MEDIUM TERM PASA PROCESS DESCRIPTION

PREPARED BY: Forecasting & Planning

DOCUMENT REF: 42

VERSION: ~~4.0~~4.1

EFFECTIVE DATE: ~~25 November 2016~~1 November 2017

~~FINAL~~

DRAFT – PROVIDED AS AN INDICATIVE GUIDE TO EXPECTED CHANGES AS A RESULT OF THE MT PASA REDEVELOPMENT. FUTHER CHANGES MAY BE MADE FOLLOWING COMPLETION OF THE RSIG CONSULTATION AND THE DEVELOPMENT AND INSTALLATION OF THE NEW MODELLING PLATFOM.

Australian Energy Market Operator Ltd ABN 94 072 010 327 www.aemo.com.au info@aemo.com.au

NEW SOUTH WALES QUEENSLAND SOUTH AUSTRALIA VICTORIA AUSTRALIAN CAPITAL TERRITORY TASMANIA

Disclaimer

Purpose

This report has been prepared by the Australian Energy Market Operator Limited (**AEMO**) for the sole purpose of meeting obligations in accordance with clause 3.7.2(g) of the National Electricity Rules.

No reliance or warranty

This report contains data provided by third parties and might contain conclusions or forecasts and the like that rely on that data. This data might not be free from errors or omissions. While AEMO has used due care and skill, AEMO does not warrant or represent that the data, conclusions, forecasts or other information in this report are accurate, reliable, complete or current or that they are suitable for particular purposes. You should verify and check the accuracy, completeness, reliability and suitability of this report for any use to which you intend to put it, and seek independent expert advice before using it, or any information contained in it.

Limitation of liability

To the extent permitted by law, AEMO and its advisers, consultants and other contributors to this report (or their respective associated companies, businesses, partners, directors, officers or employees) shall not be liable for any errors, omissions, defects or misrepresentations in the information contained in this report, or for any loss or damage suffered by persons who use or rely on such information (including by reason of negligence, negligent misstatement or otherwise). If any law prohibits the exclusion of such liability, AEMO's liability is limited, at AEMO's option, to the re-supply of the information, provided that this limitation is permitted by law and is fair and reasonable.

Glossary

ABBREVIATION	ABBREVIATION EXPLANATION
AEMO	Australian Energy Market Operator
ASEFS	Australian Solar Energy Forecasting System
AWEFS	Australian Wind Energy Forecasting System
ESOO	Electricity Statement of Opportunities
~~LOR~~	~~Lack of Reserve Level~~ • ~~LOR1: Lack of Reserve Level 1~~ • ~~LOR2: Lack of Reserve Level 2~~ • ~~LOR3: Lack of Reserve Level 3~~
LP	Linear Program
LRC	Low Reserve Condition
MMS	Electricity Market Management System
MNSP	Market Network Service Provider (Scheduled Network Service Provider in the National Electricity Rules)
MRL	Minimum Reserve Level

Native demand	The electricity demand met by scheduled, semi-scheduled, non-scheduled and exempt generation.
NEM	National Electricity Market
NEFR	National Electricity Forecasting Report
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

Contents

Version Release History

VERSION	DATE	BY	CHANGES
1.0	27/04/2006	SOPP	Initial version
2.0	22/03/2013	Systems Capability	Review document to reflect current processes
3.0	30/05/2013	Systems Capability	Updated Sections 4, 5 and Appendix E to include new ~~runtype~~run type RELIABILITY_MSR_MUR, reporting of MaxUsefulResponse (MUR) and four new ~~runtypes~~run types associated with interconnector capability reporting.
4.0	25/11/2016	Forecasting & Planning	Review document to reflect current processes
4.1	08/06/2017	Supply Planning	Amended document to reflect new MT PASA solution using probabilistic modelling to take effect from November 2017.

1 Introduction

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

The *PASA* is the principal method of indicating to the National Electricity Market (NEM) a forecast of power system security and supply reliability ~~of electricity~~ for ~~a period of~~ up to ~~2~~two years. The *Rules* require AEMO to administer the *PASA* for two timeframes:

1. *Medium Term PASA* (MT PASA) which covers a 24 month period commencing from the Sunday after the *day* of publication with a daily resolution; and
2. *Short Term PASA* (*ST* PASA) which covers ~~a~~the period of six *trading days* starting from the end of the *trading day* covered by the most recently *published pre-dispatch schedule* with a *trading interval* resolution.

The MT *PASA* assesses ~~the~~ *power system security* and *reliability* under a minimum of 10% Probability of Exceedance (POE) and 50% POE demand conditions based on generator availabilities submitted by *market participants* ~~with due consideration to planned transmission outages.~~, with due consideration to planned transmission outages. The *reliability standard* is a measure of the effectiveness, or sufficiency, of installed capacity to meet demand. It is defined in clause 3.9.3C of the Rules as the maximum expected *unserved energy* (USE) in a *region* of 0.002% of the total *energy* demanded in that region for a given *financial year*. USE is measured in gigawatt hours (GWh).

The MT PASA ~~has the following objectives:~~process includes (but is not limited to):

- ~~Provide sufficient information on the expected level~~Information collection from Scheduled Generators, Market Customers, Transmission Network Service Providers and Market Network Service Providers about their intentions for:
  - Generation, transmission and market network service maintenance scheduling.
  - Intended plant availabilities.
  - 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 ~~capacity reserve and hence allow *market*~~ power system security and reliability of supply.
- Forecasts of supply and demand.
- Provision of information that allows participants to ~~schedule planned~~make decisions about supply, demand and outages of ~~generating units.~~ transmission networks for the upcoming two year period.
- ~~Alert~~ Publication of sufficient information to allow the market ~~of any *days* on which *low reserve condition* (LRC) or *lack of reserve* (LOR) are forecast to occur.~~
- ~~Provide~~to operate effectively with a ~~basis for~~minimal amount of intervention by AEMO ~~to intervene in the market (i.e. Reserve Trading process[1]) through the Reliability and Emergency Reserve Trader provisions as per clause 3.20 of the *Rules*~~.

The MT PASA process is administered according to the timeline set out in the Spot Market Operations Timetable[2] (*timetable*) in accordance with the *Rules*.

~~[1] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management~~

[2] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Dispatch-information http://www.aemo.com.au/Electricity/Market-Operations/Dispatch/Spot-Market-Operations-Timetable

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

2 MT PASA process and Rules requirements

The PASA is a comprehensive program for ~~the collection~~collecting and ~~analysis of~~analysing information ~~in order~~ to assess ~~the~~ medium~~ term~~- and short~~-~~-term power system security and reliability of supply prospects.

~~The assessment of medium term power system security and~~ This is so that *Registered Participants* are properly informed to enable them to make decisions about *supply*, demand and *outages* of *transmission networks* in respect of periods up to two years 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* ~~in the MT *PASA* process is based on comparing the medium term capacity reserves available against the required levels determined in the Reliability Standard.~~ *standard.*

~~Medium term capacity reserve, as defined by the *Rules*, is the aggregate amount of generating capacity indicated by the relevant Generators as being available any time on a particular day during the period covered by the medium term *PASA*, and which is assessed by *AEMO* as being in excess of the capacity requirement to meet the forecast peak load, taking into account the known or historical levels of demand management.~~

~~The objective of the *PASA* is to provide projected system reserve conditions, and projected regional reserve conditions to *market participants* in the MT *PASA* timeframe along with additional information including forecast demand, expected aggregate plant capacity.~~

~~Clause 3.7.2 of the *Rules* details the requirements for the administration of the MT *PASA*.~~

~~Under this *Rules* clause,~~ MT PASA incorporates two separate functions:

1. A high frequency three-hourly information service that gives a regional breakdown of the supply situation over the two-year horizon, taking into account participant submissions on availability.
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 ~~of~~in accordance with the ~~MT *PASA* every week,~~frequency specified in clause 3.7.2(a), covering the 24~~-~~-month period ~~commencing~~starting from the Sunday after ~~the~~ *day* of publication with a daily resolution. Additional updated versions of ~~the~~ 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*.

~~The~~Each party's responsibilities ~~of each party~~ in ~~the preparation of the~~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 following MT PASA *inputs*: • Regional demand forecasts - 10% POE and most probable daily peak load (50% POE) • ~~Reserve requirements~~ • *Network constraints* forecasts • *Unconstrained intermittent generation forecasts* for *semi-scheduled generating unit*	3.7.2(c)
Scheduled Generator or *Market Participant*	Submit to AEMO the following MT PASA *inputs*: • PASA *availability* of each *scheduled generating unit, scheduled load* or *scheduled network service*	3.7.2(d)

	• Weekly *energy constraints* applying to each *scheduled generating unit* or *scheduled load*	
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 ~~both~~ AEMO and *market participants*. They are discussed in detail below.

3.1 Market participant inputs

Market participants are required to submit the following data in accordance with the *timetable*, covering a 24~~-~~-month period from the Sunday after the *day* of publication of ~~the~~ MT PASA.

3.1.1 Generating unit availabilities for MT PASA

- *Generating unit* PASA availabilities:

  MT PASA uses PASA availabilities of generating units. PASA availability includes the generating capacity in ~~services~~service as well as the generating capacity that can be delivered with 24 hours' notice.

- As per clause 3.7.2(d)(1), *Generators* are required to provide the expected daily MW capacity of each *scheduled generating unit* or *scheduled load* ~~on a daily basis~~ for the next ~~2~~two years. The actual level of *generation* 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[3].

  Generators should take into account the ambient weather conditions expected at the time when the Region where the generating unit is located experiences the 10% Probability of Exceedance (POE) *peak load* defined as Generation Capacity Reference Temperatures. The summer and winter AEMO generation capacity reference ~~temperature~~temperatures for each region are available in the Background Information worksheet of the Generator Information spreadsheet for each region published on the AEMO website[4].

