MARKET MODELLING METHODOLOGY AND INPUT ASSUMPTIONS

FOR PLANNING THE NATIONAL ELECTRICITY MARKET, EASTERN AND SOUTH-EASTERN GAS SYSTEMS

Published: **December 2016**

AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

IMPORTANT NOTICE

Purpose

AEMO has prepared the 2016 National Transmission Network Development Plan (NTNDP) Market Modelling Methodology and Input Assumptions under clause 5.20.2 of the National Electricity Rules. This report is based on information available to AEMO up to 14 October 2016.

Disclaimer

This report contains data provided by or collected from third parties, and conclusions, opinions, assumptions or forecasts that are based on that data.

AEMO has made every effort to ensure the quality of the information in this report but cannot guarantee that the information, forecasts and assumptions in it are accurate, complete or appropriate for your circumstances. This report does not include all of the information that an investor, participant or potential participant in the gas market might require, and does not amount to a recommendation of any investment.

Anyone proposing to use the information in this report should independently verify and check its accuracy, completeness and suitability for purpose, and obtain independent and specific advice from appropriate experts.

This document or the information in it may be subsequently updated or amended. This document does not constitute legal or business advice, and should not be relied on as a substitute for obtaining detailed legal advice about the National Electricity Law, the National Electricity Rules, or any other applicable laws, procedures or policies.

Accordingly, to the maximum extent permitted by law, AEMO and its officers, employees and consultants involved in the preparation of this document:

- make no representation or warranty, express or implied, as to the currency, accuracy, reliability or completeness of the information in this report; and
- are not liable (whether by reason of negligence or otherwise) for any statements, opinions, information or other matters contained in or derived from this publication, or any omissions from it, or in respect of a person’s use of the information in this report.

Version control

Version	Release date	Changes
1	23/12/2016	

CONTENTS

TABLES

FIGURES

CHAPTER 1. INTRODUCTION

AEMO provides planning and forecasting information for the National Electricity Market (NEM), and eastern and south-eastern gas systems, to support efficient long-term investment decisions in Australia's electricity markets and infrastructure services.

AEMO produce a comprehensive suite of planning publications each year, including:

- **National Electricity Forecasting Report (NEFR)** – an independent forecast for electricity consumption, maximum demand, and minimum demand over a 20-year outlook period for the NEM.
- **National Gas Forecasting Report (NGFR)** – an independent forecast for gas consumption, and maximum gas daily consumption over a 20-year outlook period for the eastern and south-eastern gas network.
- **NEM Electricity Statement of Opportunities (ESOO)** – a supply adequacy assessment of the NEM. Provides market and technical data to aid market participants, new investors, and jurisdictional bodies in assessing electricity market opportunities over a 10-year outlook period.
- **National Transmission Network Development Plan (NTNDP)** – provides an independent and strategic view of the efficient development of the NEM transmission grid across a range of credible scenarios over a 20-year planning horizon.
- **Victorian Annual Planning Report (VAPR)** – considers the adequacy of the Victorian transmission network to meet its reliability requirements, and identifies development opportunities to address emerging network constraints.
- **Gas Statement of Opportunities (GSOO)** – reports on the transmission, production, and reserves supply adequacy of eastern and south-eastern Australian gas markets over a 20-year outlook period.

These reports comprise AEMO's long-term view on the evolution of the NEM and the eastern and south-east Australian gas transmission network.

An overview of the suite of planning and forecasting publications is shown in Figure 1 below.

AEMO generally uses four models to perform market modelling activities:

- The capacity outlook model.
- The time-sequential model.
- The network development outlook model.
- The gas supply model.

These models and other supporting activities form an iterative loop ensuring market modelling activities' quality, completeness, and robustness.

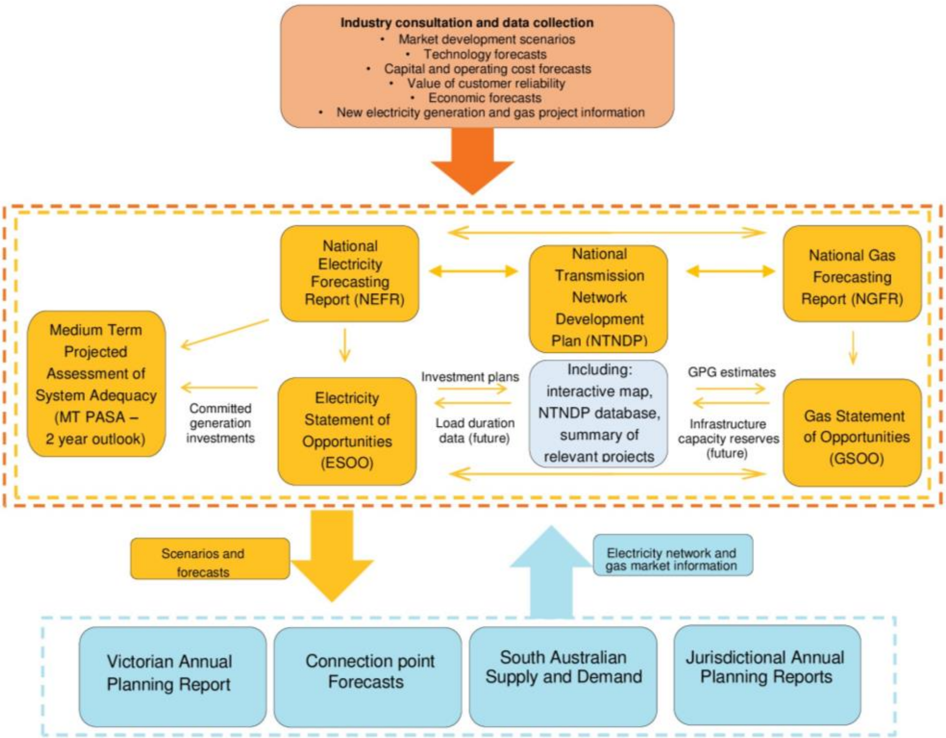
This document provides an overview of methodologies employed to support AEMO's market modelling activities across a range of publications. Supplementary methodology and input assumption reports are also provided with each publication[1],[2],[3]. These highlight specific assumptions or approaches of relevance in that planning publication cycle.

[1] AEMO. *Gas Statement of Opportunities methodology*. Available at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities

[2] AEMO. *Electricity Statement of Opportunities methodology*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities

[3] AEMO. *National Transmission Network Development Plan methodology*. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan

Figure 1 AEMO's planning and forecasting publications – NEM, and eastern and south-eastern gas systems



1.1 Data sources and flow

Assumption data originates from many sources, both externally and as a result of AEMO's activities in the national gas and electricity markets. Appendix A presents all data sources and the items taken from each.

Data updates become available at different times of the year. Each planning report uses the latest data that is available when modelling commences.

CHAPTER 2. SCENARIOS

AEMO's long-term planning begins with the development of a series of credible global economic and technological development scenarios.[4] These scenarios are designed to cover a wide range of potential future development pathways, and describe the environment in which Australia's energy networks may operate for up to 25 years into the future.

The scenarios are intended to explore a range of credible futures, with each scenario based on themes of development such as fast or slow economic growth, high or low technology costs, or relaxed or strict carbon policies.

AEMO scenarios are developed in conjunction with industry working groups. Representatives were selected to capture generation businesses and network development, energy consumers, policy makers, and promoters of emerging technologies.

Detailed descriptions of these scenarios are published on the AEMO website.[5]

Table 1 shows major drivers that influence market modelling results.

Table 1 Major drivers

Scenario drivers	Description	Relevance	Common Source
Demographic changes and economic activity	Reflects the impact of population growth and economic projections on electricity demand	Economic activity drives electricity consumption	*National Electricity Forecasting Report*
Emerging technologies	A technology scan of relevant and likely technologies that could significantly impact the electricity market	Disruptive technologies may significantly change system needs and operating regime	External consultation
Capital and operation cost trajectories	An assessment of the price impact of upstream and downstream industries	Investment and operating costs define the total system cost of running the electricity market	External consultation
Carbon abatement policies	National, state-wide and company policies enforce transition to low carbon economy	Incentivise investment in renewable energy and penalise heavy carbon emitters	Government legislation
Network development options	Augmentation options for emerging network limitation	Limits efficient operation of the power system	In-house studies

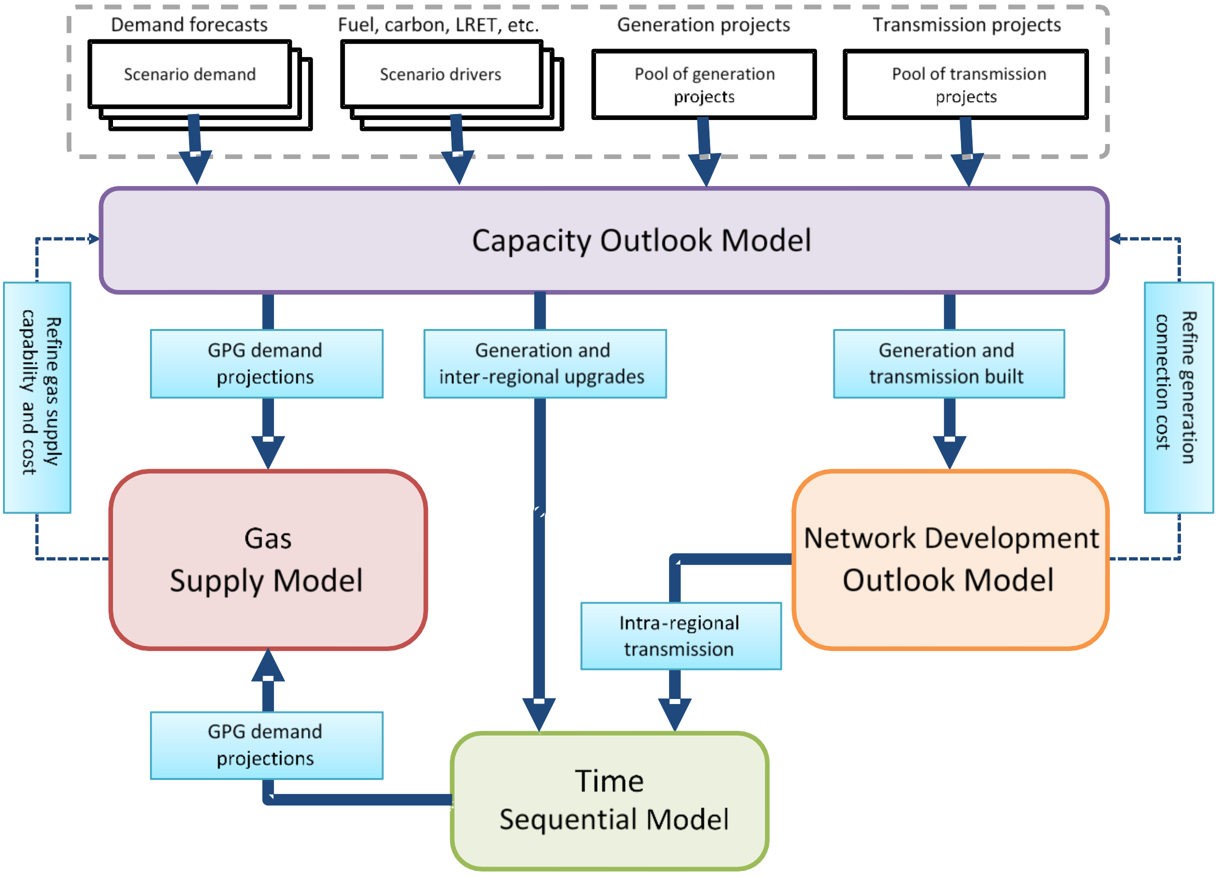
[4] In the context of AEMO planning, a scenario is a self-consistent set of assumptions covering economic and policy settings, estimates of generation technology costs, fuel and carbon cost trajectories, price-demand relationships, and other externalities that influence but are not materially affected by the generation and transmission outlook developed by capacity outlook modelling.

[5] AEMO. *National Electricity Forecasting Report*. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

CHAPTER 3. MODELS

AEMO maintains four mutually-interacting planning models, shown in Figure 2. These models incorporate the assumptions about future development described by the scenarios, and simulate the operation of energy networks to determine a reasonable view as to how those networks may develop under different demand, technology, policy, and environmental conditions.

Figure 2 Market modelling process flow



The NEM ESOO, NTNDP, and VAPR primarily use three models to deliver their key outputs:

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator and transmission investments and retirements to maintain power system reliability.
- **Time-sequential model**[6] – carries out an hourly simulation of generation dispatch and regional demand while considering various power system limitations, generator forced outages, variable generation's availability, and bidding models. This model validates insights on power system reliability, available generation reserves, emerging network limitations, and other operational concerns. Depending on the study this model is used for, the generation and transmission outlook from the capacity outlook model may be incorporated.
- **Network development outlook model** – examines and investigates possible engineering and operational solutions to emerging transmission network limitations identified by the capacity outlook model and time-sequential model.

[6] The time-sequential model is composed of three simulation phases: 1. PASA – schedules maintenance, 2. Medium-term schedule – optimises energy production schedule, 3. Short-term schedule – hourly simulation.

The **Gas supply model** is used primarily in the GSOO, with daily granularity to deliver its key outputs.

The capacity outlook model, time-sequential model and gas supply model all make use of the PLEXOS Integrated Energy Model platform developed by Energy Exemplar.

The network development outlook model utilises PSS/e software.

3.1 National electricity market topology

The NEM is comprised of the five Commonwealth States of Queensland, New South Wales, Victoria, South Australia, and Tasmania, referred to as regions and shown in Figure 3.[7] AEMO's electricity modelling replicates these regions, representing the network as a system of five regional reference nodes connected by inter-regional flow paths.

The regional topology allows the model to respond to regional changes in demand, and to optimise regional generation and inter-regional transmission expansion. This arrangement also mirrors the operation of the National Electricity Market Dispatch Engine (NEMDE), which is responsible for directing generation dispatch in the NEM.

Figure 3 Regional representation of the NEM

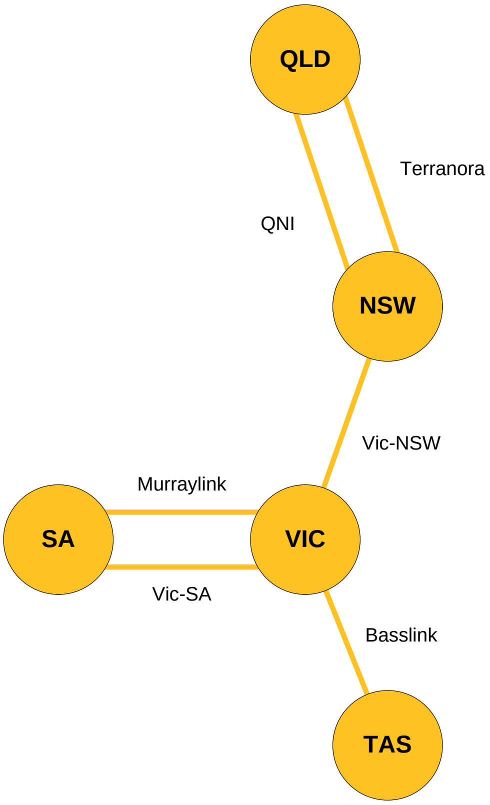
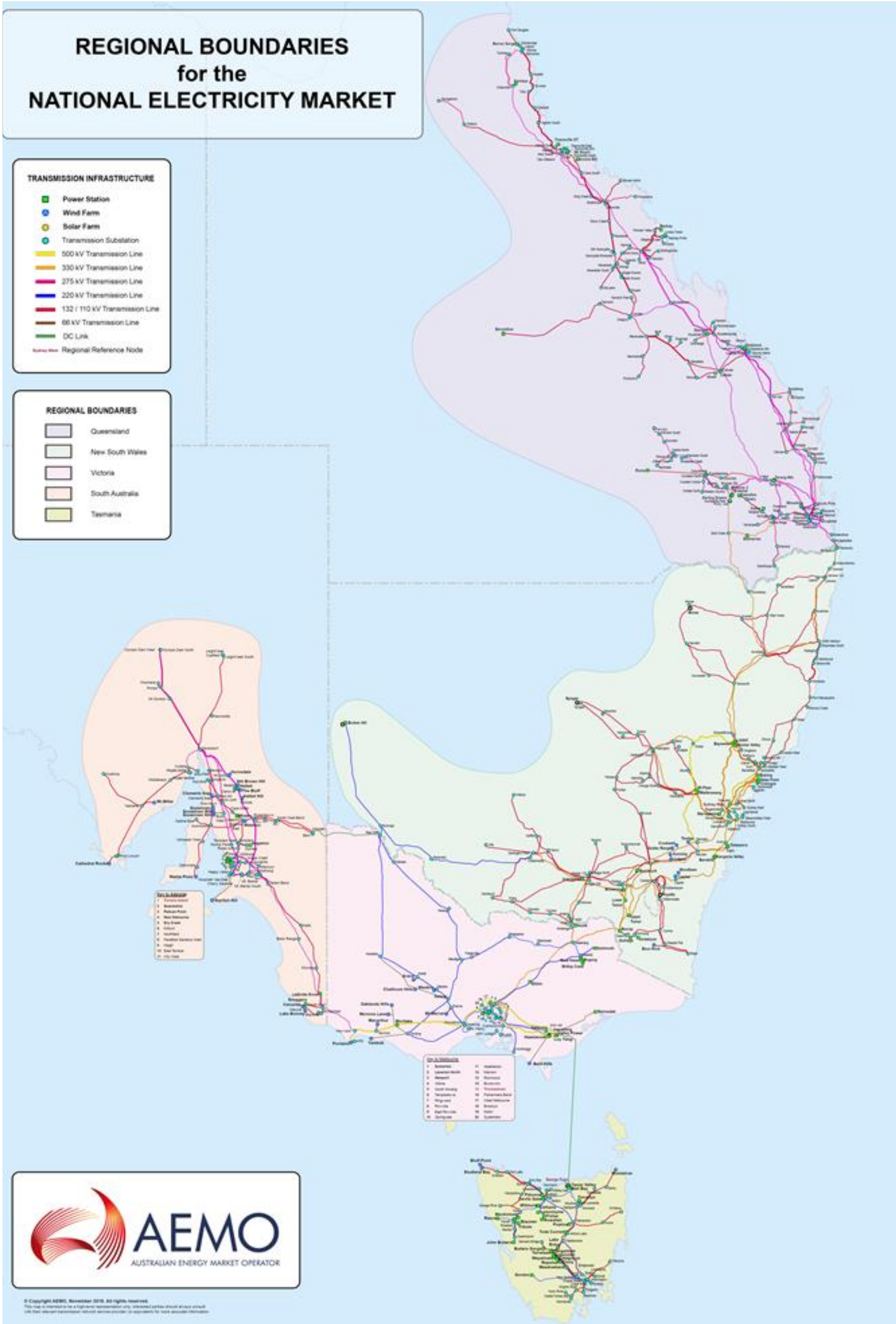


Figure 4 shows the electricity infrastructure and the latest regional boundaries definition for the NEM.

