Draft ISP Methodology

April 2021

Draft: For the Integrated System Plan (ISP)

Important notice

PURPOSE

AEMO publishes the Draft ISP Methodology pursuant to National Electricity Rules (NER) 5.22.8(d). This report includes key information and context for the methodology used in AEMO's ISP.

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VERSION CONTROL

Version	Release date	Changes
1.0	30/4/2021	Initial Release

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1. Modelling overview

AEMO's *Integrated System Plan* (ISP) is underpinned by integrated energy market modelling and power system analysis. The objective of the suite of models and analysis is to determine an Optimal Development Path (ODP) that optimises benefits to consumers.

Each individual process is important in the overall ISP process, however the linkages and interactions between the processes are also critical in ensuring the ISP delivers an integrated solution.

This section focuses on describing the high-level process that is used in the modelling and assessment undertaken to prepare the ISP, including the key interactions between the various models and analytical processes. Each individual process is considered in more detail in later sections:

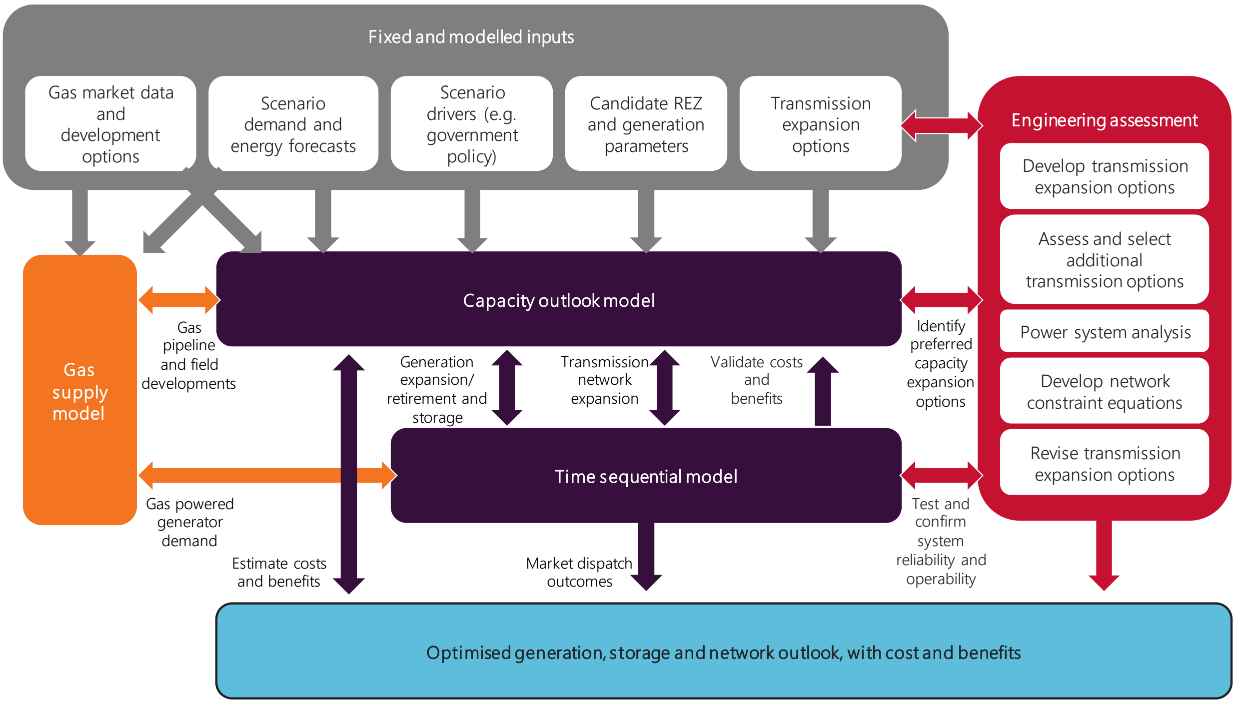
- Section 2 describes the models and methodologies using the capacity outlook modelling process.
- Section 3 details the approach that is used in more granular time-sequential modelling to inform and validate the capacity outlook modelling.
- Section 4 documents the various engineering assessments of system reliability, security, and operability.
- Section 5 steps through the cost-benefit analysis approach which is used to inform selection of the optimal development.

Figure 1 provides an overview of the integrated suite of forecasting and planning models and assessments which are used to prepare the ISP. The overall ISP process is an iterative approach, where the outputs of each of the different models or analytical processes are used to determine or refine inputs into the other models and processes. Using the colours shown in Figure 1:

- The **fixed and modelled inputs** are the inputs, assumptions and scenarios published in the *Inputs, Assumptions and Scenarios Report* (IASR). These are influenced by earlier engineering assessments used to describe the existing capability of the National Electricity Network (NEM) and to develop a set of network and non-network expansion options.
- The **capacity outlook model** (Section 2) uses all the available inputs to develop projected generation expansion, transmission expansion, generation retirement, and dispatch outcomes, in each of the ISP scenarios. The aim when doing so is to minimise capital expenditure and operational costs over the long-term outlook while achieving the objectives (social, political, and economic) within each scenario.
- The **time-sequential model** (Section 3) then optimises electricity dispatch for every hourly or half-hourly interval. In so doing, it validates the outcomes of the capacity outlook model, and feeds information back into it. The model is intended to reflect participant behaviour hour-by-hour, including generation outages, to reveal performance metrics for both generation and transmission.
- The **engineering assessment** (Section 4) tests the capability outlook and time-sequential outcomes against the technical benchmarks of the power system (security, strength, inertia) as well as assessing future marginal loss factors (MLFs) to inform new grid connections. These assessments feed back into the two models to continually refine outcomes.

- The **gas supply model** (see the *Gas Statement of Opportunities* [GSOO] gas adequacy methodology[1]) may be deployed to validate the assumptions and impact regarding the adequacy of gas pipeline and field developments, by using the outcomes of the capacity-outlook and time-sequential models.
- Finally, the **cost-benefit analyses** (Section 5) test each individual scenario and development plan considered by the ISP, to determine the ODP and test its resilience.

Figure 1 Overview of ISP modelling methodology



REZ: renewable energy zone.

[1] At https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2020/gas-supply-adequacy-methodology.pdf?la=en.

2. Capacity outlook modelling

Capacity outlook modelling is the core process to explore how the energy system would develop in each ISP scenario, and to determine candidate development paths from which the optimal development path is selected.

The model reveals long-term outcomes for generation expansion and retirement, transmission expansion, storage, and dispatch options, in all ISP scenarios. The objective is to minimise capital expenditure and operational costs of the entire NEM over the long-term outlook.

The capacity outlook model takes all the relevant inputs through two modelling processes:

- The **Single-Stage Long-Term Model (SSLT)** optimises over the entire modelling horizon (out to 2050).
- The **Detailed Long-Term Model (DLT)** optimises over sequential, shorter time horizons.

In this chapter:

- Section 2.1 introduces the purpose and constraints of the capacity outlook modelling.
- Section 2.2 describes the SSLT and DLT models that make up the capacity outlook model.
- Section 2.3 explains how input assumptions are developed and used in the capacity outlook modelling.
- Section 2.4 focuses on specific applications of the modelling (for example, an early generation retirement or the demand or variable renewable energy [VRE] profile), and the methodologies for them.
- Section 2.5 explores the modelling of large-scale uptake of NEM-connected hydrogen.

2.1 Purpose and size of the modelling process

Purpose of the modelling

The capacity outlook modelling process seeks to minimise capital expenditure and generation production costs over the long-term planning outlook. In doing so, it must:

- Ensure there is sufficient supply to reliably meet demand at the current NEM reliability standard, allowing for inter-regional reserve sharing,
- Meet legislated and likely policy objectives (in accordance with the scenario definitions).
- Observe physical limitations of the generation plant and transmission system.
- Account for any energy constraints on resources.

Simplification of inputs and assumptions required

The model applies a mathematical 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)[2].

A single run of the capacity outlook model can take up to three days to complete, and over 1,000 simulations are completed during an ISP process. The model must therefore focus on its most valuable uses, that is, the details most material to understanding potential investment needs.

For the modelling to remain computationally feasible through this complex task, some inputs and assumptions must be simplified. These simplifications include:

- Using multiple configurations of interacting capacity outlook models.
- Breaking the optimisation into smaller steps (optimisation windows).
- Aggregating demand and VRE profiles.
- Avoiding integer decision variables by linearising generation, transmission build, and retirement decisions (effectively allowing partial units or lines to be built if desired). Many of these key linear decisions are validated in subsequent models.
- Generally reducing the number of decision variables through limiting the number of generator and storage augmentations which are considered and aggregating inputs where appropriate.

2.2 The Single-Stage and Detailed Long-Term models

The capacity outlook process uses two interacting models to address different aspects of the long-term optimisation. Together, the SSLT and DLT can represent detailed demand and VRE outcomes over the length of planning horizon.

Figure 2 provides an overview, focusing on the decisions that are made at each stage.

[2] These options are outlined in the most recent version of the IASR, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp.

Figure 2 Overview of ISP capacity outlook model

Single-Stage Long-Term Model

*Longest look-ahead model – provides ability to allocate emissions budget, consider potential development or retirement of long-lived thermal generation and account for electrolyser build developments to meet long-term hydrogen demand**

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Outputs:
- P{rojected thermal retirements
- Projected development of high utilisation thermal generation
- Decomposed carbon budget
- Indication of possible inter- and intra-regional transmission augmentations
- *Projected location and size of electrolysers within each sub-region**

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Detailed Long-Term Model

More granular representation to better capture VRE variability, the operation of electrolysers and the value of storage and other generation (such as peaking gas generation), to compare costs and benefits of alternative development paths*

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Outputs:
- Estimated costs and benefits of alternative development paths
- Projected generation and storage expansion
- Transmission network outlooks.
- *Operation of electrolysers**

*Hydrogen inputs and outputs are only applicable for scenarios that model significant hydrogen uptake.

Single-Stage Long-Term Model (SSLT)

The **SSLT** optimises the entire modelling horizon (out to 2050) in a single stage, to allow consideration of aspects with long-term impacts, such as:

- **Emissions budgets across the entire horizon**, including determining the pathway for electricity generation emissions given that cumulative budget. The emissions pathway is then split into segments and used as an input for each of the smaller optimisation windows in the DLT Model. Further detail on this approach is provided in Section 2.4.5.
- **New high-utilisation thermal generation** (for example, combined-cycle gas turbines [CCGTs] or coal-fired generation) which needs to consider future emissions limitations.
- **Generator retirements brought forward** from expected closure years. The configuration of this modelling ensures that these retirement decisions consider the impact of the variability and flexibility of any potential replacements, while also maintaining sufficient look-ahead of future conditions and the impact of emissions constraints. This modelling is supported by an economic assessment of coal closures through time-sequential modelling (see Section 3.1.3).
- **Co-optimisation of generation and transmission developments**. In this model, inter- and intra-regional transmission augmentations are linearised due to computational limitations. The linear transmission build decisions from this model provide the first indication of potential network investments, and are used as a starting point for the development of alternative development paths. The collection of development paths is then tested rigorously within the DLT Model, which may lead to substantially different development paths being identified as preferable relative to the developments of the SSLT.

This extended modelling horizon requires a coarser representation of demand and VRE variability to address computational limitations. To achieve this, the model applies a sampled chronology setting, which maintains a representation of intermittency and chronology but potentially reduces the level of variation explored in the SSLT. Further information about the sampled chronology setting is covered in Section 2.4.2.

The key inputs used in the SSLT that are distinct from those used in the DLT are:

- A cumulative emissions budget across the entire horizon.
- Consideration of retirement candidates which are then able to be brought forward from their assumed closure year within the model.
- Linearised inter- and intra-regional transmission augmentations. These are developed by averaging the assumed configurations and costs across the different distinct options for a given transmission flow path. The options that are included in this averaging are adjusted iteratively throughout the ISP process to focus on those options which are most frequently assessed as potentially viable. This is to improve the consistency between the SSLT and the DLT.

The DLT divides the modelling horizon into multiple steps which are optimised sequentially. The shorter optimisation windows allow a chronological optimisation of each day of the modelling horizon that preserves the original chronology of the demand and renewable resource time series, ensuring a more detailed representation of demand and VRE variability than the SSLT. Demand and VRE profiles are represented using a fitted chronology which is described in Section 2.4.2.

The DLT provides a granular representation of each day's demand and VRE availability, while leveraging the outcomes of the SSLT such as the decomposition of the carbon budget, retirement decisions, and development of high-utilisation thermal generation. The increased accuracy of variability and flexibility of the modelled power system provides better assessment of dispatch and operability of the generation fleet, including the operation of storages (both daily and seasonally), providing a more accurate estimation of costs and benefits.

The DLT is primarily used to:

- Optimise the development, location, and operation of VRE, storage (battery and pumped hydro), electrolysers (if applicable), and other generation such as peaking gas generation.
- Evaluate the transmission development paths[3]. Each alternative development path is tested individually through the DLT. Testing of the network development paths is a key process in determining the ODP and performing cost-benefit analysis. This process is described in more detail in Chapter 5.

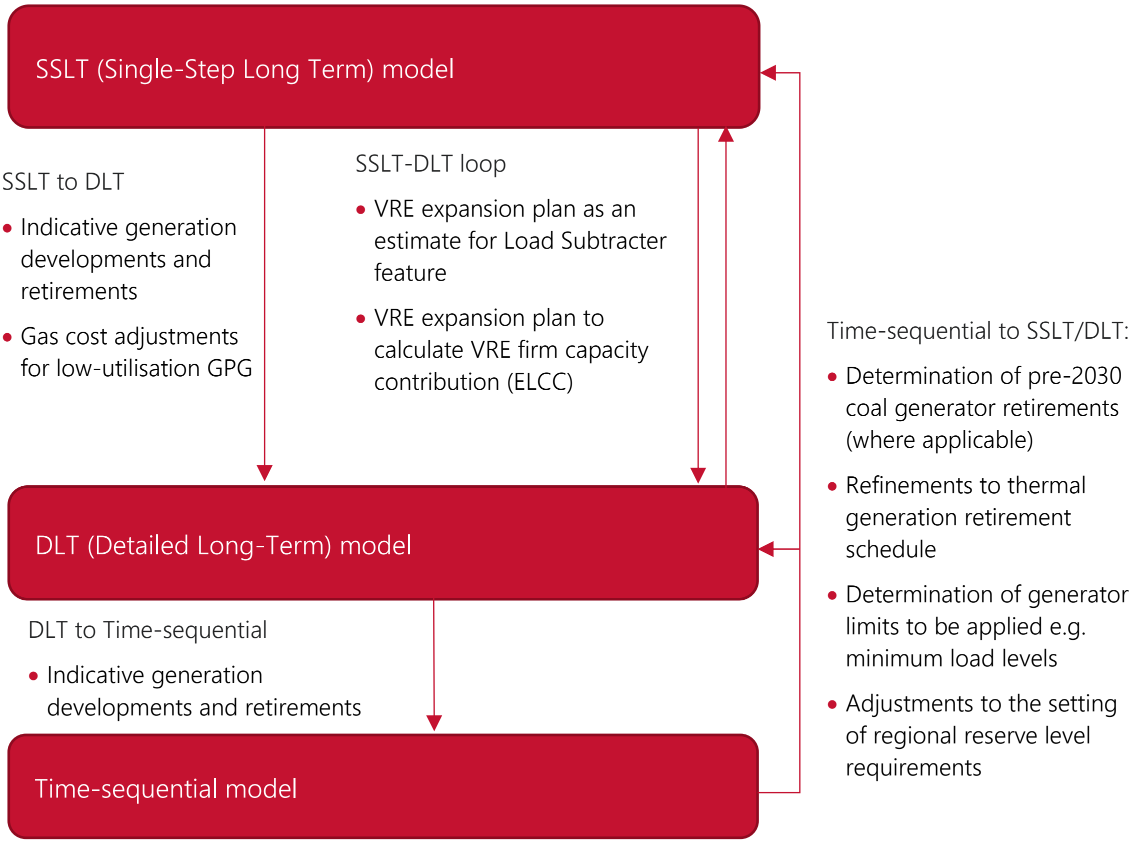
Iterative market modelling process

Figure 2 above focuses on the decisions and outcomes which are taken from the capacity outlook models. In addition to this sequential process, the inputs to the capacity outlook models are refined using the outputs of each other, as well as time-sequential modelling. The interactions between the models and the inputs and methodologies used in each are explored in detail throughout this section.

Figure 3 below illustrates the various interactions between the market models which are used to refine modelling outcomes; these are described in more detail in Section 2.4.

[3] Development paths refer to combinations of transmission and non-network augmentations. Section 6 has more detail on the use of development paths.

Figure 3 Interactions between market models



Consideration of stakeholder feedback

Several stakeholder submissions requested more clarity and detail on the interactions between the various models used in the ISP. AEMO has therefore provided more detailed descriptions of the high-level approach, as well as expanding on each interaction in more detail throughout Section 2.

2.3 Preparing inputs for the capacity outlook model

2.3.1 Market modelling topology

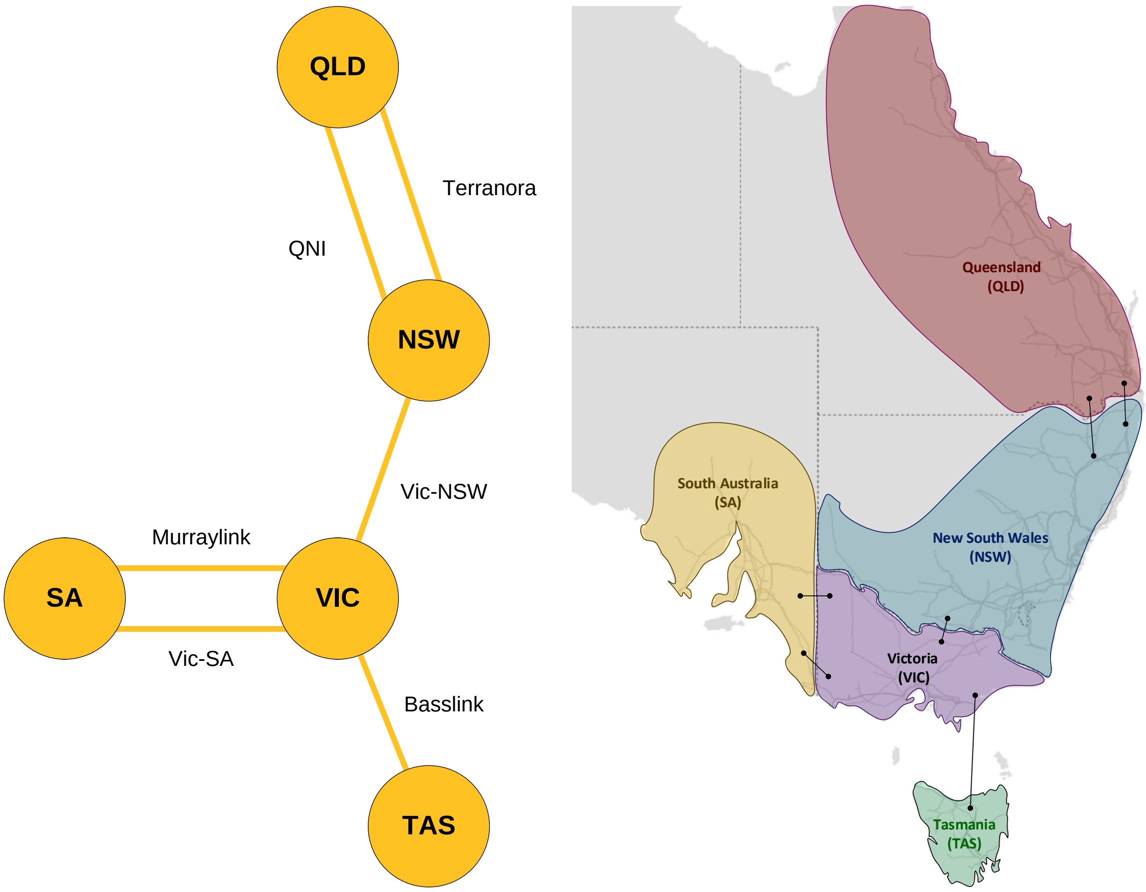
The NEM is comprised of the five states of Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia, and Tasmania, referred to as regions. The capacity outlook model can apply two alternative approaches to this regional market topology:

- **Regional representation** – this approach replicates the classic NEM regions, representing the network as a system of five regional reference nodes, connected via existing and potential inter-regional flow paths. This representation was applied in the 2020 ISP.
- **Sub-regional representation** – this disaggregates some regions into sub-regions to better reflect current and emerging intra-regional transmission limitations.

Regional topology

The regional topology mirrors the operation and settlement of the NEM Dispatch Engine (NEMDE) which is responsible for directing generation dispatch in the NEM, and is shown in Figure 4. AEMO will endeavour to reflect any changes in the NEM regional boundaries[4] into the capacity outlook model.

Figure 4 Regional representation of the NEM, including existing interconnection



Sub-regional topology

AEMO uses a sub-regional topology in the capacity outlook models, because as more geographically diversified VRE generation develops, a regional representation limits:

- The representation of intra-regional transmission constraints, which in turn limits consideration of renewable energy zone (REZ) transmission augmentations, and
- AEMO's consideration of congestion between major load centres, given how it can be influenced by generation between regional reference nodes.

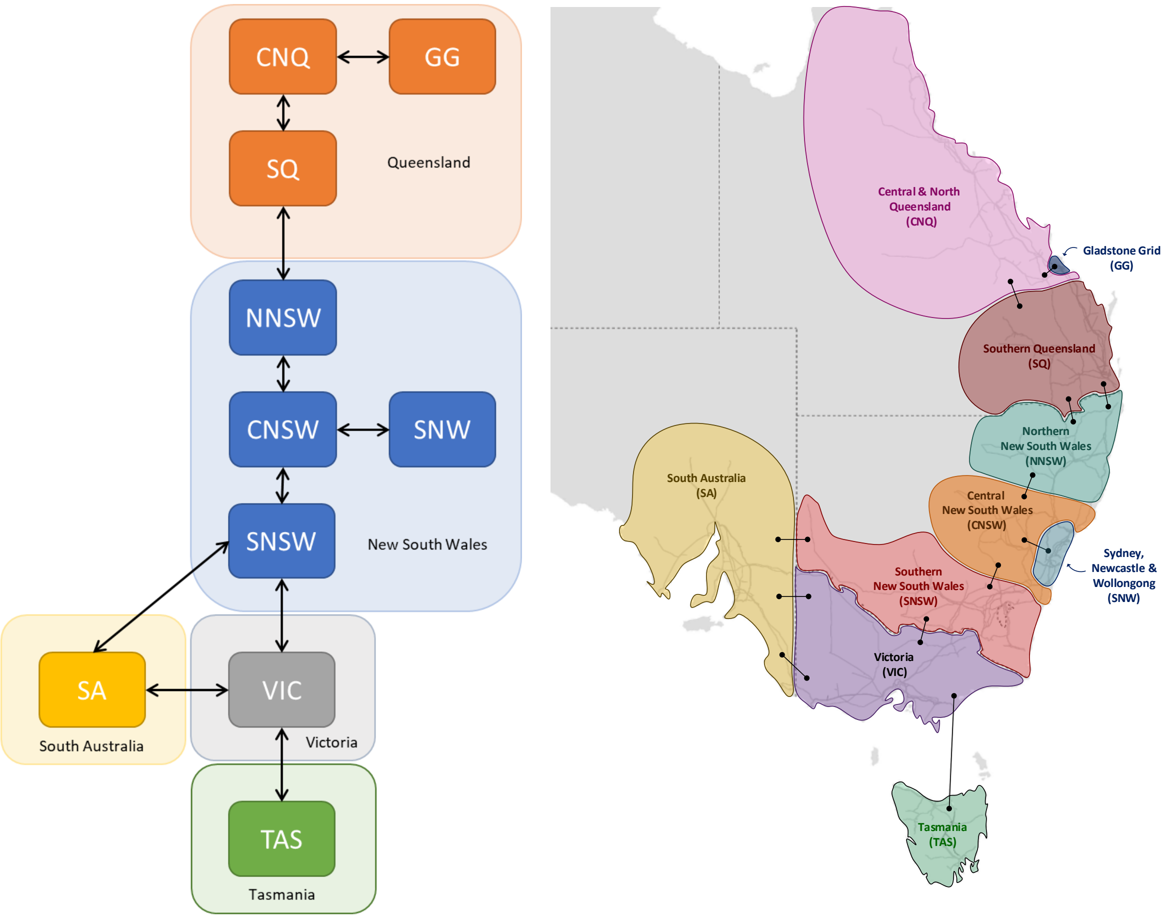
The approach disaggregates some regions into one or more sub-regions, configured to identify major electrical subsystems within the electricity transmission network that allow free-flowing energy between transmission elements. Where key flow paths are identified that may materially constrain the transmission system from delivering energy between locations, this alternative sub-regional approach splits these areas from each other, to better identify the capacity of the intra-regional transmission system and the value of potential augmentations.

[4] AEMO. *Loss factors and regional boundaries*, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

An example of the sub-regional topology that was outlined in the Draft 2021-22 IASR can be seen in Figure 5 below. In this case, regions were split into sub-regions so the capacity outlook model could make informed decisions on specific projects previously identified as being actionable or having preparatory activities[5]:

- Central & North Queensland was separated from Southern Queensland so the link between the two sub-regions (Central to Southern Queensland augmentation) could be modelled with increased detail. The Gladstone Grid was then further separated from Central & Northern Queensland so local options to supply the Gladstone area could be examined if needed.
- New South Wales was disaggregated into four sub-regions representing the North, Central, South, and Sydney/Newcastle/Wollongong (SNW) areas of the state. This enables an improved evaluation of proposed network projects that increase network transfer capability between these areas.
- Victoria, South Australia, and Tasmania were each preserved as single nodes because the proposed network projects to increase transfer capacity in those regions generally connect from regional borders or REZs to major load centres. This may be modified in future if a need arises to model different network projects in more detail.

Figure 5 NEM sub-regional topology



[5] An ISP can trigger "preparatory activities" for future ISP projects. This creates a requirement for the responsible transmission network service provider (TNSP) to provide cost estimates and preliminary designs for use in a future ISP.

2.3.2 Allocation of electricity demands to sub-regions

Modelling the sub-regional network topology requires the capacity outlook model to use sub-regional inputs, including demand traces. These traces are based on the regional demand traces developed as part of the *Electricity Demand Forecasting Methodology*[6].

The sub-regional demand traces and inputs are built based on the following half-hourly components of the regional demand:

- "Underlying" demand excluding large industrial loads (LILs) – this essentially represents energy consumed by residential and commercial customers gross of the generation provided by distributed energy resources (DER).
- DER forecasts – distributed photovoltaics (PV), battery storage, and electric vehicle (EV) profiles.
- LIL forecasts – LILs tend to have a flatter load profile, reflecting a traditional 'block load'; separating these from residential and commercial underlying demand improves the representation of total demand.

These regional components are then allocated in each half-hour to the sub-regions based on historical analysis and projected information.

Allocation of underlying demand

The underlying demand profile has any impact of historical DER uptake and LILs removed, and therefore represents actual electricity usage by residential and commercial customers. The underlying profile is allocated to sub-regions based on a historical half-hourly analysis of connection point demand data to determine a relative share of each sub-region. The underlying profile is not allocated by customer type, but rather from total demand from all residential and commercial customer types.

This allocation is then applied to each half-hour of the regional demand profile. Because the allocation is done at a half-hourly temporal resolution, daily, weekly and seasonal variations are captured. The half-hourly allocations for each reference do not change over the duration of the forecast period, meaning that underlying consumption growth in each sub-region matches the regional growth forecast. Further methodology improvements will explore enhanced methods to reflect different consumption patterns within regions, and the way in which demand growth may evolve differently within a region.

Allocation of DER components

AEMO sources forecasts of DER uptake at a postcode level. From this data, AEMO calculates each sub-region's share of DER at a monthly level and applies that to the regional half-hourly trace for that component.

Some components of DER, for example aggregated storage such as virtual power plants (VPPs), are modelled explicitly within the capacity outlook model rather than through half-hourly traces. For these components, the same sub-regional share calculated for the DER type is allocated to these regional inputs.

For example, if zone A and zone B have a 60% and 40% share respectively of distributed PV, and a region has 250 megawatts (MW)/500 megawatt hours (MWh) of VPP available, then zone A is assumed to have 150 MW/300 MWh of VPP, and zone B has 100 MW/200 MWh.

Forecast Large Industrial Load (LIL)

LILs are modelled at a facility level throughout AEMO's demand forecasting process. Each LIL is mapped individually to a sub-region based on its electrical connection. The sub-regional LIL forecast is simply an aggregation of the forecast of each LIL in that sub-region.

[6] Currently under consultation; further details available at https://aemo.com.au/en/consultations/current-and-closed-consultations/electricity-demand-forecasting-methodology.

Aggregation of components

Once the sub-regional half-hourly traces are developed for each component, a resulting sub-regional demand profile is then constructed by aggregating the necessary components. Further checks are then done to confirm that the regional annual consumption and maximum and minimum demands are maintained in the aggregated sub-regional demand traces.

> **Consideration of stakeholder feedback**
>
> Several submissions requested further clarity on the approach to sub-regional demands, and in particular their alignment with regional demand forecasts (Shell Energy, Hydro Tasmania). AEMO has provided additional detail in this methodology which outlines how the sub-regional forecasts are developed to ensure complete alignment with the regional forecast when aggregated.

2.3.3 Transmission limits and augmentation options

Electricity networks have physical limits on their ability to transfer energy. Transfer capability across the transmission network is determined by assessments of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength. Transfer capability varies throughout the day with generation dispatch, load, and weather conditions. Other factors also play a part, such as status and availability of transmission equipment, operating conditions of the network, generator, or high voltage direct current (HVDC) runback schemes, and any special protection schemes (SPSs).

Transmission limits are included within the capacity outlook model to reflect the ability of the network to transfer electricity between sub-regions.

Representation of transmission limits in capacity outlook model

For capacity outlook modelling, a range of notional transfer limits between sub-regions is used. This approach is aligned with the approach for setting generator capabilities (see Section 2.3.7)[7] and broadly allows the transfer limits to reflect the impact of two major influences on transfer limits: ambient temperatures and demand.

AEMO first determines the transmission limits for reference temperatures listed in the *Electricity Statement of Opportunities (ESOO) and Reliability Forecast Methodology Document*[8]. This gives three conditions – "Summer 10% POE Demand", "Winter Reference" and "Summer Typical".

The approach to applying these ratings in the ISP is as follows:

- The winter reference capacity will be used for all periods during winter.
- The Summer 10% POE capacity will be applied to the subset of hottest summer days, using the same approach outlined in the *ESOO and Reliability Forecasting Methodology Document*.
- For all other days in summer, the average of the summer typical capacity and the winter reference capacity is applied. This approach is different to that used in reliability forecasting, and better estimates the energy transfer capability of the network in summer, as opposed to focusing on the transfer capability during peak periods which is more critical for unserved energy assessments.

The following steps are applied to identify transfer limits for each seasonal condition:

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[7] AEMO. *Electricity Statement of Opportunities (ESOO) and Reliability Forecast Methodology Document*, page 7, at https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

[8] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

1. AEMO gathers input data from asset owners, for example network ratings for various ambient temperature conditions, any runback schemes or SPSs. AEMO also gathers historical operational data for the network.
2. AEMO consults with the local transmission network service providers (TNSPs) to understand potential limiting factors.
3. Either AEMO or the TNSP undertakes power system analysis[9] to evaluate the impact of each of the limiting factors on the transfer capacity. This includes:
   a. A mixture of thermal capacity, voltage stability, transient stability, oscillatory stability, and power system security/system strength assessments, depending on the sub-region, and
   b. Testing worst-case conditions and typical conditions, and a selection of appropriate demand and generator dispatch conditions.
4. AEMO selects the most binding transfer limit. For example, if there is a transient stability issue which limits flow between sub-regions to a particular MW value, but that value is higher than the MW flow value for the voltage stability limit for that sub-region, then the voltage stability limit will be used to set the transfer capability.

Consideration of stakeholder feedback

AEMO has considered the following options for expanding the set of transfer limits:

- A worst-case limit, and a limit for 'typical conditions' for the remainder of the year.
- Peak and off-peak limits for both summer and non-summer conditions.
- A worst-case limit, and limits for 'typical conditions' for summer and non-summer.