- Generating unit energy availabilities:

  Generating plant such as hydroelectric power stations cannot generally operate at maximum capacity indefinitely ~~due to the possibility of~~because their energy source ~~being~~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 with energy constraints (referred to as energy constrained plant~~)~~ are required to submit their weekly energy limit in MWh for each week for the upcoming 24~~-~~-month period commencing from the first Sunday after the latest MT PASA

[3] http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information
[4] Generation capacity reference temperatures are available at: http://www.aemo.com.au/Electricity/Planning/Related-Information/Generation-Information

run. ~~The energy constrained plant[5] are allocated accordingly~~AEMO may also use other information available such as that provided through the Generator Energy Limitation Framework (GELF) to ~~the ratio of the forecast demand to the *PASA* availabilities, i.e. more~~develop annual energy ~~is located to period when the ratio of the forecast demand to the *PASA* availabilities is high~~constraints for MT PASA modelling.

~~For MT *PASA* to be able to allocate the energy constrained plants, it requires information on expected demand and its profile as well as *PASA* availabilities on any given day.~~

- Wind turbine and large-scale solar availabilities:

  To facilitate AEMO to fulfil its obligation in producing *semi-scheduled generating unit* forecasts as per clause 3.7.2(c)(4), participants who ~~own~~operate such units are required to submit wind turbine or solar availability information to AEMO. Based on this information, semi-scheduled~~ wind forecast~~ profiles are developed by AEMO. This is discussed in more detail in section 3.2.1.

3.1.2 Network outages and Interconnector availabilities

Under clause 3.7.2(e), *Network Service Providers* must provide to AEMO an outline of planned *network outages* and any other information on planned *network outages* ~~that is ~~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 1.1.1~~3.2.33.2.4.~~.

3.1.3 Auxiliary load

AEMO requires auxiliary load information to reconcile participant bids that are supplied on an "as generated" operational demand basis with demand forecasts that are constructed on a "sent out" operation basis to ensure accurate modelling outcomes.

3.2 AEMO inputs

3.2.1 Plant availabilities for MT PASA

~~In addition to the~~AEMO prepares other plant availability ~~information~~data, not provided by *market participants*~~ as discussed in the earlier section, *AEMO* also prepares the following data as part of the plant availabilities.~~:

- 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 ~~to~~with clause 3.7.2(c)(4).

  AEMO develops the UIGF ~~is the equivalent ~~using historically observed wind speed and solar irradiation. The same historic weather conditions are used to forecast ~~of electrical power output from an~~demand, ensuring that any correlation between intermittent ~~generating unit (or intermittent generating system, if aggregated under clause 3.8.3 of~~generation and demand is preserved.

  Power factors for individual units, sourced from AEMO's Australian Wind Energy Forecasting System (AWEFS) and the ~~*Rules*) based on~~Australian Solar Energy Forecasting System (ASEFS), are applied to convert the ~~forecast amount of raw energy available for conversion~~wind speed and solar irradiation into ~~electrical power, as limited by the available~~

---

[5] ~~The capacity of all energy constrained plants within each region is reported as CONSTRAINEDCAPACITY and the capacity of all generating plants that are not limited by energy within each region are reported as UNCONSTRAINEDCAPACITY in the MTPASA.RegionSolution table. A guide to the information contained in the MT *PASA* is available in the form of a data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx .~~

~~generating capacity of that generating facility. This generation forecast is~~generation forecasts for at least five weather reference years.

These generation forecasts are "unconstrained" in the sense that ~~it is~~they are based on the raw energy input to ~~the~~a unit's power conversion process and ~~ignores~~ignore overriding factors that are external to the power conversion process~~, such as~~. These factors include the impact of any network constraint on the output or any economic requirement to otherwise operate at reduced levels.

~~The process taken by *AEMO* to generate semi-scheduled wind and solar generation forecasts is shown in figure 1 below, in which the Australian Wind Energy Forecasting System (AWEFS) model or the Australian Solar Energy Forecasting System (ASEFS) model is used as the forecasting tool.~~

~~-~~For the Loss of Load Probability Assessment (see section 4.5), a forecast regional distribution of intermittent generation at times of 90th percentile demand is also determined for every half hour based on historical weather observations, forecast intermittent generation capacity, and the power factors discussed above.

~~*Figure 1: Semi-scheduled generating unit forecasts*~~

- Non-scheduled generation forecasts:

  In accordance ~~to~~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 ~~constitute of~~have two ~~components~~parts: non-scheduled wind and solar generation and other non-scheduled generation. The non-scheduled wind and solar generation forecasts[6] are produced in ~~a similar~~the same way ~~to the~~as semi-scheduled wind and solar generation forecasts, while the other non-scheduled generation forecasts are consistent with figures published in the National Electricity Forecasting Report (NEFR)[7].

  The non-scheduled generation forecasts for units under 30MW are used as an input to the MT PASA demand forecasting process and are not modelled explicitly. This is discussed in more detail in Section 3.2.2.

- Demand Side Participation (DSP):

  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 ~~perspective of the~~ transmission network perspective, consumers may effectively reduce demand by turning off electricity-using equipment or starting up on-site generators.

  ~~*AEMO* conducted a survey of stakeholders to ascertain potential DSP sites and future DSP opportunities. The results of the survey form the basis of *AEMO*'s regional estimates of historical and projected DSP. This information is published in the ESOO.~~

  ~~The~~ MT PASA uses the NEFR's seasonal ~~DSP forecasts of~~ medium growth~~.~~ reliability response forecasts for demand side participation estimates in the form of five different price-quantity bands

- Future generation:

[6] The non-scheduled wind generation forecasts are reported as TOTALINTERMITTENTGENERATION in the MTPASA.RegionSolution table. A guide to the information contained in the MT *PASA* is available in the form of a data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx

[7] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/~/link.aspx?_id=80D4B633C2C646B388513FD14536623C&_z=z

Committed generation projects currently under development with a dispatch type of scheduled ~~or~~, semi-scheduled or significant non-scheduled are also modelled in MT PASA.

Before the unit is registered, ~~it is modelled as future generation which has the~~ PASA ~~availabilities as its~~ availability for a committed scheduled generating unit is estimated based on participant information regarding the commercial use date and seasonal capacity ~~and is available from the start date of commercial operation. This~~. The Generator information page reports this information[8].

The unit is entered into a Future Generation table that is ~~obtained from the ESOO, and subsequent updates are obtained from *Generators*.~~referenced during modelling to include all committed but not registered units. Once the unit is registered, it is removed from the Future Generation table. In the case of scheduled units, the *Generator* that owns the unit is responsible for submitting MT PASA unit offer data to AEMO ~~and~~.

In the ~~unit is modelled similarly to other~~case of semi-scheduled generators and significant non-scheduled generators, reference weather traces for modelling are developed for the unit for use in modelling through either:

- using a "shadow generator" based on existing ~~generations~~intermittent generation in close proximity
- using meteorological data for the generation site, and assuming a power factor based on similar unit type.

3.2.2 Demand forecasts

~~For the MT *PASA*,~~ AEMO ~~prepares a forecast~~ develops two separate types of ~~electricity~~ demand forecasts for MT PASA modelling:

- Annual demand profiles, consisting of half-hourly demand points, with energy consumption and maximum demand ~~for each region~~ aligned with the NEFR forecasts.
- Half-hourly demand estimates representing the 50th and 90th percentile demand forecast for ~~each~~that time and day ~~based on~~.

The annual demand profiles are used in MT PASA modelling to identify and quantify any projected breach of the reliability standard. For this purpose, both the peak demand ~~forecasts from the National Electricity Forecasting Report and historical patterns of electricity used, allowing for factors such as seasons~~and energy consumption are important to capture, and the profile is developed considering past trends, day of the week and public holidays~~, as per clause 3.7.2(c)(1).~~.

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

- A 10% POE forecast[9] indicates ~~that there is~~ a 10% chance that ~~the~~ actual demand will exceed the forecast value (i.e. Peak demand will be exceeded once in 10 years).
- A 50% POE forecast indicates ~~that there is~~ a 50% chance that actual demand will exceed the forecast value.

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

To capture the impact of weather variations on demand, at least sixteen different annual demand profiles (corresponding to model base cases discussed in Section 4.3) are developed for each region, based on different historic weather patterns and POE peak demand forecasts. While this

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

[9] The 10% POE and 50% POE Demand forecasts are reported as DEMAND10 and DEMAND50 in the MTPASA.RegionSolution table. A guide to the information contained in the MT *PASA* is available in the form of a data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx

captures a reasonable range of different weather-driven demand conditions, it unavoidably requires assumptions to be made about precisely when the peak demand could occur, based on historical demand patterns even though it is impossible to predict when the peak demand will occur in future.

Consequently, it is important that AEMO also considers the loss of load probability in each period of the modelling horizon, assuming that extreme weather conditions were to occur in that period (see Section 4.5 for more detail). This requires forecasts of the 90th percentile demand forecast for that time and day. In other words, determining the forecast value in each half hour that has a 10 percent chance of being exceeded. Each demand period is considered independently of the next – summing the half hours will not produce realistic annual energy consumption forecasts.

Refer to Appendix B for further information on the derivation of MT PASA demand forecasts.