[7] The Australian Capital Territory is included within the New South Wales NEM region.

Figure 4 NEM regions and power system infrastructure



3.1.1 Geographical and electrical diversity

A regional representation cannot account for differences in energy resources and infrastructure within a region. To incorporate these aspects, AEMO's electricity modelling defines sixteen planning zones, shown in Table 2 and Figure 5, each of which displays a characteristic demand and resource pattern.

The South West Queensland (SWQ) zone, for example, has low local demand but sizable solar, coal, and gas resources. Electricity export is the major challenge in this zone. The neighbouring zone to the east, South East Queensland (SEQ), has high demand, limited access to generation fuels, and limits on infrastructure development to maintain the amenity of Brisbane, its suburbs, and nearby coastal tourist centres. Energy import is the major challenge in this zone.

Energy resource availability and cost, along with generation build limits, are defined according to these zones. Network constraint equations capture transmission limits between zones.

Zones with the greatest resources, or those with the lowest resource cost, will likely receive new generation first, provided network limits do not unduly constrain that generation.

In some cases, the low cost of generation in a particular area will justify both investment in generation infrastructure and investment in transmission infrastructure to supply power elsewhere.

Table 2 Electricity planning regions and zones for the electricity market modelling

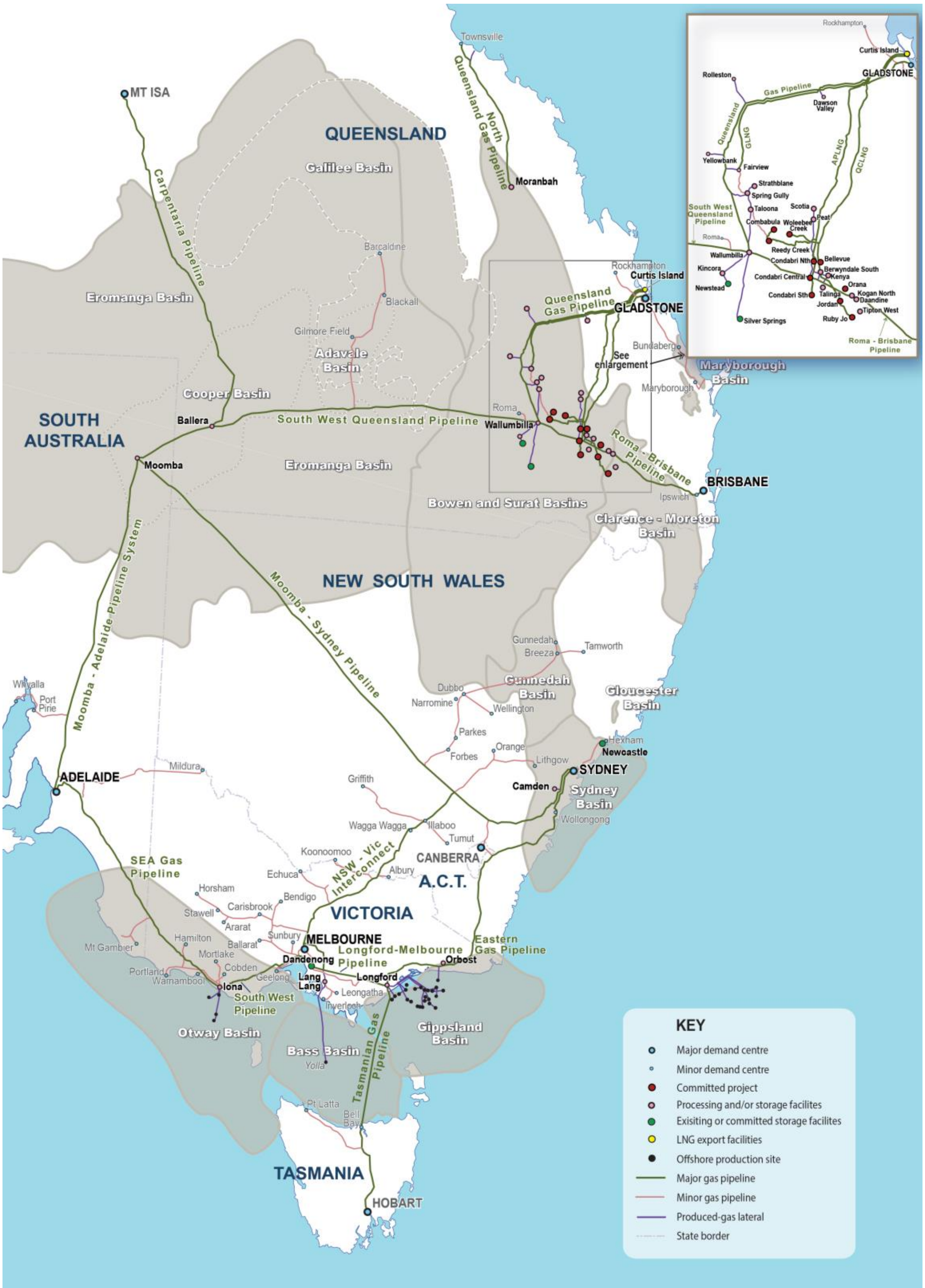
Region	Zones
QLD (Queensland)	NQ (North Queensland)
	CQ (Central Queensland)
	SWQ (South West Queensland)
	SEQ (South East Queensland)
NSW (New South Wales)	NNS (Northern New South Wales)
	NCEN (Central New South Wales)
	CAN (Canberra)
	SWNSW (South West New South Wales)
VIC (Victoria)	LV (Latrobe Valley)
	MEL (Melbourne)
	CVIC (Country Victoria)
	NVIC (Northern Victoria)
SA (South Australia)	ADE (Adelaide)
	NSA (Northern South Australia)
	SESA (South East South Australia)
TAS (Tasmania)	TAS (Tasmania)

Figure 5 Electricity planning zones

3.2 Gas network topology

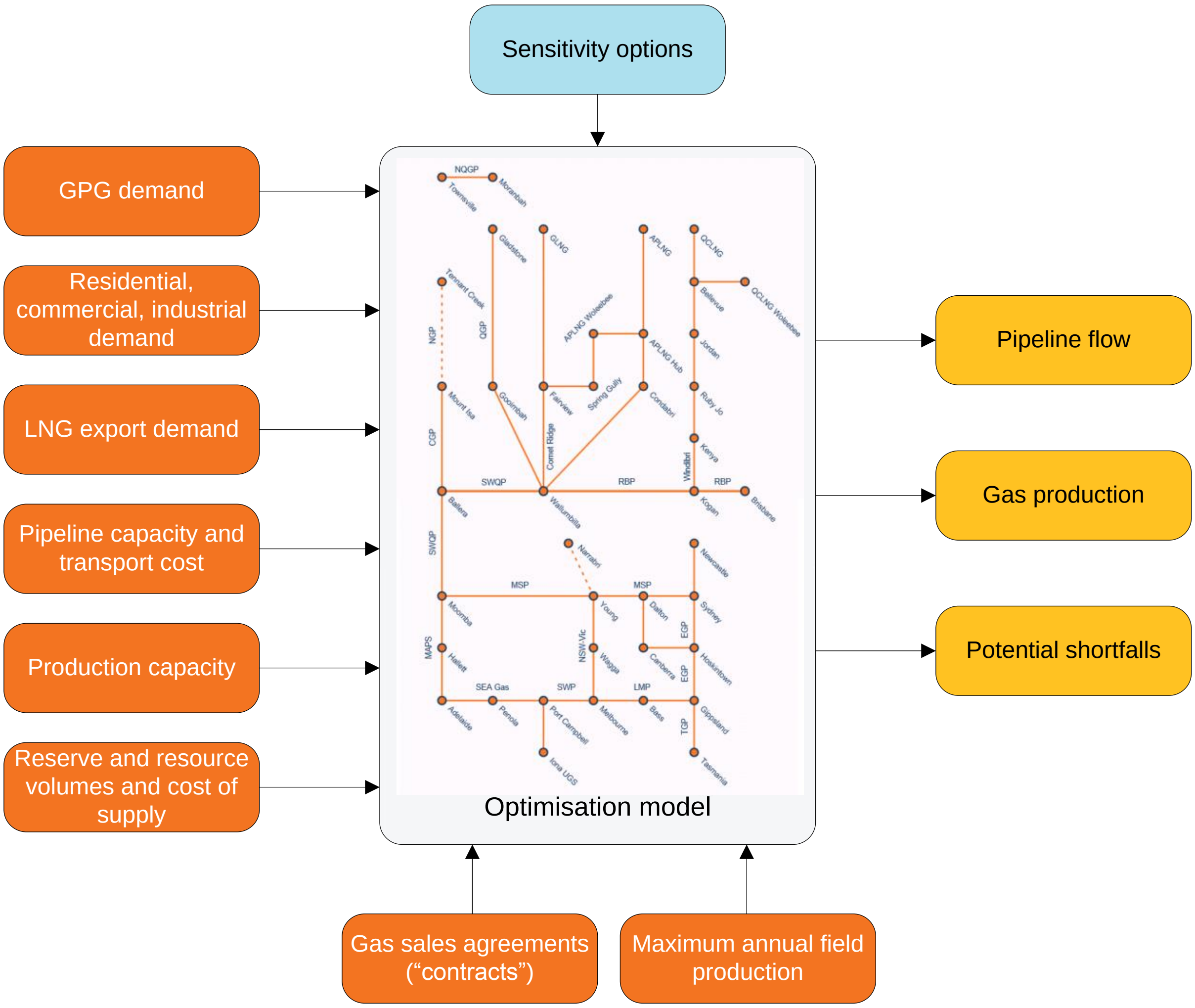
Major gas transmission and production infrastructure in eastern and south-eastern Australia is shown in Figure 6.

Figure 6 Eastern and south-eastern Australian gas production and transmission infrastructure



The gas supply model incorporates major gas transmission pipelines, demand centres and production facilities, as shown in Figure 7.

Figure 7 Gas model topology, inputs, and outputs



3.3 Capacity outlook model

The capacity outlook model is used to develop plans for generation and inter-regional transmission expansion over the long term. It does so by co-optimising electricity generation and inter-regional transmission investment and withdrawals to efficiently meet future operational demand and energy policy objectives (such as emissions abatement) at lowest cost.

The objective of the model is to minimise the capital expenditure and generation production costs over a 20- to 25-year planning outlook, subject to:

- Ensuring there is sufficient supply to reliably meet demand at the current NEM reliability standard[8], allowing for inter-regional reserve sharing.
- Meeting legislated and advanced policy objectives.
- Observing physical limitations of the generation plant and transmission system.
- Accounting for any energy constraints on resources.

[8] The reliability standard specifies that the level of expected USE should not exceed 0.002% of operational consumption per region, in any financial year. Australian Energy Market Commission (AEMC) Reliability Panel. NEM Reliability Standard – Generation and Bulk Supply. Available at http://www.aemc.gov.au/getattachment/f93100d9-72d2-46fb-9c25-ac274a04ae58/Reliability-Standards-(to-apply-from-1-July-2012).aspx.

The modelling approach applies a mathematical formulation of a mixed integer linear program to solve for the most cost-efficient generation and transmission development schedule (considering size, type, location, and commissioning and retirement date of generation and transmission assets).

The capacity outlook model is rich in options for the location and technology of new generation, candidates for retirement, and transmission augmentation options. These options are outlined in the NTNDP database published each year.[9]

Due to the size of the problem and the length of the planning horizon, it is necessary to make some simplifying assumptions, trading off some model accuracy for computational manageability. These simplifications may include:

- Aggregating hourly demand across the 20+ year planning horizon into a representative number of load blocks per month.
- Simplifying the network representation, using static notional interconnector limits, and no intra-regional transfer limitations.
- Reducing the number of integer decision variables by linearising the majority of generation and transmission build decisions (effectively allowing partial units to be built if desired).
- Using minimum capacity reserve levels to approximate the amount of firm capacity required in each region to meet the reliability standard.
- Using minimum capacity factors to represent minimum technical and economic duty cycles for coal generators.
- Setting convergence thresholds to control the run time of the model.

These simplifications are explained in more detail in the following sections.

As the capacity outlook model makes these simplifications and does not simulate hourly operation of the power system, detailed analysis is subsequently carried out using the time-sequential model. Where necessary, a feedback loop is included allowing the time-sequential model to inform the capacity outlook model. This feedback might include limiting the amount of build in a particular region, if constrained off due to transmission limitations, or adding additional firm peaking capacity in a region if unserved energy (USE) in excess of the reliability standard is observed in the time-sequential model.

Consequently, generation and transmission expansion development is an iterative process. Where possible, integer retirement decisions made by the modelling during the early stages of the development are ‘locked down’ if common to many of the simulations. This helps improve the robustness of the expansion/retirement plan by reducing the number of integer decisions to be made in subsequent iterations and improves stability between scenarios.

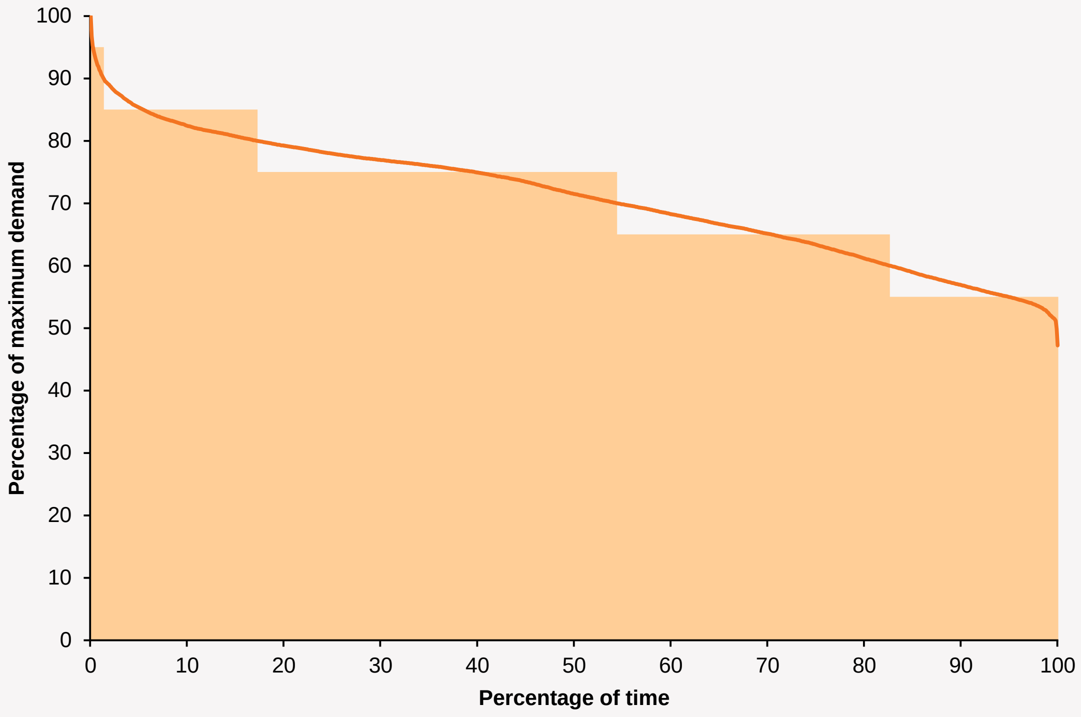
3.3.1 Load blocks

Load blocks are created for each month modelled, using a ‘best-fit’ approach to approximate the monthly load duration curves, as demonstrated in Figure 8. The monthly partitioning captures seasonal variation and maximum and minimum demands are preserved, but within each month the demand chronology is lost.

To ensure supply capacity adequacy, 10% probability of exceedance (POE) demand curves are used. Operational consumption ‘sent out’ is used rather than ‘as generated’ to account for the fact that new generation technologies may use different auxiliary loads.

[9] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

Figure 8 A load duration curve partitioned into five load blocks



When underlying consumption is modelled explicitly, the hourly rooftop PV generation trace is first netted off the demand trace within the model before aggregating into load blocks. This ensures the load blocks represent periods of similar operational demand, which is more relevant for determining scheduled dispatch.

Each load block typically represents a number of time periods within the month with similar operational demand levels. However, other time-varying data, such as wind generators' availability, could vary considerably within that same load block but are averaged to a single representative availability value. This highlights a weakness of aggregating demand into load blocks – the hourly intermittency and chronology of wind and utility-scale solar generation is unavoidably smoothed.

