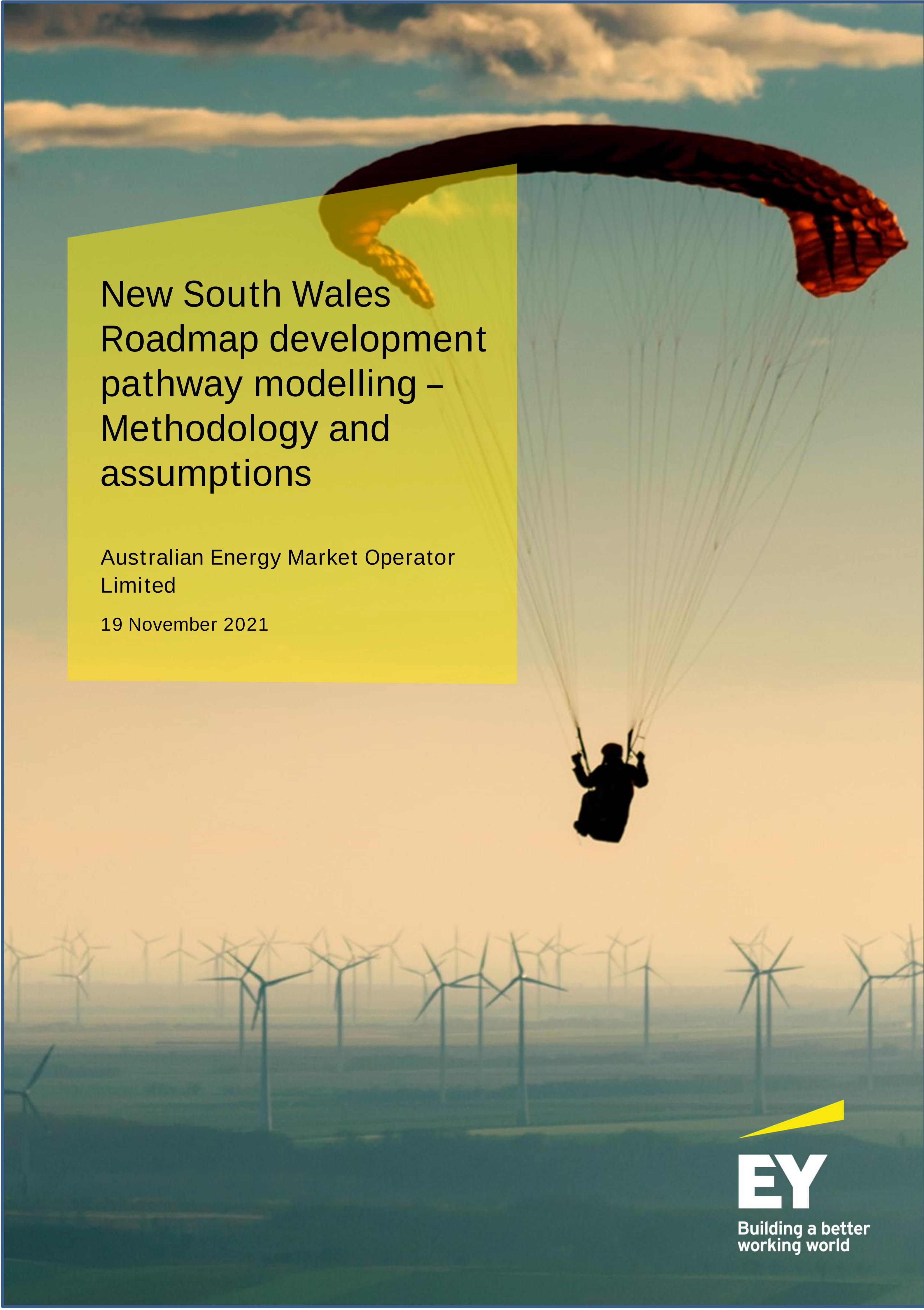


New South Wales Roadmap development pathway modelling – Methodology and assumptions

Australian Energy Market Operator Limited

19 November 2021

Building a better working world

RELEASE NOTICE

Ernst & Young was engaged on the instructions of Australian Energy Market Operator Limited (AEMO) to deliver electricity market modelling services informing a recommended development pathway for the Consumer Trustee over the following 20 years that delivers the New South Wales Government's infrastructure investment objectives.

The key inputs, assumptions, methodology, scenarios and qualifications made in preparing the modelling are set out in EY's report dated 19 November 2021 ("Report"). You should read the Report in its entirety including any disclaimers and attachments. A reference to the Report includes any part of the Report. No further work has been undertaken by EY since the date of the Report to update it.

Ernst & Young has prepared the Report for the benefit of AEMO and has considered only the interests of AEMO. Ernst & Young has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, Ernst & Young makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes. Our work commenced on 26 March 2021 and was completed on 19 November 2021. Therefore, our Report does not take account of events or circumstances arising after 19 November 2021 and we have no responsibility to update the Report for such events or circumstances.

No reliance may be placed upon the Report or any of its contents by any party other than AEMO ("Third Parties"). Any Third Parties receiving a copy of the Report must make and rely on their own enquiries in relation to the issues to which the Report relates, the contents of the Report and all matters arising from or relating to or in any way connected with the Report or its contents. Ernst & Young disclaims all responsibility to any Third Parties for any loss or liability that the Third Parties may suffer or incur arising from or relating to or in any way connected with the contents of the Report, the provision of the Report to the Third Parties or the reliance upon the Report by the Third Parties.

No claim or demand or any actions or proceedings may be brought against Ernst & Young arising from or connected with the contents of the Report or the provision of the Report to the Third Parties. Ernst & Young will be released and forever discharged from any such claims, demands, actions or proceedings. Our Report is based, in part, on the information provided to us by AEMO and other stakeholders engaged in this process. We have relied on the accuracy of the information gathered through these sources. We do not imply, and it should not be construed that we have performed an audit, verification or due diligence procedures on any of the information provided to us. We have not independently verified, nor accept any responsibility or liability for independently verifying, any such information nor do we make any representation as to the accuracy or completeness of the information. We accept no liability for any loss or damage, which may result from your reliance on any research, analyses or information so supplied.

Modelling work performed as part of our scope inherently requires assumptions about future behaviours and market interactions, which may result in forecasts that deviate from future conditions. There will usually be differences between estimated and actual outcomes, because events and circumstances frequently do not occur as expected, and those differences may be material. We take no responsibility that the projected outcomes will be achieved. We highlight that our analysis and Report do not constitute investment advice or a recommendation to you on a future course of action. We provide no assurance that the scenarios we have modelled will be accepted by any relevant authority or third party.

Ernst & Young have consented to the Report being published electronically on AEMO's website for informational purposes only. Ernst & Young have not consented to distribution or disclosure beyond this. The material contained in the Report, including the Ernst & Young logo, is copyright. The copyright in the material contained in the Report itself, excluding Ernst & Young logo, vests in AEMO. The Report, including the Ernst & Young logo, cannot be altered without prior written permission from Ernst & Young.

Readers are advised that the information provided is based on many detailed assumptions. These assumptions were selected by AEMO after consultation with other stakeholders. The modelled scenarios represent several possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

Table of contents

1. Introduction

EY has been engaged by the Australian Energy Market Operator (AEMO) to provide electricity sector modelling, consultancy and support services in relation to establishing the inaugural 20-year New South Wales Roadmap development pathway. This modelling informs the infrastructure investment objectives report for the New South Wales Department of Planning, Industry and Environment (the Department) contemplated in the New South Wales Electricity Infrastructure Investment Act 2020. The primary purpose of EY's modelling is to compare the merits of several Alternative Development Pathways developed as an outcome of the market modelling.

In this Report, an Alternative Development Pathway is defined as:

> Alternative Development Pathway: an annual commissioning schedule of transmission augmentations, electricity generation and storage developments in New South Wales over a 20-year outlook. This includes the locations by renewable energy zone (REZ) or other location, and the technologies of the generation and storage capacity.

The high-level scope of EY's modelling and analysis is:

- To conduct half-hourly electricity market modelling for a 20-year horizon to forecast the future capacity mix in the National Electricity Market (NEM) in response to a set of input assumptions and objectives for a single Scenario. These assumptions were selected by AEMO and the Department in consultation with EY.
- The primary objectives of the modelling are to:
    - Meet the minimum New South Wales Roadmap 2030 targets for renewable generation and long duration storage.
    - Improve the affordability of electricity supply in New South Wales as per the infrastructure investment objectives (IIO)[1], by minimising the combination of wholesale electricity prices, scheme costs, transmission charges for New South Wales electricity customers, where scheme costs refers to the net payments to generators under the New South Wales Government's long-term energy service agreements (LTESAs).

To achieve these primary objectives, EY conducted market modelling applying a standard 'scenario and sensitivity' methodology. For the purposes of this analysis:

- Scenario refers to a set of market assumptions that drive the modelling outcomes, including the capacity mix, for the 20-year outlook across the NEM.
- Several baseline cases are simulated, examining the merits of Alternative Development Pathways that meets the above primary objectives, by adjusting the timing, location and capacity of variable renewable energy (VRE) capacity, long duration storage capacity and transmission augmentation schedules where applicable.
- Sensitivities are used to explore the resilience of each Alternative Development Pathway to plausible but unexpected changes in the assumptions. Unexpected changes to be explored include delayed delivery of transmission and generation developments, and/or early closures of coal power stations.
- The total costs to New South Wales electricity customers with each Alternative Development Pathway are compared along with additional outcomes. This analysis

[1] Electricity Infrastructure Investment Act 2020 No 44 - NSW Legislation

informs the strengths and weaknesses of each Alternative Development Pathway that minimises risks and regrets to New South Wales customers of over- or under-investment.

This Report describes the methodologies, key assumptions and data sources used in the modelling. It accompanies a Development Pathways Report, which describes the main results and analysis of the modelling.

This Report is structured as follows:

- Section 2 describes the modelling methodology, the objectives, and how these objectives are achieved.
- Section 3 describes an overview of the Scenario assumptions.
- Section 4 describes the themes for each Alternative Development Pathway and the sensitivities examined.
- Appendix A provides a detailed description of EY's market dispatch modelling software suite, 2-4-C® and the Scenario assumptions.
- Appendix B provides a list of definitions and acronyms used in this Report.

We note that AEMO and the Department has selected the Scenario assumptions and the themes for the Alternative Development Pathways and sensitivities in consultation with EY.

It should be noted that there is a significant range of alternative assumptions that, in isolation or in aggregate, could transpire to produce outcomes that will differ from those that have been modelled. These possible alternative futures have not been considered in this engagement.

1.1 Conventions used in this document

All prices in this Report refer to real June 2020 dollars unless otherwise labelled. All annual values refer to the fiscal year (1 July – 30 June) unless otherwise labelled.

2. Modelling methodology

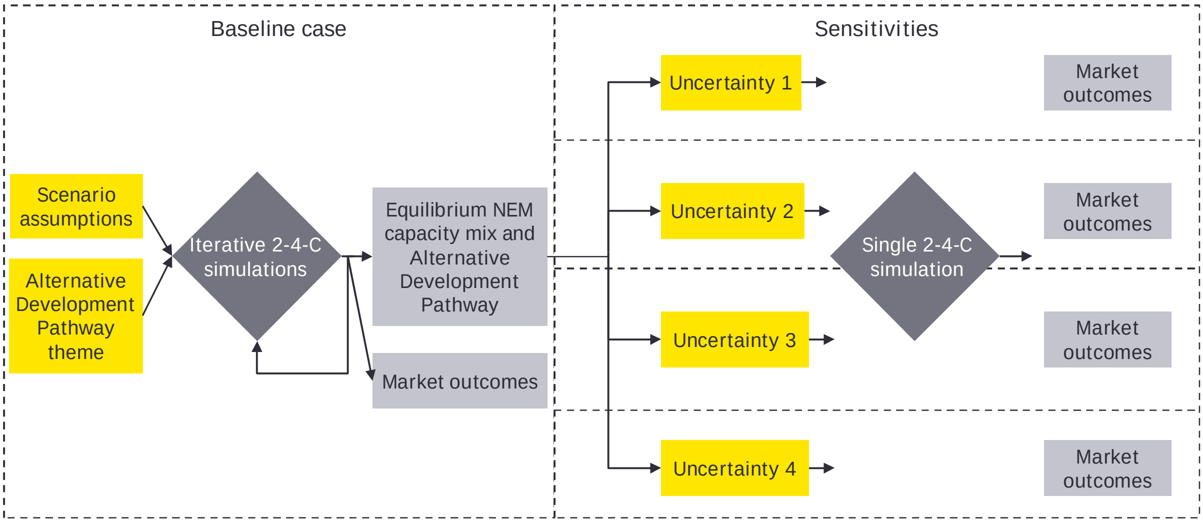
This section contains a description of the methodology including the modelling objectives and rationale for the modelling approach used to deliver those objectives.

2.1 Methodology overview – a scenario/sensitivity approach

As stated in Section 1, the primary objective of the modelling is to analyse the strengths and weaknesses of Alternative Development Pathways with respect to minimising the cost to New South Wales electricity customers, in light of the risks they might entail.

An Alternative Development Pathway with the most merit will be robust in achieving the IIO subject to various uncertainties in unexpected changes and inaccuracy in assumptions. To explore uncertainties, a scenario/sensitivity approach is applied with the modelling. Figure 1 illustrates this approach as applied in this engagement.