Some stakeholders noted that an appropriate set of conditions to consider for transfer capability could consider different demand conditions. AEMO considers that while all of the options mentioned above would provide for a greater variety of demand conditions, the proposal to align with temperatures considered for generator capability will be the best option to provide for more conditions while also minimising additional modelling complexity.

Augmentation options

This section describes the method and approach to developing credible augmentation options.

Generally, transmission corridors are still conceptual when modelling for the ISP. As such, specific details on route selection and easements are not yet identified, and the essential consultation with community, traditional owners, or property title holders has not yet commenced. It is vital that developers and TNSPs identify key stakeholders and commence engagement on land and access as early as possible.

In the IASR, AEMO starts this process by consulting on the broad geographic properties of augmentation options. This includes:

- The design of the sub-regional model (previously called a zonal model).
- Transmission corridors for augmenting the backbone of the network – this includes interconnector upgrades and sub-regional upgrades.
- REZ geographic boundaries.

[9] AEMO. 2020 ISP Appendix 9 – ISP Methodology, Section A9.4.4 Power system analysis, at https://www.aemo.com.au/-/media/files/major-publications/isp/2020/appendix--9.pdf?la=en.

AEMO publishes an interactive map[10] that shows resource quality and REZ locations to support engagement on these broad geographic properties. Transmission corridors for sub-regional upgrades are provided within the IASR or via a separate consultation.

Example – establishing and refining an augmentation option

In the Draft IASR, AEMO seeks feedback on options to increase transfer capacity between two areas – for example, Central to Southern Queensland. Several options are proposed, including new high voltage alternating current (HVAC) or HVDC transmission lines, upgrades to the existing network, and non-network options (for example, virtual transmission lines or other alternatives). For each option, AEMO describes and seeks feedback on the approximate geographic and technical parameters. AEMO also seeks feedback on non-network technologies and the approach to costing non-network options.

AEMO then collaborates with TNSPs to develop the cost and capacity of each option – including options to stage projects and consideration of feedback that is received to the Draft IASR. AEMO then consults publicly on transmission costs via a Draft Transmission Cost Report. Feedback to the Draft Transmission Cost Report, and TNSP estimates from active Regulatory Investment Tests for Transmission (RIT-Ts) and Preparatory Activities, are then included in the final Transmission Cost Report which accompanies the IASR.

The augmentation options in the IASR are inputs which may be refined to cater to modelling outcomes throughout the ISP modelling process (for example, optimisation with nearby projects, staging, and new information). AEMO will publish any changes to transmission costs in the Draft or Final ISP.

Once the broad geographic properties are defined, AEMO collaborates with TNSPs to create preliminary designs for augmentation options, and then proceeds to develop an initial estimate of the cost and transfer capability of each option.

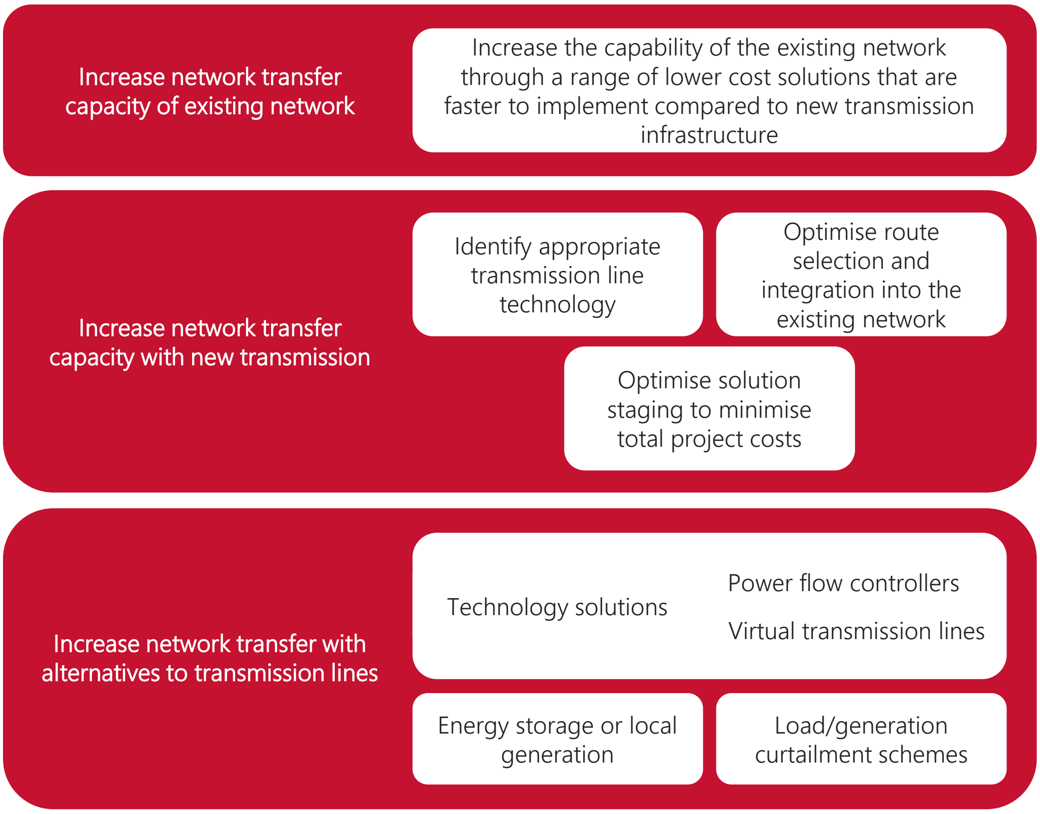
Figure 6 summarises the parameters considered in developing each type of transmission option. Sub-regional network augmentation options, including interconnector options, typically fall into the following categories:

- Minor network upgrades and augmentations to the existing network (brown field augmentation).
- Additional new transmission lines (green field augmentation).
- Alternative technologies to minimise the requirement for new transmission lines, including non-network options.

When considering whether to upgrade existing network or build new transmission, AEMO also assesses alternative technologies to increase the transfer capacity of the existing network, including power flow controllers and other options that do not involve new or expanded transmission. Once the credible options have been identified, detailed power flow studies are undertaken to assess the capability of the resultant augmentation options.

[10] AEMO. *Interactive Map*, at https://www.aemo.com.au/aemo/apps/visualisations/map.html.

Figure 6 Developing credible transmission options to increase network transfer capacity in the ISP



Options to increase network transfer capacity of the existing network

Minor network upgrades and augmentations to the existing network can be relatively low cost and have a short lead time to implementation, with lower environmental and community impacts than those of major new transmission lines. They usually meet the needs for small capacity gains on the network.

The options considered to increase capability of the existing transmission network are:

- Network reconfiguration to balance or reduce overloaded network elements.
- Application of dynamic line ratings for transmission lines for additional thermal capacity under favourable weather conditions.
- Control schemes to reduce generation and load immediately following a contingency.
- Uprating of transmission lines for additional thermal capacity.
- Additional new transformers for additional thermal capacity.
- Additional new static and/or dynamic reactive plant.

New transmission line options

The configuration of new transmission lines to increase network capacity is assessed based on:

- Identification of appropriate transmission line technology with technical feasibility.
- Consideration of route selection factors and integration into the existing network, including cost effective access to renewable generation and consideration of energy losses.
- Identification of solution staging to minimise total project costs.

In the NEM at present, HVDC is currently used for three point to point interconnection links between regions. When assessing new transmission line proposals, both HVAC and HVDC implementations are considered:

- HVDC can be more economic than HVAC for longer distance point to point applications, typically several hundred kilometres, or for applications under ground and under water, even when including the converter stations at each end of the transmission line.
- An exception to this is where multiple converter stations are required along the route, for example, when connecting multiple REZs along the line route. This is the case in the 2020 ISP, where most actionable ISP projects are related to connection of multiple REZs. As the costs of converter stations are material, the overall cost of a HVAC implementation can be cheaper than the overall cost of a HVDC implementation.
- For shorter transmission lines, the added cost of converter stations may make HVDC implementations more expensive than HVAC alternatives.

The benefits of each technology are assessed and verified through a technical feasibility study to determine the most appropriate technology to use, to design a new transmission line or network augmentation. This is followed by an economic analysis to determine the net market benefits.

In designing new transmission line options, AEMO will assess the possibility of solutions to be delivered in stages (see Section 5.4 for discussion on staging and option value).

Alternatives to transmission lines

Alternative technologies and non-network solutions are also considered in order to assess the most efficient approach to meet the identified need (see Section 5.9.2). Alternative technologies and non-network options can fulfil the need to increase power system capacity while still optimising economic benefit to all those who produce, consume and transport electricity in the market. Delivery of these alternative technologies and non-network options is often a case-by-case regulatory treatment, depending on the nature of the identified need and the alternative option selected.

Alternatives to transmission can include:

- Technology solutions such as power flow controllers and virtual transmission lines[11].
- Energy storage or local generation.
- Control schemes such as fast acting load curtailment schemes, or local generation run-back and curtailment schemes.

Modelling of non-network solutions can occur as bespoke options within the ISP or as alternatives to a network investment within the RIT-T framework. The approach to assessing these options is similar to the assessments needed for transmission options. AEMO (or the RIT-T proponent) conducts a technical analysis to determine the system limits with the option in service. This is followed by an economic analysis to determine the net market benefits.

An accurate assessment of alternative technologies may require information which is only available in the late stages of project completion and is often commercially sensitive. AEMO receives non-network submissions throughout the ISP consultation process, and a TNSP may receive additional options within the RIT-T. AEMO's approach is to assess the technical capability of options with the available information and undertake economic analysis to consider each submission as an alternative to network options.

Transmission costs

For actionable ISP projects that are proceeding under the current RIT-T process, AEMO works with the relevant TNSPs and incorporates the published costs and designs in its assessments.

[11] Virtual transmission lines use storage (or fast acting power response) at both ends of a particular transmission line which is expected to constrain power transfer. Immediately following a contingency event, the storage at the sending end of the transmission line absorbs power and the storage at the receiving end releases the same amount of power (less the transmission line losses). This avoids any thermal overloading on surrounding parallel transmission lines. This process of placing energy storage on a transmission line and operating it to inject or absorb real power, mimicking transmission line flows, is an alternative to uprating, replacing, or building new transmission lines to increase transmission capacity.

TNSPs also provide estimates of costs and initial designs for projects that are 'Future ISP projects with Preparatory Activities' or are undergoing the RIT-T process. Information provided by TNSPs is cross-checked by AEMO and included in the IASR.

Other transmission network augmentation options and costs are consulted on in the preparation of the IASR. Through that process, a Transmission Cost Database (TCD) is developed in collaboration with the TNSPs and the Australian Energy Regulator (AER). The TCD is released for public visibility alongside a Transmission Cost Report that demonstrates its use on ISP projects.

Because interconnector and REZ designs are inter-related, AEMO may update transmission designs and their costs using building blocks in the published TCD throughout the course of ISP modelling. This is done in the Engineering Assessment model (see Section 4).

Consideration of stakeholder feedback

Following feedback from stakeholders on the transmission costs assumed for the 2020 ISP, AEMO has commenced an initiative to improve the approach to and transparency of input cost estimation for transmission used for the 2022 ISP, by developing a new TCD.

2.3.4 Renewable Energy Zones (REZs)

REZs are geographical areas in the NEM where clusters of large-scale renewable generation can potentially be developed. The capacity outlook models include REZs to account for differences in energy resource availability and infrastructure limitations within each sub-region. The geographic boundaries for REZs are determined through the IASR consultation process.

This section covers methodologies relating to REZs:

- Resource and transmission limits.
- Network expansion.

REZ resource and transmission limits

For the purposes of capacity outlook modelling, REZ capabilities can be described using two key concepts:

- Resource limit – the assumed upper limit of generation supported by land availability and resource quality.
- Transmission limit – the amount of power that can be transferred from the REZ through the shared transmission network.

REZ transmission limits can be increased by augmenting the shared transmission network (modelled as a network expansion cost), and REZ resource limits can be increased by utilising a larger land area or converting more land within a REZ to be suitable to host generation (modelled as a land use penalty factor). By using a land-use penalty factor, AEMO can model a staged increase in land costs, reflecting more complicated arrangements required for planning approvals and social licence as more infrastructure is built within a REZ.

REZ resource limit

REZ resource limits reflect the total available land for renewable energy developments, expressed as installed capacity (MW). The availability is determined by existing land use (for example, agriculture) and environmental and cultural considerations (such as national parks), as well as the quality of wind or solar irradiance. Resource limits are 'soft' limits – this means the resource limits can be exceeded if a penalty factor is incurred by the model.

REZ resource limits and penalty factors are determined through the IASR consultation process.

REZ transmission limit

REZ transmission limits represent the maximum generation that can be dispatched at any point in time within a REZ, reflecting the transfer capability of the shared transmission network, and taking into account any local load. Network studies using PSS®E are undertaken to identify transmission limits for REZs.

These transmission limits are able to be increased through:

- Augmentation between sub-regions – these could pass through a REZ and improve its access to the shared transmission network (for example, a new interconnector that passes through a REZ).
- Augmentation from a REZ to the NEM shared transmission network.

The REZ transmission limit is expressed as an inter-temporal generation constraint in the capacity outlook model. The purpose of the constraint is to limit the generation dispatch up to the transmission limit which can be increased when it is economically optimal.

The generation constraint takes the following form:

$$Gen_{Solar} + Gen_{Wind} \leq Transmission\ limit + \text{REZ}\ Augmentation$$

Where:

- Gen_{Solar} is the generation from solar capacity (variable optimised within the capacity outlook model).
- Gen_{Wind} is the generation from wind capacity (variable optimised within the capacity outlook model).
- REZ $Augmentation$ are transmission developments between the NEM transmission network and the REZ. The transmission cost is considered by the modelling.
- $Transmission\ limit$ is the original intra-regional network limit (input to the model). This value changes in cases where interconnector developments improve access to the REZ.

Modelling the instantaneous transmission limit and generation dispatch captures the diversity of wind and solar generation and the potential for these technologies to effectively 'share' the transmission network. This enables the capacity outlook model to optimise network investment against generation curtailment.

Both battery and pumped hydro storage have the potential to help manage transmission curtailment and therefore impact the potential value of REZ augmentations. While it is not computationally tractable to model storage options in all REZs, if a major REZ augmentation is expected to become an actionable project during the cost benefit analysis (CBA), then storage options may be selectively added to the REZ constraints to assess the benefits of alternative solutions which incorporate storages. The storage projects would appear in the left-hand side of the equation above, with positive coefficients on generation/discharge and negative coefficients on pumping/charging. See Section 5 for further details on the CBA process.

Consideration of stakeholder feedback

ElectraNet's submission to the ISP Methodology Issues Paper proposed a methodology for calculating REZ hosting capacity that considers the diversity of wind and solar as well as local storage. AEMO has adopted the suggested improvements to capture the impact of wind and solar diversity.

The ability of battery storage to reduce curtailment and increase network utilisation is acknowledged, but AEMO is unable to optimise this aspect within the capacity outlook modelling due to the increase in computational complexity. The locational placement of battery storage (for example, within a REZ) is a manual process taken after the capacity outlook modelling stage, where improvement of network utilisation is one factor considered alongside being able to meet local demand at peak periods and deferral of network upgrades as part of non-network options (see Section 2.3.3).

Group constraints for transmission limits

"Group constraints" combine the generation output and transmission limits from more than one REZ to reflect transmission limits that apply to wide areas of the power system. These are developed by considering the limits observed from power system analysis, and in consultation with TNSPs.

Group constraints also have network upgrade options developed, and specific expansion costs applied within the capacity outlook optimisation as per the normal REZ network expansion methodology.

The transmission limits for REZ group constraints are expressed in the same format as a single transmission limits, however the Gen_{Solar} and Gen_{Wind} is the summation of the generation in all REZ to which the group constraint applies.

REZ network expansion

The capability to transfer power from the REZ to the load centres often needs to increase to support VRE development within a REZ. This is achieved by the development of network expansion options to increase the REZ hosting capacity and REZ transmission limit.

There are two main steps to this:

- Development of network augmentation options that increase the REZ transmission limit.
- Linearisation of the network augmentation options for each REZ for input into the capacity outlook model.

Development of network expansion options

Credible options to increase the transmission limit through REZ augmentation are developed through a technical assessment. The methodology to develop REZ network augmentation options is consistent with the sub-regional network augmentation options described in Section 2.3.3.

The REZ expansion costs determined are specific to the network location of the REZ, and need to be designed to integrate with nearby network upgrades. In instances where nearby network upgrades are chosen by the capacity outlook model, REZ designs and expansion costs may be revised.

Linearised representation of REZ network expansion options

Having a series of discrete network augmentations as possible candidates to be selected in the capacity outlook modelling (similar to inter-sub-regional options) which represents all credible REZ expansions is computationally intensive. Therefore, to represent the cost of expanding the network servicing a REZ, an incremental expansion cost (measured in $/MW) is determined. This expansion cost is a linearised value derived from the total cost ($) and REZ hosting capacity increase (MW) of a network augmentation option.

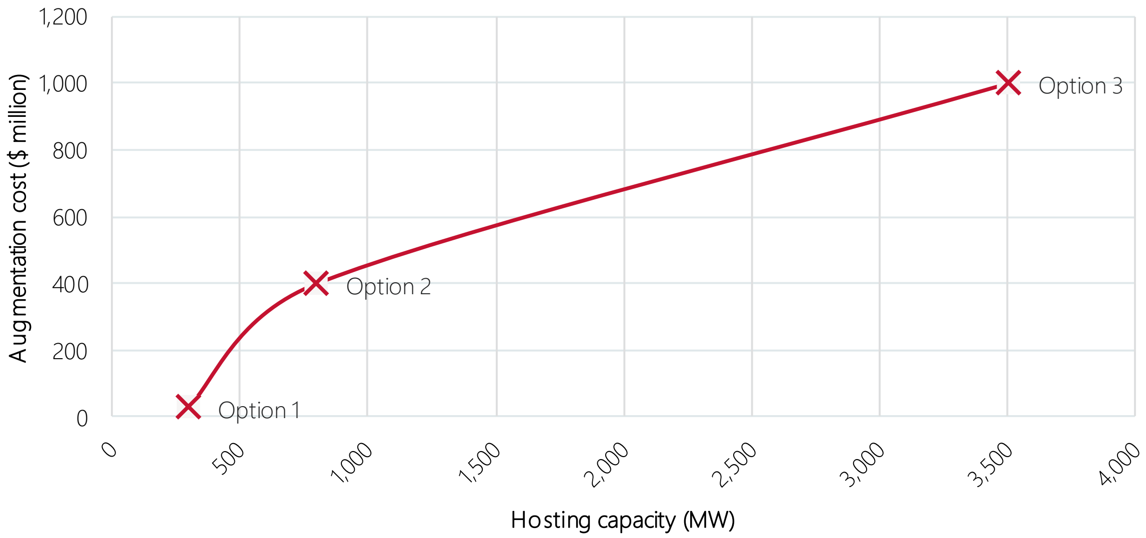
The cost-effectiveness of network options can vary significantly between small and large augmentation options – larger options will generally deliver economies of scale. It is therefore not appropriate to use a linearised value derived from a minor network augmentation to represent the cost-effectiveness of much larger options, or vice versa. AEMO must therefore select an appropriate linearised value from a set of possible network augmentations as a starting point. Table 1 outlines several hypothetical options to expand the hosting capacity of a REZ.

Table 1 REZ network expansion options

Option	Description	Augmentation cost	Additional hosting capacity	Linearised value
Option 1	Uprating critical spans	$30 million	300 MW	$100,000/MW
Option 2	Rebuilding entire 220 kilovolt (kV) line at higher rating	$400 million	800 MW	$500,000/MW
Option 3	New 500 kV loop	$1,000 million	3,500 MW	$285,714/MW

The augmentation options outlined in Table 1 are illustrated in Figure 7. AEMO initially selects a point on the line which best represents the linearised cost of a particular network expansion. This point will generally be the least-cost linearised value as a starting point (for example, Option 1). If the optimised model builds significantly more or less generation in the REZ compared to the chosen point, then the point can be revised (for example, Option 2 or 3). AEMO considers that approximately two to three network options per REZ will provide a sufficiently broad range of options.

Figure 7 Cost and capacity of REZ network expansion options



The range of credible network options may result in a function which is not necessarily monotonically increasing, and may have discontinuities that reflect the capability of discrete network options. Therefore, the linearised approach requires careful selection of the appropriate point on the function to reflect a realistic REZ expansion in terms of size and cost. This is an iterative process that ensures the resulting REZ network expansions and their costs are appropriate.

Consideration of stakeholder feedback

Stakeholders asked for further detail to be included on the process used for the derivation of the REZ network expansion costs. Further explanation of this process has now been included, including reference to the section detailing the intra-regional augmentation study and option methodology. Further breakdown of the range of projects and costs associated with REZ network expansion will also be provided as part of the Transmission Cost Report.

Interplay between sub-regional augmentations and REZ network capacity

Sub-regional augmentations are augmentations of any flow path between two sub-regions, whether inter- or intra-regional, and include interconnector augmentations or new lines. Within a sub-region, there may be a need to reflect the capability of the local network to export renewable generation from multiple REZs – this is done with group constraints that limit REZ output from a combination of REZs.

Sub-regional limits can therefore apply additional constraints on the maximum output from REZs, as well as any other generation or interconnector flow within a sub-region. Depending on the location of the REZs and definition of the sub-regional flow paths, this could impose limits on a REZ expansion which are automatically increased if a sub-regional augmentation then occurs.

Sub-regional upgrades do not necessarily require REZ expansions to show a need for upgrades to be implemented; it could be based on other factors, such as being able to supply demand under peak load conditions. An increase in a Group constraint limit is in effect the same as a REZ expansion.

This interplay helps ensure the full network upgrade costs when a REZ expansion is required are correctly captured, and assists in co-ordinating network upgrades that could be required for a number of different reasons.

REZ expansion costs for load centres not at the Regional Reference Nodes (RRNs)

The REZ network expansion costs have been determined by the need to increase network capacity to allow transfer of generation output from the REZs to the existing load centres. These load centres are usually the capital cities, or RRNs. Under some scenarios, such as when considering electrolyser loads, load centres may emerge near ports in order to provide access to export facilities. In this case, network upgrades to deliver supply (including REZ supply) to these new load centres need to be adequately represented, and may differ from power system needs in other scenarios.

Depending on the specifics of the scenario, and timings of the upgrades required, high level transmission cost assumptions reflecting the distance from the REZ to each nearby emerging load centre may be utilised in lieu of full modelling of new nodes/sub-regions and load centres. It is proposed that expansion costs will initially be calculated using an annualised cost per MW per km equivalent ($/MW/km), based on a generic large capacity upgrade (for example, 500 kilovolt [kV] double circuit) which applies to all REZs, although other cost options will be considered depending on the level of expansion required.

Modelling renewable energy without REZ network expansion

When determining the economic benefits of a development path, AEMO must compare system costs against a counterfactual where no transmission is built. In this counterfactual, new transmission to increase REZ transmission limits will generally not be allowed.

To conduct this analysis, it is necessary to increase the allowance for renewable generation to connect to areas with network capacity, but which may also have low quality resources (these parts of the network are not already defined as REZs due to their poor resource quality). For this reason, shadow resource limits and hosting capacities are also determined for areas of the network that have existing capacity, or where generation retirement is expected resulting in additional network capacity. These shadow resource limits and hosting capacities are included in all scenarios, not just the counterfactual studies. This ensures the capacity outlook model can determine the optimal trade-off between development of high-quality renewable resources in REZs, with associated network build, compared to developing lower quality resources in areas with spare hosting capacity.

2.3.5 Representing weather variability

AEMO optimises expansion decisions across multiple historical weather years known as "reference years" to account for short- and medium-term weather diversity. Where practical, these weather years also account for the variance around a long-term climate trend.

The use of multiple reference years allows the modelling to capture a broad range of weather patterns affecting the coincidence of 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 or hydro "droughts", representing extended periods of very low output from any particular renewable generation source, which may be observed across the NEM within or across multiple years.

To achieve this, AEMO uses a "rolling reference years" approach in the capacity outlook models. This involves combining a number of demand and renewable historical profiles including hydro inflows to produce a time series that captures a diverse set of historical 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 projected trends in rainfall and hydro inflows.

In the capacity outlook models, reference years are assigned to the planning horizon 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 demonstrated in Figure 8.

AEMO tests a number of alternative sequences focusing on the first 10 years in the DLT for a representative transmission outlook to determine the sequence and ensure results are not unduly influenced by the reference year mapping. The sequence that results in the most "typical" outcomes for key results such as the development of VRE and firm capacity is selected, to ensure the sequence chosen is not resulting in an outlier outcome.

Figure 8 Rolling reference years in capacity outlook modelling

Renewable resource quality and network expansion plans

The resource quality for renewable generators (including potential REZs) is based on mesoscale wind flow modelling at turbine hub height for wind, while Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) data derived from satellite imagery are used to assess solar resource quality. The methodology used to develop VRE resource profiles is detailed in the *ESOO and Reliability Forecast Methodology Document*[12].

In the ISP, VRE is identifiable at either a specific location (for existing, committed, or anticipated projects), or aggregated within a geographical area, such as a REZ. For REZ aggregation, AEMO applies the same resource profile development technique, but considers the aggregated resource, rather than a specific location. For wind profiles, given the variance that may exist in the wind resource across a small geographical area, the wind resource is split into two tranches, as outlined below. For solar profiles, AEMO estimates the solar resource by selecting the geographical centre of the REZ as the solar measurement point.

This approach is commensurate with considering that not all available land will be developed for VRE generation purposes, considering competing land use and focusing only on developing above-average sites. Further detail on the REZ aggregation profile approach is provided below.

Aggregate REZ wind generation profiles

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:

[12] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

- 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.
- The second tranche represents the remaining good quality resource – above the average of the REZ, assuming 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.

Consideration of stakeholder feedback

EnergyAustralia provided specific feedback on the potential materiality of the sequence in rolling reference years, and AEMO has refined the methodology in response to this feedback.

2.3.6 Network losses

As electricity flows through the transmission and distribution networks, energy is lost due to electrical resistance and the heating of conductors. For HVAC, losses are generally equivalent to approximately 10% of the total electricity transported between power stations and market customers.

Energy losses on the network must be factored in at all stages of electricity production and transport, to ensure the delivery of adequate supply to meet prevailing demand and maintain the power system in balance. In practical terms, this means more electricity must be generated than indicated in demand forecasts to allow for this loss during transportation.

This section presents three complementary approaches to modelling different aspects of network losses:

- Inter-regional transmission losses.
- Intra-regional transmission losses.
- Generator marginal loss factors.

Inter-regional transmission losses

The capacity outlook model (described in Section 2.3.1) uses a topology which splits the five regions defined in the NEM into a number of sub-regions. Despite this, AEMO maintains a regional representation of losses for the transmission network; that is, inter-regional losses are the determined losses on a notional interconnector between two RRNs[13].

Augmentations of the network influence these losses. For the existing network configuration, and each network augmentation option between sub-regions that is explicitly modelled in the capacity outlook model, three types of inputs are required to represent physical and economic impacts of transmission losses:

- Inter-regional loss flow equations – used to determine the amount of losses on an interconnector (that is, between RRNs). These are used to determine net losses for different levels of transfer between regions to ensure the supply-demand balance includes losses between regions. Inter-regional loss equations are used for DC interconnectors.
- Interconnector MLF equations – describe how the losses will change for an increase or decrease in transfer between regions and are essentially the derivative of inter-regional loss flow equations. These equations are necessary to cater for the large variations in loss factors that may occur between regions as a result of different power flow patterns on interconnectors, and incorporate the impact of regional demand. Interconnector MLF equations are used for AC interconnectors.

[13] For an explanation of notional interconnectors, see AEMO, *Proportioning Inter-Regional Losses to Regions*, 2009, at https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2009/0170-0003-pdf.pdf.

- Interconnector loss proportioning factors – used to separate the inter-regional losses into the amount belonging to each of the two regions.

Consideration of stakeholder feedback

AEMO received mixed feedback on whether inter-regional losses should be calculated between regions or between sub-regions. AEMO agrees with EnergyAustralia's recommendation to model losses between regions, because:

- An inter-regional loss representation provides a reasonable representation of losses in the transmission network, and sub-regional augmentations can still impact those loss equations.
- Modelling losses between existing regions is consistent with the published Forward-Looking Transmission Loss Factors methodology[14], so this approach is consistent with how losses are presently accounted for in the NEM.

Three different approaches are taken to calculate loss flow equations, depending on how complex the physical network is that is represented by notional interconnectors:

- **Inter-regional loss flow equation scaling** – used in instances where the proposed network option augments an exists transmission corridor.
- **First principles** – used in circumstances where the losses between regional reference nodes are dominated by one link (for example, HVDC connection connecting in the vicinity of RRNs).
- **Case extrapolation and regression** – used to build an inter-regional loss flow equation when the network augmentation option is for an entirely new and complex transmission corridor.

Inter-regional loss flow equation scaling for network augmentations

For existing interconnectors, the current inter-regional loss equations and MLF equations are available through the NEM's annual loss factor calculation process[15].

Using the power system modelling tool PSS®E (which contains a model of the network), the losses are calculated and plotted across a range of flows on each interconnector for a single PSS®E case. The augmentation is then applied, and the losses recalculated. Where there is a linear relationship between the two loss curves (which is generally the case, especially for incremental upgrades), the average scaling factor is used to scale the inter-regional loss flow equation for the existing interconnector, creating an inter-regional loss flow equation for the augmented interconnector.

The marginal losses are calculated by differentiating the inter-regional loss flow equation and using the same scaling approach to determine the new marginal loss equation.

Finally, the loss proportioning factor is determined by calculating network losses in either region as the inter-regional flows are scaled. This loss proportioning factor is again averaged and scaled against the existing proportioning factor to determine new loss proportioning factors.

First principles

This approach is most accurate for examples where one link dominates the losses between regions (that is, multiple parallel pathways do not increase the complexity of the calculation). In this instance, calculation of losses uses the traditional formula of current squared by resistance ($I^2 * R$).

[14] At https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/forward-looking-loss-factor-methodology.pdf.

[15] See AEMO's Loss factors and regional boundaries web page, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries.

Case-extrapolation and regression

In the absence of an existing inter-regional loss equation to use as a starting point, an entirely new loss equation must be calculated. To do this, losses, demand terms and interconnector flows are calculated using PSS®E. However, instead of a single PSS®E case, over 100 variations of load and generation are used to obtain data for losses, demand and interconnector flows for a wide variety of system conditions. Using this set of data:

- A linear regression is performed to determine an equation for losses, then
- A marginal loss equation is calculated by differentiating the inter-regional loss flow equation, and loss proportioning factors are based on the average regional split of losses across all cases.

Intra-regional transmission losses

Where a consideration of intra-regional losses is material to the assessment of a particular asset and where the potential actionable ISP project has marginal benefits, AEMO may undertake additional analysis to ensure that any consumer benefits that arise from lower transmission losses are considered. To do this analysis, AEMO will follow the following process:

- Use the capacity outlook model or time-sequential model to report on the marginal electricity production cost in each time period – measured in $/MWh.
- Use load flow analysis to calculate the change in local network losses with and without the potential actionable ISP project for each time period modelled in the previous step – measured in MWh.
- Estimate the cost or benefit of intra-regional losses by multiplying the change in losses by the marginal cost of losses.

Generator marginal loss factors

The NEM uses marginal costs as the basis for setting spot prices in line with the economic principle of marginal pricing. There are three components to a marginal price in the NEM: energy, losses, and congestion.

The spot price for electrical energy is determined, or is set, by the incremental cost of additional generation (or demand reduction) for each dispatch interval. Consistent with this, the marginal loss is the incremental change in total losses for each incremental unit of electricity. The MLF of a connection point represents the marginal losses to deliver electricity to that connection point from the RRN.

For input into the capacity outlook model, the latest calculated MLF values are selected. For future generators, a MLF from an existing generator which is similar technology and in a similar location is selected.

2.3.7 Generation and storage in the capacity outlook models

Seasonal ratings

AEMO applies the typical summer capacity[16], in combination with the 10% POE peak derated capacities across the seasons[17], in a manner that will better reflect expected generator capabilities in the capacity outlook models. The definitions of these seasonal ratings and the temperature specifications are consistent with the ESOO, and described in the *ESOO and Reliability Forecast Methodology Document*[18].