~~3.2.3 Minimum Reserve Levels~~

~~Under the Reliability Standard, the NEM should aim to achieve an expected unserved energy (USE) of no more than 0.002% in each financial year, each region and in the NEM as a whole. *AEMO* is required to determine *reserve* requirement for each *region* in accordance with the *medium term capacity reserve standards* as per clause 3.7.2(c)(2).~~

~~The Minimum Reserve Level (MRL) that is used in MT *PASA* for each region is derived off-line from a series of probabilistic Monte-Carlo studies that aim to determine the minimum local generation required in each region to target 0.002% USE in all regions. In other words, the USE Reliability Standard is translated into operational trigger in the form of MRL equations.~~

~~The MRL is expressed relative to 10% POE maximum demand conditions. Currently static MRL equations are applied in MT *PASA* for Queensland, New South Wales, and Tasmania regions while shared MRL equations are applied to Victoria and South Australia regions:~~

~~*Table 2: Regional MRLs*~~

~~Regions~~	~~MRL~~
~~Queensland~~	~~913~~
~~New South Wales~~	~~-1,564~~
~~Tasmania~~	~~144~~
~~Victoria and South Australia~~	~~Vic. Reserve >= 205.00~~ ~~5.88 * Vic. Reserve + SA Reserve >= 1237.88~~ ~~1.33 * Vic. Reserve + SA Reserve >= 228.00~~ ~~0.43 * Vic. Reserve + SA Reserve >= -40.53~~ ~~0.23 * Vic. Reserve + SA Reserve >= -147.55~~ ~~SA Reserve >= -368.00~~

~~In order to remain consistent with the calculation of the MRL equations, the following interconnector headroom constraints (net import and export limit constraints) are applied in the MT *PASA*:~~

- ~~The Queensland MRL is assessed with 0 MW of maximum net import into Queensland~~
- ~~The New South Wales MRL is assessed with 330 MW of minimum net export from New South Wales~~
- ~~The Victoria MRL is assessed with 940MW of maximum net import into Victoria~~
- ~~The South Australia MRL is assessed with 0 MW of maximum net import into South Australia~~

~~Refer to "Final Report for Operational MRLs – 2010 MRL Recalculation"[10] for further details on the methodology employed to determine the MRL equations.~~

~~[10] http://www.aemo.com.au/-/media/Files/Electricity/NEM/Data/MMS/2016/Final-Report-for-Operational-MRLs---2010-MRL-Recalculation.pdf~~

~~3.2.4~~3.2.3 Power transfer capabilities used in MT PASA

For ~~the purpose of the~~ MT PASA, AEMO is required to forecast *network constraints*[11] ~~that are~~ known to AEMO at the time under clause 3.7.2(c)(3).

Network constraints used in ~~the~~ 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.

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 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 approved planned network outage constraints applied.

Information to formulate *network constraint equations* is provided to AEMO by Transmission Network Service Providers (TNSPs) via Network Outage Scheduler (NOS)[12] and limit advice. The process of producing *network constraint equations* is detailed in the Constraint Formulation Guidelines[13]. Within AEMO's market systems, *constraint equations* are marked as system normal if they apply ~~for~~to all plant in service. To model network or plant outages in the power system, separate outage *constraint equations* are formulated and applied ~~along~~ with system normal *constraint equations*.

~~AEMO constructs system normal and outage constraint equations for the MT *PASA* time frame based on the capabilities of the MT *PASA* process and the data available for this time frame. For example, no Frequency Control Ancillary Service (FCAS) constraints are included, and constraints are formulated on a daily resolution using peak forecast data. As such many constraint equations are simplified versions of their dispatch counterparts or a single static value (e.g. Vic-SA <= 250 MW). Thus a more simplified version of the network is represented in MT *PASA*, providing a high level approximation of power transfer capabilities.~~

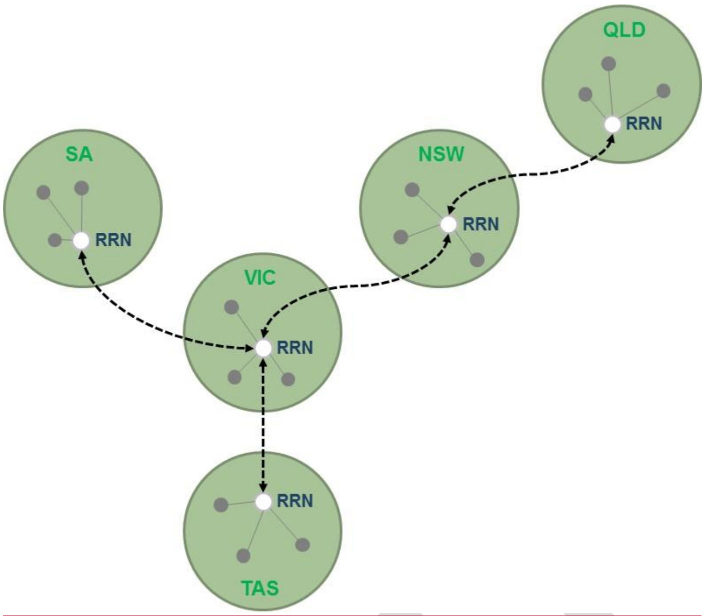
4 MT PASA Solution Process

Information on the proposed probabilistic modelling solution has been included in this section, and represents current thinking on the design. This information may change once AEMO has completed the RSIG consultation and development, installation and testing of the new probabilistic model.

4.1 NEM Representation

The power system model used within the MTPASA simulation will match the model applied for AEMO's wholesale electricity market systems:

[11] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information
[12] http://nos.prod.nemnet.net.au/nos
[13] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Congestion-information



~~In order to assess system adequacy, the MT *PASA* performs three groups of Linear Programming (LP) runs to identify low reserve conditions (LRC) or lack of reserve conditions (LOR) in NEM regions:~~

~~4.1 Reliability LRC (RELIABILITY_LRC)~~

~~This run assesses whether the medium term capacity reserves in NEM over the MT *PASA* period is adequate. For this assessment a Capacity Adequacy LP model is used.~~

~~Capacity Adequacy LP model:~~

~~This model maximises spare generation capacity (MT *PASA* considers scheduled and semi-scheduled generation only) in NEM above the summation of 10% POE regional demand forecasts and regional minimum reserve requirements subjected to:~~

- ~~*PASA Availability* of generation and weekly energy limits (includes committed future generation)~~
- ~~Power transfer planned network outages~~

~~Where medium term capacity reserves do not meet the required level, the deficit is shared on a pro-rata basis among regions subject to applicable interconnector constraints. Reporting reserve deficits shared on a pro-rata basis is referred to as "Pain Sharing". Refer Appendix D for an example of the application of Pain Sharing.~~

~~The outcome of the Reliability LRC run is an indication of the supply reliability in NEM over the MT *PASA* period and is used as a key input to trigger Reliability and Emergency Reserve Trader (*RERT*) process as required by the Rules Clause 3.20[14].~~

~~4.2 Regional Reliability MSR MUR (RELIABILITY_MSR_MUR)~~

~~This run uses the same inputs as the Reliability LRC run (10% POE Demand, PASA Availability and energy limitations with no network outages). The purpose of this run is to report the Maximum Useful Response (MUR) and Maximum Surplus Reserve (MSR) assessments based on 10% POE Demand and system normal conditions. Maximum Useful Response (MUR) and Maximum Surplus Reserve (MSR) assessments are detailed below:~~

~~Regional Maximum Useful Response (MUR)~~

~~[14] Procedure for the Exercise of Reliability and Emergency reserve Trader is available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Emergency-Management~~

~~The MUR LP model determines the maximum MW contribution from each region useful to relieve a reserve deficit reported in the Regional Reliability LRC (RELIABILITY_LRC) Capacity Adequacy run defined in Section 4.1. MUR determines useful contribution from each NEM region by running this model multiple times, taking each region as the study region in turn.~~

~~Regional Maximum Surplus Reserve (MSR) LP model:~~

~~The MSR model determines the maximum generation that can be withdrawn from a region without causing a Low Reserve Condition (LRC) in any of the NEM regions. MSR determines the maximum generation that can be withdrawn from each NEM region by running this model multiple times, taking each region as the study region in turn.~~

~~Regional Lack of Reserve (LOR):~~

The salient features of the power system model are:

- ~~This model maximises spare generation in NEM regions above their 50% POE~~ Single regional reference node (RRN) within each market region at which all demand ~~forecasts subjected~~within the region is deemed to apply.
- Generators 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 and stability 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 assessment 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.[15]

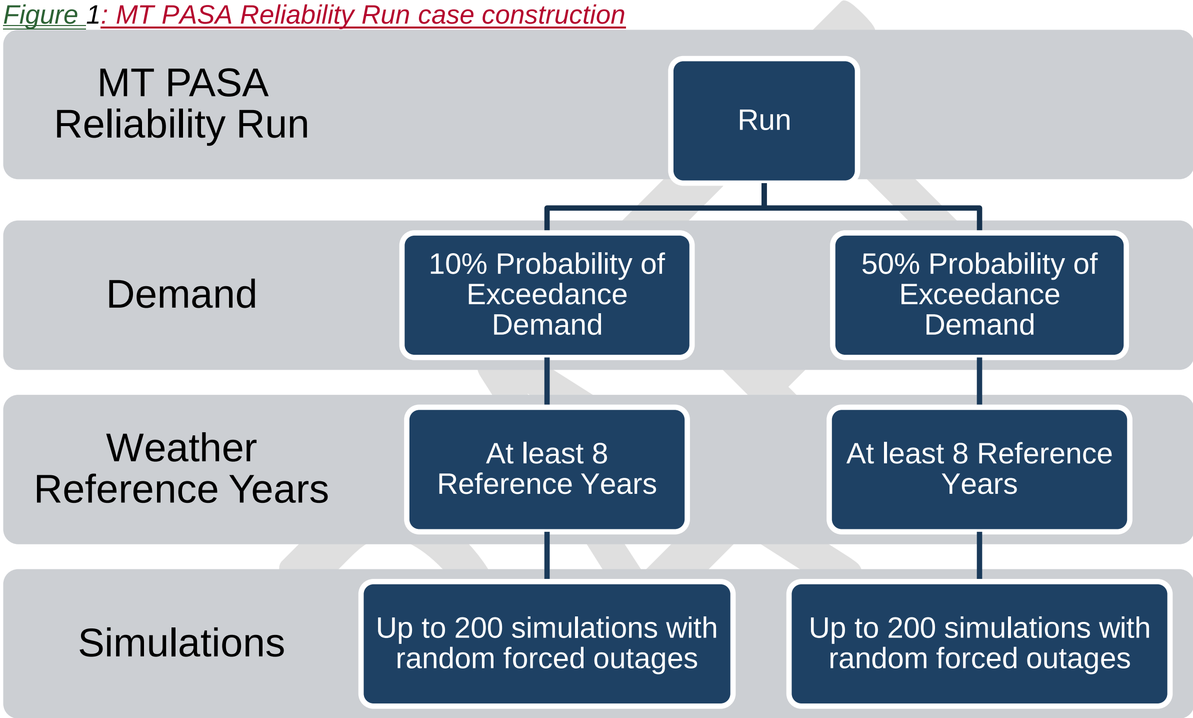
[15] The Reliability Run will be conducted on a weekly basis if computation times are sufficiently fast. Alternatively it may be run fortnightly in the absence of material changes to inputs.