3.3.2 Reserve modelling

The reliability standard, set by the Australian Energy Market Commission (AEMC) Reliability Panel, specifies that, on average, a region should not experience USE exceeding 0.002% of energy consumption per year.

Due to the lack of granularity in the capacity outlook model, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year. Instead, minimum capacity reserve levels for each region are used as a proxy. These minimum capacity reserve levels are generally set equal to the size of the largest generating unit, (although may be adjusted over time if the time-sequential modelling indicates that more firm capacity needs to be built in a region to avoid reliability standard breaches). The capacity outlook model ensures that sufficient firm capacity is installed/maintained within each region, or imported from neighbouring regions, to meet these minimum capacity reserve levels.

Key reserve modelling inputs include:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region).
- Maximum inter-regional reserve sharing (based on notional interconnector transfer capabilities).
- Firm capacities (discounted for wind farms and solar PV to reflect the intermittent nature of these technologies).

Firm contribution factors

AEMO develops wind and solar contribution factors that specify the amount of wind and solar generation that can be relied on during times of maximum demand. Wind generation during peak demand depends on both wind speed and the operational limitations of wind turbines across the region. Wind is intermittent by nature, with periods of low wind (and in some cases very high wind) resulting in low generation output. Solar generation during peak demand depends on levels of cloud cover and time of peak demand.

AEMO computes the wind contribution to peak demand to be the 85th percentile level of expected wind generation across summer or winter peak periods (top 10% of five-minute demand dispatch intervals) over the past five years.

These contribution factors are only used by the capacity outlook model to estimate the renewable generation contribution to meeting the minimum reserve margins.

The contribution of wind and solar to peak demand was most-recently reported as part of the latest Generation Information Page and South Australian Advisory Functions.[10]

Unit maintenance is captured through the use of maximum annual energy constraints.

3.3.3 New entrant candidates

AEMO generally considers a wide range of available generation technologies as new entrant candidates, including:

- Open-cycle gas turbines (OCGT).
- Combined-cycle gas turbines (CCGT).
- Wind farms.
- Large-scale solar photovoltaic (PV) generation.
- Pumped-hydro storage generation.
- Large-scale batteries.
- Solar thermal generation.

To represent variation due to geographical location, AEMO includes distinct options for each of the planning zones described in Section 3.1.1. In this way, resource variability, particularly for intermittent renewable generators, is captured, and the model reasonably reflects potential geographical diversification within regions.

The financial economic viability of each generation technology (determined by its economic and technical parameters in Chapter 5 and Chapter 6) dictates the likelihood of it getting built.

3.3.4 Linear build decisions

The capacity outlook model can build new generation or transmission developments of specific size or continuous size.

The first method better reflects the discrete and ‘blocky’ nature of new build and estimates costs with higher confidence (for example, the cost of a 300 MW OCGT is well-known), but results in a ‘mixed integer program’ which rapidly becomes computationally impractical.

The second method reduces computational overhead by allowing build of incremental capacities but results in non-standard capacities for new thermal generation or transmission augmentations, with costs more difficult to confirm (for example, the input costs assumed for a 300 MW OCGT are less likely to apply for a 94.2 MW OCGT).

[10] AEMO. South Australia Advisory Functions. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions; AEMO. Generation Information Page. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information.

To keep computation time manageable, AEMO employs the second method for all new generation and transmission build. The thermal generation and transmission investment schedule results are then rounded to standard capacities as part of the post-processing activities.

- OCGTs are rounded up to make sure there is sufficient capacity built to meet the reliability standard. If not required in the time-sequential model, they simply do not generate.
- CCGTs are only included in the time-sequential model once half the capacity has been built in the capacity outlook model. For example, if 1.3 CCGTs were built in the capacity outlook model, only one CCGT would be added to the time-sequential model.
- If fractions of transmission augmentations are built, the capacity outlook model is re-run both with and without the augmentation in its entirety, to determine whether or not the augmentation reduces total system costs.

Renewable generation builds are allowed to remain continuous, as the size of a wind/solar farm is far more flexible – they can typically be scaled up to any size simply by adding more turbines / panels.

Build limits and lead times

In the capacity outlook model, the maximum amount of new generation of any technology type that can be established in any zone is limited in the model (“build limits”).

There are two major sources of information behind the build limit assumptions – advice provided by consultants as input into AEMO’s market modelling activities, and further refinement through network studies and Transmission Network Service Provider (TNSP) advice during studies themselves. The limits provided by consultants were intended to primarily reflect issues around access to fuel and land.

Once a generation and transmission outlook is produced using the build limits, more detailed work is undertaken to explore the impact this would have on the network – and the costs of resolving any issues. In some cases, this leads us to modify the build limits to ensure that the (less granular) capacity outlook model has some visibility of the (more-detailed) network limitations. This process of iteration can be repeated several times to settle on the final set of build limits used by the model.

Instead of just limiting the amount of generation investment in a zone, build limits are sometimes modelled as soft constraints, with additional costs incurred when the limit is exceeded. This violation penalty represents the additional transmission investment cost required to increase the network capacity.

Construction lead times for each technology type are reflected in the model by specifying the earliest build date.

3.3.5 Retirement candidates

The capacity outlook model allows for existing generators to retire if cost-effective to do so. The main factors driving retirements in the capacity outlook model are carbon abatement policies and demand reductions. With the NEM currently transforming in preparation for a low carbon future, costs may be minimised by replacing existing capacity with new capacity with a combination of lower fuel, emission or operating costs, or a location proximal to demand (reducing costs due to losses).

Retirement of under-utilised existing generation assets also avoids the overhead cost of keeping the unit in service but may advance rehabilitation costs for cleaning up the site. The capacity outlook model co-optimises these costs among other components when developing the generation and transmission development schedule.

The retirement decisions are integer decisions. Unlike the continuous new capacity build method (discussed in the previous section), the total existing plant capacity is retired. This is in recognition of the large unit size of many of the retirement candidates, and the need to capture the impact that withdrawal of large volumes of capacity has on new build requirements. Further, in instances where the power station consists of four or more generating units, retirement of all but one generating unit is not considered feasible. The fixed costs associated with operating just a single unit are likely to be prohibitively high.

AEMO narrows down the retirement candidates to generators most likely to retire within the modelling horizon based on age, reliability, or emission intensity of the generation plant. Generation may also be explicitly withdrawn from participation in the model if a generator has advised AEMO of its intention to decommission generating capacity.

3.3.6 Minimum capacity factors

In the capacity outlook model, the use of load duration curve blocks breaks the chronology within each month, meaning unit commitment cannot be modelled accurately. Instead, baseload units are modelled as ‘must run’ or with minimum capacity factors applied. This avoids coal-fired generators operating with unreasonable duty cycles as they gradually get displaced by lower emission alternatives, but allows some flexibility for the units to adapt by potentially changing to two shift operation.

While more robust techniques are available to manage the phenomenon of coal-powered generators becoming marginal, all require either more detailed collection of data (for example, the modelling of true heat rate curves or tuning of start-up costs), or result in significantly longer computation time (for example, using a chronological representation of load).

3.3.7 New transmission projects

The capacity outlook model includes network representations of committed, advanced, and proposed interconnector transmission projects. The model selects projects for inclusion in the future network development based on their ability to reduce total costs.

In determining network options for consideration, AEMO surveys transmission projects suggested by jurisdictional planning bodies[11] in annual planning reports (APRs). AEMO may also develop new transmission projects where study requirements are not met by the APR survey.

3.3.8 Generic constraints

Inter-temporal constraints

Inter-temporal energy constraints limit the generation production from some generation facilities, i.e. annual rain flow dictates hydroelectric generation. In this case, the capacity outlook model and/or medium-term schedule (see Section 3.4.1) solves for the generation schedule throughout a year while ensuring the water storage end level is the same as the initial level.

Generally, the model uses the same technique of scheduling production throughout the year for all inter-temporal constraints such as energy limitations and emission budget constraints.

Network limitations

The capacity outlook model incorporates a representation of the forward and reverse[12] transfer capability of interconnectors. These are static limits that set the maximum flow allowable in the models.

Operational interconnector limits change in response to a significant number of real-time variables that are impractical to consider in the context of long-term modelling.

The application of static limits is a compromise that is simple to implement but can lead to over- or underestimation of flows. In 2012, AEMO investigated whether a new set of constraint equations could improve the modelled specification of interconnector transfer limits without imposing full operational complexity. A more complex set of constraint equations were found not to materially affect the generation and transmission outlook produced by the capacity outlook model.

The capacity outlook model does not incorporate representation of intra-regional network limitations for the same reason. AEMO instead assesses the resulting generation and transmission development schedule’s impact on the intra-regional limits in the time-sequential model.

[11] In Queensland, Powerlink. In New South Wales, Transgrid. In Victoria, AEMO. In South Australia, ElectraNet. In Tasmania, Transend.
[12] Each interconnector has a conventional ‘forward’ direction. For example, on Basslink positive or forward direction flow is from Tasmania to Victoria.

3.3.9 Network losses

Transmission lines are not perfect conductors, and power transfer between locations results in a loss of energy. To account for this, the underlying demand in the models includes an allowance for intra-regional transmission losses explicitly. The capacity outlook model also applies the marginal loss factors (MLFs) of generators as calculated annually by AEMO.[13] For new generator options, a ‘shadow’ generator is chosen based on the connection point of the generation option. Given the uncertainty of the impact of wind and solar farms on network flows, a marginal loss factor (MLF) of 1.0 is applied for these technologies, such that the capacity outlook model develops based on the resource assessment rather than introducing loss factor bias.

For inter-regional transmission flows, the models calculate losses as a quadratic function based on the demand in both connected regions and the flow on the interconnector itself.

Further discussion on the treatment of network losses is provided in Chapter 3.4.5.

3.3.10 End effects

When a new asset’s expected lifetime goes beyond the modelling horizon, simply summing total costs over the period underestimates the true system cost. This would bias towards later investments to incur cheaper and incomplete amortised costs. Conversely, if all the capital costs of an investment are apportioned to the single time period in which it occurs, there may not be sufficient time in the modelled horizon to recover the capital expenditure, biasing outcomes towards the beginning of the modelled horizon. This is called the “end effect” or “terminal effect”.

To manage the ‘end effects’, the Capacity Outlook Model extends the system cost (includes amortised capital cost) beyond the modelled horizon to ensure representation of the complete investment costs. AEMO uses the “perpetuity” method to extend these costs, which assumes the final year’s costs continue perpetually.

3.3.11 Simulation accuracy

Since the capacity outlook model requires high computing power to evaluate and compare huge permutations of possible solutions, it requires a high degree of computational error tolerance. AEMO uses a 0.0001% tolerance to facilitate robust comparison between scenarios.

3.4 Time-sequential model

The generation and transmission outlook developed by the capacity outlook model is validated using a time-sequential model that mimics the dispatch process used by NEMDE.

The time-sequential model considers the modelled time horizon at a much higher resolution compared to the capacity outlook model. The time-sequential model optimises electricity dispatch for every hour in the modelled horizon, and includes Monte Carlo simulation[14] of generation outages, allowing the development of metrics of performance of generation (by location, technology, fuel type, or other aggregation) and transmission (flow, binding constraint equations).

The time-sequential model is used to provide insights on:

- Possible breaches of the reliability standard.
- Feasibility of the generation and transmission outlook when operating conditions and network limitations are modelled.
- Number of synchronous generation online.
- Generation mix and fuel offtake.
- Network augmentation benefits.

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

[14] The Monte Carlo approach simulates the model iteratively, taking into account random events to ensure that the result is statistically robust. See Section 7.1.

- Impact of inter-regional demand diversity.
- Diversity between intermittent supply and demand.
- Unplanned generation outages.

Modification of the capacity outlook model, or further investigation using power flow studies, may be triggered by these insights.

3.4.1 Simulation phases

The time-sequential model is composed of three interdependent phases run in sequence. Designed to better model medium-term to short-term market and power system operation, these phases are:

- PASA – allocates generator units' maintenance schedule while maximising spare capacity across an outlook period. The resulting maintenance outage schedule is passed on to both the medium-term schedule and short-term schedule
- Medium-term schedule – schedules generation for energy limited plants over a year, i.e. hydroelectric power stations or emission-constrained plants. A resulting daily energy target or an implicit cost of generation is then passed on to the short-term schedule to guide the hourly dispatch.
- Short-term schedule – solves for the hourly generation dispatch to meet consumption while observing power system constraints and chronology of demand and variable generation. This phase uses a Monte Carlo mathematical approach to capture the impact of generator forced outages on market outcomes.

3.4.2 Supply bidding models

While the investment and production costs are the primary drivers of the capacity outlook model, generator bidding behaviour drives the time-sequential model hourly dispatch results.

Bidding behaviours are typically difficult to determine as they depend on each company's risk profile, contract position, and future ownership of new entrants.

AEMO may use any of the following generator bidding models as it may see fit:

- Short Run Marginal Cost (SRMC) model – the simplest bidding model, which represents perfect competition. This model assumes that all available generation capacities are bid in at each unit's SRMC. Consequently, this model is fast to solve and renders insights excluding competition benefits.
- Nash-Cournot model – used to study the modelled generators' production by dynamically changing generators bids such that their profit is maximised. The modelled generator may sacrifice cleared generation volumes in exchange for price increases and higher revenue if in so doing they increase the resulting price received.

3.4.3 Unit commitment

Unit commitment optimisation determines which generating units to switch on, and for how long. Apart from the dispatch cost, this optimisation also includes the generator units' start-up cost, minimum uptime and minimum stable level. There may be periods when it is optimal to keep generators on at low generation levels, even when making a loss, to avoid the cost of restarting later.

This methodology solves the whole outlook period (24 hours) simultaneously and includes an additional day of look ahead at less granular resolution to inform unit commitment decisions towards the end of the 24 hours. Otherwise, units may choose to shut down towards midnight without considering the cost of restarting the next day.

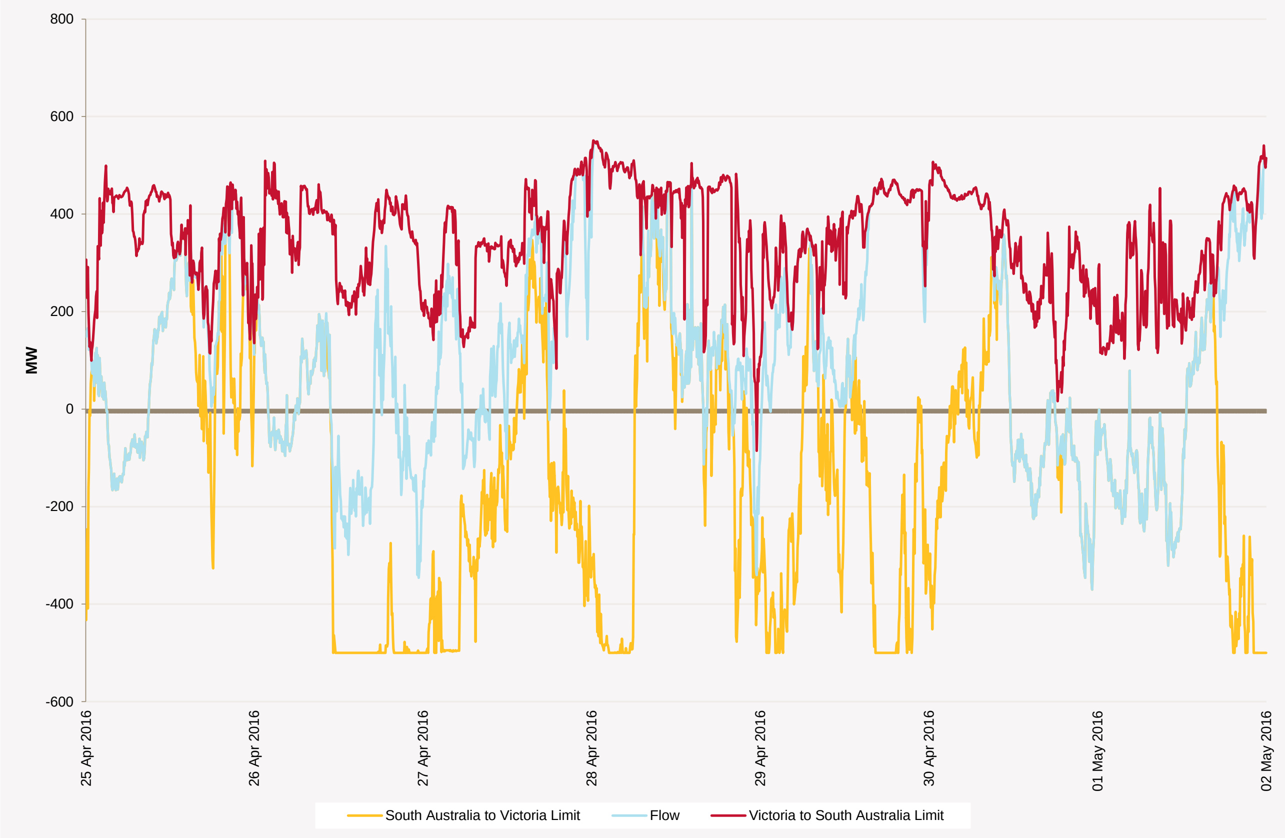
A combination of Nash-Cournot bidding model and unit commitment is used by AEMO to forecast the level of inertia and gas-powered generation (GPG) fuel offtake.

3.4.4 Transmission limits

Inter-regional constraint equations

Interconnector flow limits change in response to network conditions. Figure 9 shows 5-minute limits and flow on the Victoria–South Australia (Heywood) interconnector for one week in April 2016.

Figure 9 Interconnector limits in actual operation, Heywood Interconnector



AEMO implements these variations in interconnector flow limits in the time-sequential model by modelling dynamic power system constraints where inter-regional network limits change as a function of the state of the system, that is, individual generation level, transfer level, online inertia, and demand.