The approach to applying these ratings in the ISP is as follows:

[16] The typical summer capacity is used to represent the capacity that would be available under regular summer conditions, based on the 85th percentile of observed maximum daily temperatures for all reference years between December and March. Further details on this approach are available in the *ESOO and Reliability Forecasting Methodology Document*, at https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf.

[17] Seasonal definitions reflect those specified in the 2020 ESOO; that is, summer ratings are applied between November to March and winter ratings between April to October.

[18] At https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/nem_esoo/2020/esoo-and-reliability-forecast-methodology-document.pdf?la=en.

- The winter capacity will be used for all periods during winter.
- The 10% POE demand summer capacity will be applied to the subset of hottest summer days, using the same approach outlined in the *ESOO and Reliability Forecasting Methodology Document*.
- For all other days in summer, the average of the typical summer and the winter rating is applied. This approach is different to that used in reliability forecasting, and better estimates the energy production capabilities of generators in summer, as opposed to focusing on the capacity available during peak periods which is more critical for unserved energy assessments.

This better reflects the availability of generation while maintaining an appropriate assessment of the contribution from generation to meeting summer peak demand. AEMO considers that this method provides an appropriate balance between the burden on participants to provide this data and the benefits of reflecting the expected contribution from generation at times of extreme peak conditions and during more typical summer conditions.

Impact of Equivalent Forced Outage Rate (EFOR) and maintenance rates

The EFOR of generators in the capacity outlook models is represented by a percentage of the total hours of availability of the unit for each year. Since Monte Carlo simulations are not possible in the capacity outlook models, these values are accounted for by derating the available capacity of each generator.

This reflects that, on average, across many simulations, you would expect the generator's available capacity in any given period to be equal to (100% - EFOR). For example, a 100 MW generator with an EFOR of 5% is assumed to have an available capacity of 95 MW in all periods.

As for maintenance events, it is assumed that they are able to be distributed throughout the year such that they do not limit generating capacity at times when it is most required. Over time, as synchronous generation declines, this may be an optimistic assumption. As a result, the impacts of maintenance outages are ignored in the capacity outlook models, but are included in time-sequential modelling to ensure this assumption does not mask reliability or system security issues.

Storage optimisation

The operation of large-scale batteries is optimised within the capacity outlook models depending on the defined capacity, power, and charge/discharge efficiencies. Similarly, the optimisation of pumped hydro energy storage (PHES) technologies is based on the pumping efficiency and capacity of each plant.

The amount of firm capacity the capacity outlook model assumes can be provided by storage technologies is covered in Section 2.4.2.

Hydro optimisation

The NEM contains scheduled hydroelectric generators in Tasmania, Victoria, New South Wales, and Queensland. These schemes are typically modelled with their associated storages and water inflows. For each storage, the generating capacity, depth of storage, initial levels, and the timing and volume of expected inflows considering rainfall variability and climate change factors determine the availability of energy for hydroelectric generation.

Hydro generators are modelled using one of two methods:

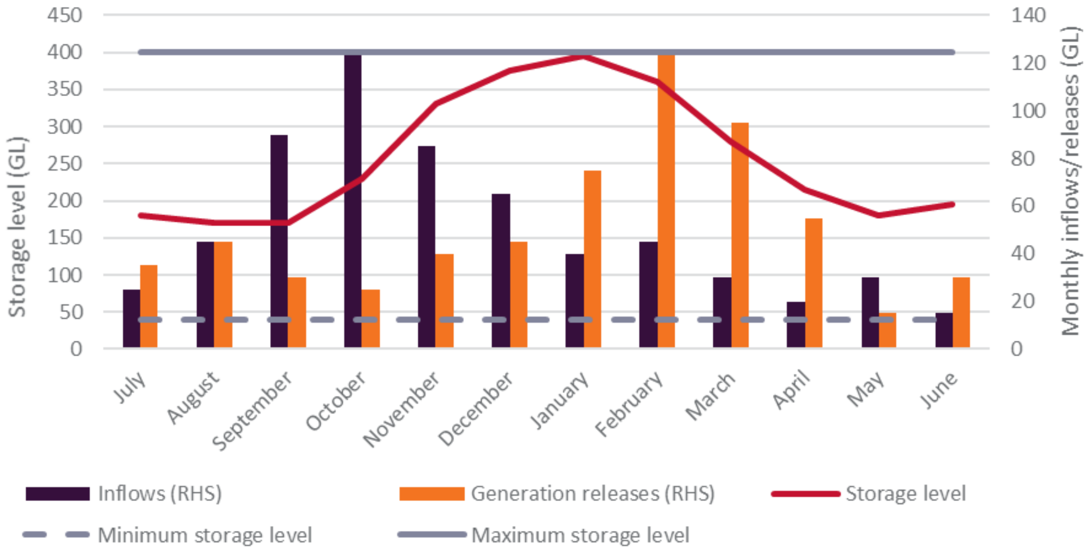
- Energy constraints – which place maximum annual, monthly or seasonal energy limits on individual generators which are then optimised to minimise total system costs.
- Storage management – which is optimised to minimise total system costs based on the management of water available in the storage, inflows and the limitations of the storage and waterways. This also considers an optimisation of any pumping capability within the scheme.

Figure 9 shows a conceptual example of hydro storage management over the course of the year, showing the accumulation of water in storage after a period of high inflows which is then released during summer and autumn, with the final volume being maintained at the level of the initial volume each year. The capacity outlook model requires storages to end each year at their initial volume. This is considered appropriate for a number of reasons:

- Without this limitation, the model may draw down heavily on its storages in early years as this delivers great cost savings simply due to the discounting of costs in future years.
- The model has perfect foresight within each multi-year optimisation window, and without the limitation may use much more aggressive or conservative storage management over a year given the inflows in the next year are known with perfect certainty.

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

Figure 9 Conceptual example of hydro storage management



Hydro scheme assumptions

AEMO has previously documented assumptions detailing the approach to individual hydro schemes in the Market Modelling Methodology Paper. The assumptions are documented here for consultation, but will subsequently be moved to the final IASR.

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.

The latest information on the annual capacity factor constraints used in market modelling studies can be found in the IASR data workbook.

Both the Hydro Tasmania and Snowy schemes are represented with more detailed storage configurations which are needed to capture the interactions between the cascaded storages, the seasonality of inflows and the variety of storage depths which all influence the operation of the schemes. 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.

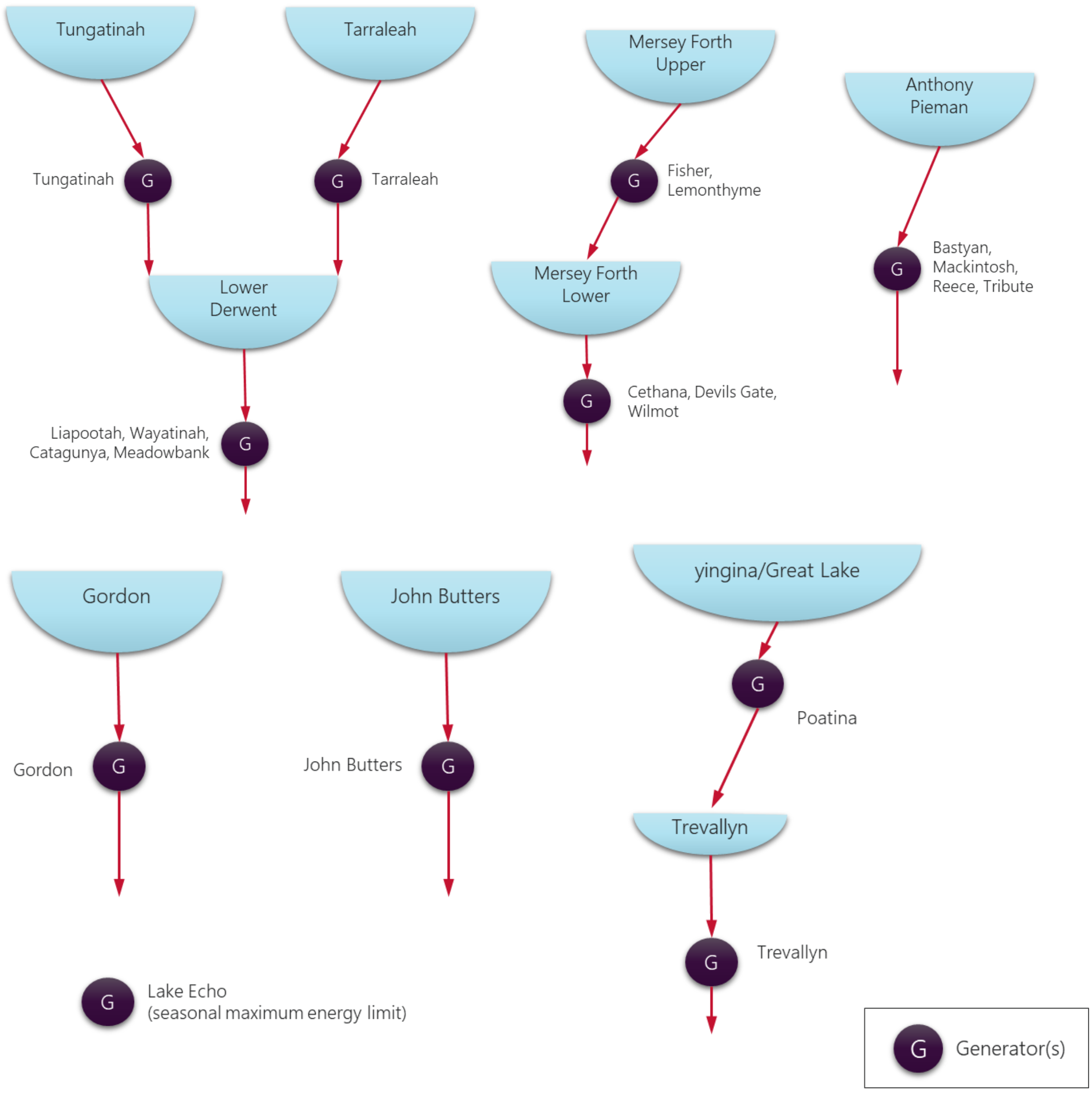
Table 2 identifies how schemes or power stations are allocated across these storages and provides an indication of the energy in storage available. Energy inflow data for each Tasmanian hydro water storage is determined from historical monthly yield information provided by Hydro Tasmania.

Table 2 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
Medium-term	400	Derwent
Run of River	200	Antony Pieman, Mersey Forth, Trevallyn

AEMO's approach to modelling the existing Tasmanian hydro schemes relies on a 10-pond[19] topology designed to capture different levels of flexibility associated with the different types of storage outlined above (see Figure 10).

Figure 10 Hydro Tasmania scheme topology



[19] The capacity outlook model may aggregate long-term storages together to reduce simulation time.

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

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

The latest information on the monthly storage inflows used in market modelling studies can be found in the IASR data workbook.

Figure 11 presents a representation of the topology currently modelled.

Figure 11 Snowy Hydro scheme topology

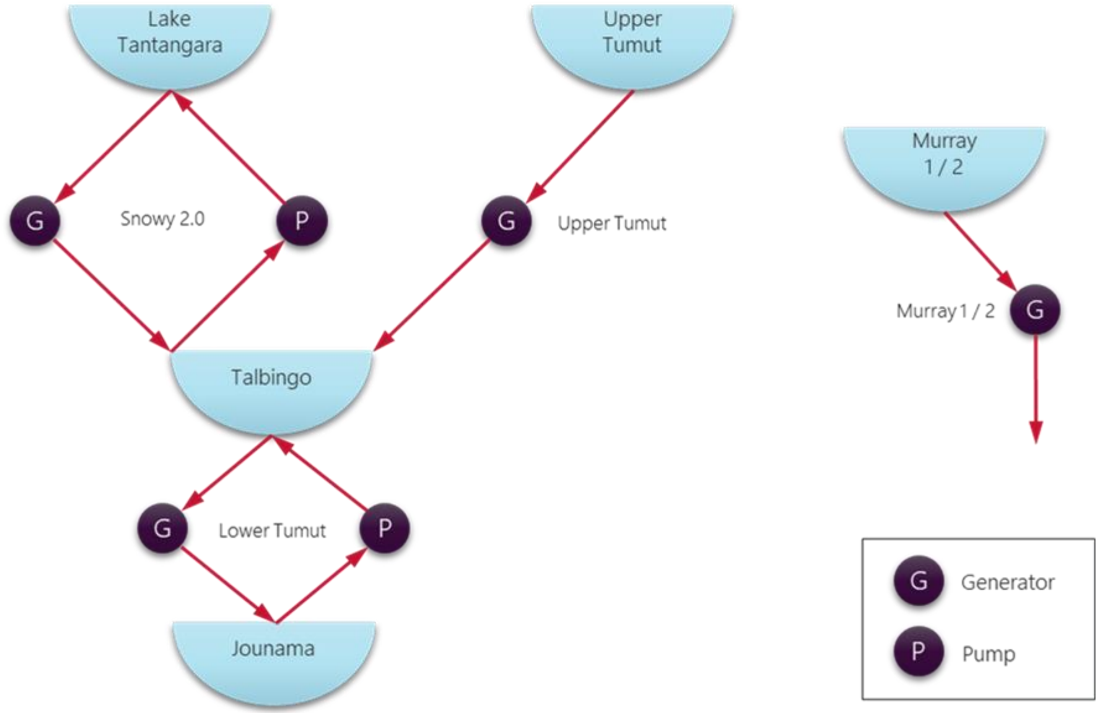


Figure 12 to Figure 20 provide graphic representations of the other hydrological models used in the market simulations, as well as the registered capacity of the adjoining generating units[20].

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

Figure 12 Barron Gorge power station hydro model

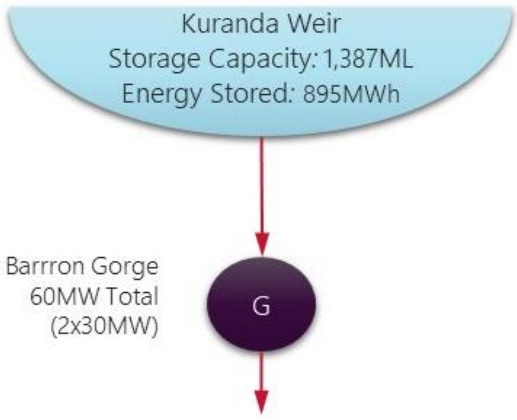


Figure 13 Blowering power station hydro model

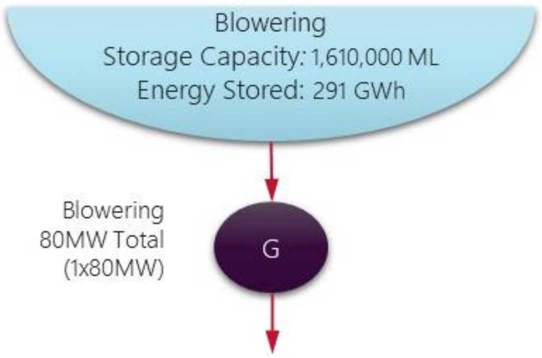


Figure 14 Hume power station hydro model

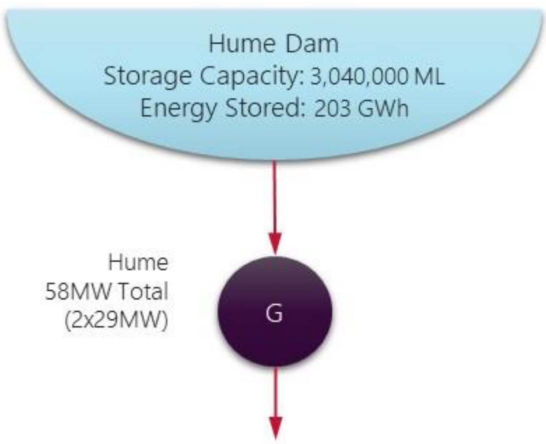


Figure 15 Kareeya power station hydro model

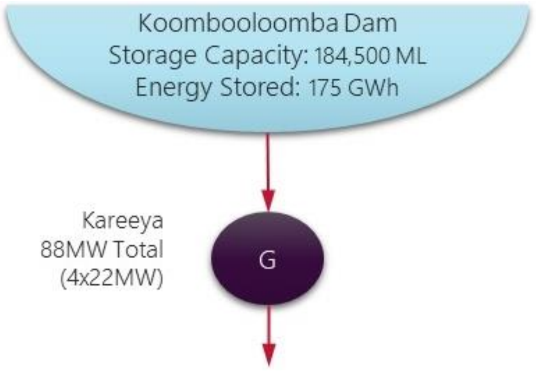


Figure 16 Guthega power station hydro model

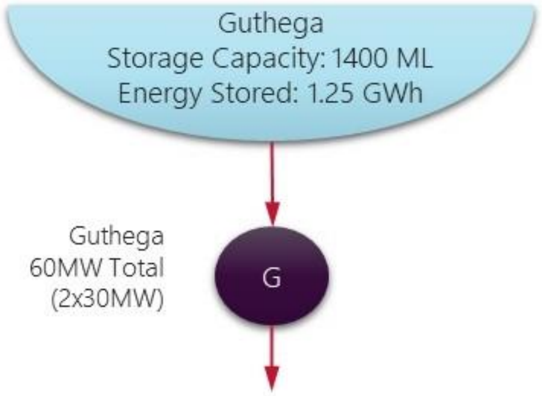
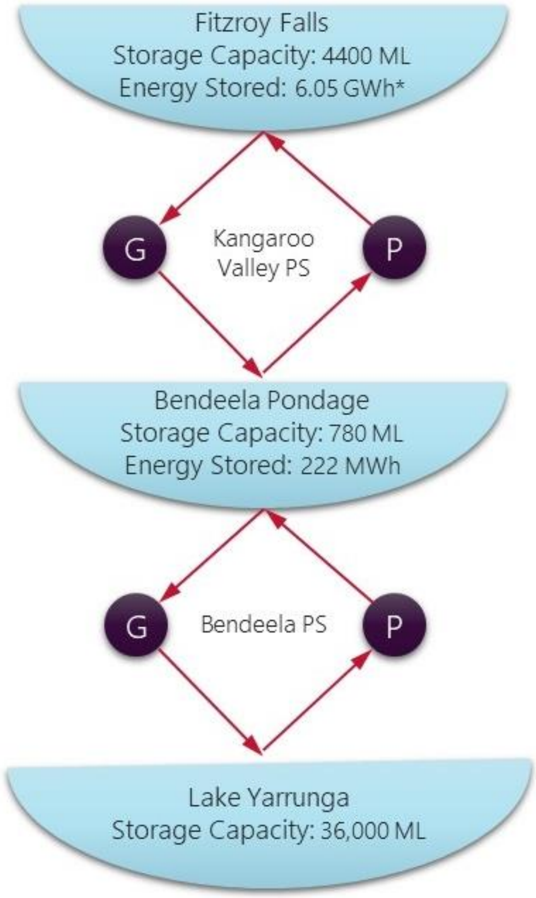


Figure 17 Shoalhaven power station hydro model



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.

*Energy storage at Fitzroy Falls includes full drop through both power stations.

Figure 18 Wivenhoe power station hydro model

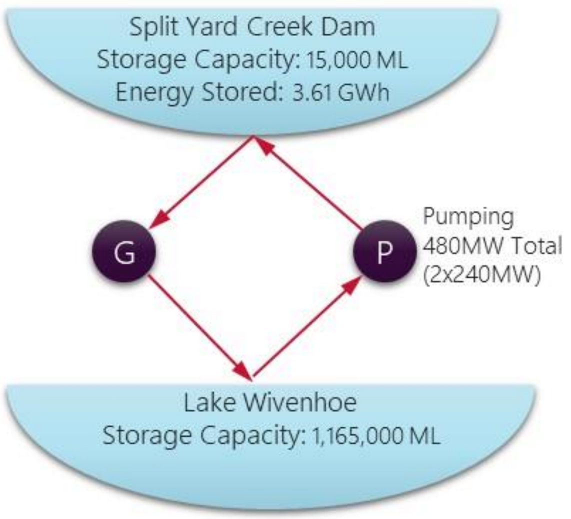


Figure 19 Eildon power station hydro model

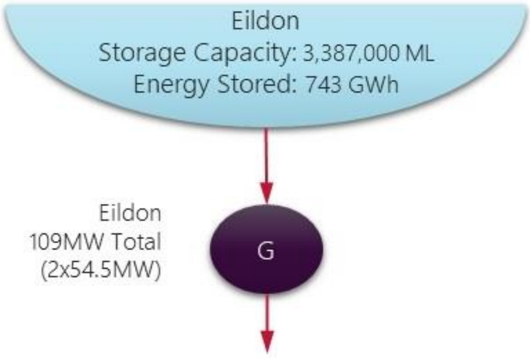
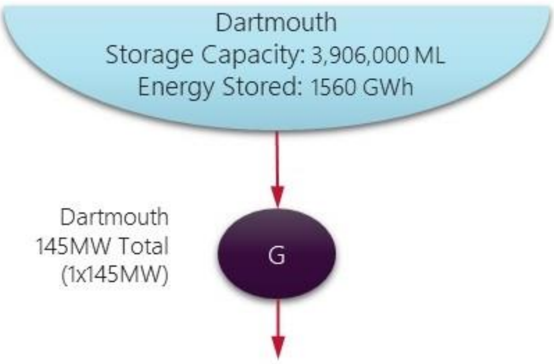


Figure 20 Dartmouth power station hydro model



Operating limits

In long-term planning studies, it is not always possible to capture all actual limits and constraints that would apply in real-time operations, because these can depend on a range of factors. Given the rapid transition currently underway, forecasting these operational limitations is increasingly complex, particularly as the underlying reasons are often opaque and may not be reasonable to assume long term. As a result, AEMO is proposing to limit assumptions of this kind to focus on what is most material, including:

- Any limitations that are due to system security implications – the approach for developing these inputs is detailed in Section 4.
- Some element of must-run operation at coal generators – it is important that some element of coal inflexibility is captured, as it significantly impacts outcomes such as the level of VRE curtailment and the potential value of storage.
- Setting maximum capacity factors on coal stations when generation levels well above historical levels are observed – important to ensure that dispatch is plausible and reflective of any upstream fuel constraints.

Even with granular time-sequential modelling, the forecasting of coal flexibility is a challenging exercise with significant uncertainty. It is not tractable to forecast any optimisation of this behaviour within the capacity outlook modelling and therefore some assumptions need to be made.

AEMO will use current observations, any market intelligence (such as company announcements), and insights from time-sequential modelling to inform a set of reasonable modelling parameters for coal units that reflect the likely operation at or above their minimum stable level in the capacity outlook models. These assessments will be informed by outcomes from time-sequential modelling such as the frequency at which stations are operating at minimum stable levels, or low capacity factors and unit commitment decisions.

These modelling parameters will be refined through an iterative process throughout the ISP, and will be documented in the Draft and Final ISP.

Minimum stable levels are defined by the minimum of observed historical performance of generators over the past several years, generator performance standards, and any feedback from power station operators.

Fuel cost adjustments

AEMO develops forecast gas prices for gas-powered generation (GPG) as a key input developed as part of the IASR development, informed by expert consultant advice. As part of this forecasting process, GPG receives a gas price that is both reflective of current and known future contract positions, as well as the evolving trend in gas pricing across each scenario, considering the influences of oil-price linkages, competition, supply and demand within the gas market.

For GPG, particularly high-utilisation plant such as CCGTs, the methodology considers an approach that reflects a gas price appropriate for an industrial customer, with a locational charge specific for each generator. For low-utilisation plant, such as open-cycle gas turbines (OCGT), the expected price reflects that appropriate for residential and commercial customers, plus a locational charge specific for each generator.

The distinction considers the increased cost associated with servicing low-utilisation customers. OCGTs, like residential consumers, require gas to be available year-round, but are unlikely to use gas in a consistent manner. Gas prices for these customers therefore incorporate additional costs associated with the time or 'shape' of the expected gas consumption, as well as gas storage costs to ensure availability when required. This improves the capture of fixed costs associated with key gas-market infrastructure, within a simplified variable-cost structure (such as a $/gigajoule (GJ) gas price).

To reflect the possibility that high-utilisation gas plant may lower their production in future years, AEMO's methodology allows for an iterative refinement to the gas price that applies to GPG. Where annual capacity factors of CCGT plant are observed to reduce to below 20%, AEMO adjusts the gas price to reflect that of an OCGT, rather than the lower CCGT charge. This iterative assessment occurs between SSLT to DLT, and DLT to DLT model phases, as well as with ST to DLT phases of the modelling approach. While this increased cost is unlikely to materially affect overall dispatch outcomes (as limited alternatives are priced between the cost of CCGT at either a high or low-utilisation gas price), the overall system costs are expected to be more reflective of actual GPG costs if utilisation was reduced to low levels and gas contracts in these circumstances reflected greater prices to recover fixed costs.

Other technologies and alternatives

Aggregated embedded energy storages

Aggregated embedded energy storages are modelled as VPPs in the capacity outlook models. VPPs are modelled similar to storage technologies with the maximum capacity (in MW) and storage duration (in MWh) being the two input parameters required. Similar to large-scale battery storage, the charge/discharge profiles will be endogenously determined within the model optimisation outcome.

Electric vehicles to grid and vehicle to home

While the charging of EVs from the grid is already accounted for in AEMO's forecast demand traces, the potential discharging of EVs to the home and/or grid (when this is assumed to occur based on the scenario) is modelled in the capacity outlook models with a daily energy target constraint. The profile of the discharge pattern will be optimised within the models, with a maximum load value used to reflect constraints on the ability to discharge, taking into account driving patterns.

Demand side participation

Demand side participation (DSP) assumptions are developed annually and forecast a certain level of DSP available at a range of price bands. The capacity available in each price band evolves over time depending on the scenario. For the capacity outlook models, DSP bands are at times aggregated to reduce computational complexity.

2.3.8 Treatment of committed and anticipated projects

AEMO includes all committed and anticipated projects in all future states of the world, in accordance with the AER's CBA Guidelines[21].

The CBA Guidelines (and the RIT-T Instrument[22]) define five criteria that must be used to assess the commitment status of generation (and transmission) projects. If the generation, storage, or transmission project has satisfied all five criteria, then it is defined in the glossary of the RIT-T Instrument as a committed project. If the project is in the process of meeting at least three of the criteria, it is defined as an anticipated project.

In classifying anticipated projects, AEMO needs to be reasonably confident that the project will proceed. If anticipated projects influence power system investment needs identified in the ISP but then do not proceed, consumers are at risk of paying more than necessary for reliable and secure power. Conversely, if anticipated projects are ignored in identifying power system needs and yet do proceed to plan, then inefficient levels of generation curtailment may occur that could similarly result in consumers paying more than necessary for reliable and secure power.

Anticipated generation and storage projects

AEMO maintains a list of committed and anticipated generation projects using information on its Generation Information page[23]. This includes a list of generating units for which formal commitments have (and have not) been made for construction or installation, to the extent that it is reasonably practicable to do so, as well as key connection information (KCI) regarding connection enquiries and applications made to TNSPs.

Generating units are categorised by their stage of development, which is assessed quarterly through survey, using a series of questions (provided in Table 3) that help determine progress against the five commitment criteria: Land, Contracts, Planning, Finance, and Construction. For the Land, Contracts, and Planning criteria, if at least half of the questions related to a particular criteria are answered in the affirmative, the project may be considered to be "in the process of meeting" this criteria. For the Finance and Construction criteria, if at least one of the questions related to a particular criteria are answered in the affirmative, the project may be considered to be "in the process of meeting" this criteria. To ensure reasonable confidence that the project will proceed, AEMO may place more importance on particular questions being answered in the affirmative, or require particular questions to be mandatorily answered in the affirmative, for a project to be considered "in the process of meeting" this criteria. The series of questions (and the method for assessing them as "in the process of meeting" commitment criteria) may be modified over time to reflect technology and policy changes, to ensure ongoing reasonable confidence that projects classed as anticipated are likely to proceed.

Scheduled and semi-scheduled generation projects that are sufficiently progressed towards meeting at least three of the five commitment criteria are assigned a commitment status classification of anticipated for ISP purposes.

To maintain this commitment classification over time, AEMO seeks evidence that the project is continuing to make progress towards meeting the commitment criteria. If a generation information survey has not been submitted by the project proponent in the previous six months the project will no longer be classified as anticipated.

If government-awarded funding is announced for a generation project, this will be considered in the assessment of whether a project is sufficiently progressed towards meeting the finance commitment criteria. For such a generation project to be considered as anticipated, it must be in the process of meeting at least

[21] At https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[22] See https://www.aer.gov.au/system/files/AER - Regulatory investment test for transmission - 25 August 2020.pdf.

[23] See https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

two other commitment criteria. In the case where government-awarded funding provides long-term investment certainty and is awarded as part of a large-scale program, AEMO may have regard to the eligibility criteria for this funding when considering a project's progress against other (non-Finance) commitment criteria.

The anticipated project commitment status classification will be included in the Generation Information publication from July 2021 onwards.

Table 3 Project commitment criteria questions

Land	• Have the rights been secured for the land that is required for construction of the generating unit(s)? • Have the rights been secured for the land that is required for easements of new lines to connect the generating system to the transmission/distribution network?
Contracts	• Has the detailed design been completed to the extent required for a connection enquiry to be made to the relevant network service provider (NSP)? • Are contracts for the supply and construction of major plant or equipment finalised and executed (officially signed), including any provisions for cancellation payments? (Major plant and equipment include components such as generating units, turbines, boilers, transmission towers, conductors, and terminal station equipment, as relevant to the project.)
Planning	• Has an application to connect been made with a NSP? • Has a connection agreement with a NSP been signed? • Have you received AEMO's official letter of acceptance of the generator performance standards? (This is confirmed with AEMO Registrations.) • Have all relevant environmental approvals for construction and operation been obtained? • Have all relevant planning and licensing approvals, from local and state government authorities, been obtained?
Finance	• Does the project/project stage/generating unit(s) have an associated Power Purchase Agreement (PPA)? • Besides a PPA, are there other financing arrangements in place (such as merchant financing and/or long-term State or Federal Government funding)? • Has the Final investment Decision (FID) been reached (signed off), under the usual commercial definition of official Board financial approval regarding when, where and how much capital is being spent?
Construction	• Has a firm construction start date (or range) been set? Provide the earliest likely date, and the latest likely date, for commencement of construction or installation at the Site. • Has construction or installation commenced at the Site? If so, provide the actual date that construction commenced. • Has a Full Commercial Use Date (or range) been set, that is, the date from which the generating system is planned to have received official approval (sign-off) of all commissioning tests, from AEMO and the NSP? If so, provide the earliest likely date, and the latest likely date, for Full Commercial Use.

Consideration of stakeholder feedback

In response to stakeholder feedback, AEMO proposes to exclude projects from the anticipated category that have not recently submitted a Generation Information survey, and consider government-awarded funding when determining the finance commitment status.

Anticipated transmission projects

Anticipated transmission projects are transmission augmentations that are not yet committed but are highly likely to proceed and could become committed soon. Such projects could be network or non-network augmentations and could be regulated or non-regulated assets. Because these projects are an input to ISP modelling, they cannot become actionable under the ISP framework. They are included in the ISP so their impact on other projects can be captured (their merit is not assessed).

AEMO consults on anticipated transmission projects through the IASR framework. If a developer intended to become licensed as a TNSP for the purpose of constructing, operating, and maintaining transmission network, AEMO intends to apply the same rigor used to determine the project status as for any other generation or network project.

2.4 Methodologies used in capacity outlook modelling

The capacity outlook modelling uses a number of methodologies described in this section, including:

- Early generator retirements, for which AEMO uses both the SSLT and time-sequential modelling.
- How demand and VRE profiles are approximated within the capacity outlook models.
- Firm capacity requirements and their application to different technologies.
- How new entrant candidates are considered.
- The approach to modelling emission trajectories and targets.
- Build decisions for generators and interconnection.

2.4.1 Early generator retirements

All generators are required to inform AEMO of their expected closure year[24] (in accordance with National Electricity Rules [NER] 2.2.1(e)(2A)), and their closure date once they seek to terminate their classification as a generating unit (in accordance with NER 2.10.1 (c1)), which is used as an input to the ISP modelling. However, the potential for early retirements needs to be explored across all scenarios given the materiality of their impact on the needs of the power system.

AEMO uses both the SSLT and time-sequential modelling to determine and explore generator retirements. The consideration of retirements is limited to the period beyond any NEM or jurisdictional notice of closure regulations[25]. Similarly, if a generator has reported its closure date (as opposed to its expected closure year) then earlier retirement of that unit will not be considered.