The probabilistic approach replaces the previous deterministic approach towards assessing reliability and removes the need to calculate minimum reserve levels.

The MT PASA Reliability Run uses about 200 Monte-Carlo simulations[16] on a set of predefined base cases to assess variability in unserved energy outcomes (see Figure 1~~1~~). Demand and intermittent generation supply assumptions vary for each base case, driven by different historical weather conditions. Within a base case, the Monte-Carlo simulations vary with respect to:

- unplanned generation outage states based on historical forced outage rates.
- intermittent generation availability (by introducing random error around the projected intermittent generation forecasts based on historically observed variations in intermittent generation output).

Figure 1: MT PASA Reliability Run case construction



In total, over 3,000 simulations are conducted for each year of the reliability assessment horizon.

The objective function associated with a simulation is:

- Minimise total generation cost subject to:
  - Supply = Demand.
  - Unit capacity limits observed.
  - Unit/power station/portfolio energy limits observed.
  - Network constraints observed.

Each simulation produces an estimate of annual USE, with the total 3,000 odd simulations providing insight into the distribution of annual USE. AEMO proposes using a minimum of 50% POE and 10% POE demand levels, weighted appropriately[17], to assess the expected USE.

[16] 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.

[17] USE results from 50% POE and 10% POE runs are aggregated with 69.6% weighting for 50 POE and 30.4% weighting for 10 POE.

If there are material levels of USE in 50% POE results, AEMO will consider running additional demand levels such as 90% POE. 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: Pain Sharing~~Appendix C: Pain Sharing~~ for a more detailed explanation).

The outputs are also used to set interconnector flow parameters for the Loss of Load Probability assessment.

4.4 MT PASA Loss of Load Probability (LOLP) assessment

To determine days most at risk of load shedding, AEMO conducts a LOLP assessment for each day in the two-year horizon, assuming that extreme weather conditions 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 run any contracted RERT.

The LOLP run is essentially a stress test on the system as it uses the half-hourly 90th percentile demand value for each region concurrently – that is, the demand value with a 10% chance of being exceeded.

An objective function is not required for this run; instead, the calculation is done through a convolution of load process within the model to derive a loss of load probability for each day in the horizon. This is carried out by iterating through all units in the system, accumulating unit outages and calculating their respective probabilities. Capacity interchange from other regions is also taken into account. These capacity limits are calculated based on outputs from the Reliability Run. The LOLP will report the single half hour of each day that has the greatest probability of loss of load.

Intermittent generation in each region will be modelled as a single multi-state generator, based on assessed distribution of wind/solar availability in the region at that time of day, and time of year, under the 90th percentile demand conditions.

4.5 Comparison of Model Features

- ~~*PASA availability* of generation and weekly energy limits (includes committed future generation)~~
- ~~Power transfer capability of the power system taking planned network outages into account~~

~~MSC run determines spare generation capacity in each NEM region by running this model multiple times, taking each region as the study region in turn.~~

~~Table 3 provides a summary of the sets of inputs and linear programming (LP) models used in performing the three runs as well as their outputs.~~

~~A brief description of the architecture of the MT *PASA* program is provided in Appendix A.~~

~~Simplified examples to illustrate methodology behind Maximum Spare Capacity calculation in LOR runs is provided in Appendix F.~~

~~4.3 Modelling of Inter-regional Reserve Sharing in MT *PASA* Solution Process~~

~~CA models~~

~~When the total generation capacity of a region is greater than required for that region, the spare capacity can be shared with adjacent regions in order to meet reserves requirements of other regions, provided that the interconnectors flow[18] limits is not exceeded. This is referred to as reserve sharing.~~

~~The inter-regional power transfers are modelled in Capacity Adequacy models used in Reliability LRC run such that the inter-regional power transfers (reserve sharing) take place only to minimise reserve shortfalls in NEM regions.~~

~~An example illustrating the reserve sharing principle is shown in Appendix C.~~

~~MUR, MSR and MSC models~~

~~These models accommodate inter-regional power transfers (reserve sharing) to maximise reserves/spare capacity in the study region after meeting the reserve requirements/supply demand balance in other regions.~~

Table 1 shows the comparison of the key features of the two MT PASA modelling runs.

~~[18] The net interconnector flow into a region in the Reliability LRC run is reported as NETINTERCHANGEUNDERSCARCITY in the MTPASA.RegionSolution table. The net interconnector flow into a region in the MSR and MUR solves of RELIABILITY_MSR_MUR run is reported as MSRNETINTERCHANGEUNDERSCARCITY and MURNETINTERCHANGEUNDERSCARCITY in the MTPASA.RegionSolution table. A guide to the information contained in the MT PASA is available in the form of a data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx~~

Table 1-: Comparison of MT PASA run features

MT PASA INPUTS		
PROPERTY	**RELIABILITY RUN**	**LOLP RUN**
Horizon	2 years (104 weeks – starting the following Sunday)	
Frequency of Run	Weekly	Weekly
Simulations	Up to 200 per case	Not applicable
Resolution	Half Hourly	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 10% POE and 50% POE demand traces	Half hourly 90th percentile demand
Generator Capacity	As per participant MT PASA declarations	
Generator Bid Offers	SRMC calculated from heat rate, fuel price, VOM etc.	Not used
Generator Forced/partial outage modelling	Probabilistic assessment of forced outages over multiple simulations	Convolution of load
Intermittent (Semi Scheduled) Generation	At least eight historical weather traces, correlated to demand traces	Modelled as a single multi-state generator for each region
Non-scheduled Generation	Significant non-scheduled generation based on NEFR estimates	
Network Representation	ST PASA formulation constraints with dynamic right hand side (RHS with network outages	Network transfer limits from the Reliability Run to be used instead of network constraints
TNSP Limit Data	Equipment ratings inclusive of seasonal variations required for evaluating generic constraint RHS	Not used. Network transfer limits from the Reliability Run to be used instead

Interconnector forced outage modelling	Not modelled	Not modelled
Demand Side Participation	At least five static Price/Quantity bands. Price not required for LOLP run	
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	Convolution of Load – a mathematical calculation that iterates through the units to calculate the combined probability of outage for each half hour of the day
	MT PASA OUTPUTS	
PROPERTY	**RELIABILITY RUN**	**LOLP RUN**
Low Reserve Condition	Forecasts of low reserve conditions based on expected annual USE	N/A
Unserved Energy	Distribution of unserved energy for each day in the horizon.	
Loss of Load Probability		Probability of loss of load on any given day

Interconnector Transfer Capabilities	Interconnector transfer capabilities with network outages for use in LOLP Run	
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	
Aggregate Capacity for each region	Aggregate capacity allowing for the impact of network constraints – with and without energy constraints	

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[19]. The main ~~output from~~ MT PASA output is the forecast of any low reserve condition[20] ~~or lack of reserve conditions~~and the estimated USE value.

~~If capacity reserves are forecast to fall below reference levels, *AEMO* may declare the following conditions in the MT *PASA*. These are defined in clause 4.8.4 of the *Rules* and applied as follows:~~

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".*

- ~~*Low Reserve Condition* (LRC)[21] - When the medium term capacity reserves available in a region is forecast to be less than the medium term capacity reserve standard for *that* region.~~
- ~~Lack of reserve level 1 (LOR1) - When the medium term capacity reserves available in a region is forecast to be less than the sum of the largest and the second largest *generation* losses due to a credible contingency event in that region.~~
- ~~Lack of reserve level 2 (LOR2) - When the medium term capacity reserves available in a region is forecast to be less than the largest generation loss due to a credible contingency event in that region.~~
- ~~Lack of reserve level 3 (LOR3) - When involuntary load shedding is forecast due to supply shortage.~~

~~The Low reserve condition for a region is reported as RESERVECONDITION in the MTPASA.RegionSolution table. Appendix E lists formulae used in the calculation of the above quantities.~~

~~Under clause 3.7.2 (6) (iv) of the Rules, *AEMO* must *publish* forecast interconnector transfer capabilities as part of the MT *PASA* process. For the publication of the interconnector transfer capabilities under different *capacity and demand* and system conditions, four new runs namely, RELIABILITY_LIMITS, OUTAGE_LIMITS, RELIABILITY_LOR and OUTAGE_LOR have been introduced in the MT *PASA* process. The LP solves used in determining the interconnector limits are the existing Capacity Adequacy (CA) and Max Spare Capacity (MSC) solves used in the Regional Reliability LRC (Section 4.1) and Regional LOR (Section 4.3) runs. Table 4 provides a summary of the sets of inputs and linear programming (LP) models used in performing the four runs as well as their outputs.~~

[19] 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 data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx

[20] http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Data-dashboard

~~[21] The Low reserve condition and Lack of Reserve Levels for each region is reported as RESERVECONDITION and LORCONDITION respectively in the MTPASA.RegionSolution table. A guide to the information contained in the MT *PASA* is available in the form of a data model at http://www.aemo.com.au/-/media/Files/PDF/MMS-Data-Model-Report.ashx~~

~~*Table 3: Summary of the three MT PASA run types in system adequacy assessment*~~

Table 3 shows each MT PASA output colour coded by the run that is used to determine the value. Outputs (1) – (4) are based on AEMO daily 50% and 10% Probability of Exceedance (POE) peak demand forecasts[22] and corresponding assumptions, and are not determined by modelling. Output (5) is supplied in the three-hourly report as the aggregate value of participant submitted availabilities. Outputs (5A) – (6) (v) are predominantly determined by the Reliability Run, although some details are still to be determined.