Figure 1: High-level illustration of the scenario / sensitivity approach



A set of Scenario assumptions provided by the Department and AEMO underpins all the baseline cases. These assumptions largely represent the Central Scenario from AEMO's Draft 2021 Inputs, Assumptions and Scenarios Report (2021 Draft IASR)[2]. Section 3 provides a more detailed overview of the Scenario assumptions.

The Scenario assumptions are applied along with an Alternative Development Pathway theme in each baseline case. Each Alternative Development Pathway theme explores different rates of VRE development that may influence the ultimate timing, technology, and location of eligible generation and storage developments that define each Alternative Development Pathway. Subject to these themes, EY's baseline case modelling analyse how much capacity could be economically built year or year, where it could potentially be built and with what technologies to minimise costs to New South Wales customers. This process includes possible influences on other incumbent generation such as New South Wales coal capacity. This involves an iterative approach to find a possible equilibrium solution for the Alternative Development Pathway as well as the capacity mix across the NEM as indicated in Figure 1. Section 2.2 describes the baseline case modelling process in more detail.

---

[2] https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en

Sensitivities are then modelled to explore isolated, unexpected changes to the market, such as an early closure of a coal power station. This explores the robustness of the Alternative Development Pathway, on the basis that the unexpected change does not give sufficient time for the planned Alternative Development Pathway to be altered (except for any direct impacts of the event itself, such as delayed transmission leading to delayed connections that were planned to utilise the transmission).

2.2 Baseline case modelling: finding an equilibrium capacity mix

As described above, the baseline case modelling process involves finding an equilibrium capacity mix across the NEM for the 20-year horizon that is driven by the Scenario assumptions as well as an Alternative Development Pathway theme. The process involves running many iterative market simulations with EY's 2-4-C dispatch model to arrive at a final set of outcomes. It involves the following steps:

- Set up an initial market simulation. Using the Scenario assumptions, conduct an initial time-sequential half-hourly market simulation over the forecast period. This simulation would typically use default settings, such as retiring thermal capacity at its assumed latest dates and attempting to build sufficient capacity to meet state-based renewable targets as a starting point.
- Iterative modelling to achieve a final simulation outcome. Adjust the new entrants and retirements of generators and storage units based on a combination of different objectives and commercial drivers (see Table 1 below). Re-simulate and repeat this process several times[3] until all objectives are achieved. The market outcomes from each simulation typically inform the adjustments made in the next one.

Table 1 describes each of the objectives and objective functions assessed simultaneously to find an appropriate equilibrium capacity mix in each baseline case. Many of the objectives consider generator net revenues, which is defined in detail in Section 2.4.

[3] The number of iterations required can vary from a few to 20 or 30 depending on the complexity and how close the initial market simulation is to the solution.

Table 1: The objective functions to achieve an equilibrium capacity mix for a baseline case

Objective	Description	Objective function
Meet the New South Wales Roadmap targets, and beyond	The legislated New South Wales Roadmap minimum targets are modelled as follows: ► 33,562 gigawatt hours (GWh)[4] eligible New South Wales renewable available energy generation to have completed construction by 31/12/2029[5]. ► 2 gigawatts (GW) of long duration (8 hours+) storage to have completed construction by 31/12/2029.	To minimise costs to New South Wales customers as the net present value (NPV) over the study horizon, subject to the Alternative Development Pathway theme. Section 2.3.1 describes more detail on the New South Wales Roadmap objective function. Section 3.2 presents the candidate generator options modelled for an Alternative Development Pathway and assumed build constraints. Section 4 presents the Alternative Development Pathway themes.
Meet the New South Wales Energy Security Target (EST)[6]	The New South Wales Government legislated an Energy Security Target where the New South Wales Energy Minister can commission additional capacity or equivalent if there is projected to be insufficient firm generation capacity to meet that target.	The EST is monitored and addressed with additional New South Wales capacity if necessary to meet the target based on the technology requiring the least additional funding to make its net revenue zero. Section 3.2.2 presents further detail on how the EST is modelled.
Meet the Victorian Renewable Energy Target (VRET)	The Victorian Government has legislated to achieve 50% Victorian renewable generation by 2030 as a percentage of all Victorian generation.	Meet the VRET with the least total amount of required subsidy for the new entrant capacity based on their modelled net revenues. This determines the timing, locations and wind/solar mix of any new entrant capacity required.
Meet the Queensland Renewable Energy Target (QRET)	The Queensland Government has announced a target of 50% Queensland renewable generation by 2030 as a percentage of Queensland demand.	Meet the QRET with the least total amount of required subsidy for the new entrant capacity based on their modelled net revenues. This determines the locations and wind/solar mix of any new entrant capacity required.
Meet the Tasmanian Renewable Energy Target (TRET)	The Tasmanian Government has legislated to double its renewable generation to 200% of its 2020 needs by 2040.	An annual linear growth of VRE generation is targeted. This assumes a fixed annual long-term average generation output from the Tasmanian hydro power stations and meets the remainder of the target with wind generation since wind is much more economical in Tasmania compared to solar PV.

[4] The Act establishes minimum objectives for new generation infrastructure that generates the same amount of renewable electricity (in volumetric terms) as 12 GW of renewable generation capacity. While the Act specifies 12 GW of capacity, distributed across the proposed New England and Central West Orana as well as outside of the renewable zones, this must be converted to an estimate of GWh of available electricity generated in NSW for planning purposes. The Department's current estimate of this amount is 33,562 GWh per annum based on assumptions of technology capacity mix and capacity factor estimates. The renewable technologies' capacity mix was taken from AEMO's 2020 Integrated System Plan, Step Change scenario, at the earliest period where NSW new build (post-November 2019) renewables reach 12 GW. The capacity factors for each technology are assumed as the average capacity factors for each technology across the NSW REZs developed by that period. The capacity mix and capacity factors are multiplied and summed to gain the final energy target in GWh.

[5] The modelling is setup to meet the legislative objective by 1/7/2029 as the granularity of EY's new entrant capacity is in financial years. However this provides some allowance for delays in commissioning to meet the 31/12/2029 minimum targets.

[6] https://energy.nsw.gov.au/government-and-regulation/consultation/energy-security-target-safeguard and https://energy.nsw.gov.au/media/2031/download. Accessed 12/06/2021

Objective	Description	Objective function
In addition to the above objectives, ensure all non-New South Wales new entrant capacity achieves the required rate of return on investment	After meeting all the state Government targets, additional new entrant capacity is installed in the Scenario if the market outcomes allow the required rate of return on their investment (i.e., they achieve a neutral or better net revenue over their economic lifetime).	The timing, locations and technologies of all candidate new entrant wind, solar, battery, pumped hydro, OCGT and CCGT capacity are determined to achieve a neutral net revenue over their economic lifetime[7].
Economic early withdrawal[8] of coal capacity	As agreed with the Department, the baseline cases apply a set of rules for withdrawing coal capacity in response to negative net revenues.	The net revenue of each coal power station is monitored and coal capacity is mothballed/withdrawn based on the following rules[9]: Only one consecutive year of negative[10] net revenues is allowed for New South Wales coal power stations. Furthermore, permanent early withdrawal of coal capacity from a power station must occur by either withdrawing the entire power station in one year, or by a staged withdrawal over two years. If there are two or more consecutive years of negative net revenues for a particular New South Wales coal power station, address the second negative year (year X) by: ► Selecting the New South Wales coal station that is next due to retire (according to the expected closure year schedule), regardless of its own net revenue, and withdraw half of its units in year X. ► Withdraw all of its units in the following year X+1 if it is not withdrawn in that year already. ► Re-simulate, and repeat the process if there still remains two or more consecutive years of negative net revenues for a New South Wales coal power station. After completing that process, if coal power stations in other regions have two or more consecutive years of negative net revenues, consider seasonal mothballing of one or more units in that power station over the affected years[11]. Finally, consider whether the timing of new entrant Roadmap capacity, such as long duration pumped hydro, could have been delayed to prevent the early coal withdrawal arising from the rules above, and if this would result in a lower cost to New South Wales customers.

The reliability standard is not modelled as a specific objective in finding an equilibrium capacity mix, as the standard is not a direct commercial driver of new capacity in the actual market. Rather, the market settings such as the market price cap are designed to incentivise sufficient capacity to meet the reliability standard, and this is captured through the modelled generator net revenues.

[7] Where needed, the final modelled year net revenue is repeated up to the economic lifetime of each generator or storage project in order to perform this calculation.

[8] In the modelling, coal withdrawals are modelled as equivalent to full year mothballing, or cold storage. The units are not necessarily retired and decommissioned, but they are not available to respond to the requirements of the market across the year. The methodology does allow consideration for whether a withdrawn unit should return from its mothballed state once withdrawn, although this would be possible if staffing, coal supply, and other logistical challenges are resolved. Withdrawal of such generation capacity from the market is subject to the commercial decisions of the relevant asset owners, who must consider a complex range of commercial factors including maintenance costs, supplier and customer contracts, end of life remediation costs and competition from other coal plants.

[9] It is acknowledged that this is a simplified view of generator retirement decisions, which are influenced by many factors specific to the stations and owners, which are often opaque. This approach has been developed in collaboration with AEMO and the Department to ensure consistency is applied when comparing Alternative Development Pathways.

[10] In consideration of the accuracy of the input assumptions including the operating costs of specific coal power stations and the bidding into the electricity market, only net revenues less than -$1/MWh are considered to be sufficiently negative to apply these rules for early withdrawal of capacity.

[11] Seasonal mothballing periods are based on an assessment of the lowest monthly average wholesale price outcomes.

2.3 The modelling objectives for New South Wales

As introduced in Table 1, the scope for the modelling in this engagement is primarily to forecast a 20-year outlook for the NEM that meets the following New South Wales Roadmap objectives:

- To establish a minimum of 33,562 GWh of additional available renewable energy from new large-scale wind and solar PV to have completed construction by 31/12/2029.
- To achieve a minimum of 2 GW of long duration storage (>8 hours storage capacity) to have completed construction by 31/12/2029.

As described, these targets are minimum targets only, and the Department instructed EY to consider the objective to minimise the cost to New South Wales electricity customers beyond these targets and beyond 2030 across the modelling horizon. As such, the modelling for each baseline case includes additional capacity beyond these minimum targets, if that capacity contributes to further minimising New South Wales customer costs.

2.3.1 Roadmap objective function

The Roadmap objective function for minimising the New South Wales customer costs has following three components[12] over a 20-year outlook period, as presented in equation (1):

$$\text{Minimise } NPV(\text{transmission costs} + \text{wholesale costs} + \text{scheme costs}) \quad (1)$$

Where,

- NPV is calculated as a discounted sum of the annual costs – see Table 2 below for more details.
- Transmission costs are the total cost of new network augmentations attributable to the achievement of the Roadmap objectives,
- Wholesale costs refer to the total wholesale electricity component of electricity bills observed by New South Wales electricity customers, and
- Scheme costs represents the total cost paid by the New South Wales Government under the LTESAs to generators and long duration storage projects to meet the primary objectives. Scheme costs also includes any new capacity built to meet the EST, if applicable.

The transmission costs are the estimated cost of building particular transmission augmentations to enable additional New South Wales wind, solar PV and storage capacity to be connected and appropriately dispatched into the power system. Section 3.2.3 presents the candidate New South Wales network augmentations considered in the modelling.

The wholesale costs component of the cost of electricity to New South Wales customers is calculated as follows in equation (2):

$$\begin{aligned}\text{Total wholesale costs} \\ &= NPV(\text{annual demand-weighted wholesale prices} \\ &\times \text{annual New South Wales energy demand}_{\text{sent out}})\end{aligned} \quad (2)$$

The scheme costs are calculated based on the assumption that LTESA payments result in the eligible Roadmap projects achieving exactly their required rate of return on their investment. This is defined as the cost of that generator's energy produced less the forecast revenue from wholesale

[12] Additional societal costs, such as from carbon emissions, can be added to this equation post modelling to account for externalities.

electricity market sales. The cost considers the total cost of the investment as the effective levelised cost of electricity produced.

This approach is equivalent to assuming that there exists a highly competitive market to the LTESA auction process, the LTESA design is transparent such that generator strike price offers reflect a price that is just enough for each generator to earn its required rate of return on investment (as set by the weighted-average cost of capital (WACC) assumptions; see Section A.5). It also covers generators that may only have an LTESA for part of their capacity based on the assumption that no other subsidy is available for New South Wales generators, allowing these cases to not be required to be considered explicitly.

The total scheme costs is defined in equation (3):

$$\text{Total scheme costs} = NPV(\text{sum of the annual net revenue for each generator eligible under the LTESA}) \tag{3}$$

For the NPV in the equations above, the assumptions of the discount rate to use and the base year to discount back to is detailed in Table 2.

Table 2: NPV calculation assumptions

Discount rate used for NPV calculations	Discounting year for NPV calculations
7% (pre-tax, real)	2021-22 (1 July 2021)

Source: the Department

The process of calculating annual net revenue for a generator (wind, solar or storage) in the modelling is detailed in Section 2.4.