Any new entrant generators that are built in the model are assumed to retire at the end of their technical life.

AEMO will deploy a slightly different approach to generation retirements depending on the scenario. For those scenarios which have periods that are not influenced by an explicit decarbonisation constraint in the electricity sector, Approach 1 will be used to reflect the primary driver of retirements being on the basis of wholesale prices, and therefore the primary determinant of retirement are forecasting wholesale prices.

When an explicit emissions constraint is influencing generator retirements, Approach 2 will be used which initially determines a retirement trajectory through least-cost modelling which takes into account the impact on cumulative emissions. These outcomes are then validated in time-sequential modelling, where only large negative profitability outcomes are sufficient to trigger further retirements.

The IASR specifies the approach used in each scenario.

Approach 1: Price forecasting and least-cost retirement hybrid approach

For the scenarios that use this approach, AEMO will apply the following steps:

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[24] AEMO publishes generator closure information as part of its regular Generation Information updates. See the *Generating Unit Expected Closure Year* spreadsheet, at https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[25] For example, Latrobe Valley coal generators in Victoria are required to give five-year notices of closure:; see https://earthresources.vic.gov.au/community-and-land-use/key-site-updates/latrobe-valley-coal-mines/rehabilitation.

- Use any generator retirement trajectory which is available in the most recent New South Wales Consumer Trustee report as a starting point for a generator retirement trajectory.
- Apply those retirements in addition to the expected closure years to generators through the SSLT capacity outlook modelling to determine representative generation and transmission developments. The SSLT model is able to bring forward generator retirements with expected closure years beyond 2030 (any retirements are integerised as described in Section 2.4.6), but not before.
- Apply the developments and retirements to time-sequential modelling until 2030, and when the following conditions are met, assume a station would bring forward its retirement, or at least mothball units:
  - A station is making a negative return which exceeds the cost of bringing forward retirement by a single year.
  - The station continues to be making a negative return over the period until 2030 or until its expected closure year/closure date.
  - Retirements may be staged over two years for four-unit stations. In closure year submissions and observed generator retirements, retirements of units at a station are typically within a short period of time, and rarely over more than two years.
- Any further early retirements are then reapplied in the SSLT in the period up until 2030, and the process continues iteratively until no further retirements are identified in the time-sequential modelling.
- A final simulation through the SSLT determines the generator retirement schedule until the end of the modelling horizon.

Approach 2: Least-cost retirement approach

For other scenarios, AEMO uses the following approach:

- Use any generator retirement trajectory which is available from jurisdictional policy objectives or implementation details[26] as a starting point for a generator retirement trajectory, and take into account any retirements brought forward in scenarios where Approach 1 was adopted.
- Apply those retirements in addition to the expected closure years/closure dates to generators through the capacity outlook modelling to determine representative generation and transmission developments. The SSLT model is able to bring forward generator retirements, provided they are not before any notice for closure restrictions (any retirements are integerised as described in Section 2.4.6).
- Apply the developments and retirements to time-sequential modelling to validate the retirements until 2030. This validation explores whether there are any remaining thermal power stations which are making considerable negative returns over multiple years. These stations may then be added to the retirement schedule, again potentially staging over two years for four-unit stations.
- Any additional retirements are added to the retirement schedule and applied in the SSLT to determine a revised schedule, with is again validated in time-sequential modelling.

Consideration of stakeholder feedback

Given that a number of stakeholders proposed economic factors should be taken into account when considering early retirements, AEMO has expanded on the description to clarify that this is part of the ISP methodology.

[26] For example, the New South Wales Consumer Trustee report; further details at https://energy.nsw.gov.au/government-and-regulation/electricity-infrastructure-roadmap

2.4.2 Representation of demand and VRE profiles

In AEMO's time-sequential modelling that is used for reliability assessments such as the ESOO, a weighting of simulation results from 10%, 50% and sometimes 90% POE simulations are used, with many iterations performed in each set of POE simulations, varying supply availability due to forced outages. For the capacity outlook modelling, this approach is not possible given that the capacity outlook model requires a single demand trace and does not use any stochastic techniques, and instead uses a constant derating of capacity by the EFOR (as described in Section 2.3.7). Compared to stochastically modelling outages, a constant derating results in an optimistic representation in terms of reliability.

To balance the need to ensure that capacity is sufficient to meet high peak demands against the simpler representation of firm capacity due to the derating approach to forced outages, 10% POE demand profiles are used. The demand profiles are on a "sent out" basis (rather than "as generated"), with load converted dynamically to "as generated" within the modelling depending on the auxiliary needs of generation being dispatched. This allows the modelling to reflect the potential change in generation auxiliary loads resulting from a changing generation technology mix.

When modelling operational consumption, distributed PV (including both residential and non-scheduled generation) is first netted off the underlying consumption trace. Distributed PV is not explicitly modelled in the capacity outlook model. Instead, it is assumed that all distributed PV excess to consumers' needs is free to export to the grid unconstrained.

Load duration curve

Load duration curves (LDCs) are used to approximate half-hourly demand in longer-term models which span multiple years, to make the problem computationally tractable. This involves aggregating a collection of demand intervals exhibiting similar characteristics and modelling them as a single load block. As much as practicable, seasonal and diurnal patterns are preserved. This aggregation of demand is then applied to VRE, such that the same periods are aggregated (using averaging) to preserve correlation between demand and VRE availability.

The extent of aggregation is determined based on the final model settings and assumptions which affect the simulation time. The level of aggregation is minimised to preserve the maximum level of granularity available within a workable simulation time. Some scenarios may therefore need to apply a lower level of granularity as needed if those scenarios require more simulation complexity in other aspects of the model.

There are many different ways that half-hourly demands can be aggregated into load blocks. Some minimise variation in operational demand within a block, but if there was large variation in VRE availability across the loads within that block then this variability would be lost due to the averaging that takes place. Further, if chronology is completely ignored, daytime loads (and hence solar generation) could be included in every load block and the value of storage to complement solar generation would diminish significantly.

The techniques used by AEMO for capacity outlook modelling have therefore been chosen to strike a balance between the importance of capturing variability in load and VRE availability and the chronological nature of energy storage. 'Sampled' and 'fitted' chronology settings are used for the SSLT and DLT models, respectively, as discussed below.

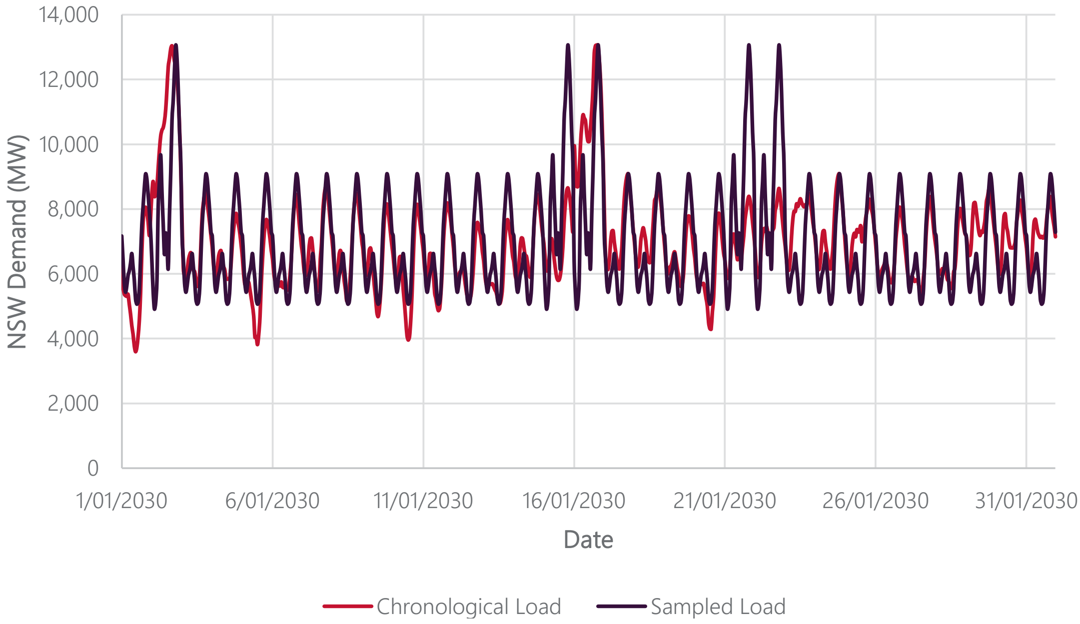
Sampled chronology

The SSLT model uses the "sampled" chronology setting, which preserves a specified number of periods (typically day(s) per month or week(s) per year) for modelling. This is shown in Figure 21, which compares sampled load profile (two days per month) against the chronological load, for a forecast of January 2030 in New South Wales. The remaining periods (unsampled) are 'mapped' to the samples to produce a full set of results. While this method preserves chronology and enables the evaluation of storage and inter-temporal constraints within the model, it has the drawback of assuming the same amount of VRE resource availability for the other 'unsampled' periods.

VRE profiles are scaled within the modelling software to ensure that the capacity factor of each VRE generator is aligned between the sampled outputs and the underlying input data.

The "sampled" chronology setting, while not as comprehensive as the approach used in the DLT, allows the SSLT to solve within a reasonable timeframe (days) while still retaining an appropriate reflection of variability and chronology.

Figure 21 Example representation of a sampled load profile



Fitted chronology

The DLT simulates with aggregations at a daily level in a chronological fashion, thus retaining granularity while covering all periods in the modelling horizon and preserving diurnal patterns. The regional demand time series fed into the DLT is fitted with a step function so the total number of simulation periods per day is reduced from 24 hours to a small, but still representative, number of load blocks (typically five to eight).

The 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 periods where demand is more variable, for example during the evening peak. The duration of each block can therefore vary depending on how the underlying intervals are grouped together.

Maximum and minimum demand in each day are not necessarily preserved through this approach, as the allocation of blocks may average over multiple periods at these times. However, the weighted least-square approach will generally result in more blocks during peak periods, particularly where peaks are much higher than surrounding periods.

Figure 22 provides an example of eight load blocks approximating the forecast hourly underlying demand of New South Wales for a sample forecast day in July 2029. 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.

Figure 22 Example representation of fitted load blocks

Load subtracter – an improvement in the representation of intermittency

The process of aggregating chronological load profiles into fitted load blocks for the DLT model results in the blocks being aggregated into time periods in such a way that there is potentially misrepresentation of solar/wind generation, for example, solar generation late in the evening/at night.

This may happen in the DLT model if a load block is allocated to a time period from 5.00 pm to 11.00 pm, for example (which would include both solar and non-solar production time). To refine the model further, an estimate of the half-hourly regional VRE generation is subtracted from the chronological load, and the step function is built around this net load instead. The estimate of regional VRE generation is based on both existing generation and previous projections of VRE development. This is an iterative process which aims to improve the accuracy of the approximation of load and VRE output. This interaction is illustrated in Figure 3 in Section 2.2.

This approach results in greater variability in net load informed by VRE profiles, which is considered when fitting the load blocks, and therefore leads to a better load block representation around the shoulder periods and better reflects the remaining load which is needing to be served by other generation and storage available. It is important to note that this net load only impacts the initial 'slicing' of the chronological load blocks, and that in all modelling simulations, the original load is always considered.

This feature is also applicable for the SSLT model, where the selection of the sample day/week/month is dependent on the net load (chronological load minus an estimate of VRE generation), hence resulting in a better representative day/week/month being used as a sample.

2.4.3 Firm capacity requirements

Reserve levels

The current 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.

In AEMO's reliability assessments for the ESOO, many Monte Carlo simulations of the time-sequential model are performed to forecast the average weighted USE. Due to the lack of granularity in the capacity outlook models, it is not possible to get an accurate, probabilistic assessment of the USE level in any given year. However, it is critical that these models are developing generation that is sufficient to achieve the reliability standard, valuing appropriately the reliability benefits provided by different generation, transmission, storage, and demand-side options.

The capacity outlook models therefore incorporate minimum capacity reserve levels for each region as a proxy for reliability, along with assumed contributions to these reserves from generation, transmission, storage, and demand-side technologies. These reserve levels are implemented as constraints in the model, targeting the achievement of the reliability standard[27], defining the minimum amount of firm capacity above load that must be either installed in each region or imported from neighbouring regions for all time periods. The regional minimum capacity reserve level is allocated to the sub-region that contains the regional reference node, with no excess reserves required in other sub-regions within each region.

The amount of reserves that can be imported from other sub-regions at any given time depends on transmission limits between sub-regions, the coincidence of peak loads, and firm capacity in other sub-regions, which is given full consideration when optimising firm capacity developments in the capacity outlook models.

More detailed assessments of supply adequacy are then simulated in future modelling stages with the more granular time-sequential models, the results of which are used to refine the capacity reserve levels and firm contribution factors used in the capacity outlook models. Through the iterative process previously presented in Figure 3, the capacity outlook models ensure that sufficient firm capacity is installed and maintained within each region, or imported from neighbouring regions, to meet the reliability standard.

If the time-sequential models (which continue to assess reliability on a purely regional basis) show the reliability standard is being exceeded, then the reserve levels are increased. If the time-sequential modelling shows that capacity was added to the system as a result of the firm capacity requirements and a region is comfortably below the reliability standard, the reserve levels are reduced.

Key reserve modelling inputs to the capacity outlook models include:

- Minimum capacity reserve levels (in the first instance, set to the size of the largest generating unit in the region, or with minimum reserve levels calculated in the most recent ISP, and adjusted based on subsequent time-sequential modelling).
- Maximum inter-regional reserve sharing (based on an assessment of the transfer capability of interconnectors at times of maximum demand).
- Firm capacities for scheduled generators using seasonal ratings, adjusted for equivalent forced outage rate (see Section 2.3.7).
- Firm capacities for VRE generation and storage which are based on firm contribution factors. These factors are only used by the capacity outlook model to estimate the contribution of these technologies to meeting minimum reserve levels.

The capacity reserve level constraint is formulated, in simple terms[28], as:

$$\begin{aligned} &SUM(Scheduled\ generator\ firm\ capacity) + SUM(Inter-regional\ reserve\ sharing) \\ &\quad + SUM(VRE\ firm\ capacity) + SUM(Storage\ firm\ capacity) \\ &\quad - Regional\ Maximum\ Demand\ (10\%\ POE) \geq Regional\ reserve\ level \end{aligned}$$

The following subsections discuss in more detail the method used to determine firm contribution of scheduled generators, VRE, storages, and transmission lines. The approach described for each component is only an approximation of the true contribution to reliability, however a simplified assumption must be made that can be formulated as an input to the model. The more complete contributions to reliability and to the system more broadly are captured through the actual capacity outlook modelling which takes into account variability and chronology, and through the validation in time-sequential modelling.

[27] The reserve levels are specified to achieve the Reliability Standard, and not other interim or region-specific targets. As such, other targets, such as the Interim Reliability Measure or the New South Wales Energy Security Target (EST) are not applied over the long-term planning horizon deployed for the ISP. The IASR will specify if any exceptions to this approach will apply.

[28] The exact implementation of this equation within the model requires greater complexity regarding the dynamic capabilities of some terms, and considering the capabilities of intra-regional network limits within this regional constraint.

Scheduled generators

Scheduled generators can typically provide power at near-full output at times of maximum demand for the purpose of meeting reserve requirements in the capacity outlook model.

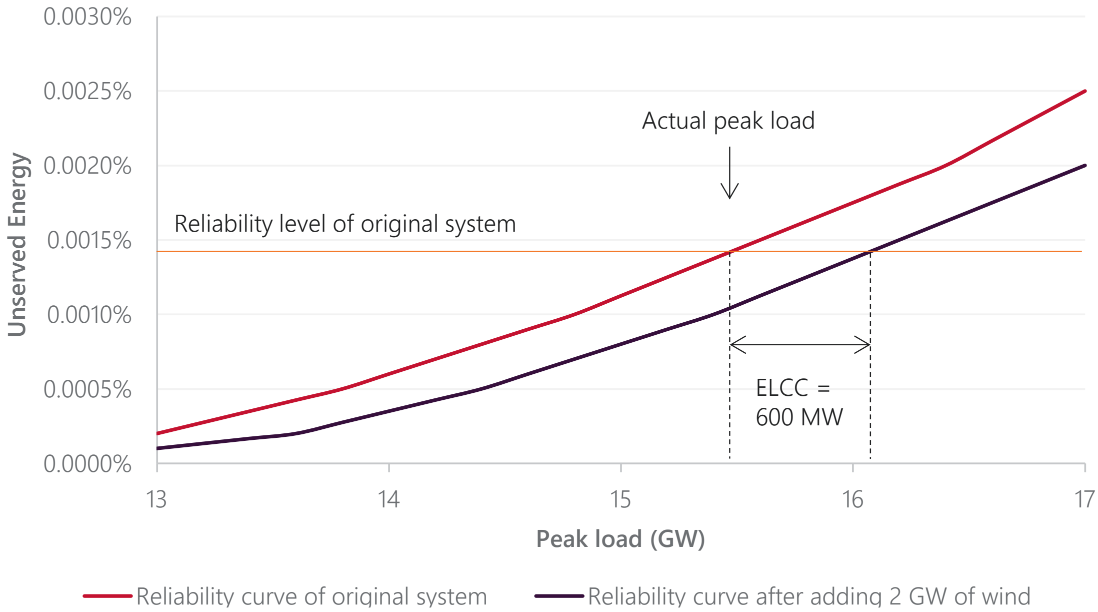
The firm contribution from scheduled generators, used solely to assess adequacy of reserves, is based on their seasonal ratings as provided to AEMO via the Generation Information page[29]. In summer, firm capacity is assumed to be their 10% POE demand summer rating, while the winter rating is used for winter. These ratings are adjusted for EFOR, as a proxy for the impact of generator outages which are modelled stochastically in reliability assessments.

Firm contribution factors for VRE

For the purpose of reserve modelling, AEMO develops wind and solar contribution factors that represent the assumed equivalent firm capacity from these technologies that can be relied on during times of peak demand. By their nature, intermittent renewable generators cannot operate at any dispatch target at any time; rather the generation they provide depends on prevailing weather conditions. As such, while VRE generation often can be observed at high levels, the capacity that may be relied upon to operate during times of 10% POE maximum demand may be materially lower than the installed capacity, especially if weather conditions that typically produce high demand events (particularly hot conditions) are highly correlated with low VRE production periods (for example still/low wind conditions).

AEMO approximates the firm contribution factors of solar and wind by calculating the effective load carrying capacity (ELCC) of these technologies. The ELCC of a generator or technology represents the equivalent amount of perfectly reliable capacity[30] that would need to be added to the system to achieve the same level of system reliability. As demonstrated in Figure 23, this value can be calculated as the amount by which load can be increased with the generator or technology in the system, while maintaining the same level of reliability as is achieved without it. In this example, after 2 gigawatts (GW) of wind generation is added to the system, load can be increased by 600 MW before reaching the same level of reliability as the original system. This means the additional wind generation has an ELCC of 600 MW, or 600/2,000 = 30%.

Figure 23 Example calculation of effective load carrying capability



[29] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information.

[30] Perfectly reliable capacity refers to capacity that is 100% available and can be operated to meet any dispatch target with instantaneous ramping.

ELCC values for solar and wind are computed endogenously within the iterative modelling process for both summer and winter for each region in the NEM, expressed as a percentage of installed capacity, and averaged across all reference years. As ELCC depends on the resource mix of the system and generally declines as penetration of VRE increases, values are calculated in five-year increments for each scenario, based on an assumed resource mix equal to that observed for the given horizon year and scenario in previous simulations. This is necessarily an iterative process, as VRE penetration may subsequently be influenced by the assumed contribution to maximum 10% POE demand, as shown in Figure 3 in Section 2.2. The calculated ELCC values for wind and solar in each scenario will be published in the assumptions workbook that accompanies the draft and final ISP.

Firm contribution factors for storage

The challenges with modelling the firm contribution from storage technologies are different to those detailed for VRE, because the issue relates to the ability to run over a continuous period, rather than to reflect variability.

AEMO approximates firm contribution factors for storage by determining the average duration of peak demand events and adjusting the firmness of different storages to reflect their ability to provide generation across this period. For example, if the average duration of peak demands was determined to be approximately three hours, a 1 MW / 2 MWh battery with an effective storage depth of two hours would be allocated a firm contribution of 2/3 = 66.7%.

Determination of the average duration of peak events will initially involve analysing modelling outcomes from the most recent ESOO to calculate the average number of hours that instances of USE are expected to last, in regions and scenarios that are close to the reliability standard.

Firm contribution from other technologies

Aggregated embedded energy storages

As discussed in Section 2.3.7, aggregated embedded energy storages (including VPPs) are represented similarly to large-scale battery storages in the capacity outlook models. As such, the firm capacity contribution from these storages will use the same approach to the one outlined above for storage technologies, based on forecasts for maximum power and storage capacity in each region and scenario.

Electric vehicles to grid

The approach to determining firm capacity will also be based on the approach outlined for large-scale storages, and take into account any time-of-day limitations that reflect driving patterns.

Demand side participation

The contribution of DSP to reserve levels in each region is equal to the total quantity of DSP available. This quantity represents the amount by which demand can be reduced at times when the supply-demand balance is tight and USE might otherwise occur, and as such has an equivalent ability to maintain system reliability as firm generation of the same capacity.

Consideration of stakeholder feedback

Several stakeholders provided feedback on the approach to firm capacity requirements. In response to EnergyAustralia's request, further clarity has been provided on the consistent approach that is applied to technologies such as behind-the-meter storage and VPPs.

In response to TasNetworks' suggestion of reconsidering the contribution factors once interconnectors are commissioned, AEMO has provided further clarity on the approach to allowing excess reserves to be shared across regions which takes into account augmented transmission capacity.

Given concern expressed over the conservatism in the previous approach to applying the 85th percentile to assess the firm capacity of wind and solar, the alternative approach of ELCC has been applied.

Shell Energy also requested clarity on how the peak demand duration would be calculated and how reserve levels are adjusted based on time-sequential modelling. AEMO has provided this clarity, and confirmed that reserve levels may be increased or decreased depending on the reliability outcomes observed in time-sequential modelling. Shell Energy also sought clarification on the interaction between the reserve modelling and the sub-regional model, and AEMO has expanded on its description to meet this request.

2.4.4 New entrant candidates

Build limits and lead time

The capacity outlook models consider a wide range of build candidate options for generation and energy storage technologies listed in the IASR. Build limits associated with new investments are incorporated to reflect the maximum development of the different options at a regional and sub-regional level. Construction lead times for each technology type are reflected in the models by specifying the earliest build date for each candidate technologies.

For renewable generators in REZs, the representation of resource potential and transmission limitations is developed separately, and described in Section 2.3.4.

Filtering approach

To manage the simulation scale of the capacity outlook models, AEMO uses filtering techniques to eliminate technology development options that are considered uneconomic or unlikely given the scenario drivers.

Further filtering is then applied to the DLT. It involves a preliminary screening of the set of candidate options, including thermal and storage options, by simulating snapshot years across the horizon to determine whether a technology is a part of the most economically efficient solution at any time across the planning horizon. For example, this might include simulations to determine the optimal generation mix in 2030, 2040, and 2050. Any technology option that is not developed in any of those simulations can then be excluded from full horizon modelling.

Applying a snapshot year approach isolates the selected years, reducing the problem size significantly, and allowing greater technology development options to be included. Years are chosen based on the DLT's step size and policy setting requirements. For example, if a key policy needs to be met by 2035, 2035 will be considered a snapshot year.

For storage candidates, options are selected considering the following conditions:

- Each region should have at least one storage candidate of each technology type from the range of available storage depth options in the region. For example, if the available options in region A include depth storages of two hours, four hours, six hours, and eight hours, the filtered candidates will consist of at least one of these options across the sub-regions.
- Pumped hydro technology is selected based on available resource for suitable sites, allowing to reduce the number of options where no feasible sites can be developed.

The filtering technique is carried out for each scenario and sensitivity.

2.4.5 Emission trajectory and targets

Modelling emission trajectories and targets

The degree of interdependency between energy sectors is projected to increase as Australia continues to decarbonise. In a low emissions economy, low or zero carbon energy fuels (such as renewable generation, green hydrogen, or bioenergy) will be required to meet an increasing share of energy demands. At the same time, not all sectors of the economy will decarbonise at the same rate, considering the varying degree of penetration, and commercial viability, of low carbon technologies across different sectors. Likewise, sectors that rapidly decarbonise may not find that full decarbonisation is economic, relative to alternatives.

In recognition of this, AEMO is using multi-sectoral modelling to better understand the degree of nation-wide emission reductions that the electricity sector may support. This allows for consideration of the relationship between emission reductions and economy-wide electrification in the capacity outlook model.

In effect, the multi-sectoral model allows AEMO to consider an economy-wide emission constraint or target consistent with its scenario ambitions, and determine emission pathways at a sectoral level, including for electricity and specifically the NEM. At the same time, the model considers individual technologies across all energy sectors, to ascertain the degree of increased electrification (for example, of transport, heating, and for industrial applications) that is consistent with a certain level of final energy demand growth, and economy-wide emission reduction ambitions.

The emission allowance (or carbon budget) obtained from multi-sectoral modelling will be used as input in AEMO's capacity outlook models.

For any given scenario, the overall cumulative amount of emissions that the multisectoral model considers consistent with the NEM will first be imposed onto the SSLT, where the carbon budget is met by influencing the retirement timing of fossil-fuelled generation and/or out-of-merit-order dispatch. An annual emission trajectory that meets the cumulative carbon budget for the NEM to 2050 at least cost to consumers is determined in the SSLT.

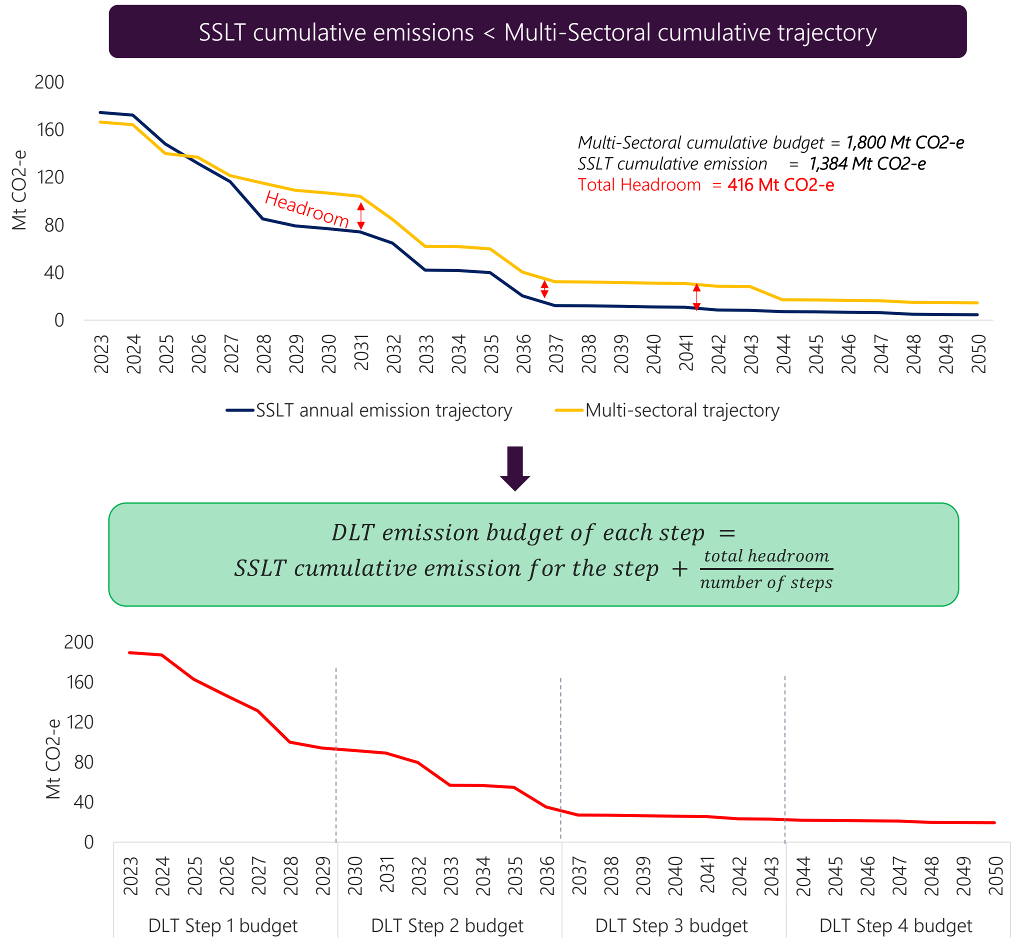
Annual emission trajectories derived from the SSLT for each scenario are then re-aggregated into cumulative emission constraints that span shorter optimisation windows equivalent to the length of each step in the DLT. Once again, this allows the model to re-optimise emissions in each step of the DLT, while respecting overall constraints derived from the SSLT and multi-sector models

The SSLT and DLT impose hard emission constraints, which means emissions are not allowed to exceed the carbon budget. If the cumulative emissions in the SSLT are lower than the emission constraint (the constraint is not binding), then calculating each step's emission budgets imposed in the DLT will account for this headroom by distributing the difference between actual emissions in the SSLT and the carbon budget to each step's budget in the DLT.

This approach is illustrated in Figure 24.

This prevents the DLT from being overly constrained beyond what the multi-sectoral model estimated was an optimal carbon budget for the electricity sector over the period, and allows flexibility to account for minor differences in modelling outcomes attributable to using a sampled chronology to fit load blocks in the SSLT.

Figure 24 Decomposition of emission constraint in the capacity outlook models



2.4.6 Build decisions for network, generation and storage

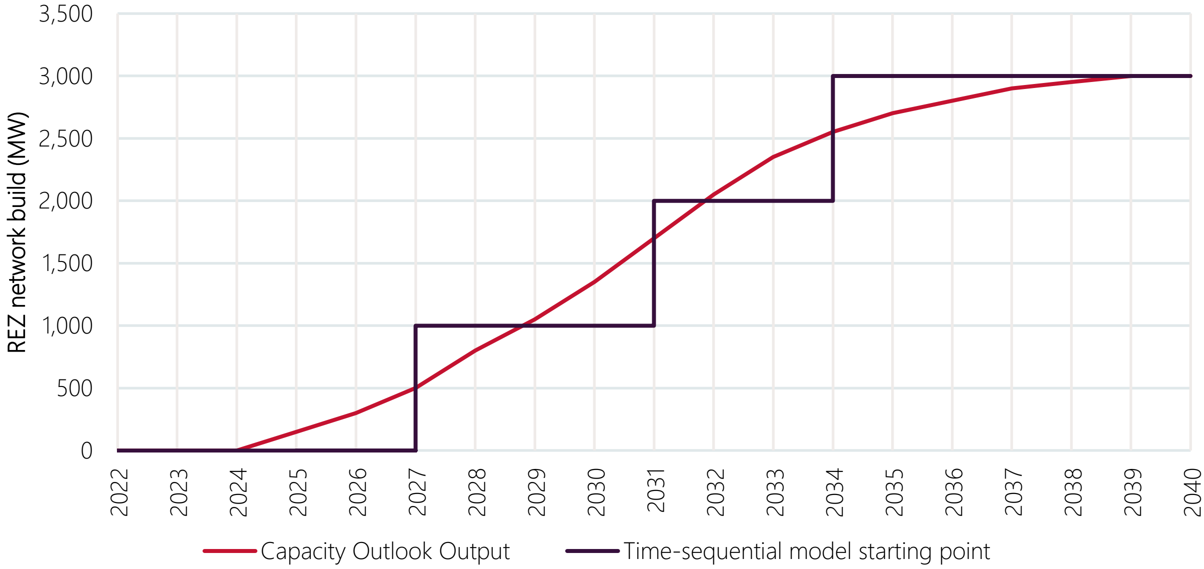
Decision variables in the capacity outlook models include the size and timing of new generation, storage, and transmission builds. To keep simulation times manageable, the models use linear programming rather than mixed integer programming, meaning that these discrete decision variables are linearised (for example, the model could choose to build 0.314 units of a 300 MW CCGT plant).

The approaches used for rounding linearised build decisions in the capacity outlook models are described below.