Table 3: MT PASA Outputs Specified in NER 3.7.2(f)

MT PASA OUTPUT SPECIFICATIONS NER 3.7.2(f)	MT PASA PUBLICATION	OUTPUT DETAILS
(1) Forecasts of the 10% probability of exceedance peak load and most probable peak load, excluding the relevant aggregated MW allowance referred to in (2) and adjusted to make allowance for scheduled load	AEMO demand forecasts	Peak operational demand - 10% POE and 50% POE demand
(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 (1)	AEMO demand forecasts	Non Scheduled Generation at times of 10% POE and 50% POE peak operational demand
(3) In respect of each of the forecasts of the 10% probability of exceedance peak load and most probably peak load referred to in (1), a value that is the sum of that forecast and the relevant aggregated MW allowance referred to in (2)	Derived from (1) and (2)	Peak native demand
(4) Forecasts of the most probable weekly energy for each region	AEMO demand forecasts	Total Weekly Energy
(5) Aggregate generating unit PASA availability for each region	3 Hourly Report	Data Fields: PasaAvailabilityScheduled
(5A) Aggregate capacity for each region, after allowing for the impact of network constraints, that can be generated continuously, calculated by adding the following categories: (i) The capacity of scheduled generating units in the region that are able to operate at the PASA availability	MT PASA Reliability Run	Still to be determined

[22] Note that this is not the same as the 90th percentile demand values used in the LOLP Run.

(ii)The forecast generation of semi-scheduled generating units in the region as provided by the unconstrained intermittent generation forecasts		
(5B) Aggregate capacity for each region, after allowing for the impact of network constraints, that cannot be generated continuously at the PASA availability of the scheduled generating units in the region due to specified weekly energy constraints; and	MT PASA Reliability Run	Still to be determined.
(6) Identification and quantification of:		
(i) Any projected violations of power system security	MT PASA Reliability Run	Constraint solution outputs identify 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	Estimated USE for each day in each region. Identify LRC based on expected annual USE
(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	Constraint library & NOS	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	Binding constraints can only be assessed through modelling as it is dependent on generation dispatch. Constraints may bind at different times, depending on the demand and intermittent generation reference trace used.

~~Table 4: Summary of the four MT PASA run types in interconnector capability assessment~~

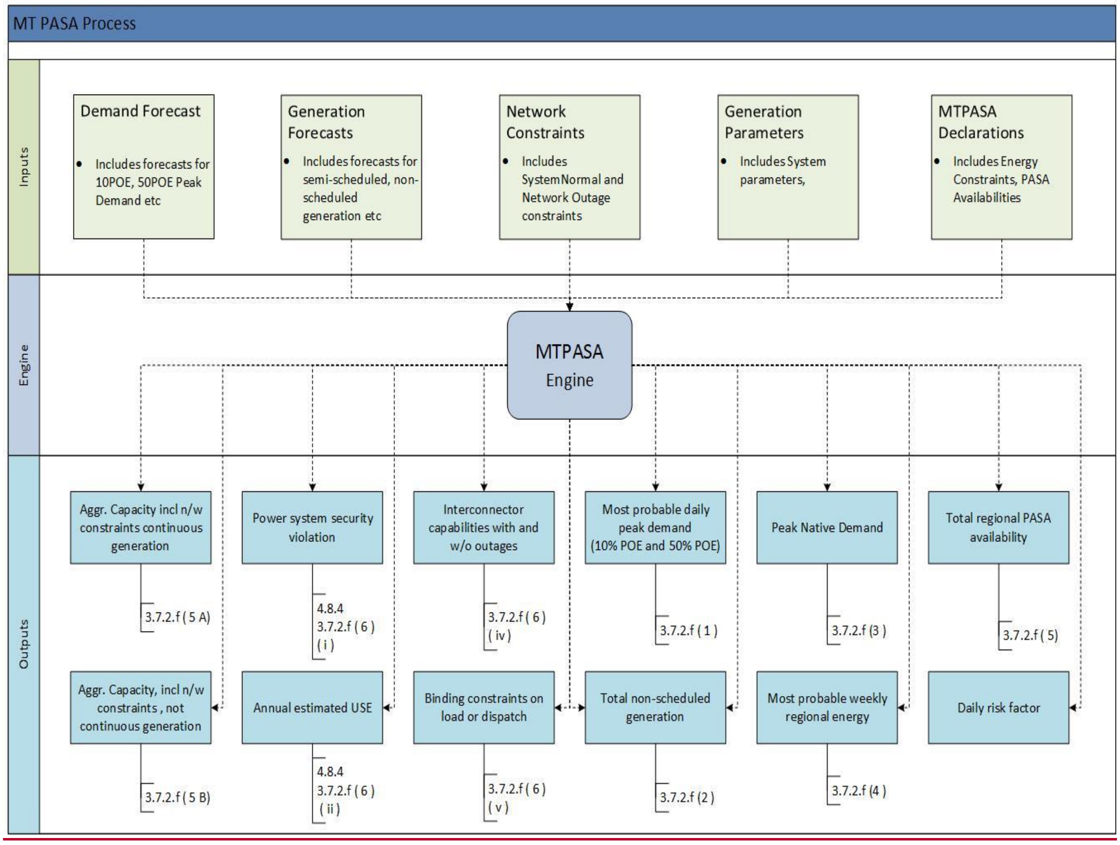
	~~RELIABILITY_LIMITS~~	~~OUTAGE_LIMITS~~	~~RELIABILITY_LOR~~	~~OUTAGE_LOR~~
~~Inputs~~	• ~~10% POE Demand~~ • ~~System normal constraints with the RHS using 10% POE demand for region terms and PASA unit availabilities for trader term~~ • ~~Full availability of interconnectors~~	• ~~10% POE Demand~~ • ~~System normal constraints and outage constraints with the RHS using 10% POE demand for region terms and PASA unit availabilities for trader term~~ • ~~Taken into account any interconnector outages~~	• ~~50% POE Demand~~ • ~~System normal constraints with the RHS using 50% POE demand for region terms and PASA unit availabilities for trader term~~ • ~~Full availability of interconnectors~~	• ~~50% POE Demand~~ • ~~System normal constraints and outage constraints with the RHS using 50% POE demand for region terms and PASA unit availabilities for trader term~~ • ~~Taken into account any interconnector outages~~
~~LP model~~	~~Capacity Adequacy (CA)~~	~~Capacity Adequacy (CA)~~	~~Max Spare Capacity (MSC)~~	~~Max Spare Capacity (MSC)~~
~~Outputs~~	• ~~Forecast export limit for all interconnectors under 10% POE demand and system normal conditions.~~ • ~~Forecast import limit for all interconnectors under 10% POE demand and system normal conditions.~~	• ~~Forecast export limit for all interconnectors under 10% POE demand and network outage conditions.~~ • ~~Forecast import limit for all interconnectors under 10% POE demand and and network outage conditions.~~	• ~~Forecast maximum export limit (of all study regions) for all interconnectors under 50% POE demand and system normal conditions.~~ • ~~Forecast minimum import limit (of all study regions) for all interconnectors under 50% POE demand and system normal conditions.~~	• ~~Forecast maximum export limit (of all study regions) for all interconnectors under 50% POE demand and network outage conditions.~~ • ~~Forecast minimum import limit (of all study regions) for all interconnectors under 50% POE demand and network outage conditions.~~

