Medium Term PASA Process Description

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Current version release details

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6.4	24 April 2023	Updated following full consultation, including to reflect the changes from 3 June 2024 under the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021.

Note: There is a full version history at the end of this document.

1. Introduction

The National Electricity Rules (the *Rules*) clause 3.7.1 require the Australian Energy Market Operator (AEMO) to administer the *projected assessment of system adequacy* (*PASA*) processes.

The *PASA* is the principal method for indicating to the National Electricity Market (NEM) the forecast adequacy of power system security and supply reliability over the next 24 to 36 months. The *Rules* require AEMO to administer the *PASA* over two timeframes:

1. *Medium Term PASA* (MT PASA): this assessment covers ~~the~~ a 24 to 36 ~~24~~ month period starting from the first Sunday after publication. Inputs provided by participants are published on a 3 hourly cycle, often out to 36 months, and outputs of the assessmen~~e~~t ~~It is updated and~~are published weekly to a daily resolution out to 24 months.
2. *Short Term PASA* (ST PASA): this assessment covers the six *trading days* starting from the end of the *trading day* covered by the most recently *published pre-dispatch schedule*. It is updated and published every two hours to a *trading interval* resolution.

MT PASA assesses *power system security* and *reliability* under a minimum of 10% Probability of Exceedance (POE) and 50% POE demand conditions based on ~~generator~~ production unit availabilities submitted by *market participants*, with due consideration to planned transmission and relevant distribution outages and limits[1]. The *reliability standard* is a measure of the effectiveness, or sufficiency, of installed capacity to meet demand and is defined in clause 3.9.3C of the *Rules*.

The MT PASA process includes (but is not limited to):

- Information collection from Scheduled Production units ~~Generators~~ and Semi-scheduled generation units,~~,~~ Market Customers, Transmission Network Service Providers and Market Network Service Providers about their intentions (as appropriate) for:
  - Generation, transmission and market network service maintenance scheduling.
  - Intended plant availabilities.
  - Unit status and recall times.
  - Energy constraints.
  - Other plant conditions which could materially impact upon power system security and the reliability of supply.
  - Significant changes to load forecasts.
- Analysis of medium-term power system security and reliability of supply.
- Forecasts of supply and demand.

[1] Constraints will be invoked on embedded generators connected to the DNSP network when there is an impact on TNSP equipment. When there is no impact on the TNSP network, constraints will not be applied. DNSPs should coordinate with generators and the generators should reflect the MW availability accordingly. For further information see https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3718---Outage-Assessment.pdf.

- Provision of information that allows participants to make decisions about supply, demand and outages of transmission networks for the next 24 months[2].
- Publication of sufficient information to allow the market to operate effectively with a minimal amount of intervention by AEMO.

The MT PASA process is administered according to the timeline set out in the Spot Market Operations Timetable[3] (*timetable*) in accordance with the *Rules*.

This document fulfils AEMO's obligation under clause 3.7.2(h) of the *Rules* to document the procedure used in administering the MT PASA.

1.1. Glossary

Terms defined in the National Electricity Law, ~~and~~ the *Rules* and the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021 No. 13 (IESS Rule)[4] have the same meanings in these Procedures unless otherwise specified in this clause.

Defined terms/Terms defined in the *Rules* and the IESS Rule are intended to be identified in these Procedures by italicising them, but failure to italicise a defined term does not affect its meaning.

The words, phrases and abbreviations in the table below have the meanings set out opposite them when used in these Procedures.

Term	Definition
AEMO	Australian Energy Market Operator
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
ESOO	Electricity Statement of Opportunities
LP	Linear Program
LRC	Low Reserve Condition
MMS	Electricity Market Management System
NEM	National Electricity Market
Rules	National Electricity Rules (the Rules)
PASA	Projected Assessment of System Adequacy • ST PASA: Short term projected assessment of system adequacy • MT PASA: Medium term projected assessment of system adequacy
POE	Probability of Exceedance
RHS	Right Hand Side of a constraint equation
Timetable	Spot Market Operations Timetable
UIGF	Unconstrained Intermittent Generation Forecast
USE	Unserved Energy
VRE	Variable renewable energy

[2] The information on generating unit availabilities and daily demands is published in the Region Availability report for the next 36 months.

[3] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Dispatch/Spot-Market-Operations-Timetable.pdf

[4] See https://www.aemc.gov.au/rule-changes/integrating-energy-storage-systems-nem

1.2. Interpretation

These Procedures are subject to the principles of interpretation set out in Schedule 2 of the National Electricity Law.

2. MT PASA process and Rules requirements

The PASA is a comprehensive program for collecting and analysing information to assess medium- and short-term power system security and reliability of supply prospects. This is so that *Registered Participants* are properly informed to enable them to make decisions about *supply*, demand and *outages* of *transmission networks* for periods up to 36 months in advance. MT PASA assesses the adequacy of expected electricity supply to meet demand across the two-year horizon through regularly identifying and quantifying any projected failure to meet the *reliability standard.*

MT PASA incorporates two separate functions:

1. A high frequency three-hourly information service (the 'three-hourly report') that gives a regional breakdown of the supply situation over a 36 month horizon, taking into account participant submissions on availability (the REGIONAVAILABILITY and DUIDAVAILABILITY reports).
2. A weekly assessment of system reliability, including provision of information on demand, supply and network conditions.

AEMO must review and *publish* the MT PASA outputs in accordance with the frequency specified in clause 3.7.2(a), covering the period starting from the Sunday after *day* of publication with a daily resolution. Additional updated versions of MT PASA may be published by AEMO in the event of *changes* which, in the judgement of AEMO, are materially significant and should be communicated to *Registered Participants*.

Each party's responsibilities in preparing MT PASA (summarised in Table 1 below) are also defined in this clause.

Table 1 Rules requirements

Responsible party	Action	Rules requirement
AEMO	Prepare the following MT PASA inputs: • Forecasts of the 10% probability of ~~exceedence~~exceedance daily peak load and the most probable daily peak load. • Network constraints forecasts. • *Unconstrained intermittent generation* forecasts for semi-scheduled generating unit. • The capabilities of generating units for which formal commitments have been made for construction or installation.	3.7.2~~(c)~~©
Scheduled ~~*Generator*~~ *production unit* or *Market Participant*	Submit to AEMO the following MT PASA inputs: • PASA *availability* of each *scheduled production unit*~~*scheduled generating unit*~~, *scheduled load* or *scheduled network service.* • Weekly *energy constraints* applying to each *scheduled* ~~*generating unit*~~ *production unit* or *scheduled load.* Unit state that provides the reason for unavailability, and unit recall time for unit states that are subject to recall of each *scheduled production unit.* • ~~Unit state that provides the reason for unavailability, and unit recall time for unit states that are subject to recall of each *scheduled production unit.*~~	3.7.2(d) 3.7.2(d1)

Responsible party	Action	Rules requirement
Semi-scheduled Generator or Market Participant	Submit to AEMO the following MT PASA inputs: • Plant availability for each *semi-scheduled generating unit*, providing all periods of expected unavailability where the unit is expected to be at least 6MW below or above the nameplate rating of the unit.	3.7B(b)
Network Service Providers	Provide AEMO the following information: • Outline of planned *network outages*. • Any other information on planned *network outages* that is reasonably requested by AEMO.	3.7.2(e)
AEMO	Prepare and *publish* the MT PASA *outputs*	3.7.2(f)

3. MT PASA inputs

Inputs used in the MT PASA process are provided by AEMO and *market participants*. They are discussed in detail below.

3.1. Market participant inputs

Market participants and *Scheduled Generators* are required to submit the following data in accordance with the *timetable*, covering a 36 month period from the Sunday after the *day* of publication of MT PASA.

3.1.1. ~~Generating unit~~Production unit availabilities for MT PASA

- *Scheduled ~~G~~production~~enerating~~ unit, and scheduled network* PASA availabilities:
  - MT PASA uses PASA availabilities of scheduled ~~generating~~ production units and scheduled networks. PASA availability includes the ~~generating~~ capacity in service as well as the ~~generating~~ capacity that can be delivered with 24 hours' notice.
- As per clause 3.7.2(d)(1), ~~*Ggenerators*~~ market participants are required to provide the expected daily MW capacity of each *scheduled ~~generating~~ production unit, scheduled network* or *scheduled load* for the next 36 months and 24 months respectively. The actual level of ~~*generation*~~ *capacity* available at any particular time will depend on the condition of the ~~generating~~ plant, which includes factors such as age, outages, and wear. Another important factor with respect to output is the reduction in thermal efficiency with increasing temperature.
- *Market participants* ~~Generators~~ should take into account the ambient weather conditions expected at the time when the Region where the ~~generating~~ production unit is located experiences the 10% Probability of Exceedance (POE) *peak load.*
- *Scheduled production* ~~Generating unit~~*unit* energy availabilities:
  - Generating plant such as hydroelectric power stations cannot generally operate at maximum capacity indefinitely because their energy source may become exhausted. Gas and coal plants can have energy constraints due to contracted fuel arrangements or emissions restrictions. Under clause 3.7.2(d)(2), scheduled generating units and integrated resource systems with a weekly energy constraint (referred to as energy constrained plant) are required to submit that weekly energy limit in MWh for all relevant

weeks over the upcoming 36-month period commencing from the first Sunday after the latest MT PASA run.

- AEMO may also use other information available such as that provided through the Generator Energy Limitation Framework (GELF) or generator surveys to develop daily, monthly, annual and/or biennial energy constraints for MT PASA modelling.
- The energy limits should be determined by ~~generators ,~~market participants taking into account:
  - The potential for fuel stockpiles or water storages to fluctuate in the short term.
  - The generator's capability to replenish stockpiles and storages if depletion occurs.

Energy limits should reflect output limits of scheduled generating units and scheduled bidirectional units. Energy limits must represent sustainable weekly limits that reflect the long term capability of the plant, not a limit for the week considered in isolation. For example, the impact of an energy limit being reached should not fully or near-fully deplete energy availability for subsequent weeks.

- ~~Wind turbine and large-scale solar~~Semi-scheduled production unit availabilities:
  - To help AEMO fulfil its obligation under clause 3.7.2(c)(4) and consistent with clause 3.7B(b), participants who operate ~~such~~ *semi-scheduled production* units are required to submit ~~local limit~~ information on their ~~wind turbine, or solar~~ availability to AEMO. This information is used to augment historical generation data, to develop *unconstrained intermittent generation forecasts*. Further details are provided in Section 3.2.1.

3.1.2. Unit state and unit recall time

~~U~~From 9 October 2023, *Scheduled ~~Generators~~production units* must submit ~~a~~daily unit state and recall times that reflect their current intentions and best estimates, alongside PASA availability and weekly energy limits from the next Sunday for a 36-month period.[5].

A unit state must be provided from the list shown in Table 2~~Table 2~~ that best describes the PASA availability submitted for each day over the next 36 months. The list of unit states is developed based on IEEE standard 762-2006, and further information, including state descriptions, is available below. Where there are multiple potential reasons for the PASA availability submitted, participants should submit the reason code that is most dominant.

The 'No deratings' category should be used when the submitted PASA availability represents 'Dependable capacity', not just 'Maximum capacity' as defined in the IEEE 762-2006 standard, which would therefore include 'Seasonal derating'. For example, a unit submitting PASA availability that represents full summer peak availability should use unit state 'No deratings' even if this availability is ~~is~~ lower than winter, registered or maximum capacity.

A unit recall time must be provided in whole days, if relevant, that represents the advance notice required, under normal conditions, to make the unit available to normal operation on the

[5] See the AEMC Enhancing information on generator availability in MT PASA rule change: https://www.aemc.gov.au/rule-changes/enhancing-information-generator-availability-mt-pasa.

day for which the recall time has been submitted. Normal operation should be interpreted as the typical capacity submitted for the time of year, assuming no outages.

For unit states that indicate an outage for economic reasons, other than a 'retired' state, the submission of a recall time is mandatory. For unit states that indicate an outage for physical reasons, the submission of a recall time is considered mandatory if available. For example, under circumstances where the unit is not recallable to normal operations, a NULL submission is valid.~~.~~

~~Table~~ Table 22 lists the unit states, the shortform codes that are used for data entry, whether the unit state is associated with an economic or physical outage, and whether an accompanying unit recall time must be provided. A recall time requirement of 'mandatory if available' means that a recall time must be provided if the unit is recallable.