REZ network expansions

The capacity outlook model uses linearised REZ expansion costs to determine the approximate scale and timing of REZ network expansions (see Section 2.3.4). This process results in a continuous build trajectory for the network expansion of each REZ (see the "Capacity Outlook Output" in Figure 25). Because network investments are discrete (i.e. they are typically large bespoke projects), the continuous trajectory from the capacity outlook model must be transformed into a step function that represents the delivery of individual network expansion projects over time (see the "time-sequential model starting point" in Figure 25). The step function is used as a starting point to determine the optimal timing and scale of REZ network expansions in the time-sequential model and for potential actionable ISP projects in the DLT model.

Figure 25 Conversion of linearised REZ expansion to network upgrade options



Sub-regional augmentations

In the SSLT, alternative options between the same regions are simplified to a MW capacity in each flow direction. The SSLT optimisation identifies whether an interconnector augmentation is developed. The size and timing of the developments identified in the SSLT provide a starting point for developing potential augmentation combinations. The combinations of sub-regional augmentations and REZ network expansions are tested for each scenario in the DLT to determine candidate development paths (see Section 5 for further information on the ODP methodology).

Thermal generation investments

For traditional thermal plants, such as coal-fired generators and CCGTs, the SSLT determines the linear build of these technologies. These continuous MW builds are then converted into discrete builds of standard turbine size for use in subsequent models through a simple rounding process. If at least 50% of the notional generator size is built in the SSLT, then it is considered committed in the DLT. For example, if 1.3 CCGTs were built in the SSLT model, only one CCGT would be modelled in the DLT model and subsequently in the time-sequential model.

The same approach is applied to any additional generation (for example, open-cycle gas turbines [OCGTs]) developed in the DLT for subsequent time-sequential modelling).

Thermal retirements

Thermal retirement decisions made in the SSLT (in addition to those informed by expected closure years/ closure dates and time-sequential modelling) are also linearised (see Section 2.4.1 for more details on the retirement approach). Due to the necessary coarseness and simplifications of the SSLT (see Section 2.2), the aggregate volume of thermal retirements determined each year is meaningful, but specifics related to choice of units to retire can be somewhat unintuitive after considering other real-world dynamics. This is because often the differences in the input assumptions for power stations of the same type are marginal.

For example, the SSLT may retire parts of a number of black coal-fired power stations within the same region without retiring an entire station. Alternatively, the sequence of retirements relative to the expected closure year information provided by participants might be completely jumbled, with the model choosing to retire plant with longer remaining technical lives ahead of plant currently expected to retire in the next decade.

To develop a more realistic schedule of retirements, AEMO applies the following approach for coal-fired generation:

1. Use the SSLT to determine the trajectory of coal retirement, and aggregate the capacity retired within each region.
2. In each year, develop an order of coal-fired generation based on closure year/closure date participant submissions (whether its expected closure date, date from the New South Wales Consumer Trustee Infrastructure Investment report, or date determined in time-sequential modelling).
3. Depending on the cumulative coal capacity that is projected to be retired in that year (based on Step 1), determine the units that need to be retired based on the order developed in Step 2. This uses a similar approach described for generator investments, where a 50% threshold is required for a unit to be retired.

For example, assume that the two power stations closest to retirement are as follows:

- Power Station A: 2 x 300 MW power station that is six years from its retirement.
- Power Station B: 4 x 500 MW power station that is eight years from its retirement.

If the SSLT modelling determined that 800 MW of coal was to be retired in four years, this would involve retiring all of Power Station A, but no units of Power Station B (as the remaining 200 MW of retirement does not meet the 50% threshold). If 900 MW were retired, this would also then retire one unit of Power Station B.

The advantage of this approach is that it maintains the aggregate level of coal retirement within each region, but brings forward power stations which are closest to the end of their life.

For gas-fired and liquid-fuelled power stations, the approach to retirements is more straightforward, in that the 50% threshold is applied on a power station basis.

Variable renewable energy, storage and hydrogen electrolyser builds

The development of new VRE, battery storage, and pumped hydro is allowed to remain continuous, as the sizes of wind/solar farms, batteries and pumped hydro are less standardised than thermal generation. These technologies can typically be scaled to any size by adding more turbines/panels/batteries (or for pumped hydro are more influenced by topographical features), and as such no rounding is applied.

The development of hydrogen electrolysers is also allowed to remain continuous, given the technology is modular and scalable. Further details on the approach to modelling hydrogen electrolysers are described in Section 2.5.

Consideration of stakeholder feedback

This section was added to the methodology given requests (from Shell Energy and EnergyAustralia) for more clarity on how the rounding of linearised decisions is used.

2.5 Modelling hydrogen in the capacity outlook model

With growing global interest in hydrogen-based energy systems, the potential for Australia to export clean hydrogen is substantial. Beyond Australia's export potential, there is also a range of domestic hydrogen opportunities. However, the technical progression and commerciality of the resource is not yet proven, and there remains substantial uncertainty.

For ISP purposes, the scale and location of hydrogen production in Australia is scenario-specific and largely assumption driven, informed by stakeholder engagement and literary reviews of targeted hydrogen development forecasts[31]. For details of scenario-specific hydrogen assumptions, refer to the latest IASR.

[31] For example, the National Hydrogen Strategy and its companion modelling reports, at https://www.industry.gov.au/data-and-publications/australias-national-hydrogen-strategy and https://energyministers.gov.au/publications/reports-support-national-hydrogen-strategy respectively.

The inclusion of hydrogen requires a number of augmentations and refinements in the capacity outlook modelling process, including:

- Electrolysers are included as variable loads, which consume electricity to produce hydrogen for domestic use and/or export.
- Additional transmission options are considered to deliver renewable generation to these load sources if necessary.
- Hydrogen-fuelled generation technologies are considered in generation build decisions.

This section details the approach that is applied when modelling scenarios with a high uptake of NEM-connected electrolysis.

2.5.1 Overview of hydrogen modelling

For the ISP, AEMO considers the electrolysis of water powered by electricity as the hydrogen production technology. The commercial-scale production of hydrogen from grid-connected electrolysers would increase electricity demand on the NEM. That would require a significant expansion of generation, and hence it has the potential to have a significant impact on Australia's electricity system. There is also potential for development of off-grid hydrogen projects, which may complement grid-connected facilities – the development uncertainty is a key driver for alternative hydrogen futures considered with AEMO's scenario collection.

In modelling the interactions of hydrogen in the NEM, AEMO uses the capacity outlook model to:

- Determine the location and size of electrolysers to meet export hydrogen demand which is specified at a NEM level and the size of electrolysers, to meet domestic hydrogen demand which is specified for each region. The domestic hydrogen supply is assumed to be produced by electrolysers at the RRN close to the load centre (or at hydrogen hubs nominated by jurisdictions). AEMO assumes the electrolysers to supply export demand will be located at ports within each region, allowing for electricity to be generated and transmitted to these export ports from optimised locations identified by the capacity outlook model considering the corresponding generation expansion and associated network development.
- Determine the flexible operation of electrolysers to meet domestic and export hydrogen demands while maximising market benefit for the NEM.
- Determine whether any additional hydrogen demand is economically optimal considering the opportunity to develop hydrogen-fuelled electricity generation (if defined as an available technology within the IASR).

The modelling of hydrogen presented in Figure 2 in Section 2.2 is further described in Section 2.5.2.

Given the uncertainties around how hydrogen production may evolve in Australia, and acknowledging that the key focus of the ISP is to understand the future power system needs for the NEM, a number of simplifying assumptions are made when modelling hydrogen in the capacity outlook model:

- The regional domestic hydrogen demand and total NEM export hydrogen demands are considered exogenous and not optimised by the model.
- Potential electrolyser locations are limited, and are assumed to be either at ports, nominated hydrogen hubs or reference nodes for export and domestic demand, respectively. The specific locations are defined within the IASR.
- There is limited consideration of factors that may differentiate ports from each other (such as development costs, proximity to export markets, and surrounding land use/easements) beyond the impact of regional differences in generation availability.
- There is limited consideration of water availability and cost on siting options.

These are discussed further in the IASR.

2.5.2 Modelling hydrogen in capacity outlook models

The main objective of hydrogen modelling in the capacity outlook models is to determine the optimal electrolyser expansion and operation and the corresponding impact on the development of generation and transmission. To this end, AEMO uses the capacity outlook models to identify the location and size of the electrolyser plants required to meet hydrogen demand at the RRNs for domestic hydrogen and at port locations for export.

The assumed domestic and export hydrogen demands are modelled as separate flexible loads, with minimum production requirements on a monthly timeframe. Export facilities also incorporate hydrogen conversion facilities (such as to ammonia), which operate as inflexible baseloads. The preferred electrolyser capacity is therefore optimised, selecting the capacity that provides an optimal balance of capital cost and operational flexibility. Hydrogen operation is flexible to minimise total costs while meeting monthly production targets, subject to an inflexible baseload component. More electrolyser capacity can increase operational flexibility and lower operating costs, but comes at a higher capital cost. Electrolyser builds are linearised as with other generation, storage, and transmission build decisions in the SSLT and DLT (see Section 2.4.6).

Within the model, the choice of ports to locate electrolysers for hydrogen export is based on minimising the development cost of powering the electrolysers, considering the cost and availability of resources (such as VRE and transmission). Water availability is considered when screening potential port locations. REZ development costs consider the relative cost to deliver energy to electrolyser locations such as ports, and/or the primary transmission backbone that services traditional load centres, as described in the IASR. The cost of network augmentations to deliver the VRE to the electrolysers is determined based on the approach discussed in Section 2.3.4.

Alternative electrolyser locations, such as on the site of retired power stations (with access to water previously used for cooling), are not considered at present for the 2022 ISP, but may be possible in future ISPs.

In the first stage, the SSLT determines:

- Location and size of electrolysers to meet total export hydrogen demand from the port options.
- Size of electrolyser capacity builds to meet regional domestic hydrogen demand located near the regional reference nodes.

The available port locations and the scale of their development are mapped to the overall capacity outlook model sub-regional topology for both export and domestic demand. These development options are then provided as committed inputs to the DLT model, along with the other inputs described in Section 2.1.

Details of hydrogen modelling within PLEXOS

There are a number of elements to be considered in the implementation of hydrogen in the capacity outlook models, including:

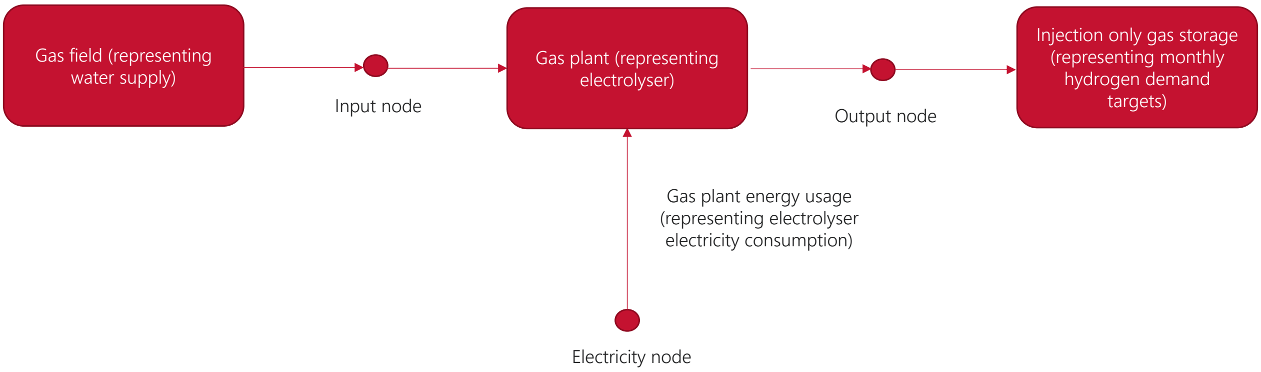
- Electrolysers as electricity loads connected to the NEM (the SSLT determines the size of electrolysers to meet hydrogen demand, and passes these details to the DLT as an input).
- The monthly hydrogen demand and additional demand from associated plant.
- Electrolyser capital and operating costs.
- Utilisation of hydrogen for electricity production, if selected as a generation technology.

The gas objects of PLEXOS can be used to represent all these hydrogen elements. Figure 26 illustrates how hydrogen production and demand are implemented in capacity outlook models using gas field, gas plant, and gas storage objects:

- Gas field objects are used to represent the water supply. The cost of water for the production of hydrogen may be given as a production cost of the gas field, and may be limited by the assumed availability of water.

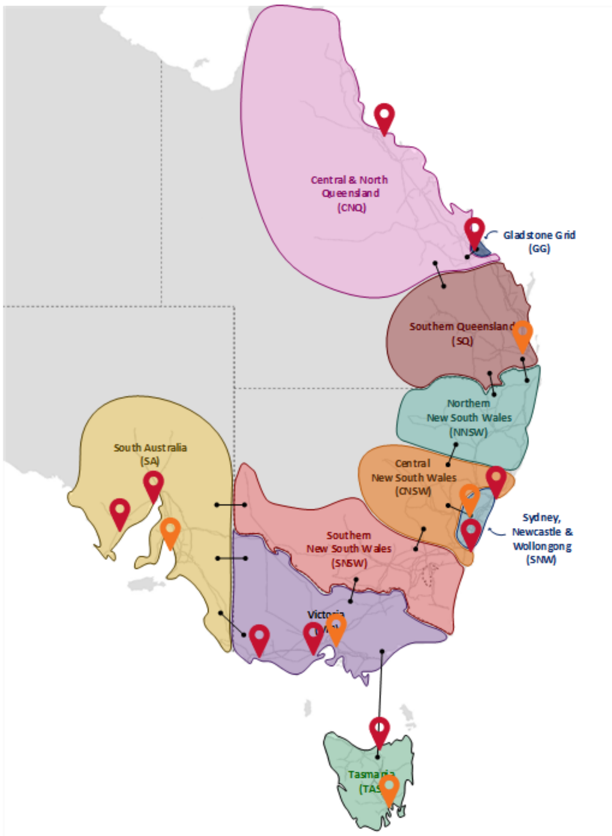
- Electrolysers are implemented as gas plant objects which are connected to gas fields, to a hydrogen demand node, and to an electricity node.
- Electrolyser electricity consumption is given as the gas plant energy usage.
- The hydrogen demand is implemented using injections-only gas storage objects, with monthly hydrogen demand targets applied as monthly targets for the gas storage levels.

Figure 26 Hydrogen implementation in capacity outlook models



As shown in Figure 26, electrolysers produce hydrogen from grid connected electricity. Figure 27 shows the network topology and the assumed potential location of electrolysers connected to the grid and to the ports.

Figure 27 Electrolyser locations and their connections to electricity nodes



Legend:

Electrolysers for export production

Electrolysers for domestic production

- **Export electrolysers** target a cumulative monthly production target, where all electrolysers contribute to the monthly target. One or both regional electrolysers (located at major regional ports) may be developed.
- **Domestic electrolysers** apply an individual monthly production target, reflecting assumed regional domestic consumption.

  REZs distant from the electrolyser locations (one or both regional ports for export, or the capital city for domestic production) may require transmission expansion to strengthen the connectivity to each location, which applies a distance-based penalty charge. Some REZs may be excluded from development to support electrolyser loads due to distance thresholds; these penalties are reflected in the IASR.

Hydrogen implementation in other scenarios

The approach described in this section only applies when large levels of NEM-connected hydrogen are assumed in a scenario. Other scenarios may assume less significant impact from grid-connected electrolysers on the NEM, with limited domestic consumption. To the extent that hydrogen production is included for domestic consumption in some scenarios, the modelling uses a simpler approach which simply accounts for the electricity demand required to meet the domestic hydrogen production located near the regional reference nodes, determined through multi-sectoral modelling.

Consideration of stakeholder feedback

TasNetworks asked AEMO to provide details on how the location and size of the electrolyser plants are calculated in the capacity outlook models. AEMO has provided a detailed methodology on hydrogen implementation in AEMO's capacity outlook models.

Shell Energy questioned the need to modify the capacity adequacy model by the inclusion of hydrogen electrolyser capacity. AEMO will modify the capacity adequacy model only for the export superpower scenarios which is forecast to have a significant impact on the electricity sector include material hydrogen exports. Without including electrolysers in the capacity expansion models, these impacts could not be adequately assessed.

Several stakeholders provided feedback on accounting for factors such as water availability, hydrogen transport, and hydrogen storage in selecting electrolyser locations. MM Technology also suggested that retiring power station sites may present ideal development locations. AEMO has accounted for these factors by limiting the number of possible electrolyser locations to either the RRNs or the ports, which is a necessary simplification for model tractability.

3. Time-sequential modelling

The time-sequential model optimises electricity dispatch for every hourly or half-hourly interval, rather than aggregating outcomes for the whole outlook period. In so doing, it validates the outcomes of the capacity outlook model, and feeds information back into it.

The time-sequential model is intended to reflect participant behaviour, including generation outages, to reveal performance metrics for both generation and transmission. These outputs can in turn provide further refinements to the models and modelling inputs.

In this chapter:

- Section 3.1 provides an overview of the time-sequential modelling process.
- Section 3.2 outlines the modelling inputs which are specific to the purpose of time-sequential modelling.
- Section 3.3 provides further detail on specific methodologies used.

3.1 Overview of time-sequential modelling process

The time-sequential modelling used in the ISP has numerous purposes, and requires a number of alternative configurations which are targeted at best meeting each purpose.

Compared to the capacity outlook modelling, the time-sequential modelling focuses more strongly on participants' behaviour. This requires AEMO to overlay strictly technical assumptions with views on portfolio dynamics and strategic decisions. AEMO applies detailed analytics to inform these considerations, although there are limitations to the extent to which these behaviour drivers can be accurately forecast and reflected in the modelling, given the dynamic nature of operational decisions applied by generation portfolios.

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 higher resolution than the capacity outlook model. It optimises electricity dispatch for every hourly or half-hourly interval in the modelled horizon using the PLEXOS modelling software, and includes Monte Carlo simulation 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 exceedance of the reliability standard and the Interim Reliability Measure.
- Potential economic drivers of generator retirements.
- The feasibility of the generation and transmission outlook when operating conditions and more detailed intra-regional network limitations are modelled.
- An indication of where possible congestions points may exist and how network augmentations would be beneficial in alleviating network issues.

- A more accurate forecast of the annual generation dispatch and fuel offtake.
- More precise cost benefit analysis/network augmentation benefits for specific projects.
- Impacts of weather variability on dispatch outcomes.
- Impacts of unplanned generation outages.
- The number of synchronous generators online.
- Assessment of system strength, inertia, and plant ramping characteristics.

The validation and analysis done in the time-sequential models may result in modification of inputs in the capacity outlook model (as shown in Figure 3 in Section 2.2), or engineering assessments (as described in Section 4).

Complexity and time required for the time-sequential modelling simulations

Much of the work involved in the ISP, particularly related to the determination of the ODP, relates to comparing modelling outcomes over an extended period for differences in the transmission and generation system.

One of the key limitations in the use of time-sequential modelling is the complexity of detailed network constraint equations which are critical in being able to represent the differences in the transmission system. This process can take significant time to develop (in some circumstances this can be a number of weeks) and the constraints are customised to a given capacity expansion determined by the capacity outlook models. As discussed in Section 2.1, the capacity outlook modelling can involve many hundreds of distinct simulations leading to an impracticable number of distinct constraint equations that would need to be developed. As such, the use of time-sequential modelling needs to be targeted in areas where its benefits over capacity outlook modelling are most valuable (such as to confirm that the proposed ODP is in the best interest of consumers).

3.1.1 Time-sequential model settings

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 – this schedules generation for energy-limited plants (hydroelectric power stations or emission-constrained plants) over a year. 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 – this 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.

Resolution and optimisation window

For the ISP, time-sequential models are generally simulated at a half-hourly level of granularity, although at times hourly simulations are performed to increase simulation speed in large simulations (for example, in reliability assessments). AEMO is exploring the use of five-minute modelling, however any use of five-minute modelling would be for detailed explorations of shorter time periods, such as understanding ramping requirements on certain highly variable days or weeks.

AEMO is also exploring future approaches to reduce the level of "perfection" in the foresight of the models, to better explore potential issues with system flexibility arising from unforeseen events. As with five-minute modelling, this would be computationally expensive and would likely focus on specific periods of interest.

Generator planned and unplanned outages

The time-sequential model uses the same inputs for forced outage and maintenance as the capacity outlook models. However, rather than applying as a static derating, full and partial outages are modelled stochastically.

Time-sequential modelling is generally performed across multiple reference years and/or demand POE levels, and uses Monte Carlo simulations to model multiple generator outage patterns. Maintenance is modelled as discrete outage events and planned through the PASA phase, as described above.

3.1.2 Types of time-sequential models used

AEMO may use any of the following time-sequential models, or a combination of them, 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. Depending on the type of assessment carried out, this model features different degrees of complexity. AEMO distinguishes between two types of SRMC models:
  - SRMC with no unit commitment – this model uses a linear solve and therefore captures the technical envelope of each generator broadly within the limits of linear programming. Only ramp rates, simple heat rates, and other continuous variables are modelled. This model is primarily used to validate network constraints and for reliability assessments.
  - SRMC with unit commitment – 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 the 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 reflects 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. New entrant generators are assumed to bid in a cost-reflective manner, given the uncertainty around their ownership and operating strategy.
  - The bidding model is used to forecast one of a number of possible future bidding outcomes with a focus on the next 10-year outlook. This model is used for price forecasting and revenue sufficiency assessments to inform retirement decisions in the model and to produce insights on the future operability and security of the system.

3.1.3 Use of time-sequential models in the ISP

Determination of generator retirements

The determination of generator retirements (outlined in Section 2.4.1) is based on projected wholesale net revenue from the bidding model. This provides the best estimate of the financial viability of each generator within the limits of the information available to AEMO.

AEMO acknowledges that the approach simplifies the complex array of considerations which are taken into account for any individual station's retirement, including areas such as contracting positions, fuel supply arrangements, and portfolio value. As these considerations are difficult to quantify and are often opaque, AEMO is not in a position to incorporate this level of detail, but will consider the potential for strategies such as seasonal decommitment.

It is critical that AEMO does consider the potential for early generator retirements and understand their implications for system security and operability and the potential impact on benefits of other investments, including the overall ODP. Therefore, AEMO has outlined an approach to determine an indicative retirement schedule which balances complexity, the availability of information, and the need to develop indicative retirement schedules for each scenario.

The general approach for identifying risk of potential early retirements will rely on a number of considerations and metrics. The primary criterion will be wholesale net revenue as described in Section 2.4.1.

Wholesale price forecasts

Time-sequential modelling is used to produce wholesale price forecasts which are used for a number of purposes. These forecasts inform retail price forecasts, which are used for forecasting demand and DER uptake, and also used to explore the distributional effects of the ODP. This is described in Section 5.10.

Cost-benefit analysis

Time-sequential modelling is used to support and validate the take-one-out-at-a-time (TOOT) analysis which is carried out as part of the cost-benefit analysis approach. This uses the SRMC model, which, compared to the capacity outlook models, includes increased granularity and detail in the representation of both the inter- and intra-regional transmission limitations addressed by the ISP project. Competition benefits are not currently considered. Further details on the TOOT approach are provided in Section 5.9.3.

Capacity expansion

There are a number of inputs to the capacity outlook modelling that are informed by the time-sequential modelling. These include the following (illustrated in Figure 3 in Section 2.2):

- Generator limitations to be applied such as units to operate with a minimum load and approximations of the impact of any system security constraints.
- Adjustments to the setting of regional reserve level requirements.

This creates a feedback loop between the capacity expansion model and the time-sequential model.

3.2 Inputs to the time-sequential models

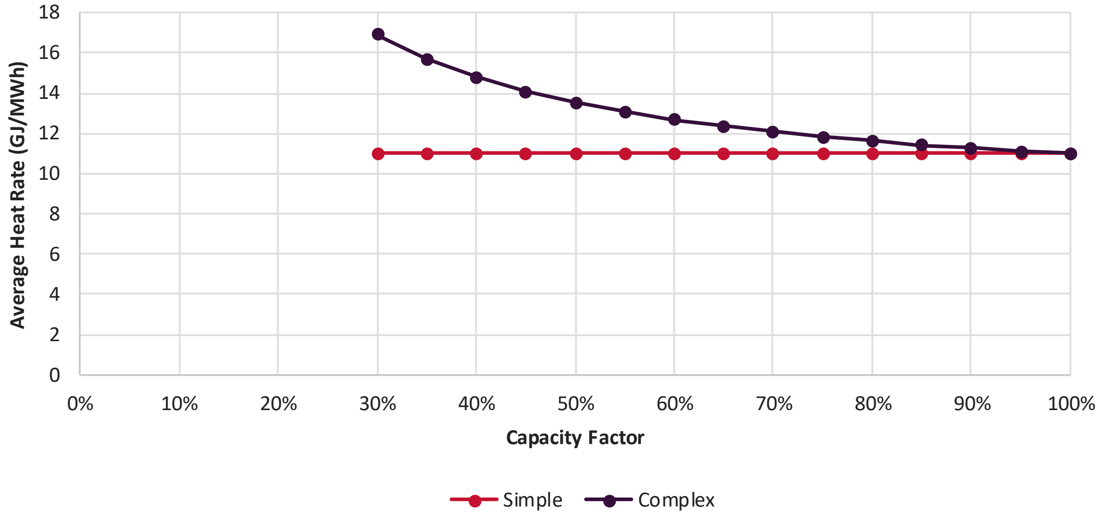
The time-sequential modelling uses the same inputs as the capacity outlook modelling but improves the level of detail used for some assumptions such as using a complete set of network constraints. The time-sequential modelling also employs additional methodologies particularly related to unit commitment.

3.2.1 Fuel consumption and heat rate modelling

Generators consume fuel according to their heat rate function, expressed in units of GJ/MWh. Simple heat rates apply a 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 gas-fired steam turbines (GFSTs). To improve its modelling, AEMO has implemented affine-linear marginal heat rates referred to as ‘complex heat rates’ (see Figure 28).

Detailed representation of the efficiency curves is computationally expensive and only applied to the SRMC models with unit commitment, which are used to inform costs 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.

Figure 28 Example of heat rates – simple versus complex



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 estimates of the start-up costs profiles which also includes costs of labour, water, and chemicals incurred by a plant when synchronising to the grid. Start-up costs profiles are only applied to CCGTs and GFSTs in the SRMC with unit commitment model and are described in the IASR.

3.2.2 Configuration of combined cycle gas turbines

AEMO's time-sequential models consider CCGTs in greater operational detail, and capture explicitly heat output/input dynamics between the gas turbine (GT) units and the steam turbines (STs). To render realistic operation regimes and correctly consider the relative inflexibility of CCGTs, AEMO enforces constraints, where applicable, to ensure that the GTs and ST unit commitment decisions are linked together as appropriate. 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.

3.2.3 Network limits

Time-sequential modelling applies detailed transmission constraint equations to a regional network topology (see Section 2.3.1), consistent with the approach used in NEMDE. These transmission constraint equations represent the network configuration following the REZ network expansions and sub-regional augmentations identified from the capacity outlook modelling.

AEMO develops constraint equations to represent five types of limits in the time-sequential model. This section describes how the five constraint types are determined, and the process to develop the constraint equations.

Types of network limits

The ISP defines these operating limits in terms of five network limits:

- Thermal capability.
- Voltage stability.
- Transient stability.
- Oscillatory stability.
- Additional power system security/system strength.

Thermal capability

The power flow through a transmission element is limited to its maximum thermal capacity. TNSPs provide transmission line and transformer ratings for different ambient temperatures, seasons, months, and times of day. The following thermal ratings are applied in the network capability assessment:

- Normal ratings for pre-contingent conditions.
- Contingency ratings for post-contingent conditions.
- Short-term ratings for post-contingency conditions, if an operational solution is available to bring the line loading below the normal rating within the allowed time.

The determination of maximum transfer levels is carried out using PSS®E studies.

Voltage stability

Voltage stability refers to maintaining stable voltage control following the most severe credible contingency event or any protected event. Assessment of voltage stability limits is undertaken as per requirements in Chapter 5 of the NER. The determination of voltage stability limits is carried out using PSS®E studies.

Transient stability

Transient stability refers to maintaining the power system in synchronism and remaining stable following any credible contingency event or protected event. Assessment of transient stability limits is undertaken as per requirements in Chapter 5 of the NER. The determination of transient stability limits is carried out using PSS®E studies.

Oscillatory stability

Oscillatory stability refers to maintaining the power system in synchronism and remaining stable in the absence of any contingency event, for any level of inter-regional or intra-regional power transfer up to the applicable operational limit; or following any credible contingency event or protected event. Assessment of oscillatory stability limit is undertaken as per requirements in Chapter 5 of the NER. The determination of oscillatory stability limits is carried out using PSS®E and Mudpack[32] studies.

Additional power system security/system strength

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

The time-sequential model implements these constraints where applicable by ensuring that 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 may be based on planning assumptions, or developed from operational advice if available.

System strength constraints are explicitly modelled for the South Australian region to address the identified system strength gap[33]. The time-sequential model applies unit commitment constraints 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.

Development of constraint equations

Depending on consumer demand, dispatch of generation, and availability of network and non-network assets, transmission elements can become congested. To manage network flows, AEMO uses constraint

[32] Mudpack is an oscillatory stability simulation software used by AEMO.

[33] 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.

equations as a mathematical way to represent the physical limitations (network limits) of the power system within the time-sequential model.

There are two specific sets of constraint equations considered in the determination of optimal market dispatch outcomes from the time-sequential model:

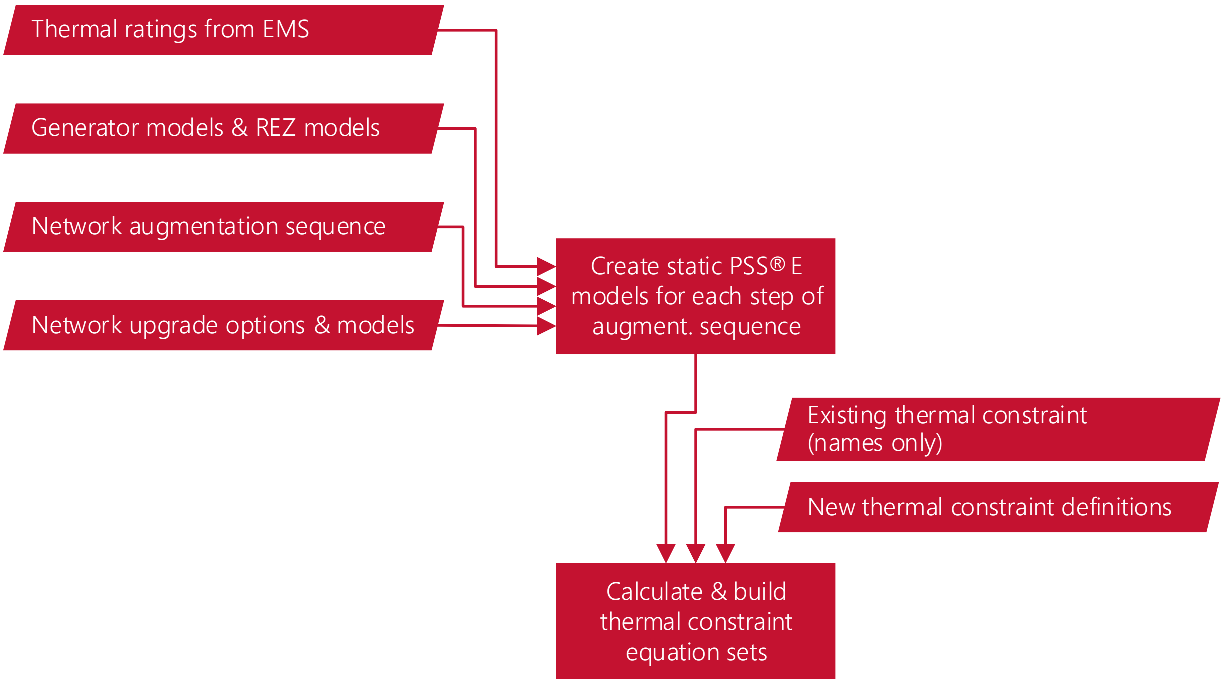
- Thermal constraint equations.
- Stability constraint equations (including voltage, transient and oscillatory limits).

These are discussed in more detail in the following sections.

Thermal constraint equations

Thermal constraint equations are built from PSS®E load flow cases for a given network configuration. Thermal ratings of the transmission network are applied as per the latest information in the IASR. The process of developing thermal constraint equations is illustrated in Figure 29.