Intra-regional constraint equations

A regional representation of the NEM is not explicitly capable of considering intra-regional power flows, either as a model result or for the purposes of modelling the physical limitations of the power system. In NEMDE, a series of network constraint equations control dispatch solutions to ensure that intra-regional network limitations are accounted for. The time-sequential model contains a subset of the NEMDE network constraint equations to achieve the same purpose.

The subset of network constraint equations includes approximately 2,500 to 3,000 pre-dispatch,[15] system normal equations reflecting operating conditions where all elements of the power system are assumed in-service. They model important aspects of network operation and include contingency for maintaining secure operation in the event of outage of a single network element.

[15] NEMDE contains equation sets for dispatch, pre-dispatch, ST PASA, and MT PASA. Within these sets, other sets cover specific network conditions such as outages, rate of change, frequency control ancillary services, and network service agreements. Pre-dispatch equations are used because dispatch equations contain terms that rely on real-time SCADA measurements not available to simulation models.

In general, the following constraint equations are included:

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

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

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

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

The latest set of constraint equations used in market modelling activities is in the NTNDP database.[17]

Excluded constraint equations

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

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

These constraint equation types are commonly excluded from the market simulations as they may be operational in nature or caused by transmission outage or non-credible events.

Shadow generators

Since the exact location and connection point of possible new entrant generators cannot be determined in advance, AEMO assumes they would be connected to nodes where there are already existing commissioned generators. This allows the new entrant power plant to 'shadow' the impact of the existing capacity to the network (thermal constraints and marginal loss factor).

The criteria for selecting a node to connect the possible new entrant depends on:

- Available network capacity.
- Proximity to the specified zone the new entrant is modelled to be connected.
- Access to fuel source (pipelines).

Existing thermal constraints are modified to reflect impact of these new entrant generators on the network.

[16] AEMO. Constraint Formulation Guidelines. Available at http://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/Constraint_Formulation_Guidelines_v10_1.pdf.
[17] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

Stability constraints and RoCoF constraints are sometimes not adjusted as this is not as straightforward as the thermal constraints adjustment.

3.4.5 Inter-regional loss model

In the time-sequential model, losses on notional interconnectors are modelled using the marginal loss factor equations defined in the *List of Regional Boundaries and Marginal Loss Factors* report.[18] For most interconnectors, these are defined as a function of regional load and flow.

AEMO uses proportioning factors to assign losses on interconnectors to regions. Operationally, this is used to determine settlement surplus. In long term modelling, proportioning factors are used to allocate losses to demand in each region. Proportioning factors are derived from marginal loss factors, as described in *Proportioning of Inter-Regional Losses to Regions*. Proportioning factors are given in the annual *List of Regional Boundaries and Marginal Loss Factors* report.

Future augmentation options considered which include the interconnection of regions not currently interconnected will have a proportioning factor of 50% assigned to each region.

3.5 Gas supply model

The gas supply model assesses reserves, production and transmission capacity adequacy for the GSOO. The model performs gas network production and pipeline optimisation at daily time intervals that minimises the total cost of production and transmission, subject to capacity constraints.

Assessment of reserves requires the gas supply model to consider the difference between production and pipeline solutions to supply any shortfall: an augmentation of production near supply shortfall may draw on a different reserve to a pipeline augmentation solution, leading to different reserve depletion projections.

For example, supply shortfall in Melbourne may be addressed by increasing production from the Gippsland Basin, increasing production from the Otway Basin, or increasing pipeline capacity between the Moomba–Sydney Pipeline and Melbourne, which will ultimately source gas from north-eastern South Australia or Queensland.

The gas supply model does not contain cost-related information in sufficient detail to form a reliable view on pipeline and production augmentation based on cost-efficiency alone. It therefore does not co-optimise pipeline expansion from a number of options like the capacity outlook model does. Instead, when a supply shortfall is reported that may be alleviated with a transmission project, the model can be used to perform sensitivity analysis to test the ability of an augmentation to restore supply.

3.6 Network development outlook model

The network development outlook model contains a highly detailed representation of the physical transmission network underlying the NEM, including individual generating units, transmission lines, transformers, switching elements, reactive power management elements, and loads represented at transmission connection points. All major transmission elements and limitations in the NEM are represented.

In most cases, major transmission elements are those that operate at 66 kilovolts (kV) and above, however there are some radial elements operating that are not represented, and there are some elements operating at lower voltages that are represented because they perform transmission functions.

The model is used to assess intra-regional transmission system adequacy under a range of conditions.[19] Different types of planning studies require a different level of detail in the network representation as well as the adequacy assessment. For example, long-term planning studies such as the NTNDP are more exploratory in nature and require a higher level network representation than a study into the local needs of a specific area.

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

[19] The capacity outlook model contains options to augment inter-regional transfer capabilities but its regional representation prevents consideration of intra-regional limitations.

The assessment is performed by undertaking load flow analysis, which calculates the instantaneous flow of power between locations where energy is generated and where it is used. This modelling validates the generation and transmission outlook from the capacity outlook model and the dispatch outcomes of the time-sequential model by confirming that the power system continues to operate in a secure and reliable manner as demand changes and the generation mix changes.

Reliability is assessed by monitoring the loading on the transmission network when the power system is operating with all equipment in-service (system normal) and also under a potential unplanned outage of a transmission network element or generating unit. The assessment considers the capability of the transmission system for transfer of energy, and identifies network limitations[20] that may be constraining power flow.

3.6.1 Ratings

Ratings on modelled transmission elements change according to the instant of time considered in each model solution. In summer, transmission element capability ratings are generally lower because higher ambient temperatures make it more difficult for those elements to dissipate heat.

AEMO uses continuous ratings for pre-contingency load flow analysis.

Transmission elements may be operated above their continuous ratings for short periods of time. These short-term ratings are used for contingency load flow analysis, as contingencies are expected to be cleared relatively quickly by power system operators.

3.6.2 Response to network limitation

The primary result of the load flow analysis is a list of the transmission system elements that may be overloaded during times of high demand under the projected conditions of demand and generation and transmission expansion. To inform this assessment, hourly generation and interconnector flows for snapshots in time are obtained from the time-sequential model.

When the power system model identifies thermal overload on monitored power system elements, AEMO modelling addresses the overload using a series of techniques that attempt to minimise costs:

- Re-dispatch generation – more expensive generation closer to the load is dispatched in preference to the generation that was dispatched by the time-sequential model.
- If simple re-dispatch cannot address the overload, relocate new generation to an alternative connection point in the same planning zone.
- If relocation of generation in the same zone cannot address the overload, relocate new generation to an adjacent zone.
- If relocation and re-dispatch of generation cannot address the overload, choose an appropriate intra-regional transmission system augmentation to address the overload directly. This may be an option presented by jurisdictional planning bodies in their annual planning reports or an option developed by AEMO.
- If intra-regional transmission augmentation is required and the cost of identified augmentations is considered material to the generation and transmission outlook, the augmentation cost is added to the costs of new generation considered by the capacity outlook model, in the zone where the augmentation is required. The capacity outlook model is re-solved, which may result in the relocation of generation, different transmission system augmentations being chosen, a combination of both, or no change to the expansion plan. Alternatively, additional peaking generation capacity may be added to the region to support load if the network overload results in USE. The expansion plan is considered stable when no further locations of transmission overload are identified.

[20] Thermal limitations arise due to the resistance of transmission lines to the flow of electrical current. When energy flows, transmission lines heat up and begin to sag. Transmission lines may be damaged if allowed to become too hot for too long and if allowed to sag, they could breach minimum safety clearances. Thermal limitations constrain the flow of current to prevent unsafe operation or potentially damaging heating of the conductors.

CHAPTER 4. DEMAND ASSUMPTIONS

4.1 Demand forecasts

Change in demand for electricity and gas is one of the drivers of the evolution of energy production and transmission systems. Demand can change in two ways:

- The amount of energy that must be provided over the course of time.
- The amount of power that must be provided instantaneously.

For electricity, these are referred to as *consumption* and *maximum demand* (MD) respectively, and are measured in megawatt hours (MWh, energy) or megawatts (MW, power).

For gas, where instantaneous demand has a lesser impact on supply, the concept of instantaneous power is less relevant and gas demand is often expressed in terms of a specific timeframe: maximum hourly quantity (MHQ), maximum daily quantity (MDQ) or annual quantity. All are measured in gigajoules (GJ), terajoules (TJ) or petajoules (PJ) depending on the length of time under consideration.

AEMO uses scenario descriptions to develop regional electricity and gas demand projections to suit long-term planning timeframes. The NEFR[21] is published by AEMO mid-year, and presents 10% and 50% POE MD and consumption projections for each NEM region up to 20 years into the future. These projections are extended to a 25-year range for use in all market modelling activities. The 50% POE projections reflect an expectation of typical MD conditions. The 10% POE projections reflect an expectation of more extreme MD conditions driven by variations in weather conditions. Projected consumption is the same in each case.

The NEFR forecasts represent operational demand ‘sent out’:

- Operational demand refers to the electricity used by residential, commercial, and large industrial consumers, as supplied by scheduled and significant non-scheduled generating units. It does not include demand met by rooftop PV (that is, operational demand decreases as rooftop PV generation increases).
- ‘Sent out’ refers to operational consumption or demand that excludes generator auxiliary load.

4.1.1 Price elasticity of demand

Consumption and MD projections incorporate the response of consumers to electricity prices, based on the price outcomes of the reference year (that is, the prices that were reported in the reference year already incorporate consumers’ response to price, because demand and prices would have been higher were there no consumer response). No further consumer price elasticity to demand is modelled in the market models.

4.2 Demand traces

The NEFR operational consumption and MD forecasts need to be converted into hourly demand traces for each region for use in the capacity outlook model and the time-sequential model. Demand trace development relies on historical reference years to provide guidance on the typical daily and weekly demand shapes, variations from hour to hour, and correlations with other regions.

The process used to develop the traces is:

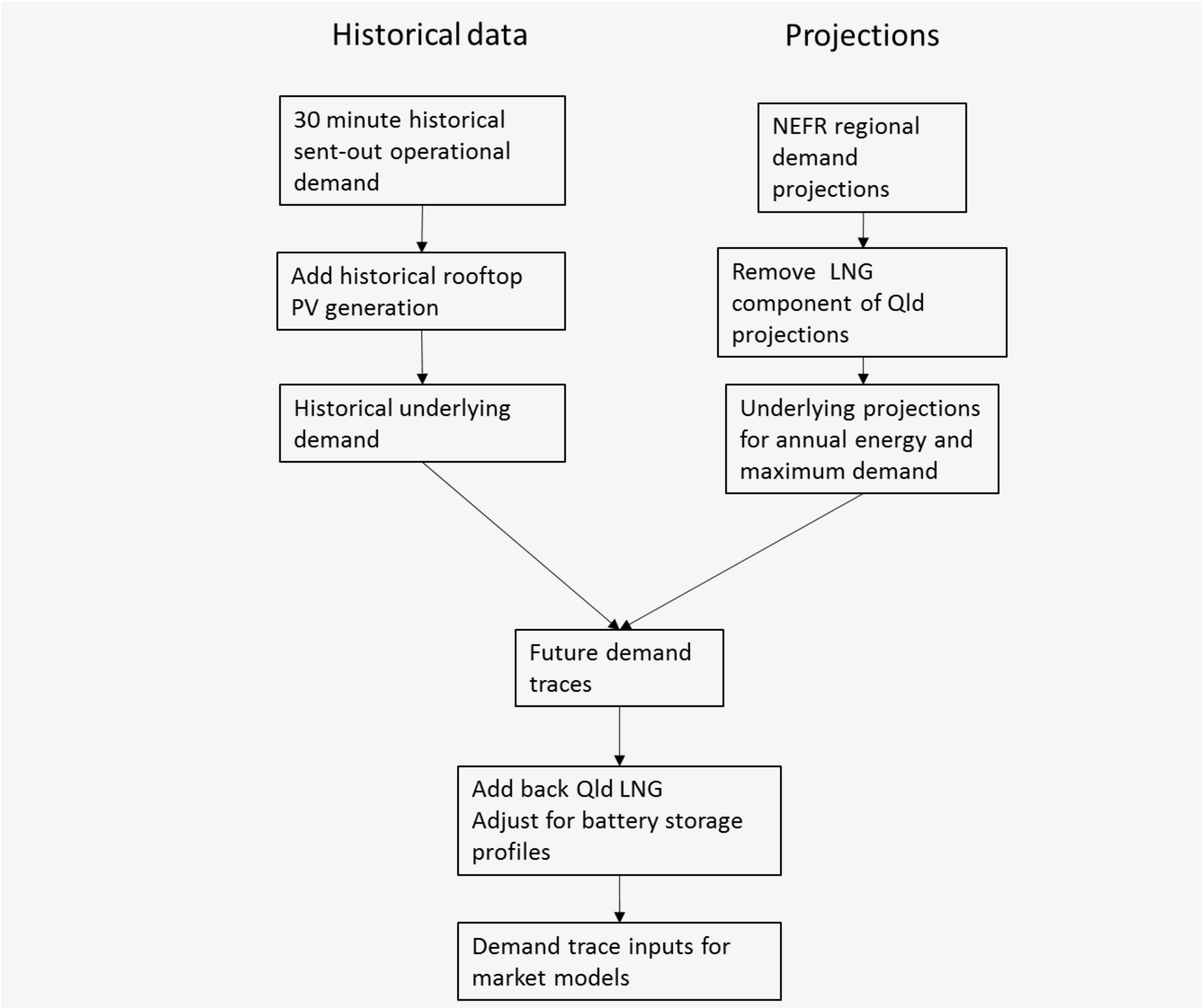
- Representative traces are obtained using historical data. Estimated production by rooftop PV generators over the same period is added to the demand traces to obtain historical traces representing total underlying demand. Contributions from large-scale non-scheduled wind generation are also added to the reference year trace.

[21] AEMO. *National Electricity Forecasting Report*. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

- Projections of future levels of annual underlying energy consumption and MD in each region are obtained from the NEFR. Projections of demand from the Queensland liquefied natural gas (LNG) export industry are subtracted from Queensland demand.
- The derived underlying historical traces are “grown” to represent future consumption and MD while preserving diurnal, weekday, weekend and seasonal patterns as much as possible.
- Further adjustments are applied to the resultant traces to reflect the impact of increasing uptake of battery storage and electric vehicles. Projections of demand from the Queensland LNG export industry are added back.

Figure 10 shows the process for developing the demand traces, and the following sections explain each of these steps in more detail.

Figure 10 Demand trace development



4.2.1 Multiple reference years

Demand and intermittent generation traces are developed based on up to six historical reference years to capture year on year variations in demand correlations across regions and intermittent generation contributions during high demand periods.

4.2.2 Weather sensitive demand

While 10% and 50% POE load traces assume a different maximum demand, the energy consumption remains constant. Therefore, the 10% POE trace notionally reflects a heat wave over say a period of one week, but with weather conditions similar to the 50% POE trace for the rest of the year.

To reflect this, AEMO develops the 10% POE demand trace from the 50% POE trace with demand being identical for most of the year, but replaces the five-day period around the annual maximum demand with a scaled up profile that meets the 10% POE forecast. Further work to refine this approach is being progressed in 2017.

4.2.3 Small-scale generation

Demand projections are developed based on the demand that appears on the transmission system. Non-significant non-scheduled generators that are connected to a distribution network appear to the transmission system as a reduction in demand from that distribution network. The capacity outlook model and the time-sequential model include representations of scheduled, semi-scheduled, and significant non-scheduled generators so the intermittent nature of the significant non-scheduled generation is represented. Non-significant non-scheduled generators, which are not represented in the market models, are incorporated into the energy and MD projections.

The latest NEFR tables the non-scheduled generators that are incorporated into energy and MD projections (those that are used in annual energy forecasts and are *not* part of operational demand).[22]

4.2.4 Rooftop solar photovoltaic uptake

In the market models, rooftop PV generation is modelled explicitly to capture its intermittent impact on the NEM. Rooftop PV's contribution to demand therefore needs to be added to the operational forecasts to get a representation of underlying MD and consumption.

Rooftop PV modifies the shape of the demand curve. As rooftop PV installations increase, the operational MD is pushed to later in the day and minimum demand is projected to occur during the middle of the day. The rate of rooftop PV uptake is also projected to differ from the rate of change in underlying demand.

To accommodate the impact of rooftop PV uptake on the demand profile, AEMO adjusts the historical reference demand curves to remove the effect of rooftop PV prior to growing future demand traces (as discussed above). The resultant underlying demand traces are used in the market models, with rooftop PV modelled as one generator per region, following a projected hourly profile. Rooftop PV generation profiles are developed independently, taking into account changes in uptake forecast in the NEFR, and output based on historical cloud cover.

4.2.5 Electricity demand for industrial block loads

When developing forecast load traces, step changes in load developments need to be accounted for separately from the organic growth or contraction of underlying demand. New industrial load developments, such as that associated with LNG production in Queensland, is removed from the reference year hourly trace before the underlying demand is grown to meet forecast energy consumption, maximum and minimum demands. The block load is then added back on at the end of the demand trace development process. This also applies for major load closures.

By isolating the regional demand net of step changes in large block loads, the appropriate shape of the underlying consumer load is maintained.

[22] AEMO. *National Electricity Forecasting Report*. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report.

4.2.6 Electric vehicles and small scale battery storage

Electric vehicles are expected to become a new source of electricity demand within the typical timeframes of AEMO's long-term planning.

Electric vehicle demand is incorporated into the models by developing a daily charging profile consistent with charging behaviour assumptions, growing the profile to accommodate growth in demand due to increased uptake, and adding the resulting profiles to the projected regional demand profiles in each scenario.