2.4 Calculating a generator’s net revenue

Most of the decisions made to determine the capacity development to achieve an equilibrium capacity mix use assessments of the annual and lifetime net revenues of generators and storage modelled within 2-4-C. A generator’s or storage power station’s annual net revenue is calculated using equation (4):

$$\begin{aligned}\text{Net Revenue} = {} & \text{pool revenue from the wholesale market} - \text{annualised capital cost} \\ & - \text{fixed and variable operating costs} - \text{fuel costs} \\ & - \text{charging costs (storage only)}\end{aligned} \tag{4}$$

Where,

- Pool revenue is the total annual wholesale market revenue earned over each trading interval in the year. In the modelling, this is the sum-product of the modelled dispatched generation (sent out) and the wholesale market price, over all trading intervals, multiplied by an assumed marginal loss factor[13] for the generator. In the case of large-scale storage, the pool revenue is defined here as the revenue earned for discharge (generation).
- Annualised capital cost represents the equivalent annual payment of an equivalent annuity for the economic life of the asset, considering the WACC of the power station. The capital cost for existing generators is considered sunk and as such is treated as zero when assessing net revenues for potential early capacity withdrawal (see Table 1 for the early coal capacity withdrawal rules).

[13] See Section 2.6 for more detail on MLF assumptions in this modelling.

- Fixed and variable operating costs are the total assumed fixed and variable operation and maintenance costs[14].
- Fuel costs are the total cost of the fuel used in the generator's modelled production of electrical energy throughout the year. The fuel cost is always zero for wind, solar PV and large-scale storage.
- The charging costs are the payments a storage power station makes to the wholesale market when it is charging and drawing electricity from the network. Based on its assumed round-trip efficiency, a storage power station is required to draw more electrical energy from the grid in order to achieve a certain amount stored and available for generation.

In this modelling, net revenue does not consider other potential revenue or cost sources such as frequency control ancillary services (FCAS) markets, large-scale generation certificates (LGCs) or hedging instruments (see Table 3 for a description of the limitations associated with these simplifications).

2.5 2-4-C® - EY's wholesale market dispatch model

EY has used its proprietary time-sequential market dispatch model 2-4-C to implement the modelling required as described above. 2-4-C incorporates application of strategic bidding profiles (see Section A.4 for more details) for each generator, as well as comprehensive network constraint equations (stability and thermal, see Section A.7 for more details), both of which are essential to forecast wholesale electricity prices and generator wholesale market revenue expectations. In addition, 2-4-C incorporates historical weather years of locational wind and solar generation profiles, all of which are key drivers of wind and solar generation dispatch and therefore ultimate energy yield expectation from the capacity development plan.

More information on the features of the 2-4-C modelling suite is provided in Appendix A.

2.6 Limitations

As described in this section, the Alternative Development Pathways are investigated by applying a single Scenario of future market conditions, including the demand growth outlook and future capital costs for different technologies (see Section 3 for an overview of these assumptions).

It should be noted that many alternative futures exist (see AEMO's 2021 IASR for some examples). While sensitivity analysis has been deployed to investigate key areas of assumption uncertainty, these assumptions should be considered with due care by AEMO and the Consumer Trustee before acting on the outcomes presented in this Report.

Along with uncertainty in the assumptions, all models and modelling approaches have some limitations in representing the real world, and these need to be understood to assist in interpreting the results and in obtaining the full value from the modelling. Table 3 lists some of the key limitations that relate to the purpose of the modelling in this Report and describes the implications of each.

---

[14] Note that the variable costs are assumed to be zero for wind, solar PV, batteries and pumped hydro storage in the Draft 2021 IASR.

Table 3: List of key modelling limitations and their implications for the outcomes

Limitation	Implications
The modelled generator bids are based on strategic behaviour in the 2018-19 year, and keeping these strategies constant throughout the modelled horizon may be unreasonable.	Generators may change their bidding behaviour significantly due to changes in the competitive dynamics of electricity supply, as well as broader market structural reforms, which is not captured in the modelling approach. Bidding behaviour is a significant uncertainty and driver of the wholesale market price outcomes. Alternative bidding behaviours can also change generation dispatch and ultimately the commercially-driven capacity mix outcomes of a modelled scenario.
Marginal loss factors (MLFs) are assumed as inputs only and holding these constant throughout the modelled horizon may be unreasonable.	If MLFs were recalculated for each future year in the baseline cases, they may provide different commercial signals for new entrant capacity at particular locations, including in New South Wales, and potentially lead to different results for the Alternative Development Pathways.
Only wholesale market revenues are considered for new entrant generators and storage	Modelling the ancillary services markets, such as FCAS was out of scope for this engagement and could be material for existing thermal generators and storage in the short term. EY considers that FCAS revenue is unlikely to be significant following Snowy 2.0's commissioning (and possibly even earlier) due to the market likely being highly oversupplied from the storage capacity installed. Similarly, there is presently a material value for LGCs for renewable generators in the short term, but this is expected to diminish quickly over the next few years and if that occurred, it is considered to be immaterial to the outcomes in this Report. However, there is the potential for future additional voluntary demand for LGCs, which may give LGCs a non-material value, which would potentially reduce overall scheme costs and lead to different modelling outcomes. Other potential future revenue sources are also not considered, such as from the supply of inertia, which pumped hydro can provide along with thermal capacity.
Coal capacity withdrawal based on wholesale market revenue and assumed costs, with specific withdrawal rules	As described earlier, the modelling outcomes for withdrawal of coal capacity earlier than their announced retirement dates are based on assumed costs, revenues from the wholesale market (only) and a set of specific rules as agreed with AEMO and the Department. Actual contracting positions, alternative revenue sources and their actual operating costs could result in very different commercial decisions being made in the actual market as to when they might withdraw capacity. Due to their size, a different timing for withdrawal of a coal power station would have a material impact on wholesale market prices and the modelling outcomes as a whole.
The transmission network is only modelled in a 'system normal' state, with all transmission lines in service.	Along with generator outages, transmission outages are a regular part of the actual market. Whilst it is a typical approach to only model system normal conditions for the network, transmission outages in the actual market put upward pressure on wholesale market prices and increase the risk of USE.
Unit commitment constraints – ramp rates/start times/start costs	Generator ramp rates are included and adhered to in this modelling, however in 30-minute time intervals they are not frequently a binding limit on dispatch. The modelling applied in this study does not apply specific unit commitment type constraints. Most thermal generation facilities offer their minimum stable load quantities at the market floor price at all times when they are available, with the exception of a few combined-cycle gas-fired generators. As described in Section 2.2, selected coal generators have been assessed for seasonal mothballing behaviour. No other decommitment behaviour has been assessed and therefore costs associated with decommitment and starting have not been included.
Integration of battery energy storage with renewable generation facilities	Energy storage has only been considered in the modelling as independent projects. However, in reality there may be a case for co-location of batteries and VRE with a potential reduction in connection costs (albeit modest) and other benefits to revenues such as through network curtailment management. If such cases were common this could have a material impact on reducing scheme costs and allow more VRE to be installed to achieve a reduced total New South Wales customer cost.

3. Scenario assumptions overview

This section provides an overview of the Scenario assumptions that are applied to all the baseline cases. These assumptions were all selected by AEMO and the Department in consultation with EY.

3.1 NEM assumptions

The Scenario assumptions that apply to the NEM broadly reflect the assumptions described in AEMO's Draft 2021 IASR for the Central scenario.

Table 4 summarises the input assumptions pertaining to operational electricity demand, being the demand that is serviced from large-scale generators in the wholesale electricity market.

Table 4: Electricity demand assumptions

Assumption	Detail
Underlying consumption - energy and peak demand	Central scenario from the Draft 2021 IASR. Both 10% and 50% probability of exceedance (POE) peak demands modelled.
New South Wales Energy Saving Scheme (ESS)	The New South Wales Energy Saving Scheme (ESS) is an energy efficiency programme looking to reduce New South Wales demand through financial incentives to households and businesses. The reduction in demand is not accounted for in the AEMO 2020 ESOO. The project impact of the ESS on New South Wales demand was provided to EY by the Department.
New South Wales Peak Demand Reduction Scheme (PDRS)	The peak demand reduction scheme (PDRS) is a certificate scheme designed to incentivise and deploy peak demand reduction technologies. The projected impact of this on New South Wales demand was provided to EY by the Department.
Rooftop PV and PVNSG	Net Zero scenario from the draft AEMO 2021 ESOO, as supplied by AEMO, which are higher than the Draft 2021 IASR Central trajectory, and reflective of the final IASR updates that were developed between the Draft 2021 IASR and the finalisation of the IASR in July 2021.
Behind-the-meter battery storage uptake	As per Central scenario in the Draft 2021 IASR.
Electric vehicles (EVs)	As per Central scenario in the Draft 2021 IASR.

Sources: AEMO Draft 2021 IASR, AEMO and the Department, New South Wales Energy Security Target & Safeguard Consultation Paper Apr 2020

Table 5 summarises some of the input assumptions pertaining to the supply of electricity in the NEM. Section 3.2 describes further key input assumptions specifically related to Alternative Development Pathways in New South Wales.

Table 5: NEM electricity supply assumptions

Assumption	Detail
Renewable energy and storage targets	► VRET (40% renewable generation by 2025, 50% renewable generation by 2030). ► QRET (50% renewable generation by 2030) ► New South Wales Roadmap minimum 2030 targets ► TRET (100% by 2022, 150% by 2030 and 200% by 2040)
Energy Security Target	Ensure New South Wales capacity meets requirements of the EST. Section 3.2.2 describes the EST assumptions in more detail.
Emissions reduction mechanisms	No explicit long-term emissions reduction policy driver has been applied beyond those policies captured within AEMO's demand forecasts (affecting consumer investment in distributed energy resources and energy efficiency), as well as the large-scale state-based renewable energy targets mentioned above.

Assumption	Detail
Committed new capacity	AEMO's existing and committed developments from AEMO May 2021 Gen Info[15], plus additional anticipated projects identified by AEMO and the Department.
Expected closure dates	Coal and high utilisation gas-fired power plants are assumed to have the expected closures as per AEMO's May 2021 Gen Info. Coal power plants in New South Wales may be withdrawn earlier than these dates in the modelling as per the early coal withdrawal methodology outlined in Table 1.
Candidate New South Wales pumped hydro projects	List of pumped hydro project candidates to meet the 2 GW long duration storage target, as supplied and agreed with the Department. For more details see Section 3.2.1.
Fuel prices	Draft 2021 IASR - Central scenario.
New entrant parameters including technology capex	Draft 2021 IASR - Central scenario.
WACCs	WACCs for different technologies, built under the Roadmap in New South Wales REZs or otherwise, as supplied by the Department, are taken from the National Australia Bank (NAB) report[16]. The technology/New South Wales REZ-specific WACCs are used to annualise the capital costs for each generation, storage and transmission capacity installed in the modelling, where applicable. See Section A.5 for more details on the WACC assumptions.

Sources: Draft 2021 IASR, AEMO May 2021 Gen Info, AEMO and the Department

3.2 Alternative Development Pathway specific assumptions

Each Alternative Development Pathway is modelled with a specific list of candidate technologies, locations and assumed available capacity factors as well as REZ build limit constraints as detailed in the Draft 2021 IASR. These assumptions are described further below. In addition, each baseline case has a specific theme for the VRE capacity in the Alternative Development Pathway, as described in Section 4.

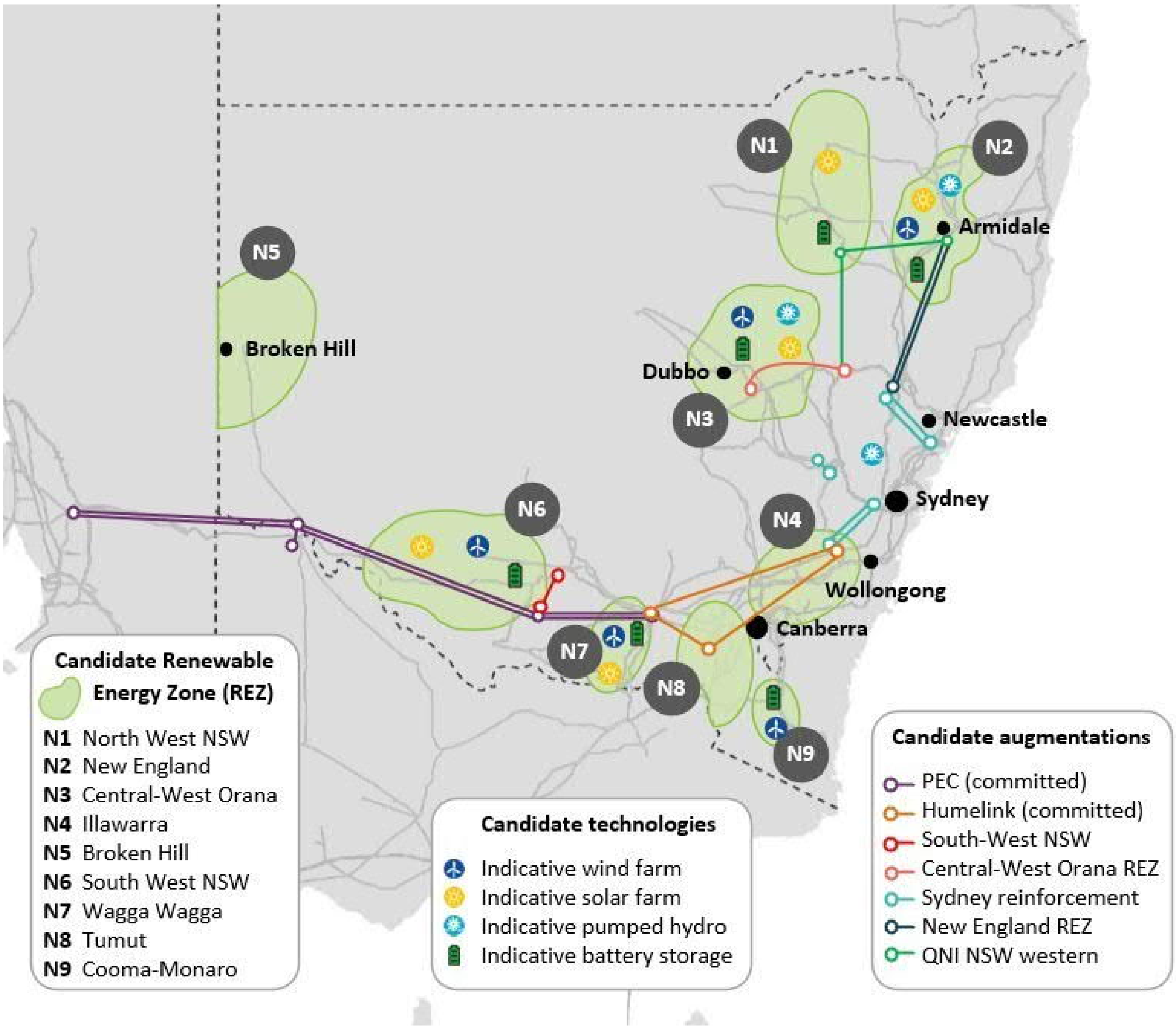
3.2.1 Generation and storage candidate capacity

Figure 2 presents a map of New South Wales showing the REZs considered in the modelling and indicating the assumed available candidate generation and storage technologies in each REZ. This is in addition to existing and committed generators and storage. The figure also shows the candidate network augmentations considered for New South Wales.

