AEMO
AUSTRALIAN ENERGY MARKET OPERATOR

Market Modelling Methodologies

July 2020

For Forecasting and Planning the National Electricity Market and Eastern and South-Eastern Gas Systems

Important notice

PURPOSE

AEMO has prepared the Market Modelling Methodology to provide information about how AEMO fulfils its forecasting and planning functions under the National Electricity Law and the National Electricity Rules and the National Gas Law and the National Gas Rules.

DISCLAIMER

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VERSION CONTROL

Version	Release date	Changes
1	16/8/2019	Initial 2019 methodology release
2	30/7/2020	New detail added including Transmission counterfactual modelling, details of time-sequential models, unit commitment strategy, heat rate modelling, storage optimisation. Removed detailed content on the Network development outlook model, and the Summary of information sources section. Refer to ISP Methodology and Inputs and Assumptions Workbook for this information. Minor wording updates.

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1. Introduction

AEMO provides planning and forecasting information for the National Electricity Market (NEM), and eastern and south-eastern gas systems, as part of its functions under the National Electricity Law and the National Electricity Rules (NER) and the National Gas Law and the National Gas Rules.

AEMO produces a comprehensive suite of planning and forecasting publications each year. Major publications that utilise AEMO's market modelling include:

- **Electricity Statement of Opportunities (ESOO)** – a supply adequacy assessment of the NEM. Provides market and technical data to assess the reliability of the electricity market over a 10-year outlook period. The ESOO incorporates an independent forecast for electricity consumption, maximum demand, and minimum demand over a 20-year outlook period for the NEM, previously referred to as the National Electricity Forecasting Report (NEFR).
- **Gas Statement of Opportunities (GSOO)** – reports on the transmission, production, and reserves supply adequacy of Australia's eastern and south-eastern gas markets over a 20-year outlook period. The GSOO incorporates an independent forecast for gas consumption, and maximum gas daily consumption, previously referred to as the National Gas Forecasting Report (NGFR).
- **Integrated System Plan (ISP)** – provides an integrated roadmap for the efficient development of the NEM over the next 20 years and beyond. Its primary objective is to maximise value to end consumers by designing the lowest cost, secure and reliable energy system, capable of meeting any emissions trajectory determined by policy makers at an acceptable level of risk.

These reports comprise AEMO's forecasts of the potential evolution of the NEM and the eastern and south-east Australian gas network across the long term. Each report typically presents several alternative futures given the uncertainty of point forecasts when market and economic drivers can change significantly over the forecast period.

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

AEMO generally uses three models to perform market modelling activities:

- The capacity outlook model, including two variants of differing granularity.
- The time-sequential 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. Independent methodologies also are provided to explain AEMO's forecasting

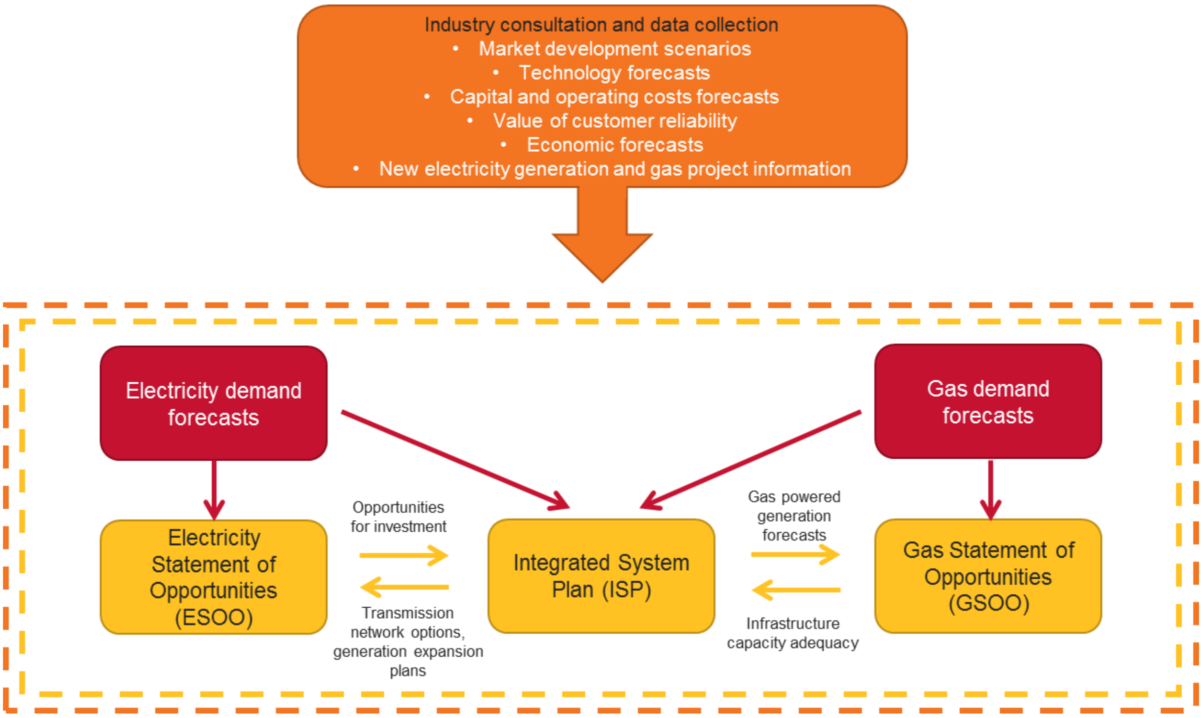
[1] AEMO. Gas Statement of Opportunities methodology, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

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

[3] AEMO. ISP methodology, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

approach for electricity and gas consumption, maximum demand, minimum demand, as well as connection point forecasts.

Figure 1 AEMO's primary national 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. Individual publications produce bespoke methodology or assumptions reports, those values should take precedence to that presented here.

At a high level:

- Electricity and gas demand forecasts are available at AEMO's forecasting portal (http://forecasting.aemo.com.au/).
- Generator technical and economic parameters are available as part of AEMO's Planning and Forecasting inputs, assumptions and methodologies (at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines).
- Regional boundary definitions and marginal loss factors are published annually, as Loss Factors and Regional Boundaries (at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries .)

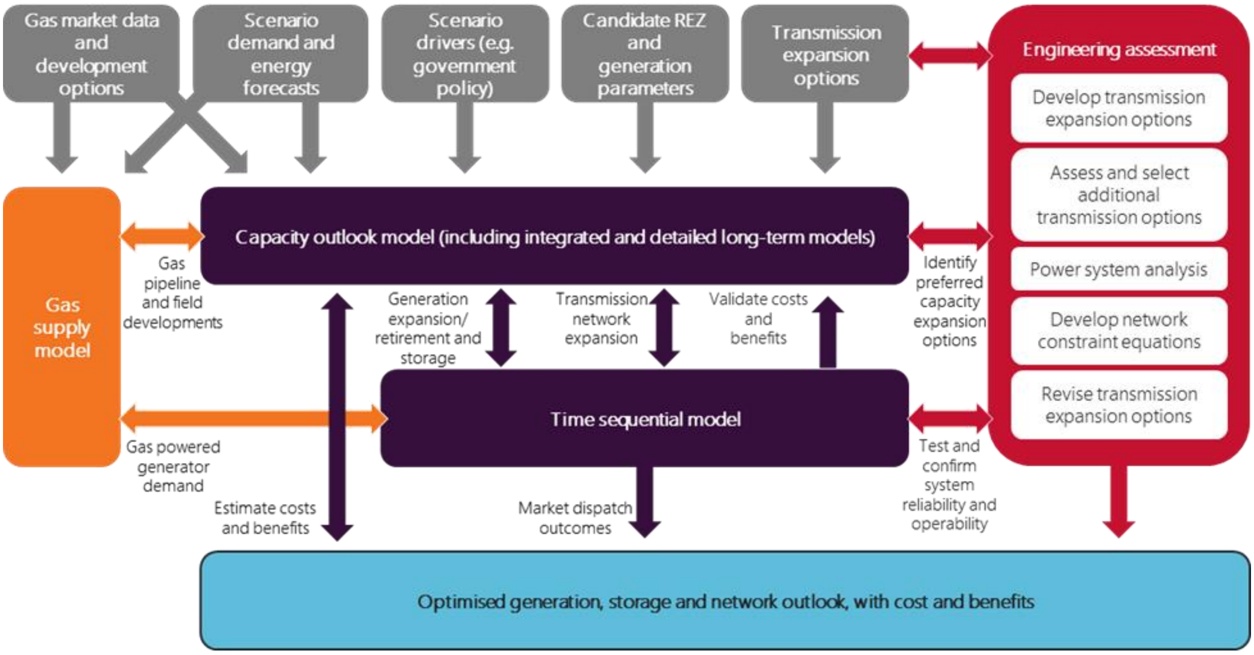
Data updates become available at different times of the year. Each planning report uses the latest data that is available when modelling commences.

2. Models

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 and credible futures and describe the environment in which Australia's energy networks may operate in the long term.

AEMO's forecasting suite of tools consists of four mutually-interacting planning models (the three market models and an engineering assessment model), 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 gas and electricity systems may develop under different demand, technology, policy, and environmental conditions.

Figure 2 Market modelling process flow



Each model may be described at a high level as follows:

- **Capacity outlook model** – determines the most cost-efficient long-term trajectory of generator and transmission investments and retirements to maintain power system reliability, as well as gas supply and transmission. Two variants exist:
  - **Long Term Integrated model (IM)** – co-optimised model of the electricity and gas systems which considers the interdependencies between each system to determine optimal thermal generation

[4] In the context of AEMO planning, a scenario is a 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.

investments, retirements, transmission, gas field and pipeline investment plans, over the longest time horizon (25 years or beyond).

  – **Detailed Long Term (DLT) model** – co-optimised model of the electricity system in isolation to the gas market, optimising new generation investments and transmission developments, as well as renewable energy zone (REZ) development opportunities, using inter-regional transmission and other long-lived thermal generation development decisions produced by the IM capacity outlook model. The DLT model is a more granular capacity outlook approach that provides chronological, detailed representations of the long term via a multi-step solve, with reduced foresight relative to the IM to compensate for the increased model complexity.

- **Time-sequential model**[5] – a suite of models that carry out half-hourly and/or hourly simulation based on available data 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. Also depending on the study, different components of the suite of models may be utilised (see Section 2.4.2 for more details on the different types of time-sequential models).
- The **Gas supply model** is used primarily to assess gas reserves, production and transmission capacity adequacy for the GSOO. The model performs gas network production and pipeline optimisation at daily time intervals.
- **Engineering Assessment –** examines and investigates possible engineering and operational solutions to emerging transmission network limitations identified by the capacity outlook model and time-sequential model. This assessment has three main steps: development of transmission options, assessment and selection of transmission options and power system analysis.

Table 1 summarises the respective models used for AEMO's Forecasting publications.

Table 1 Major publication models

Publication	Capacity outlook model	Time-sequential model	Engineering assessment	Gas supply model
ESOO		✓	✓	
GSOO	✓	✓	✓	✓
ISP	✓	✓	✓	✓

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

The Engineering Assessments are refined through power system studies using the PSS®E platform.

2.1 National Electricity Market topology

The NEM is comprised of the five Commonwealth States of Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania, referred to as regions and shown in

[5] 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 or half-hourly simulation.

Figure 3[6]. 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 NEM Dispatch Engine (NEMDE), which is responsible for directing generation dispatch in the NEM.

Figure 3 Regional representation of the NEM, including existing interconnectors

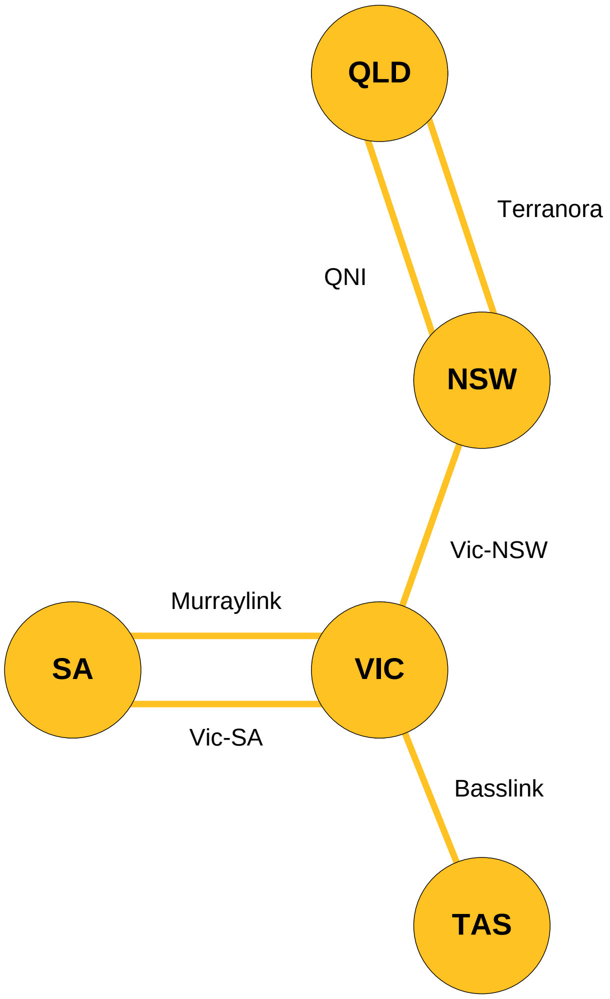
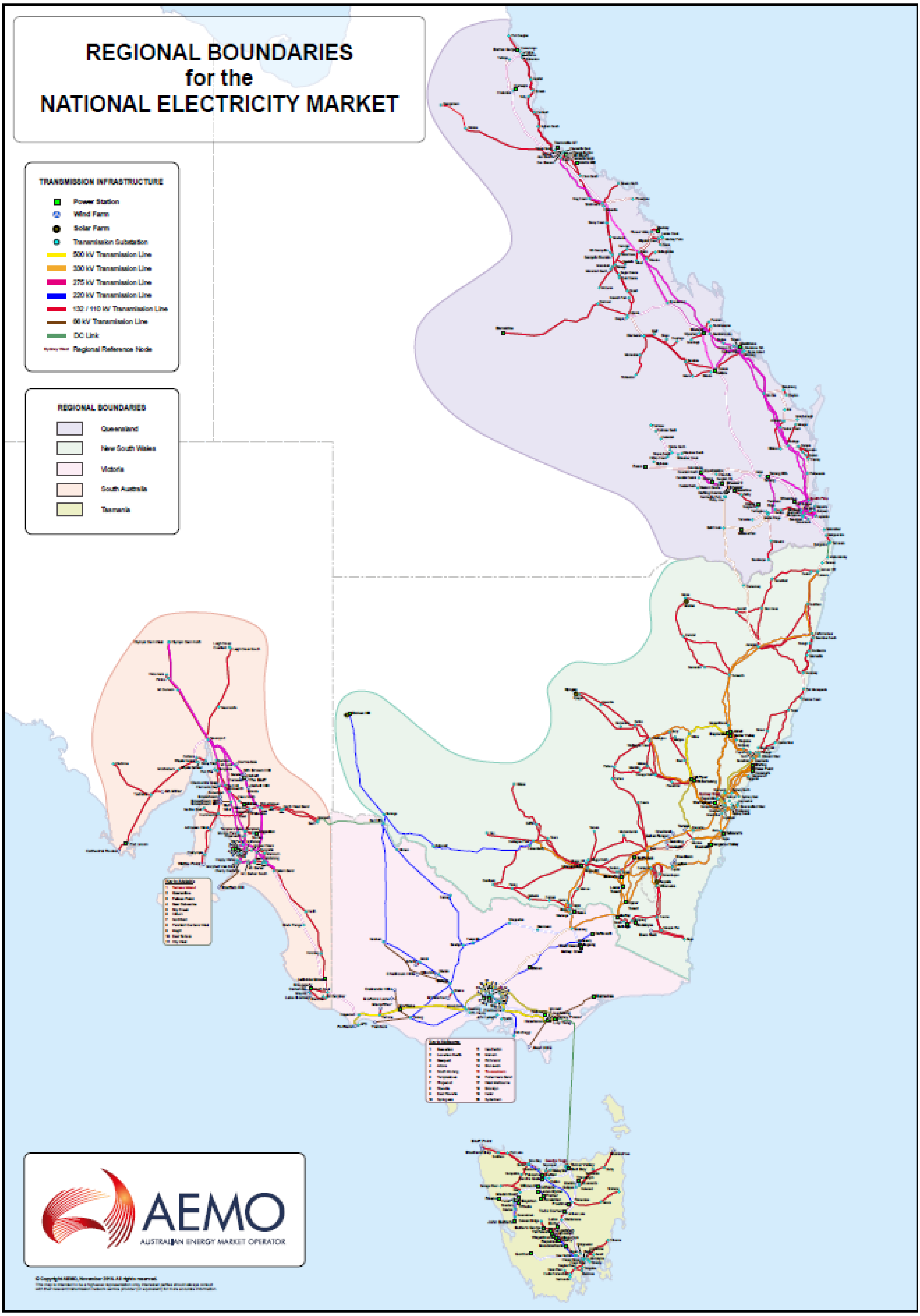


Figure 4 shows the electricity infrastructure and the latest regional boundaries definition for the NEM. AEMO also produces an interactive map that contains a clear visualisation of regional definitions as well as key outcomes from AEMO's planning and forecasting publications[7].