Currently, reference year demand profiles are assumed not to contain time of day distortions due to electric vehicle load or battery charging and discharging. In this case, reference year historical demand profiles are not adjusted prior to application of projected future electric vehicle charging load profiles.

Uptake of electric vehicles and small scale storage systems is sourced the NEFR but may vary by scenario depending on the nature of the study.

4.3 Demand side participation

Demand-side participation (DSP) is an agreed, additional change in demand beyond price elasticity that can occur when the power system becomes stressed. It is often provided by industrial customers that have interruptible loads.

The DSP volumes available in each region are sourced from the latest NEFR. DSP is assumed 100% reliable and is available in several price bands.

4.4 Gas demand forecasts

Gas demand forecasts are produced by combining data from four sources:

- Mass market (residential and commercial) customers.
- Large industrial facilities.
- GPG.
- LNG export facilities.

Detailed forecasts are developed by AEMO each year and published in the NGFR.[23]

Detailed descriptions of daily gas demand development are presented in the GSOO methodology document.[24]

[23] AEMO. *National Gas Forecasting Report.* Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report.
[24] AEMO. *Gas Statement of Opportunities.* Available at http://www.aemo.com.au/-/media/Files/PDF/2016_GSOO_Methdology.pdf.

CHAPTER 5. SUPPLY ASSUMPTIONS

5.1 Electricity production

5.1.1 Electricity parameters

All market simulation results are influenced by the generator's technical parameters used in the models. Table 3 provides a summary of the key parameters and describes how they are incorporated within the market models. Generator properties such as capacities, efficiency, marginal loss factors, minimum generation levels, and forced outage rates simultaneously drive the modelling results.

Table 3 Summary of generator technical parameters

Parameters	Description	Relevance	Modelling methodology
Rated capacities	Seasonal capacities reflect thermal generators weather dependence	Summer regional capacities tend to be lower than winter	Seasonal ratings of capacities
Minimum generation level	Technical minimum stable loading	Forces units to generate at a certain level	Constant minimum generation level
Firm capacities	Reliable capacity able to generate during peak demand	Contributes to the available capacity to serve maximum demand and minimum capacity reserve level	Seasonal ratings for scheduled generator Contribution to peak demand for variable generators
Ramp rate	Rate at which generation can increase output	May constrain generation output	Constant rate from minimum generation level to maximum capacity
Minimum uptime and minimum downtime	Technical limitation on the length of time thermal generators must remain online or offline	Impact the unit commitment schedule	Number of hours
Auxiliary load	Station load that supports operation of the power station	Lessens the generation supplied to the operational consumption	As percentage of 'as gen' production
Heat rate	Efficiency of converting the chemical or potential energy to electrical energy	Cost of electricity production	Constant conversion rate
Emission rate	CO2-e production for each MWh of electric energy produce.	Direct carbon abatement policies significantly impacts heavy carbon emitters	Constant emission production rate
Inflow rates	Long-term reservoir inflow average represented as monthly inflow rates	Hydroelectric generators availability depends on dam levels	Annual sequence based on long-term average
Outage rates	Historical maintenance and unplanned failure rates describes the probability of capacity deration of each technology	Further lowers the regional available capacity to serve operational consumption	Maintenance rates and probability of failure and derated capacities
Marginal loss factor	Impact of network losses on spot prices is represented as loss factors.	Incentivise generators that lowers network losses and penalize those the increase it	Factor for each node in the NEM

This information comes from a number of different sources. For all current assumptions please refer to the NTNDP database on AEMO's website.[25]

[25] AEMO. NTNDP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

The generation economic parameters outlined in Table 4 influence the results of both the capacity outlook model and the time-sequential model.

Table 4 Generator economic parameters summary

Parameters	Description	Relevance	Modelling methodology
FO&M cost	Annual fixed cost for keeping plants in service	Increases the cost of keeping the plants in service	Fixed cost per MW of installed capacity
VO&M cost	Additional cost for running the units	Impacts the generators' running costs	Fixed rate per MWh of electricity production
Gas fuel cost	Gas price path for each existing GPG and gas zones	Impacts the gas generators' running costs	Fixed rate per GJ of fuel consumed
Coal fuel cost	Coal price path for each existing coal plants	Impacts the coal generators' running costs	Fixed rate per GJ of fuel consumed
Build cost	Overnight investment cost for each available generation technology	Shift from one technology to another over the outlook period	Overnight cost per MW of capacity
Connection cost	Cost of accessing network	Represents additional cost for network access	Overnight cost per MW of capacity
WACC	Cost of capital	Amortisation of build cost	Percentage
Economic life	Project life	Capital payment period	Number of years
Minimum capacity factors	Represents the minimum technical and economic duty cycles	Applied on the Capacity Outlook Model to represent the minimum economic running regime	Percentage of total available energy for production
Reservoir initial dam level	Latest dam levels	Available water for generation at the start of every year	Dam volume levels are updated every year in GL

This information comes from different sources. For all current assumptions, please refer to the NTNDP database on AEMO's website.[26]

5.1.2 Marginal loss factors

MLFs represent the incremental loss incurred for an incremental power supplied at connection points and determines the marginal impact of losses on spot prices. It incentivises generators that lowers network losses and penalises those the increase it.

MLFs are pre-computed figures that are influenced by forecast demand, network configuration, and generation dispatch. This is modelled explicitly as a static factor that does not change over the outlook period.

AEMO performs an annual study to estimate the MLF for each connection point using historical network performance and forecast consumption. Generators are assigned with the MLF for the connection point they are connected to.

For further information, please refer to the latest *Loss Factors and Regional Boundaries* page.[27]

[26] AEMO. NTNDP Database. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

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

5.2 Renewable resources

5.2.1 Variable generation

Generally, the following variable generation types are modelled, for planning purposes:

- All scheduled and semi-scheduled generation.
- Some significant non-scheduled generation with capacities greater than or equal to 30 MW.
- Those that are believed to impact simulated network capability.

As variable generation's output depends on their fuel source availability, wind farm generation is limited by the wind speed, and solar farms are limited by solar irradiance.

Wind bubbles

In 2009, the Inter-Regional Planning Committee developed the concept of a 'wind bubble' to model the wind resource available to the NEM. A wind bubble defines a geographical area where wind speeds are considered sufficient to be attractive for new wind development.

AEMO generally uses the following methodologies to forecast long-term variable generator's availability.

- For each wind bubble where no existing generation already exists, a typical hourly wind speed profile is developed that covers a single trading year, based on proprietary data provided by the Commonwealth Scientific and Industrial Research Organisation (CSIRO). Wind speed profiles are converted to normalised[28] wind turbine power output profiles based on a generic turbine power conversion curve. New wind farms generate according to a combination of the normalised power output profile and its modelled capacity, subject to network constraints.
- For each wind bubble where existing wind facilities exist, AEMO uses statistical analysis on available historical generation to produce normalised forecasts for each reference year modelled using the following steps:
  - Calculate the average historical hourly generation per installed capacity from all wind farms in each wind bubble for each financial year since 2009–10.
  - Grow the normalised hourly generation availability for the next 25 years.
  - Apply the grown availability trace to all wind farms in the same wind bubble.

For existing semi-scheduled wind generation, power output is available in AEMO's MMS database, from which a single reference year[29] is used to determine a power output profile for modelling. The power output of small, non-scheduled wind generation is included in the demand profiles as a reduction in demand.

Table 5 and Figure 11 present wind bubbles across the NEM.

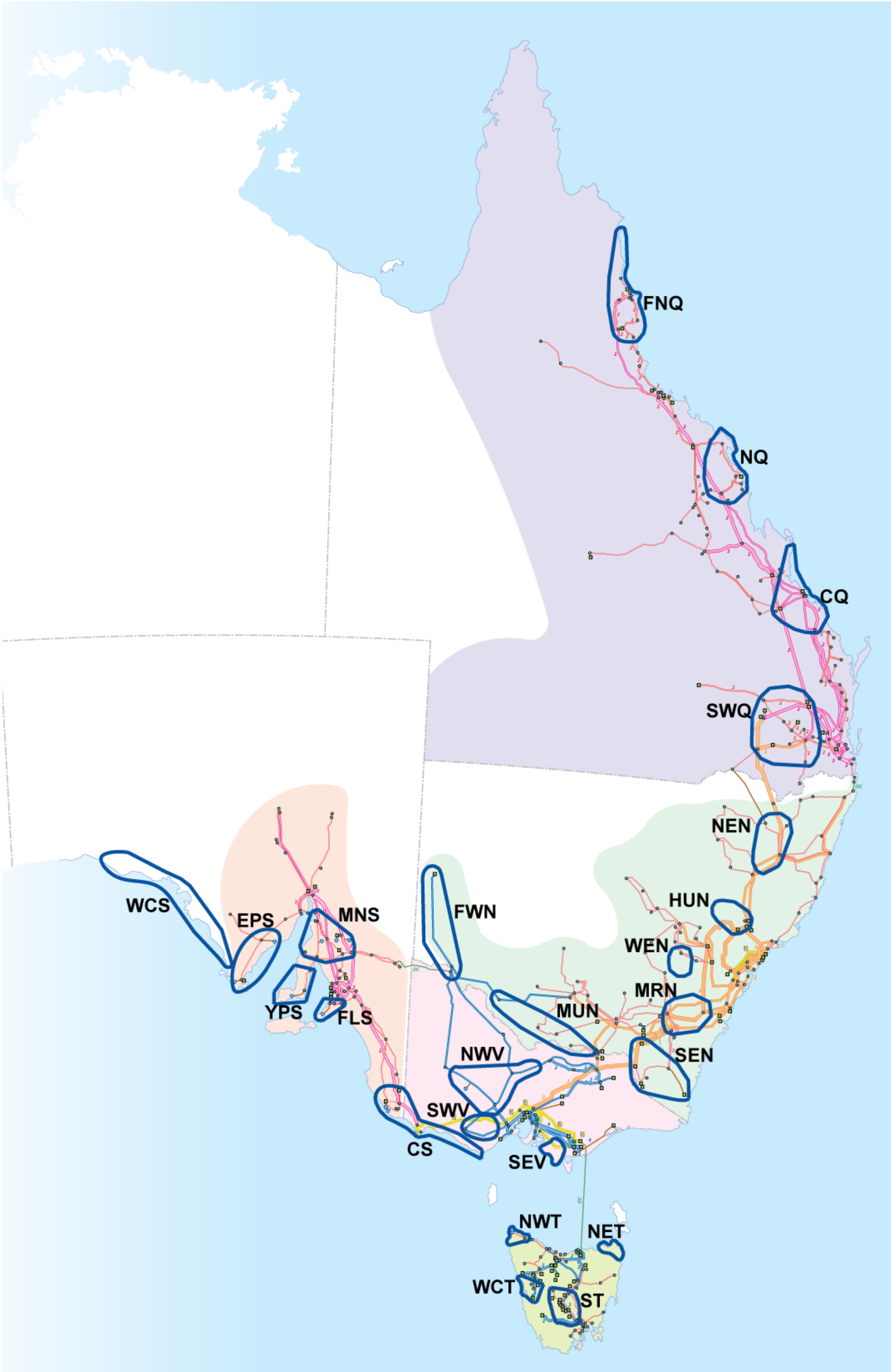
[28] Where the maximum output is 1, and the minimum output is 0.
[29] The reference year is the same as the reference year for demand profiles.

Table 5 Wind bubbles in the NEM

Region	Zone	Bubble code	Description
QLD	NQ	FNQ	Far North QLD
		NQ	North QLD
	CQ	CQ	Central QLD
	SWQ	SWQ	South West QLD
NSW	SWNSW	FWN	Far West NSW
		MUN	Murray NSW
	CAN	SEN	South East NSW
		MRN	Marulan NSW
	NCEN	WEN	West NSW
		HUN	Hunter NSW
	NNS	NEN	New England NSW
VIC	LV	SEV	South East VIC
	CVIC	NWV	North West VIC
		SWV	South West VIC
	MEL	CS	Central South[A]
SA	NSA	WCS	West Coast SA
		EPS	Eyre Peninsula SA
		YPS	Yorke Peninsula SA
		MNS	Mid North SA
	ADE	FLS	Fleurieu Peninsula SA
	SESA	CS	Central South[1]
TAS	TAS	NWT	North West TAS
		NET	North East TAS
		WCT	West Coast TAS
		ST	South TAS

A. Central South is shared between VIC and SA, as shown in Figure 11.

Figure 11 Wind bubble map



Large-scale solar PV

AEMO produces large-scale solar availability traces for all planning zones in the NEM by looking at historical irradiance and cloud cover and estimating the normalised output generation for a fixed-frame panel (FFP) solar generator at the most optimal panel tilt for each planning zone.

The availability trace for single-axis tracking (SAT) and dual-axis tracking (DAT) technologies are developed by repeatedly scaling up the FFP availability trace while capping the daily maximum generation until the expected total energy production over a year is achieved.

5.3 Hydroelectric generation schemes

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales, and Queensland. These schemes are typically modelled in the time-sequential model with their associated reservoirs and water inflows. For each reservoir, the capacity, initial levels, and the expected inflows from rainfall all determine the availability of energy for hydroelectric generation.

Hydro schemes are generally grouped into three modelling methods:

- Generator constrained – for the Victorian hydroelectric generation scheme (excluding Murray).
- Storage managed – for the Tasmanian hydroelectric generation scheme.
- River chain – for all other hydroelectric generation scheme.

In the market simulations, AEMO applies a return to average conditions approach. Reservoir levels are restored to initial levels by the end of each simulated year. Reservoir levels are initialised with levels as at 1 July of the current year, while inflow data reflects long-term average conditions from the start of the simulation period.

5.3.1 Generation constrained

Victorian hydroelectric generators' production is modelled by placing a maximum annual capacity factor constraint of between 13% and 15% on each individual generator. The model schedules the electricity production from these generator across the year such that the system cost is minimised within this energy constraint.

5.3.2 Storage management

Tasmanian hydroelectric generation is modelled by means of individual hydroelectric generating systems linked to one of three common storages:

- Long-term storage.
- Medium-term storage.
- Run of river.

Table 6 identifies how individual generators are allocated across these storages, and provides an indication of the storage energy available to the units.

Energy inflow data for each Tasmanian hydro water storage is determined from historical monthly yield information provided by Hydro Tasmania. In both the capacity outlook model and time-sequential model, AEMO uses a scaled version of average monthly yield, extracted from records spanning 81 years, to deliver an annual inflow of 8,700 gigawatt hours (GWh).

Table 6 Storage energy (in GWh) of the three types of generation in Tasmania

Storage Type	Storage energy	Stations
Long-term	11,200	Gordon, Poatina.
Medium-term	3,200	Lake Echo, Tarraleah, Tungatinah, Liapootah, Wayatinah, Catagunya, Fisher, Lemonthyme, Mackintosh, Bastyan, John Butters.
Run of River	140	Meadowbank, Trevallyn, Wilmot, Cethana, Devils Gate, Reece, Tribute.

5.3.3 River chain

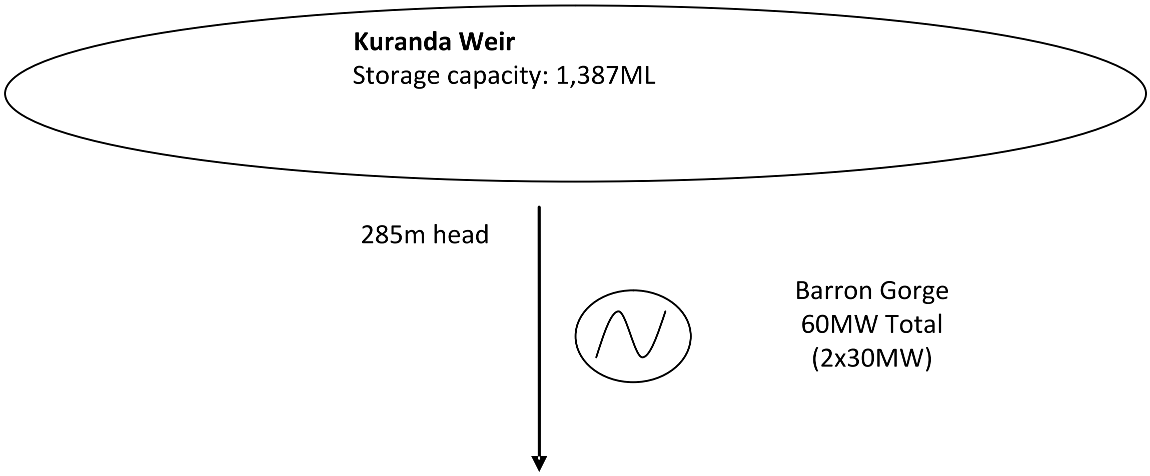
Other hydroelectric generation is represented by a physical hydrological model, describing parameters such as:

- Maximum volume.
- Initial storage volume.
- Monthly reservoir inflow rates reflecting average historical inflows.