[15] AEMO| Generation Information| https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/generation-information

[16] National Australia Bank| https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20WACC%20Report.pdf

Figure 2: Map of New South Wales REZs indicating candidate VRE and long duration storage technologies* where build limits are modelled to be greater than zero, plus candidate New South Wales transmission network augmentations[17] (Map source: AEMO) (grey lines indicate the existing transmission network)



* The REZs shown are limited to New South Wales only. The map indicates the locations of VRE and long duration storage options by REZ but does not indicate actual locations within each REZ. There are also new entrant gas-fired power station options considered in the modelling that are located outside REZs (not shown). Note that while Broken Hill has non-zero build limits for wind and solar in the Draft 2021 IASR, EY did not consider candidate generators or batteries in this REZ due to known transmission and network stability limitations and no relevant transmission augmentations being considered. Also, no long duration batteries were considered in the Illawarra and Tumut REZs to coincide with the zero build limits for VRE in those REZs.

For each candidate VRE and battery capacity option by REZ shown in Figure 2, up to three separate connection points are considered in the modelling. For each REZ, typically two of these are in the existing network and the third is in new network associated with the candidate network augmentations. This allows for the modelling analysis to have some diversity in the wind and solar profiles modelled as well as explore the impact of network curtailment for different grid connection locations.

Table 6 lists the assumed total capacity limits for solar PV and wind by REZ.

[17] PEC stands for Project Energy Connect and QNI stands for Queensland - New South Wales Interconnector.

Table 6: Technology new build limits by REZ

REZ	New capacity limit (MW)		
	High wind	Medium wind	Solar PV
North West NSW	0	0	6,500
New England	1,800	5,600	3,500
Central-West Orana	800	2,200	6,900
Broken Hill*	1,300*	3,800*	8,000*
South West NSW	1,100	3,200	4,000
Wagga Wagga	300	700	1,000
Tumut	0	0	0
Cooma-Monaro	100	200	0
Illawarra	0	0	0

Source: Draft 2021 IASR, except for Illawarra, where the zero build limits were provided by AEMO and the Department

* As described above, Broken Hill is considered to have a zero build limit for all technologies in the modelling due to known transmission constraints and no candidate transmission augmentation for Broken Hill being considered.

These build limits apply to new candidate capacity over and above the existing and committed capacity assumed in the Scenario. Medium and High wind in Table 6 refers to the resource quality of wind generation in the REZ. With a higher relative resource quality, High wind generation candidates achieve a higher capacity factor, and therefore a lower levelised cost of energy than Medium wind generation candidates for the same REZ, and will thus be preferred in the modelling (up to their resource limits).

Where candidate long duration battery capacity is considered for a REZ, the potential capacity is assumed to be unlimited. The candidate long duration pumped hydro capacity in each REZ is determined by seven specific proposed projects provided by the Department, and total 3.4 GW across New South Wales. This is in addition to the assumed committed Snowy 2.0 pumped hydro power station.

Table 7 presents the assumed annual total build limit of new wind, solar and storage capacity across the NEM, along with their first possible commissioning year.

Table 7: Annual NEM new build limits and first commissioning year by technology

Technology	Annual NEM build limit (MW)	First commissioning year
Pumped storage hydro	8 GW	1/07/2024[18]
Wind		1/07/2023
Solar PV		1/07/2023
8-hr batteries		1/07/2023

Source: Commissioning years as per Draft 2021 IASR, except for pumped hydro, which was supplied by the Department. Build limit assumed and agreed with the Department and AEMO.

In addition, it is assumed new capacity can only produce its full output at a new network augmentation connection point from 12 months after commissioning of that network

[18] The earliest date of commissioning differs by pumped hydro project. 1/7/2024 is the earliest date.

augmentation. This is to reflect the complex connection and commissioning process including various hold point testing requirements.

3.2.2 Energy Security Target

The EST is set as the level of firm capacity needed to meet a 1 in 10-year peak New South Wales electricity demand while maintaining a reserve margin to account for the unexpected loss of two of New South Wales' largest available generation units[19].

The EST applies AEMO's 10% POE operational peak demand forecast as the measure of the 1 in 10-year peak demand. Operational demand accounts for energy efficiency and peak reduction schemes such as the ESS.

The supply that contributes to meeting the EST in every year is a combination of firm local electricity generation capacity, imports from other regions through interconnectors and demand side response.

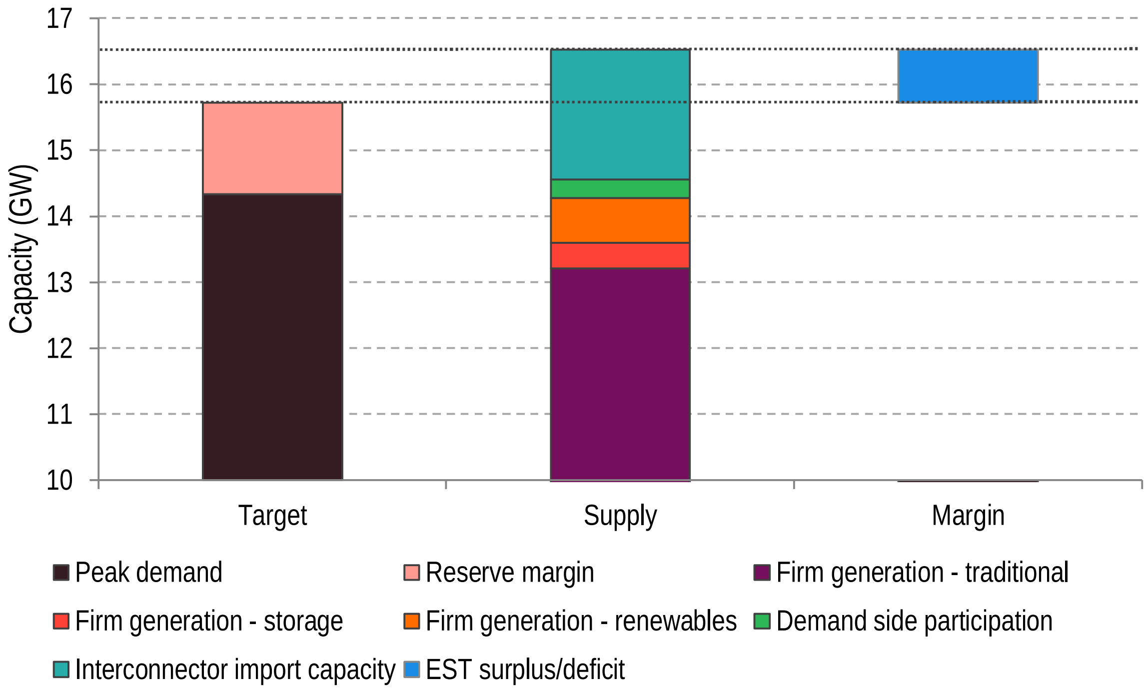
Firm wind and solar capacities are defined as the average generation available during the previous 3 summer peak periods, which was determined by AEMO for this modelling to be 13% for solar and 10% for wind. The full summer rating is used for all other technologies including storage.

AEMO provided assumptions for the firm interconnector capacity across Terranora, QNI, the Victorian - New South Wales Interconnection (VNI) and PEC as well as values for demand side values.

Figure 3 shows a waterfall diagram to represent an example of the different components of EST demand and supply.

[19] https://energy.nsw.gov.au/government-and-regulation/consultation/energy-security-target-safeguard and https://energy.nsw.gov.au/media/2031/download. Accessed 12/06/2021

Figure 3: Illustration of the Energy Security Target and the supply-side (note the y-axis is truncated)



3.2.3 Network augmentations

Table 8 summarises the detail for the committed network augmentation details and timings applied in the Scenario along with the candidate New South Wales network augmentations. The assumed network augmentations for this modelling are defined in the 2020 Integrated System Plan (ISP) and TransGrid's 2020 Transmission Annual Planning Report resources. Additional details have been provided by AEMO for the Central West Orana REZ, New England REZ, SW NSW stability improvement, QNI medium - western path (New South Wales segments only), and Sydney Ring augmentations as summarised in the table and detailed in this section.

Table 8: Network augmentation assumptions and timing

Name	Year	Description
QNI Minor (Option 1A from 2020 ISP)	1/07/2021	Increase max southerly and northerly transfer limit Uprating Liddell-Muswellbrook, Muswellbrook-Tamworth and Liddell-Tamworth 330 kV lines
VNI Minor (VIC-NSW Option 1 from 2020 ISP)	1/07/2021	Increase northerly transfer limit Install second 500/330 kV 1,000 MVA transformer at South Morang Uprate Dederang-South Morang 330 kV lines Uprate Canberra-Upper Tumut 330 kV line
Project EnergyConnect	1/07/2024	New South Wales-South Australia transfer limit of 800 MW (both directions) Increase Heywood transfer limit (both directions) New Bundey - Buronga – Dinawan – Wagga 330 kV double circuit line New 220 kV single-circuit line from Buronga to Red Cliffs Turn Robertstown - Para 275 kV line into Tungkillo

Name	Year	Description
Central West Orana REZ (Based on network diagram in Table 29 of 2020 ISP Appendix 3)	Candidate	Turn Bayswater-Wollar 500 kV line at Merriwa Tap Bayswater-Mt Piper 500 kV line at Wollar 2x500/330 kV 1,500 MVA transformers at Stubbo 1x500 kV line from Merriwa to Uarbry 1x500 kV line from Uarbry to Stubbo 1x500 kV line from Stubbo to Wollar Turn Wellington-Wollar 330 kV line at Stubbo Establish new substations at Merriwa, Uarbry and Stubbo
SW NSW stability improvement Option 1A (TransGrid TAPR 2020)	Candidate	New 330 kV line from Darlington Point to Dinawan
Western Victoria (preferred option from 2018 PADR)	1/07/2025	2x500/220 kV 1,000 MVA transformers at North Ballarat New North Ballarat - Sydenham 500 kV double circuit line A new North Ballarat - Bulgana 220 kV line and a new North Ballarat-Waubra-Bulgana 220 kV line
Humelink (sole option from 2020 ISP)	1/07/2026	New Snowy 2.0 terminal station with 3x330/500 kV,500 MVA transformers (Maragle terminal) New 500 kV lines Snowy 2.0 - Wagga Wagga - Bannaby - Snowy 2.0 1x330/500 kV,500 MVA transformer at Wagga Wagga
Reinforcing Sydney Newcastle and Wollongong Supply 500 kV-North and South paths (TransGrid TAPR 2020)	Candidate	Two new 500 kV lines from Bayswater to Eraring Two 500 kV lines from Bannaby to South Creek Tap both Eraring–Kemps Creek 500 kV lines at South Creek Tap Sydney West–Bayswater 330 kV line at South Creek Tap Sydney West–Regentville 330 kV line at South Creek 2x500/330 kV, 500 MVA transformers at South Creek 1x500/330 kV, 500 MVA transformer at Bannaby New 330 kV transmission line from South Creek to Sydney West Third Mt Piper–Wallerawang 330 kV line Third Bayswater–Liddell 330 kV line
New England REZ (TransGrid TAPR 2020)	Candidate	Turn Armidale – Tamworth 330 kV lines into Uralla New Uralla substation and 1x500/330 kV, 500 MVA transformer Two new Bayswater – Uralla 500 kV lines
QNI medium - western path (New South Wales segments only) (QNI Option 2E from AEMO's 2020 ISP)	Candidate	New Boggabri 500 kV Substation New 500 kV line between Uralla and Boggabri New 500 kV line between Boggabri and Uarbry
Marinus link Stage 1 (ISP 2020)	1/07/2028	New 750 MW HVDC interconnector between Burnie and Hazelwood New 220 kV Burnie to Sheffield double circuit New 220 kV Sheffield to Palmerston double circuit
Gladstone Grid Reinforcement (ISP 2020)	1/07/2035	Uprate the 275 kV Bouldercombe - Raglan - Larcom Creek - Calliope River circuit with high capacity conductor (additional 800 MVA rating) Uprate the 275 kV Bouldercombe - Calliope River circuit with high capacity conductor (additional 800 MVA rating) Turn Bouldercombe - Calliope River 275 kV circuit in at Larcom Creek New 275 kV Calvale - Larcom Creek double circuit Install a third Calliope River 275/132 kV transformer

The following subsections describe the candidate network augmentations in more detail.