Table 2 List of unit states, shortform codes, economic/physical reason, and recall time requirements

Unit state	Shortform code	Reason for outage	Recall time requirements
Inactive reserve	InactiveReserve	Economic	Mandatory
Mothballed	Mothballed	Economic	Mandatory
Retired	Retired	Economic	None
No deratings	NoDeratings	N/A	None
Basic planned deratings	DeratingPlanBasic	Physical	Mandatory if available
Extended planned deratings	DeratingPlanExtend	Physical	Mandatory if available
Unplanned forced deratings	DeratingUnplanForced	Physical	Mandatory if available
Unplanned maintenance deratings	DeratingUnplanMaint	Physical	Mandatory if available
Basic planned outage	OutagePlanBasic	Physical	Mandatory if available
Extended planned outage	OutagePlanExtend	Physical	Mandatory if available
Unplanned forced outage	OutageUnplanForced	Physical	Mandatory if available
Unplanned maintenance outage	OutageUnplanMaint	Physical	Mandatory if available

The following IEE762-2006 definitions apply to each of the unit state's listed.

Table 3 Unit state definitions consistent with IEEE762-2006

~~U~~Unit state	Definition
Inactive reserve	Unavailable for service but can be brought back in a relatively short period of time, typically measured in days
Mothballed	Unavailable for service but can be brought back with appropriate notification, typically weeks or months
Retired	Unavailable for service and not expected to return to service in the future.
No deratings	Available with no deratings, or only seasonal deratings.
Basic planned deratings	Planned derating as originally scheduled and with a predetermined duration.

UUnit state	Definition
Extended planned deratings	Planned derating that is an extension of the basic planned derating beyond its predetermined duration.
Unplanned forced deratings	Unplanned derating that cannot be deferred beyond the end of the next weekend
Unplanned maintenance deratings	Unplanned derating that can be deferred beyond the end of the next weekend but required before next planned derating.
Basic planned outage	Planned outage as originally anticipated and with a predetermined duration.
Extended planned outage	Planned outage that is an extension of the basic planned outage beyond its anticipated duration.
Unplanned forced outage	Unplanned outage that cannot be deferred beyond the end of the next weekend.
Unplanned maintenance outage	Unplanned outage that can be deferred beyond the end of the next weekend but required before next planned outage.

The following examples may assist participants to understand how they may apply a unit state and recall time consistent with the requirements:

Example 1: A participant has made a decision to mothball a unit of a power station, due to the ongoing financial viability of the unit. Under normal conditions, the unit could be recalled to normal operations with six months notice. In this case, the participant should submit daily information, for the period of the planned mothballing:

- PASA availability of zero,
- Unit State of 'Mothballed'
- Recall Time of 180 days

Example 2: A participant has decided to undertake maintenance on a production unit that makes it entirely unavailable. It may be recalled under some circumstances during the maintenance but only to half of full capacity. For the time of the planned maintenance, the participant should submit:

- PASA availability of zero
- Unit State of 'Basic planned outage'
- Recall Time of NULL, which reflects that the unit can not be recalled to 'normal' operations'.

During planned maintenance the participant identifies that economic conditions following the maintnenance are not favourable, and decides to keep the unit out of service for four further weeks. If the need arises, the participant could recall the unit with 3 days notice under normal conditions, but could not recall it within 24 hours under direction. The participant should submit, for the period of the additional expected unavailability:

- PASA availability of zero
- Unit State of 'Inactive reserve'
- Recall Time of 3 days

Example 3: Following the identification of a fault that makes operation at full capacity impossible, a participant has undertaken an unplanned forced derating that will take three weeks to fix. Until this fault is fixed, the unit is unable to operate at full capacity. The participant should submit, for the period over which the unplanned forced derating is expected to occur:

- PASA availability reflecting the reduced operating capacity, that is available within 24 hours notice.
- Unit State of 'Unplanned forced deratings'
- Recall Time of NULL

During the period of repair, the participant decides to commit to further repairs on the affected components, noting that economic conditions were unfavourable to return to earlier service. The participant intends to operate the plant at the reduced operating capacity, or not at all. The participant would return the unit to service within 3 days under normal conditions, but can make full capacity available within 24 hours notice under direction. The participant should submit:

- PASA availability reflecting full capacity, since this capacity is available within 24 hours notice.
- Unit State of 'No deratings'
- Recall Time of NULL

Example 4: Following the identification of a fault that results in an unplanned outage the participant chooses to delay maintenance to rectify the fault for economic reasons.

In circumstances where multiple outage codes could apply, participants should submit the single outage code that is most representative.

For example, the participant may determine that the relevant skills, parts and access could be arranged to repair the fault within a six month timeframe, considering reasonable expectations for delays and complications. For the first six months of the outage, the participant might choose to submit:

- PASA availability of zero
- Unit State of 'Unplanned forced outage-'
- Recall Time of NULL

Should the participant decide to defer the maintenance for economic reasons, the participant may choose to submit (after the period it would reasonably take the participant to restore service that resulted in an unplanned outage):

- PASA availability of zero
- Unit State of 'Mothballed-'
- Recall Time of 180 days

~~3.1.2.~~3.1.3. Network outages and Interconnector availabilities

Under clause 3.7.2(e), *Network Service Providers* must provide AEMO with an outline of planned *network outages* and any other information on planned *network outages* reasonably requested by AEMO. This includes interconnector availability information (e.g. Basslink). The planned *network outages* are converted into *network constraints* by *AEMO*. This process is further discussed in Section 3.2.3.

3.2. AEMO inputs

3.2.1. Plant availabilities for MT PASA

AEMO prepares other plant availability data, not provided by *market participants*:

- Semi-scheduled wind and solar generation forecasts:
  - AEMO is required to produce an *unconstrained intermittent generation forecast* (UIGF) for each *semi-scheduled generating unit* for each *day* in accordance with clause 3.7.2(c)(4).

- AEMO develops the UIGF using historically observed generation outputs and historical meteorological data for wind and solar units to develop generation output estimates based on relevant energy conversion models based on the generator technology for at least eight reference years. These outputs reflect the weather conditions that underlie the demand traces for those reference years, ensuring that any correlation between variable renewable energy (VRE) generation and demand is preserved.

- ~~Where historical generation data is unavailable or unsuitable, AEMO may use historical meteorological data for the site, and an energy conversion model based on the generator technology to develop a generation forecast.~~
- Non-scheduled generation forecasts:
  - In accordance with clause 3.7.2(f)(2), AEMO is required to prepare and *publish* the aggregated MW allowance (if any) to be made by AEMO for *generation* from *non-scheduled generating systems*.
  - The non-scheduled generation profiles have two parts: large non-scheduled wind and solar generation (refer to Table 4~~Table 4~~ for further details) and small non-scheduled generation. The large non-scheduled wind and solar generation forecasts are calculated based on historically-observed generation outputs over at least eight reference years, while the small non-scheduled generation forecasts are consistent with figures published in AEMO's demand forecasts[6].
  - The small non-scheduled generation forecasts for units under 30MW are used as an input to the MT PASA operational demand forecasting process and are not modelled explicitly.
- Demand side participation:
  - Demand side participation (DSP) includes all short-term reductions in demand in response to temporary price increases (in the case of retailers and customers) or adverse network loading conditions (in the case of networks). An organised, aggregated response may also be possible. From the transmission network perspective, consumers may effectively reduce demand by turning off electricity-using equipment or starting up on-site generators.
- Future ~~generation~~production unit projects:
  - Consistent with clause 3.7.2(c)(2), scheduled, semi-scheduled or large non-scheduled ~~generation~~production unit projects with a commitment to construct or install[7] are also modelled in MT PASA. AEMO applies future production projects to MT PASA consistent with the criteria applied to the ESOO, which includes those projects assessed as being 'committed', 'committed*' or 'anticipated', using inputs -and project delay assumptions consistent with the ESOO.

[6] Available at http://forecasting.aemo.com.au/.

[7] Information on the criteria used by AEMO to classify projects as committed can be found at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

Before the unit is registered, PASA availability for a ~~committed~~ new scheduled ~~generating~~ production unit is estimated based on participant information regarding the commercial use date and seasonal capacity. The Generator information page reports this information[8].

The unit is entered into a Future Generation table that is referenced during modelling to include all "~~committed~~ new but not registered" units. Once the unit is registered, it is removed from the Future Generation table.

Participants are responsible for submitting MT PASA unit data to AEMO once registered.~~In the case of scheduled generators, the *Generator* that owns the unit is then responsible for submitting MT PASA unit offer data to AEMO.~~

In the case of semi-scheduled ~~generating units~~~~ors~~production units and large non-scheduled generators, AEMO applies availability traces for the unit for use in modelling, developed ~~through either:~~

- ~~Using a "shadow generator" based on existing VRE generation of a similar technology type in close proximity; or~~

~~Using meteorological data for the generation site, and assuming an energy conversion model based on a similar technology type.~~using an approach consistent with existing semi-scheduled participants.

3.2.2. Demand forecasts

AEMO develops a range of demand forecasts for MT PASA that are used for both modelling and reporting obligations. Table 4~~Table 4~~ shows the definitions of the different types of demand that are referenced in this document.

For a more detailed explanation of the calculation of demand forecasts, please consult Appendix B.

~~Table 2~~Table 4 AEMO demand definitions

Demand type	Definition	Description
Underlying	Customer consumption	Consumption on premises ("behind the meter") including demand supplied by rooftop PV and battery storage.
Delivered	Underlying – PV – battery	The energy the consumer (either residential or business) withdraws from the electricity grid.
Native	Delivered + (network losses)	Total generation fed into the electricity grid. May be specified as "sent-out" (auxiliary load excluded) or "as-generated" (auxiliary load included). Includes both transmission and distribution losses.
Operational "sent-out"[9]	Native – Small Non-Scheduled ("as sent out")	Demand met by generation "as sent out" by scheduled / semi-scheduled / large non-scheduled ~~generators.~~production units.
Operational "as generated"	Operational "as sent out" + auxiliary loads	Demand met by generation "as generated" by scheduled / semi-scheduled / large non-scheduled ~~generators~~ production units including demand on generator premises (auxiliary load).
VRE	Variable renewable energy	Demand met by semi-scheduled and large non-scheduled ~~generators~~ production units excluding the impact of network constraints. This is a non-standard demand definition used for LOLP modelling.

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

[9] For details on operational demand please refer to demand definitions here https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/dispatch-information.

Demand type	Definition	Description
Operational "ex VRE"	Operational "sent out" - VRE	Demand met by scheduled ~~generators~~production units. This is a non-standard demand definition used for LOLP modelling.
Non-scheduled	Large + Small Non-Scheduled	Demand met by large and small non-scheduled ~~generators~~production units.
Large Non-scheduled	Also referred to as Significant Non-Scheduled	Large non-scheduled generators include: • Wind or solar generators >=30 MW • Generators classified as non-scheduled but treated as scheduled generators in dispatch.

MT PASA demand forecasts are summarised and the specific demand requirements for each of the two modelling runs are discussed in further detail below.

The daily demand forecasts published in the REGION AVAILABILITY table are provided for reporting purposes only and are not the demand traces that are used in any of the MT PASA reliability assessments.

MT PASA Modelling:

- Annual operational "sent-out" demand profiles, consisting of half-hourly demand values, with energy consumption and maximum demand aligned with AEMO's latest sent-out forecasts. (Reliability Run).
- Abstract operational demand and VRE generation forecasts constructed, based on the evaluation of the years of historical observations. The traces represent conditions of high demand levels occurring coincidentally with low VRE generation output and are abstract since these conditions are assumed every day (LOLP Run).

MT PASA Reporting - Clause 3.7.2(f)(1) – (4):

- Daily peak 10% POE and 50% POE demand met by scheduled and semi-scheduled generators (clause 3.7.2(f)(1) and (1A))[10], non-scheduled allowance (clause 3.7.2(f)(2)), and native demand (clause 3.7.2(f)(3)), aligned with AEMO's latest forecasts.
- Weekly 50% POE energy consumption (clause 3.7.2(f)(4)).

Reliability Run

The annual operational "sent-out" demand profiles used in MT PASA modelling identify and quantify any projected breach of the *reliability standard*. For this purpose, both maximum demand and energy consumption are important to capture, and the profile is developed considering past trends, day of the week and public holidays. Auxiliary load is calculated directly in the modelling, based on assumed auxiliary load scaling factors for each generator and integrated resource system.

The actual demand differs from forecast, mainly due to weather. Statistically, it can be assumed that the forecast error follows a normal distribution. Accordingly, a forecast can be qualified by the probability that actual demand will exceed forecast demand or POE:

- A 10% POE forecast indicates a 10% chance that actual demand will exceed the forecast value over the relevant period (i.e. peak demand will be exceeded once in 10 years).

[10] Note, this is not the same as operational demand as it excludes both large and small non-scheduled generation.

- A 50% POE forecast indicates a 50% chance that actual demand will exceed the forecast value over the relevant period.