Appendix A: MT PASA Process Architecture

Figure 2~~A.1: Architecture of the~~: MT PASA ~~program~~Process

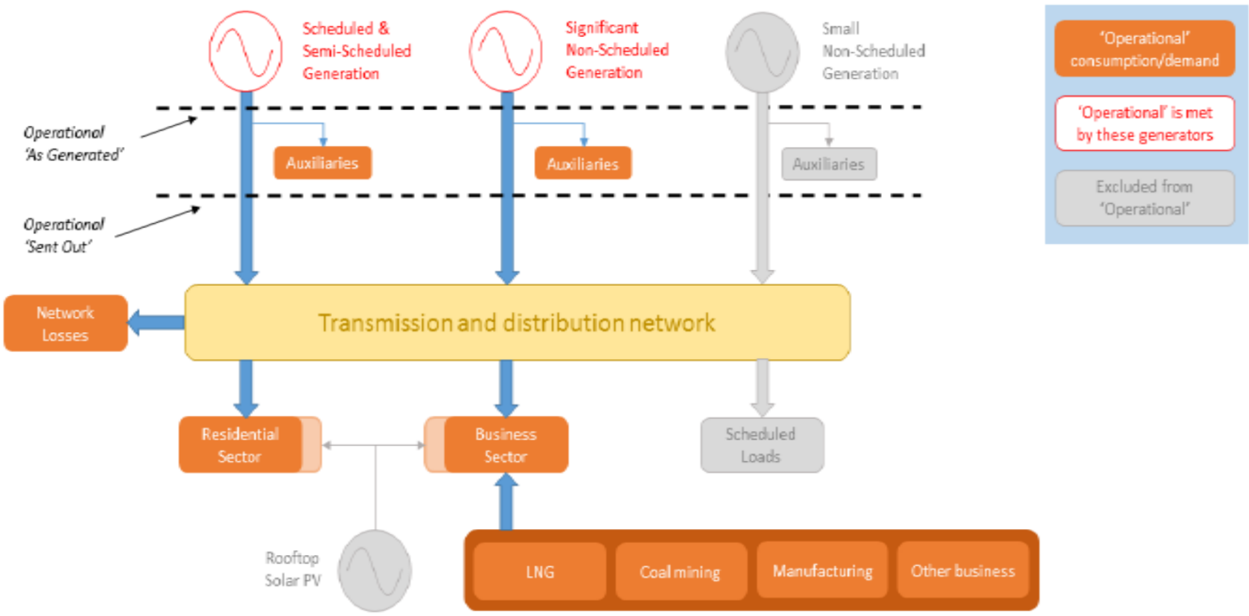
~~The MT *PASA* process operates as follows as described in figure A.1 above:~~

1. ~~The valid *Registered Participant* bid files are loaded into tables in the central Market Management System (MMS) Database. Bid acknowledgments are returned to *Registered Participants*.~~
2. ~~All relevant input data is consolidated into two input files which are solved by two separate MT *PASA* solvers.~~
3. ~~The MT *PASA* solvers sets up various linear constraints based on the input data and run several linear programs.~~
4. ~~The MT *PASA* solvers produce an output file each and are merged into one file by the MTPASASolutionMerger application. This file is then transferred to the National Electricity Market (NEM) database.~~
5. ~~A public MT *PASA* file is created from the input and solution files from the MT *PASA* solver.~~
6. ~~The new public MT *PASA* files are reformatted and sent to each *registered participant*.~~


MT PASA Process
Inputs
Demand Forecast
Includes forecasts for 10POE, 50POE Peak Demand etc
Generation Forecasts
Includes forecasts for semi-scheduled, non-scheduled generation etc
Network Constraints
Includes SystemNormal and Network Outage constraints
Generation Parameters
Includes System parameters,
MTPASA Declarations
Includes Energy Constraints, PASA Availabilities
Engine
MTPASA Engine
Outputs
Aggr. Capacity incl n/w constraints continuous generation
3.7.2.f (5 A)
Power system security violation
4.8.4
3.7.2.f (6)
(i)
Interconnector capabilities with and w/o outages
3.7.2.f (6)
(iv)
Most probable daily peak demand (10% POE and 50% POE)
3.7.2.f (1)
Peak Native Demand
3.7.2.f (3)
Total regional PASA availability
3.7.2.f (5)
Aggr. Capacity, incl n/w constraints , not continuous generation
3.7.2.f (5 B)
Annual estimated USE
4.8.4
3.7.2.f (6)
(ii)
Binding constraints on load or dispatch
3.7.2.f (6)
(v)
Total non-scheduled generation
3.7.2.f (2)
Most probable weekly regional energy
3.7.2.f (4)
Daily risk factor

Appendix B: Medium Term Demand Forecasting Process

Demand Type	Definition	Description
Underlying	Actual customer consumption	Actual consumption on premises ("behind the meter") ignoring effect of rooftop PV and battery storage.
Delivered	Underlying – PV – battery	What the consumer (either residential or business) must withdraw from the electricity grid.
Native	Delivered + (network losses)	Total generation that must be fed into the electricity grid.
Operational "sent-out"	Delivered – (Small Non-Scheduled Generation) + (network losses)	Total generation by scheduled / semi-scheduled / significant non-scheduled generators needed to meet system demand.
Operational "as generated"	(Operational "as sent out") + (auxiliary loads)	Total generation by scheduled / semi-scheduled / significant non-scheduled generators needed to meet system demand and demand on generator premises.



The methodology for creating "as generated" deman trace inputs is covered below:

- Representative traces are obtained using at least eight years of historical data.
- Derived operational traces (with rooftop PV added) are "grown" to represent future energy consumption and maximum demand. 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.
- Projections of future levels of annual underlying energy consumption and maximum demand in each region are obtained from the most recent NEFR
- Estimated auxiliary load is added to the "as sent out" demand to obtain the final "as generated" demand

- Rooftop PV is not modelled in MT PASA but is reported separately. In developing the operational demand traces, rooftop PV contribution in historical year is added to the original reference year trace, the trace “grown” and then forecast rooftop PV is subtracted from the grown trace and retained for reporting. The impact of battery storage is not considered presently due to low uptake, but may be incorporated in future.

AEMO is seeking to obtain more accurate information from participants on auxiliary load which would enable MT PASA to use “sent out” operational demand, while taking the auxiliary load into account within the model.

~~Figure B1 shows the relationship between the regional native demand published in the National Electricity Forecasting Report (NEFR) and the demand used in the MT *PASA* process. As shown in the figure, the MT *PASA* uses the demand met by scheduled and semi-scheduled generation.~~

~~*Figure B.1: Various demand components constituting* **Native** *Demand*~~

~~Developing MT *PASA* demand forecasts consists of two steps:~~

- ~~Step 1 – Derive regional daily peak native demand profiles using NEFR native summer/winter demand as the basis~~
- ~~Step 2 – Derive regional daily peak demand profiles for MT *PASA* by subtracting the demand met by non-scheduled and exempt generation form the regional daily native peak demand profiles~~

~~Following sections explain the method of performing the above two steps.~~

~~*Figure B.2: Method of developing* MT *PASA demand forecasts*~~

~~In figure B.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 NEFR for the given historical year. They are derived taking historical demand and temperature data into consideration. Refer figure B.3 below. Note that *AEMO* uses historical data for past ten years for these steps.~~

~~*Figure B.3: Development of weekly factor profile*~~

~~The weekday factor profile referred to in figure B.4 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 last ten years into consideration. The weekday factors are used consistently across all weeks of the forecast period when MT *PASA* demand forecasts are produced.~~

~~*Figure B.4: Development of weekday factor profile*~~

~~Step 2 (refer Figure B.2) consists of deriving the regional 10% POE and 50% POE daily peak demand profiles met by scheduled and semi-scheduled generations.~~

~~MT *PASA* regional 10% POE daily peak demand =~~

~~– Regional 10% POE daily native peak demand~~

~~- the most recent daily forecasts of non-scheduled regional wind & solar generation produced by AWEFS & ASEFS (90% POE forecast)~~

~~- regional daily forecast profiles of demand supplied by other non-scheduled generation published in NEFR (Medium growth scenario)~~

~~MT *PASA* regional 50% POE daily peak demand =~~

~~Regional 50% POE daily native peak demand~~

~~- the most recent daily forecasts of non-scheduled regional wind & solar generation produced by AWEFS & ASEFS (50% POE forecast)~~

~~- regional daily forecast profiles of demand supplied by other non-scheduled generation published in NEFR(Medium growth scenario)~~

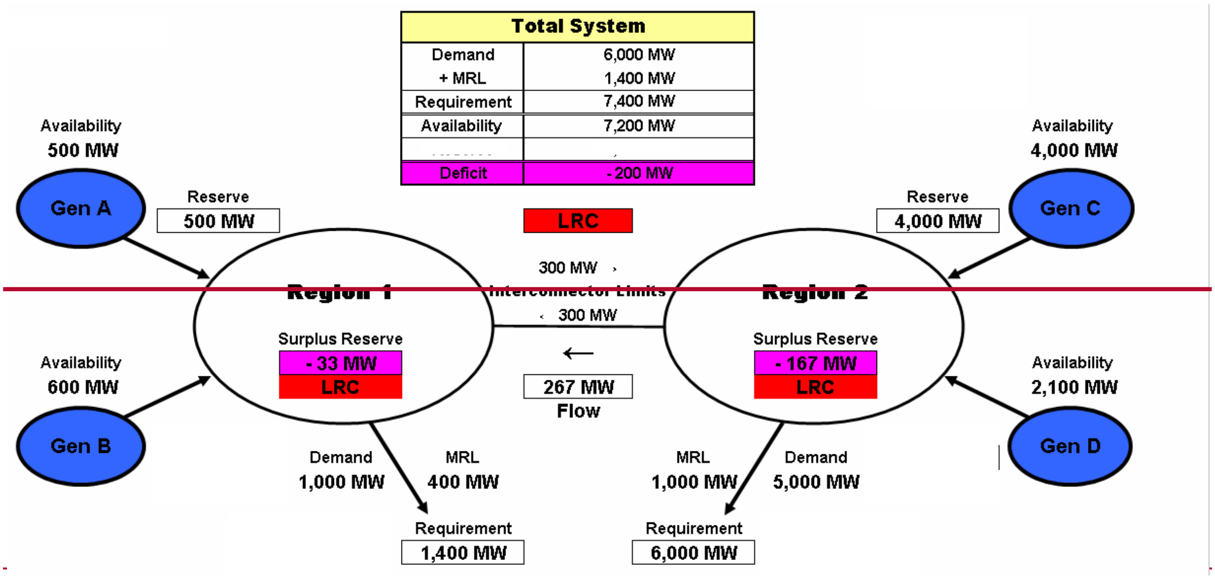
~~Appendix C: Reserve Sharing Example~~

~~In the example shown below, 100 MW of surplus capacity in Region 2 is supplied over the interconnector to meet the deficit capacity in Region 1. This still leaves a reserve shortfall of 200 MW in Region 1. Since the flow on the interconnector has reached its limit, no further capacity can be allocated to Region 1 from Region 2 to reduce its deficit.~~