Latest information on the monthly storage inflows used in market modelling studies can be found in the NTNDP database.[30]

Figure 12 to 19 provide graphic representations of the hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units.[31]

Figure 12 Barron Gorge power station hydro model



[30] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

[31] Storage capacities are defined in megalitres (ML)

Figure 13 Blowering power station hydro model

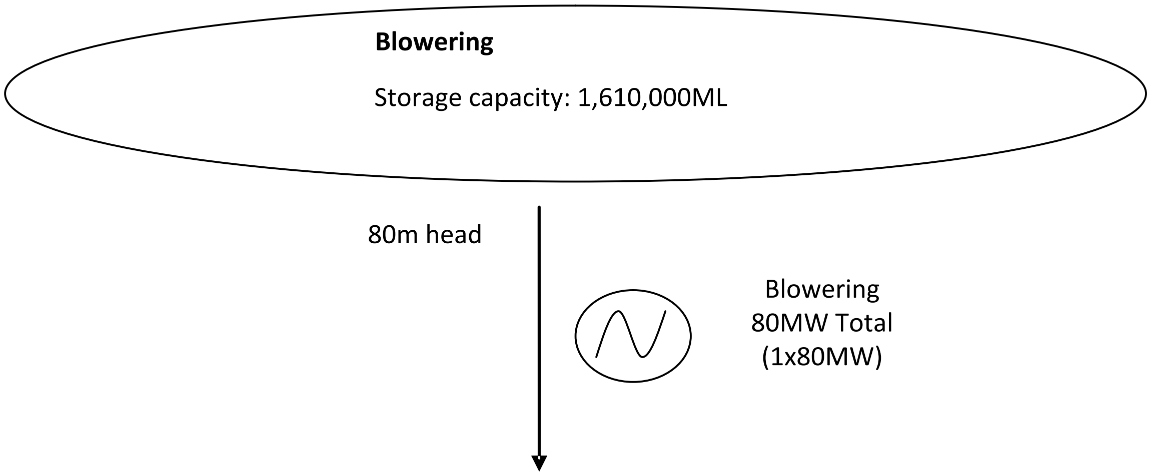


Figure 14 Hume power station hydro model

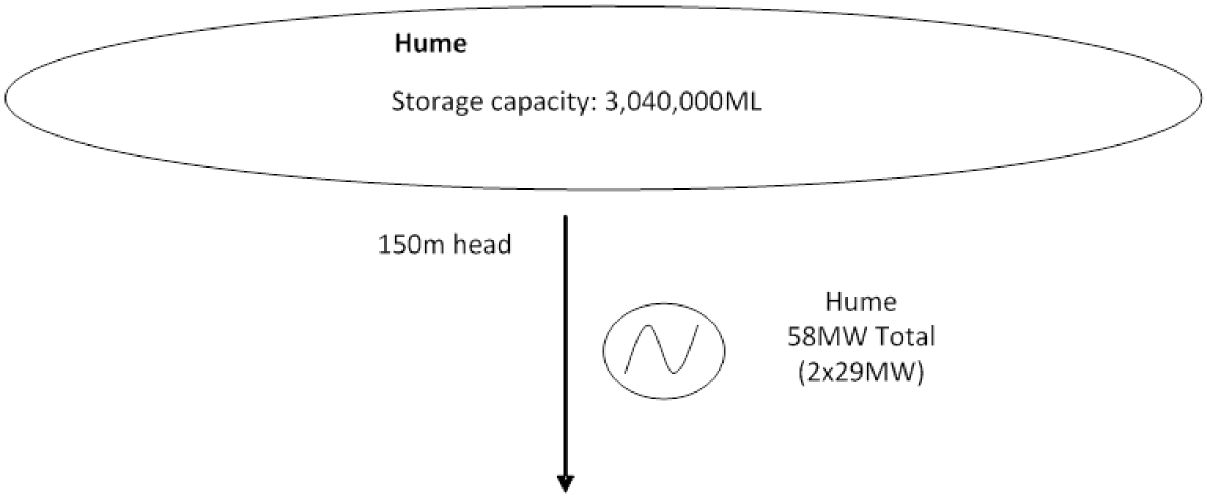


Figure 15 Kareeya power station hydro model

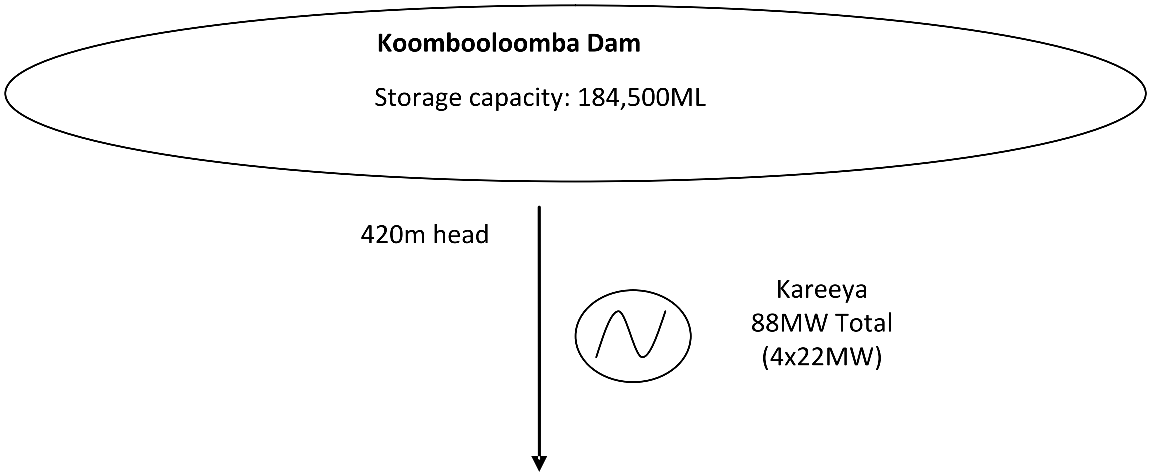


Figure 16 Guthega power station hydro model

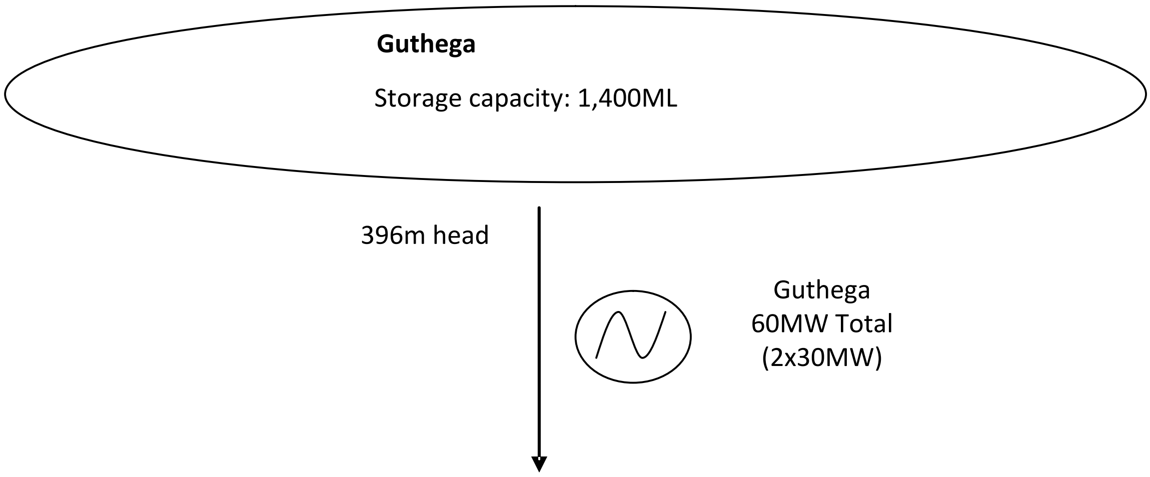


Figure 17 Shoalhaven power station hydro model

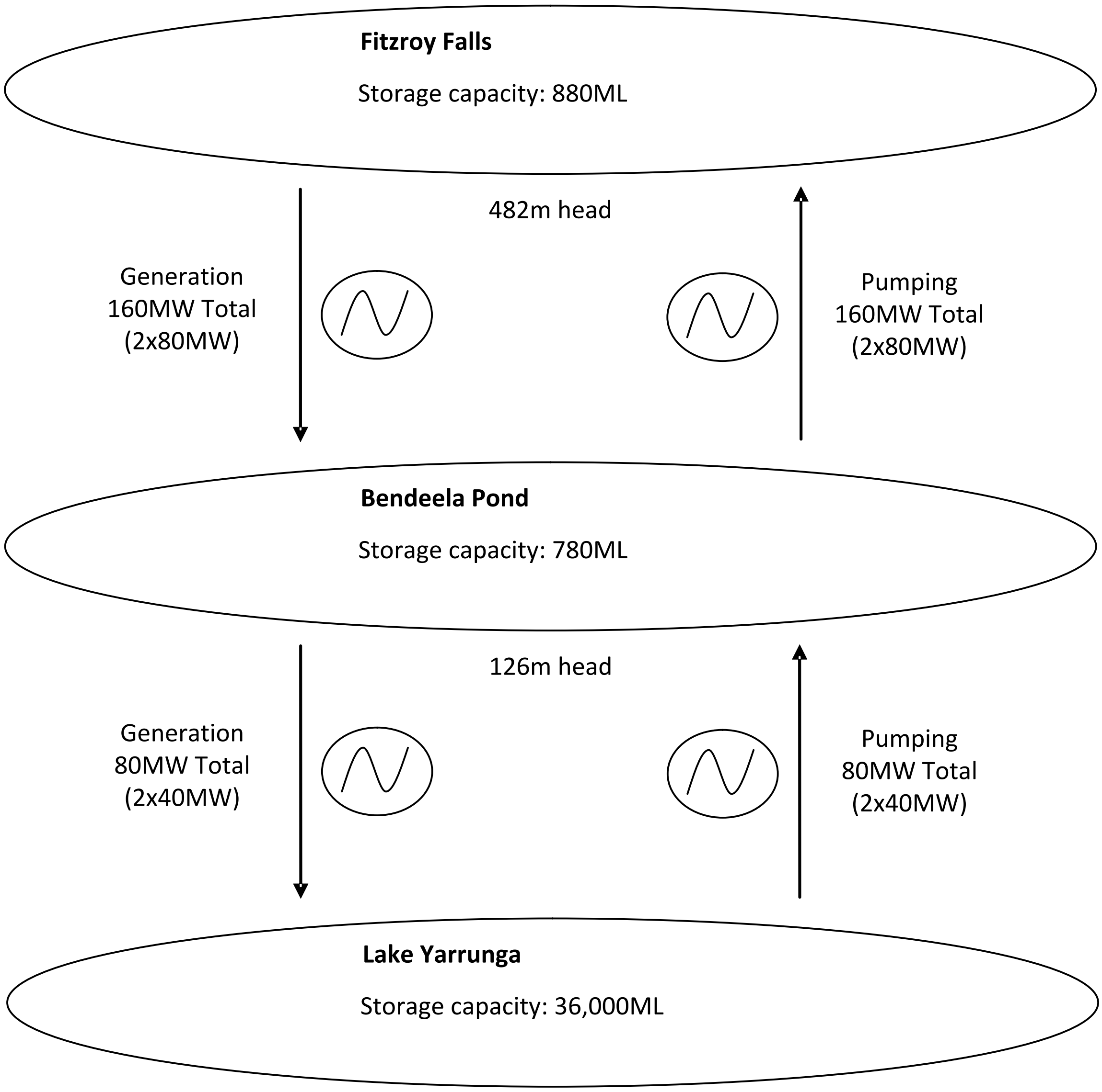


Figure 18 Upper Tumut, Lower Tumut, and Murray power station hydro models

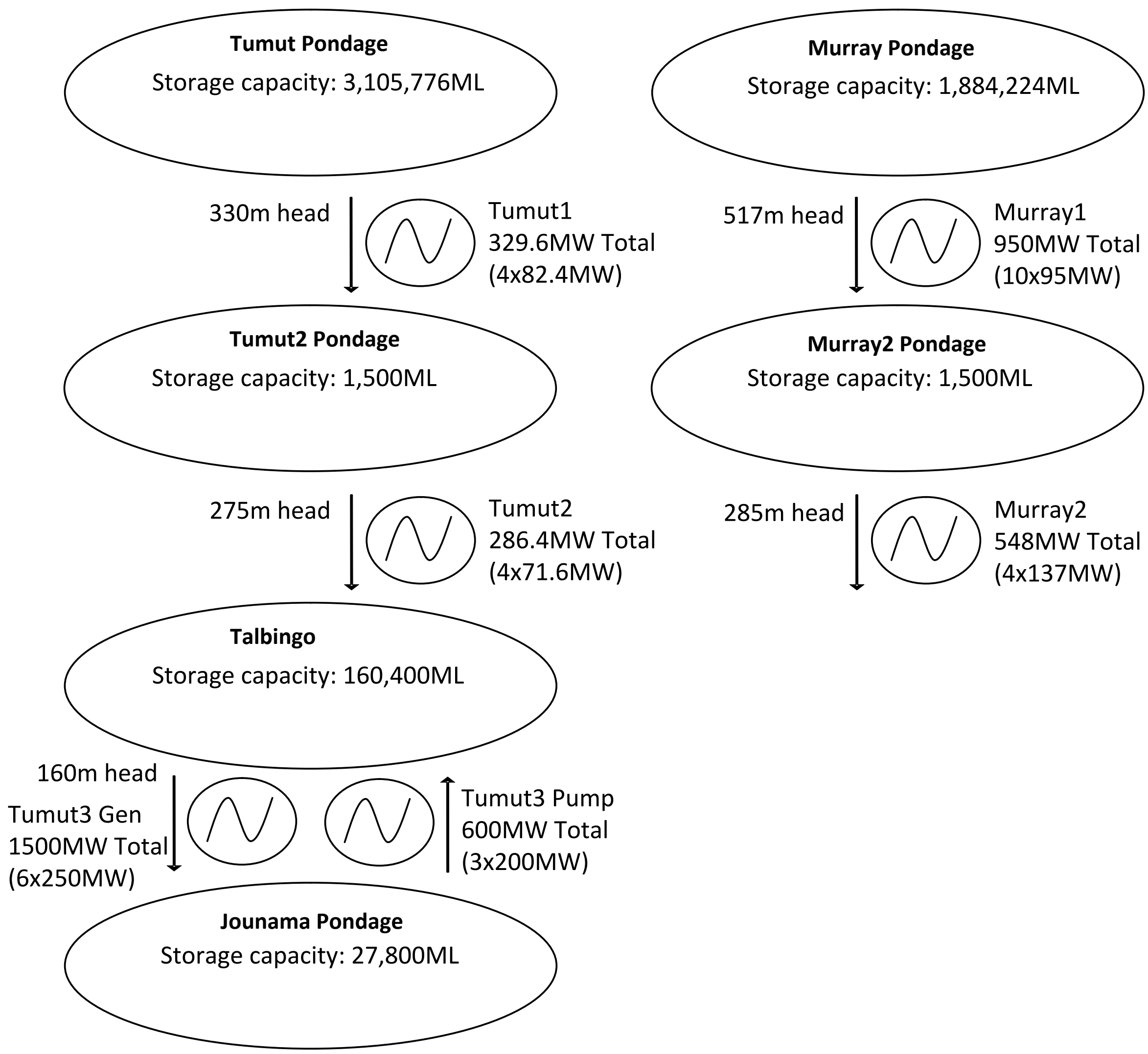


Figure 19 Wivenhoe power station hydro model

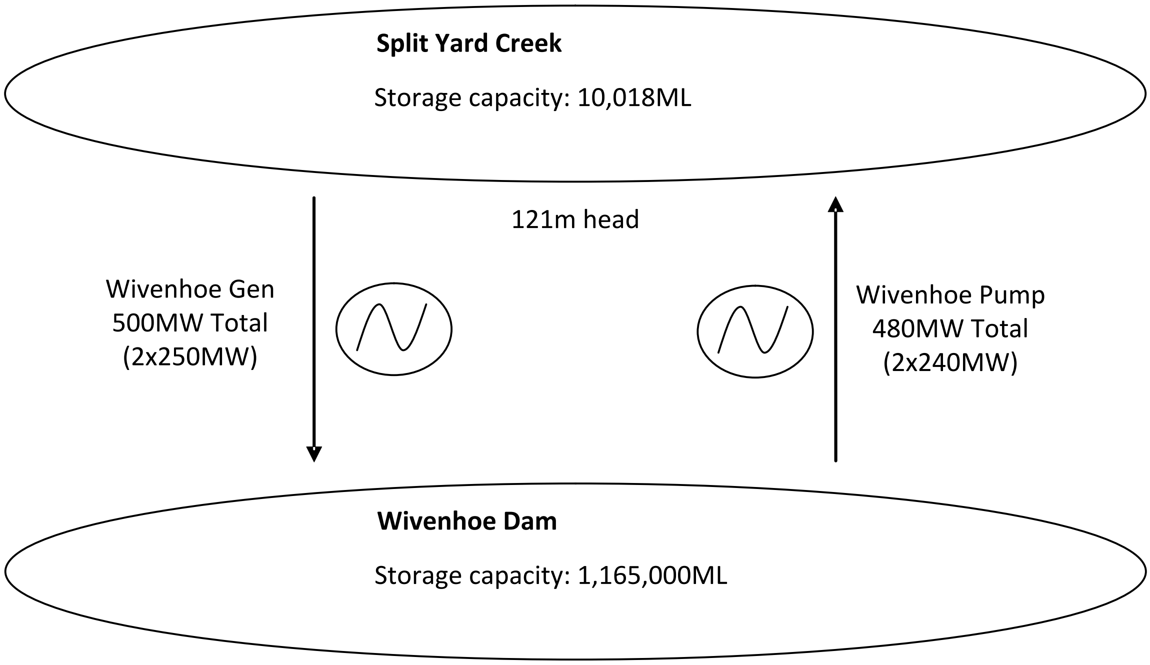


Figure 20 Eildon power station hydro model

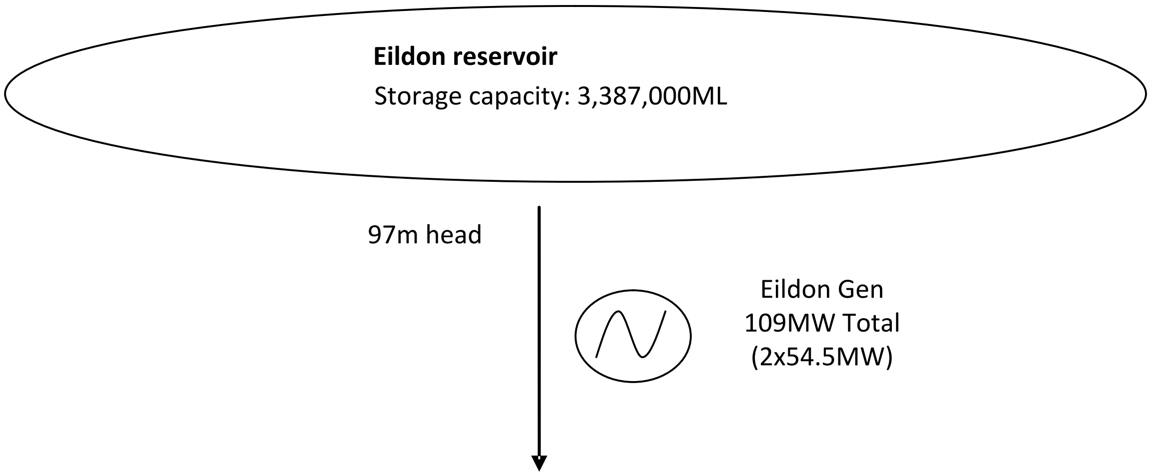
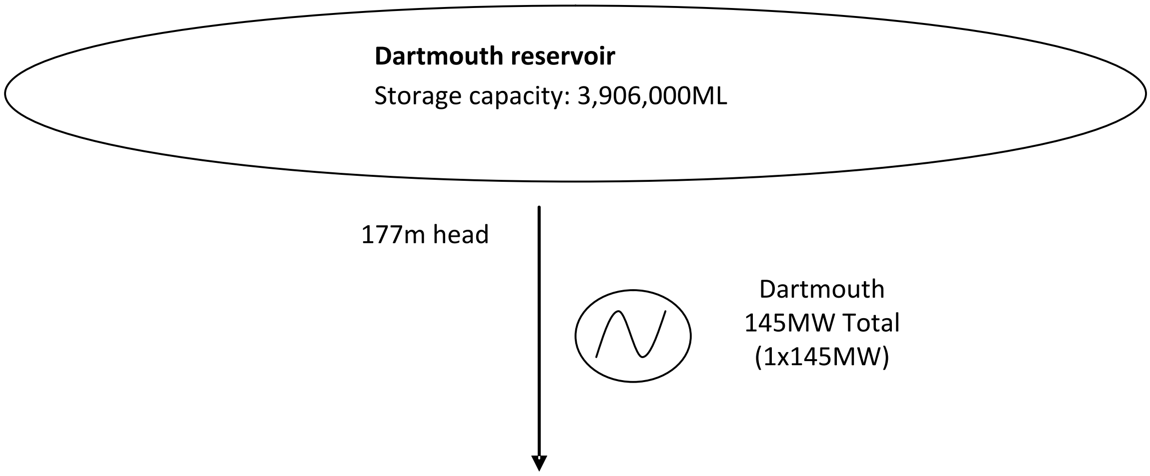


Figure 21 Dartmouth power station hydro model



5.4 Large-scale batteries

Batteries' operation is expected to change, from simply generating when energy is available, to generating opportunistically based on price and the efficiency loss associated with charging and discharging the battery.

Opportunistic generation depends on operators developing a forward view of price to inform the decision to divert energy to storage. The second phase of the time-sequential model (medium-term schedule) completes an energy management study across a year to schedule energy consumption and generation from batteries. This is further refined by the third phase of the time-sequential simulation, where operational limitations are included.

The storage capacity and the rated power are defined for each modelled large-scale battery. The latest assumptions can be found on the most recent NTNDP database.[32]

5.5 Gas production

The gas supply model contains a representation of 40 gas production facilities that inject gas into the eastern and south-eastern Australian gas transmission network. The representation is limited to the connection point and maximum supply capacity of each facility, and the annual field production limits.

The gas supply-demand outlook model does not contain information about forced outages, production ramp rates or maintenance schedules.

Production cost

The gas supply model uses a representation of the cost of gas production at each facility to optimise network flows.

5.6 New production

Each model defines a set of new generation or gas production projects that may be included in the capacity outlook model, time-sequential model, or gas supply model simulations.

In the capacity outlook model, new generators are partitioned by fuel type, technology, and location within the electricity planning zone. Each technology will take on specific values for parameters of importance such as thermal efficiency, emission characteristics, minimum stable generation levels, standard capacities, build

[32] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

costs, and appropriate earliest dates for which the technology is considered current.[33] Each location imposes different fuel costs that reflect the fuel availability and transport requirements applicable to each zone.

The time-sequential model uses the generation and transmission outlook developed by the capacity outlook model.

The gas supply model includes committed production and transmission projects and a selection of proposals that are assessed for their efficacy in eliminating supply shortfall.

5.6.1 Committed, advanced, proposed and conceptual

New production and transmission projects fall into one of four classes of certainty:

- **Committed** – projects that will proceed, with known timing, satisfying all five of the commitment criteria outlined in Table 7. These criteria apply to electricity investments. There are no equivalent commitment criteria for gas projects; however the principals of commitment outlined in Table 7 are applied for the purposes of gas modelling. The costs of committed projects are considered sunk for the purposes of modelling: because there is no investment decision that is calculable for committed projects, their costs are not included in any of the market models.
- **Advanced** – projects that satisfy at least three, but not all, of the commitment criteria, and for which commissioning timing is in doubt. In electricity modelling, advanced projects are tested for economic efficiency in the capacity outlook model. In gas modelling, advanced projects are considered as candidates to relieve supply shortfall for the purposes of reserves adequacy assessment.
- **Proposals** – projects that have fewer than three of the commitment criteria, uncertain timing, and which are strongly subject to changes in the commercial environment. In general, projects classed as proposals do not have sufficient definition to justify special consideration in capacity expansion or gas supply-demand modelling. AEMO uses generic conceptual projects in these cases.
- **Conceptual** – capacity that belongs to a technology class and which may be required to satisfy reserve requirements, but for which no proposal has been forwarded. Conceptual projects include items such as a generic OCGT or CCGT generator, or a pipeline project of a specific length, diameter and pressure class. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour.

Table 7 Commitment criteria

Category	Criteria
Site	The proponent has purchased/settled/acquired land (or legal proceedings have commenced) for the construction of the proposed development.
Major components	Contracts for the supply and construction of the major components of plant or equipment (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) should be finalised and executed, including any provisions for cancellation payments.
Planning consents/ construction approvals/EIS	The proponent has obtained all required planning consents, construction approvals, and licences, including completion and acceptance of any necessary environmental impact statements (EIS).
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Final construction date set	Construction must either have commenced or a firm commencement date must have been set.

[33] Technologies that are not yet in commercial development are assigned an earliest build date.

5.6.2 New production projects

Electricity

Committed new generation projects will be sourced from AEMO's Generation Information Page, using the latest information available when modelling begins. Committed generation projects are included, with fixed timing and without build costs, in all electricity modelling.

Conceptual utility-scale generation and storage projects are developed using a combination of technology cost and performance data from different sources which can be found at AEMO's website[34] and may include:

- 2015 Australian Power Generation and Technology Report (APGT).
- Bloomberg's New Energy Outlook.
- Published battery storage values from the Energy Storage for Commercial Renewable Integration South Australia Project[35] (ESCRI-SA), funded by the Australian Renewable Energy Agency (ARENA).
- Due to the rapid pace of development in the solar industry, more recent publically available data published by ARENA[36] and industry participants[37,38,39] has been used as the basis of cost and performance assumptions. AEMO has also discussed solar cost assumptions with a number of industry participants to ensure the assumed values align with current Australian conditions.