The timing and regional spread of these weather events also impacts on demand – hot weather in a single region on a weekend will impact demand (and potentially reliability) differently than a heat wave that has been building for days with impact felt across multiple regions.

To capture the impact of weather variations on demand, at least 16 different annual demand profiles (corresponding to model cases discussed in Section 4.3) are developed for each region, based on different historic weather patterns and POE annual peak demand forecasts. While this captures a reasonable range of different weather-driven demand conditions, it unavoidably requires assumptions to be made about precisely when the annual peak demand could occur, based on historical demand patterns, even though it is impossible to predict when the annual peak demand will occur in future.

Loss of Load Probability Run

Appropriate timing of maintenance scheduling can reduce the likelihood of unserved energy in times of high demand. Consequently, it is important that AEMO also considers the loss of load probability in each period of the modelling horizon, assuming weather conditions resulting in a combination of high demand and low VRE generation were to occur in that specific period, to help guide outage scheduling.

The LOLP demand and VRE generation modelling traces are based on high demand and low VRE generation conditions observed over the different reference years, assessed on a month-by-month basis for each day of the week. The traces can be classed as “abstract” since each day is considered independently of the next, assuming close to monthly 10% POE weather conditions occurring each day. Summing daily energy consumption will not produce realistic annual energy consumption forecasts. Each region is considered independently but allows for support from adjacent regions across interconnectors.

3.2.3. Power transfer capabilities used in MT PASA

For MT PASA, AEMO is required to forecast *network constraints* known to AEMO at the time, under clause 3.7.2(c)(3).

Network constraints used in MT PASA represent technical limits on operating the power system. These limits are expressed as a linear combination of generation and interconnectors, which are constrained to be less than, equal to or greater than a certain limit.

Information to formulate *network constraint equations* is provided to AEMO by Transmission Network Service Providers (TNSPs) via Network Outage Scheduler (NOS)[11] and limit advice. The process of producing *network constraint equations* is detailed in the Constraint Formulation Guidelines[12]. Within AEMO’s market systems, *constraint equations* are marked as system normal if they apply to all plant in service. To model network or plant outages in the power system, separate outage *constraint equations* are formulated and applied with system normal *constraint equations*.

AEMO continues to update and refine *network constraints* through its ongoing modelling projects. MT PASA uses the latest version of ST PASA formulation constraints as a starting

[11] http://nos.prod.nemnet.net.au/nos

[12] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information

base, with additional customised *network* constraints associated with future planned *network* and generation upgrades. AEMO constructs system normal and outage constraint equations for the MT PASA time frame. MT PASA modelling is conducted with system normal and approved planned network outage constraints applied.

See Appendix D for further information on the calculation of transfer capabilities.

4. MT PASA solution process

4.1. NEM representation

The power system model used within the MT PASA simulation is similar to the model applied for AEMO's wholesale electricity market systems:

The salient features of the power system model are:

- Single regional reference node (RRN) within each market region at which all demand within the region is deemed to apply.
- ~~Generators~~ Units connected to the regional reference node via a "hub and spoke" model. Static transmission loss factors are used to refer price data from the generator connection point to the RRN of the host region.
- Flow between market regions via interconnectors, which provide transport for energy between regions. Losses for flows over interconnectors are modelled using a dynamic loss model.
- Modelling of thermal, stability and energy constraints to be achieved by overlaying constraint equations onto the market-based model.

4.2. Overview of modelling approach

MT PASA assessment is carried out at least weekly using two different model runs:

1. Reliability Run – to identify and quantify potential *reliability standard* breaches, and assess aggregate constrained and unconstrained capacity in each region, system performance and network capability

2. Loss of Load Probability Run – to assess days most at risk of load shedding.

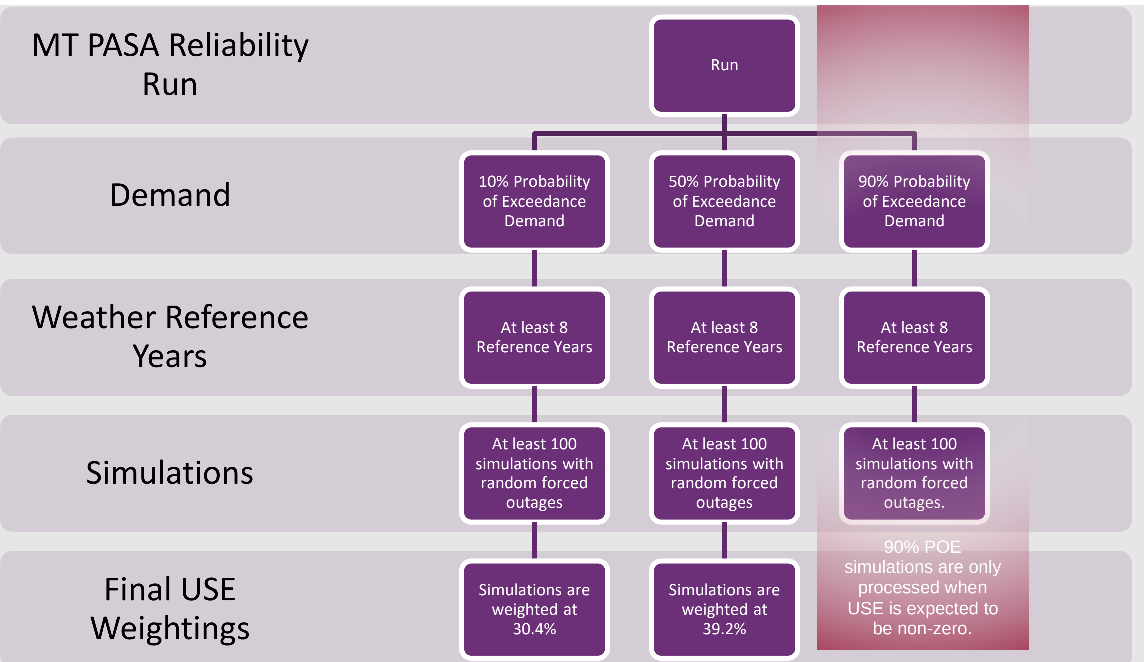
These two runs are discussed in more detail in the following sections.

4.3. MT PASA Reliability Run

The MT PASA Reliability Run implements the *reliability standard* by assessing the level of unserved energy and evaluating the likelihood of *reliability standard* breaches through probabilistic modelling. The Reliability Run is conducted weekly.

The MT PASA Reliability Run uses at least 100 Monte-Carlo simulations[13] on a set of predefined cases to assess variability in unserved energy outcomes (see Figure 1). Demand and VRE generation supply assumptions vary for each case, driven by different historical weather conditions. Within a case, the Monte-Carlo simulations vary with respect to unplanned generation outages based on historical forced outage rates.

Figure 1 MT PASA Reliability Run case construction



In total, at least ~~1,0~~800 simulations are conducted for each year of the reliability assessment horizon and are weighted to form the final estimate of USE. AEMO MT PASA weightings ~~now~~ match ESOO weightings of 30.4% for 10% POE, 39.2% for 50% POE and 30.4% for 90% POE, where 90% POE demand will not be subject to simulation to minimise costs (unless USE is expected to be non-zero, and simulations will therefore improve accuracy).

The objective function associated with the simulation is:

- Minimise total generation cost plus hydro storage violation cost subject to:

[13] Probabilistic modelling involves many repetitions of the simulation model while applying random sampling to certain components of the model. In MT PASA the random sampling is applied to the occurrence of forced outages for generation. Other uncertain variables such as regional demand coincidence and VRE generation availability are varied through use of the different cases.

- Supply/demand balance.
- Unit capacity limits observed.
- Unit/power station/portfolio energy limits observed.
- Network constraints observed.
- DSP bounds observed.

The Reliability Run is conducted in three phases:

1. Generate random patterns of forced outages and determine any other stochastic parameters required for each simulation run.
2. Split the two-year MT PASA horizon into two one-year periods that are solved at a reduced level of time detail to allow long-term energy constraints to be optimised so that resources subject to constraints are deployed at the most appropriate time. Inter-temporal constraints are decomposed into a set of ending targets for each weekly time frame selected for use in phase three.
3. Solve the entire horizon in shorter weekly steps with full half-hourly detail, using the weekly allocation targets determined in phase two. MT PASA weekly energy limits are co-optimised with dispatch of other resources, including VRE generation, to maximise the value of the energy limited resource.

Most hydro generators are modelled with storages and their generation is subject to historically assessed inflows and outflows from these storages. Annual energy limits are implemented through the requirement that the storage at the end of the year must be equal to or greater than the storage at the start of the year. Storage levels must also remain within upper and lower bounds. During phase two, a series of optimal storage targets for each weekly period are set for use in phase three. If these targets are not met in phase three, penalties are applied according to a series of penalty bands that are low for small variations and high for large variations from target levels.

In addition to the storage targets, hydro generation is also constrained according to both PASA availability and any MT PASA weekly energy constraints submitted. Weekly energy constraints for all generation types are considered in both phase two and phase three, and cannot be violated.

Each simulation produces an estimate of annual USE, with the simulations providing insight into the distribution of annual USE. AEMO uses a weighting of 39.2% for 50% POE and 30.4% for 10% POE demand levels, to assess the expected USE as a weighted average across all simulations. The 90% POE demand levels are not normally modelled explicitly as AEMO assumes that USE will be zero, which is reflected in the weightings provided.

If there are material levels of USE in 50% POE results, AEMO considers running additional demand levels such as 90% POE. The USE outcomes in these simulations would then be weighted by 30.4%. AEMO is developing a broader range of POE traces for modelling and will update this document should any changes be made, including weightings. The expected annual USE value from the simulations can be compared directly against the *reliability standard*. This allows AEMO to accurately assess whether the *reliability standard* can be met. AEMO declares a LRC if the expected value of USE across all simulations exceeds the *reliability standard*.

Pain sharing is not included. Instead, the annual USE reported in a region reflects the source of any supply shortfall and is intended to provide participants with the most appropriate locational signals to drive efficient market responses. (See Appendix C for a more detailed explanation).

4.4. MT PASA Loss of Load Probability (LOLP) Run

To determine days most at risk of load shedding, AEMO conducts a LOLP assessment for each day in the two-year horizon, assuming that weather conditions associated with high demand and/or low VRE generation availability were to occur on that day. The main objective is to determine which days have higher relative risk of loss of load to help participants schedule outages outside of these periods, and indicate when AEMO may be required to direct or contract for reserves under the RERT.

The abstract operational demand and VRE generation traces discussed in Section 3.2.2 are used for the LOLP run. A detailed explanation of trace construction is given in Appendix B.

The LOLP run uses a probabilistic modelling approach similar to the Reliability Run. Up to 500 simulations with random unplanned outages of *scheduled* ~~generation~~ production units are carried out. ~~Energy constraints are not included for LOLP modelling, as only one day at a time is modelled and there is no optimisation over the full horizon.~~ Network constraints incorporating system normal limits and planned outages are used along with the MT PASA availability and weekly energy limits submitted by participants.

The loss of load probability is calculated by firstly determining the probability of loss of load in each half-hour of the day. For example, if 50 out of 500 simulations show loss of load, there is approximately a 10% chance of loss of load in that particular half hour. The maximum half-hourly LOLP across all 48 half hours is reported as the LOLP for the day.

4.5. Comparison of model features

Table 5~~Table 5~~ shows the comparison of the key features of the two MT PASA modelling runs.