~~Figure C.1: Reserve sharing example~~

~~Appendix D: Pain Sharing Example~~

~~In the example shown below, the surplus capacity in Region 2 is supplied over the Interconnector to meet the deficit capacity in Region 1. The deficit is reported in proportion to each region's demand and subject to interconnectors' limits. This leaves a reserve shortfall of 33 MW in Region 1 and 167 MW in Region 2.~~



~~Figure D.1: Pain sharing example~~

~~Appendix E: Formulae for Reserve Calculations in RELIABILITY_LRC, RELIABILITY_MSR_MUR and LOR solves~~

~~Table E.1 below provides the formulae used in deriving the regional reserve data in the different LP solves:~~

~~Table E.1: Formulae for reserve calculations~~

~~Data Field~~	~~Run Type~~	~~Formula~~
~~SURPLUSCAPACITY~~	~~RELIABILITY_LRC~~	~~UNCONSTRAINEDCAPACITY + CONSTRAINEDCAPACITY - NETINTERCHANGEUNDERSCARCITY[23] – DEMAND10~~
~~DEFICITRESERVE~~	~~RELIABILITY_LRC~~	~~- Min { 0, UNCONSTRAINEDCAPACITY + CONSTRAINEDCAPACITY - NETINTERCHANGEUNDERSCARCITY – (DEMAND10 + MRL[24])}~~

~~[23] A positive value for NETINTERCHANGEUNDERSCARCITY denotes a net export from the region and a negative value for NETINTERCHANGEUNDERSCARCITY denotes a net import into the region.~~
~~[24] The MRL values used for the different regions are listed in Section 3.2.3.~~

~~RESERVECONDITION~~	~~RELIABILITY_LRC~~	~~If DEFICITRESERVE > 0, RESERVECONDITION = 1~~ ~~If DEFICITRESERVE = 0, RESERVECONDITION = 0~~
~~DEMAND_AND_NONSCHEDGEN~~	~~RELIABILITY_LRC~~	~~DEMAND10 + TOTALINTERMITTENTGENERATION~~
~~MAXSURPLUSRESERVE~~	~~RELIABILITY_MSR_MUR~~	~~Max { 0, UNCONSTRAINEDCAPACITY + CONSTRAINEDCAPACITY - MSRNETINTERCHANGEUNDERSCARCITY – (DEMAND10 + Static MRL value[25])}~~
~~MAXUSEFULRESPONSE~~	~~RELIABILITY_MSR_MUR~~	~~Min { 0, UNCONSTRAINEDCAPACITY + CONSTRAINEDCAPACITY - MURNETINTERCHANGEUNDERSCARCITY – (DEMAND10 + Static MRL value)}~~
~~MAXSPARECAPACITY~~	~~OUTAGE_LOR~~	~~UNCONSTRAINEDCAPACITY[26] + CONSTRAINEDCAPACITY - LORNETINTERCHANGEUNDERSCARCITY – DEMAND50~~
~~LORCONDITION~~	~~OUTAGE_LOR~~	~~If MAXSPARECAPACITY > CALCULATEDLOR1LEVEL, then LORCONDITION = 0~~ ~~If MAXSPARECAPACITY < CALCULATEDLOR1LEVEL, then LORCONDITION = 1~~ ~~If MAXSPARECAPACITY < CALCULATEDLOR2LEVEL, then LORCONDITION = 2~~ ~~If MAXSPARECAPACITY < 0, then LORCONDITION = 3~~

~~Appendix F: Lack of Reserve (LOR) Condition Calculation~~

~~The LOR condition checks for contingent reserve in a region. The LOR Triggers are calculated as follows:~~

~~LOR1 Trigger = Capacity of the largest two Gens in the region~~

~~LOR2 Trigger = Capacity of the largest Gen in the region~~

~~The Max Spare Capacity (MSC) is calculated from the LOR run and indicates the reserve left in a study Region after meeting the supply demand balance in the other regions i.e. supply is at least equal to demand in the other regions.~~

~~Note that LOR Calculations take into account the 50% POE Demand.~~

[25] ~~The static MRL value for each region corresponds to the minimum reserve that the MSR solve requires to be available in each region, before the amount of generation that can be retracted from that region could be calculated.~~

[26] ~~The UNCONSTRAINEDCAPACITY and CONSTRAINEDCAPACITY values calculated in the LOR MSC solve may not be the same as the UNCONSTRAINEDCAPACITY and CONSTRAINEDCAPACITY values calculated in the RELIABILITY_LRC solves. Due to practical reasons associated with the quantity of data that can be published on the website, the results of the LOR MSC solve are not currently published.~~

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[27] 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 0.002% if at all 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 and thus the total quantity of USE will usually increase. 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 in order 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.

[27] http://www.aemc.gov.au/getattachment/deafe4fa-c992-4c34-bb74-c8d83cd1ba67/Guidelines-for-Management-of-Electricity-Supply-Sh.aspx

Appendix D: Indicative Graphical Outputs

The following charts represent proposed outputs from the MT PASA runs. These are subject to change during the MT PASA model development and testing stage and are based on "mock data" As such they do not represent real modelling outcomes.

Figure 4 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 F.1 below is a simplified example of Max Spare Capacity (MSC) calculation.~~

	~~Region 1~~	**~~Region 2~~**	**~~Region 3~~**
~~Total Capacity (CONSTRAINEDCAPACITY + UNCONSTRAINEDCAPACITY)~~	~~6000~~	~~10800~~	~~4000~~
~~50% POE demand (DEMAND50)~~	~~6100~~	~~10200~~	~~4200~~
~~Surplus Capacity (SURPLUSCAPACITY)~~	**~~-100~~**	**~~+600~~**	**~~-200~~**
~~LOR1/2 Trigger Levels (CALCULATEDLOR1LEVEL, CALCULATEDLOR2LEVEL)~~	~~1000/500~~	~~1400/700~~	~~500/250~~

~~Study Region 1~~

~~Comments~~	~~The MSC value of R1 is calculated such that the supply/demand balance of R2 & R3 are just met. Hence move 200MW from R2 to R3 and then move the remaining 400MW from R2 to R1. Positive denotes flow out of the region~~		
~~Surplus Capacity (SURPLUSCAPACITY)~~	~~-100~~	~~+600~~	~~-200~~
~~LOR Net Interchange for **R1** (LORNETINTERCHANGEUNDER SCARCITY)~~	~~-400~~	~~+600~~	~~-200~~

~~Maximum Spare Capacity **R1** (MAXSPARECAPACITY)~~	~~**+300 =**~~ ~~-100-(-400)~~		
~~LOR Condition R1 (LORCONDITION)~~	~~**LOR2**~~		

~~Study Region 2~~

~~Comments~~	~~The MSC value of R2 is calculated such that supply/demand balance of R1 & R3 are just met. Hence move 100MW from R2 to R1 and 200MW from R2 to R3. Positive denotes flow out of the region.~~		
~~Surplus Capacity (SURPLUSCAPACITY)~~	~~-100~~	~~+600~~	~~-200~~
~~LOR Net Interchange for **R2** (LORNETINTERCHANGEUNDER SCARCITY)~~	~~-100~~	~~+300~~	~~-200~~
~~Maximum Spare Capacity **R2** (MAXSPARECAPACITY)~~		~~**+300 =**~~ ~~600-(+300)~~	
~~LOR Condition **R2** (LORCONDITION)~~		~~**LOR2**~~	

~~Study Region 3~~

~~Comments~~	~~The MSC value of R3 is calculated such that supply/demand balance of R1 & R2 are just met. Hence move 100MW from R2 to R1 and the remaining 500MW R2 to R3. Positive denotes flow out of the region~~		
~~Surplus Capacity (SURPLUSCAPACITY)~~	~~-100~~	~~+600~~	~~-200~~
~~LOR Net Interchange for **R3** (LORNETINTERCHANGEUNDER SCARCITY)~~	~~-100~~	~~+600~~	~~-500~~

~~Maximum Spare Capacity **R3** (MAXSPARECAPACITY)~~			~~**+300 =**~~ ~~-200-(-500)~~
~~LOR Condition **R3** (LORCONDITION)~~			~~**LOR 1**~~