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

[7] AEMO Interactive Map, at http://www.aemo.com.au/aemo/apps/visualisations/map.html.

Figure 4 NEM regions and power system infrastructure



2.1.1 Modelling geographical and electrical diversity

A regional representation cannot account for differences in energy resources and infrastructure limitations within a region. To incorporate these aspects, AEMO's electricity modelling defines planning zones subject to the specific modelling exercise. Each zone is modelled considering the expected quality and availability of generation resources, including the correlation of renewable generation resources, to inform the capacity outlook model and time-sequential modelling.

Energy resource availability and cost, along with generation build limits dictated by the intra-regional network dynamics, 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 zone may justify both investment in generation and transmission infrastructure to supply power elsewhere.

AEMO has identified renewable energy zones (REZs) – an extension to previous planning zones. REZs are geographical areas in the NEM where clusters of large-scale renewable generation can be developed to promote economies of scale. Ideally, REZs will also allow for geographical and technological diversity for large scale renewable projects.

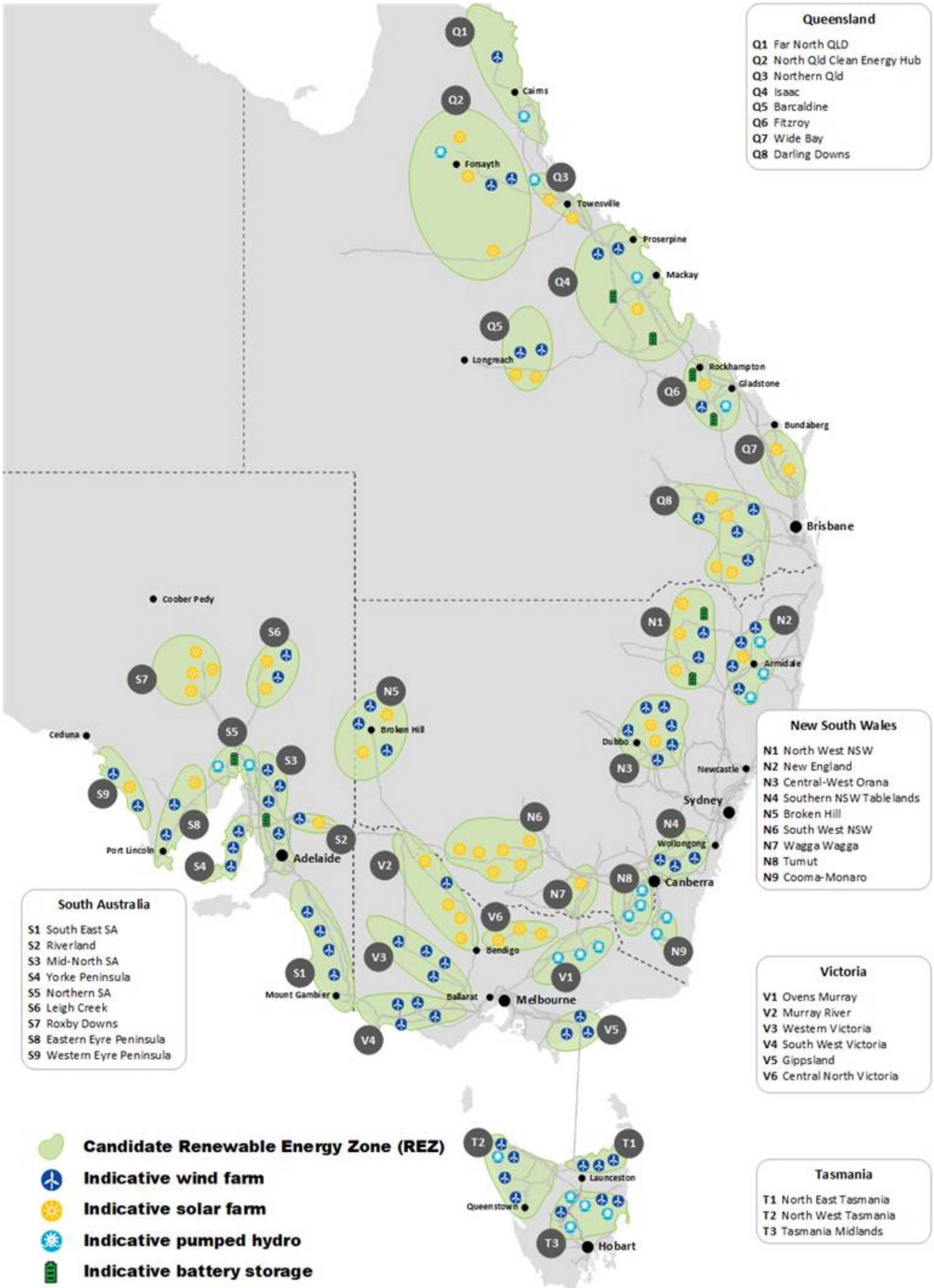
The purpose of identifying the location and timing of REZs is to enable the efficient connection of new geographically diverse generation sources while maintaining reliable supply to consumers. To efficiently and reliably connect this generation will require complementary network development at both intra and inter-regional level. The REZs identified by AEMO are shown in Table 2 and Figure 5.

Table 2 Renewable energy zones

REZ number	REZ name	NEM region
Q1	Far North QLD	QLD
Q2	North Qld Clean Energy Hub	QLD
Q3	Northern Qld	QLD
Q4	Isaac	QLD
Q5	Barcaldine	QLD
Q6	Fitzroy	QLD
Q7	Wide Bay	QLD
Q8	Darling Downs	QLD
N1	North West NSW	NSW
N2	New England	NSW
N3	Central-West Orana	NSW
N4	Southern NSW Tablelands	NSW
N5	Broken Hill	NSW
N6	South West NSW	NSW
N7	Wagga Wagga	NSW

REZ number	REZ name	NEM region
N8	Tumut	NSW
N9	Cooma-Monaro	NSW
V1	Ovens Murray	VIC
V2	Murray River	VIC
V3	Western Victoria	VIC
V4	South West Victoria	VIC
V5	Gippsland	VIC
V6	Central North Vic	VIC
S1	South East SA	SA
S2	Riverland	SA
S3	Mid-North SA	SA
S4	Yorke Peninsula	SA
S5	Northern SA	SA
S6	Leigh Creek	SA
S7	Roxby Downs	SA
S8	Eastern Eyre Peninsula	SA
S9	Western Eyre Peninsula	SA
T1	North East Tasmania	TAS
T2	North West Tasmania	TAS
T3	Tasmania Midlands	TAS

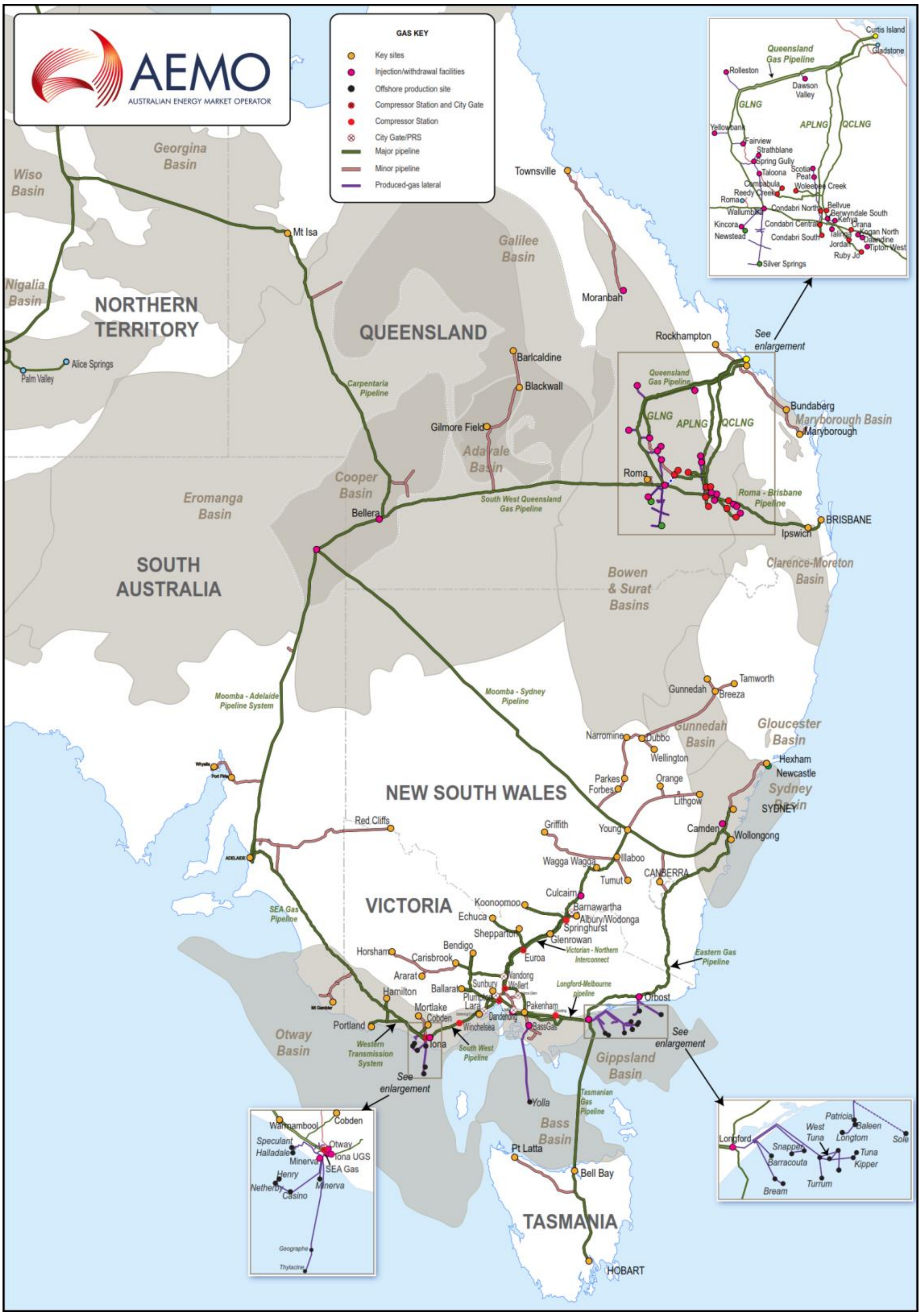
Figure 5 Renewable Energy Zones map



2.2 Gas network topology

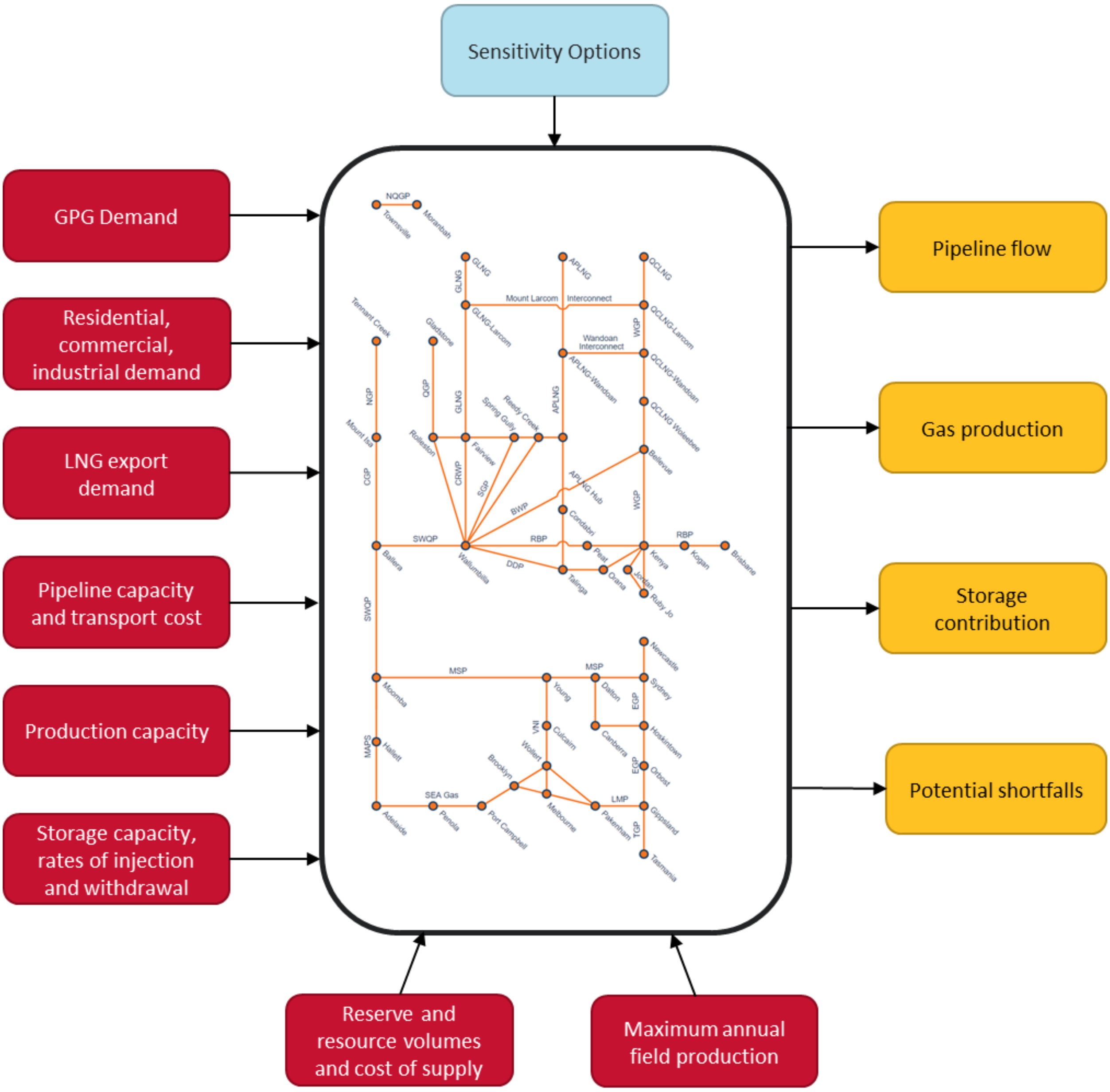
Major gas transmission and production infrastructure in eastern and south-eastern Australia is shown in Figure 6. This map (and AEMO's gas supply model) includes the recent completion of the Northern Gas Pipeline (NGP) linking Tennant Creek with Mt Isa.