The capacity outlook model develops a generation and transmission outlook for each studied scenario. The plant configurations selected as candidates for entry are included in the capacity outlook model.

Gas

For electricity, committed projects are those that satisfy AEMO's five commitment criteria, listed in Table 7. There are no equivalent commitment criteria defined for gas production, however the principals of commitment in Table 7 are applied to gas projects for modelling purposes.

5.6.3 Production build limits

In the capacity outlook model, the maximum amount of new generation of any technology type that can be established in any zone is limited ("build limits").

There are two major sources of information behind the build limit assumptions – advice provided by consultant as input into AEMO's market modelling activities, and further refinement through network studies and TNSP advice during studies themselves. The limits provided by consultants are intended to primarily reflect issues around access to fuel and land.

Once a generation and transmission outlook is produced using the build limits, more detailed work is undertaken to explore the impact this would have on the network – and the costs of resolving any issues. In some cases, this leads us to modify the build limits to ensure that the capacity outlook model has some visibility of the (more-detailed) network limitations. This process of iteration can be repeated several times to settle on the final set of build limits used by the model.

5.7 Fuel prices

GPG are end-consumers of gas, and the fuel costs they incur are a key input to the electricity capacity outlook model and time-sequential model. In general, the cost of fuel to a power station consists of a production cost, a transport cost and a volume cost, where the volume cost reflects market conditions. GPG

[34] AEMO. National Transmission Development Plan Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.

[35] ESCRI-SA. December 2015. *Milestone 5 Phase 1 – General Project Report*. Available: http://arena.gov.au/files/2016/04/ESCRI-General-Project-Report-Phase-1.pdf, Viewed 26 July 2016.

[36] ARENA. Energy Storage for Commercial Renewable Integration Available at https://arena.gov.au/project/energy-storage-for-commercial-renewable-integration/.

[37] Origin Energy, Macquarie Australia Conference slides, 4-6 May 2016. Available: https://www.originenergy.com.au/content/dam/origin/about/investors-media/presentations/160504%20Macquarie%20Conference%20Presentation_FINAL.pdf, Viewed: 26 July 2016.

[38] http://reneweconomy.com.au/2016/solarreserve-proposes-110mw-solar-tower-and-storage-plant-for-australia-16693, Viewed: 26 July 2016.

[39] http://reneweconomy.com.au/2015/saudi-power-giant-sees-solar-taking-on-base-load-fossil-fuels-57218, Viewed: 26 July 2016.

with low power output or low capacity factor incur higher volume costs than higher-power, higher capacity factor plant.

In the capacity outlook model and time-sequential model, OCGTs are assumed to operate at a lower capacity factor and at lower power output compared to CCGTs. OCGT generators subsequently pay higher volume costs (approximately 25% higher) compared to CCGT generators.

CHAPTER 6. EMISSION REDUCTION POLICIES

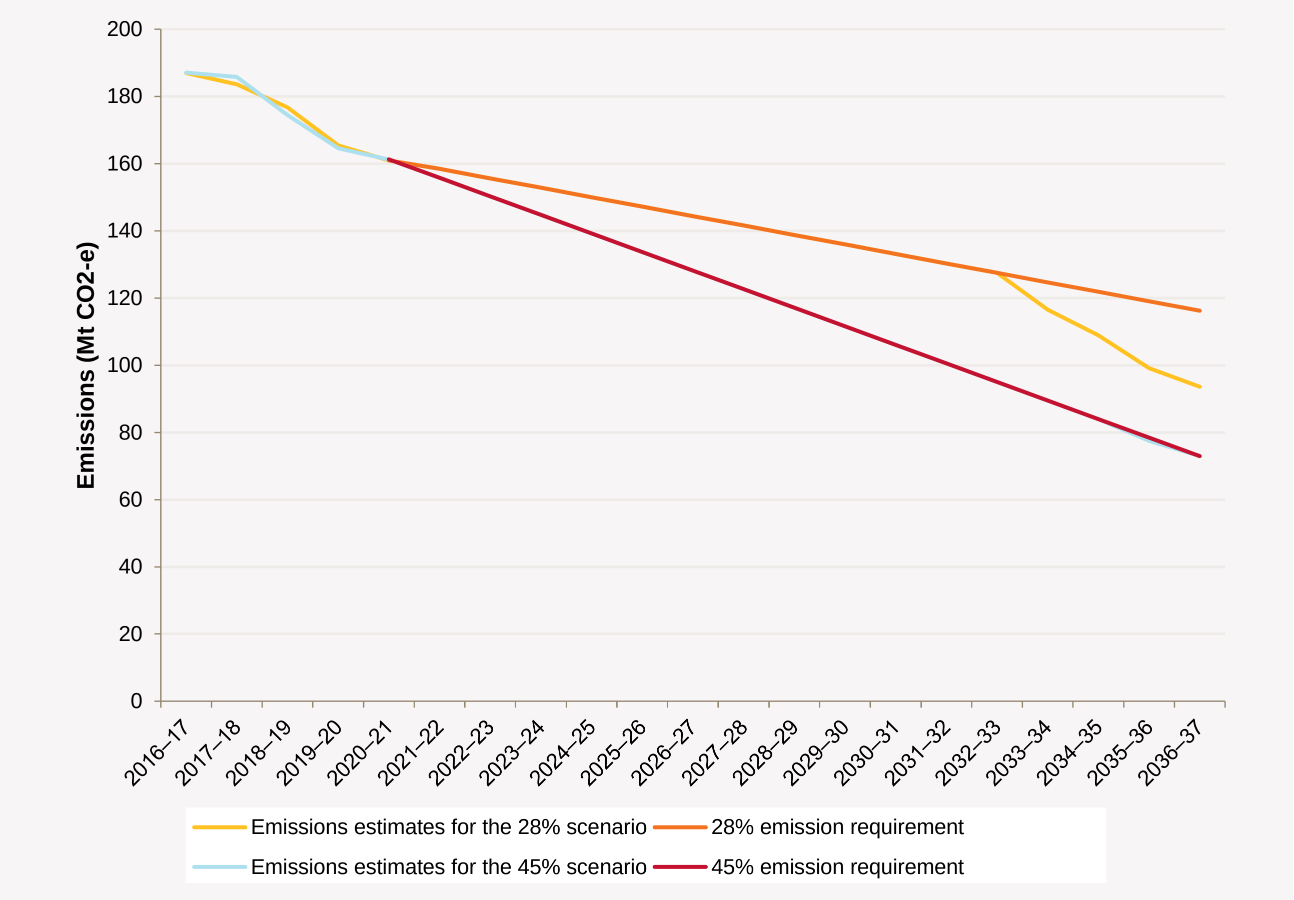
6.1 Australia's commitment to the 21st Conference of Parties

NEM-wide emission constraints, such as Australia's commitment to the 21st Conference of Parties (COP21) in Paris in 2015, are modelled as hard constraints on the capacity outlook model to force the simulation to meet the emission constraint trajectories.

Australia has set a target to reduce carbon emissions by 26% to 28% below 2005 levels by 2030, agreed at COP21. The Council of Australian Governments (COAG) Energy Council has agreed that the contribution of the electricity sector should be consistent with national emission reduction targets. COAG has stated that a 28% reduction from 2005 levels by 2030 is an appropriate constraint for AEMO to use in its ongoing forecasting and planning processes.

This constraint is modelled in the 2016 market modelling activities. The trajectory of the emissions target between 2020 and 2030 has been assumed to follow a linear trend, as shown in Figure 20. Prior to 2020, no emissions constraint has been applied.

Figure 22 Example of carbon constraint trajectory used in 2016 planning studies



6.1.1 Emission intensities

ACIL Allen Consulting were engaged to provide updated emission factors to accurately model emissions for each NEM generator. For the latest information on the emission intensities, please see the latest NTNDP database.[40]

6.2 Renewable energy targets

6.2.1 Large-Scale Renewable Energy Target (LRET)

The Australian Government sets targets for energy generated by renewable sources through the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES). These targets are encouraged by requiring wholesale purchasers of electricity to purchase Renewable Energy Certificates (RECs) which, from 1 January 2011, are classified as either Large-scale Generation Certificates (LGCs) or Small-scale Technology Certificates (STCs) for the purposes of meeting the LRET and the SRES respectively.[41]

In the capacity outlook model, the LRET is enforced by setting an annual energy target that must be met by renewable generation (or penalty price paid). To incorporate the LRET into the capacity outlook model, four adjustments are made to the published LRET figures:

- The number of LGCs that are required to meet the target is scaled by an amount that reflects the energy generated in the NEM compared to the amount of energy generated Australia-wide.
- The calendar-year targets defined by the LRET are converted to financial year targets by averaging the targets in adjacent calendar years.
- The target in the first three years of the model is reduced to account for any surplus RECs currently available in the market.
- The penalty price is increased by $15/MWh to account for the SRMC bidding approach used in the capacity outlook model. With bidding that reflects bidding behaviours proximal to actual market behaviours, renewable generation projects would receive a premium on electricity prices cleared, as compared with the prices calculated under SRMC bidding. As such, these generators should not need such a high price in the LGC market to make the project financially viable, compared with that calculated as necessary using SRMC bidding. This $15/MWh is a simplifying assumption to representing the premium received over a year.

The majority of STCs are generated by domestic rooftop PV installations. The uptake of rooftop PV is modelled as part of the demand projections, so no explicit representation of STCs is included in any of the models.

Renewable energy targets could be modelled as hard of soft constraints. AEMO generally models legislated policies that have no mechanism defined as hard constraints. For those where mechanisms, are already defined, AEMO chooses the most appropriate modelling methodology.

6.2.2 GreenPower

GreenPower is a federal government program to empower consumers to purchase electricity from renewable sources. Sales of GreenPower[42] electricity represent an additional requirement for renewable generation over and above the targets imposed by the LRET and the SRES. The Capacity outlook model and time-sequential model use renewable generation targets that are adjusted to include GreenPower sales.

[40] AEMO. NTNDP Database. Available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database.
[41] Australian Government. Available at http://www.environment.gov.au/climate-change.
[42] http://www.greenpower.gov.au/.

6.2.3 ACT 100% Renewable Energy Target

In 2016, the ACT Government legislated a new target of sourcing 100% of the Territory's electricity from renewable sources located in the ACT or across the NEM by 2020.[43] This target[44] has been incorporated into the capacity outlook model.