~~Table 3~~Table 5 Comparison of MT PASA run features

MT PASA inputs		
Property	**Reliability Run**	**LOLP Run**
Horizon	2 years	
Frequency of Run	Weekly	
Simulations	At least 100 per case	Up to 500, one case only.
Resolution	Half Hourly, returning a single half hour per day based on worst demand/supply conditions	
Registration	Using market system registration as a base including regions, interconnectors, generators, transmission loss factors, interconnector loss models, fuel and regional reference node memberships for generators	
Demand	At least eight half hourly demand traces for each of 10% POE and 50% POE maximum demand forecasts.	One half hourly abstract operational demand trace based on the maximum operational "ex VRE" demand observed in the half hourly reference years
Generator Capacity	As per participant MT PASA declarations	
Generator Bid Offers	SRMC calculated from heat rate, fuel price, VOM etc.	
Generator Forced/partial outage modelling	Probabilistic assessment of forced outages over multiple simulations	

MT PASA inputs		
Hydro Modelling	Based on AEMO hydro storage model[14] with monthly inflows associated with average levels of annual production. Pumped storage modelled. MT PASA Weekly energy constraints applied.	Energy limitations are not considered.
VRE (Semi Scheduled) Generation	At least eight historical weather traces, correlated to demand traces	Traces based on extreme monthly demand and VRE generation conditions observed in the half hourly historical reference years
Non-scheduled Generation	Large non-scheduled generation is modelled individually through traces. Small non-scheduled generation (<30MW) is based on the most recent AEMO forecast which can be found on the AEMO forecasting portal[15]. Further details on the methodology for forecasting non-scheduled demand can be found on the AEMO ESOO information page[16].	
Network Representation	ST PASA formulation constraints with dynamic right hand side (RHS with network outages)	
TNSP Limit Data	Equipment ratings inclusive of seasonal variations required for evaluating generic constraint RHS	
Interconnector forced outage modelling	Not modelled	
Demand Side Participation	At least eight static Price/Quantity bands.	
Rooftop PV	Correlated to demand trace, but not explicitly modelled.	
MT PASA solution		
Property	**Reliability Run**	**LOLP Run**
Purpose of run	Assess level of unserved energy and the likelihood of reliability standard breaches.	Assess the days at highest risk of loss of load
Type of run	LP minimising total generation cost subject to: Supply = demand Unit capacity limits observed Generator Energy limits observed Network constraints observed Hydro storage bounds observed	LP minimising total generation cost subject to: Supply = demand Network constraints observed Hydro storage bounds observed
MT PASA outputs (See Appendix F for Detailed Description of Outputs)		
Property	**Property**	**Property**
Low Reserve Condition	Forecasts of low reserve conditions based on expected annual USE	
Unserved Energy	Distribution of unserved energy on a half hourly snapshot, daily, monthly and annual basis.	
Loss of Load Probability		Highest half hourly LOLP on any given day.
Interconnector Transfer Capabilities	Interconnector transfer capabilities under system normal conditions are published on the AEMO website[17]. Interconnector capabilities in the presence of outages are assessed during the Reliability Run.	

[14] AEMO's '*Market modelling methodology report'* document contains details on the hydro storage model and can be found here: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[15] Available at http://forecasting.aemo.com.au/.

[16] See the Demand Forecasting Methodology information provided at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

[17] Published in the 'Interconnector Capabilities report' which can be found at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource/network-status-and-capability.

MT PASA inputs		
Network Constraint Impacts	When and where network constraints may become binding on the dispatch of generation or load	
Projected violations of Power System Security	Reporting on any binding and violating constraints that occur during modelling	

5. MT PASA outputs

Under clause 3.7.2(f) of the *Rules*, AEMO must *publish* the MT PASA outputs as part of the MT PASA process[18]. From a reliability perspective, the main MT PASA output is the forecast of any low reserve condition and the estimated USE value.

The NER 4.8.4(a) defines an LRC as:

"Low reserve condition – when AEMO *considers that the balance of generation capacity and demand for the period being assessed does not meet the reliability standard as assessed in accordance with the reliability standard implementation guidelines".*

Table ~~4~~ 6 shows the MT PASA outputs produced by the Reliability Run. The outputs are based on short-run marginal cost bidding rather than any estimate of strategic bidding to emulate observed market behaviour. Given the probabilistic nature of the Reliability Run, distributions of simulated outputs are reported in most instances.

~~Table 4~~Table 6 MT PASA outputs specified in NER 3.7.2(f)(6) produced by Reliability Run

MT PASA output specifications NER 3.7.2(f)	MT PASA publication	Output details
(6) Identification and quantification of:		
(i) Any projected violations of power system security	MT PASA Reliability Run	Constraint solution outputs identifying binding and violating constraints. If any constraints are violated, it indicates that there is a projected violation of power system security.
(ii) Any projected failure to meet the reliability standard assessed in accordance with the RSIG	MT PASA Reliability Run	Annual regional weighted average USE used to identify LRC level if above the reliability standard.
(iii) Deleted		
(iv) Forecast interconnector transfer capabilities and the discrepancy between forecast interconnector transfer capabilities and the forecast capacity of the relevant interconnector in the absence of outages on the relevant interconnector only	MT PASA Reliability Run Constraint library & NOS Interconnector Capability Report	MT PASA Reliability Run will provide range estimates of interconnector capabilities in the presence of outages. The Interconnector Capability Report will provide estimates of interconnector capabilities under system normal conditions. AEMO recommends using the Constraint Library and the Network Outage Schedule for accurate and comprehensive information on applicable constraints.
(iv) Forecast interconnector transfer capabilities and the discrepancy between forecast interconnector transfer capabilities	MT PASA Reliability Run Constraint library & NOS	MT PASA Reliability Run will provide range estimates of interconnector capabilities in the presence of

[18] http://www.nemweb.com.au/REPORTS/CURRENT/MEDIUM_TERM_PASA_REPORTS/. A guide to the information contained in the MT *PASA* is available in the form of a '*MMS Data Model Report*' found here: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/data-nem/market-management-system-mms-data.

MT PASA output specifications NER 3.7.2(f)	MT PASA publication	Output details
and the forecast capacity of the relevant interconnector in the absence of outages on the relevant interconnector only		outages. The Interconnector Capability Report[19] will provide estimates of interconnector capabilities under system normal conditions. AEMO recommends using the Constraint Library and the Network Outage Schedule for accurate and comprehensive information on applicable constraints.
(v) When and where network constraints may become binding on the dispatch of generation or load	MT PASA Reliability Run Constraint Report	Constraints may bind at different times in Reliability Run, depending on the demand and VRE generation trace used, forced outages and generation dispatch. AEMO will also provide a "plain English" report on constraints that provides further details on generators impacted by binding constraints[20]. Appendix G provides a link with instructions for this report.

Appendix F shows a detailed list of output fields that will be published as part of the MT PASA results sent to participants. Due to the high number of simulations and the quantity of data produced during the runs, the results are aggregated before release to participants.

Where results are reported for a day on a half-hourly snapshot basis, the period selected is the half-hourly interval corresponding to the maximum of the average NEM operational "ex VRE" demand[21] across all 10% POE simulations. Most daily outputs represent a half-hourly snapshot, reported on this basis.

Outputs prescribed under clause 3.7.2(f)(1) and (2) – (4) are based on AEMO peak demand forecasts and corresponding assumptions, and are not utilised by modelling.

Outputs prescribed under 3.7.2(f)(1A) are based on the demand traces used in the MT PASA reliability run, adjusted to remove all non-scheduled generation.

Output requirements under clauses 3.7.2(f)(1), (1A), (2) and (4) are supplied in the three-hourly report, and output under clause 3.7.2(f)(3) can be derived from other information provided, as explained in Appendix B.

Outputs (5), (5A) and (5B) are also supplied in the three-hourly report as the aggregate value of participant submitted availabilities, and in the DUIDAVAILABILITY report which shows the DUID level submitted ~~availabilitities~~availabilities, unit states and unit recall times for the next 36 months.

~~On MT PASA system change implementation[22], ~~Outputs (5C) are supplied in the MT PASA reliability run.

[19] The latest report can be found at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information/Network-status-and-capability.

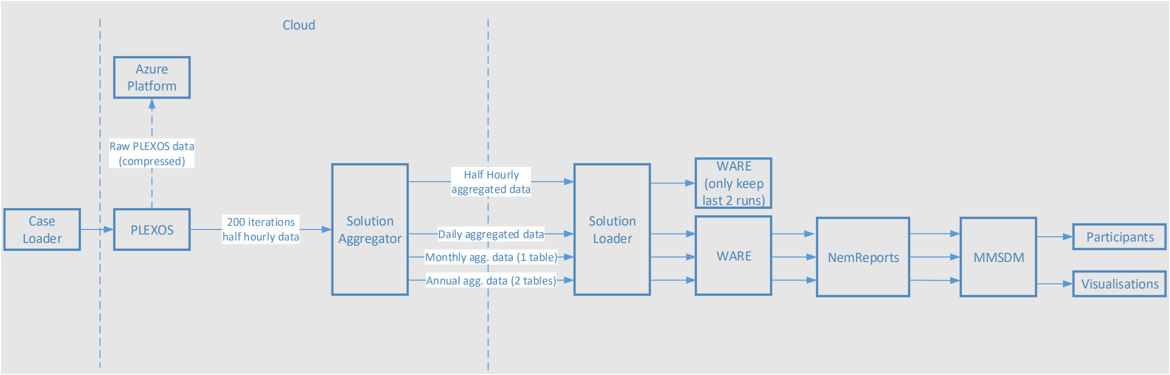
[20] This report provides a list of the constraint equations for outages that are binding in any of the scenarios. The terms on the ~~the~~ left-hand side (affected generators and interconnectors) are shown and the constraint set the constraint equation belongs to is indicated. This then ties back to a description of the outage and NOS.

[21] Calculated as the maximum of 48 half hourly average "ex VRE" demands. Average is taken across all 10% POE model runs e.g. 5 historical reference years x 100 iterations = 500 simulations.

~~[22] Expected December 2020.~~

Appendix A. MT PASA process architecture

Figure 2 MT PASA data flows



The MT PASA process operates as follows:

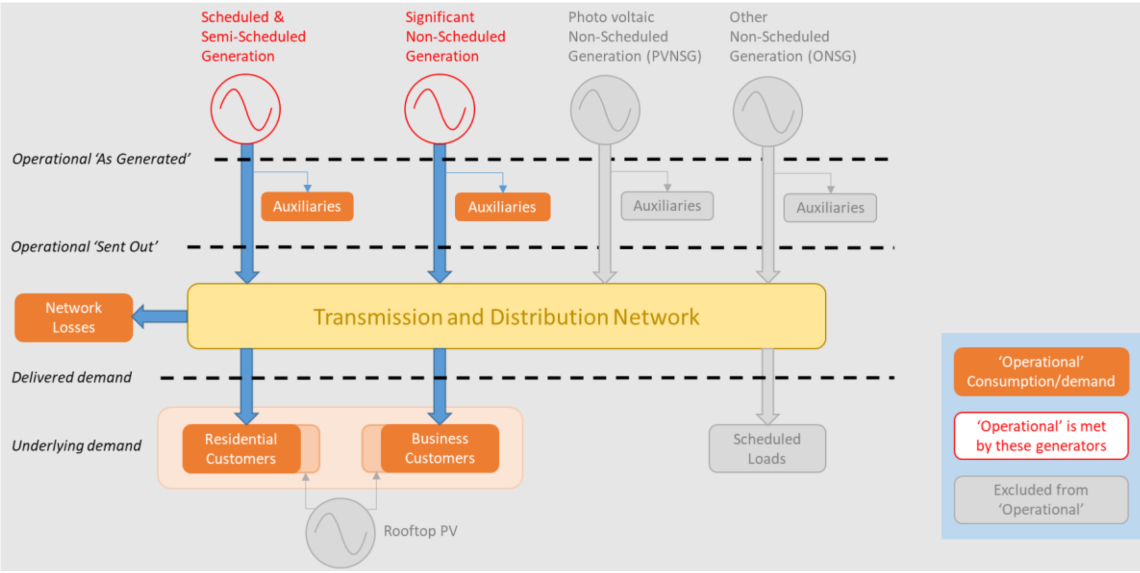
1. The valid *Registered Participant* bids are loaded into tables in the central Market Management System (MMS) Database. Bid acknowledgements are returned to *Registered participants*.
2. All relevant input data is consolidated by the MT PASA Case Loader for loading into the Reliability and LOLP models. This includes information from participant bids, network limits and outages, generator parameters, hydro modelling information and model configuration details.
3. The MT PASA Case Loader populates the input models for the Reliability and LOLP runs and activates the modelling simulations in Azure.
4. The MT PASA Solution Aggregator then aggregates the modelling results which are merged into a file for transfer out of Azure into the Solution Loader.
5. The Solution Loader loads the file into output tables in the NEM database (WARE).
6. The MT PASA NEM report file is then created from the input information and solution information.
7. The new MT PASA files are reformatted according to the MMS Data Model (MMSDM) and sent to each *Registered Participant.*
8. The visualisations are created from the solution tables, and can be accessed via https://portal.prod.nemnet.net.au/.

Appendix B. Medium-term demand forecasting process

MT PASA modelling is based on operational demand forecasts. Figure 3 gives a pictorial definition of this demand. Participant bids are received on as "as generated" basis, while demand forecasts used in MT PASA are on a "sent-out" basis. The difference between the two is the auxiliary load – the station load that supports the operation of the power station.

The estimated auxiliary load is automatically calculated during the modelling as a fixed percentage of "as generated power". The ~~generator~~ production unit ~~auxillary~~auxiliary information supplied to the model is based on AEMO's latest modelling assumptions[23] which are published on the AEMO website. The overall auxiliary load is therefore dependent on the particular dispatch outcome in each simulation as all generator types have varying levels of auxiliary load.