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



2.3 Capacity outlook model

The capacity outlook model consists of two separate models – the IM and DLT models – which complement each other in identifying the optimal generation and transmission pathway in the long term across different scenarios.

The IM co-optimises electricity generation and transmission investment and withdrawals, along with gas production and pipeline infrastructure, to efficiently meet future operational demand and government policy objectives (such as renewable generation development) at lowest cost for the entire system. Gas and electricity sector-coupling is included in the IM capacity outlook model, given the critical dependencies between these two sectors.

The objective of the capacity outlook models, in combination, is to minimise the capital expenditure and generation production costs over the long-term planning outlook (at least 20 years), 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 likely policy objectives (in accordance with the scenario definitions).
- Observing physical limitations of the generation plant and transmission system.
- Accounting for any energy constraints on resources.

The modelling approach applies a mathematical formulation of a 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 Planning and Forecasting inputs, assumptions and methodology documentation, 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.
- Breaking the optimisation into smaller steps.
- Simplifying the network representation, using static notional interconnector limits.
- Reducing the number of integer decision variables by linearising generation and transmission build, operational and retirement decisions (effectively allowing partial units or lines to be built if desired). Many of these key linear decisions are subsequently validated via sensitivity analysis, applying 'with' and 'without' modelling as required.
- 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 and minimum load levels to represent minimum technical and economic duty cycles for thermal generators across the NEM.

The DLT model is a chronological optimisation which has greater resolution relative to the IM, although some load aggregation is still required. Computational feasibility of this model is maintained by breaking the optimisation into smaller steps. This technique allows increased granularity to preserve the original chronology of demand (and renewable resource) time series, thus ensuring a greater reflection of renewable intermittency, storage balancing capabilities and other inter-temporal constraints which require a chronological relationship between simulation intervals.

Another technique used to ensure tractability involves a preliminary screening of the set of generation candidates. This involves optimising the DLT model for a representative selection of snapshot years across the horizon to determine whether a technology is part of the most economically efficient solution at any time across the planning horizon. Applying a snapshot year approach essentially isolates the selected years, reducing the problem size significantly allowing greater technology development options to be included. Candidates that are planted in at least one of the snapshot years are retained and fully optimised in subsequent DLT simulations spanning the entire study period. Build options that are not developed in any of the snapshot years are withdrawn from further assessment. The screening is carried out for each scenario and

[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. Available at https://www.aemc.gov.au/our-work/developing-electricity-guidelines-and-standards.

[9] AEMO. Planning and Forecasting inputs, assumptions and methodologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

sensitivity. Reinstating candidates is considered based on the results of the full DLT simulation that follows as well as the insights provided by the time-sequential simulations. This is captured through the iterative simulations between the DLT and ST models.

As the capacity outlook models rely on some problem simplifications to manage simulation timeframes, 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 setting minimum operational constraints or maximum build limits on generators based on observations in the gas models, the time-sequential model, and power system models, or refining the minimum capacity reserves to meet the reliability objective based on time-sequential model analysis.

This feedback is critical from a whole-of-system perspective to make sure gas consumption in the capacity outlook models (which is inevitably less granular) is representative and could be adequately supplied given reserve estimates and pipeline constraints in the gas system. Further, it enables inclusion of system security considerations that would otherwise not be captured directly within the model, and then need to be represented by adding additional constraints into the formulation. Not considering these would risk invalidating the projections.

Consequently, generation and transmission expansion development is finalised through an iterative modelling process where the capacity outlook model and the time-sequential model are used to deliver a range of expansion plans for all scenarios. Where possible, decisions made by the modelling during the early stages of the development are 'locked down' if common to many of the simulations. These development options could be interconnector builds, generation developments or retirements that are driven by consistent settings across the scenarios. This helps improve the robustness of the expansion/retirement plan by reducing the number of decisions to be made in subsequent iterations and improves stability between scenarios.

2.3.1 Planning for weather variability and climate change

The availability of renewable energy, including hydro generation, is important given the degree of penetration of intermittent and weather-driven generation projected over the medium term. The weather driven generation will be affected by short-, medium- and long-term climatic trends such as seasonal weather variability, El Nino/La Nina and climate change. To capture short- and medium-term weather diversity, AEMO optimises expansion decisions across multiple historical weather years known as "reference years". Where practical, these weather years also capture the variance around a long-term climate trend.

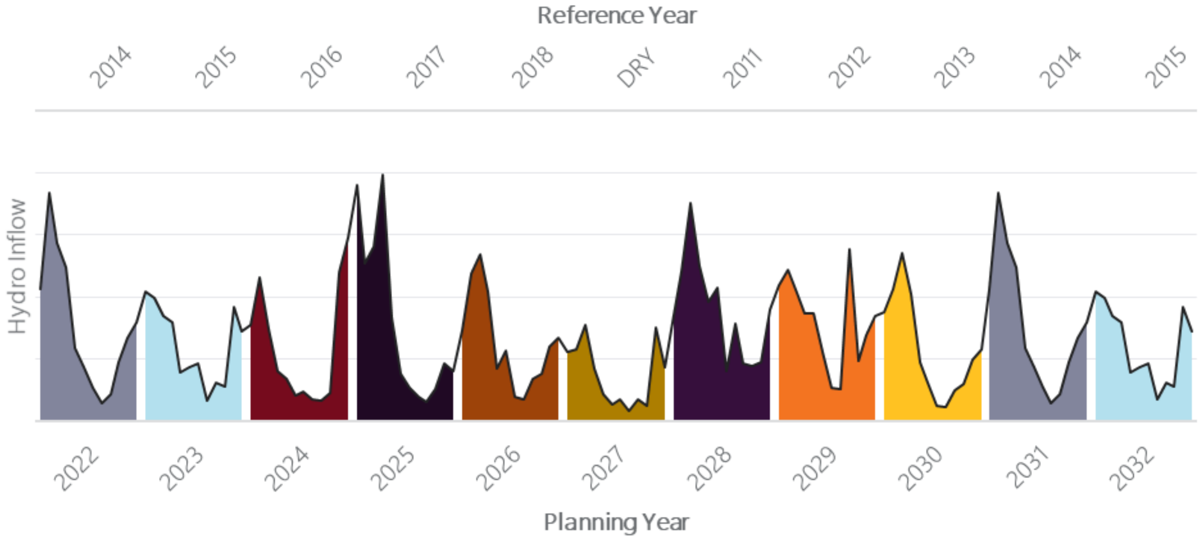
Short- and medium-term weather diversity

The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coinciding customer demand, wind, solar and hydro generation outputs. This approach increases the robustness of AEMO's expansion plans by inherently considering the risks of renewable energy "droughts", representing extended periods of very low output from any particular renewable generation source, which are observed across the NEM.

To achieve this, AEMO uses a "rolling reference years" approach which involves combining a number of demand and renewable historical profiles including hydro inflows to produce a time series that would capture a variety of weather patterns throughout the planning horizon. To appreciate the effect of persistent drought and its potential impact on long-term hydro yield, AEMO also models water years representative of a severe water drought, and scales historical water inflows throughout the planning horizon in line with scenario definitions and forecast rainfall and inflow outlooks.

Within the capacity outlook models, reference years are matched to the planning years by rolling through and repeating each of the input reference years. This approach results in a repeating sequence of reference years across the study period, as illustrated in Figure 8.

Figure 8 Rolling reference years in capacity outlook modelling



Climate change

Climate change is predicted to drive substantial variation in weather patterns, and therefore coincident customer demand and renewable generation profiles. However, in many cases the range of uncertainty is large. AEMO seeks to consider both:

- The uncertainty attributable to future atmospheric greenhouse concentrations.
- The uncertainty attributable to climate modelling.

Representative Concentration Pathways (RCPs) have been developed by climate scientists to describe possible pathways for atmospheric greenhouse gas concentrations, and the associated climate change impacts. Development of Shared Socio-economic Pathways (SSPs) has broadened the future climate scenarios, providing narratives around global emissions drivers, mitigative capacity and adaptive capacities that may result in particular RCPs. The RCP/SSP framework is designed to be complementary, and AEMO has considered it appropriate to apply this framework, focusing on RCPs, to long-term planning and forecasting scenarios. Each scenario modelled is allocated an RCP that is consistent with the scenario narrative. Where possible, the physical impacts of this RCP are incorporated where relevant to the electricity sector.

For a given future atmospheric greenhouse concentration specified by the RCP, AEMO will sample appropriate global climate models (GCMs) to determine (at minimum) a median-case outcome, as well as a best- and worst-case outcome for sensitivity testing. Each GCM is internally consistent across all relevant variables (wind, solar, temperature, precipitation), so the selection of GCMs for each case must consider the impact across all relevant variables. The proposed GCMs for the Australian electricity sector are shown in Table 3.

Table 3 Selected global climate models (GCMs)

Case	GCM*	Impacts
Best case	NorESM1-M	Hot and wet
Median case	ACCESS1-0	Middle of the pack
Worst case	GFDL-ESM2M	Hot, dry and windy

* Further details on each GCM are available at https://www.climatechangeinaustralia.gov.au/en/support-and-guidance/faqs/eight-climate-models-data/.

This climate adjustment is captured in the modelling by applying a linearised indexation of reference years across the capacity outlook and time-sequential models. This approach is most relevant in the ISP, given that the physical symptoms of climate change are more observable within the longer planning horizon.

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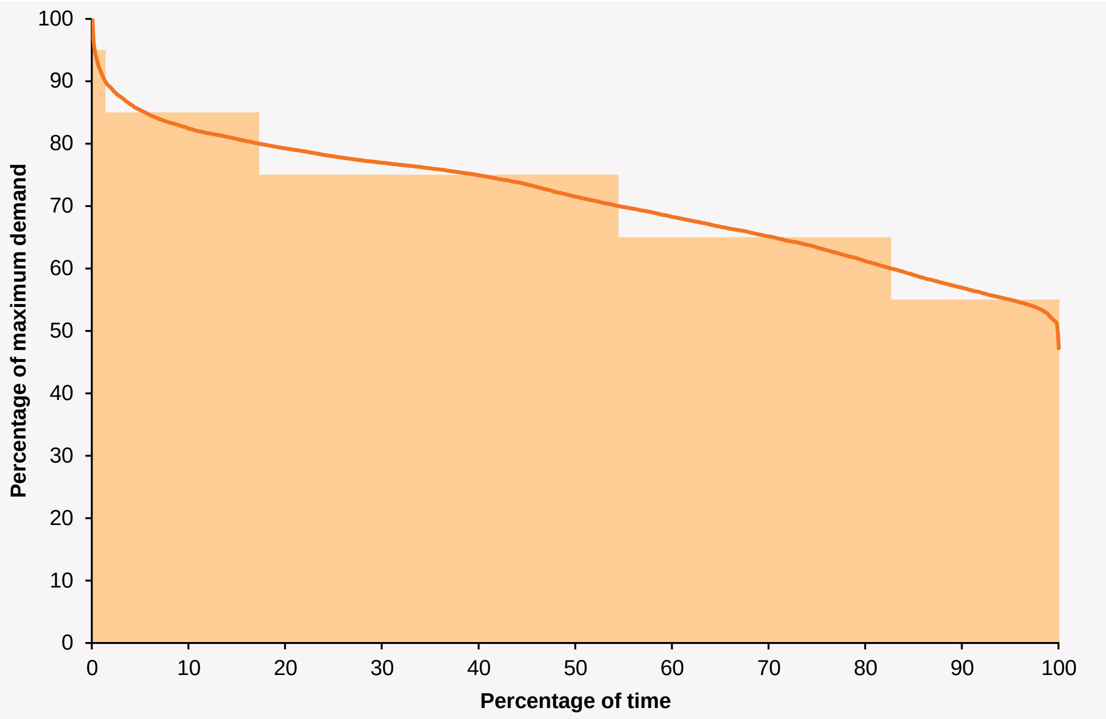
2.3.2 Load blocks

The IM model uses the Load Duration Curve (LDC) approach to approximate hourly demand.

Load blocks are created for each month modelled, using a 'best-fit' approach to approximate the monthly load duration curves, as demonstrated in Figure 9. The monthly partitioning captures seasonal variation and maximum and minimum demands are preserved, but within each month the demand chronology is lost. The exact number of load blocks used in the capacity outlook models is highest at the start of the forecast period and may reduce through the horizon to reduce the problem complexity. The exact number of blocks at any stage may change depending on the modelling purpose and need for finer granularity.

Figure 9 Example representation of a load duration curve partitioned into five load blocks



To ensure supply capacity adequacy, 10% probability of exceedance (POE) demand curves are used, while operational consumption is modelled on a "sent out" basis (rather than "as generated") to allow the modelling to reflect the potential change in generation auxiliary loads resulting from a changing generation technology mix.

