methodology report	At https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/Inputs-Assumptions-Methodologies/2019/Market-Modelling-Methodology-Paper.pdf.

* More information on the process for converting maximum demand, minimum demand, and annual consumption projections into half-hourly profiles is in the Electricity Demand Forecasting Methodology Information paper, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2019/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

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
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 gap	A 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. In determining this reliability gap, AEMO has considered inter-regional reserve sharing. 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.
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. The USE that contributes to the reliability standard excludes unserved energy resulting from multiple or non-credible generation and transmission events, network outages not associated with inter regional flows, or industrial action (NER 3.9.3C(b)).
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, intermittent generation, energy constraints, network constraints, and treatment of extreme weather events.

Term	Definition
USE	Unserved energy is the amount of energy that cannot be supplied to consumers, resulting in involuntary load shedding (loss of consumer supply). The USE that contributes to the reliability standard excludes unserved energy resulting from multiple or non-credible generation and transmission events, network outages not associated with inter regional flows, or industrial action (NER 3.9.3C(b)).