Figure 3 AEMO operational demand diagram



B.1 Reliability Run demand traces

The methodology for creating "as sent out" half hourly demand trace inputs for modelling is covered below:

- Representative traces are obtained using at least eight years of historical data.
- Future liquefied natural gas (LNG) export demand is assumed to have a flat profile across the year and is added to the future Queensland demand traces.

[23] The latest information on AEMO's modelling of generator auxiliary load can be found at https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo.

- Projections of future levels of annual underlying energy consumption and maximum demand in each region are obtained from the most recent published AEMO demand forecasts[24].
- Derived operational traces (with rooftop PV added) are "grown" to represent future energy consumption and maximum demand.
- Forecast rooftop PV is subtracted from the grown trace and retained for separate reporting.
- The assumed impact of behind-the-meter battery storage is also incorporated.

Although not used in the model, "as-generated" half-hourly demand traces are also created for the purpose of calculating the required output properties related to demand discussed in section B.3 below. These traces incorporate assumptions around the annual energy and seasonal maximum demand contributions from auxiliary load which are based on market simulations[25].

B.2 Loss of Load Probability Run demand traces

The LOLP run uses abstract operational demand and VRE generation traces that assume high demand and low VRE generation weather conditions on every day. The abstract traces for each region are developed as follows:

- For each historical reference year (e.g. 2014-15), take the forecast 10% POE operational "sent out" demand trace (the same one used for the Reliability Run).
- Determine the regional total of VRE generation in the same reference year, by aggregating the individual VRE generation traces, taking into account the size/timings of committed new entrants.
- Subtract total regional VRE generation from demand for that particular reference year to determine a regional "ex VRE" demand trace.
- For each month/subset of a month[26] and day-of-week[27] type, find the maximum half-hour operational "ex VRE" demand value across the historical reference years and record the date (day and year).

~~Table 5~~Table 7 Example: Maximum dates and time for ex VRE demand in February

Date & time of maximum ex VRE demand for month	Day of week	Historical reference year	Operational demand (MW)	VRE demand (MW)	Ex VRE demand (MW)
19/02/2018 17:00	Monday	1213	3,221	395	2,826
06/02/2018 16:00	Tuesday	910	3,311	555	2,756
07/02/2018 17:00	Wednesday	1617	3,350	276	3,074
08/02/2018 18:00	Thursday	1617	3,197	227	2,971
23/02/2018 17:00	Friday	1112	3,191	321	2,870
24/02/2018 18:00	Saturday	1112	3,119	218	2,902

[24] Available at http://forecasting.aemo.com.au/.

[25] Also available at http://forecasting.aemo.com.au/.

[26] Smaller time periods may be used to account for holidays e.g. Christmas, and to better represent months where the early weeks are demonstrably different than later months based on historical demand patterns.

[27] Each day of the week is considered separately – i.e. all Mondays are considered together, then all Tuesdays, and so on.

Date & time of maximum ex VRE demand for month	Day of week	Historical reference year	Operational demand (MW)	VRE demand (MW)	Ex VRE demand (MW)
25/02/2018 17:00	Sunday	1415	3,120	180	2,940

- For each date selected above, record the level of operational "ex VRE" demand, and VRE generation availability for each VRE generator in each of the 48 half hours within the day, from the corresponding reference year forecast traces.
- Construct the abstract operational "sent out" demand and individual VRE generation traces repeating values for each day-of-week type (Monday to Sunday) in the month.

B.3 MT PASA daily maximum and minimum demand values

Under clauses 3.7.2(f)(1) to (3), AEMO is required to prepare and publish the following in respect of each day covered by the MT PASA:

(1) forecasts of the 10% probability of exceedance daily peak load, forecasts of the most probable daily peak load and forecasts of the time of the peak, on the basis of past trends, day type and special events, including all forecast scheduled load and other load except for pumped storage loads;

(1A) the maximum and minimum values of the forecasts of the 10% probability of exceedeance peak load and the forecasts of the most probable peak load, prepared by AEMO in accordance with paragraph (c)(1);

(2) the aggregated MW allowance (if any) to be made by AEMO for generation from non-scheduled generating systems in each of the forecasts of the 10% probability of exceedance peak load and most probable peak load referred to in subparagraph (1);

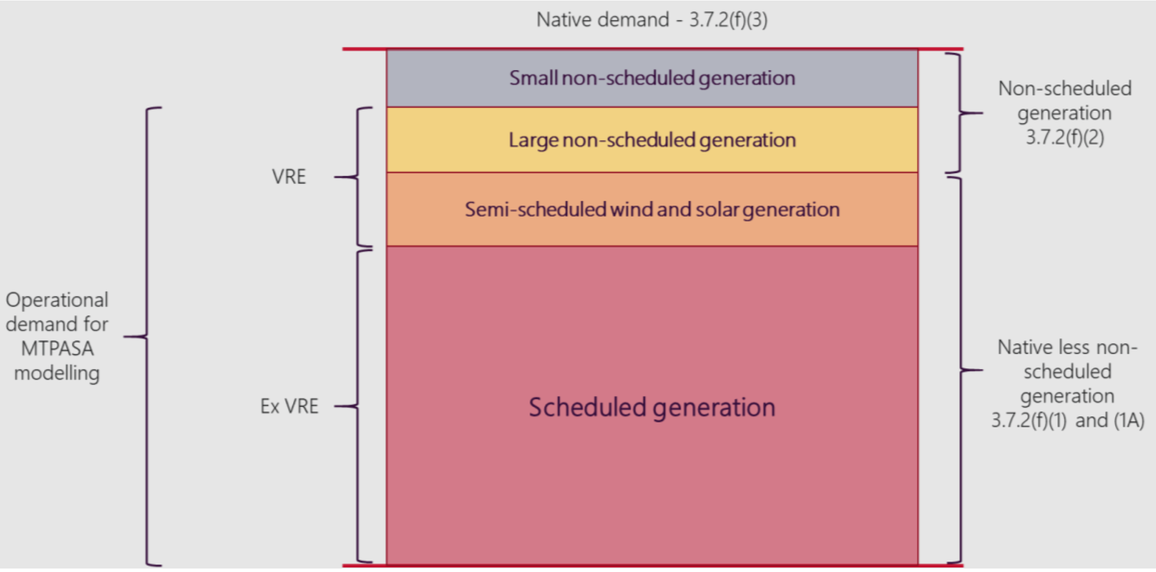
(3) in respect of each of the forecasts of the 10% probability of exceedance peak load and most probable peak load referred to in subparagraph (1), a value that is the sum of that forecast and the relevant aggregated MW allowance referred to in subparagraph (2).

All the modelling in MT PASA is on an operational basis and therefore includes the contribution from large non-scheduled generation. For the purpose of meeting the requirement in 3.7.2(f), AEMO calculates the total regional generation from these large non-scheduled generators in each reference year and subtracts that from the operational as-generated (OPGEN) load traces and targets.

For the purpose of the daily peak demand values, scheduled loads are assumed to be off at time of peak if storage based, and considered on if large industrial loads. The possible reduction in demand from large industrial loads during high price events, including wholesale demand response, is captured in AEMO's demand side participation forecast.

Figure 4 shows various measures of demand that are required to be published under the *Rules* or are used in the MT PASA modelling and how they relate to each other.

Figure 4 Native demand components[28]



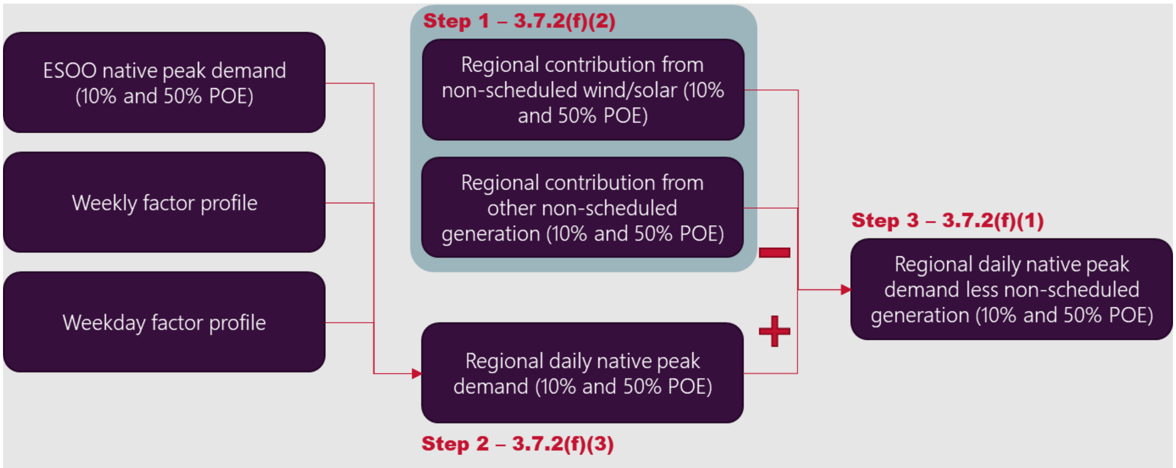
The abstract demand traces used for the LOLP run are not directly comparable to 10% POE daily demand met by scheduled and semi-scheduled generators due to a different treatment of VRE. LOLP traces consider output of large non-scheduled generation (i.e. not including small non-scheduled generators) at times of high “ex VRE” demand.

The components for 3.7.2(f)(1)-(3) are produced in three steps:

- Step 1 – Calculate aggregated MW allowance for non-scheduled generation (3.7.2(f)(2)) by adding the contribution to peak of large non-scheduled generation to the small non-scheduled generation values published in AEMO’s latest demand and energy forecasts.
- Step 2 – Derive regional daily peak native demand profiles (3.7.2(f)(3)) using the latest forecasts of summer and winter peak demand as the basis (reported in three-hourly report) and statistical analysis of historical weekly demand levels relative to these seasonal peaks and a similar assessment of peak demand of each weekday relative to the weekly peak demands.
- Step 3 – Derive regional native daily peak demand less non-scheduled generation profiles for MT PASA (3.7.2(f)(1)) by subtracting the components from Step 1 from Step 2.

These are explained in more detail in the following pages.

Figure 5 Method for developing reported MT PASA daily demand forecasts



Step 1

Non-scheduled demand represents the demand met by both small and large non-scheduled generation. The small non-scheduled demand is supplied through AEMO's latest forecasts as an annual summer and winter figure. The large non-scheduled demand is derived by determining the average generation from large non-scheduled generation across the top 10 hours in each reference year. The total non-scheduled generation is calculated as the sum of the small and large non-scheduled components. This value is published in the three-hourly report and meets the requirements under Clause 3.7.2(f)(2).

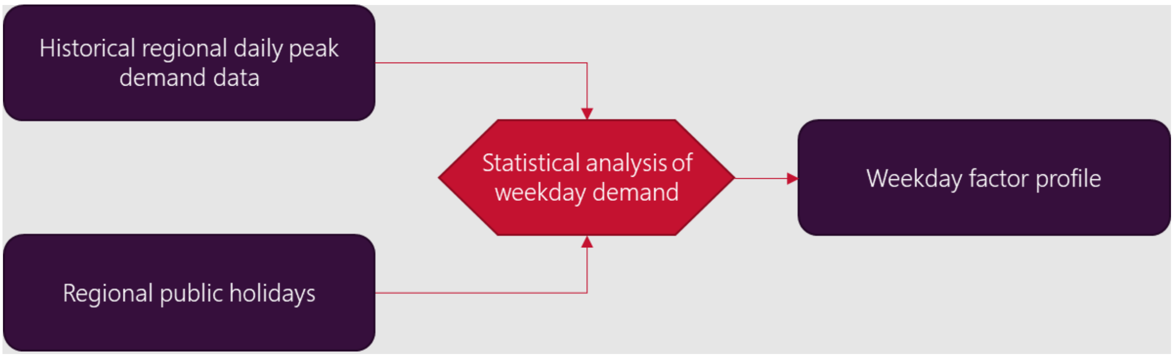
Step 2

The weekly factor profile represents a normalised set of factors (i.e. one factor for each week in the year) determined by taking the ratios of actual maximum weekly demand to the seasonal demand published in AEMO's forecasts for the given historical year. The normalised set of factors are derived taking historical demand and temperature data into consideration. Refer Figure 6 below. Note that AEMO uses historical data for the past ten years (if available and relevant) for these steps.

Figure 6 Development of weekly factor profile

The weekday factor profile represents the ratios of daily maximum demand to the maximum demand of each week in a year. Weekday factors are derived taking historical daily peak demand data as well as regional public holidays for the past 10 years into consideration. The weekday factors are used consistently across all weeks of the forecast period when MT PASA demand forecasts are produced and are derived from operational demand data (that exclude large wind/solar non-scheduled generation, but which contribution on average on a weekly basis would see a minimal variation).