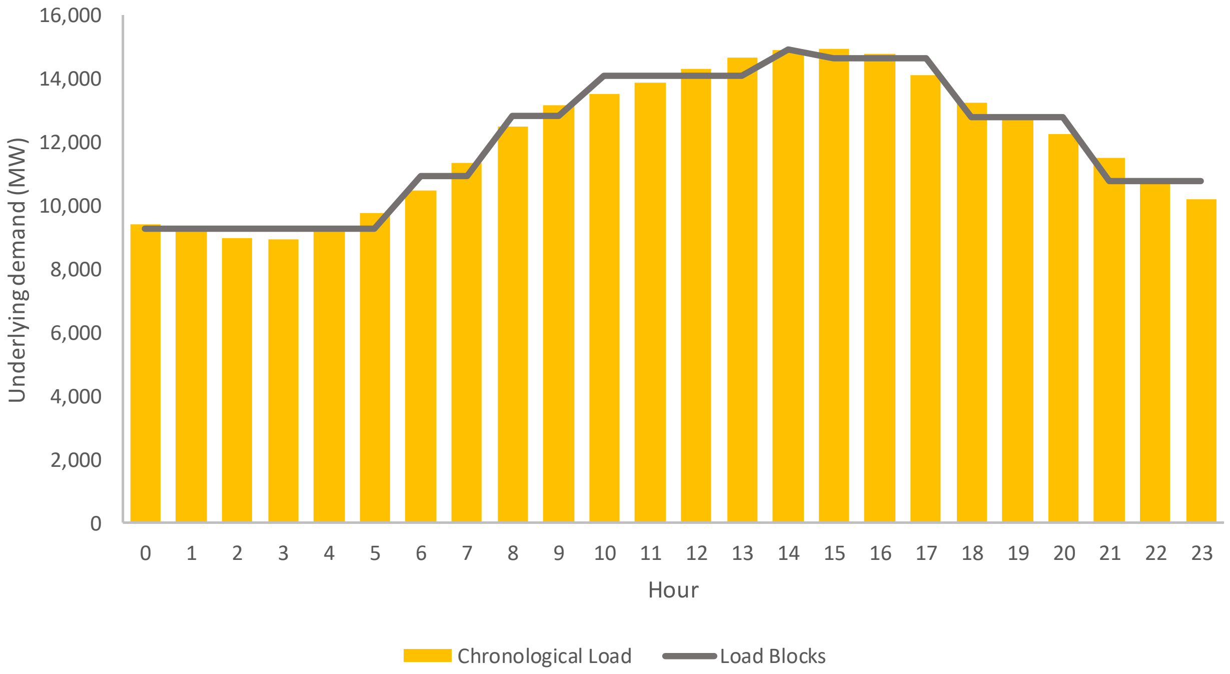
When modelling operational consumption, the hourly distributed PV and large non-scheduled generation trace is first netted off the underlying consumption trace before aggregating into load blocks. This ensures the load blocks represent periods of similar operational demand, which is more relevant for 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 and solar generators' availability, could vary considerably within that same load block. The LDC approach effectively averages these to a single representative availability value, smoothing the hourly intermittency and chronology of wind and utility-scale solar generation. To enhance representation of renewables, particularly solar, time periods with high solar activity are aggregated into the same blocks, whereas night and early morning periods with zero or very low solar activity are kept separate, regardless of the operational demand profile. This materially improves solar representation avoiding a representation of solar generation at night.

AEMO has developed the DLT to compensate for these known yet necessary simplifications. The DLT simulates with aggregations at a daily level in a chronological fashion, thus dramatically increasing the model's granularity. The regional demand time series fed into the DLT is fitted with a step function so that the total number of simulation periods per day is reduced from 24 hours to a small, but still representative, number of load blocks. These load blocks are created using a weighted least-square fit method which performs an optimisation that minimises the sum of squared errors (that is, the square of the difference between the hourly demand fed into the model and the step function approximation). The weighted least-square approach has the advantage of fitting the step function more tightly to the original demand time series – allocating more blocks to higher load periods and less to periods of low demand. The duration of each block can therefore vary depending on how the underlying intervals are grouped together.

Figure 10 provides an example of eight load blocks approximating the forecast hourly underlying demand of New South Wales for a sample day in 2018-19. The methodology produces a load block "trace" that varies to reasonably fit the hourly demand profile. More load blocks are reserved to shoulder and peak periods as a result of the weighted least-square approach, whereas off-peak hours are generally represented by fewer and thus longer blocks. Given the diurnal nature of solar generation, the increased granularity of the model during peak demand periods, particularly during daylight hours, increases the ability of the model to value renewable energy despite resource intermittency.

Figure 10 Example representation of load blocks vs daily chronological demand



Due to computational limitations, the finer chronological resolution of the DLT is not able to model efficiently the length of planning horizon of the IM. Instead, the planning horizon is broken into multiple smaller steps of five to seven years. As such, in any step generation expansion, decisions are made with limited foresight of the planning horizon. Given assumed continued cost reductions of renewable energy technologies and storage technologies, allowing the model to invest in these technologies based on limited future foresight is not likely to result in significant regret cost (unlike build decisions for larger thermal plant, which may be exposed to volume risk as emission constraints become more constraining over time). The shorter planning step is therefore considered an acceptable trade-off for this second optimisation, to better assess the mix of generation technologies and locations that minimises total system costs, including the cost of transmission access and the need for balancing services such as storage. As required, iterations with time-sequential modelling may then lead to refinements of the generation mix produced by the capacity outlook models.

2.3.3 Reserve modelling

The reliability standard, set by the NER, specifies that a region's maximum expected unserved energy (USE) should not exceed 0.002% of energy consumption per year.

Due to the lack of granularity in the IM 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; more detailed assessments of supply adequacy can then be simulated in future modelling stages with more granular models. These minimum capacity reserve levels are generally set equal to the size of the largest generating unit (although may be adjusted over time as the generation mix evolves and if the time-sequential modelling indicates that more (or less) firm capacity needs to be built in a region to avoid reliability standard breaches). The capacity outlook models (both IM and DLT) ensure 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 included:

- 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 farms 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 depends on levels of cloud cover and the time of the peak demand (being before or after sunset).

AEMO computes the wind and solar contribution to peak demand to be the 85th percentile level of expected wind and solar generation across summer or winter peak periods (top 10% of 30-minute trading intervals) for each region in the NEM, averaged across all reference years. AEMO calculates these factors for both existing generators and new entrant wind and solar farms, using historical generation (existing) and forecast renewable generation resources across each region's REZs. Currently, for Queensland and Tasmania there are insufficient existing generators to provide sufficient rigour in determining an existing technology contribution to peak factor. As such, AEMO applies the new entrant contribution to peak factor for both existing and new entrant generator in these regions. For solar generation, a contribution to peak of zero may result if distributed PV generation has shifted the timing of the top 10% of demand intervals sufficiently such that the 85th percentile generation is observed after sunset.

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

2.3.4 New entrant candidates

AEMO generally considers a wide range of available generation technologies as new entrant candidates as specified in the respective assumptions book for each modelling exercise.

To represent variation due to geographical location, AEMO includes distinct options for renewable generators for each of the REZs described in Section 2.1.1. In this way, resource variability and cost differences are captured, and the model reasonably reflects potential geographical diversification within regions. For thermal generation developments, and storage, the candidates are considered on a regional basis, with the specific connection location considered within the time-sequential modelling.

The financial economic viability of each generation technology (determined by its economic and technical parameters in Chapter 4) is one influence on the likelihood of the generator being developed in the model, but equally important is the value provided by generation at the time that it is available. For wind and solar resources, the timing of expected generation (driven by resource generation profiles), the correlation to demand, and the network capacity all influence the economically efficient build decisions.

2.3.5 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 open-cycle gas turbine [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).

To keep computation time manageable, the capacity outlook models employs the second method for all new generation build and retirements as well as transmission augmentations. Where partial outcomes are obtained, the following heuristics and iterations between IM and DLT models are used to resolve these linear decisions into realisable project sizes:

- **Interconnector augmentations** – in the IM model, transmission augmentation options that have many alternative options between the same regions are simplified to a MW capacity in each flow direction. The IM then identifies the optimal timing and size of the transmission need, which is then validated by the DLT model, using "installed" and "not installed" variations to identify the decision of least overall cost. Sensitivities on augmentation timing are also undertaken to identify the optimal timing with respect to system costs. Where only single augmentation options exist, a 50% minimum build threshold of the transmission capacity is used to then trigger DLT validation, as above.

  Transmission augmentation options that are similar in capacity but differ in geographical routes or other considerations may be considered in further detail in the time-sequential modelling and power system modelling considering the influence they may have on transmission constraints, with the insights providing a potential feedback loop between IM-DLT-ST-PSS®E models.

- **Thermal generation investments** – high utilisation thermal generation developments such as coal plant and combined-cycle gas turbines (CCGTs) are optimised by the IM and validated by the DLT model. This validation may involve optimising both with and without the investments (or divestments for retirement decisions) to determine which choice, when converted to a whole development (or retirement), is least-cost. New generators are considered committed only if at least 50% of the notional generator size is built in the IM. For example, if 1.3 CCGTs were built in the IM model, only one CCGT would be modelled in the DLT and subsequently in the time-sequential model. If peaking plant are running hard in the time-sequential model, the decision to round down rather than up in this example may be revisited in subsequent iterations of the DLT.

- **Renewable generation builds** – planting of new renewable generation is allowed to remain continuous, as the size of a wind/solar farm is less rigid than thermal generators. Renewable generators can typically be scaled to any size by adding more turbines/panels. Storage candidates are also treated in this way, unless they relate to specific storage projects, in which case the thermal generation investment criteria are applied.

2.3.6 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"). Build limits associated with generation investments reflect minimum development timeframes for each generation technology, and maximum development levels for generation technologies on at least a regional basis, considering resource and transmission access. Construction lead times for each technology type are reflected in the model by specifying the earliest build date.

For renewable generators in REZs, different layers of constraints are designed to capture both resource potential as well as transmission limitations that could constrain the deliverability of energy produced in certain REZs. The limits represent existing transmission access, and these limits can change either due to:

- Interconnector developments which can improve transmission access to REZs, or
- Explicit transmission developments that increase, at an appropriate cost, transmission access between the NEM transmission network and the REZ.

The capacity outlook models choose to develop transmission only if it is economical to do so, considering the cost and benefit of transmission. In the context of REZs, estimated investment cost of mitigating intra-regional transmission congestions are converted into annualised charges and applied to the model as penalty prices on 'soft' REZ build limit constraints.

2.3.7 Retirement candidates

The capacity outlook model allows for existing generators to retire if the retirement minimises total system costs or if a predefined technical age limit is met (typically up to 50-60 years), or if a generator has advised AEMO of its intention to decommission generating capacity. As generators are now required to inform AEMO of their expected closure year, this is the primary retirement influence.

Retirement of under-utilised existing generation assets may avoid 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.

To manage the size of the mathematical problem, retirement decisions may be optimised linearly in the IM model, thus leading to partial retirements Where partial retirements were obtained a rounding method was applied to determine whether and when a generator is retired. As per interconnector augmentations, any retirement of at least 50% of a unit by the end of the horizon was validated (as a whole unit retirement) by the DLT model.

2.3.8 Operational limits

In long-term planning studies, AEMO applies reasonable assumptions to project future investment needs. It is recognised that the actual limits and constraints that would apply in real-time operations will depend on a range of factors, as the real-world conditions will often vary to some extent from those assumed in planning projections, no matter how reasonable the assumptions applied. The objective of the capacity outlook models in combination is to minimise the capital expenditure and generation production costs over the long-term planning outlook, subject to:

- Ensuring there is sufficient supply to reliably meet demand at the current NEM reliability standard, allowing for inter-regional reserve sharing.
- Meeting current and likely policy objectives.
- Observing physical limitations of the generation plant and transmission system.

- Accounting for any energy constraints on resources.

In the capacity outlook models, the relative coarseness of the models requires that these limitations are applied using simpler representations such as minimum capacity factors to represent technical constraints or likely gas consumption. This helps ensure that relatively inflexible coal-fired generators are not dispatched intermittently, and that likely gas consumption is not under-estimated at this initial stage.

Operational limits included in the capacity outlook models include:

- **Minimum capacity factors** are informed through analysis of historical behaviours, and through endogenous application of the iterative nature of the layered market models. That is, the capacity outlook models are informed initially by applying minimum capacity factors that represent technical, physical constraints of the power station or the power system, and are refined as informed by more detailed time-sequential analysis.
- **Maximum capacity factors** may be applied to power stations to reflect physical constraints, such as fuel constraints, that impact the operations of a power station. As not all limits are public information, analysis of historical operating behaviours may assist in identifying these levels.
- **Minimum stable levels** are defined by the minimum of observed historical performance of generators over the past several years, and the generator performance standards. AEMO maintains a register of generator performance standards[10].
- **Seasonal ratings** are applied to match the planned seasonal availability from generators, informed by the generator's submissions to AEMO's Generator Information survey. The submissions are a key input to AEMO's ESOO modelling and represents a 10-year projection of seasonal availability. For the capacity outlook model, the horizon beyond the initial 10-years repeats the seasonal trend observed in the submitted data.
- **Generator maintenance and unplanned outages** are captured through the derating of each generator, applied to all periods. This approach conservatively applies across all periods, resulting in less capacity available on average and avoiding major supply disruption due to large-generator outages. The time-sequential model assists in validating the forecast reliability of the power system in the capacity outlook model. Transmission maintenance is not captured.

2.3.9 New transmission projects

The capacity outlook model includes network representations of committed, advanced, and proposed transmission augmentations. Projects differ in terms of lead time, investment costs, and transfer capabilities, and are selected based on their ability to reduce total system costs. Some augmentations are dependent on the development (or non-development) of other projects – the models take these interactions into consideration. The projects, and their related capabilities and assumptions, were developed in consultation with the relevant transmission network service providers (TNSPs).

Further to inter-regional augmentations, the capacity outlook models feature soft constraints to represent intra-regional network limitations affecting REZ development. That is, it allows the increased access to generators connected to REZs so long as a financial penalty is paid, equivalent to the reasonable cost of augmentations specific to that REZ, as described in Section 2.3.6 above.

AEMO's engineering assessment methodology[11] describes in greater detail the process for identifying and evaluating transmission development options, for inter- and intra-regional augmentations.

2.3.10 Transmission counterfactuals

For market modelling in relation to the ISP, the Australian Energy Regulator's (AER's) cost benefit analysis (CBA) guidelines require a transmission development counterfactual for each scenario that limits transmission

[10] Generator performance standards – further information available at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Generator-performance-standards.

[11] AEMO. ISP methodology, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

investment. This counterfactual, which is used to identify the overall net market benefit of each candidate development path, examines the generation development response and system costs without the development of both inter-regional and intra-regional transmission corridors.

Modelling inputs for the counterfactual case include:

- **Existing and committed transmission capacity** – only committed transmission projects are considered beyond existing transmission capacity.
- **Existing intra-regional transmission capacity** – no REZ developments beyond existing transmission access is allowed.
- **Renewable generation builds** – planting of new renewable generation in REZs is allowed up to the existing transmission capacity.
  - Because of the potential lack of transmission capacity augmentation in the system under the counterfactual case, it is highly possible that existing and committed transmission capacity for renewable developments is insufficient to meet system and policy requirements. Alternative REZ expansion developments are enabled when spare network capacity becomes available as a result of thermal plant retirements and are included as "shadow REZs" as part of the optimisation.
- **Existing renewable generators** – generators have the option for an additional refurbishment to extend their operational life if it is economic to do so. The cost of extending their operational life was assumed to be the same as building a new generator in a nearby REZ zone.

Counterfactual simulations and net market benefits assessments include the following steps:

1. Identify the candidate development path and calculate the total system cost.
2. Identify generation developments and total system cost for a counterfactual.
3. Determine net market benefits of the candidate development path, by comparing total system costs (candidate development path against counterfactual case).

2.3.11 Generic constraints

Inter-temporal constraints

Inter-temporal energy constraints limit the generation production, reflecting energy limits that mean that operational decisions at one point in time affect the availability of the generator to operate in the future. For example, hydroelectric generators with storage facilities are influenced by seasonal or annual water inflows, and the decisions to use stored water throughout the year.

In some instances, energy constraints may be modelled simply, through the use of capacity factor constraints, while in others a generic constraint may be applied. In this case, the capacity outlook model and/or medium-term schedule (see Section 3.4.1) decides on a production schedule throughout the year with 'recycle' constraints to ensure water storages at the end of a simulation period are 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 models are configured with a regional representation of the NEM, and are 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 the capacity outlook models, key transmission limitations are isolated to interconnectors with a single notional defined import and export limit. As the expansion model is regional these limits can influence the ability for adjacent regions to share export capabilities to meet high demand periods. This reserve sharing is defined independently of the notional import and export limit to adequately reflect the prevailing conditions at peak demand periods between regions.

In the real-time 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.