Figure 29 Thermal constraint equation process



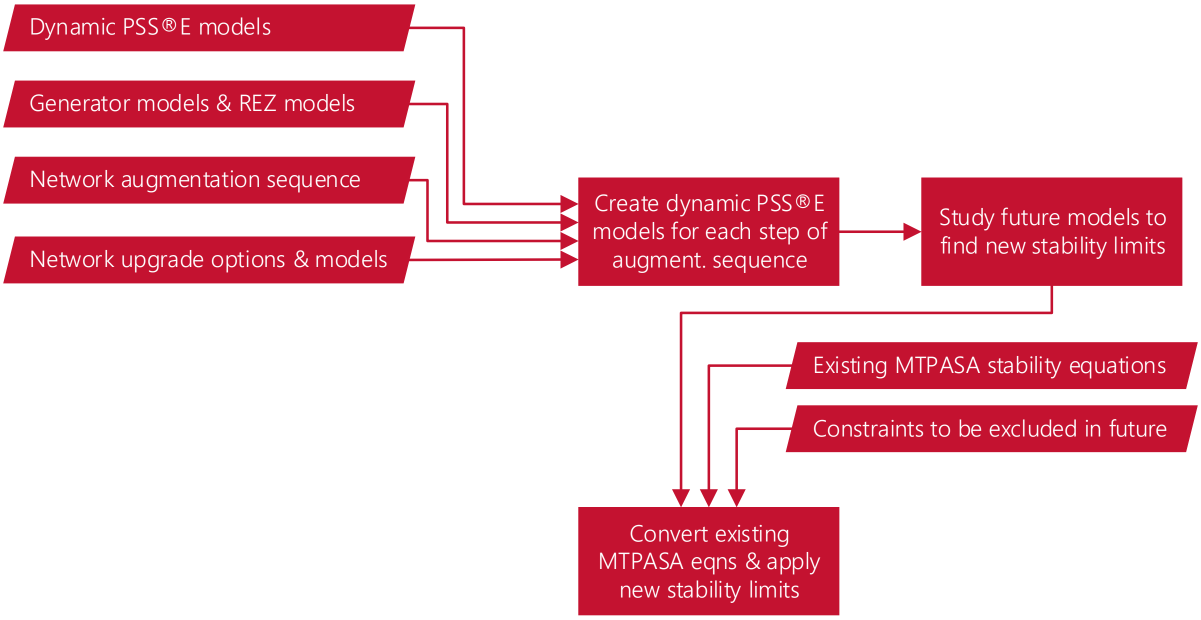
Note: EMS – Energy Management System

Stability constraint equations (voltage, transient and oscillatory)

Stability constraint equations for the existing network are developed and validated by the relevant TNSP. AEMO conducts due diligence on these constraints before applying them in dispatch. Development of these stability constraint equations is time-consuming. For modelling the existing network, dispatch stability constraint equations are converted into a format that can be interpreted by PLEXOS for time-sequential modelling. These stability equations include transfer levels determined by voltage, transient, oscillatory, rate of change of frequency (RoCoF) and system strength limits.

For the future network, dynamic network models are created with future upgrades and then studied to determine the difference in stability limits from the existing network. For some upgrades, the TNSPs have already completed these studies, so their results are used wherever possible. From these studies, an offset to the right-hand-side of the existing Pre-Dispatch, Short-Term or Medium-Term Projected Assessment of System Adequacy (ST PASA or MT PASA) constraint equation is determined and applied in the stability constraint equations. This process is detailed in Figure 30.

Figure 30 Stability constraint equation process



Note: MT PASA – Medium Term Projected Assessment of System Adequacy

Additional constraints for power system security/system strength

These are developed on a case-by-case basis. Where an existing constraint is in MT PASA, ST PASA, or Pre-dispatch PASA, these are utilised and modified as appropriate. Additionally, where there are future constraints not currently in NEMDE, these are developed on a first principles basis. Where these constraints have terms related to operational measures that are taken that are able to alleviate the constraint, such as putting on a capacitor or putting a unit in synchronous condenser mode, it is assumed that these measures will be taken within the formulation of the constraint.

Constraints within the market modelling are also required to represent known operational measures, such as directions that force generation on and therefore impact on dispatch. An example of these is how the system strength generator combinations in South Australia are represented. While the limit advice for the system strength combinations contain a large number of permutations, only a reduced set of combinations needs to be modelled. This is to allow for the least-cost directions outcome, but also allows for sufficient gas units to be included in other combinations to allow for maintenance and forced outages of some of these units.

3.3 Methodologies used in time-sequential modelling

3.3.1 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-times 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. AEMO only considers the inclusion of integer-optimal unit commitment modelling where it is deemed important to understand a potential emerging trend or issue. At other times, unit commitment is rounded from a linear solve, or assumed (for plant that typically operate base load).

When optimised unit commitment modelling is used, the 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 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.

It should be noted that unit commitment optimisation and minimum stable levels are not strictly modelled for peaking plant when using an hourly or 30-minute model resolution and are therefore not included in the time-sequential model. These units can typically start up to operate in minutes rather than hours, and it would not be appropriate to impose a constraint in the model that forces them to remain operating at their technical minimum stable level for an entire hour if dispatched.

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 online for system security purposes.
- Are involved in unit commitment constraints to emulate a known 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 GFSTs).

3.3.2 Optimisation of large-scale storage operation

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, effectively arbitraging between periods of high and low price. For example, in a future energy mix with high renewable penetration, VRE 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 (short-term schedule), 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 the IASR and in AEMO's current planning and forecasting inputs, assumptions, and methodologies data set[34].

[34] At https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Inputs-Assumptions-and-Methodologies.

4. Engineering assessment

The engineering assessment is the final stage of the linear modelling process. It tests the capacity outlook and time-sequential outcomes against the technical benchmarks of the power system (security, strength, inertia) as well as assessing MLFs to inform new grid connections.

The engineering assessments feed back into the two models to continually refine outcomes towards the ODP. They ensure the capacity outlook and time-sequential outlook are robust and credible from a technical perspective, before considering the financial or commercial viability of the option.

This section sets out the methodology that AEMO uses to:

- Verify that capacity outlook outcomes are technically feasible – including revision to inputs such as network augmentation options (see Section 4.1).
- Evaluate power system security services (see Section 4.2).
- Assess MLF robustness to help inform risks for new generators connecting to the grid (see Section 4.3).

These five assessments feed into the continuing iterative process to refine to the outcomes from the capacity outlook and time-sequential models.

Throughout the engineering assessment process, the cost-effectiveness of transmission options is considered, to maximise their economic benefit.

Iteration of engineering assessment and market modelling

Throughout the engineering assessment, there are refinements to inputs to the other stages of the ISP process. The most technically viable and economical options for generation, storage, and transmission expansion identified in the engineering analysis can be input back into the capacity outlook model, and then further refined using the PSS®E platform. Because interconnector and REZ designs are inter-related, AEMO may update transmission designs and their costs using building blocks in the published TCD.

The process is repeated until the outputs from both stages are aligned.

A similar iterative process occurs between the engineering assessment and time-sequential model. The time-sequential model results in optimal generator dispatch outcomes and options to ensure transmission is adequate over the ISP horizon. If the engineering assessment suggests network changes, the inputs into the time-sequential model are adjusted and the process is repeated. Iterations continue until the optimised generation, storage, and network outlook has met the system reliability and operability needs and the overall costs and benefits have been determined.

4.1 Verify capacity outlook outcomes

Once the capacity outlook and time-sequential modelling has been completed, it is important to verify outcomes to see if they are robust and to understand if any additional investment is required to ensure power system security and reliability.

This step is essential; the previous stages of the modelling do not directly model the electrical characteristics of the power system because doing so would result in an unworkably complex model. Instead, the power system limits are modelled through constraint equations, and AEMO must verify that these constraint equations are correctly representing the power system limits and the process is not missing any power system limitations. This ensures a technically robust ISP.

To verify the capacity outlook, AEMO uses outcomes from the time-sequential modelling. These include generation dispatch, operation of network constraints, and frequency of binding constraints.

Power system analysis

AEMO carries out power system analysis through PSS®E load flow to investigate the performance of the network and to identify any additional network augmentation to ensure system security and reliability. The analysis is performed on generation dispatch at selected intervals to verify:

- Network design under regional maximum and minimum demand conditions.
- Network design under regional maximum and minimum variable renewable energy generation conditions.
- An augmentation under selected conditions of interest, for example high interconnector flow plus inclusion of REZ generation.

The analysis typically includes investigating whether:

- Network equipment is within its thermal ratings.
- The voltage can be managed within its operating range.
- The voltage stability and transient stability of the network can be maintained.

If the analysis uncovers any issues, then AEMO will revise the scope of relevant network designs and the implementation of those designs in the capacity outlook model and time sequential model.

Example – refining the scope of an augmentation option

The Engineering Assessment will test the feasibility of optimal augmentation options, such as a Queensland to New South Wales interconnector upgrade. In doing this, AEMO conducts power system analysis to investigate several snapshots – such as high transfer levels and high demand conditions.

If AEMO's analysis determines, for example, that voltage stability cannot be maintained, then the design of the augmentation option will be revised. In this instance, AEMO adds additional dynamic reactive plant to the scope of the HVAC augmentation option – an additional synchronous condenser (or a static Var compensator [SVC]) might enable voltage stability to be maintained. This design change would result in a change to the cost and performance of the augmentation option. AEMO will use the Transmission Cost Database to determine the cost associated with the design change. The technical and economic characteristics of the revised augmentation option are updated and fed into the capacity outlook model to test whether the option remains optimal.

This process ensures that the capacity outlook model and the time sequential model are evaluating an option that is appropriately costed and capable of delivering the benefits modelled.

Constraint equations

Statistics on constraints that bind in the time-sequential model are analysed. This analysis involves investigating the type, timing, and frequency of the constraints which are binding, that is, affecting the generation dispatch, as well as the marginal value of the constraint[35].

[35] See AEMO's *congestion information resource* for more details, at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/system-operations/congestion-information-resource.

Constraint equations that bind frequently or have a high marginal value are considered critical. The presence of critical constraints indicate that network limits are causing congestion. AEMO may need to add new network or non-network augmentations so that the models can assess whether these are economic to address critical constraints. For example, if a thermal constraint on an interconnector is projected to be critical, it is important that there are options in the models to alleviate that constraint where economic. Within the engineering assessment, AEMO will review the performance of the capacity outlook model and the time-sequential model in assessing options to alleviate these critical limits. Outcomes of this assessment could involve refinements to those models or modifications to the augmentation options.

4.2 Evaluation of power system security services

The adequacy of system security services of critical importance as the power system continues to transition. The ISP engineering assessment evaluates current and emerging system security needs (including the new and potential power system services) as follows:

- Iteratively – given the dependence on outcomes such as synchronous generation retirements, the size and location of inverter-based resource (IBR) builds, new storage builds, and transmission network builds.
- Holistically – considering all system security services together, not in isolation; for example, a synchronous condenser could provide system strength, reactive compensation, and inertia.
- With broad planning assumptions – to capture a reasonable cost impact.

The engineering assessment considers the system security services, outlined in Table 4. These services are described in more detail in AEMO's *Power System Requirements Paper*[36], setting out the fundamental technical attributes necessary for secure and reliable system operation. This section outlines how the ISP studies evaluate the need for different system security services.

Table 4 Summary of system security services and references

System security service	This document	Power System Requirements Paper reference
Frequency control	Section 4.2.1	Section 3.2
System inertia	Section 4.2.2	Section 3.2.1
Voltage control	Section 4.2.3	Section 3.3
System strength	Section 4.2.4	Section 3.3.3
System restoration	Section 4.2.5	Section 3.4
System flexibility	Section 4.2.6	Section 3.1.3 (operating reserves)

4.2.1 Frequency control

The power system must have the ability to set and maintain frequency within a tight range to continue to operate securely. Power system frequency is controlled by the constant balancing of electricity supply and demand. If electricity supply exceeds demand at an instant in time, power system frequency will increase. If electricity demand exceeds supply at an instant in time, power system frequency will decrease.

The power system uses on frequency control services to maintain this balance: primary frequency control is used to hold frequency close to 50 hertz (Hz), and secondary frequency control services are triggered and act to inject active power to remedy a frequency excursion. The services which maintain frequency must

[36] AEMO, July 2020, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power-system-requirements.pdf.

collectively provide a continuous response to arrest any deviation in frequency, and then return it to desired levels.

The ISP model considers only system normal (network intact) conditions. Under these conditions it is expected that the frequency control ancillary services (FCAS) market will ensure sufficient headroom is available on generation or batteries, as well as provide signals for investment if needed. Given the wide range of potential sources of global FCAS providers, this is not seen to influence the ODP, and given the computational overhead, it has not been seen to be necessary to model the FCAS market as part of the ISP.

Where detailed investigation of the potential benefits of FCAS for a specific augmentation is required, it is considered that this is an aspect that can be captured as part of any subsequent RIT-T.

4.2.2 Inertia

In relation to the power system, inertia is an inherent electromechanical response provided by large synchronous generators as a by-product of energy production. It arises because the rotating parts of synchronous generating units (such as the turbine and rotor) connected to an AC power system spin in lockstep with the system frequency. The response is provided by the physical properties of the machine, and does not require control system interaction.

AEMO is required to plan and operate the power system to meet the frequency operating standards using inertia services provided by the local TNSP. AEMO determines two levels of inertia for each NEM region[37] required to be available for dispatch when a region is islanded[38] or at credible risk of islanding:

- The Minimum Threshold Level of Inertia (MTLI) is the minimum level of inertia required to operate an islanded region in a satisfactory operating state.
- The Secure Operating Level of Inertia (SOLI) is the minimum level of inertia required to operate the islanded region in a secure operating state.

AEMO can agree to adjust the MTLI or SOLI if inertia support activities (such as Fast Frequency Response [FFR]) will reduce the levels of synchronous inertia needed to meet system security requirements.

There are a number of trials underway in Australia which aim to provide an inertia-like response using IBR. AEMO's approach for determining inertia requirements includes technologies that are commercial or have been demonstrated at a large scale. For this reason, AEMO’s modelling approach in the ISP is consistent with the current inertia framework in the NER – where inertia must be provided by synchronous rotating machines but can be offset by FFR.

The *Inertia Requirements Methodology* document[39] details the minimum inertia calculation method to be used, defines the inertia sub-networks, and specifies the minimum threshold and secure operating levels of inertia for each inertia sub-network. The most recent inertia requirements will be utilised when assessing inertia across the NEM.

Method used to assess inertia requirements

Online inertia is determined from time-sequential market modelling generation dispatch outcomes. These are post-processed to also include inertia from synchronous condensers, as well as consideration for FFR from new batteries[40]. This is compared to the local regional inertia requirements prior to assessing any need for additional inertia services. If new interconnectors are built between regions, the need for local inertia services based on existing requirements is considered to be eliminated.

[37] AEMO, *Inertia Requirements Methodology. Inertia Requirements and Shortfalls*, 1 July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[38] Islanding means the physical separation of the NEM region from other regions, through disconnection of all interconnection.

[39] AEMO. *2018 Inertia Requirements Methodology*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/inertia_requirements_methodology_published.pdf.

[40] When sufficient local experience from trials is available to support the use of synthetic inertia and inertia response from batteries, these services could be included.

Projected online inertia for each region is calculated in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[41] for each half-hour interval.
2. The corresponding inertia constants for all online generation are then obtained.
   – The model assumes typical parameters for projected new synchronous plant such as gas peaking, CCGT, and pumped hydro.
   – The inertia constants for future TNSP synchronous condensers are also added into the calculations for the time periods they expected to be in service, for example the high inertia synchronous condensers in South Australia.
3. The total inertia is then calculated for each region by summating all the inertia constants.
4. The process is repeated for each half-hour market modelling interval to produce annual inertia duration curves.

Inertia investments are identified when the projected regional inertia falls below the regional secure operating level of inertia for more than 1% of a year, and the risk of the region needing to be operated as an island or while at credible risk of islanding is deemed to be likely.

4.2.3 Voltage control

Voltage control in the power system acts to maintain voltages at different points in the network within acceptable ranges during normal operation, and to enable recovery to acceptable levels following a disturbance. Acceptable voltage ranges are defined in the NER[42].

Voltage control is managed through balancing the production or absorption of reactive power[43]. Reactive power does not 'travel' far, meaning it is generally more effective to address reactive power imbalances locally, close to where it is required. Adequate reactive power reserves are maintained to ensure the security of the transmission system in the event of a credible contingency.

AEMO plans and operates the power system to maintain voltage levels across connection points in the transmission network within limits set by NSPs and to a target voltage range. Acceptable voltage ranges are defined in the NER[44].

The costs for new reactive compensation are included as part of network augmentation costs. Network augmentations are designed to include reactive compensation that meets the NER standards. AEMO may revise the scope of network augmentations throughout the ISP modelling process to ensure these standards will be met.

4.2.4 System strength

Methods used to assess system strength

System strength requirements are calculated through fault level studies that take into account network developments and generation dispatch. AEMO's ISP modelling evaluates system strength requirements through two different fault level metrics as follows:

- **System strength needed to feasibly operate the network** – assessed by calculating the synchronous three phase fault level at each simulated dispatch interval.

[41] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

42 AEMC. Schedule 5.1a of the NER, at http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules.

[43] The rate at which reactive energy is transferred. Reactive power, which is different to active power, is a necessary component of AC electricity. Management of reactive power is necessary to ensure network voltage levels remains within required limits, which is in turn essential for maintaining power system security and reliability.

44 AEMC. Schedule 5.1a of the NER, at http://www.aemc.gov.au/Energy-Rules/National-electricity-rules/Current-Rules.

- **System strength needed to connect and operate IBR** – assessed by calculating with available fault level.

The system strength needed to operate the network

The synchronous three phase fault level is used to determine the system strength needed to operate the network. This is measured in megavolt-amperes (MVA) and includes fault level contribution from synchronous machines. It is calculated under system normal conditions, and also under credible contingencies.

It is a helpful measure for system strength because it can be used to assess:

- The correct operation of protection systems,
- The size of voltage deviations due to static voltage control devices, such as switched inductors or capacitors, and
- The stable operation of existing generation.

AEMO's *System Strength Requirements Methodology*[45] details the fault level calculation method to be used, and defines the fault level nodes and requirements for each region. The ISP will use the most up-to-date minimum fault level requirements for each node. The fault level requirements are calculated by deriving minimum fault levels from electromagnetic transient (EMT) studies that determine the minimum synchronous generator combinations required to be online in each NEM region[46].

AEMO calculates the synchronous three phase fault level in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[47] for each half-hour interval.
2. The synchronous unit status is applied to the PSS®E network model.
   – The model assumes generic parameters for projected new synchronous plant such as gas peaking, CCGTs, and pumped hydro.
   – The model includes committed synchronous condensers and network upgrades.
   – The model does not assume any system strength mitigation with future IBR.
3. All IBR are switched off.
4. The fault level is then calculated at each fault level node using PSS®E.
5. The network model used in the calculations is updated in a time-sequential manner to account for future ISP network upgrades.
6. The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

System strength investments are identified when the synchronous three phase fault level falls below the existing minimum fault level requirements for more than 1% of the period.

The system strength needed to connect and operate IBR

Available fault level is used as a method to determine the system strength needed. This is measured in MVA and defined as the actual synchronous three phase fault level minus the required synchronous three phase fault level specified by the manufacturer of IBR. It is a helpful measure for system strength because it assesses whether the control systems of IBR will operate correctly. It is considered superior to a weighted short circuit

[45] 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.

[46] AEMO. *Transfer Limit Advice – System Strength*, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

[47] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

ratio (SCR)[48], because the calculation includes the impact of surrounding IBR and also their relative electrical distances.

The *System Strength Impact Assessment Guidelines*[46] describe the assessment process and the methodology for determining available fault level.

AEMO calculates the available fault level in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[49] for each half-hour interval.
2. The status is applied to the PSS®E network model.
   - The model assumes typical parameters for projected new synchronous plant such as gas peaking, CCGTs, and pumped hydro (that is, generic power system models).
   - The model includes future TNSP synchronous condensers and network upgrades.
   - The model starts by not assuming any system strength mitigation with future IBR.
   - The impedance of IBR is modified according to minimum required SCR (assumed to be 3) and unit MW capacity.
   - Two fault levels for each node are calculated using PSS®E:
     - Three phase synchronous fault level (contributed by synchronous resources only), and then
     - Total three phase fault level required for IBR to operate in a stable manner, based on the previous SCR assumptions.
   - Available fault level (AFL) is then calculated for each node by subtracting the total required fault level from the actual synchronous fault level. A negative outcome indicates a need for additional synchronous fault level at the location. This reduced equation provides an indication of the positive contribution from synchronous resources, and the current understanding of interplay between synchronous resources and inverter-based resources with relation to system strength. It is important to note that this is an area of evolving understanding and technical innovation.
   - The network model used in the calculations is updated in a time-sequential manner to account for the proposed ISP network upgrades.
   - The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

Investment needs for system strength are identified when the available fault level becomes negative.

How system strength costs are approximated

AEMO's approach for estimating costs includes technologies that are commercial or have been demonstrated at a large scale. For this reason, synchronous condensers are used as a proxy for estimating system strength costs. While AEMO expects that alternative technologies, such as grid-forming inverters, are likely to improve system strength in future, their performance and cost are uncertain.

The system strength needed to feasibly operate the network

As synchronous generating units reduce operation and exit the market, system strength solutions will be required to feasibly operate the electricity network. To take into account the anticipated lead time for system strength remediation, AEMO takes a different approach depending on the timing of a system strength need.

In early projections (in the first five years – or a period stated in the IASR), the time-sequential model ensures a minimum dispatch of synchronous generation (consistent with existing operational requirements).

[48] AEMO. *System Strength Impact Assessment Guidelines*, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

[49] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

For longer timeframes (beyond five years – or a period stated in the IASR), the costs for installing synchronous condensers to meet the system strength mitigation needs is used as a proxy for system strength remediation costs (unless other solutions are known)[50].

The system strength needed to connect and operate IBR

System strength remediation will be required to connect high levels of IBR. This cost is incorporated in the ISP model via connection costs and REZ expansion costs and as part of network upgrades. The cost of system strength remediation solutions is approximated using the cost of appropriately sized synchronous condensers in the Transmission Cost Database.

4.2.5 System restoration

The ISP model typically projects a significant amount of resources that can provide system restart services – primarily hydroelectric generation, pumped storage, battery storage, and GPG. As AEMO anticipates system restart ancillary services (SRAS) requirements to be met and costs to not significantly vary between network development outcomes, SRAS requirements are not independently assessed as part of the ISP.

4.2.6 System flexibility

Large generators and demand response can require many hours' notice before they can start generating or provide an initial response. To ensure the system operates in real time with high technical integrity, it is necessary to ensure the system is able to cope with unexpected variations in supply and demand.

As the penetration of VRE increases, the system needs to operate more flexibly to accommodate increases in variability and uncertainty. AEMO's Renewable Integration Study Appendix C (Section C5)[51] showed that a range of flexible resources must be utilised and planned ahead of time, so the right mix of system resources is available when needed to maintain the supply-demand balance across different time scales. It also showed that the supply of flexibility is specific to the rate of change, region, market behaviour, and other operational or system events.

The time-sequential model captures variability to an extent, however some aspects are not captured, due to:

- The use of a 30-minute simulation timestep (high ramps that can occur over shorter periods like 5-15 minutes may be missed).
- The difficulty in accurately modelling fast start generator start-up times (if offline when high ramping period occurs).
- The difficulty in accurately modelling slow start-up/ramp rates for thermal generators if offline (start-up time can be dependent on time previously offline).

There are ongoing reviews and studies regarding ramping and operational reserve requirements, so where ramping limits or headroom requirements are identified[52] they will be incorporated into ISP studies.

System flexibility can be sourced from interconnection, existing online generation, battery energy storage systems (BESS), VRE (if pre-curtailed), VPPs, DER, or fast-start generation.

4.3 Marginal loss factor robustness

Once the generation and transmission outcomes are verified in the engineering assessment, AEMO investigates how sensitive MLFs (see Section 2.3.6) are to additional generation being added within a REZ. Even though the analysis does not affect projections of generation in the ISP, the outcome is provided because it has a commercial impact on the NEM, and consequently is highly valued by many stakeholders.

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[50] For example, in Tasmania hydro generation is contracted to operate in synchronous condenser mode.

[51] AEMO, Renewable Integration Study, Appendix C, April 2020, at https://aemo.com.au/-/media/files/major-publications/ris/2020/ris-stage-1-appendix-c.pdf?la=en.

[52] For example, as outcomes of the Engineering Framework studies, at https://aemo.com.au/en/initiatives/major-programs/engineering-framework.

The MLF robustness is the sensitivity of current and future MLFs to increased generation capacity within each REZ. AEMO has defined a grading for MLF robustness as indicated in Table 5. This system shows the amount of additional generation capacity (MW) that can be installed before the MLF changes by -0.05.

Transmission models are first created for each stage of the ODP. The models include any future augmentations and installed capacity at REZs. The flows through each line and transformer for each 30-minute interval in a year are calculated with a direct current approximation using the power system modelling tool PSS®E (which contains a model of the network) and the market modelling results.

Then for each candidate REZ:

- A base case volume-weighted MLF for the year of interest is calculated with the flows through each line and transformer.
- The generator outputs from the market modelling results are modified by scaling up the active power output of candidate REZ, then scaling down the region's remaining generation by the same amount.
- The line and transformer flows are re-calculated with the modified generator outputs.
- The new volume-weighted MLF is calculated with the new line and transformer flows.
- The robustness is found by comparing the base MLF with the new MLF as further active power is added.

Table 5 Added installed capacity before MLF changes by -0.05 and robustness score allocated

Added REZ capacity	≥1,000 MW	≥800 MW	≥600 MW	≥400 MW	≥200 MW	<200 MW
MLF robustness score	A	B	C	D	E	F

Note: For reporting purposes, AEMO may use different thresholds in subsequent publications.

Effect of energy storage on MLFs

The effect of energy storage on a MLF depends on how well its charging and discharging profiles correlate with the generation profile and load profile. The MLF of a site will improve if the energy storage is charging at times when the generation of the REZ is high and the local area load is low. For example, co-locating a battery with a solar farm could not only assist in shifting the output to times when needed, but could also improve the MLF for the site.

5. Cost benefit analysis methodology

The CBA is the approach AEMO uses to develop and test alternative development paths, and ultimately determine the ODP.

The market modelling and engineering analysis documented in the sections above explores how the energy sector may develop across a set of scenarios. This modelling and analysis are also a critical input into the determination of the ODP.

The ODP is the suite of actionable projects which best serves the long-term interests of consumers of electricity by minimising the risk of over- and under-investment given all the uncertainties in the energy future. It also delivers positive net market benefits in the most likely scenario.

The appropriate test for that investment is a transparent CBA approach that considers the costs and benefits of alternative development paths, and the robustness of those paths under different futures.

Section 5.1 provides an overview of the objectives and principles that govern AEMO's approach to the CBA. Section 5.2 then details the approach to quantifying the cost of each development path.

The steps AEMO will use to determine and to test the resilience of the ODP are:

- Section 5.3: Determine the least-cost development path for each scenario.
- Section 5.4: Build candidate development paths.
- Section 5.5: Assess each candidate development path across all scenarios.
- Section 5.6: Evaluate net market benefits.
- Section 5.7: Rank candidate development paths.
- Section 5.8: Finalise the draft ODP selection through sensitivity analysis.
- Section 5.9: Key information for actionable ISP projects.
- Section 5.10: Transparency around decision-making criteria, further testing, and analysis of the ODP.

5.1 Principles that govern the cost benefit analysis

The CBA outlined in this methodology comprises numerous steps which are used to determine the ODP, based on the AER's CBA Guidelines. Throughout the process, a number of principles are pursued including:

- Ensuring flexibility to respond to the conditions in each scenario is appropriately valued, including the consideration of any option value provided by early works and other forms of project staging or timing.
- A consideration of the concept of regret as a measure of risk to consumers when considering the merits of any decision to invest or not invest in an ISP project.
- The need to ensure that the determination of the ODP is resilient to changes in input assumptions.

This section also outlines some of the terminology which is used throughout the chapter.

The importance of option value in maintaining flexibility in the development path

The ISP identifies the future need for broad electricity system investments in generation and transmission, including identifying actionable transmission projects that need to commence construction within that ISP cycle (every two years). However, to minimise risk to consumers of over- or under-investment, any actionable ISP project must consider future developments of generation, network, and storage investment, and the evolving needs of consumers, over the life of the project (to 2050 or beyond).

Projects that are more capable of adapting to different future market conditions and drivers are inherently valuable. Actionable ISP projects must demonstrate a need to progress now, such that the benefits of investing now outweigh the potential value in delaying investment until more information is available, given the inherent uncertainties that may impact decision-making.

The ISP can add optionality to actionable ISP projects, adding flexibility to projects with more uncertain benefits. This includes options such as staging the overall size or timing of the project (splitting a project into smaller sizes, and retaining the flexibility to deliver subsequent stages if and when needed), using non-network options that manage the immediate need (and enable ISP projects to be delivered if and when needed in future), and undertaking early works (to enable rapid delivery in future if required). Decision rules may also be introduced to assist in identifying the ongoing need of staged or delayed projects.

By incorporating these options, the ISP considers the risks of both under-investment (not being prepared) and over-investment (the costs of building projects that are not needed).

Regrets

In the ISP context, regrets are associated with investment decisions that are later shown to be in excess of, or short of, future needs, given the future conditions that are present subsequent to an investment decision. For example, consumers may regret over-investing in infrastructure if conditions no longer require these assets and benefits are therefore not realised, or consumers may regret under-investment if disruption occurs faster than anticipated and the asset is needed sooner than what is possible when improved visibility of future conditions are apparent.

Recognising potential regrets is important in the ISP because uncertainty and consumers' risk tolerance need to be understood and considered. In some future circumstances, the risk of high future costs may be significant with particular investment combinations, and outweigh the potential benefits of these investments if these circumstances eventuate. Where investments are identified as having high risks, the cost-benefit analysis must consider the risk tolerance of consumers to these events occurring, which may not be adequately captured by simply averaging across scenarios.

These risks can occur for both under- and over-investment – often the lack of investment can have higher risks associated with reliability than over-investment. As such, the CBA approach must consider regret costs that consider consumer risk tolerance in a transparent manner.

AEMO applies a 'Least-Worst Regrets' (LWR) approach as one approach to inform the determination of the ODP. This helps understand potential regrets for consumers and the cost of building robustness into the plan to help minimise the likelihood for regret. Regrets are defined as the reduction in net market benefits that result from making sub-optimal investment decisions in a future world.

It is not reasonable to assume that perfect foresight is available for investment decision-making, nor is it reasonable to assume that all investments can be deferred until scenario likelihoods are more certain. The LWR approach to inform determination of the ODP seeks to minimise the potential regret across all reasonably likely scenarios, testing the regrets (that is, cost of adapting and impact on benefits) associated with various alternative investment options, across the range of scenarios. If a development path which was desirable in one or many future market conditions was highly regretful in another, the LWR approach provides a means for highlighting and acting to avoid that potential risk, even if the investments were valuable in other future market conditions.

Robustness

A desirable feature of the ODP is its robustness to changes in key assumptions. Scenario analysis provides an inherent opportunity to test the impact of different future worlds on the preferred development options and benefits to consumers, however scenarios typically differ in a number of ways and this change in collections of inputs may mask the impact of specific, significant variables. The use of sensitivity analysis provides a more appropriate exploratory vehicle to test whether or not the ranking of alternate candidate development paths changes with a change in single input.

The ODP selection approach should retain the flexibility to factor the additional benefits and lesser regrets that may exist in development paths that deliver more stable streams of consumer benefits under a plausible range of inputs.