Central West Orana REZ

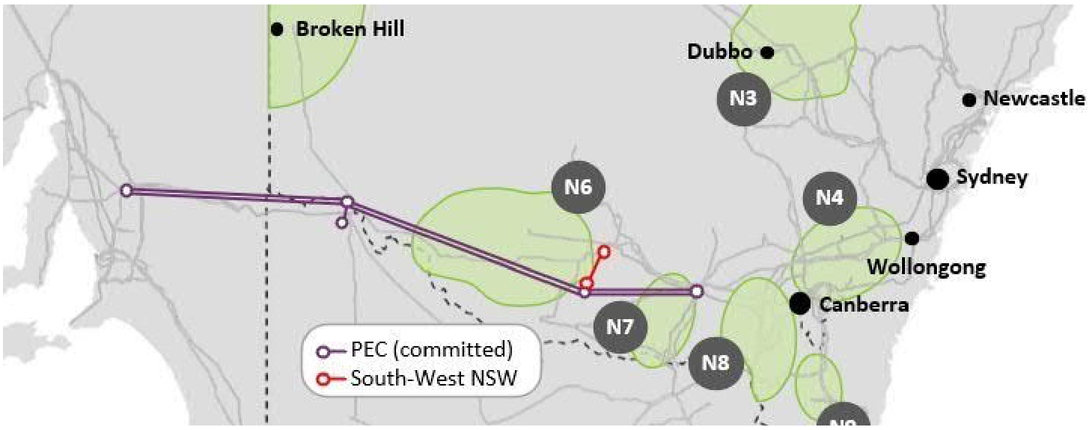
Figure 4 shows a diagram of the Central West Orana REZ network augmentation as applied to the modelling and detailed in Table 8. This transmission augmentation provides backbone infrastructure in the Central West Orana REZ to unlock regional investment and new generation infrastructure within the REZ.

Figure 4: Central West Orana REZ[20]

South-West NSW network

As per TransGrid's 2020 TAPR, there is an opportunity to increase the level of renewable generation that can be integrated in south-west New South Wales by improving a SW NSW voltage stability limit. This will address a constraint on flows in an easterly direction on the 330 kV transmission line from Darlington Point towards Wagga Wagga (line #63). Among three TransGrid augmentation options, option 1A has been selected as a candidate for this modelling which represents a new 330 kV line between Darlington Point and Dinawan substations as shown in Figure 5.

Figure 5: SW NSW stability improvement options[21]



New England REZ (Bayswater to Armidale) and QNI medium - western path (New South Wales segments)

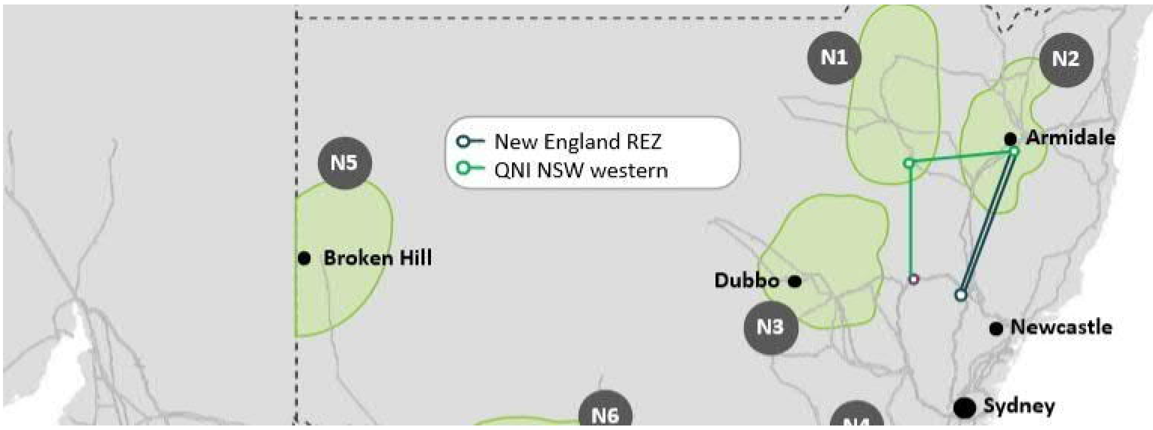
The limited capacity of the existing 330 kV and 132 kV networks in the New England REZ may result in network curtailment risk for connecting generators as generation in the area increases. Increasing transmission capacity would reduce this risk and facilitate new generator connections in the New England area. The New England REZ (Bayswater to Armidale) and QNI medium - western path (New South Wales segments only) candidate augmentations are shown in Figure 6 and detailed

[20] Source: TransGrid TAPR 2020

[21] Source: TransGrid TAPR 2020

in Table 8. This combination of network augmentations along with CW Orana REZ provides backbone infrastructure for additional renewable projects in these REZs.

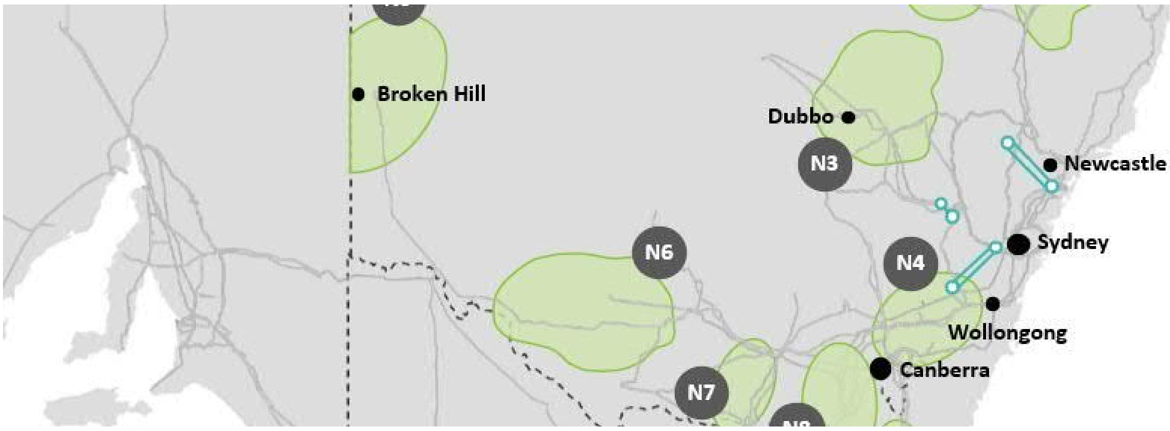
Figure 6: New England REZ (Bayswater to Armidale) and QNI medium - western path (New South Wales segments only)[22]



Reinforcement to Sydney/Newcastle/Wollongong load centres

The Sydney, Newcastle and Wollongong area includes significant loads that comprise about three quarters of electricity demand in New South Wales. After the retirement of Vales Point and Eraring power stations, it is expected that future demand will be supplied by generation outside of these regions. The proposed network reinforcements will increase the network capability for further generation developments within the core New South Wales network. Figure 7 represents the network augmentation geographically based on details in Table 8.

Figure 7: Reinforcement to Sydney/Newcastle/Wollongong load centres[23]



[22] Source: AEMO

[23] Source: TransGrid TAPR 2020

4. Overview of the Alternative Development Pathway themes and sensitivities

This section describes the Alternative Development Pathways themes modelled in the baseline cases, along with the sensitivities conducted to examine the resilience of the Alternative Development Pathways. These were developed through extensive consultation with AEMO and the Department. Each Alternative Development Pathway is simulated considering a single Scenario of the future market, based on policy and technical specifications that mirror the Central scenario described in AEMO's Draft 2021 IASR (as discussed in Section 2 previously).

The high-level modelling methodology is described in Section 2.1. Figure 8 presents the methodology diagram (as presented in Section 2.1) with the selected baseline cases and sensitivities labelled.

Figure 8: Baseline case and sensitivities overview

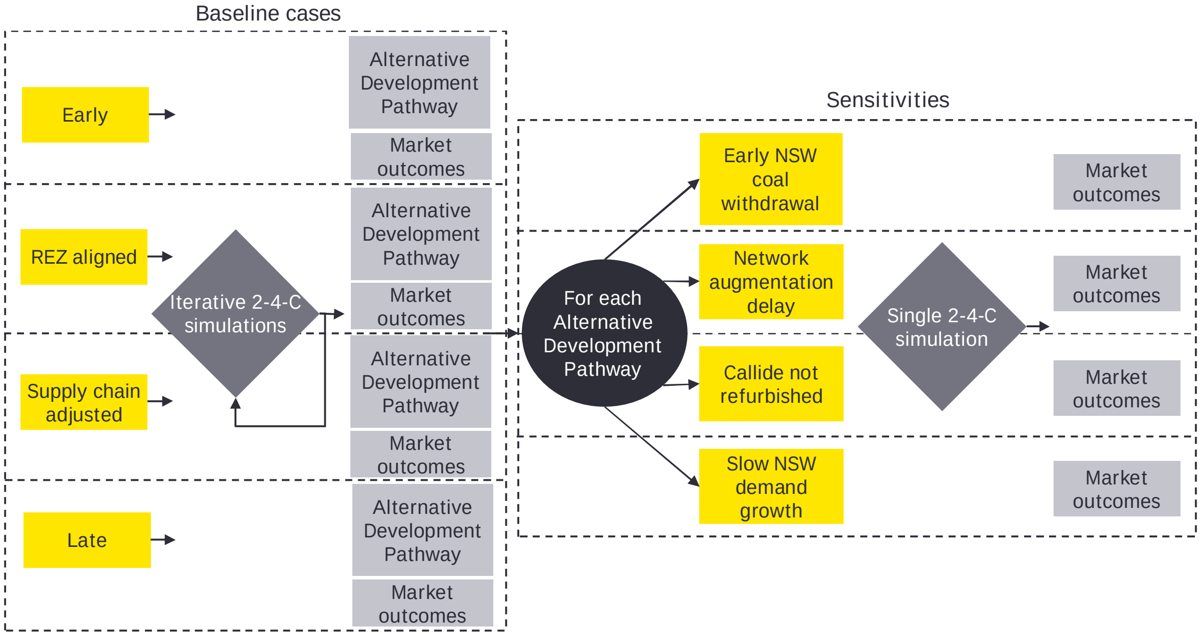


Table 9 describes the Alternative Development Pathway themes in more detail and Table 10 describes the sensitivities.

Table 9: Summary of the Alternative Development Pathway themes

Alternative Development Pathway	Purpose	Description
Early	To explore building wind and solar capacity as early as possible, even if it is economic to defer commissioning to a later year.	The earliest possible commissioning schedule, using available network connection points prior to network augmentations being built.
REZ aligned	To explore building wind and solar capacity in line with the schedule of network augmentations.	While developments are relatively early, this deploys VRE capacity with foresight of expanded transmission capacities, delaying until REZ augmentations enable 500 kV connections rather than connecting to existing networks, where appropriate.
Supply chain adjusted	To explore building VRE subject to supply chain constraints.	Considering the maximum developed renewable capacity observed historically, this pathway develops capacity more gradually than other modelled alternatives, minimising the risk of supply chain disruption and constraints across the next decade.
Late	To explore building wind and solar capacity as late as possible to meet the objectives.	Examines the costs and benefits of delayed investment to minimise disruption to incumbent generation and maximise the opportunity for lower development costs in future years.