Figure 7 Development of weekday factor profile



Step 3

Step 3 consists of deriving the regional 10% POE and 50% POE daily peak native demand less non-scheduled generation profiles by subtracting non-scheduled demand (step 1) from the daily native demands calculated in step 2. This meets the requirements of Clause 3.7.2(f)(1).

It should be noted that the demand values published to meet 3.7.2(f)(1), (2) and (4) are not directly reflective of inputs, that is demand traces, that are used in the reliability run, but are prepared to meet the requisite rules obligations.

Calculation of maximum and minimum daily peak loads

In contrast, the values published in clause 3.7.2(f)(1A) are almost identical to the range of daily maximum demands considered across the traces for use in the reliability run, with minor differences being:

(a) The published values assume an expected annual auxiliary load and an auxiliary load at time of peak to convert from sent-out to as-generated, for better comparison with demand published by AEMO after each trading period, whereas the demand inputs to the reliability run are sent-out.

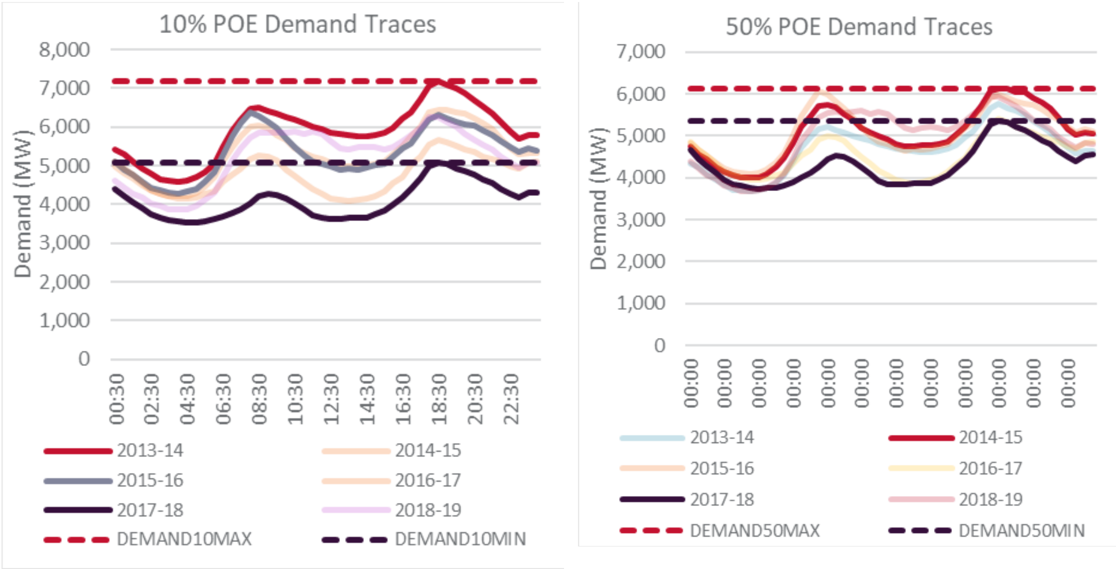
(b) The published values are net of all non-scheduled generation based on the assumed profiles of large non-scheduled generation within each region in each reference year, whereas in the reliability run large non-scheduled generation (and associated demand) is modelled explicitly.

The following published demand values are calculated based on the load traces across each reference year used in the reliability run, but adjusted as outlined above:

- DEMAND10MAX – calculated as the maximum daily demand across all 10% POE traces.
- DEMAND10MIN – calculated as the minimum daily demand across all 10% POE traces.
- DEMAND50MAX – calculated as the maximum daily demand across all 50% POE traces.
- DEMAND50MIN – calculated as the minimum daily demand across all 50% POE traces.

Figure 8 shows an example of the calculation of the above properties for a single day. This shows that the DEMAND10MAX and DEMAND10MIN values represent the range of daily maximum demands considered in the 10% POE MT PASA simulations on that day. Similarly the DEMAND50MAX and DEMAND50MIN values show the range of daily maximum demands considered in the 50% POE simulations.

Figure 8 Example of daily demand calculations



MT PASA weekly energy

The most probable weekly energy requirement is specified in Clause 3.7.2(f)(4). It is calculated from the historical reference year half-hourly demand traces described above which excludes the contribution from non-scheduled generation.

For each demand trace, the weekly energy is calculated as the sum of the half-hourly energy in the week divided by two[29]. The average weekly energy across the traces is reported.

[29] Division by two is needed as AEMO is summing half-hourly demand values.

Appendix C. Pain sharing

The pain sharing principle of the NEM states that load shedding should be spread pro rata throughout interconnected regions when this would not increase total load shedding. This is to avoid unfairly penalising one region for a supply deficit spread through several interconnected regions.

Specifically, the Equitable Load Shedding Arrangement[30] states "as far as practicable, any reductions, from load shedding as requested by AEMO and/or mandatory restrictions, in each region must occur in proportion to the aggregate notional demand of the effective connection points in that region, until the remaining demand can be met, such that the power system remains or returns (as appropriate) initially to a satisfactory operating state."

It is open to interpretation whether the pain sharing principles should apply over the annual period, or be more literally applied to each half-hour period where USE may be projected, irrespective of previous incidents. One may argue that, for planning purposes, pain sharing should aim to equalise USE across all NEM regions over the year, taking account of localised USE events that have already occurred. This would be consistent with implementation of the *reliability standard*, using pain sharing to keep load shedding in all regions to less than the level defined in the *reliability standard* where possible.

Irrespective of the interpretation of the principle, the EY Report on MT PASA stated that pain sharing is problematic in models, since shifting USE between regions will almost inevitably change interconnector losses, generally increasing the total quantity of USE. Since the purpose of MT PASA is to accurately assess USE, EY recommended that pain sharing be considered a non-core component of MT PASA design.

AEMO considers that the interests of the markets are best served by providing an accurate assessment of USE in any region, where shortfall occurs to encourage efficient locational investment signals.

Application of pain sharing to MT PASA modelling results has the potential to obscure the true state of supply issues in a region and thus will not be incorporated into the reliability assessments.

[30] https://www.aemc.gov.au/sites/default/files/content//Guidelines-for-Management-of-Electricity-Supply-Shortfall-Events.PDF

Appendix D. Calculation of transfer limits

Interconnector transfer capabilities in the presence of outages are calculated by examining the results of the MT PASA Reliability Runs according to the following process:

- Obtain the static import and export rating for each interconnector.
- Examine each binding constraint that has the interconnector term on the LHS.
- Move all non-interconnector terms to RHS and calculate RHS value based on dispatch outcomes.
- Divide the constraints RHS value by the coefficient of the interconnector term on the LHS.
- Positive values refer to an export limit, negative values are imports.
- Set the interconnector limit for a given Monte-Carlo sample equal to the minimum value from all relevant constraints.

To assess whether interconnector flow is binding for import or export, the following logic is used:

1. Examine list of constraints before they are put into simulation.
2. Flag a group of those constraints as 'Interconnector export limiting' (defined as a constraint with an interconnector term on LHS and a positive interconnector term factor) -> do this for each interconnector ID.
3. Flag a group of those constraints as 'Interconnector import limiting' (defined as a constraint with an interconnector term on LHS and a negative interconnector term factor) -> do this for each interconnector ID.

For each flagged group of constraints, perform the following aggregation logic for the probabilities:

PROBABILITYOFBINDINGEXPORT = [Count of all iterations in a specific demand POE level and time period that have a constraint with both Constraint.HoursBinding>0 and is flagged as 'Interconnector export limiting' for that interconnector id] / [Total number of Iterations]

PROBABILITYOFBINDINGIMPORT = [Count of all iterations in a specific demand POE level and time period that have a constraint with both Constraint.HoursBinding>0 and is flagged as 'Interconnector import limiting' for that interconnector id] / [Total number of Iterations]

Appendix E. Graphical outputs

The following charts represent outputs that will be available on the AEMO website following each MT PASA run. They are based on "mock data" and do not represent real modelling outcomes. The charts in this Appendix are interpretative only.

Figure 9 shows the output from the Reliability Run that indicates whether the *reliability standard* can be met in each region for each year of the reliability assessment. The red line indicates the *reliability standard*, so any bars that exceed the *reliability standard* indicate a *low reserve condition* exists.

Figure 9 Assessment of reliability standard

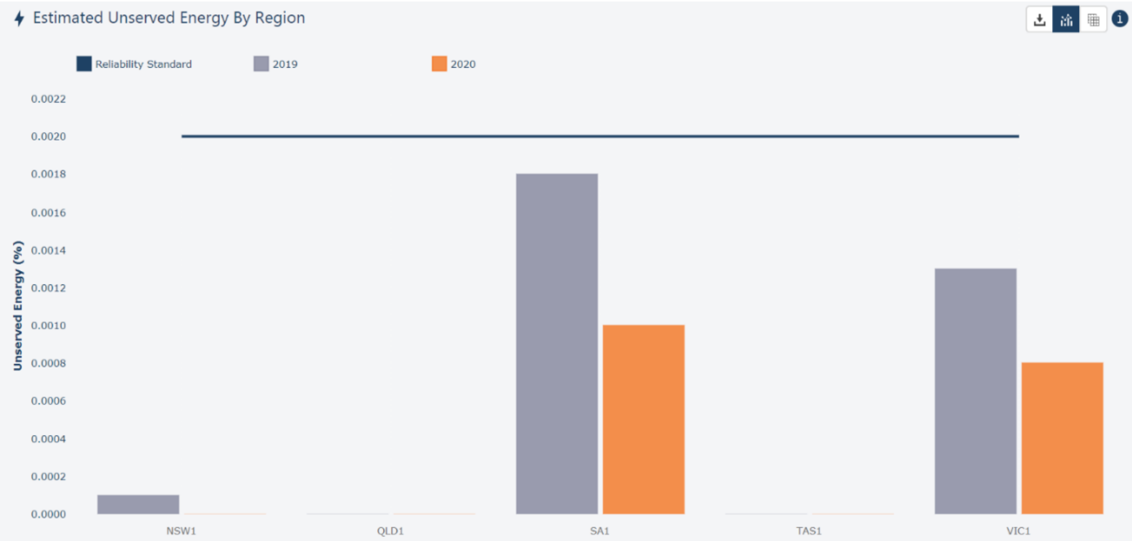


Figure 10 shows the distribution of unserved energy (USE) across a year and is intended to give information on the range of USE outcomes observed in each simulation run conducted for different demand POE levels. The chart indicates that approximately 40% of simulation runs under 10% POE conditions showed the *reliability standard* was breached, while less than 10% of simulation runs at the 50% POE level reported a breach of the *reliability standard*.

Figure 10 Annual distribution of unserved energy (user to select region and year)

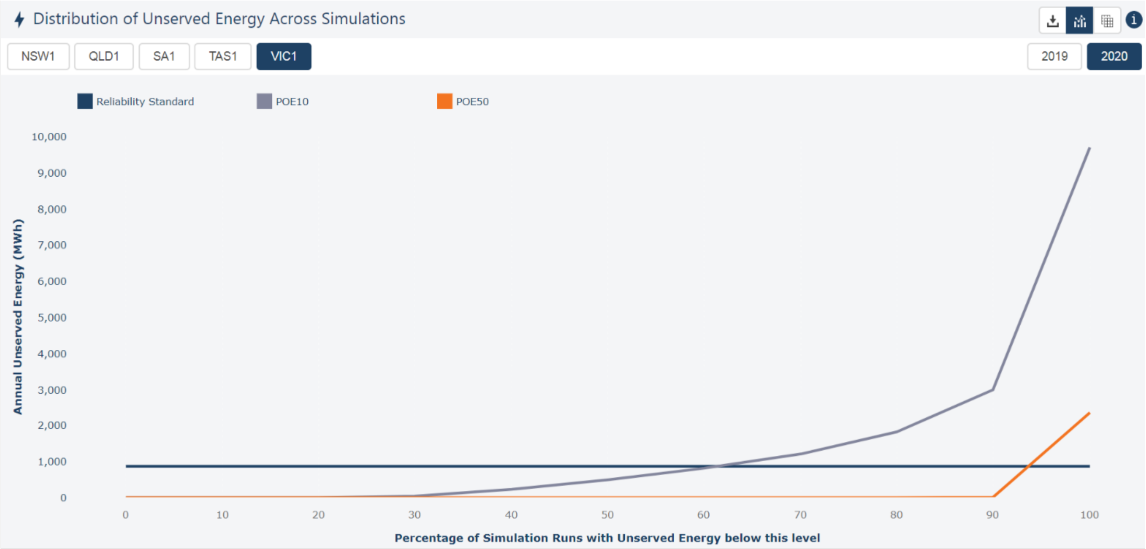


Figure 11 shows the distribution of the size of USE events seen in each month in boxplot format. Only those periods where USE was greater than zero are shown on the plot. The boxes represent the 25th to 75th percentiles of USE (the median line is in the middle of the box) when comparing the total monthly USE for each simulation run. The whiskers show the minimum and maximum values observed across the simulations.