Terminology

This section uses key terms, many of which have not been referred to in this Methodology to this point. Some terms used are defined by the NER, or the accompanying AER Guidelines, in which case those definitions apply, and the terminology here provides an appropriate interpretation of those definitions. For reference, these terms are defined as follows:

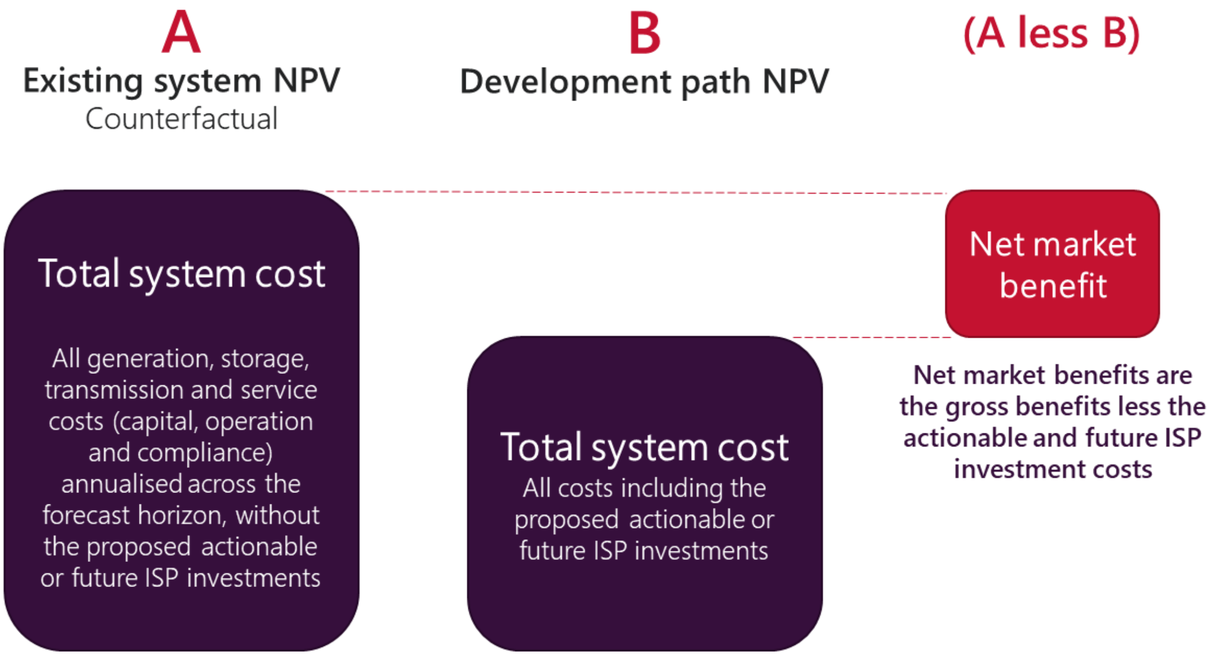
- The **earliest in-service date (EISD)** of a project is the earliest date the project can be completed.
- **Actionable ISP projects** are projects that require a Project Assessment Draft Report (PADR) to be completed within 24 months of the ISP publication. As such, a project is identified as actionable where the CBA has concluded that the project should proceed at the EISD (or EISD + 1 given the two-year cycle of the ISP), or else the project's PADR should be commenced after the following ISP has reassessed its benefits.
- **Future ISP projects** are defined in the NER as those projects which address an identified need, form part of the ODP, and may be actionable ISP projects in the future. As such, a future ISP project is identified where the CBA has concluded that the project should proceed after the EISD.
- ***Potential* actionable and future ISP projects** share the definitions outlined above, except these concepts appear before the determination of the ODP.
- **Development Paths (DPs)** are defined in the NER as a set of projects (actionable projects, future projects, and development opportunities) that together address power system needs. For the purposes of assessing the CBA, DPs refer to a combination of ISP projects that enable development opportunities. DPs are not scenario-specific, as they can be imposed and modelled for more than one scenario. DPs are not necessarily optimal in any scenario – many DPs are generally required to be tested to determine which is optimal in any given scenario.
- **A Candidate Development Path (CDP)** represents a collection of DPs which share a set of potential actionable projects. The timings of potential future ISP projects are then allowed to vary across scenarios depending on the needs of a given scenario.
- The **Optimal Development Path (ODP)** is chosen from the set of CDPs as the suite of actionable and future ISP projects which optimises benefits to consumers given the uncertainties in the future outlook.
- The **counterfactual DP (CFDP)** represents a DP with no future network augmentation other than committed and anticipated projects, or small intra-regional augmentations and replacement expenditure projects. It forms the basis on which all other DPs are compared within each scenario.
- An **ISP development opportunity** means a development identified in an ISP that does not relate to a transmission asset or non-network option and may include distribution assets, generation, storage projects or demand side developments that are consistent with the efficient development of the power system.
- **Net Present Value (NPV)** is the discounted sum of all costs and is used to determine the discounted total system cost of each DP.

5.2 Quantification of costs and market benefits

To enable development paths to be compared, AEMO is required to determine the NPV of their net market benefit which requires the calculation of the **discounted total system cost** of each DP compared against a counterfactual.

When conducting whole-of-system planning, the least-cost DP is also the DP that maximises net market benefits. This is because the DPs include generation and storage developments and their fuel costs as well as transmission developments and other associated infrastructure. This is shown in Figure 31.

Figure 31 Cost-benefit analysis calculation of net market benefits of development paths



This section:

- First identifies the relevant categories of market benefits which are assessed for each development path.
- Then details how AEMO considers the cost of investments which have economic lives which extend beyond the modelling horizon, including both the approach to annuitising capital costs and the considerations of terminal value.

Classes of market benefits included in the CBA

The AER's CBA Guidelines set out the classes of market benefits that are able to be considered in the ISP. The classes of market benefits included in AEMO's CBA assessment include:

- **Benefits related to the development and operational costs of generation and storage assets**:
  - Changes in fuel consumption arising through different patterns of generation dispatch.
  - Changes in costs for parties due to the timing of new plant, differences in capital costs, and differences in operating and maintenance costs.
- **Development and operational costs of transmission assets:**
  - Differences in the timing of expenditure.
  - Differences in operating and maintenance costs.
- **Costs associated with demand reduction:**

  - Changes in voluntary load curtailment (through DSP).
  - Changes in involuntary load shedding costs, valued at the value of customer reliability (VCR).

Several classes of market benefits within the CBA Guidelines are not explicitly accounted for above, and AEMO's approach to accounting for these classes of benefit is as follows:

- **Changes in network losses:**
  - To some extent, differences in losses attributable to differences in interconnector flows and interconnector loss equations are accounted for in the changes to the fuel and operating costs of generation assets, because interconnector losses are calculated dynamically as a function of interconnector flow, and allocated between regions as additional demand within the model.
  - Changes in intra-regional losses that may arise in alternative DPs are not necessarily captured by the interconnector loss equations.
  - Where a consideration of intra-regional losses is material to the assessment of a particular asset, and where the potential actionable ISP project has marginal benefits, AEMO may undertake additional analysis to ensure any consumer benefits that arise from lower transmission losses are considered.
- **Additional option value:**
  - AEMO's scenario analysis already includes considerations of option value through the assessment of flexibility in DPs, the approach to identifying the ODP, and through the other classes of market benefits.
- **Changes in ancillary service costs:**
  - AEMO does not consider changes in ancillary costs as part of its CBA analysis, because they are challenging to quantify and are generally not material compared to the cost of the projects assessed in the ISP.
  - Where material, changes in ancillary service costs may be considered by TNSPs as part of subsequent RIT-T analysis on any actionable projects.
- **Competition benefits:**
  - Competition benefits refer to the increased economic efficiency that may occur from improved competitive behaviours in the market as a result of investments.
  - Quantification of competition benefits is a challenging task even when considering a single investment. Including competition benefits throughout the consideration of alternative DPs on a whole-of-system plan would not be possible, nor would the benefits be expected to be material relative to project costs.
  - AEMO does not include competition benefits in the CBA analysis, but they could be included by TNSPs as part of subsequent RIT-T analysis on any actionable projects.

Annuitisation and discounting of costs

For the ISP, capital investment in generation, storage and transmission infrastructure is converted into an equivalent annual annuity to allow like-for-like comparison on assets with different economic lives and different commissioning dates.

The capital investment is spread over the economic life of the asset as a stream of equal annual payments using the following formula:

$$P = \frac{C \times r}{1 - (1 + r)^{-t}}$$

where P is the annualised cost of the asset applied during the CBA process, C is the capital cost of the asset, r is its weighted average cost of capital (WACC), and t is its economic life.

For example, suppose a new generator is developed in the capacity outlook model in 2029-30 with a capital cost of $100 million (real), and an assumed WACC of 5% and economic life of 25 years. Using the above formula, the capital cost of the generator is converted to an annual payment of $7.1 million and applied for the duration of its economic life that lies within the modelling horizon, starting from its first year of operation.

In the ISP, the discounted total system cost of a development path represents the present value of annual costs accrued during the modelling horizon, and is determined using the following formula for NPV:

$$\mathrm{NPV} = \sum_{i=1}^{n} \frac{A_i}{(1+r)^i}$$

where A_i is the total annual system cost (in real terms) in year i of the modelling horizon, n is the length of the modelling horizon in years, and r is the discount rate for that scenario.

Consideration of stakeholder feedback

Several stakeholders questioned the approach to terminal value outlined in the Issues Paper, and the ISP Consumer Panel stated that the approach was not clearly described. In response to this feedback, AEMO has provided greater clarity in this section, outlining in more detail how AEMO's approach is applied. The Consultation Paper also provides a comparison of alternative methods.

AEMO is requesting further feedback on the approach, noting that the potential application of discount rates to different costs is a separate issue that relates to discount rate assumptions, rather than to the approach for accounting for costs beyond the modelling horizon. AEMO is continuing to investigate the appropriate discount rate, as part of the finalisation of the IASR.

5.3 Step 1: Determining least-cost Development Paths for each scenario

The first step in determining the ODP is to determine the least-cost DP for each scenario. These least-cost DPs maximise non-competition net market benefits for consumers for a given scenario assuming perfect foresight.

This forms a starting point for exploring potential DPs that best serve the long-term interests of consumers of electricity by optimising market benefits and taking into account risks given all the uncertainties reflected in the scenarios and sensitivities.

In this first step, a significant number of alternative DPs are simulated in each scenario to determine which DP is least-cost in that scenario. As outlined in Section 2.1, the results of the SSLT are used to inform the development of DPs in each scenario, but many alternative combinations of projects and timings are tested.

This process includes a consideration of physical staging through the potential projects which are tested. For example, a double-circuit 275 kV line may be included as an option. However, this option can be separated into two stages. The first stage is building a single circuit 275 kV line using towers which can accommodate a second circuit in the future. The second stage is subsequently installing a second circuit onto the towers built in the first stage. This approach adds option value, but also cost, compared to building the double-circuit option from the outset.

The remainder of this section considers a complete example of the CBA process based on four scenarios and testing four potential augmentation options.

Table 6 presents the timings of projects in four illustrative least-cost DPs for hypothetical scenarios A, B, C, and D and projects 1, 2, 3, and 4. For the purposes of this example, consider that Project 4 represents a smaller version of the augmentation provided in Project 3.

Each DP has been assigned a four-digit identifier denoting each unique combination of projects and timings. Only the DP that was identified as least-cost is shown in this table for simplicity, although potentially many other DPs (hundreds) were simulated with different timings and options to determine these optimal combinations for each scenario.

Table 6 Scenario least-cost Development Paths

	DP	Project 1	Project 2	Project 3	Project 4	Total cost ($m)
EISD	-	2023-24	2025-26	2027-28	2027-28	-
Scenario A least-cost	0012	**2023-24**	**2026-27**	2035-36	-	212
Scenario B least-cost	0022	**2023-24**	**2026-27**	**2027-28**	-	535
Scenario C least-cost	0045	**2023-24**	–	**2027-28**	**-**	111
Scenario D least cost	0061	**2023-24**	**2026-27**	-	2030-31	141

Table 6 also presents the EISD for each project based on project lead times, and determines which projects in a given DP would be considered as potential actionable ISP projects based on their timing for this scenario. In the above example, Project 1 and Project 2 would be considered potential actionable ISP projects based on DP 0012, as the project start date matches the EISD or the EISD+1. On the other hand, this DP delays development of Project 3 until 2035-36, well beyond its EISD of 2027-28. Considering this DP in isolation, Project 3 would not be classified as a potential actionable ISP project and is instead classified as a potential future ISP project.

Potential actionable ISP projects within each of the DPs have been bolded above. Potential actionable ISP projects would include those projects that are developed at their EISD, or their EISD + 1 year, given the two-yearly cycle of the ISP.

5.4 Step 2: Building candidate development paths

The determination of least-cost DPs in each scenario is an important first step in the CBA process. These DPs are used as the basis for identifying a set of CDPs which are then assessed across all scenarios.

CDPs consolidate the identified DPs, creating a shortlist of varying investment decisions that may need to be made within the next two years, separately or in combination, to optimise benefits for consumers. The development of a set of CDPs is important for testing the risks and benefits of alternative combinations of potential actionable ISP projects. Beyond the initial investment in potential actionable ISP projects, the CDPs may flexibly develop future ISP projects as needed, or stop progressing any subsequent stages of a potential actionable ISP project, depending on the scenario being assessed.

The set of CDPs developed using this approach is designed to provide the ability to determine whether to invest now, to defer an investment until there is greater certainty, or to stage the investment to retain flexibility to hedge against uncertainty.

Initial formation of CDPs based on least-cost DPs from each scenario

The least-cost DPs in Step 1 form the basis of the initial set of CDPs. Each least-cost DP with a unique set of initial investments (potential actionable ISP projects) is used to form a CDP by fixing only the potential actionable ISP projects from that DP, with other projects classified as potential future ISP projects. Table 7 presents an example of the first set of CDPs that would be formed based on the least-cost DPs presented earlier in Table 6.

Table 7 Candidate Development Paths based on least-cost Development Paths

Candidate Development Path	Description	Potential actionable projects		
CDP1	Based on Scenario A and D's least-cost DP	Project 1	Project 2	
CDP2	Based on Scenario B's least-cost DP	Project 1	Project 2	Project 3
CDP3	Based on Scenario C's least-cost DP	Project 1	Project 3	

Note in the example above that although Scenario A and Scenario D had different least-cost DPs (see Table 6), they shared the same combination of potential actionable projects and therefore are consolidated into a single CDP.

Refining the set of Candidate Development Paths to include early works

As described earlier in this chapter, early works are pre-construction activities that can be taken now, while keeping open the option to either continue, defer, or cancel the project as new information becomes available. Some projects may have capacity to undertake early works, maintaining momentum on the project to still enable delivery at or shortly after the EISD if the future unfolds in a way that makes this project beneficial, without committing to the full development.

The inclusion of early works is therefore one of the means of capturing the option value that is attributable to the ability to stage a project delivery, or at least to delay the full approval of the entire project without materially compromising the project delivery schedule. Other forms of staging, such as building a large project in stages in such a way that each individual stage provides distinct value and enables a subsequent stage to be built cheaper or quicker if subsequently needed, are captured through the testing of development paths – these staged projects can be specified as separate projects (for example, building a single-circuit transmission line on double-circuit towers and stringing the second circuit at a later date).

A potential actionable ISP project that has the ability to be staged (through early works) may warrant an additional CDP or CDPs that investigate the option value of the early works. These projects fall into two categories:

- Those that are potential actionable ISP projects in all scenarios – in this instance early works would never present any value, given the consistent timing preference across scenarios to deliver the project as early as the project's EISD (or EISD + 1). The CBA would therefore not consider early works as a valuable first stage. These projects are classified as 'no regret projects', but are subject to final confirmation in the ODP (see Section 5.8).
- Those that are potential actionable ISP projects in only some scenarios – in this instance the timing uncertainty of the project suggests that early works may provide option value to retain delivery flexibility.

In the example above, assume that Project 1 and Project 3 have the option of early works[53].

- Project 1 is a potential actionable project in all scenarios and is therefore considered a no regrets project, without any need to consider early works.
- Project 3 is only a potential actionable project in Scenario C's least-cost DP. From this point on, an additional CDP is created with only the early works component of Project 3 fixed across scenarios so that

[53] Project 2 and Project 4 are assumed to not have early works available for the purpose of this conceptual example. This could be because both projects have already completed early works in a prior ISP (for example).

the option value of early works can be assessed. In all scenarios, a CDP incorporating early works on a project may be slightly more expensive than a CDP with the project developed as a single stage due to:

- Rework costs associated with delays (if the project does not progress immediately to construction on completion of early works in the scenario), or
- Cost increases that are associated with a slightly longer planning timeline that follows from considering early works ahead of the full project.

The difference between CDP2 and CDP4 is that the decision to progress through to construction could be deferred, potentially indefinitely, under certain scenarios, whereas CDP2 does not have this flexibility.

The decision to proceed with early works should therefore consider the breadth of outcomes modelled across the scenario/sensitivity analyses. If the benefits of early works exceeded the cost only under highly unlikely conditions, then it may be appropriate to dismiss the early works staging option. If, however, there is a higher likelihood that conditions arise that would provide greater benefits of project delivery flexibility, then AEMO may exercise its professional judgement discretion in preferring CDPs with early works. In so doing, AEMO will develop a decision tree that identifies the circumstances and value provided by the staging (physical or early works).

These conditions may be identifiable within the scenarios, or sensitivity analyses, AEMO conducts.

Table 8 Candidate Development Paths adjusted for early works

Candidate Development Path	Description	No-regrets projects	Potential actionable projects	
CDP1	Based on Scenario A and D's least-cost DP	Project 1	Project 2	
CDP2	Based on Scenario B's least-cost DP	Project 1	Project 2	Project 3
CDP3	Based on Scenario C's least-cost DP	Project 1	Project 3	
CDP4	Based on Scenario B's least-cost DP (updated for early works)	Project 1	Project 2	Project 3 – early works only

Augmenting the set of Candidate Development Paths to consider project deferrals

At this stage, the CDP collection is based on the least-cost DP in each scenario. However, the determination of the ODP is based on the value of projects when considered across all scenarios, and the CDP collection may be augmented with additional CDPs that represent DPs that may be near-optimal in all, some, or many scenarios.

In addition, to better understand the potential costs or benefits of deferring projects, additional CDPs are added that consider the removal of combinations of potential actionable ISP projects from each CDP. This would result in a set of additional CPs in the example which are shown in Table 9.

Table 9 Additional Candidate Development Paths with project deferrals

Candidate Development Path	Description	No-regret projects	Potential actionable projects
CDP5	Based on CDP1, removing Project 2	Project 1	
CDP6	Based on CDP4, removing Project 2	Project 1	Project 3 – early works only

Note that only two additional CDPs are required at this stage. This is because there is significant overlap. For example, if Project 3 is removed from CDP3, this results in only Project 1, which is already covered by CDP5.

It should also be noted that although Project 2 has been removed as a potential actionable ISP project in CDP6, Project 2 may be developed as a potential future ISP project when assessed across scenarios. In this circumstance, its EISD is delayed by two years, reflecting the ISP cycle.

This testing and analysis of the removal of potential actionable ISP projects from the set of CDPs is an important feature of this process. The comparison of CDPs with and without a potential actionable project indicates the benefits of progressing a project immediately. The CDP that does not feature that project at its EISD considers one of two potential responses in each scenario:

- Proceeding with the project at a later date. If the CDP with the project as actionable optimises consumer benefits more than the CDP which delays that project, all else being equal, then it means that the analysis has determined that the value of immediately progressing with the project exceeds any value from deferring the decision on the project.
- Not proceeding with the project at all, either by proceeding with an alternative network or non-network investment or by not investing in network and instead using other alternatives such as more localised generation development. A comparison between network and more localised generation and storage solutions is considered throughout the entire CBA process.

Augmenting the set of Candidate Development Paths by adding other combinations

At this point, other CDPs may be added which, based on consideration of the scenario least-cost DPs, are considered to be potentially optimal.

For example, in considering Table 6, Project 4 is identified as a potential future ISP project in Scenario D. Although not potentially actionable in any of the least-cost DPs, this is a smaller and cheaper alternative to Project 3, which in this example is assumed to have been close to being in the least cost development plan across a number of scenarios. Therefore, there may be value in testing this as an alternative CDP, as seen below in Table 10. Assuming that Project 4 could be built upon over time to match the capability of Project 3, this additional option effectively represents another form of project staging. Even if Project 3 and Project 4 were mutually exclusive, Project 4 may deliver a more stable set of market benefits across scenarios and therefore prove to have a lower regret cost and be more robust to variations in inputs than Project 3.

Table 10 Additional Candidate Development Paths to explore other alternatives

Candidate Development Path	Description	No-regrets projects	Potential actionable projects	
CDP7	Based on both CDP1 and CDP2	Project 1	Project 2	Project 4

5.5 Step 3: Assessing each Candidate Development Path across all scenarios

Once the collection of CDPs has been determined, they are applied across all scenarios so their value can be quantified. The output of this stage is that each CDP is modelled across each scenario, with each yielding a discounted total system cost.

As CDPs "lock in" various combinations of potential actionable ISP projects, these remain fixed when applied across all scenarios. All further investment in future ISP projects (including the potential to complete projects that have advanced through early works) is then co-optimised with generation and storage development opportunities considering the investment drivers that exist for each scenario.

Timings for any subsequent network investment are re-assessed, informed incrementally by each simulation. These potential future ISP projects are restricted from entering before their EISD plus two years, as by definition they are not progressing within the next two years in that CDP, and may only become actionable after the following ISP, which will add a two-year development delay.

Table 11 highlights a conceptual result for the application of each CDP across the four scenarios. Focusing on CDP1, which is built off the Scenario A least-cost DP (0012), Project 1 and Project 2 are fixed as potential actionable ISP projects across all or most scenarios. The timings of Project 3 and Project 4, which are potential future ISP projects in this CDP, are allowed to vary to meet the needs of each scenario at lowest cost, as long as that timing is beyond the EISD plus two years.

For example, in Table 6 it was identified that the least-cost DP for Scenario B (0022) developed Project 1, Project 2, and Project 3 all at their respective EISDs. In CDP1, however, Project 3 is classified as a potential future ISP project, and therefore cannot be developed for 2027-28. In the example below, an alternative DP (0028) has been found where Project 3 is introduced in 2029-30, which is the earliest possible timing if the project is not declared actionable within the current ISP[54].

Similarly, if the decision is made to invest in Project 1 and Project 2 immediately (CDP1), and Scenario C eventuates, then in this illustrative example it is no longer optimal for Project 3 to progress under that scenario. Given that Project 1 and Project 2 have been developed, developing Project 3 by 2032-33 now provides greater cost savings for consumers compared to the original 2027-28 timing. On the other hand, in Scenario D, the potential actionable projects in CDP1 are consistent with the least-cost DP in this scenario, and therefore the cost is unchanged from that shown in Table 6.

CDP4 is an example which includes early works (for Project 3). In Scenario A's least-cost DP (CDP1), Project 3 is not required until 2035-36. Under CDP4, early works are delivered for the project to ensure it is ready when needed under some scenarios, but in Scenario A the completion of the project remains in 2035-36. If, in two years' time when the next ISP is prepared, this scenario is still plausible and reasonably likely and other scenarios less likely, it would be in consumers best interests to delay development of Project 3 rather than progress with a costly investment that is not yet needed[55]. The difference in total cost between the least-cost DP (CDP1) and CDP4 for Scenario A therefore reflects the proportion of early works on Project 3 which will need to be reworked at a later date as a result of the delayed delivery ($8m in this example).

Table 11 DPs for each scenario in CDP1 to CDP6 (based on scenario least-cost DPs)

	DP	Project 1	Project 2	Project 3 early works	Project 3 completion	Project 3	Project 4	Total cost ($m)
CDP1	-	**No-regrets**	**Potential actionable**	-	-	**Potential future**	**Potential future**	-
Scenario A	0012	**2023-24**	**2026-27**	N/A	N/A	2035-36	-	212
Scenario B	0028	**2023-24**	**2026-27**	N/A	N/A	*2029-30*	-	575
Scenario C	0057	**2023-24**	**2026-27**	N/A	N/A	2032-33	-	181
Scenario D	0061	**2023-24**	**2026-27**	N/A	N/A	-	2030-31	141
CDP2	-	**No-regrets**	**Potential actionable**	-	-	**Potential actionable**	**Potential future**	-
Scenario A	0074	**2023-24**	**2026-27**	N/A	N/A	**2027-28**	-	248
Scenario B	0022	**2023-24**	**2026-27**	N/A	N/A	**2027-28**	-	535

[54] All projects which are not potential actionable ISP projects but which are developed at their earliest date as potential future ISP projects are italicised.

[55] In reality, if early works had proceeded, in two years' time a decision would need to be made as to whether construction should commence on Project 3 and this decision would need to consider risks of over- and under- investment across the range of plausible scenarios explored at that time. This decision would still need to be made based on imperfect information but would benefit from knowledge of how the future has unfolded in the past two years.

	DP	Project 1	Project 2	Project 3 early works	Project 3 completion	Project 3	Project 4	Total cost ($m)
Scenario C	0078	**2023-24**	**2026-27**	N/A	N/A	**2027-28**	-	147
Scenario D	0081	**2023-24**	**2026-27**	N/A	N/A	**2027-28**	-	191
CDP3	-	No-regrets	Potential future	-	-	Potential actionable	Potential future	-
Scenario A	0129	**2023-24**	*2027-28*	N/A	N/A	**2027-28**	-	290
Scenario B	0135	**2023-24**	*2027-28*	N/A	N/A	**2027-28**	-	570
Scenario C	0149	**2023-24**	-	N/A	N/A	**2027-28**	-	111
Scenario D	0164	**2023-24**	*2027-28*	N/A	N/A	**2027-28**	-	169
CDP4	-	No-regrets	Potential actionable	Potential actionable	Potential future	-	Potential future	-
Scenario A	0075	**2023-24**	**2026-27**	**TRUE***	2035-36	N/A	-	220
Scenario B	0022	**2023-24**	**2026-27**	**TRUE**	2027-28	N/A		535
Scenario C	0078	**2023-24**	**2026-27**	**TRUE**	2027-28	N/A	-	147
Scenario D	0085	**2023-24**	**2026-27**	**TRUE**	-	N/A	2030-31	149
CDP5	-	No-regrets	Potential future	-	-	Potential future	Potential future	-
Scenario A	0098	**2023-24**	*2027-28*	N/A	N/A	2035-36	-	241
Scenario B	0105	**2023-24**	*2027-28*	N/A	N/A	*2029-30*		672
Scenario C	0109	**2023-24**	-	N/A	N/A	*2029-30*	-	156
Scenario D	0118	**2023-24**	*2027-28*	N/A	N/A	-	2030-31	150
CDP6	-	No-regrets	Potential future	Potential actionable	Potential future	-	Potential future	-
Scenario A	0127	**2023-24**	*2027-28*	**TRUE**	2035-36	N/A	-	249
Scenario B	0135	**2023-24**	*2027-28*	**TRUE**	2027-28	N/A		570
Scenario C	0149	**2023-24**	-	**TRUE**	2027-28	N/A		111
Scenario D	0168	**2023-24**	*2027-28*	**TRUE**	-	N/A	2030-31	158
CDP7	-	No-regrets	Potential actionable	-	-	-	Potential actionable	-
Scenario A	0172	**2023-24**	**2026-27**	N/A	N/A	-	**2027-28**	230
Scenario B	0175	**2023-24**	**2026-27**	N/A	N/A	-	**2027-28**	552
Scenario C	0181	**2023-24**	**2026-27**	N/A	N/A	-	**2027-28**	137
Scenario D	0185	**2023-24**	**2026-27**	N/A	N/A	-	**2027-28**	148

* The value TRUE here for early works here refers to early works commencing as a potential actionable project.

5.6 Step 4: Evaluation of net market benefits

The next step in the process is to determine the estimated market benefits by comparing for each CDP, the discounted total system cost of each DP in each scenario against the discounted total system cost of the counterfactual DP (CFDP) for that scenario.

5.6.1 Defining the counterfactual Development Path

The CBA assesses the benefits of ISP projects against a status quo where no ISP projects are built. This requires the development of a CFDP to be modelled for each scenario. This counterfactual case considers the development of the system without any actionable or future ISP projects (although ISP development opportunities may be included) and is used to identify the market benefits of the set of ISP projects included in each DP. These benefits are the differences between the discounted total system cost of the CFDP and the discounted total system cost of each DP (see Figure 31).

Consistent with the AER's CBA Guidelines, the CFDP considers the costs of meeting the needs of consumers within each scenario, without the continued development of transmission infrastructure, having to instead rely on large-scale generation, storage, DER, and small intra-regional augmentation and replacement expenditure projects[56]. This means the CFDP does not include any inter-regional or intra-regional augmentation projects that are not already committed or anticipated. This restricts the ability to expand the transmission system beyond transmission limits that result from existing, committed, and anticipated projects, even if this leads to significant generation curtailment in REZs.

For the purpose of the example in this section, the CFDP has been denoted as "0000", as shown in Table 12.

Table 12 Counterfactual Development Path timings by scenario

Counterfactual	DP	Project 1	Project 2	Project 3	Project 4	Total cost ($m)
Scenario A	0000	-	-	-	-	356
Scenario B	0000	-	-	-	-	903
Scenario C	0000	-	-	-	-	278
Scenario D	0000	-	-	-	-	342

5.6.2 Calculation of net market benefits

Once discounted total system costs have been calculated for the CFDP in each scenario, for each CDP, the net market benefits of each DP are determined by subtracting the DP's discounted total system cost from the discounted cost of the CFDP in each scenario. This results in a measure of the NPV of net market benefits across each scenario for each CDP.

Table 13 highlights this process for the examples presented above. For example, for Scenario A – CDP 1, the cost of the least-cost DP (0012, $212 million) is subtracted from the cost of the Scenario A CFDP ($356 million). The reduction in costs of meeting system requirements in Scenario A arising from project investment (a $144 million reduction) can then be interpreted as the net benefits (cost savings) of that CDP under that scenario.

[56] As described in Section 3.3.2 of the AER's CBA Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Table 13 **Calculating the net market benefits ($m) for each scenario – counterfactual Development Path combination**

	Scenario A	Scenario B	Scenario C	Scenario D
CDP1	356 - 212 = 144	903 - 575 = 328	278 - 181 = 97	342 - 141 = 201
CDP2	356 - 248 = 108	903 - 535 = 368	278 - 147 = 131	342 - 191 = 151
CDP3	356 - 290 = 66	903 - 570 = 333	278 - 111 = 167	342 - 169 = 173
CDP4	356 - 220= 136	903 - 535 = 368	278 - 147 = 131	342 - 149 = 193
CDP5	356 - 241 = 115	903 - 672 = 231	278 - 156 = 122	342 - 150 = 192
CDP6	356 - 249 = 107	903 - 570 = 333	278 - 111 = 167	342 - 158 = 184
CDP7	356 - 230 = 126	903 - 552 = 351	278 - 137 = 141	342 - 148 = 194

5.7 Step 5: Ranking the candidate development paths

Once the net market benefits of each CDP are calculated, the final step is to apply appropriate methodologies to rank the CDPs and select the ODP.

The AER's CBA Guidelines describe the framework used to select the ODP. According to these guidelines, the ODP must:

- Promote the efficient development of the power system,
- Be based on quantitative assessment of costs and benefits across a range of scenarios, and
- Have a positive net benefit in the most likely scenario.

The robustness of the ODP is tested through the use of sensitivities, as discussed in Section 5.8.

Consistent with this framework, AEMO ranks the CDPs using three approaches, with each exploring the relative benefits of different CDPs in a different manner to help inform the selection of an ODP which considers the risks and uncertainties reflected in the scenarios and delivers positive net market benefits in the most likely scenario.

This section:

- Describes the alternative approaches which AEMO uses to inform the selection of the draft ODP.
- Compares and contrasts the approaches.
- Details the approach AEMO uses to determine scenario weights through stakeholder consultation.

Section 5.8 provides further detail on how the robustness of high ranking CDPs is assessed using a risk assessment approach based on further sensitivity analysis, and how this informs a final decision on the draft ODP for consultation in the Draft ISP.

5.7.1 Approaches for selecting the draft ODP

Under the CBA Guidelines, at a minimum, AEMO is required to use a scenario-weighted average approach to rank the CDPs against each other. AEMO is also allowed to use professional judgement in balancing the outcomes of the scenario-weighted approach with alternative approaches.

The mandatory 'scenario-weighted' average approach

The scenario-weighted approach calculates the weighted average net market benefits of each CDP by applying scenario weights based on scenario-relative likelihoods to each net market benefit. This approach relies on the determination of weights for each scenario (see Section 5.7.2).