Table 10: Summary of sensitivities modelled

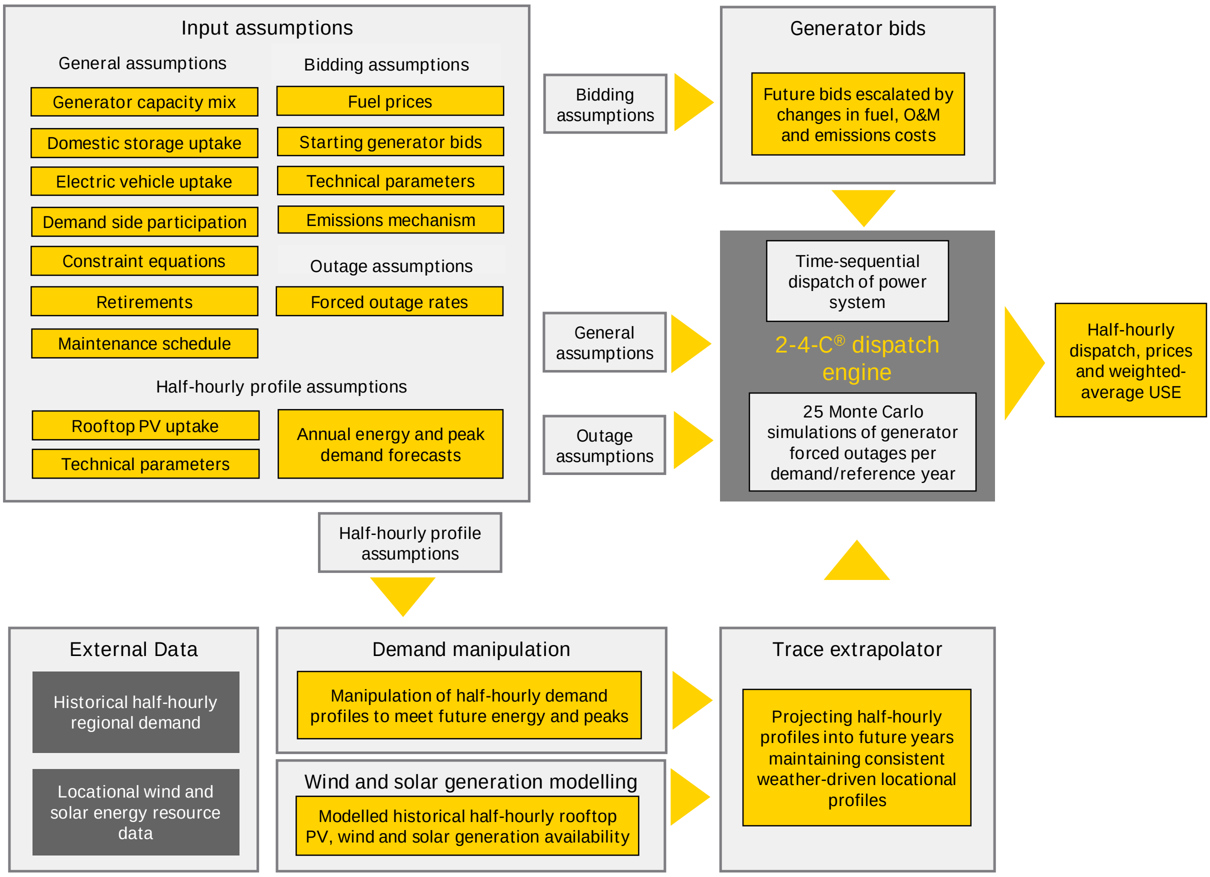
Sensitivity	Description	Purpose
Early New South Wales coal exit	Retirement of a large coal station in New South Wales up to 2 years earlier than anticipated in the baseline case	To explore the impact of a shock New South Wales coal power station failure or exit.
Delayed network augmentation	Delayed New England and QNI (New South Wales section) major network augmentations by 2 years	To explore the impact of a delay to augmentation commissioning.
Callide not refurbished	Callide C generator not refurbished	To explore the impact of a shock Queensland coal power station exit.
Slow demand growth	AEMO IASR Slow Growth demand scenario applied	To explore the impact of unforeseen lower customer demand.
Delayed pumped hydro timing	There is a risk that pumped hydro projects cannot be built as quickly as assumed in the Scenario	To explore what capital costs would be required for long duration battery capacity to be built instead of pumped hydro, if pumped hydro project timings were to be delayed.

Appendix A Further details and assumptions on modelling the NEM with 2-4-C

A.1 Market simulations

The market simulations are conducted using EY's in-house market modelling suite of software 2-4-C, which consists of an energy market dispatch engine and several software tools that develop input data and analyse output data. The 2-4-C dispatch engine is equivalent to the NEM Dispatch Engine (NEMDE) used by the AEMO in operating the market in real time. The 2-4-C dispatch engine has been applied in this engagement with half-hourly time-sequential modelling over the 20-year study horizon, with explicit modelling of each generating unit and the capabilities of the electricity transmission network. Figure 9 provides an overview of the array of inputs used in a market simulation with 2-4-C.

Figure 9: Key input data flows in EY's 2-4-C electricity market model



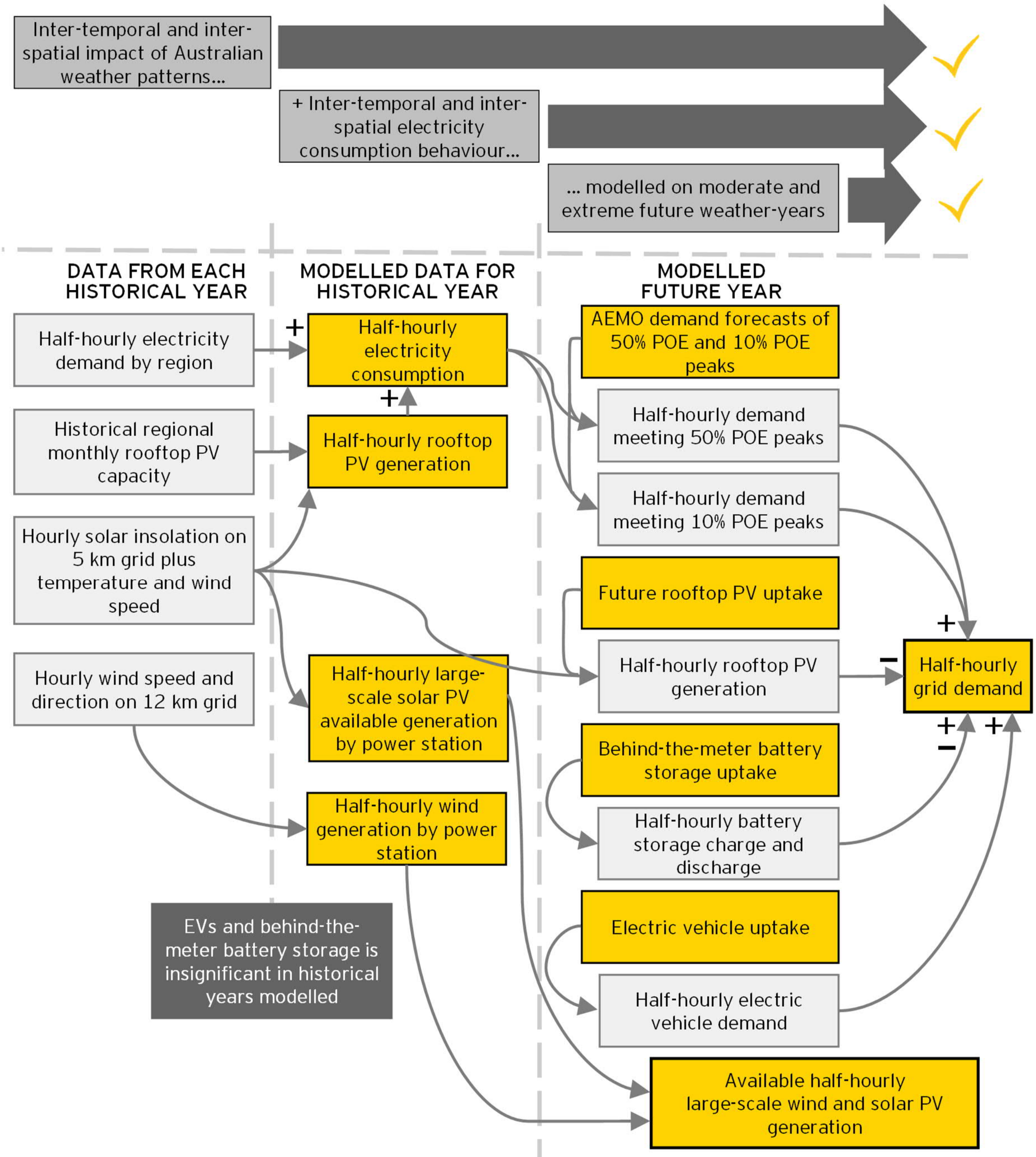
As with NEMDE, 2-4-C bases dispatch decisions on the market rules, considering generator strategic bidding patterns and availabilities to meet regional demand. The model considers full and partial forced outages and planned outages for each generator, half-hourly renewable energy generation availability by individual power station as well as inter- and intra-regional transmission capabilities and constraints. This results in typical levels of price volatility at 30-minute time intervals captured in the modelling outcomes.

A.2 Forward-looking half-hourly modelling

EY's approach to forward-looking half-hourly modelling is to base all the inter-temporal and inter-spatial patterns in electricity demand, wind and solar energy on the weather resources and consumption behaviour in one or more historical years (reference years).

Figure 10 depicts EY's methodology to modelling future half-hourly electricity demand, rooftop PV generation and large-scale wind and solar PV available generation, in terms of the data used.

Figure 10: Flow diagram showing EY's use of an historical year of electricity and atmospheric conditions data to make a half-hourly forecast



The top section of Figure 10 also highlights the philosophy behind what features in the historical half-hourly data are projected forward, and what features are modified to capture future conditions. These are described in more detail as follows.

The historically observed inter-temporal and inter-spatial impact of weather patterns are maintained in the forecast. Historical hourly locational wind and solar resource data[24] is used by EY

[24] The data source is the Australian Bureau of Meteorology. See Section A.2.2 for more details.

to model half-hourly[25] generation from rooftop PV, large-scale solar PV and wind generation. All the interactions between wind and solar generation at different sites are projected forward consistently, maintaining the impact of actual Australian weather patterns on the future NEM. The available half-hourly large-scale wind and solar PV generation profiles are bid[26] into the market to meet grid demand in the 2-4-C® dispatch modelling. These may not be fully dispatched in case of binding network constraints or being the marginal generator and setting the price, with the volume above the marginal price being spilled.

Inter-temporal and inter-spatial (regional) electricity consumption behaviour is maintained in the forecast. Historical half-hourly grid demand is obtained from AEMO and added to EY's historical modelled rooftop PV to produce the historical electricity consumption. By projecting consumption forward instead of grid demand, EY maintains the underlying half-hourly consumer behaviour while specifically capturing the future impact of increasing rooftop PV generation in changing the half hour to half hour shape of grid demand during each day. EY also separately models behind-the-meter storage profiles and electric vehicle charging profiles to capture their impact on the shape of grid demand. Other changes in underlying consumption patterns are not considered, such as due to changes in energy use as a result of Covid-19 and associated increased frequency of working from home.

The historical year(s) used in the modelling consist of various types of weather, which may or may not be considered typical or average. With respect to demand, the historical electricity consumption is processed to convert it into two types of weather-years for each future year modelled. One could be considered a moderate year, which uses AEMO's 50% POE peak demand forecast[27], while the other is considered a year with more extreme weather, using AEMO 10% POE peak demand[28].

Overall, the half-hourly modelling methodology ensures that the underlying weather patterns and atmospheric conditions are projected in the forecast capturing a consistent impact on demand, wind and solar PV generation. For example, a heat wave weather pattern that occurred in the historical reference year is maintained in the forecast for each future year. The forecast is developed in the context of a moderate or extreme weather year from a demand perspective. The availability of renewable generation which is assumed to be operational within the period is a function of the atmospheric conditions specific to each plant location and as would have been experienced across the whole NEM during the same weather event.

A.2.1 Multiple iterations

For this assessment, each future year is modelled with 48 individual iterations that make up one simulation. The 48 iterations are comprised of:

- Six different half-hourly demand profiles, comprising:
  - Three historical (reference) years of half-hourly underlying consumption patterns plus solar rooftop PV and small non-scheduled solar PV (PVNSG) profiles, and
  - Two seasonal peak demand projections, representing 50% POE and 10% POE years.
- Eight Monte Carlo simulations, or iterations, of different generator forced outage profiles, based on the forced outage probabilities for each generator, as sourced from AEMO's Draft 2021-22 IASR.
- Each reference year also uses different wind and large-scale solar generation availability profiles based on the historical weather data. Three reference years are used to capture a wide range of weather patterns and their impacts on electricity demand and locational wind and

---

[25] Hourly historical resource data is interpolated to half-hourly data.

[26] EY's bidding methodology is described in Section A.4.

[27] The 50% POE peak demand forecast is expected to be exceeded for one half hour once in every 2 years.

[28] The 10% POE peak demand forecast is expected to be exceeded for one half hour once in every 10 years.

solar generation. In general, the more reference years modelled, the more different types of weather patterns can be captured.

The 48 iterations used in the modelling are summarised in Table 11 below.

Table 11: Summary of individual half-hourly iterations made on each future year

Variable	Description	Number
Peak demand outlooks	50% POE 10% POE	2
Reference year	2016-17 2017-18 2018-19	3
Monte Carlo iterations	Different generator forced outage profiles	8
Total iterations per simulation		48

All simulated years of half-hourly results are then collated with a weighted average of 0.7 on the 50% POE iterations and 0.3 on the 10% POE iterations. The reasoning behind this weighting is discussed in Box 1.

Box 1: Reasoning behind weightings used to collate 50% POE and 10% POE demand outcomes

In the absence of time constraints and data availability considerations the modelling would ideally apply a very wide range of key factors such as atmospheric conditions and peak demand and simply weight each event equally. Monte Carlo iterations of unplanned outage events on generation and transmission elements are each considered to be equally likely. The sample of six reference years for atmospheric conditions and 'load shape' are also considered to be equally likely for the purpose of the modelling. Ideally, we would model a large number of POE peak demand conditions however the computation time would be intractable. To manage the problem size, we limit POE peak demand samples to 10% and 50% POE scenarios. In order to establish the expected wholesale market price from these samples we assume that the probability density function of the demand POE samples is normally distributed. We then seek to find the quantum of the cumulative distribution function exceeding the 90th, 50th and 10th percentile. It is found that 30.4% of the cumulative distribution is contained above the 10th percentile, 30.4% is below the 90th percentile and 39.2% between the 10th and 90th percentile. As peak demand expectation reduces the chance of high market pricing events also reduces. We therefore make a simplifying approximation that the market price expectation is similar for all POEs below the 50% POE peak demand forecast. It then follows that we establish the expected wholesale market price from the Monte Carlo simulations as follows in equation (5).

$$\begin{aligned} Expected\ price = {} & 0.304 \times Avg\ of\ 10\%\ POE\ USE\ (3\ Ref\ Years\ \times 8\ Monte\ Carlo\ simulations\ ) \\ & + 0.696 \times Avg\ of\ 50\%\ POE\ USE\ (3\ Ref\ Years\ \times 8\ Monte\ Carlo\ simulations) \end{aligned} \tag{5}$$

EY applies a rounded 0.3 weighting on all 10% POE outcomes and 0.7 weighting on 50% POE outcomes. While the above analysis is based on assessing expected unserved energy specifically, EY applies the weightings to all outcomes (such as generator revenues and prices) for simplicity.