Figure 3: Assessment of Reliability Standard

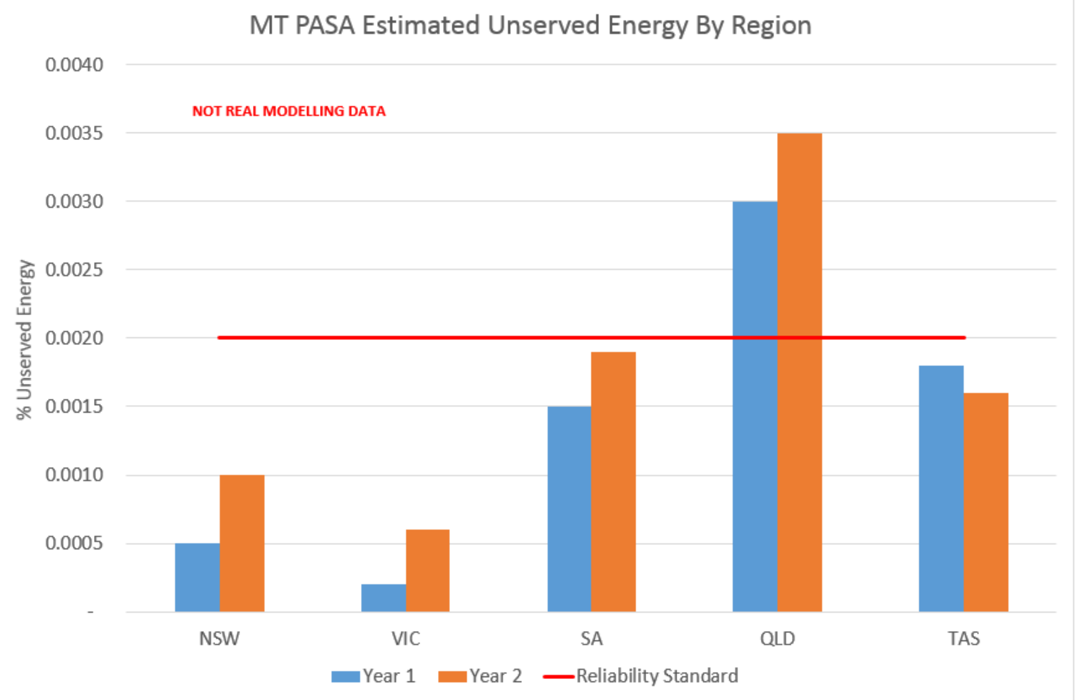


Figure 4 shows the LOLP assessed for each day. It also provides a breakdown of supply and demand at times of highest LOLP each day to help gain insights into conditions driving the higher LOLP outcomes. The black line represents installed capacity, the red line the 90th percentile demand and the green line the total available capacity. The dashed lines show the components of the available capacity – scheduled generation and intermittent generation.

Figure 4: Demand shown with supply availability and loss of load probability

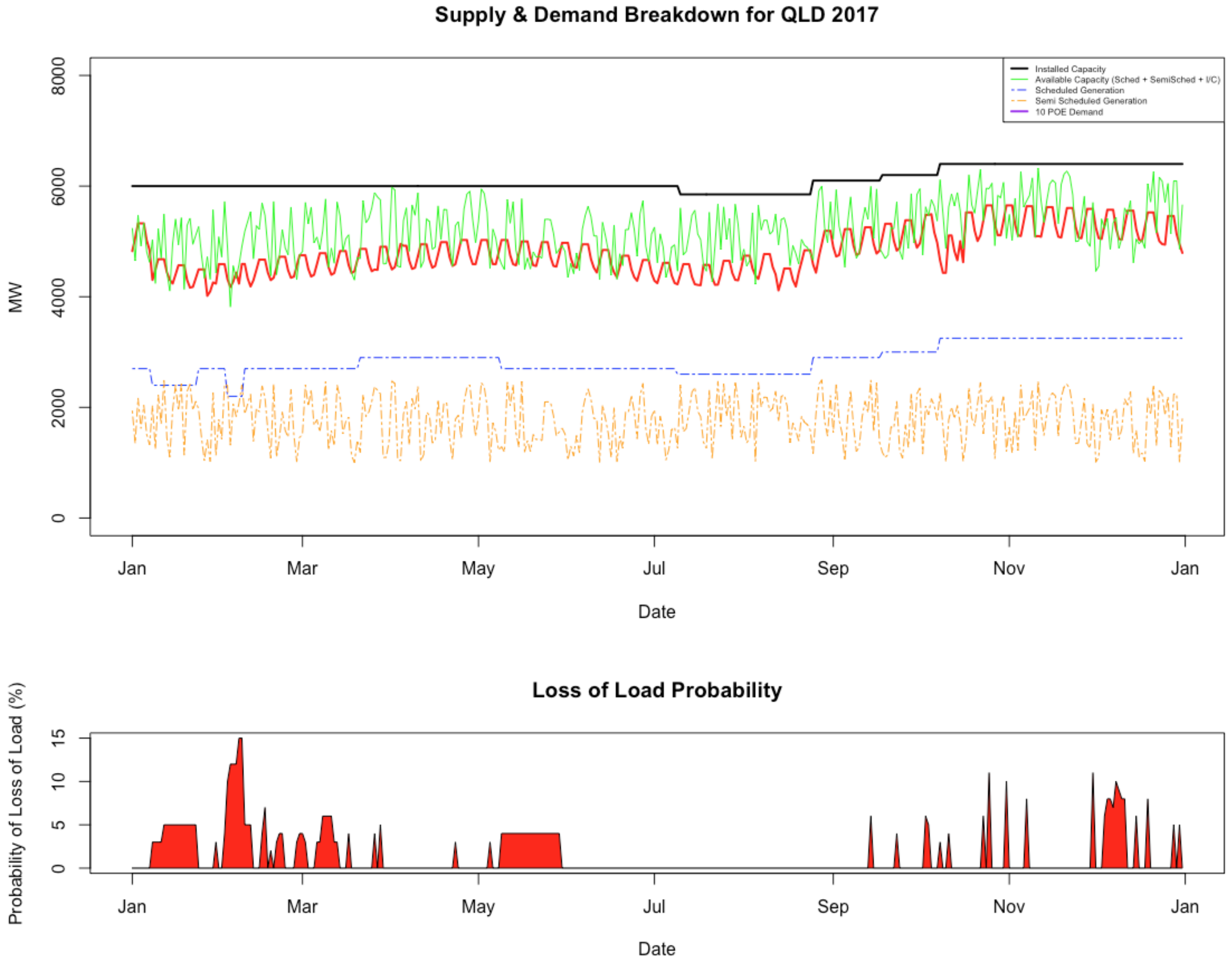


Figure 5 indicates the extent of unserved energy across the different probabilistic simulations and the periods where unserved energy occurred most often. This helps quantify the USE by showing the frequency and magnitude of load shedding in each simulation.

Figure 6 shows a more detailed monthly breakdown of unserved energy by reference year and demand level.

Figure 5: Variations in Unserved Energy by region and reference year across probabilistic modelling simulations

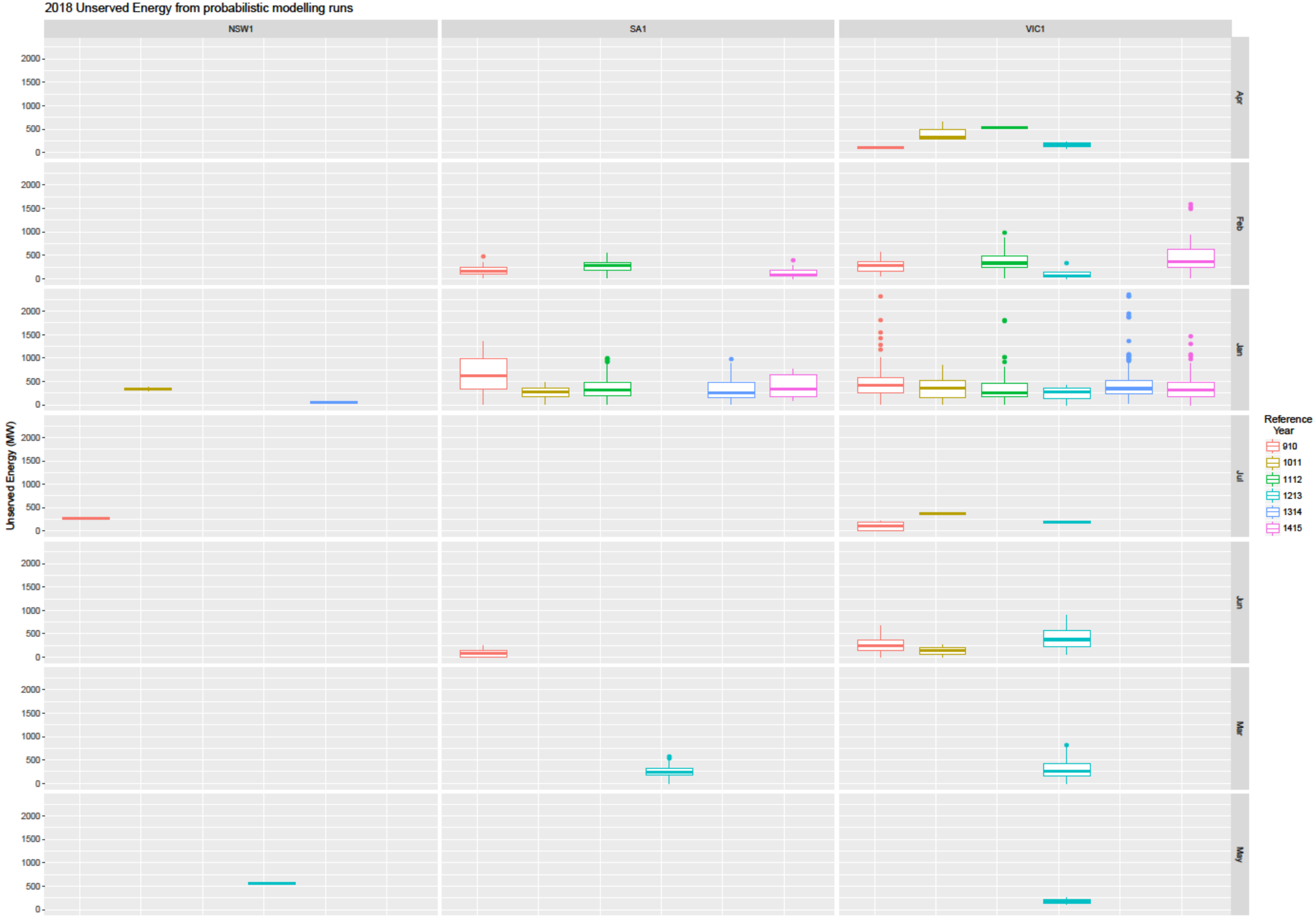


Figure 6: Detailed USE breakdown for a single month by reference year and demand level