Figure 11 Size of unserved energy events by month (user to select POE demand level, region and year)

Figure 12 gives more detailed insight into the USE observed through modelling outcomes by considering the frequency of events as well as the expected size of the USE events. The chart shows the 10% POE condition's USE events are larger in size and more frequent than those of the 50% POE condition.

Figure 12 Severity and frequency of unserved energy (user to select region and year)

Figure 13 shows the average interconnector capacity limits (averaged across the Monte-Carlo simulations) in the presence of network outages as well as a half-hourly snapshot of flow on the interconnector.

Figure 13 Interconnector flow limits (user to select interconnector)

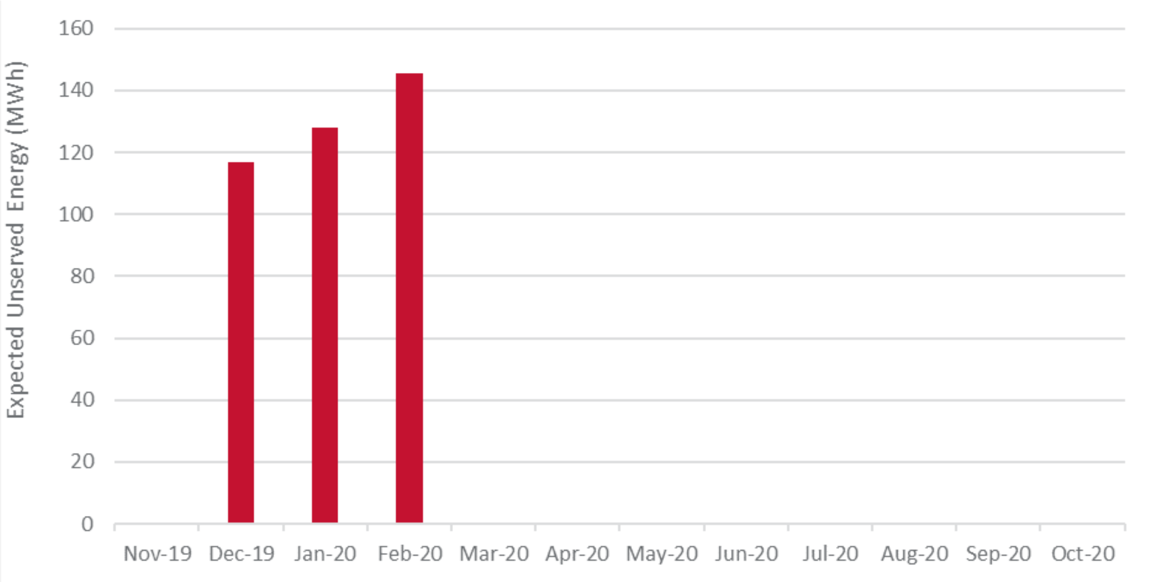
Figure 14 shows the output from the LOLP run. The grey area shows the scheduled generation and integrated resource system availability according to MT PASA bids. The black line shows the operational demand trace calculated for the LOLP run with the associated VRE generation (orange area). The top line represents the total available nameplate capacity (both scheduled and VRE).

The Daily LOLP index shown at the bottom of the chart indicates the periods at risk of loss of load under extreme weather conditions. Periods of relatively high LOLP should be avoided if possible when scheduling maintenance. The LOLP is colour coded according to the extent of USE expected in that half hour with the highest loss of load in each day. Red indicates that the magnitude is high (greater than 400 MW), orange that the magnitude is moderate (between 150 MW and 400 MW) and yellow that the magnitude is low (less than 150 MW).

Figure 14 Supply demand breakdown and maintenance period overview from LOLP run (user to select region and year)

Figure 15 shows the expected monthly USE for a given year and region. The figure below will be updated to reflect the final format.

Figure 15 Monthly expected unserved energy (User to select region and year)



Appendix F. MT PASA output tables

Column_name	Data type	Description
MTPASA_CONSTRAINTRESULT		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10
DAY		Day this result is for
CONSTRAINTID		The unique identifier for the constraint. Only binding or violating constraints are reported
EFFECTIVEDATE		The effective date of the constraint used
VERSIONNO		The version of the constraint used
PERIODID		Half hourly period reported, selected as period of maximum NEM operational “ex VRE” demand (calculated as maximum of “ex VRE” demands, averaged over reference years and iterations)
PROBABILITYOFBINDING	Snapshot – half hourly (NEM Max)	Proportion of a constraint binding across iterations and reference years
PROBABILITYOFVIOLATION	Snapshot – half hourly (NEM Max)	Proportion of a constraint violating across iterations and reference years
CONSTRAINTVIOLATION90	Snapshot – half hourly (NEM Max)	The 90% percentile violation degree for this constraint, across iterations and reference years (MW)
CONSTRAINTVIOLATION50	Snapshot – half hourly (NEM Max)	The 50% percentile violation degree for this constraint, across iterations and reference years (MW
CONSTRAINTVIOLATION10	Snapshot – half hourly (NEM Max)	The 10% percentile violation degree for this constraint, across iterations and reference years (MW)
LASTCHANGED		Date the report was created
MTPASA_CONSTRAINTSUMMARY		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10
DAY		Day this result is for
CONSTRAINTID		The unique identifier for the constraint. Only binding or violating constraints are reported
EFFECTIVEDATE		The effective date of the constraint used
VERSIONNO		The version of the constraint used
AGGREGATION_PERIOD	Snapshot – half hourly peak/shoulder/off-peak	Period data is aggregated over. Values are PEAK, SHOULDER, OFFPEAK or PERIOD
CONSTRAINTHOURSBINDING	Snapshot – half hourly peak/shoulder/off-peak	Constraint hours binding for period
LASTCHANGED		Date the report was created
MTPASA_INTERCONNECTORRESULT		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10

Column_name	Data type	Description
DAY		Day this result is for
INTERCONNECTORID		The unique identifier for the interconnector
PERIODID		Half hourly period reported, selected as period of maximum NEM “ex VRE” demand (calculated as maximum of “ex VRE” demands, averaged reference years and iterations)
FLOW90	Snapshot – half hourly (NEM Max)	The 90% percentile for flows across iterations and reference years. Positive values indicate exporting, negative values indicate importing (MW)
FLOW50	Snapshot – half hourly (NEM Max)	The 50% percentile for flows across iterations and reference years. Positive values indicate exporting, negative values indicate importing (MW)
FLOW10	Snapshot – half hourly (NEM Max)	The 10% percentile for flows across iterations and reference years. Positive values indicate exporting, negative values indicate importing (MW)
PROBABILITYOFBINDINGEXPORT	Snapshot – half hourly (NEM Max)	Proportion of iterations and reference years with interconnector constrained when exporting
PROBABILITYOFBINDINGIMPORT	Snapshot – half hourly (NEM Max)	Proportion of iterations and reference years with interconnector constrained when importing
CALCULATEDEXPORTLIMIT	Snapshot – half hourly (NEM Max)	Calculated Interconnector limit of exporting energy on the basis of invoked constraints and static interconnector export limit, averaged across iterations and reference years
CALCULATEDIMPORTLIMIT	Snapshot – half hourly (NEM Max)	Calculated Interconnector limit of importing energy on the basis of invoked constraints and static interconnector import limit, averaged across iterations and reference years
LASTCHANGED		Date the report was created
MTPASA_LOLPRESULT		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always LOLP
DAY		Day this result is for
REGIONID		The unique region identifier
WORST_INTERVAL_PERIODID	Snapshot – half hourly (worst of day)	The half hourly interval period with the highest LOLP, or highest region demand net of VRE generation if LOLP = 0 for all intervals (1..48)
WORST_INTERVAL_DEMAND	Snapshot – half hourly (worst of day)	The LOLP half hourly operational as-generated demand for the worst interval in this region (MW)
WORST_INTERVAL_INTGEN	Snapshot – half hourly (worst of day)	The half hourly aggregate VRE generation for the interval period with the worst LOLP in this region (MW)
WORST_INTERVAL_DSP	Snapshot – half hourly (worst of day)	The half hourly aggregate demand side participation for the interval period with the worst LOLP in this region (MW)
LOSSOFLOADPROBABILITY	Snapshot – half hourly (worst of day)	Loss of Load Probability for day reported
LOSSOFLOADMAGNITUDE	Snapshot – half hourly (worst of day)	Loss of Load Magnitude for day reported. Values are LOW, MEDIUM, HIGH
LASTCHANGED		Date the report was created
MTPASA_REGIONRESULT		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id

Column_name	Data type	Description
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10
DAY		Day this result is for
REGIONID		The unique region identifier
PERIODID	Snapshot – half hourly (NEM Max)	Half hourly period reported, selected as period of maximum NEM "ex VRE" demand (calculated as maximum of "ex VRE" demands, averaged reference years and iterations)
DEMAND	Snapshot – half hourly (NEM Max)	OPGEN Demand value from selected half hourly interval (MW). This value includes contribution from large non-scheduled generation so may be higher than the demand values published in the REGION_AVAILABILITY table.
AGGREGATEINSTALLEDCAPACITY	Snapshot – half hourly (NEM Max)	The total rated capacity of all active generation (MW)
NUMBEROFITERATIONS	Snapshot – half hourly (NEM Max)	Total number of iterations and reference years performed
USE_NUMBEROFITERATIONS	Snapshot – half hourly (NEM Max)	Number of iterations and reference years showing USE
USE_AVERAGE	Snapshot – half hourly (NEM Max)	Average USE across all iterations and reference years (MW)
USE_EVENT_AVERAGE	Snapshot – half hourly (NEM Max)	Average USE event size across all iterations and reference years (MW)
USE_MAX	Snapshot – half hourly (NEM Max)	Maximum USE across all iterations and reference years (MW)
USE_MIN	Snapshot – half hourly (NEM Max)	Minimum USE across all iterations and reference years (MW)
USE_MEDIAN	Snapshot – half hourly (NEM Max)	Median USE across all iterations and reference years (MW)
USE_LOWERQUARTILE	Snapshot – half hourly (NEM Max)	Lower quartile USE across all iterations and reference years (MW)
USE_UPPERQUARTILE	Snapshot – half hourly (NEM Max)	Upper quartile daily USE across all iterations and reference years (MW)
TOTALSCHEDULEDGEN90	Snapshot – half hourly (NEM Max)	The 90% percentile for scheduled generation across iterations and reference years (MW)
TOTALSCHEDULEDGEN50	Snapshot – half hourly (NEM Max)	The 50% percentile for scheduled generation across iterations and reference years (MW)
TOTALSCHEDULEDGEN10	Snapshot – half hourly (NEM Max)	The 10% percentile for scheduled generation across iterations and reference years (MW)
TOTALINTERMITTENTGEN90	Snapshot – half hourly (NEM Max)	The 90% percentile for VRE generation across all iterations and reference years (MW)
TOTALINTERMITTENTGEN50	Snapshot – half hourly (NEM Max)	The 50% percentile for VRE generation across all iterations and reference years (MW)
TOTALINTERMITTENTGEN10	Snapshot – half hourly (NEM Max)	The 10% percentile for VRE generation across all iterations and reference years (MW)
TOTALSEMISCHEDULEDGEN90	Snapshot – half hourly (NEM Max)	The 90% percentile for semi-scheduled generation across all iterations and reference years (MW)
TOTALSEMISCHEDULEDGEN50	Snapshot – half hourly (NEM Max)	The 50% percentile for semi-scheduled generation across all iterations and reference years (MW)
TOTALSEMISCHEDULEDGEN10	Snapshot – half hourly (NEM Max)	The 10% percentile for semi-scheduled generation across all iterations and reference years (MW)
DEMANDSIDEPARTICIPATION90	Snapshot – half hourly (NEM Max)	The 90% percentile for demand side participation across all iterations and half hours (MW)