The methodologies to produce the forecast half-hourly demand, wind and solar profiles for the modelling are described in more detail in the following sections.

A.2.2 Half-hourly locational renewable generation modelling

EY models future half-hourly generation availability for forecast uptake of individual wind and large-scale solar PV power stations, based on historical wind and solar resource data and achieving the available capacity factor assumptions by technology and REZ in the Draft 2021 IASR. An overview of the methodology for wind and solar is as follows:

Wind: EY's wind energy simulation tool (WEST) uses historical hourly short-term wind forecast data from the BOM on a 12 km grid across Australia to develop wind generation profiles for existing and future potential wind power stations used in the modelling. WEST manipulates the BOM wind speed data for a site and processes this through a typical wind farm power curve to target a specific available annual energy in the half-hourly profile for each power station. Existing wind farms use the historical average achieved annual energy from actual data, while all new wind farms use an assumed annual energy that varies depending on their location in the NEM.

Solar PV: EY's solar energy simulation tool (SEST) uses historical hourly satellite-derived solar insolation data on a 5 km grid across Australia, obtained from the BOM, along with BOM weather station data of temperature and wind speed. The resource data from the BOM is processed using the System Advisory Model (SAM) from the National Renewable Energy Laboratory (NREL) to develop locational solar PV generation profiles. The annual energy output varies from site to site as a result of calibration to the performance of existing solar farms and the locational resource data.

A.3 Thermal generator availability

Planned maintenance and reliability

Planned maintenance is allocated such that the availability adjusted peak demand is minimised throughout the year. By allocating the largest units first, they are going to be on maintenance during the lowest demand periods. The ultimate date chosen is the date which has the lowest demand period throughout the maintenance duration, not necessarily the lowest demand day.

As described in A.2.1, EY conducts several Monte Carlo iterations in a market simulation to capture the impact of forced (unplanned) generator outages. Each Monte Carlo iteration assigns random outages to each generating unit, based on assumed outage statistics.

2-4-C applies forced outage rate statistics for different generator types, or each individual generation facility depending on the data sets available. These parameters are applied to randomly schedule forced outages for the relevant units in each Monte Carlo iteration. The relevant units are typically thermal units such as coal, gas and hydro. Outages for wind and solar PV units are built into the half-hourly availability profiles for these units.

A.4 Bidding

For this project, EY has constructed bidding profiles for each individual generator based upon recent historical data published by AEMO. This strategy yields results that accurately model a generator's market behaviour for most of the time, implicitly capturing their bidding behaviour with respect to portfolio and contracting positions. Some of the units have different bidding profiles applied to different time slices, such as evenings, daytimes and early mornings if their historical bidding behaviour was determined to be better captured in that way.

In any single trading interval, each generating unit is modelled with a bid offering their capacity at up to 10 price-quantity pairs, as in the actual market. For example, a coal unit will bid a certain proportion of its load at or near the market floor price (-$1,000/MWh) to reflect its self-commitment intention, and incremental proportions of its capacity at positive prices to reflect their running costs and higher priced bids potentially up to the market price cap to recover fixed costs and be exposed to opportunistic pricing events in the market.

All new wind and solar projects installed in the model bid at their operating costs, which are assumed to be zero as per the Draft 2021 IASR. Some existing wind and solar projects bid negative prices to reflect historical bidding behaviour which is expected to continue assuming that this reflects their individual contracting positions.

Whilst this approach produces a useful benchmark and provides probable volatility in pricing outcomes, its limitations are that it does not consider potential changes in portfolios over time and how the portfolios would respond with different bidding strategies to major changes in the competitive dynamics of the market over the 20-year horizon.

A.5 WACC

The WACC applied to each candidate new entrant generator, storage and transmission augmentation is outlined in the table below.

Table 12: WACC parameters for new entrant candidates

WACC (%)- real*	New South Wales	Other regions
Wind	1.84	3.29
Solar PV	1.49	3.03
Batteries	1.68	2.65
Pumped hydro	1.83	N/A
OCGT	3.62	3.41
Transmission	4.00	N/A

* The WACC assumptions were supplied by the Department and use the pre-tax cost of debt and post-tax cost of equity in the NAB report[29]. EY uses these numbers for the purpose of annualising capital costs in the modelling, which is based on real dollars.

The Department also provided higher WACC assumptions for new New South Wales generators located outside REZs. However, these are not shown as EY did not consider candidate wind, solar PV or battery projects outside REZs in the modelling since the minimum target objectives could be easily met with projects located inside REZs, and the lower WACC assumptions for these gives them an advantage. All the supplied candidate pumped hydro projects were also considered to be New South Wales REZs for the purposes of applying a consistent WACC assumption as shown in Table 12.

The Department also provided higher WACC assumptions for new New South Wales generators that do not receive an LTESA contract and are installed commercially in their own right. As advised by the Department, LTESA contracts can be written for generation capacity that exceeds the minimum Roadmap targets if it reduces costs to New South Wales customers. Since this was found to be the case for all new entrant capacity in the modelling, the lower Roadmap WACCs in Table 12 are used for all new entrants in New South Wales in the modelling, and the higher WACC assumption alternative is not shown.

Since new OCGT capacity is likely to be located near existing gas infrastructure, and the majority of this is located outside REZs near Sydney, EY only used the supplied New South Wales OCGT WACC outside REZs (as shown in Table 12).

A.6 Battery and pumped hydro storage modelling

Box 2 summarises EY's modelling approach to storage discharge and charging operation. This is used for all large-scale batteries in the modelling plus battery VPPs and pumped hydro generators, except Snowy 2.0. Snowy 2.0 is modelled with a different approach due to its significant storage capacity and volume, which takes into account monthly variations in the New South Wales prices as well as day-to-day price variations.

[29] National Australia Bank| https://energy.nsw.gov.au/sites/default/files/2020-11/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20WACC%20Report.pdf

Box 2: Residual demand – battery operating strategy

EY's residual demand strategy for battery operation in a time-sequential market simulation with 2-4-C aims to simulate a realistic strategy that could be applied in the actual market. The strategy is based on developing an imperfect forecast of the wholesale market prices for the next two days and planning an optimal charging and discharging profile over those two days to maximise wholesale market price arbitrage. The strategies developed take into account the parameters of each specific battery including the present state of charge, available storage capacity and the round-trip efficiency.

The imperfect price forecast is based on residual demand, which is equal to operational demand minus the available large-scale wind and solar generation. The strategy develops a relationship between residual demand and prices over the previously simulated four days, and then uses this relationship to predict the price for the next two days to feed into the battery charge and discharge decisions. The price prediction uses a perfect forecast of residual demand for those next two days (which is known by the model as half-hourly demand, wind and solar generation are inputs into the model). However, the price is imperfect since it does not consider any curtailment of wind and solar generation and does not foresee any changes to generator availability. The optimal battery charge and discharge profiles determined by the strategy take into account the impact the battery's charging and discharging may have on the price, effectively considering that the battery's charge or discharge would change the residual demand.

Once the battery charge and discharge profiles are determined, these are fixed for 24 hours of time-sequential modelling, and the discharge profile is bid at $0/MWh and the charge profile at $300/MWh (where the battery will charge at its profile in a given half-hour if the price is less than $300/MWh). Any remaining discharge capacity over and above the discharge profile is effectively bid at the market price cap of $15,000/MWh such that the battery will discharge at its maximum discharge capacity to avoid unserved energy, as long as there is storage capacity available. The residual demand strategy is then reset taking in the previously simulated four days (a moving window of four days) and determining a new charge and discharge profile for the following two days.

The residual demand algorithm is applied to all modelled large-scale batteries and pumped hydro units with a storage capacity of eight hours or less. The modelled dispatch of the storage units in 2-4-C (and their impact on the modelling outcomes for the market) can deviate from the residual demand strategy's planned profiles due to the modelled price, curtailment due to network constraint equations or hitting the limits of its storage capacity. 2-4-C ensures that these energy limits of the storage units are obeyed; for example, if a storage unit is not able to fully charge as planned due to price, this flows on to the planned discharge profile where it will not be able to completely follow the plan as it will run out of charge.

A.6.1 Snowy 2.0

Snowy 2.0's proposed Snowy 2.0 pumped hydro power station is expected to have a generation capacity of 2 GW and a storage reservoir capacity of approximately 7 days of continuous generation at the full load of 2 GW[30]. Table 13 summarise the key assumptions used to model Snowy 2.0 for this Report.

Table 13: Snow 2.0 modelling parameters

Parameter	Value
Installed capacity	2040 MW
Storage capacity	168 hours
Pumping efficiency	76%
Commissioning schedule	Units 1&2: 1/11/2025, Units 3&4: 1/5/2026, Units 5&6: 1/11/2026

Due to Snowy 2.0's relatively large storage capacity, a market price driven generation and pumping load requires consideration of much longer time horizons than a two-day look-ahead that is used for optimising battery storage operation. Hence, EY adopts a different approach to modelling the dispatch of the Snowy 2.0 generation and pump, which considers a full financial year. The approach captures the relatively predictable seasonality across the year, but with imperfect foresight on the day-to-day and half-hourly prices.

[30] Draft AEMO 2021-22 Input and Assumptions Workbook - https://www.aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2021/draft-2021-22-inputs-and-assumptions-workbook.xlsx?la=en accessed 05/08/2021

The EY methodology assumes a 20% annual capacity factor for Snowy 2.0 generation. The 20% value represents a balance between the need for the pumped hydro station to be pumping more often than it generates (to account for its round-trip efficiency) and that it would not make commercial sense to generate/pump at full load as much as possible.

A key assumption to EY's Snowy 2.0 modelling methodology is that the station will generate the most when prices are highest and pump the most when prices are lowest, from intra-day to inter-month time scales. Due to its large reservoir size, it can generate more in some months and pump more in others to take advantage of months with higher or lower prices, respectively.

To allocate Snowy 2.0 generation for a given month, all months of the financial year are ordered from highest to lowest average price using a market simulation that excludes Snowy 2.0 operation. In the month with the highest average price Snowy 2.0 is assumed to generate at 23% capacity factor with capacity factors stepping down to 17% in the month with the lowest average price.

To allocate pumping for a given month a similar approach is taken independently of the generation allocation. Months of the financial year are ordered from lowest to highest price and pumping capacity factors are ordered from 29.66% linearly dropping to 23.66%. These capacity factors are chosen through a testing process that ensures the Snowy 2.0 reservoir stays within its operational limits.

The monthly generation and pumping values are then broken into half-hourly generation and pumping values using a linear step-wise function to allocate different levels of generation and pumping across the month. Firstly, a set of half-hourly periods with the highest prices is determined for generation such that, after allocation, the allocated capacity factor for that month would be achieved in those periods. Then, 5% of half-hourly periods with the highest prices are allocated the maximum generation output from Snowy 2.0 and the 5% of periods with the lowest prices are allocated the maximum pumping from Snowy 2.0. The next 5% the highest-priced periods are allocated 1.9 GW of generation, then the next 5% 1.8 GW and so on until the generation requirements for Snowy 2.0 for the given month is met. The inverse process is applied to the pumping where the first 5% of set of periods with the lowest prices are allocated 2 GW of pumping, the next 5% 1.9 GW etc. until the pumping requirements for the month are met.

When there are extended periods of identically low prices, there is no way to discriminate between the periods based on price alone. However, when the pumping is included, some of those periods will likely result in a higher price due to the large additional load supplied by Snowy 2.0. In such scenarios, the pumping allocation uses the lowest residual demand periods to rank the identically low-price periods.

The result of the above is a fixed half-hourly profile for the pumping load and generation of Snowy 2.0. However, this half-hourly profile is adjusted with the above process several times during the iterative modelling process.

A.7 Network constraints

The network constraint equations used in the modelling for this Report have been created for all transmission lines and transformers in the NEM. The constraint equations included in the modelling are:

1. N-1 thermal constraint equations, designed to avoid an overload of a transmission line due to a single credible contingency in the power system (i.e., a possible outage of a transmission line or a transformer). This set of constraint equations has been created to monitor all transmission lines for 220 kV or higher for every single possible contingency in the NEM transmission network. EY developed a new set of N-1 equations for each interconnector upgrade assumed in the Scenario.
2. N-0 constraint equations reflect 'system intact' conditions and are designed to avoid overloading of a transmission system component (a line or a transformer) assuming no contingency. This set of constraint equations has been created for all transmission lines for

110 kV or higher in the NEM. As with the N-1 constraints, EY developed a new set of N-0 constraints for each interconnector upgrade assumed in the Scenario.

3. Stability constraint equations, as published by AEMO. EY primarily modelled AEMO's ESOO 2018 stability constraints, rather than the more recent 2020 stability constraints due to the fact that more of the assumed network upgrades are included in the 2018 set. However, AEMO advised for this Report on some material updates to the ESOO 2018 stability constraints sets. This included addition of four constraint equations as following. A few of these constraints will be revoked by the mentioned network augmentations addition in Table .