2.3.12 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[12]. For new generator options, a "shadow" generator is chosen based on the connection point of the generation option.

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 Section 2.4.7.

2.4 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 than the capacity outlook model. The time-sequential model optimises electricity dispatch for every hourly or half-hourly interval in the modelled horizon, and includes Monte Carlo simulation[13] 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 and the Interim Reliability Measure (IRM)[14].
- Feasibility of the generation and transmission outlook when operating conditions and network limitations are modelled.
- An indication of where possible congestions points may exist and how network augmentations would be beneficial in alleviating network issues.
- Generation mix and fuel offtake.
- Cost benefit analysis/network augmentation benefits.
- Impact of weather variability on dispatch outcomes.
- Unplanned generation outages.
- Number of synchronous generators online.
- Assessment of system strength, inertia, and plant ramping characteristics.

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

[13] The Monte Carlo approach simulates the model iteratively, taking into account random events to ensure that the result is statistically robust. See Section 5.1.

[14] The IRM, agreed to at the March 2020 COAG Energy Council, seeks to ensure expected USE is no more than 0.0006% in any region in any financial year. It is intended to supplement the existing reliability standard for a limited period of time by allowing the Retailer Reliability Obligation (RRO) to be triggered by a forecast exceedance of the IRM, and allowing AEMO to procure reserves if the ESOO reports that this measure is expected to be exceeded. This change has been made through the Draft National Electricity Amendment Rule 2020, clause 3.9.3C.

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

2.4.1 Simulation phases

The time-sequential model comprises three interdependent phases that operate in sequence. Designed to better model medium-term to short-term market and power system operation, these phases are:

- Projected Assessment of System Adequacy (PASA) – this phase determines the generator units' maintenance schedule while optimising capacity reserves 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, that is, 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 or half-hourly generation dispatch to meet consumption while observing power system constraints and chronology of demand and variable generation. This phase can use a Monte Carlo mathematical approach to capture the impact of generator forced outages on market outcomes.

2.4.2 Short-term 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 models, or a combination throughout the outlook period, depending on the purpose of the modelling:

- Short Run Marginal Cost (SRMC) model – the simplest dispatch model, which represents perfect competition. This model assumes that all available generation capacities are bid in at each unit's SRMC. This model produces insights that may not, therefore, appropriately reflect realistic market dispatch. Depending on the type of assessment carried out, this model features different degrees of complexity. AEMO distinguishes between two type of SRMC models:
  - <u>SRMC with no unit commitment</u>: this model uses a linear solve and is primarily used to validate network constraints and for reliability assessments. The technical envelope of each generator is captured broadly within the limits of linear programming so that only ramp rates, simple heat rates, and other continuous variables are modelled.
  - <u>SRMC with unit commitment</u>: this model overlays the pure SRMC algorithm with additional technical limitations at unit level as well as system security constraints thus requiring a mixed integer solve. This model is used to carry out cost benefit analysis and to produce insights on future operability and security of the system.
- Bidding behaviour model – this model uses historical analysis of actual bidding data and back-cast approaches for the purposes of calibrating generator bids, rather than costs, that determine the generator dispatch outcomes. The historical bidding analysis captures current market dynamics such as contract and retail positions of portfolios by ensuring that modelled generator bids broadly replicate dispatch preferences of generators and portfolios submitted in each generator's actual historical bids. Portfolio outage management (by adjusting bids at times of generator outages to maintain portfolio positions) is considered for some large generation portfolios. In the short term these dynamics are assumed to stay relatively unchanged, however the evolution in the energy mix in the medium to long term may reduce the accuracy of this approach beyond the next decade.
- Nash-Cournot model – used to study the modelled generators' production by dynamically changing generators bids such that their profit is maximised, given assumptions regarding costs and contract

positions. The modelled generator may sacrifice cleared generation volumes in exchange for price increases and higher revenue if in so doing it increases the resulting price received and therefore maximises profit.

2.4.3 Unit commitment

Solving a unit commitment problem involves determining which generating units to switch on/off, and for how long, over a given horizon. Apart from the marginal cost of generation, optimal constrained unit commitment problems also include technical limitations such as minimum stable levels for operation, and minimum up time and down times. Start-up and shut-down cost profiles may also be considered to solve for an economically optimal and feasible dispatch.

Unit commitment problems are computationally complex as they involve making integer/binary decisions subject to intertemporal constraints. Complexity is balanced by solving the study period in multiple chronological steps. AEMO's approach involves optimising decisions over an outlook of 24 hours. To ensure optimality, an additional forward-looking period with a less granular resolution is modelled to inform unit commitment decisions towards the end of each step. This way the optimisation is able to "look-ahead" and know that it might be better to keep a unit online overnight at low generation levels, even when making a loss, to avoid the cost of restarting it the next day and to be available during high price periods that might occur in the first hours of the morning.

AEMO models in detail unit commitment constraints at unit level under SRMC assumptions, although the technical operating limits of each generator are broadly captured across the entire suite of time-sequential models.

It should be noted that unit commitment optimisation and minimum stable levels are not strictly modelled for peaking plant when using an hourly or half-hourly model resolution and are therefore not included in the market model. These units can start up to operate for minutes rather than hours, and it would not be appropriate to impose a constraint in the market model that forces them to remain operating at their technical minimum stable level for an entire hour if dispatched.

These peaking units also do not materially impact the annual gas consumption that would need to be reflected in the gas-electricity integrated market model. Therefore, to maximise the efficiency of the market model and to ease computational burden, unit commitment decisions are only imposed in the time-sequential modelling on generators that:

- Are required to be on-line for system security purposes.
- Are involved in unit commitment constraints to emulate a definite network requirement.
- Are likely to materially impact the level of annual gas consumption.
- Have limited flexibility to start up and shut down (such as coal-fired generation, CCGTs, and gas-fired steam turbines [GFSTs]).

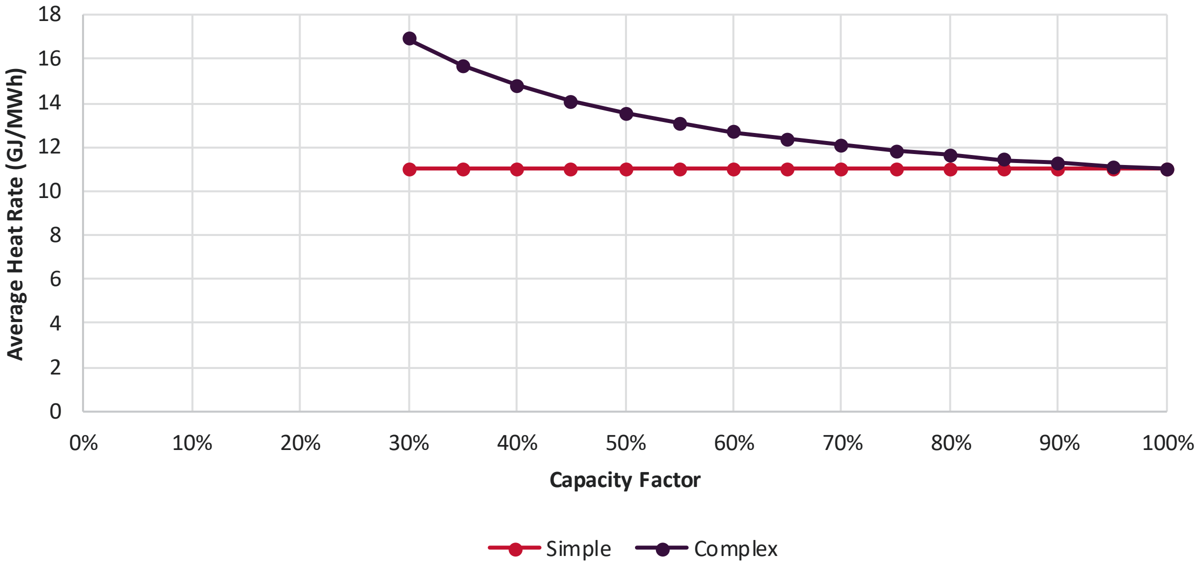
Modelling combined cycle gas turbines

AEMO's short-term models in detail CCGTs and captures explicitly heat output/input dynamics between the gas turbine (GT) units and the steam turbine (ST). To render realistic operation regimes and correctly consider the relative inflexibility of CCGTs, AEMO enforces constraints, where applicable, to ensure the GTs and ST unit commitment decisions are linked together. In instances where the CCGTs are by design equipped with a bypass stack upstream of the ST (for example, Darling Downs Power Station), these constraints are omitted so the model has the option to run the asset more flexibly in open-cycle mode.

2.4.4 Fuel consumption and heat rate modelling

Generators consume fuel according to their heat rate function, expressed in units of GJ/MWh. Simple heat rate curves have constant average heat rate and can be modelled without the use of integer variables. However, in applying the heat rate at maximum output to the entire range of output, they overestimate efficiency at low operation level. This affects dispatch and fuel offtake projections, particularly for CCGTs and GFSTs. To improve its modelling, AEMO has implemented affine-linear marginal heat rates referred to as "complex heat rates" (Figure 11).

Figure 11 Example of heat rates – simple versus complex



AEMO estimates complex heat rate curves for each turbine generator modelled. The complex heat rate curves feature a constant marginal heat rate but variable average heat rate, modelling a no-load component and the dependency between fuel-efficiency and load. The heat rate curves were derived from input/output curves of new entrants' generic technologies provided by GHD[15]. The two components were adjusted to align with the assumed heat rate at maximum output for each station while maintaining the shape of the heat rate curve for that technology.

Where generic curves were not available, publicly available historical information from both the Gas Bulletin Board and AEMO's Market Management System data were used to derive the gas usage as a function of hours online and electrical output data for each station. A linear regression model was used to estimate the no-load heat input and the marginal heat rate.

While complex curves were estimated for all turbine generators modelled, AEMO continues to use simple heat rate curves[16] for a subset of small, modular units (listed below) for which a simplified approach to heat rate modelling was deemed reasonable given the materiality to modelling objectives:

- Smithfield
- Barcaldine
- Roma
- Yarwun
- Hallett
- Barker Inlet
- Bell Bay.

[15] GHD, "AEMO revised, 2018-19 Costs and Technical Parameter", available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/InputsAssumptions-Methodologies/2019/GHD-AEMO-revised---2018-19-Costs_and_Technical_Parameter.xls.

[16] PLEXOS unit commitment optimality for these generators is set to linear and thus their heat rate functions are approximated by the average heat rate at their max capacity.

Detailed representation of the efficiency curves is computationally expensive and only applied to the SRMC models with unit commitment which are used to inform cost benefits analysis and specific operational insights. Other time-sequential models focusing on competition dynamics and or reliability assessments, where fuel consumption is not a key variable, employ simple heat rates for computational reasons.

Complex heat rates do not explicitly capture the fuel consumed in starting a plant from off-line status to its minimum stable level. This is captured in the start-up cost profiles which also include costs of labour, water, and chemicals incurred by a plant when synchronising to the grid.

2.4.5 Large-scale storage operation optimisation method

Large-scale storage operation (battery, hydro, pumped hydro, or any other dispatchable storage) is expected to generate opportunistically based on price and the efficiency loss associated with charging and discharging the storage. For example, in a future energy mix with high renewable penetration, variable renewable energy may be smoothed by effectively charging storages when high renewable energy volumes are available, for later discharge when renewable energy is low.

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 large-scale reservoirs that are part of cascading systems. This is further refined by the third phase of the time-sequential simulation, where network limitations are included on a more granular time scale. This phase has limited foresight, ranging from one day to a week depending on the model configuration and optimises operation of most storage systems, including batteries and closed pumped hydro. The latest assumptions can be found in AEMO's planning and forecasting inputs, assumptions and methodologies data set[17].

2.4.6 Modelling of regional system strength and security constraints

The modelling of a system strength or security requirement ensures the projected generation outlook can withstand a credible fault and loss of a synchronous unit, at different non-synchronous generation levels.

The time-sequential model implements these constraints where applicable by ensuring a certain number of synchronous thermal units are online at any time within a region – as directed by the system strength requirements. The modelled formulation of unit combinations is based on planning assumptions rather than operational advice.

System strength constraints are explicitly modelled for the South Australian region to address the identified system strength gap[18]. The time-sequential model applies unit commitment constraints within this region to a number of South Australian synchronous plants to ensure that the system strength requirements are met. These requirements are adjusted as the operational environment in South Australia evolves.

For system normal:

- The minimum requirement is to ensure that at least five units out of Osborne, Pelican Point CCGT1 and 2, Quarantine unit 5, and Torrens Island A1-A4, B1-B4 remain online until the synchronous condensers are commissioned in April 2021.

Following commissioning of the synchronous condensers:

- The minimum requirement in South Australia drops to two synchronous units online, mainly for system security reasons rather than to address the system strength shortfall. This requirement remains until the commissioning of Project EnergyConnect (if built).

Following the commissioning of Project EnergyConnect (if built):

- The system strength unit commitment constraints are revoked.

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[17] AEMO. Inputs, assumptions and methodologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

[18] AEMO. System strength requirements methodology. System strength requirements and fault level shortfalls; July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

2.4.7 Inter-regional loss model

In the time-sequential model, losses on notional interconnectors are modelled using the MLF equations defined in the List of Regional Boundaries and Marginal Loss Factors report[19]. 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 MLFs, as described in Proportioning of Inter-Regional Losses to Regions[20]. Proportioning factors are given in the annual List of Regional Boundaries and Marginal Loss Factors report.

Future augmentation options between regions not currently interconnected will have an estimated proportioning factor assigned to each region.

2.5 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, a 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 or new supply source to restore supply.

More information on the detailed gas supply and demand methodologies are available in AEMO's GSOO publication materials[21].

2.6 Engineering assessment

The technical and cost input data provided to the market modelling and outcomes of market modelling are investigated through power system analysis to ensure system reliability and operability needs have been met.

The engineering assessment has three main steps:

- Development of transmission options.
- Assessment and selection of transmission options.
- Power system analysis.

[19] AEMO, 1 April 2020, at http://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Security-and-reliability/Loss-factor-and-regional-boundaries.

[20] AEMO, June 2016, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

[21] AEMO, Gas Statement of Opportunities methodology – supply adequacy, at https://www.aemo.com.au/Gas/National-planning-and-forecasting/Gas-Statement-of-Opportunities.

The generation and transmission expansion options identified in the engineering analysis and by the capacity outlook model are assessed and the most technical and economical transmission options are selected.

The inputs into the time-sequential model are provided following a series of power system analyses where thermal and stability constraint equations result in optimal generator dispatch outcomes. System strength and security constraints across the regions may be captured in the network constraints and are only explicitly included in the market modelling as required (see Section 2.4.6).

For more information on the engineering assessment, formulation of network constraints, and system strength and security concerns, refer to the 2020 ISP Appendix 9, ISP Methodology[22].

[22] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

3. Demand assumptions

3.1 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 be measured in two ways:

- The amount of energy that is consumed over the course of time.
- The amount of power that is consumed 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 incorporates regional electricity and gas demand projections within the scenarios defined for planning and forecasting activities, including the ISP, ESOO and GSOO. The electricity forecasts present 10%, 50% and 90% POE MD and consumption projections for each NEM region up to 20 years into the future. These projections are extended to a longer range for use in all long-term 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 90% POE MD forecast is not considered in assessing gas and electricity infrastructure requirements for the ISP.