The methodology with this approach is as follows:

1. Ascribe probabilities to each of the scenarios ($P_1,...,Pn$, where n is the number of scenarios) considered for the CBA.
2. Calculate the net market benefits for each of the CDPs (1, 2,…i where i is the total number of CDPs) in each of the scenarios: $B_{1,1},B_{1,2},...,B_{i,n}$. (described in the previous steps).
3. Eliminate from further consideration any CDP that does not deliver positive net market benefits in the most likely scenario.
4. Calculate the scenario-weighted net system benefit A of all CDP not eliminated in Step 3 by applying the weights to the net market benefits: $A_i = (B_{i,1}*P_1 + B_{i,2}*P_2 + ... + B_{i,n}*P_n)$.
5. Rank the CDPs in order from highest to lowest weighted-average net market benefit.

For example, in Table 14, CDP4 would be ranked highest using this approach and with the scenario weights specified.

Table 14 Ranking Candidate Development Paths via weighted net market benefits

	Net market benefits				Weighted average net market benefits ($m) (ranking)
	Scenario A	Scenario B	Scenario C	Scenario D	
Weight	40%	25%	25%	10%	-
CDP1	144	328	97	201	184 (4)
CDP2	108	368	131	151	183 (5)
CDP3	66	333	167	173	169 (6)
CDP4	136	368	131	193	**198 (1)**
CDP5	115	231	122	192	153 (7)
CDP6	107	333	167	183	186 (3)
CDP7	126	351	141	194	193 (2)

The least-worst regrets (LWR) / 'least-worst weighted regrets' (LWWR) approach:

An alternative approach is the LWR approach, which aims to identify the CDP that would cause the least regret associated with under- or over-investment considering the uncertainties reflected across the scenarios.

The standard LWR approach does not require the explicit inclusion of scenario weights. A potential outcome of the standard LWR approach is that a highly unlikely scenario may drive the "worst regrets" and therefore is heavily influential in the ranking of CDPs. If these outcomes were observed, the unlikely scenario could be removed and the calculation repeated. However, a more general approach is to apply a 'least-worst weighted regrets' (LWWR), which accounts for the scenario weights in determining the scale of regrets, and therefore explicitly reduces the potential impact of unlikely scenarios.

In its work for National Grid, the University of Melbourne[57] proved mathematically that the standard LWR approach is in fact an application of the LWWR approach where equal weights are assumed for all scenarios (provided that unlikely scenarios that were heavily influencing outcomes were not removed). Therefore, the LWR and LWWR approaches can be thought of as a single approach, with the application of different weights.

AEMO applies the LWR and LWWR approaches as alternatives for ranking CDPs as part of the process for determining the ODP. In these approaches, AEMO first identifies, for each scenario, the CDP that results in the largest net market benefit. The (negative) difference in net market benefits between all other CDPs and this identified DP will be calculated for each scenario, and defined as the 'regret' of developing a sub-optimal pathway in that scenario. This results in a series of regrets (lower net market benefits relative to a scenario's best case), for each CDP in each scenario.

Generally, the more the CDP varies from the least-cost DP for that scenario, the greater the regret associated with either under- or over-investment. To the extent that projects can be staged, with access to recourse at a later point in time, the regret cost may be relatively small, but this will not always be the case.

For the LWWR, the 'regret' calculated for each CDP in each scenario is then weighted by the scenario's probability. This has the effect of reducing the impact of high levels of regret in unlikely scenarios, and similarly placing greater emphasis on regrets in more likely scenarios.

The approach is described as follows:

1. Calculate the net market benefits for each of the CDPs (1, 2,…i where i is the total number of CDPs) in each of the scenarios: $B_{1,1}, B_{1,2}, \ldots, B_{i,n}$. (described in the previous steps).
2. For each scenario, identify the least-cost DP and determine the net market benefit through comparison with the counterfactual ($LB_1, LB_2, \ldots, LB_n$).
3. Calculate the regret cost for $R_{i,n}$ of a CDP/scenario pairing by subtracting the net market benefits from the net market benefit of each scenario's least-cost DP: $R_{i,n}$ = (LB_1- $B_{i,1}$, LB_2- $B_{i,2}$,…, LB_n- $B_{i,n}$).
4. Weight each of these regret costs $R_{i,n}$ by the scenario probabilities (for LWWR) ($P_1, \ldots, Pn$, where n is the number of scenarios) in the CBA, to calculate a series of weighted regrets.
5. Identify, for each CDP, the greatest of the possible weighted regret costs across all scenarios: $W_1, W_2, \ldots, W_i$ and rank from lowest to highest. For the standard LWR approach, the CDPs are ranked according to their unweighted regrets (potentially excluding unlikely scenarios).

Table 15 below demonstrates how regret costs are calculated to determine least-worst regrets. For each scenario, the CDP with the maximum net market benefits is identified (this is equivalent to the least-cost DP). For Scenario A below it is CDP1, with $144 million. The net market benefit of each CDP (for each scenario) is then subtracted from that scenario's maximum net market benefit, to calculate its regret cost.

In the standard LWR approach, once regret costs are determined, the highest regret is identified for each CDP – which in the case of CDP1 would amount to $70 million. The resulting highest regrets are then ranked from lowest to highest to determine the least-worst regret. In this example, CDP7, which made Project 4 a potential actionable project (rather than its more expensive and larger alternative, Project 3) results in the lowest maximum regret across all scenarios.

[57] Available at: https://www.nationalgrideso.com/document/185821/download

Table 15 Calculating the regret cost ($m) and ranking of Candidate Development Paths via LWR

	Scenario A	Scenario B	Scenario C	Scenario D	Worst regret (ranking)
CDP1	(144 - 144) = 0	(368 - 328) = 40	(167 - 97) = 70	(201 - 201) = 0	70 (5)
CDP2	(144 - 108) = 36	(368 - 368) = 0	(167 - 131) = 36	(201 - 151) = 50	50 (4)
CDP3	(144 - 66) = 78	(368 - 333) = 35	(167 - 167) = 0	(201 - 173) = 28	78 (6)
CDP4	(144 - 136) = 8	(368 - 368) = 0	(167 - 131) = 36	(201 - 193) = 8	36 (2)
CDP5	(144 - 115) = 29	(368 - 231) = 137	(167 - 122) = 45	(201 - 192) = 9	137 (7)
CDP6	(144 - 107) = 37	(368 - 333) = 35	(167 - 167) = 0	(201 - 184) = 17	37 (3)
CDP7	(144 - 126) = 18	(368 - 351) = 17	(167 - 141) = 26	(201 - 194) = 7	**26 (1)**

Table 16 shows the determination of the LWWR and corresponding CDP rankings. The regret costs within each scenario from Table 15 are weighted by the scenario probabilities, to calculate weighted regrets and then the worst of these across the scenarios is recorded for the purpose of ranking. Ranking CDPs to determine the LWWR shows once again that CDP7 results in the lowest maximum weighted regret across all scenarios.

Table 16 Calculating the weighted regret cost ($m) and ranking of Candidate Development Paths via LWWR

	Weighted regrets				Worst weighted regret (ranking)
	Scenario A	Scenario B	Scenario C	Scenario D	
Weighting	40%	25%	25%	10%	-
CDP1	0 * 40% = 0	40 * 25% = 10	70 * 25% = 18	0 * 10% = 0	18 (5)
CDP2	36 * 40% = 14	0 * 25% = 0	36 * 25% = 9	50 * 10% = 5	14 (3)
CDP3	78 * 40% = 31	35 * 25% = 9	0 * 25% = 0	28 * 10% = 3	31 (6)
CDP4	8 * 40% = 3	0 * 25% = 0	36 * 25% = 9	8 * 10% = 1	9 (2)
CDP5	29 * 40% = 12	137 * 25% = 34	45 * 25% = 11	9 * 10% = 1	34 (7)
CDP6	37 * 40% = 15	35 * 25% = 9	0 * 25% = 0	17 * 10% = 2	15 (4)
CDP7	18 * 40% = 7	17 * 25% = 4	26 * 25% = 7	7 * 10% = 1	**7 (1)**

Comparison of the LWR/LWWR and scenario-weighted average approaches

The mandatory scenario-weighted approach seeks to maximise net market benefits and make the best decision on the balance of probabilities. However, the scenario-weighted approach focuses on expected outcomes and may obscure significant risks that may be apparent in some scenarios, especially if these are considered unlikely (akin to high impact, low probability events).

The alternative LWR and LWWR approaches choose the option which minimises the worst 'regret' across all scenarios being considered (which may exclude unlikely scenarios in the case of the standard LWR approach). The LWR/LWWR approach provides a robust decision against the range of uncertainties examined, clearly demonstrates risks, and minimises the chance of particularly adverse outcomes impacting consumers.

Compared to the scenario-weighted approach, it may rank more highly a CDP that has less upside benefit for consumers but limits the downside risk, while still delivering positive net market benefits in the most likely scenario. The calculation of benefits using this approach provides information that increases transparency around the risks and rewards of alternative CDPs.

By comparing the weighted net market benefits of the draft ODP against the highest ranked CDP under the scenario-weighted approach, the cost associated with selecting a CDP that helps mitigate risks to consumers can be determined. In this example, CDP7 delivers $5 million fewer net market benefits to consumers compared to CDP4, but minimises the risk of over-investment if Scenario C were to eventuate.

The AER's CBA Guidelines require AEMO to rank the CDPs based on the scenario-weighted approach, but allow AEMO to use an alternative approach (such as LWR/LWWR) and professional judgement to select the ODP provided the choice is explained fully and reasonably reflects consumers' level of risk neutrality or aversion.

AEMO considers that each of the assessment approaches provides value in understanding the merits of alternative CDPs and, in combination, provide transparency to help inform decision-making. The ranking of CDPs under each approach, as well as their performance in sensitivity testing (outlined in Section 5.8) is all considered in the selection of the draft ODP for consultation in the Draft ISP. AEMO also consults with its ISP Consumer Panel to understand consumers' level of risk neutrality or risk aversion.

5.7.2 Allocating weights to scenarios

The use of a scenario-weighted average approach requires AEMO to determine a weight for each scenario. The scenario weights must add to 100% and AEMO must identify a most likely scenario that takes the most probable value for each input variable and/or parameter, provided that together they form an internally consistent and plausible scenario[58].

Scenario weights are developed through the use of the Delphi technique and refined through a consultation process that follows the finalisation of scenarios through the IASR process. This section sets out the process AEMO follows in determining scenario weights.

The Delphi technique draws on an anonymous panel of up to 10 subject matter experts, both internal and external to AEMO, to rank the relative likelihood of each scenario using a questionnaire, and provide reasoning for their selection. Responses are collected, analysed, common and conflicting views identified, and shared with the panel. Panel members then have the opportunity to modify their original views based on the varying positions of other panel experts, with the goal being to reach consensus where possible.

Following this process, a stakeholder workshop provides the opportunity for discussion with a broader range of stakeholders, seeking feedback on the reasonableness of weights proposed through the Delphi technique.

Before this engagement, AEMO will provide the following information with sufficient time provided for stakeholder consideration:

- A scenario or selection of scenarios that meet the criteria for being a candidate for the most likely scenario, that being those scenarios that take the most probable or central outlook for key input variables (for example, economic and population growth, DER uptake). If more than one scenario is specified, these will differ with respect to input such as key events or policy drivers.
- A preliminary view of AEMO's assessment of the weights of each scenario, along with an explanation for how AEMO has made this assessment using outcomes of the Delphi survey technique.

During the workshop, AEMO will reiterate these positions and provide the ability for stakeholders to discuss the preliminary assessment of weights.

[58] See Section 3.2.2. of the AER's CBA Guidelines, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

Following the discussion, AEMO will facilitate a structured survey where stakeholders will provide a view on whether the preliminary weight allocated to the scenario is appropriate, should be increased or reduced. Each stakeholder will identify as one of the following groups:

- Market participant – for example, retailer, generator, developer.
- Consumer representative or advocate.
- Network service provider (or representative).
- Other – for example, market bodies, government representatives, consultants, advocates.

For each scenario, the summarised view from the survey responses will be calculated in a transparent manner, such as by equally weighting the responses from the groups above. This takes into account that the groups above may not be equally represented in AEMO's workshops.

These aggregated views will provide an indication of the relative view on each scenario, such as which scenarios should be considered more or less likely. Based on this aggregated feedback, AEMO will then consider adjustments to the preliminary weights in the directions indicated by stakeholders, and provide a final set of weights to stakeholders with further justifications for the final decision.

Consideration of stakeholder feedback

The submissions from Shell Energy and the ISP Consumer Panel both encouraged AEMO to explore and outline further alternative methods for determining an ODP – specifically referencing the National Grid approach. AEMO has provided additional detail on the consideration of alternative methods in the accompanying consultation paper, and why they have not been considered appropriate or preferred for the ISP analysis. AEMO has also provided an explanation of how the National Grid single-year regret approach is closely aligned with AEMO's application of the LWR approach.

AEMO has also taken on board feedback that the use of multiple methods would be preferred, and has refined the approach to the determination of the ODP to align with this feedback.

Several stakeholders also provided a view that the methodology should consult on scenario weights, or at least the approach to determining weights. AEMO has therefore added a description of the approach that will be undertaken later in 2021 to determine scenario weights.

5.8 Step 6: Finalising the draft Optimal Development Path selection through sensitivity analysis

Once the CDPs have been ranked under the ODP selection approaches outlined above, AEMO will apply further scrutiny to explore the robustness of high ranking CDPs to changes in some key assumptions through sensitivity analysis.

In the scenario analysis described above, there may be CDPs that are not ranked at the top of any approach, but perform strongly in each approach and are much more robust than other CDPs to variations in assumptions. These more robust CDPs may, in AEMO's professional judgement, better balance risk and benefit for consumers and ultimately influence selection of the ODP.

This section lays out the framework for how AEMO conducts sensitivity analysis and how this analysis is considered in selecting the ODP. The use of sensitivity analysis provides an opportunity for AEMO to test the robustness of the CDP rankings, the magnitude of net market benefits, and the importance that should be placed on accuracy of particular assumptions to strengthen the validity of the analysis. Sensitivities are deviations from a scenario that adjusts a single assumption, or at most a single combination of assumptions. These sensitivities are applied to one or more of the scenarios and effectively substituted for that scenario/set of scenarios in the CBA analysis.

In conducting sensitivity analysis, AEMO may need to limit the breadth of analysis that is conducted, given the complexity and time required to re-optimise each stage of this process. AEMO therefore uses an approach that considers the trade-off of complexity versus breadth, such as:

- When testing sensitivities, the CDPs assessed will not re-optimise future ISP projects, rather adopting the transmission augmentations of the primary simulations in identifying the impact of the sensitivity to the net market benefits.
- When testing sensitivities, the analysis may be limited to a subset of scenarios, for example, the scenario or scenarios considered most likely according to their weight. For example, if a project in the ODP is suspected of being sensitive to minor variations in a key input variable and the project's presence in the ODP is heavily influenced by the outcomes of a given scenario, the sensitivity may only be applied to that scenario.
- Not all sensitivities may be logical to apply to all scenarios, or may represent an outcome that is already reflected in that scenario's inputs or outputs.
- Sensitivities may only be applied for CDPs that were highly ranked in the alternative methodologies applied.

An example is provided in Table 17, where a sensitivity has been applied to Scenario B which results in lower net market benefits in all CDPs. However, the reduction in market benefits for CDP4 is much more significant than the reduction in CDP7, and – as shown in the final column – this results in a significant revision in the rankings of the CDPs, with CDP7 being optimal in this sensitivity. For simplicity, this example focuses only on scenario weighted-average net market benefits.

Table 17 Impact of a sensitivity analysis on Scenario B

	Net market benefits					Weighted average NMB – original (ranking)	Weighted average NMB – sensitivity (ranking)
	Scenario A	Scenario B	Scenario B (sensitivity)	Scenario C	Scenario D		
Weight	40%	25%	25%	25%	10%	-	
CDP1	144	328	302	97	201	184 (4)	177 (2)
CDP2	108	368	306	131	151	183 (5)	168 (5)
CDP3	66	333	268	167	173	169 (6)	152 (6)
CDP4	136	368	278	131	193	**198 (1)**	176 (3)
CDP5	115	231	189	122	192	153 (7)	143 (7)
CDP6	107	333	264	167	184	186 (3)	169(4)
CDP7	126	351	326	141	194	193 (2)	**187 (1)**

Table 18 expands the sensitivity analysis above and shows how the net benefits and relative ranking of the top four CDPs compares across four additional sensitivities to that presented above. From this example, it is clear that although CDP4 performs relatively poorly across the sensitivities examined, CDP1 and CDP7 perform relatively strongly.

Table 18 Summary of conceptual sensitivity analysis

	Original	Sensitivity 1	Sensitivity 2	Sensitivity 3	Sensitivity 4	Sensitivity 5
CDP1	184	177	175	188	168	90
CDP4	198	176	168	192	143	83
CDP6	186	169	162	168	140	85
CDP7	193	187	183	204	145	87

Note: For each sensitivity in the above figure, weighted NMBs have been graded from white (lowest NMB) to dark (highest NMB).

Given the above result, it is likely that CDP7 may ultimately represent a preferred choice as the ODP, given its relative robustness to the additional uncertainties examined through sensitivity analysis, and its strong performance under the base settings.

In applying its professional judgement in finalising the ODP, AEMO must identify whether the sensitivity analysis it chooses to perform provides any influence on the ODP selection. If a higher ranking CDP under one or both of the CDP ranking approaches is a poor performer in the sensitivity analysis conducted, it may be more appropriate to switch to another CDP that performed well in both the scenario and sensitivity analyses.

Even if the sensitivity analysis is not influential in the choice of the ODP, the presentation of the results of the sensitivity analysis will be valuable in demonstrating the level of robustness of the ODP, and the relative importance of various inputs.

Consideration of stakeholder feedback

This section outlines an approach for determining the ODP, taking into account alternative methods and sensitivity testing, consistent with the approach recommended in the submissions from the ISP Consumer Panel and Shell Energy.

In submissions, and in discussions at the Draft IASR submissions webinar, much of the discussion was around seeking clarity on how sensitivities are treated differently to scenarios. This section has attempted to explain the key differences.

5.9 Key information for actionable ISP projects

This section outlines the approach to preparing key information relevant to actionable ISP projects including:

- The approach to applying decision rules.
- An overview of how AEMO assigns an identified need.
- The approach to estimating transmission cost thresholds.

5.9.1 Application of decision rules

AEMO in its professional judgement may identify circumstances where it is appropriate to qualify the actionability of projects given the outcomes identified within the ISP's CBA.

Two options exist for this purpose:

- **Staging** – as described previously, staging can provide protection to consumers from under- or over-investment by enabling progression of investments to achieve early investment milestones without committing to the development of the complete project, where sufficient uncertainty exists.

- **Decision rules** – these can provide protection to consumers from over-investment, by identifying conditions that must exist in order for actionable projects to proceed from one stage to the next. This is important where actionable projects rely heavily on future market conditions or events that may have identifiable signposts, such that decisions to proceed do not need to wait to the next ISP before moving forward if it becomes clear that they would now deliver benefits to consumers. The following principles would apply for defining and applying decision rules to projects:
  - The circumstances for the decision rules are identifiable and measurable.
  - The timing of this identification and measurement must be reasonably expected between the current and next ISP, or prior to the completion of the stage currently being progressed.
  - There is a need to provide clear investment direction ahead of the next ISP, rather than waiting for a re-assessment at the next ISP.

5.9.2 Determining the identified need

The AER's CBA Guidelines[59] describe the identified need as "the reason why an investment in the network is needed". AEMO is required to specify at least one identified need for each actionable ISP project. The identified need(s) must be described as an objective(s) to be achieved by investing in the network, and can be addressed by either network or non-network options (or a combination of the two).

Informing the identified need

For an actionable ISP project, AEMO will evaluate the benefits of the project that led to it being part of the ODP. The identified need for an actionable ISP project is therefore informed by the ISP modelling process. This process begins with the capacity outlook modelling (see Section 2), is informed by the time-sequential model and engineering assessment (see Sections 3 and 4) and is finalised through the CBA (see Section 5).

Consideration of benefits from the capacity outlook model

The capacity outlook model makes build decisions in order to minimise capital expenditure and operational costs of the entire NEM over the long-term outlook. It has an extensive set of options to choose from when making decisions – including renewable generation, gas-fired generation, storage, network, and non-network options[60].

Often, the capacity outlook model makes build decisions which increase the transfer capability of the network. This can be for a variety of reasons, including:

- Enabling generation to be developed in areas with high quality energy resources (for example, building new network into a REZ).
- Increasing network transfer capability across the NEM (for example, an interconnector upgrade).
- Increasing the capability to supply major load centres (such as supply to a major city).

Consideration of the engineering assessment and the time-sequential model

The engineering assessment and the time-sequential model will ensure outcomes of the capacity outlook model can meet the power system needs[61] – including the reliability standard, power system security, system standards, technical requirements in the NER, other applicable regulatory instruments, and environmental or energy policy. This consideration may also include outcomes of the Power System Frequency Risk Review or its successor[62].

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[59] AER. *Cost Benefit Analysis Guidelines*, at https://www.aer.gov.au/system/files/AER%20-%20Cost%20benefit%20analysis%20guidelines%20-%2025%20August%202020.pdf.

[60] See the *Input, Assumptions and Scenarios Report* for further details, at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios.

[61] The power system needs are defined in section 5.22.3 of the NER.

[62] AEMC. *Implementing a general power system risk review*, at https://www.aemc.gov.au/rule-changes/implementing-general-power-system-risk-review.

Consideration of benefits from the cost benefit analysis

Additional value identified through the CBA could relate to:

- Option value – the inclusion of early works (see Section 5.1) or the ability to adapt or stage an option to cater to uncertainty.
- Risk mitigation – the ability for an option to provide benefit across a range of scenarios to mitigate risks relating to the future being uncertain.

As outlined in previous sections, scenario analysis may identify the option value of investments while future uncertainty exists. Alternatively, sensitivity analysis on the most likely scenario may identify risks that may be avoidable with the actionable investment, and decision-tree analysis may be deployed to assess the value in the actionable investment that assists in avoiding this risk.

To determine the option value of an actionable early works project, the ODP is compared with a CDP that shares the same actionable projects except for the early works for scenarios that exclude the most likely scenario. The difference in the weighted benefits between these two CDPs across the remaining scenarios provides an estimate of the option value attributable to the early works.

Describing the identified need

After considering benefits from the capacity outlook model, time-sequential model, engineering assessment, and CBA, AEMO will describe the identified need in a written statement. When describing an identified need, AEMO will:

- Support the long-term interests of electricity consumers by including an increase in market benefits into the statement (unless reliability corrective action is required). This could include specific reference to categories of market benefits or power system needs[63] that are fundamental to the actionable project, or the risks or uncertainties that a project may assist in minimising.
- Consider related elements in the ODP and any approach used to incorporate risk into the selection of the actionable project as a part of the ODP.
- Provide sufficient specificity such that options can be narrowed without pre-supposing a particular outcome.
- Consider opportunities to realise option value by enabling staged investments and aligning with decision rules.
- Include a reference to reliability corrective action[64] if it is required.

Consideration of stakeholder feedback

Major Energy Users (MEU) suggested that a defined need must be specified and held constant such that a non-network option can be developed and fairly evaluated against that need. AEMO agrees that an identified need should be evaluated and described such that non-network solutions can be developed and evaluated fairly. AEMO has drafted a methodology for determining and describing the identified need for actionable ISP projects. The RIT-Ts for any actionable ISP projects must use the identified need determined by the ISP such that developers of non-network solutions can tailor their solutions.

[63] The power system needs are defined in clause 5.22.3 of the NER.

[64] Reliability corrective action is defined in clause 5.10.2 of the NER.

5.9.3 Transmission cost thresholds

For each actionable ISP project in the ODP, AEMO performs TOOT analysis to provide a guide as to the project's sensitivity to transmission cost variations.

The TOOT approach removes the actionable ISP project from the ODP, along with any augmentations along the project route, for example, augmentations in the capacity available in REZs along the project route. The TOOT analysis is generally limited to the most likely scenario but may extend to other scenarios if appropriate and material to the ODP selection or to the specification of scenarios for RIT-T analysis.

The TOOT assessment includes the following steps:

1. Identify the expansion plan of the ODP and calculate the total system cost (already covered in earlier steps, and with validation through time-sequential modelling if possible).
2. For the 'base case', remove the actionable ISP project from the ODP and adjust REZ expansion limits associated with the actionable project.
   - For REZs not affected by the actionable ISP project, the development in the 'base case' is optimised as normal.
   - For REZs affected by the actionable ISP project, the additional capacity associated with the development of the actionable ISP project is removed from the capacity, and the adjusted limit considers the initial capacity plus any additional REZ expansion from the ODP, and any additional capacity informed by a broader assessment of comparable DP developments.
     - For example, assume the capacity is 1,000 MW, which consists of an initial capacity of 300 MW and an upgrade of 700 MW from the actionable project in 2026-27. If in 2029-30 an additional 500 MW REZ capacity expansion occurred (over and above the additional capacity provided by the earlier actionable project), the REZ-adjusted limit for the TOOT case in 2029-30 will be 800 MW (300 MW of initial capacity plus 500 MW of additional expansion identified in the ODP).
     - In addition, if a DP that did not include the actionable project still preferred to develop the REZ associated with the project, as an independent REZ expansion spur potentially to support another power system need, this additional capacity may also be added to the capacity.

Other aspects for the TOOT case include:

- All other major transmission augmentations (whether committed, anticipated, actionable, or future ISP projects) such as interconnector developments will remain as stated by the ODP.
- No other major transmission developments are allowed.

The TOOT analysis therefore focuses on a comparison without any replacement in transmission along the actionable project's route that delivers to the identified need of the actionable project, so it demonstrates that the actionable project delivers net market benefits compared to not developing any transmission at all along that route. The size of these incremental benefits are an indicator of the transmission cost threshold which, if exceeded, would lead to this project no longer being beneficial, all other inputs remaining unchanged.

Further analysis in the TOOT

For REZ developments which are determined to be actionable projects, AEMO proposes to extend the TOOT analysis to consider the potential for reducing the scale of REZ augmentation through the co-location of storage. This is not intended to be a complete replacement of the consideration of non-network options in the RIT-T process. By testing the potential benefits of using additional storage to reduce network investment, the ISP can provide an indication of whether non-network options are likely to be beneficial. The inclusion of storage in REZs where there are likely actionable projects may also be considered, as discussed in Section 2.3.4.

Consideration of stakeholder feedback

AEMO received a range of feedback on the design and purpose of the TOOT analysis which has informed the approach described in this section.

The ISP Consumer Panel and Shell Energy proposed that the TOOT analysis should consider an alternative option, rather than a case where no project replaces the actionable project. AEMO understands the value of the transparency in understanding why the actionable project has been preferred, but considers that this is best demonstrated outside the TOOT analysis. The TOOT analysis therefore retains its comparison with a case with no transmission to achieve the purpose set out in this section. To provide transparency on the comparison between options, for large actionable projects AEMO will aim to provide analysis comparing the ODP against a CDP which has a combination of smaller and/or non-network options which will demonstrate the relative benefits of the alternatives.

AEMO also received feedback that the TOOT should be aligned with the RIT-T process. AEMO has outlined a process in this section that it considers comparable to the approach that would be undertaken by TNSPs in performing RIT-Ts on actionable ISP projects, without creating process inefficiencies by duplicating the RIT-T analysis.

5.10 Transparency around decision-making criteria, further testing and analysis of Optimal Development Path

AEMO considers that, in optimising consumer benefits, a multi-criteria decision making approach is required, delivering:

- Market benefits through cost savings, particularly in the most likely scenario.
- Resilience to events that can adversely impact future costs to consumers (low regret cost).
- Reliable and secure power supply.
- Robust solutions that are relatively insensitive to changes in input assumptions.

The preceding sections outline AEMO's approach to assessing the performance of CDPs and the draft ODP against these criteria. The AER Guidelines provide AEMO with the flexibility to rely fully, partly, or not at all on the results from any decision-making process it uses, however AEMO will need to justify and explain its choice.

AEMO provides additional analysis to increase the transparency around the choice of the ODP. The following information is provided in the draft ISP, along with the draft ODP for consultation:

- The reasons and justifications of the choice of the ODP, particularly where the ODP differs from the highest ranked CDP in the scenario-weighted approach.
- Quantification of the difference in costs (if any) between the ODP and the highest-ranked CDP in the scenario-weighted approach.
- The resulting net market benefits across the CDPs in all scenarios, and where relevant in the sensitivity analysis. This will allow the value of each project (including no regret projects) to be clearly demonstrated through comparison with CDPs that do not have that project, or feature smaller or other alternative projects.

Beyond the determination of the ODP, further analysis is also undertaken to explore a range of issues. Potential areas of analysis include:

- Distributional effects such as the impact of the ODP on consumer bills, including wholesale costs and transmission network charges, through detailed time sequential modelling as outlined in Section 3.
- The resilience of the ODP against major climate risks, through time-sequential modelling (Section 3) using extreme weather case studies that have been co-designed with climate scientists[65].

This additional analysis is provided for information purposes only and will not influence the determination of the ODP.

Consideration of stakeholder feedback

In submissions, and in discussions at the ISP Methodology webinar, much of the discussion around TOOT analysis focused on the need for transparency around why an actionable project has been preferred over alternatives. Rather than using the TOOT analysis for this purpose, AEMO has provided details in this section about how providing more complete results for alternative CDPs would deliver this transparency in a more holistic manner than the TOOT analysis.

[65] AEMO formally collaborates with the Bureau of Meteorology and CSIRO through the Electricity Sector Climate Information (ESCI) project, which is funded by the Department of Industry, Science Energy and Resources. Through this project, AEMO has access to extensive climate data and advice for long-term climate risk planning in the electricity sector. For more information on the project see: https://www.climatechangeinaustralia.gov.au/en/projects/esci/.

Abbreviations

Term	Definition
AER	Australian Energy Regulator
AFL	Available fault level
BESS	Battery energy storage system
CBA	Cost benefit analysis
CCGT	Closed-cycle gas turbine
CDP	Candidate development path
CFDP	Counterfactual development path
DER	Distributed energy resources
DLT	Detailed long-term (model)
DNI	Direct Normal Irradiance
DP	Development path
DSP	Demand side participation
EFOR	Equivalent forced outage rate
EISD	Earliest in-service date
ELCC	Effective Load Carrying Capability
EMT	Electromagnetic transient
ESCI	Electricity Sector Climate Information (project)
ESOO	Electricity Statement of Opportunities
EV	Electric vehicle
FCAS	Frequency control ancillary services
FFR	Fast frequency response
GFST	Gas-fired steam turbine
GHI	Global Horizontal Irradiance
GPG	Gas-powered generation
GSOO	Gas Statement of Opportunities
GT	Gas turbine

Term	Definition
GW	Gigawatt/s
HVAC	High voltage alternating current
HVDC	High voltage direct current
Hz	Hertz
IASR	Inputs, Assumptions and Scenarios Report
IBR	Inverter-based resources
ISP	Integrated System Plan
KCI	Key connection information
kV	Kilovolt/s
LDC	Load duration curve
LIL	Large industrial load
LWR	Least-worst regrets
LWWR	Least-worst weighted regrets
MLF	Marginal loss factor
MT PASA	Medium-Term Projected Assessment of System Adequacy
MTLI	Minimum Threshold Level of Inertia
MVA	Megavolt-amperes
MW	Megawatt/s
MWh	Megawatt hour/s
NEM	National Electricity Market
NEMDE	NEM Dispatch Engine
NER	National Electricity Rules
NPV	Net present value
NSP	Network service provider
NSCAS	Network Support and Control Ancillary Services
OCGT	Open-cycle gas turbine
ODP	Optimal development path
PADR	Project Assessment Draft Report
PASA	Projected Assessment of System Adequacy
PHES	Pumped hydro energy storage
POE	Probability of exceedance
PV	Photovoltaic

Term	Definition
REZ	Renewable energy zone
RIT-T	Regulatory Investment Test for Transmission
RoCoF	Rate of change of frequency
RRN	Regional Reference Node
SCR	Short circuit ratio
SOLI	Secure Operating Level of Inertia
SSP	Special Protection Scheme
SRAS	System restart ancillary services
SRMC	Short Run Marginal Cost
SSLT	Single-stage long-term (model)
ST	Steam turbine
ST PASA	Short-Term Projected Assessment of System Adequacy
SVC	Static Var compensator
TCD	Transmission Cost Database
TNSP	Transmission network service provider
TOOT	Take-one-out-at-a-time (analysis)
USE	Unserved energy
VCR	Value of customer reliability
VPP	Virtual power plant
VRE	Variable renewable energy
WACC	Weighted average cost of capital