Table 14: Additional stability constraint equations to ESOO 2018 constraint set

Constraint ID	Description	Comment
N^^N_NIL_2	Out=Nil, limit Darlington Point to Wagga line (63) line flow to avoid voltage collapse at Darlington Point 132kV post contingency trip of line 63, Feedback	Revoke for SW NSW stability improvement option 1 (Dinawan-Darlington Point 330 kV line)
N^^N_NIL_3	Out= Nil, limit power flow on line X5 from Balranald to Darlington Point (X5) to avoid voltage collapse for contingency trip of Bendigo-Kerang 220kV line in NW Victoria	No solutions in augmentation list
Q^^NIL_QNI_SRAR	Out = Nil, limit Queensland to New South Wales on QNI to avoid voltage instability on trip of Sapphire – Armidale (8E) 330 kV line	Revoke for QNI Medium (the option all the way to Queensland)
V^^SML_NSWRB_2	Out = Nil, Victoria to South Australia transfer limit on Murraylink to avoid voltage collapse at Red Cliffs for the loss of either the Darlington Point to Balranald (X5) or Balranald to Buronga (X3) 220kV lines	Revoke for PEC

EY's model was configured such that the constraint equation data set includes mapping of all existing and new generator connection points to constraint equation terms as appropriate.

A.7.1 Thermal constraint equation formulation

The objective of a thermal constraint equation is to prevent overloading of any transmission element during both system normal operation and following any single credible contingency (post contingent). A constraint equation is made up of terms on the left-hand side (LHS) and right-hand side (RHS) of the equation such that the sum of terms on the LHS is less than or equal to the sum of terms on the RHS.

The elements within a thermal constraint equation can be categorised as follows:

- Generator coefficients
- Interconnector coefficients
- Redistribution factor
- Demand coefficient
- Constant term

Generator coefficients

Generator coefficients in a constraint equation are Power Transfer Distribution Factors (PTDFs) associated with generators within the network. The PTDF for transmission element connecting bus j to bus k with respect to a generator at bus m is a sensitivity measure of the power flow on the transmission element, expressed in terms of a percentage distribution of an incremental power injection at bus m.

The coefficient for a generator connected at bus m can be calculated by differentiating the power flow across a monitored element connecting bus j to bus k with respect to the power injection at bus m, that is:

$$PTDF_{m,j\rightarrow k} = \frac{dF_{j\rightarrow k}}{dP_m}$$

Where P_m is the power injection at bus m and $F_{j\rightarrow k}$ is the power flow across the monitored element from bus j to bus k. An underlying assumption that is inherently applied is that the RRN (location of the slack bus) will absorb any incremental injection at bus m. Therefore, the PTDFs can be viewed as the contribution of a small amount of power injection at bus m on the power flow across element connecting bus j to bus k to supply a small increase in demand at the RRN.

Generator coefficients defined this way will be dependent purely on the system network topology and the location of the RRN. They will not be influenced by the regional demand or generation dispatch across the system.

Interconnector coefficients

Similar to the calculation of generator coefficients outlined in the previous section, interconnector coefficients are PTDFs associated with power injection at the regional boundary buses. That is, the coefficient for an interconnector at the regional boundary bus n for a monitored element connecting bus j to bus k is defined as:

$$PTDF(INTER)_{n,j\rightarrow k} = \frac{dF_{j\rightarrow k}}{dP(INTER)_n}$$

Where $P(INTER)_n$ is the interconnector power injection (positive for importing power and negative for exporting power) from neighbouring regions into bus n.

Demand coefficients

Demand coefficients correspond to the contribution of regional demand towards the power flow on a monitored network element. To calculate the demand coefficient for a monitored network element connecting bus j to bus k, EY calculate the derivative of the power flow from bus j to bus k with respect to the regional *as generated* demand (as delivered demand plus system losses and auxiliary loads), that is:

$$\text{Demand Coefficient}_{j\rightarrow k} = \frac{dF_{j\rightarrow k}}{d\,\text{Demand}}$$

This value can be approximated accurately by scaling the regional demand up by a small amount (less than 1%) and dividing the difference in power flow by the difference in regional demand, that is:

$$\text{Demand Coefficient}_{j\rightarrow k} = \frac{F'_{j\rightarrow k} - F_{j\rightarrow k}}{\text{Demand}' - \text{Demand}} = \frac{\Delta F_{j\rightarrow k}}{\Delta\text{Demand}}$$

Where $F'_{j \to k}$ is the observed flow associated with the scaled demand, and Demand$'$ is the scaled up demand.

It is worth mentioning that the methodology described above assumes that the change in the regional demand is balanced by power injection at the regional reference node (RRN). Furthermore, since the demand is scaled up in proportion to the existing demand distribution, different demand distributions from different system operating states will result in different demand coefficients. Therefore, some consideration is required to decide upon the most adequate demand coefficient for a particular constraint equation.

Constant term

The constant term corresponds predominantly to the thermal line rating (in MW) of the monitored element, with an additional offset referred to as the *constant-ex-rating* value, that is:

$$\text{Constant Term} = \text{Rating}_{\text{MW}} + \text{Constant-ex-rating}$$

Thermal line ratings are typically given in MVA. To convert MVA ratings to MW ratings, EY assumes a power factor (PF) of 0.95 and equates the MW ratings as:

$$\text{Thermal Rating}_{MW} = PF \times \text{Thermal Rating}_{MVA}$$

The *constant-ex-rating* value is required in addition to the thermal rating to take into account the difference in power flow between AC and DC solutions (since generator coefficients are calculated based on a DC load flow solution) and the contribution (equivalent PTDF) of all other generators with small coefficients which are not explicitly included in the constraint equation. This value is computed as the difference between the calculated flow across the monitored element based on generator and demand coefficients obtained and the actual AC power flow solution. For a system with *M* generator connection points and *N* interconnector boundaries, the *constant-ex-rating* value for the monitored element connecting bus j to bus k is calculated as:

$$\begin{aligned} \textit{constant-ex-rating}_{j \to k} = & \sum_{m=1}^{M} PTDF_{m,j \to k} \cdot GEN_m \\ & + \sum_{n=1}^{N} PTDF(INTER)_{n,j \to k} \cdot P(INTER)_n \\ & + \text{Demand Coefficient}_{j \to k} \cdot \text{Demand} - F_{j \to k} \end{aligned}$$

Formulating a constraint equation

Having defined all of the key elements, a constraint equation is formulated with generation and interconnector terms on the LHS and constant and demand terms on the RHS as:

$$\begin{aligned} \sum_{m=1}^{M} PTDF_{m,j \to k} \cdot GEN_m \quad & \leq \quad \text{Thermal Limit'}_{MW} + \text{Constant-ex-rating}_{j \to k} \\ + \sum_{n=1}^{N} PTDF(INTER)_{n,j \to k} \cdot P(INTER)_n \quad & \quad\quad - \text{Demand Coefficient}_{j \to k} \cdot \text{Demand} \end{aligned}$$

Further to this, AEMO has specified that in cases where the coefficient of a term on the LHS is relatively small then the risk of NEMDE choosing sub-optimal dispatch decisions may exist. To avoid such situations the following rule has been adopted:

- LHS Terms shall not have coefficients less than 0.07. This can be achieved as follows.
- Scale the constraint equation such that all coefficients for LHS terms are not less than 0.07 provided that the absolute value of largest coefficient of any LHS term does not then

exceed 1.0. This is to ensure that the effective violation penalties of network constraint equations grade adequately with other constraints in the dispatch algorithm.

- If after scaling terms with such small coefficients remain, transfer these terms to the RHS.

EY has adopted the above methodology as a final step in the formulation of thermal constraint equations.

Appendix B Definitions and acronyms

Table 15: List of defined terms

Defined terms	
Baseline case	The modelling cases using the Scenario assumptions and an intention or constraints for an Alternative Development Pathway where an Alternative Development Pathway is developed along with New South Wales coal capacity withdrawal outcomes. The outcomes of this case represent where the market plays out as expected and these are compared to the market outcomes in sensitivity cases.
Capex	Capital expenditure
the Department	New South Wales Department of Planning, Industry and Environment
Alternative development pathway	An annual commissioning schedule of New South Wales transmission augmentations, new New South Wales electricity generation and storage over a 20-year outlook. This includes the locations by REZ or other location, and the technologies of the generation and storage capacity.
Alternative development pathway theme	Input assumptions for a baseline case pertaining to intentions and/or constraints in the build schedule for New South Wales VRE capacity over the 2020s.
Iteration	Half-hourly modelling of a single possible outcome for a future set of years
Equilibrium capacity mix	An equilibrium capacity mix is an annual capacity development outcome for a baseline case. Finding this outcome involves iterating on several market simulations to arrive at a final simulation.
Market outcomes	Any set of outcomes from a modelled case (baseline or sensitivity), which can be New South Wales customer costs, wholesale prices, generator curtailment, etc.
Planting	The iterative process of adding/removing new renewable, gas, battery capacity until the model reaches a competitive market equilibrium
Reference year	A historical 12-month period of time series of data of atmospheric weather conditions and customer consumption behavior that is applied to construct a correlated set of wind and solar generation expectations and electricity consumption behavior for a future modelling year
Region	There are five pricing regions in the NEM: Queensland, New South Wales (including the Australian Capital Territory), Victoria, South Australia and Tasmania
Residual demand	The demand required to be met by large-scale scheduled generation. This is calculated by taking the total customer electricity demand and netting off rooftop PV and large-scale wind and solar PV generation, as well as the net effect of behind-the-meter battery storage
Scenario assumptions	The set of market assumptions that drive the modelling outcomes for the 20-year outlook, except for the guidance/constraints on the Alternative Development Pathways in the 2020s.
Scenario outcomes	The market outcomes that are driven by the Scenario assumptions that are independent of the intentions and/or constraints underpinning the Alternative Development Pathways.
Sensitivity	The modelling process where an isolated, unexpected change to the market is explored. These cases do not attempt to find a new equilibrium Alternative Development Pathway on the basis that there is no time to respond to the unexpected changes. These are used to analyse the resilience of Alternative Development Pathways.
Simulation (sims)	Half-hourly modelling of a future set of years, comprising multiple iterations for each year
Trace	Half-hourly time series representing, for example, the dispatch of a generator or the demand of a load
10% and 50% POE peak demand trajectories	Seasonal peak demand projections, representing 10% probability of POE and 50% POE years.

Table 16: List of abbreviations used in this report

Abbreviations	
2-4-C®	EY's in-house wholesale electricity market dispatch modelling software suite
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
BOM	Bureau of Meteorology
CF	Capacity factor
CT	Consumer Trustee
DSP	Demand side participation
ESOO	Electricity Statement of Opportunities
EST	Energy Security Target
EV	Electric Vehicle
EY	Ernst & Young
FCAS	Frequency Control Ancillary Services
GW/GWh	Gigawatt/gigawatt hour
IASR	Input Assumptions and Scenarios Report
ISP	Integrated System Plan
kV	Kilovolt
LGC	Large-scale generation contract
LHS	Left-hand side
LRET	Large-scale renewable energy target
LTESA	Long-term electricity supply agreement
MW/MWh	Megawatt/megawatt hour
NEM	National Electricity Market
NEMDE	National Electricity Market Dispatch Engine
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NSW	New South Wales
O&M	Operations and Maintenance
PADR	Project Assessment Draft Report
POE	Probability of Exceedance
PTDF	Power Transfer Distribution Factors
PVNSG	PV non-scheduled generation
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RHS	Right-hand side
RRN	Regional reference node
SAM	System Advisory Model
SEST	Solar energy simulation tool
SW NSW	South-west New South Wales
SWIS	South-west interconnected system

Abbreviations	
TAPR	Transmission Annual Planning Report
TEX	Trace Extrapolator (EY model)
TRET	Tasmanian Renewable Energy Target
VNI	Victoria-New South Wales interconnector
VPP	Virtual power plant
VRE	Variable renewable energy. In this Report this refers to large-scale wind and solar PV.
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital
WEST	Wind Energy Simulation Tool

EY | Building a better working world

EY exists to build a better working world, helping to create long-term value for clients, people and society and build trust in the capital markets.

Enabled by data and technology, diverse EY teams in over 150 countries provide trust through assurance and help clients grow, transform and operate.

Working across assurance, consulting, law, strategy, tax and transactions, EY teams ask better questions to find new answers for the complex issues facing our world today.

About EY Strategy and Transactions

EY Strategy and Transactions teams work with clients to navigate complexity by helping them to reimagine their ecosystems, reshape their portfolios and reinvent themselves for a better future. With global connectivity and scale, EY Strategy and Transactions teams help clients drive corporate, capital, transaction and turnaround strategies through to execution, supporting fast-track value creation in all types of market environments. EY Strategy and Transactions teams help support the flow of capital across borders and help bring new products and innovation to market. In doing so, EY Strategy and Transactions teams help clients to build a better working world by fostering long-term value. For more information, please visit ey.com/strategyandtransactions.

Our report may be relied upon by AEMO for the purpose of outlining key assumptions, strengths and weaknesses of the alternative development pathways and evidence that they meet the objectives of the Act pursuant to the terms of our engagement letter dated 26 March 2021. We disclaim all responsibility to any other party for any loss or liability that the other party may suffer or incur arising from or relating to or in any way connected with the contents of our report, the provision of our report to the other party or the reliance upon our report by the other party.

ey.com