The electricity forecasts may be represented as operational or underlying, "sent out" or "as generated"; typically, they are represented as 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 distributed PV (that is, operational demand decreases as distributed PV generation increases).
- "Sent out" refers to operational consumption or demand that excludes generator auxiliary load.

AEMO's demand forecasting methodology and current assumptions are detailed in the Demand Forecasting Methodology Information Paper and supplementary materials[23].

3.2 Demand traces

The operational annual consumption, maximum demand and minimum demand forecasts are converted into half-hourly demand traces for each region for use in the capacity outlook models 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 use

[23] AEMO, 2018, Electricity Demand Forecasting Methodology Information Paper, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2018/Electricity-Demand-Forecasting-Methodology-Information-Paper.pdf.

of historical reference years is internally consistent with capturing weather variability for renewable generation, hydro inflows, and network ratings.

The process used to develop the demand traces is detailed in the Demand Forecasting Methodology Information Paper.

3.2.1 Electric vehicles and small-scale battery storage

Electric vehicles (EVs) are expected to become a new source of electricity demand within the typical timeframes of AEMO's long-term planning, and may provide the capability to also discharge to offset consumption at times of peak demand with implementation of vehicle-to-home discharging. Charging of EVs will add load to the power system, and the timing of this will depend on the available infrastructure to drivers, driving behaviours and distances, and the availability of tariffs that may incentivise charging structures that minimise grid disruption and costs.

Small-scale batteries charge and discharge typically to manage household loads, however the development and deployment of battery aggregators will enable the development of virtual power plants (VPPs). AEMO models aggregated distributed storage systems as operating to meet system peaks (rather than household demand). These VPPs are assumed to operate with day-ahead foresight and optimise charge and discharge behaviours to minimise total system costs. These batteries could also be operated to offset the risk of USE. Currently, no limitation is placed on the frequency of aggregators to interact with these VPP-enabled ESS devices.

Non-aggregated battery systems installed by homeowners are assumed to operate to minimise costs for supply paid for that household. This is much more passive behaviour, and may not discharge optimally with market requirements, instead following default battery algorithms to discharge when stored energy is available to meet demand that exceeds on-site generation through distributed PV systems.

3.2.2 Demand side participation

Demand-side participation (DSP) typically appears as short-term curtailment of non-scheduled load or the provision of unscheduled generation in respect to the demand for, or price of, electricity. It may also occur in accordance with a contractual arrangement between a Participant and a customer. It is often provided by industrial customers that have large, yet interruptible, loads. The DSP projections represent the most likely amount of response, at defined wholesale price bands, and are assumed 100% reliable when applied to market modelling.

Submissions to AEMO's DSP data portal[24] assist in developing these DSP projections.

3.3 Gas demand forecasts

Gas demand forecasts are produced for four customer categories:

- Mass market (residential and commercial) customers.
- Large industrial facilities.
- Gas-powered generation of electricity (GPG).
- Liquefied natural gas (LNG) export facilities.

Detailed forecasts are developed by AEMO each year and published in the GSOO. Detailed descriptions of daily gas demand development are presented in the GSOO methodology document[25].

[24] AEMO. Demand Side Participation Information Guidelines, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Demand-Side-Participation-Information-Guidelines.

[25] AEMO. Gas Statement of Opportunities, at http://aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/Gas-Demand-Forecasting-Methodology.pdf.

4. Supply assumptions

4.1 Energy production facilities

4.1.1 Electricity generation parameters

All market simulation results are influenced by the generator's technical parameters used in the models. Table 4 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, details of these parameters are presented in the ISP assumptions book[26].

Table 4 Summary of generator technical parameters

Parameter	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 applied
Minimum generation level	Technical minimum stable loading	Forces units to generate at a certain level	Capacity outlook model: Must-run generation levels on coal and some GPG. Time-sequential model: Must-run on coal. GPG minimum stable levels in unit-commitment models.
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 generators Contribution to peak demand for variable generators
Ramp rate	Rate at which generation can increase or decrease output	May constrain generation output	Constant limit applied minimum stable level to maximum capacity
Minimum uptime/downtime	Technical limitation on the length of time thermal generators must remain online/offline	Impacts the unit commitment schedule	Number of hours online/offline is constrained
Start cost profiles	Operations and maintenance costs associated with start of a unit	Impacts the unit commitment schedule of CCGTs	Cost of unit start is based on the active cooling state
Auxiliary load	Station load that supports operation of the power station	Lessens the generation supplied to the operational consumption	Modelled as a percentage of 'as gen' production

[26] AEMO. ISP Assumptions, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan.

Parameter	Description	Relevance	Modelling methodology
Heat rate	Efficiency of converting the chemical or potential energy to electrical energy	Cost of electricity production and amount of fuel consumed	No-load and marginal heat-rates applied
Emission rate	CO2-e production for each MWh of electric energy produce.	Achieving targeted carbon budgets	Constant emission production rate
Inflow rates	Historical reservoir inflow represented as inflow rates	Hydroelectric generators availability depends on dam levels	Sequences based on historical data. Annual, monthly or daily sequences are used depending on modelling approach
Hydro unit efficiency	Efficiency of converting flow (cumec) into power (MW)	Relates hydro inflows to energy available	Constant conversion rates applied
Storage efficiency	Energy lost to friction and resistance in pumped hydro and battery storage	Slightly more energy is required by storage than can be drawn out again	Efficiency rates applied on pumping or charging
Outage rates	Historical maintenance and unplanned failure rates describe the probability of capacity derating of each technology	Further lowers the regional available capacity to serve operational consumption	Maintenance rates and probability of (full and partial) failure and de-rated capacities
Marginal loss factor	Impact of network losses on spot prices is represented as loss factors.	Incentivise generators that lowers network losses and penalise those that increase it	Factor for each connection point in the NEM

The generation economic parameters outlined in Table 5 influence the results of both the capacity outlook model and the time-sequential model.

Table 5 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

Parameters	Description	Relevance	Modelling methodology
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
Bid profiles	Energy market offer stacks	For realistic pricing, generation tranches are offered above or below SRMC	(ST bidding model only) Mark-up quantities and prices relative to SRMC
Conditional re-bidding	Energy market offers under outage conditions	Generation companies will alter bids for some units when other units are on outage	(ST bidding model only) Adjustments to mark-ups conditional on number of units out at stations in same portfolio
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 for each of these data sets comes from a variety of sources. AEMO's current assumptions are collated and reported in the 2019 Inputs and Assumptions Workbook, available as part of AEMO's planning and forecasting inputs, assumptions and methodologies data set[27].

Marginal loss factors

MLFs represent the incremental loss incurred for an incremental unit of power supplied at connection points and determines the marginal impact of losses on spot prices. It incentivises generator development and operation to locations that lowers network losses and penalises those the increase losses.

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[28].

4.1.2 Gas production facilities

The gas supply model contains a representation of approximately 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 model also contains LNG import facilities as a build option to address any potential gas shortfalls.

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

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

For further information, please refer to the latest Gas Supply Adequacy Methodology Information Paper[29].

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[27] AEMO. Inputs, assumptions and methodologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

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

[29] AEMO, 2019 Gas Supply Adequacy Methodology Information Paper, at https://www.aemo.com.au/-/media/Files/Gas/National_Planning_and_Forecasting/GSOO/2019/Gas-Supply-Adequacy-Methodology.pdf.

4.2 Energy project commitment criteria

New committed or anticipated generation or gas production projects 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 zones. Each technology will take on specific values for parameters of importance such as thermal efficiency, emission characteristics, minimum stable generation levels, standard capacities, build costs, and appropriate earliest dates for which the technology is considered current.[30] Each location imposes different fuel costs that reflect the fuel availability and transport requirements applicable to each zone. Committed (and for ISP, anticipated) projects are included in the capacity outlook and time-sequential models.

The time-sequential model uses the generation and transmission outlooks 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.

Electricity projects

New generation and transmission projects are assessed against five different commitment categories, described in Table 6, that must be assessed to determine the level of commitment.

Table 6 Commitment category descriptions

Category	Criteria
Site	The project proponent has purchased / settled / acquired (or commenced legal proceedings to purchase / settle / acquire) land for the construction of the project.
Major components	Contracts for the supply and construction of major plant or equipment components (such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment) have been finalised and executed, including any provisions for cancellation payments.
Planning and approvals	The proponent has obtained all required planning consents, construction approvals, connection contracts (including approval of proposed negotiated Generator Performance Standards from AEMO under clause 5.3.4A of the National Electricity Rules), and licences, including completion and acceptance of any necessary environmental impact statements.
Finance	The financing arrangements for the proposal, including any debt plans, must have been concluded and contracts executed.
Date	Construction of the proposal must either have commenced or a firm commencement date must have been set. Commercial use date for full operation must have been set.

Depending on the number of these categories that have been satisfied, the commitment level is determined as shown in Table 7.

A commitment category is deemed to be satisfied if all associated questions have been answered in the positive, with the category represented as green. An amber status reflects that some, but not all, of the questions have been answered in the positive. A status of red means that no questions within that category were answered positive.

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

Table 7 Minimum commitment criteria

Category	Committed	Committed *		Advanced		Maturing	Emerging	Publicly announced
Site	🟢	🟢	🟢	🟢	🟢	🟢	🔴	🔴
Components	🟢	🟡	🟢	🟡	🟢	🔴	🔴	🔴
Planning	🟢	🟢	🟡	🟢	🟡	🟡	🔴	🔴
Finance	🟢	🟢	🟢	🟢	🟢	🟡	🟡	🔴
Date	🟢	🟢	🟢	🟢	🟢	🔴	🔴	🔴

Table 8 provides a description for each of these commitment categories. Anticipated projects, defined by the AER[31], are ones not yet committed based on above criteria, but are in the process of meeting at least three of the criteria. Maturing and advanced projects are treated as anticipated projects based on this definition.

Table 8 Commitment category descriptions

Commitment status	Description
Committed	Projects that will proceed, with known timing, satisfying all five of the commitment criteria. That is, all categories are green.
Committed*	Projects that qualify as "Advanced" and where construction or installation has also commenced. Typically, Committed* projects are included in sensitivity analysis for MLF calculations and in the base case for reliability assessments.
Advanced	Projects that are highly likely to proceed, satisfying Site, Finance and Date criteria plus either Planning or Components criteria. Progress towards meeting the final criteria is also evidenced.
Maturing	Projects that have progressed with site, planning applications, and finance arrangements, but not to the point that they can be classified as advanced. Maturing projects may be explicitly included in scenario analysis to assess future reliability or market impacts and are tested for economic efficiency in capacity outlook modelling.
Emerging	Projects with financing arrangements, but site/planning approvals/construction is uncertain, and development is strongly subject to changes in policy or commercial environment. These projects may be explicitly included in scenario analysis to assess future market impacts, and are tested for economic efficiency in capacity outlook modelling. However, a higher weighted average cost of capital will be assumed to reflect greater development uncertainty compared to proposed projects.
Publicly announced	These projects have been announced publicly, but do not yet have any finance arrangements in place. Costs and capabilities of these projects are developed using recently-completed projects and projections of cost components such as raw material supply and labour.

Committed and anticipated new generation projects are 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. Anticipated generation projects are included, with fixed timing and without build costs, in all ISP modelling including the counterfactual.

[31] AER, Draft RIT–T, May 2020.

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[32].

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 projects

AEMO is working with industry to clarify project definitions for gas projects to create a set of commitment criteria similar to electricity projects. In the interim, AEMO applies the following definitions for production and transmission projects:

- **Committed projects** – all necessary approvals have been obtained and implementation is ready to commence or is underway. Committed projects consist of 2P reserves[33] (developed and undeveloped).
- **Anticipated projects** – developers consider the project to be justified on the basis of a reasonable forecast of commercial conditions at the time of reporting, and reasonable expectations that all necessary approvals (such as regulatory approvals) will be obtained and final investment decisions are made. Anticipated projects typically include 2P undeveloped reserves and selected 2C resources[34].
- **Uncertain projects** – these projects are more uncertain or at early stages of development. Uncertain projects include uncertain 2C contingent and prospective resources that are accessible by existing pipeline and processing infrastructure.

New gas projects are sourced from AEMO's annual GSOO survey, using the latest information available when modelling begins. Committed projects are included with fixed timing and without build costs, in all gas modelling. Anticipated, uncertain and generic projects are included as candidates in the capacity outlook model or included as fixed sensitivities in the GSOO modelling.

4.3 Renewable resources

4.3.1 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 fuel source availability, wind farm generation is limited by the wind speed, and solar farms are limited by solar irradiance.

AEMO considers a range of requirements for the selection of preferred REZs. This section presents the methodology applied to determine resource quality, potential wind and solar generation capacity, transmission investment to develop REZs, projected network losses and diversity of renewable generation within the region and across REZs.

4.3.2 Renewable resource quality

The resource quality for potential REZs is based on mesoscale wind flow modelling at a height of 150 m above ground level (typical wind turbine height), while Global Horizontal Irradiance (GHI) and Direct Normal

[33] Gas reserves and resources are categorised according to the level of technical and commercial uncertainty associated with developing them. Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations and proved and probable (2P) is considered the best estimate of commercially recoverable reserves.

[34] Contingent resources are not yet considered commercially viable, and 2C is considered the best estimate of those sub-commercial resources.

Irradiance (DNI) data from the Bureau of Meteorology (BOM) were used to assess solar resource quality. This information has been provided by DNV-GL.

AEMO represents the wind resource available in each REZ in two tranches, to represent the resource quality differences that are observed in the mesoscale data. The first tranche represents the highest quality wind resource, and maximum build limits are applied given the land area identified through the mesoscale data at a 5km resolution (the granularity of the mesoscale data).

The second tranche represents the remaining good quality resource – above the average of the REZ, as wind development would be targeted at only the better wind sites. Build limits also apply for this second tranche.

Wind generation profiles

The DNV-GL mesoscale data provides wind measurements at a granularity of 5 km. AEMO's representation of the renewable resource must sample from this dataset (or historical measurements for existing wind farms) to produce reasonable representations of wind resources.

AEMO represents the wind resource available in each REZ in two tranches, to represent the resource quality differences that are observed in the mesoscale data. The first tranche represents the highest quality wind resource (top 5%), and maximum build limits are applied given the land area identified through the mesoscale data at a 5 km resolution (the granularity of the mesoscale data).

The second tranche represents the remaining good quality resource – above the average of the REZ, as wind development would be targeted at only the better wind sites (sites which are in the top 20% of locations, not including the first tranche resources). Build limits also apply for this second tranche.

Where possible, generation traces for existing wind farms are based on historical output for the period that they have been in full service. For earlier reference years (prior to commissioning), AEMO applies a power curve derived from metered output to mesoscale data at the wind farm's location (the nearest 5 km grid location) to construct the generation profile. For new wind farms, AEMO applies a reference wind-turbine power curve to the selected REZ tranche 5 km location.

Solar generation profiles

For solar generation, AEMO considers a collection of connection points within each REZ as potential network connection locations. Using irradiance data derived from satellite imagery[35] and the System Advisor Model (SAM)[36], AEMO develops a solar resource trace for each location. Air temperature measurements and wind speed data is captured within the SAM model to capture the effects of ambient temperatures on the generation profile, with higher ambient temperatures (adjusted by the cooling effect of wind) de-rating the generation capability of the panels. AEMO uses BOM weather station temperature and wind-speed measurements for this.