Column_name	Data type	Description
DEMANDSIDEPARTICIPATION50	Snapshot – half hourly (NEM Max)	The 50% percentile for demand side participation across all iterations and half hours (MW)
DEMANDSIDEPARTICIPATION10	Snapshot – half hourly (NEM Max)	The 10% percentile for demand side participation across all iterations and half hours (MW)
TOTALAVAILABLEGEN90	Snapshot – half hourly (NEM Max)	The 90% percentile for total Scheduled availability across all iterations and half hours (MW)
TOTALAVAILABLEGEN50	Snapshot – half hourly (NEM Max)	The 50% percentile for total Scheduled availability across all iterations and half hours (MW)
TOTALAVAILABLEGEN10	Snapshot – half hourly (NEM Max)	The 10% percentile for total Scheduled availability across all iterations and half hours (MW)
TOTALAVAILABLEGENMIN	Snapshot – half hourly (NEM Max)	The minimum for total Scheduled availability across all iterations and half hours (MW)
TOTALAVAILABLEGENMAX	Snapshot – half hourly (NEM Max)	The maximum for total Scheduled availability across all iterations and half hours (MW)
LASTCHANGED		Date the report was created
MTPASA_REGIONSUMMARY		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10 or POE50
AGGREGATION_PERIOD		Period data is aggregated over. Values are YEAR, MONTH
PERIOD_ENDING		Date time of day at end of interval (which may be over a year, a month)
REGIONID		The unique region identifier
NATIVEDEMAND	Average monthly/annual iteration totals	Native demand from AEMO forecast, pro-rated for horizon year specified in PERIOD_ENDING (MWh)
USE_PERCENTILE10	Percentiles assessed over iteration totals for either month or year	USE period amount at the 10% percentile of iterations and reference years (MWh)
USE_PERCENTILE20	Percentiles assessed over iteration totals for either month or year	USE period amount at the 20% percentile of iterations and reference years (MWh)
USE_PERCENTILE30	Percentiles assessed over iteration totals for either month or year	USE period amount at the 30% percentile of iterations and reference years (MWh)
USE_PERCENTILE40	Percentiles assessed over iteration totals for either month or year	USE period amount at the 40% percentile of iterations and reference years (MWh)
USE_PERCENTILE50	Percentiles assessed over iteration totals for either month or year	USE period amount at the 50% percentile of iterations and reference years (MWh)
USE_PERCENTILE60	Percentiles assessed over iteration totals for either month or year	USE period amount at the 60% percentile of iterations and reference years (MWh)
USE_PERCENTILE70	Percentiles assessed over iteration totals for either month or year	USE period amount at the 70% percentile of iterations and reference years (MWh)
USE_PERCENTILE80	Percentiles assessed over iteration totals for either month or year	USE period amount at the 80% percentile of iterations and reference years (MWh)

Column_name	Data type	Description
USE_PERCENTILE90	Percentiles assessed over iteration totals for either month or year	USE period amount at the 90% percentile of iterations and reference years (MWh)
USE_PERCENTILE100	Percentiles assessed over iteration totals for either month or year	USE period amount at the 100% percentile of iterations and reference years (MWh)
USE_AVERAGE	Average monthly/annual iteration totals	Average period USE across iterations and reference years (MWh)
WEIGHT	Fixed value	Weighting use for aggregating POE Demand Level. 0.392 (50 POE) or 0.304 (10 POE)
USE_WEIGHTED_AVG	Regional Weighted Average USE (Percent)	((USE_AVERAGE_POE10 / NATIVE_DEMAND_POE_10 * WEIGHT_POE_10) + (USE_AVERAGE_POE50 / NATIVE_DEMAND_POE_50 * WEIGHT_POE_50))*100
LRC	LRC reporting for region	LRC Condition reported (Value=1) if USE_WEIGHTED_AVG >= 0.002% otherwise no LRC (Value=0)
NUMBEROFITERATIONS	Value by month/year	Total number of iterations and reference years performed
USE_NUMBEROFITERATIONS	Value by month/year	Number of iterations and reference years showing USE
USE_EVENT_UPPERQUARTILE	Assessed over iteration totals for either month or year	Upper quartile USE event size across all half hourly intervals and iterations and reference years that have USE>0 (MW)
USE_EVENT_LOWERQUARTILE	Assessed over iteration totals for either month or year	Lower quartile USE event size across all half hourly intervals and iterations and reference years that have USE>0 (MW)
USE_EVENT_MAX	Assessed over iteration totals for either month or year	Max quartile USE event size across all half hourly intervals and iterations and reference years that have USE>0 (MW)
USE_EVENT_MIN	Assessed over iteration totals for either month or year	Min quartile USE event size across all half hourly intervals and iterations and reference years that have USE>0 (MW)
USE_EVENT_MEDIAN	Assessed over iteration totals for either month or year	Median quartile USE event size across all half hourly intervals and iterations and reference years that have USE>0 (MW)
LASTCHANGED		Date the report was created
MTPASA _REGIONITERATION		
RUN_DATETIME		Date processing of the run begins
RUN_NO		Unique run id
RUNTYPE		Type of run. Always RELIABILITY
DEMAND_POE_TYPE		Demand POE type used. Values are POE10 or POE50
AGGREGATION_PERIOD		Period data is aggregated over. Values are YEAR, MONTH
PERIOD_ENDING		Date time of day at end of interval (which may be over a year, a month)
REGIONID		The unique region identifier
USE_ITERATION_ID	-	Iteration ID, only produced for iterations showing unserved energy>0
USE_ITERATION_EVENT_NUMBER	Value by month/year	Number of half hours showing unserved energy over year, for iteration
USE_ITERATION_EVENT_AVERAGE	Assessed over iteration totals for either month or year	Average unserved energy event size for iteration over year (MW)

Column_name	Data type	Description
LASTCHANGED		Date the report was created
MTPASA_REGIONAVAILABILITY – THREE-HOURLY REPORT		
PUBLISH_DATETIME		Date Time the report was published.
DAY		Date on which the aggregation applies.
REGIONID		NEM Region
PASAAVAILABILITY_SCHEDULED	Regional aggregation of bid values	Aggregate of the offered PASA Availability for all Scheduled ~~generators~~ production units in this region.
LATEST_OFFER_DATETIME		Date Time of the latest offer used in the aggregation for this region and date.
ENERGYUNCONSTRAINEDCAPACITY		Sum of Regional capacity MW which has no energy limits as per participant submissions~~Region energy unconstrained MW capacity~~
ENERGYCONSTRAINEDCAPACITY		Sum of Regional capacity MW which has energy ~~constrained~~ limits ~~MW capacity~~as per participant submissions
NONSCHEDULEDGENERATION	Daily Peak	Allowance made for small non-scheduled generation in the demand forecast (MW).
DEMAND10	Daily Peak	10% POE peak demand, as-generated, excluding non-scheduled generation and scheduled load.
DEMAND50	Daily Peak	Most probable peak demand, as-generated, excluding non-scheduled generation and scheduled load.
DEMAND10MAX	Daily Peak	Maximum of the scheduled demand peaks that occur in the 10% POE traces (MW), excluding scheduled load and non-scheduled generation.
DEMAND10MIN	Daily Peak	Minimum of the scheduled demand peaks that occur in the 10% POE traces (MW), excluding scheduled load and non-scheduled generation.
DEMAND50MAX	Daily Peak	Maximum of the scheduled demand peaks that occur in the 50% POE traces (MW), excluding scheduled load and non-scheduled generation.
DEMAND50MIN	Daily Peak	Minimum of the scheduled demand peaks that occur in the 50% POE traces (MW), excluding scheduled load and non-scheduled generation.
ENERGYREQDEMAND10	Weekly Total	Weekly Energy (Operational as-generated, excluding scheduled load) calculated directly from the half hourly 10% POE trace (GWh).
ENERGYREQDEMAND50	Weekly Total	Weekly Energy (Operational as-generated, excluding scheduled load) calculated directly from the half hourly 50% POE trace (GWh).
LASTCHANGED		Date the report was created
MTPASA _ DUIDAVAILABILITY – THREE-HOURLY REPORT		
PUBLISH_DATETIME		Date Time the report was published.
DAY		Date on which the aggregation applies.
DUID		Unit level DUID
REGIONID		Region ID for the DUID
PASAAVAILABILITY		PASA availability (MW)
PASAUNITSTATE		Unit state
PASARECALLTIME		Recall time
LATEST_OFFER_DATETIME		Date Time of the latest offer used for this unit and date.
LASTCHANGED		Date the report was created

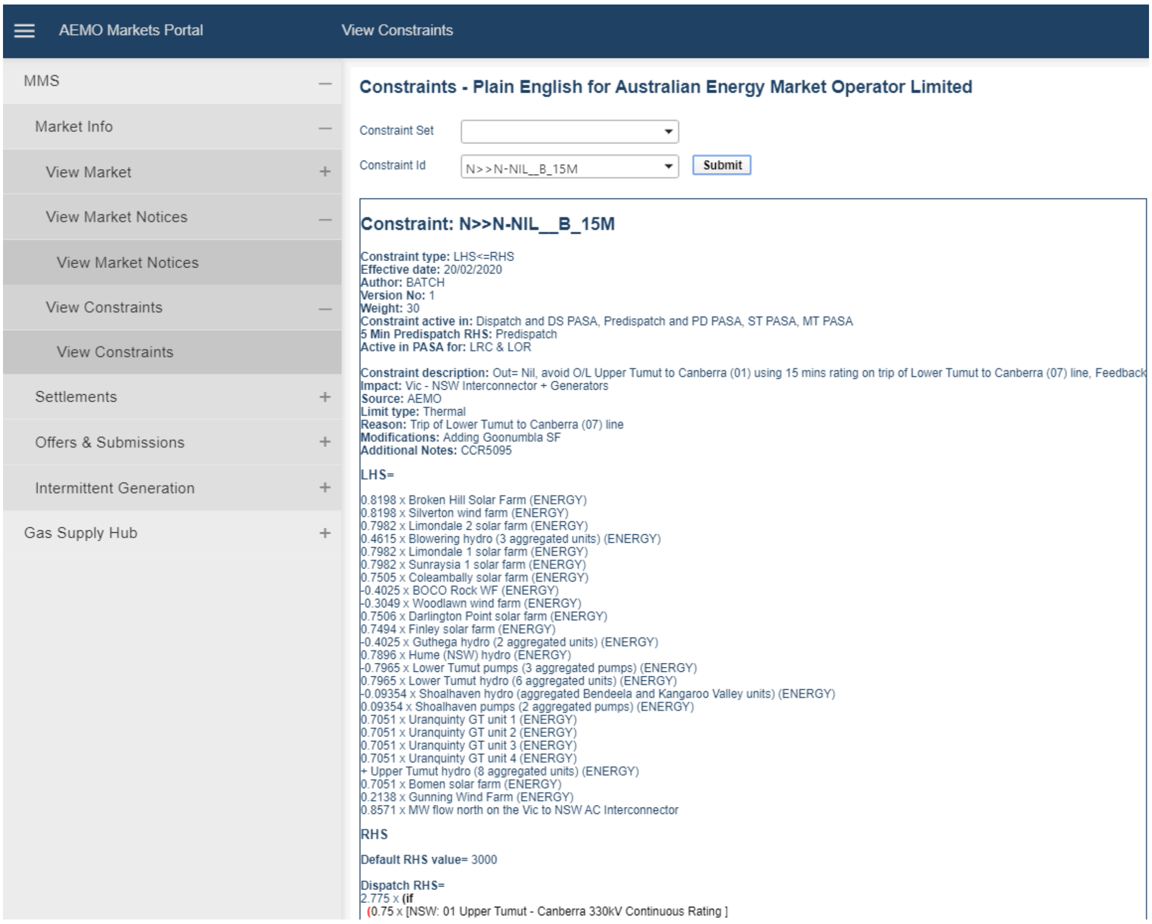
Appendix G. "Plain English" report on constraints

AEMO will provide a "plain English" report on constraints that provides further details on generators impacting by binding constraints.

To access the "plain English report" service:

1. Access via: https://portal.prod.nemnet.net.au/#/signin
2. From menu items: MMS➔Market Info➔View Constraints➔View Constraints
3. Type in constraints in the Constraints ID field, and Submit as per the screenshot below. The "plain English" report will be displayed on submission.

Figure 16 Example constraints viewer



Version release history

Version	Effective date	Summary of changes
6.4	24 April 2023	Updated following full consultation, including to reflect the changes from 3 June 2024 under the National Electricity Amendment (Integrating energy storage systems into the NEM) Rule 2021.
6.3		Draft update to reflect the Reliability Forecasting Guideline and Methodology consultation
6.2	1/12/2021	Administrative update to reflect POE weighting changes now implemented
6.1	7/9/2020	Updated following full consultation[31]
6.0	25/5/2020	Forecasting
5.1	7/5/2017	Forecasting
5.0	15/8/2017	Supply Planning
4.1	08/6/2017	Supply Planning
4.0	25/11/2016	Forecasting & Planning
3.0	30/5/2013	Systems Capability
2.0	22/3/2013	Systems Capability
1.0	27/4/2006	SOPP

[31] https://aemo.com.au/en/consultations/current-and-closed-consultations/rsig-mtpasa-process-description-eaap-guidelines-and-spot-market-operations-timetable