6.2.4 Desalination

All major desalination plants in Australia are committed to purchasing renewable energy over and above the requirements of the LRET.

The end of drought conditions in eastern Australia has resulted in all major desalination plants being placed in standby mode. LGC purchase agreements for desalination plants usually apply in the long term, and are not affected by the plants' operational status. It is assumed that LGCs purchased under such agreements will be re-sold, however, so demand for LGCs from desalination plants do not add to the LRET when plant are non-operational.

In 2016, demand for LGCs from desalination plants is assumed to be zero.

6.2.5 Victorian Renewable Energy Target (VRET)

AEMO assumes that the Victorian Renewable Energy Target (VRET) will be legislated and will result in at least 25% of the energy generated in Victoria coming from renewable energy sources by 2020 and 40% by 2025.

AEMO models this scheme as a hard target on energy generation, in conjunction with the latest inputs assumptions for this year's NTNDP modelling. For more details on the VRET please refer to the Victorian Government website.[45]

[43] http://www.environment.act.gov.au/energy/cleaner-energy/renewable-energy-target,-legislation-and-reporting.
[44] http://www.environment.act.gov.au/energy/cleaner-energy and http://www.environment.act.gov.au/__data/assets/pdf_file/0007/987991/100-Renewal-Energy-Tri-fold-ACCESS.pdf.
[45] http://earthresources.vic.gov.au/energy/sustainable-energy/victorias-renewable-energy-targets.

CHAPTER 7. ANALYSIS

7.1 Reliability assessments

AEMO's long-term market modelling activities take into account uncertainties in energy consumption, maximum demand, generator outages and variable generations' intermittence and coincidence with consumption by employing a Monte Carlo simulation approach. A Monte Carlo simulation is an iterative method of running models that:

- Uses different sets of input parameter sensitivities to generate a large population of results that supports statistically robust conclusions.
- In AEMO's market modelling, captures the impact of key uncertainties such as generator outage patterns, weather sensitive demand, intermittent generation availability, and coincidence of demand across regions.

For each iteration of the Monte Carlo simulation, AEMO uses a combination of generator random forced outages, a reference year, and a maximum demand. For reliability assessment studies such as the NEM ESOO, hundreds of Monte Carlo iterations are normally completed per simulation year to create statistically robust results and capture the impact of uncertainties around these parameters.

AEMO aggregates all the Monte Carlo results by weighting the 10% and 50% POE simulation results. The calculation of the weighting factor is discussed in the following section.

A straight average across the reference years results is applied when a single metric is required.

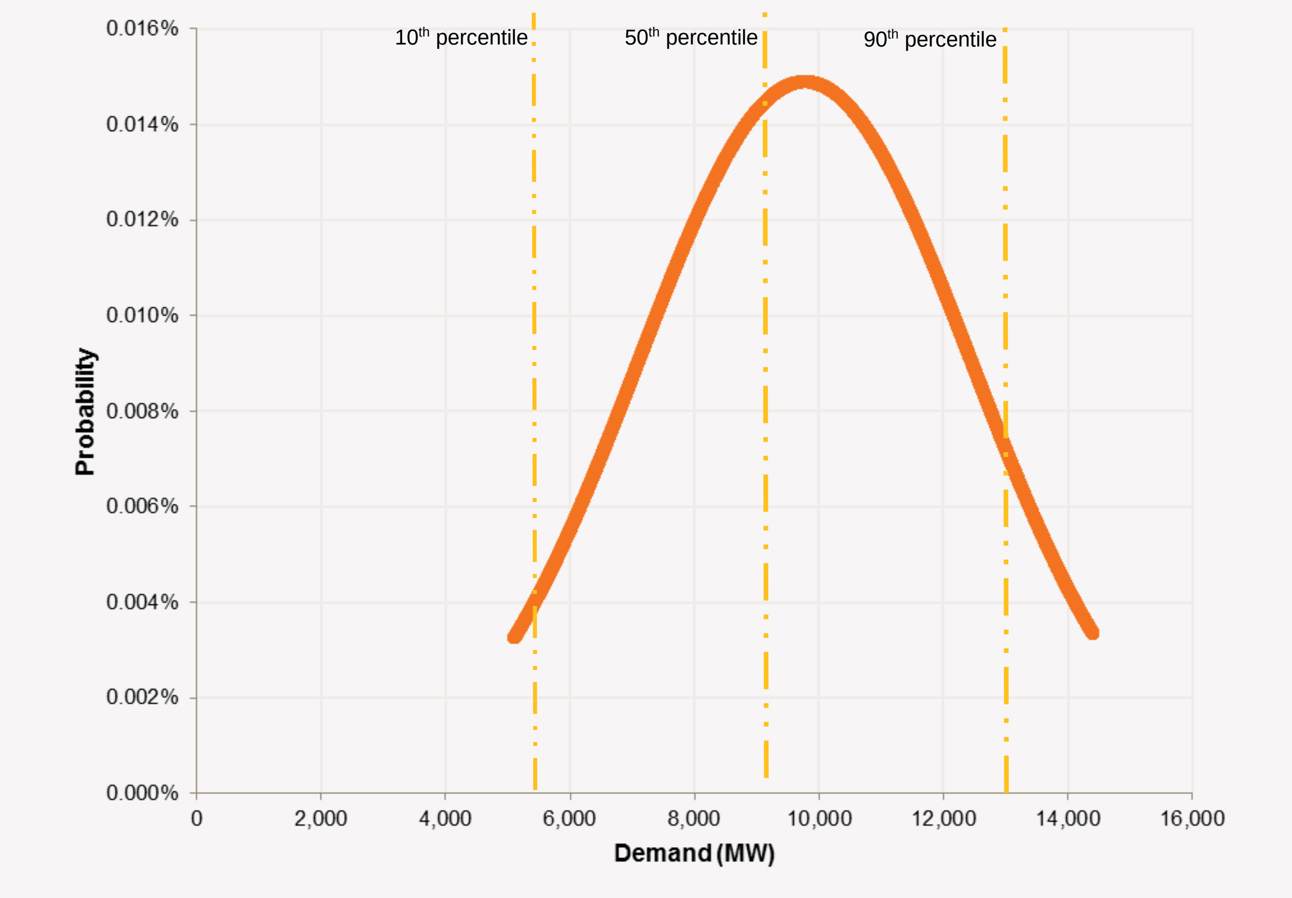
7.1.1 Weighting factors

Figure 21 shows a normal probability distribution for demand and the three relevant points the weighting factor is calculated for.

The following set of equations are developed are and solved simultaneously to give the probabilities for each of the points:

- The sum of probabilities assigned for each point in the distribution curve (10%, 50% and 90% POE) is 1.
- The sum of the probabilities multiplied by respective POE demands should be equal to the mean of the continuous distribution.
- Not only should the mean, or the first moment, of the discrete approximation match that of the continuous, the other moments should be as similar as possible for the continuous and discrete distributions.

Figure 23 Simplified probability density of the load duration curve



Assuming a normal distribution with mean 0 and variance 1, we have the following equations:

$$p_1 + p_2 + p_3 = 1$$

$$p_1x_1 + p_2x_2 + p_3x_3 = 0$$

$$p_1x_1^2 + p_2x_2^2 + p_3x_3^2 = 1$$

The values for x_1, x_2, *and* x_3 should correspond to density function values of 0.1, 0.5 and 0.9 respectively. Using Microsoft Excel's goal seek function:

x_1 = -1.2815516

$x2$ = 0

x_3 = +1.2815516

Using these values and Microsoft Excel's Solver function to solve for the equations provided above, the probabilities are found to be:

p_1 = 0.304, the probability for the 10% POE demand

p_2 = 0.392, the probability for the 50% POE demand

p_3 = 0.304, the probability for the 90% POE demand

When the results of the 50% POE and 90% POE simulations are approximated to be similar and only 10% POE and 50% POE simulations are performed, the 50% POE new weighting factor is taken to be the sum of the two weighting factors, i.e., weighting factor for 50% POE = 0.696 = 0.304 + 0.392.

7.2 Market benefits

Some modelling exercises are designed to determine the benefit to the market delivered by specific network or non-network augmentation projects.

Where calculation of market benefits is warranted, time-sequential modelling is used to developed detailed hour-by-hour costs in both of:

- The case in which an augmentation project is not present.
- The case in which the augmentation is present.

The difference in cost between these two cases represents the market benefit of the augmentation. Where an augmentation is expected to affect the development of generation, a generation expansion plan will also be developed for each case.

AEMO demonstrates the economic value of the augmentation options by providing a high level overview of the potential benefits that are allowable by the Australian Energy Regulator (AER) in a Regulatory Investment Test for Transmission (RIT-T).[46] The allowable market benefits may include:

- Capital costs benefits – indicates savings from deferring investments.
- Operating cost benefits – indicates operating costs reduction which may include fuel, operating, maintenance, and transmission loss costs savings.
- DSP benefits – the savings from avoiding price-sensitive responses.
- Reliability benefits – indicates customer reliability improvements measured by the reduction in USE. Reduction in USE due to long-term non-credible contingencies may also be evaluated.
- Environmental scheme benefits – savings from reduced payments for renewable targets.
- Competition benefits – optional under the RIT-T.
- Option value – refers to a benefit that results from retaining flexibility in a situation where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options available are sufficiently flexible to respond to that change.
- Ancillary services benefit – the reduction in net costs required to provide sufficient ancillary services to meet the projected system needs.

The sum of these benefits represents the total market benefits of an augmentation. Comparing these potential market benefits with the cost of the augmentation provides an insight into whether this project is likely to be justified under the RIT-T.

Market benefit analysis requires comparison of a discounted cash flow of total system costs using the most up-to-date range of discount rates.

7.2.1 Generation capital costs

An augmentation may defer generation capital expenditure, saving the cost to finance investment during the deferral period. In extreme cases, generation may not need to be built at all. An augmentation may allow a less capital-intensive form of generation to be established in an alternate location.

Generation capital deferral benefits are determined by capacity outlook modelling outcomes.

[46] Australian Energy Regulator, Final regulatory investment test for transmission, https://www.aer.gov.au/system/files/Final%20RIT-T%20-%2029%20June%202010.pdf. Accessed 2 December 2016.

7.2.2 Transmission capital costs

An augmentation may defer the need to build other transmission projects. Transmission capital deferral benefits are determined by capacity outlook model outcomes.

7.2.3 Operating cost benefit

An augmentation may relieve limitations on existing or new generation with lower fuel, emissions, fixed or variable operating costs, allowing lower-cost generation to operate more frequently.

Operating cost benefits are determined by time-sequential modelling outcomes.

System operating cost benefit includes:

- Production costs savings – due to lowered operational costs and includes transmission loss cost.
- Fixed operating and maintenance costs savings – due to decreased total fixed costs incurred for keeping generators in service.

7.2.4 Transmission system losses

An augmentation may allow generation to be dispatched closer[47] to the locations where energy is consumed, reducing the cost to transport energy on the network.

An augmentation may change the flow patterns on interconnectors in ways that reduce losses when transferring power between regions.

Transmission system loss benefits are determined by capacity outlook model outcomes (when new generation is established closer to load centres) and time-sequential modelling outcomes (when changes in network limitations change interconnector flow patterns).

7.2.5 Reliability benefits

A Value of Customer Reliability (VCR, usually expressed in dollars per kilowatt-hour) indicates the value different types of customers place on having reliable electricity supplies under different conditions. It is used to monetise USE so investment options can be compared on an economic basis.

An augmentation may reduce the amount of reported USE, reducing the penalties associated with failing to supply consumers. Reliability benefits are determined by time-sequential modelling outcomes.

Calculating the value of customer reliability

In 2014, AEMO carried out a VCR review to improve understanding of the levels of reliability customers expect, and to produce a range of VCR values for residential and business customers.[48] This VCR value was obtained through extensive consultation and surveys, and is used in AEMO market modelling studies to evaluate cost-effective ways to build or upgrade infrastructure.

High Impact Low Probability events

High Impact Low Probability (HILP) events can result in widespread and/or prolonged outages. The current VCR values cannot be extrapolated to cover these events, because VCR survey respondents are not expected to have a good understanding of their social and safety implications. Therefore, AEMO has decided to use 2 x VCR when assessing the impact of HILP events.

7.2.6 Option value and competition benefits

AEMO's modelling activities may quantify option value or competition benefits if these benefits are considered to be material to the outcomes of the study.

[47] Electrical proximity. That is, substituted generation may be physically further away, but connected to a lower-loss transmission line, or operates in a way that reduces total losses in delivering energy to the point of consumption.
[48] AEMO. *Value of Customer Reliability Review*. Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Value-of-Customer-Reliability-review.

CHAPTER 8. FINANCIAL PARAMETERS

Cost-benefit comparisons between augmented and unaugmented cases use a discounted cash flow (present value) calculation to determine the present day value to the market of spending that occurs in the future.

8.1 Inflation

Monetary values in the models refer to real value, as opposed to nominal value. That is, future values are not adjusted by assumptions about inflation, whereas values defined in the past are adjusted to account for inflation. For example, in AEMO's 2016 planning publications, values are expressed in 2016–17 Australian dollars unless otherwise stated. Values that were originally expressed in dollars of earlier years are adjusted upwards by 2.5%, or the observed appropriate inflation measure, to account for inflation.[49]

Time value of money is reflected in the model by the most up-to-date range of possible discount rates.

8.2 Goods and Services Tax

Prices are exclusive of Goods and Service Tax.

8.3 Weighted average cost of capital

The capital cost of an investment is increased beyond its purchase price by the cost of finance. The weighted average cost of capital (WACC) is the rate that a company is willing to pay to finance its assets.[50] The WACC is the weighted sum of the cost of debt and the cost of equity, where the cost of debt is determined by interest rates, and the cost of equity is determined by reference against the returns received by other projects with similar risk.

AEMO uses real, pre-tax WACC values in its capacity outlook modelling, consistent with Bloomberg's *New Energy Outlook* report. Values may differ by scenario or technology, reflecting the difficulty in obtaining credit under different economic conditions or climate policy futures.

8.4 Discount rate

Present value calculations estimate all future cash flows which are discounted to account for the amount of cash that would need to be invested in the present day to yield the same future cash flow.

AEMO may use a range of discount rates to calculate the Net Present Value (NPV) of future cash flows. Practically, lower discount rates emphasise market benefits that accrue later in the modelled horizon, while higher discount rates emphasise market benefits that accrue earlier in the modelled horizon. A higher discount rate can be used to accommodate the uncertainty inherent in the estimates of cost to operate modelled energy infrastructure, which increases with time.

8.5 Project lifetime

Capital investments are annualised over the life of the asset in order for costs to be compared against annual market benefits over the planning horizon (typically 20 to 25 years for generation projects, and 50 years for transmission projects).

In some instances, a terminal value is estimated by assuming that average market benefits observed in the final simulated years are the same as future years. However, with the market transforming so dramatically, it is no longer reasonable to assume that the market benefits observed in the final year will be the same as future years. On the other hand, given such large uncertainties in future outcomes, modelling to a false level of precision so far out in the future may also be considered unproductive.

[49] Inflation is calculated from Australian Bureau of Statistics consumer price index adjustments.
[50] The return the company would expect to receive from an alternative investment with similar risk.

APPENDIX A. SUMMARY OF INFORMATION SOURCES

Table 8 Summary of information sources

Information	Source
Adjustment to demand due to rooftop PV	*National Electricity Forecasting Report* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report
Auxiliary loads	*National Transmission Network Development Plan* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Carbon price trajectories	*National Electricity Forecasting Report* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report
Committed and proposed transmission augmentations	Annual Planning Reports Project Summary workbook Available for at m http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Demand side participation amounts	*National Electricity Forecasting Report* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report
Emissions intensity factors	*National Transmission Network Development Plan* Available from http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Existing and new gas production, storage and transmission infrastructure	GSOO Inputs and Stakeholder Information Available at http://www.aemo.com.au/-/media/Files/Doc/GSOO-input-data.xlsx
Gas and coal prices	*National Transmission Network Development Plan* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Gas annual and peak day demand forecasts	*National Gas Forecasting Report* Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report
Gas production and transmission costs	GSOO Inputs and Stakeholder Information Available at http://www.aemo.com.au/-/media/Files/Doc/GSOO-input-data.xlsx
Gas reserves	GSOO Inputs and Stakeholder Information Available at http://www.aemo.com.au/-/media/Files/Doc/GSOO-input-data.xlsx
Generation inventory	Generation Information Page Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information
Generator ramp rates	*National Transmission Network Development Plan* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Marginal loss factors and proportioning factors	Loss Factors and Regional Boundaries Available at: http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries
Minimum capacity reserve levels	*National Transmission Network Development Plan* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database

Information	Source
New generation technology costs	*National Transmission Network Development Plan* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Projections of demand for LNG export	*National Gas Forecasting Report* Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report
Regional electricity energy and maximum demand forecasts	*National Electricity Forecasting Report* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report *National Gas Forecasting Report* Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report
Reliability Standard	Reliability Standards (AEMC) Available at http://www.aemc.gov.au/panels-and-committees/reliability-panel/guidelines-and-standards.html
Renewable energy targets	Clean Energy Regulator Available at http://ret.cleanenergyregulator.gov.au/About-the-Schemes/lret
Scenario descriptions	*National Electricity Forecasting Report* Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Electricity-Forecasting-Report *National Gas Forecasting Report* Available at http://www.aemo.com.au/Gas/National-planning-and-forecasting/National-Gas-Forecasting-Report
Significant constraint equations	*National Transmission Network Development Plan* Available for at m http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan/NTNDP-database
Wind contribution to peak demand	Generation information page Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Generation-information South Australian Advisory Functions Available at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/South-Australian-Advisory-Functions