Existing and committed solar projects are modelled as either single-axis tracking or fixed flat panels, depending on the technology actually installed. New REZ solar traces are either single-axis tracking (as the dominant solar PV technology) or concentrated solar thermal.

Generation traces for the energy available from existing, committed and potential wind and solar farms are created over the same reference years as the demand traces and hydro inflows. The base traces model what each generator would have produced if it was operating during the reference period and not constrained by the limitations of the network. These base traces are projected into the future as per the demand traces, such that the weather relationships between demand, solar and wind conditions are preserved.

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[35] The 2020 ISP uses this 60-minute irradiance product from the BOM http://www.bom.gov.au/climate/how/newproducts/IDCJAD0111.shtml. The 2020 ESOO uses a 30-minute product from Solcast http://www.solcast.com.

[36] System Advisor Model (SAM) developed by the National Renewable Energy Laboratory (NREL) is a techno-economic model designed to facilitate decision making for the renewable energy industry. More information is available at https://sam.nrel.gov/.

4.3.3 Network capacity and transmission investment

High level network studies are undertaken to identify additional generation which can be accommodated within the existing network. In addition, interconnector expansion options are assessed to identify additional generation that may be enabled by interconnectors developed near or through REZs. The following steps are undertaken:

- Amount of additional generation which can be added within the existing transmission network capability.
- Amount of additional generation which can be added with inter-regional network upgrade options.
- Network expansion to connect REZs to the major transmission network and amount of generation which can be accommodated.
- Cost estimate of transmission network expansion to connect REZs.

The cost estimates to connect each REZ are applied within the capacity outlook models as a linear cost to increase the development potential of each REZ beyond existing transmission hosting capabilities. Expansion of the REZ capacity may then be selected by the capacity outlook models at the determined linear expansion cost. Inter-regional network upgrades also may be selected to increase REZ expansion capacity.

4.3.4 Hydroelectric generation schemes

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales, and Queensland. These schemes are typically modelled with their associated reservoirs and water inflows. For each reservoir, the capacity, initial levels, and the expected inflows considering rainfall variability and climate change 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 schemes.

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.

For the capacity outlook models, some aggregations and simplifications of some hydro schemes may be used if it is deemed not material to the overall objective of the modelling, and if it simplifies the problem size sufficiently to warrant the simplification.

Generation constrained

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

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 9 identifies how schemes or power stations are allocated across these storages and provides an indication of the energy in storage available.

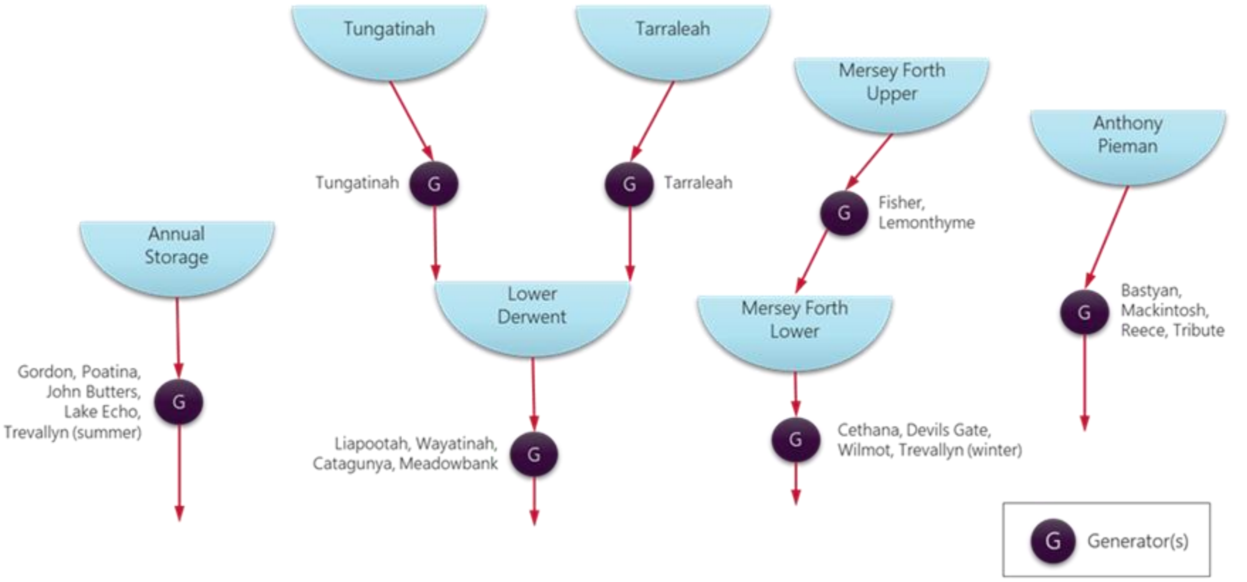
Energy inflow data for each Tasmanian hydro water storage is determined from historical monthly yield information provided by Hydro Tasmania.

Table 9 Storage energy (in GWh) of the three types of generation in Tasmania

Storage type	Energy in storage	Schemes and stations
Long-term	12,000	Gordon, Poatina John Butters, Lake Echo, Trevallyn (summer)
Medium-term	400	Derwent
Run of River	200	Antony Pieman, Mersey Forth, Trevallyn (winter)

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a seven-pond topology designed to better capture different levels of flexibility associated with the different types of storage outlined above (Figure 12).

Figure 12 Hydro Tasmania scheme topology



River chain

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

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

Latest information on the monthly storage inflows used in market modelling studies can be found in the 2019 Inputs and Assumptions Workbook[37].

Since the 2018 ISP, AEMO has improved the modelling detail associated with the Snowy Hydro scheme and proposed Snowy 2.0 project, including updated rainfall inputs as well as a revised generation and pond storage topology. Figure 13 presents a representation of the topology currently modelled.

[37] AEMO. 2019 Inputs and Assumptions Workbook, available as part of AEMO's Planning and Forecasting inputs, assumptions and methodologies, at https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

Figure 13 Snowy Hydro scheme topology

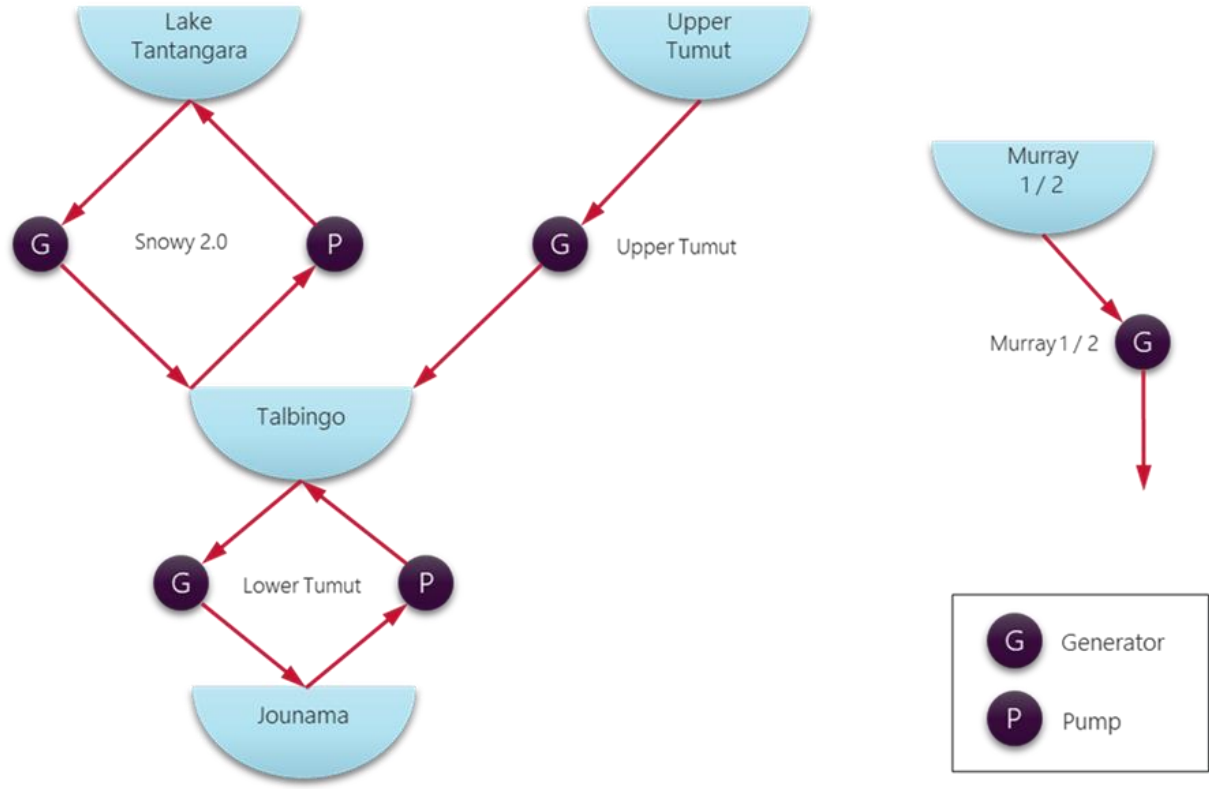
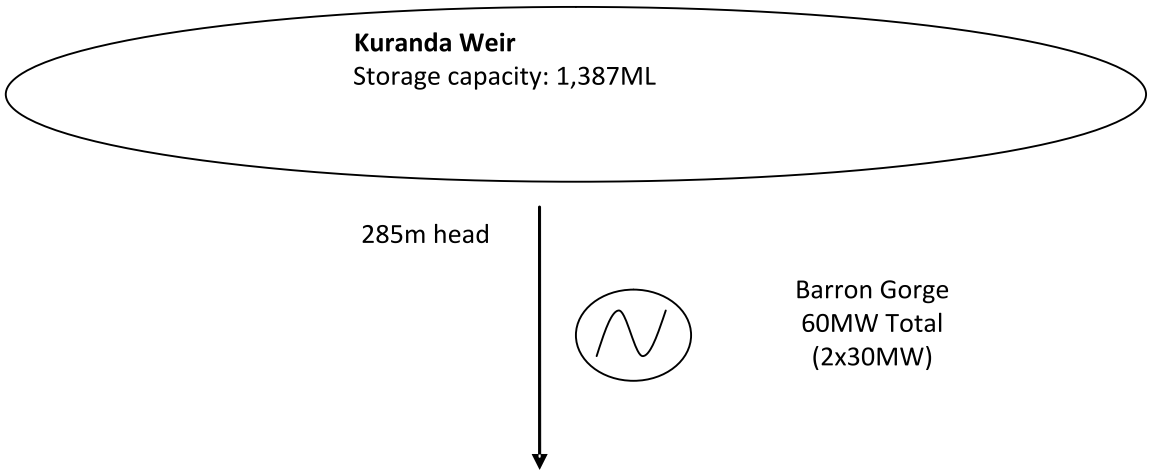


Figure 14 to Figure 22 provide graphic representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units[38].

Figure 14 Barron Gorge power station hydro model



[38] Storage capacities are defined in megalitres (ML).

Figure 15 Blowering power station hydro model

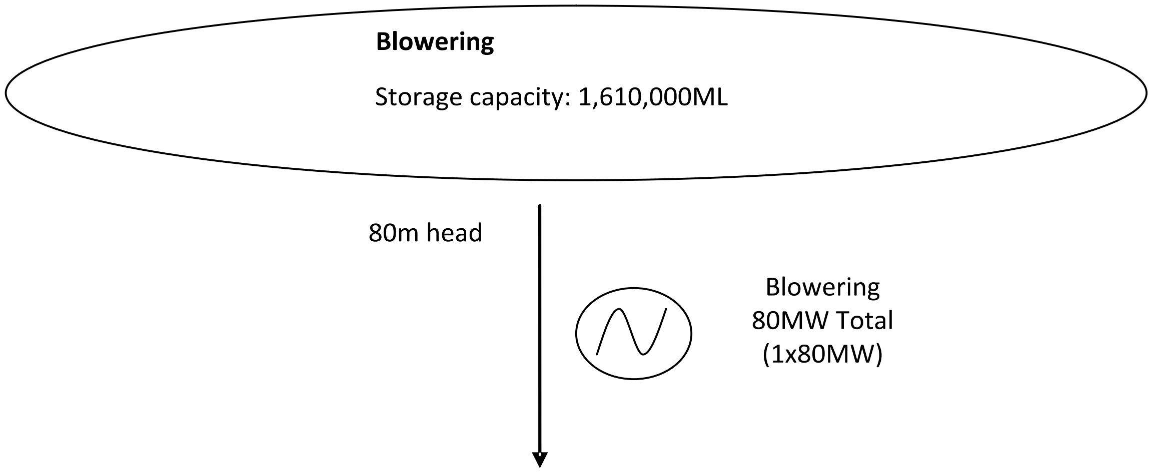


Figure 16 Hume power station hydro model

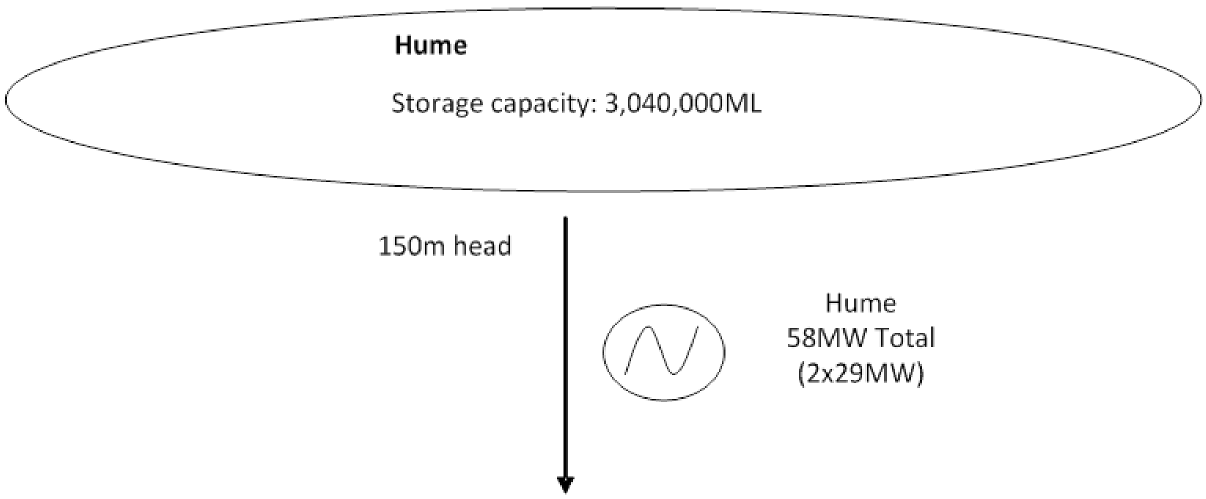


Figure 17 Kareeya power station hydro model

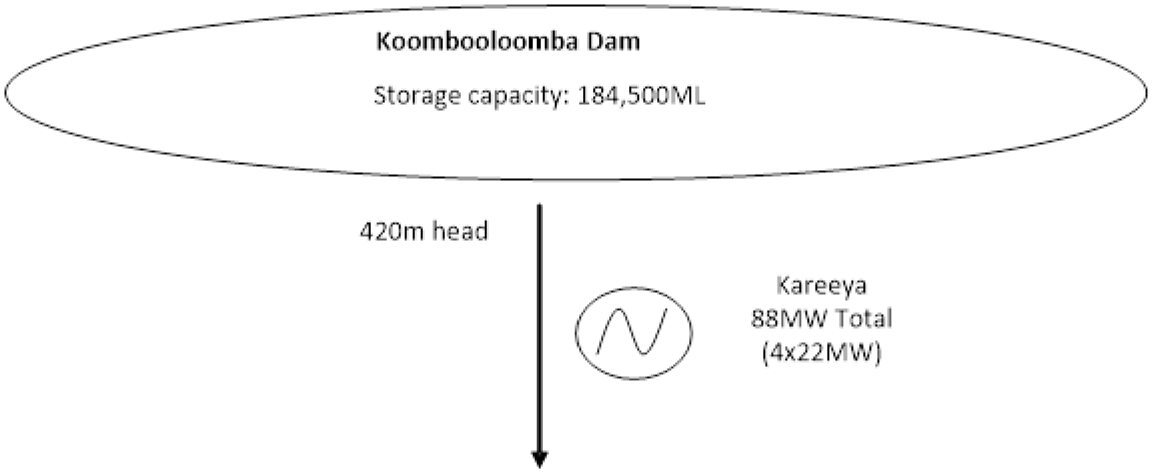


Figure 18 Guthega power station hydro model

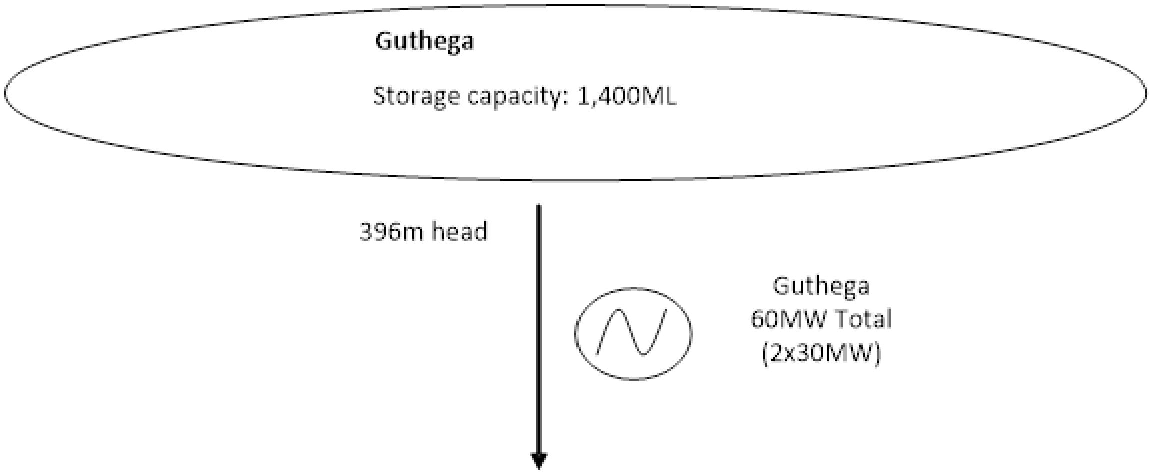
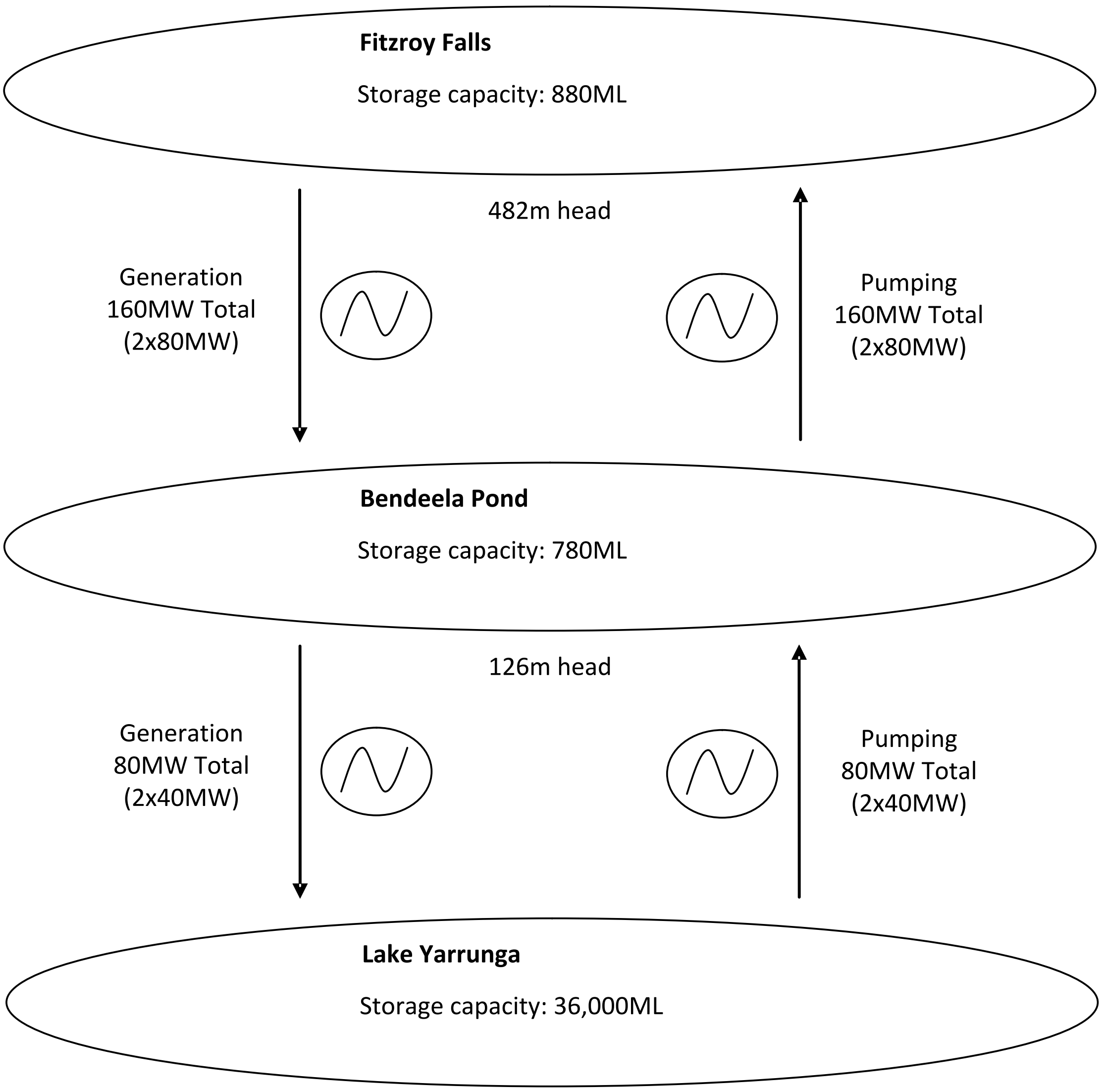


Figure 19 Shoalhaven power station hydro model



Note. Origin Energy has proposed an expansion of the Shoalhaven pumped hydro scheme, increasing the storage capacity of the project. As this project is not yet committed, the representation provided reflects the existing capacity only.

Figure 20 Wivenhoe power station hydro model

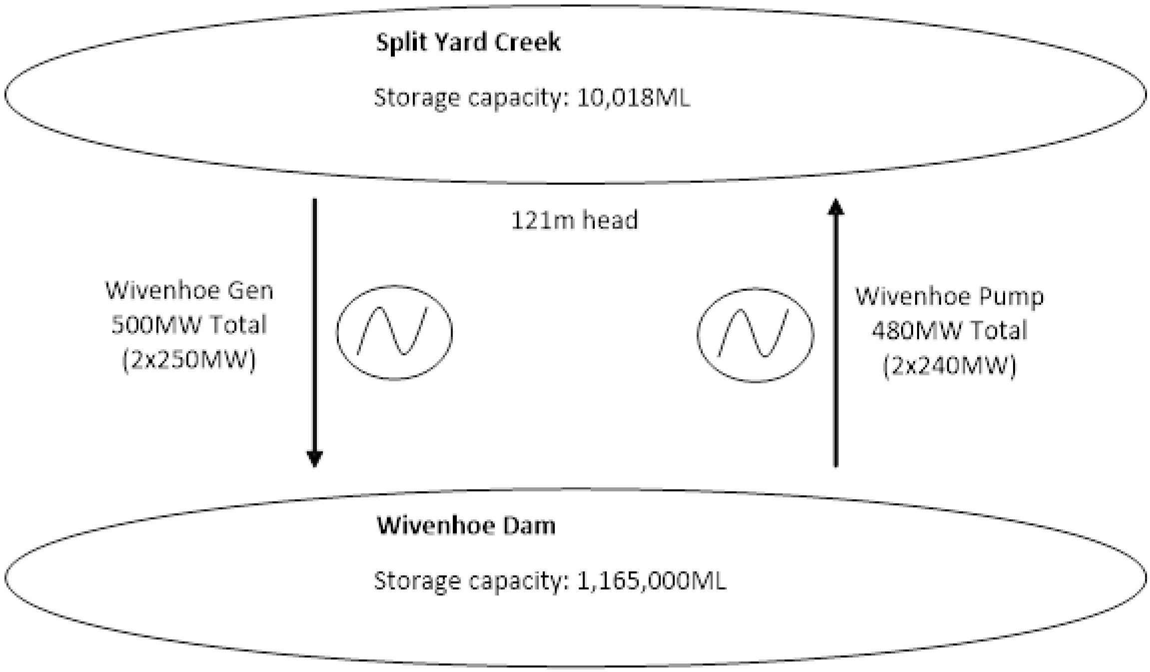


Figure 21 Eildon power station hydro model

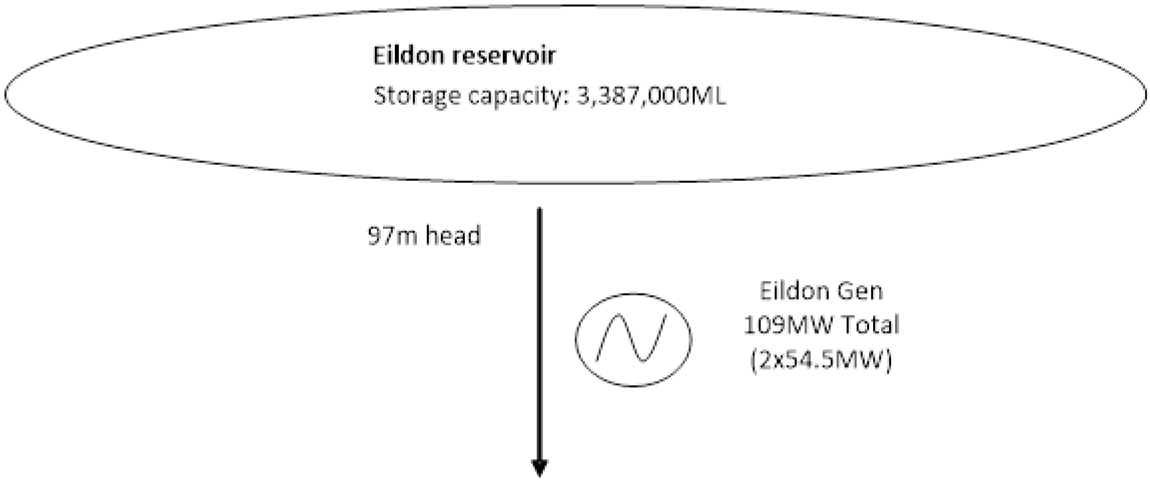
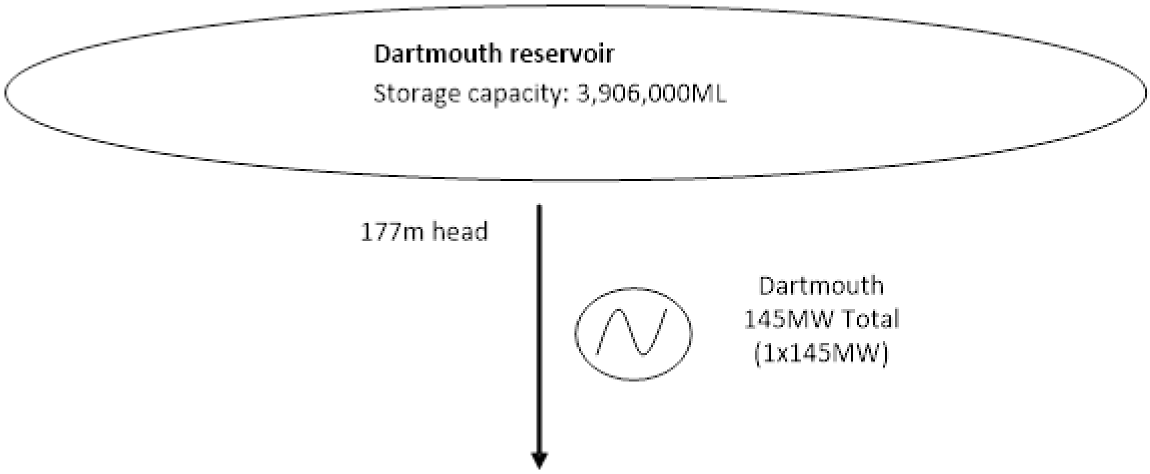


Figure 22 Dartmouth power station hydro model



4.3.5 New pumped hydro schemes

Pumped hydro energy storage (PHES) candidates are modelled as closed systems where the amount of water available to cycle between upper and lower reservoirs is assumed to be constant throughout the technical life of the asset.

AEMO models multiple PHES storage depth options equivalent to 6, 12, 24, and 48 hours. This allows the capacity outlook model to identify a suite of storage candidates across the forecast horizon, addressing evolving challenges that are mitigated by alternative storage duration options.

5. Analysis

5.1 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 demand profile that adheres to specific consumption, minimum demand and maximum demand targets. 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.

The ESOO methodology report[39] is the primary reference for the current methods employed when conducting reliability assessments.

5.2 Market benefits

Some modelling exercises (such as the ISP, a Regulatory Investment Test for Transmission [RIT-T] or the Victorian Annual Planning Report [VAPR]) are designed to determine the benefit to the market delivered by specific network or non-network augmentation projects.

To value any proposed augmentation, detailed costings of the augmentation, and the counterfactual scenario without the augmentation developed, are modelled. 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 AER in a RIT-T.[40] 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.

[39] AEMO, ESOO Methodology Document, at https://www.aemo.com.au/-/media/Files/Stakeholder_Consultation/Consultations/NEM-Consultations/2019/Reliability-Forecasting-Methodology/ESOO-Methodology-Document-v2---draft-2019.pdf.

[40] Australian Energy Regulator, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-2018.

- 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.

5.2.1 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.

5.2.2 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.

5.2.3 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.

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.

5.2.4 Transmission system losses

An augmentation may allow generation to be dispatched closer 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).

5.2.5 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.

5.2.6 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.

6. 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.

6.1 Inflation

Monetary values in the models refer to real value, as opposed to nominal value.

6.2 Goods and Services Tax

Prices are exclusive of Goods and Service Tax.

6.3 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[41]. 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.

6.4 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. 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.

AEMO uses a single discount rate to calculate the net present value (NPV) of future cash flows. In AEMO's 2019-20 modelling, AEMO applies the same discount rate as the WACC. Sensitivities testing variations in the discount rate may be considered for some analysis where appropriate.

6.5 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.

[41] The return the company would expect to receive from an alternative investment with similar risk.