Maintaining reliable supply to Bathurst, Orange and Parkes areas PADR market modelling

TransGrid

3 February 2022

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Ernst & Young was engaged on the instructions of NSW Electricity Networks Operations Pty Limited as trustee for NSW Electricity Networks Operations Trust (TransGrid) to undertake market modelling of system costs and benefits to maintaining reliable supply to Bathurst, Orange and Parkes areas (BOP) Regulatory Investment Test for Transmission (RIT-T) relating to various non-network options.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by TransGrid after public consultation. 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.

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1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits to support the "maintaining reliable supply to Bathurst, Orange and Parkes areas (BOP)" Regulatory Investment Test for Transmission (RIT-T) relating to various non-network options[1].

This Report forms a supplementary report to the Project Assessment Draft Report (PADR) prepared and published by TransGrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by TransGrid and the modelling methods used.

EY calculated the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with five non-network options for the Progressive Change scenario from the 2022 Australian Energy Market Operator (AEMO) Draft Integrated System Plan (ISP)[2].

To determine the least-cost solution, a Time Sequential Integrated Resource Planner (TSIRP) model was used. It makes decisions for each hourly trading interval in relation to the dispatch of generators and commissioning of new entrant capacity, while taking into account several operational and technical constraints. From the hourly time-sequential modelling we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed (capex),
- total Fixed Operation and Maintenance (FOM) costs of all generation capacity,
- total Variable Operation and Maintenance (VOM) costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and involuntary load curtailment (unserved energy, USE),
- transmission expansion costs associated with renewable energy zone (REZ) development.

For each simulation with a BOP option and in the Base Case (without a BOP option), we computed the sum of these cost components and compared the difference between each option and the Base Case. The difference in present values of costs is the forecast gross market benefits[3] due to the presence of the corresponding option, as defined in the RIT-T.

The forecast gross market benefits capture the impact on transmission losses to the extent that losses across interconnectors and intra-connectors affect the generation that is needed to be dispatched in each trading interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including Pumped Storage Hydro (PSH) and large-scale battery storage between each BOP option and the counterfactual Base Case.

Table 1 shows the details of the modelled options. TransGrid has advised EY to maintain the confidentiality of the modelled options. As such, no dollar value results are provided in this report. In addition, the y-axis in all the comparison charts throughout the Report have been removed. For more details on each option, refer to the PADR[1].

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[1] TransGrid, *Bathurst, Orange and Parkes Supply*, available at: https://www.transgrid.com.au/projects-innovation/bathurst-orange-and-parkes-supply. Accessed 21 January 2022.

[2] Note that while most of the assumptions are from the 2021 Inputs and Assumptions workbook published 10 December 2021, some assumptions like the timing of major upgrades are based on the draft 2022 ISP outcomes. AEMO, *2022 Draft ISP Consultation*, available at https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation, and AEMO, *Current inputs, assumptions and scenarios*, available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed on 21 January 2022.

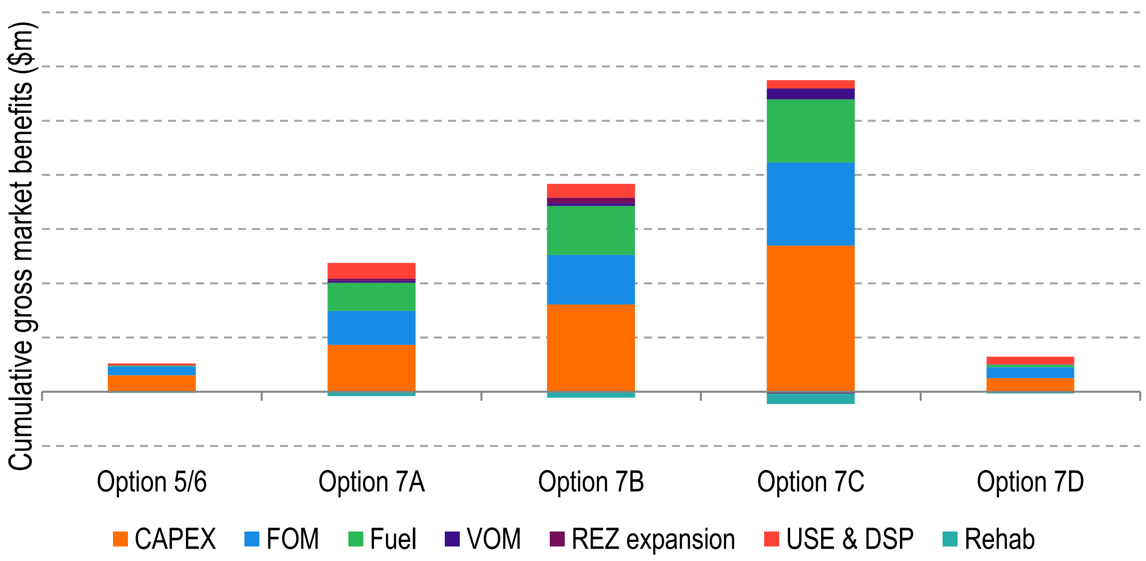
[3] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the RIT-T guidelines and "net economic benefit" as defined in the RIT-T guidelines.

Table 1: Summary of the BOP Options[1]

Option	Commissioning date	Description
Option 5/6	1st July 2026	Large-scale battery at Panorama Large-scale battery at Parkes
Option 7A	1st July 2023	Solar PV and large-scale battery at Parkes Large-scale battery at Panorama
Option 7B	1st July 2023	Solar PV and large-scale battery at Parkes Large-scale battery at Panorama
Option 7C	1st July 2024	Large-scale battery at Parkes Large-scale battery at Panorama
Option 7D	1st July 2023	Large-scale battery at Parkes Large-scale battery at Panorama

The composition of market benefit categories in the forecast gross market benefits for all modelled options is shown in Figure 1. In general, higher benefits accrue from larger options with larger associated costs. The forecast gross market benefits of each option in each scenario need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by TransGrid, by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits.

Figure 1: Composition of forecast total gross market benefits for all options



Sources of benefits and the key drivers are discussed below:

- Across the options, the relative size of the gross market benefits is forecast to vary with the capacity and storage volume of the option, and whether the option includes a solar farm. The majority of the gross market benefits is expected to be attributed to capex, fuel and FOM savings across all the options. Avoided or deferred capex is forecast to be the highest contributor to gross market benefits across all options. The capex savings are a result of avoided generation build due to the non-network options being installed. Some savings are also forecast as a result of deferred build of new gas generation in some options.

- FOM and fuel benefits combined are forecast to make up a similar proportion to the capex benefits across all options. Forecast FOM and fuel benefits are a result of the non-network options reducing black-coal generation and some enabling economic retirement of black coal. The bulk of these benefits are forecast to occur between the early 2020s to 2031-32.

- The gross market benefits are forecast to accumulate across the whole modelled period depending on the timing and scale of the option considered.

2. Introduction

TransGrid has engaged EY to undertake market modelling of system costs and benefits to support the "maintaining reliable supply to Bathurst, Orange and Parkes (BOP) areas" Regulatory Investment Test for Transmission (RIT-T) relating to various non-network options[1]. The RIT-T is a cost-benefit analysis used to assess the viability of investment options in regulated electricity transmission assets.

This Report forms a supplementary report to the broader Project Assessment Draft Report (PADR) published by TransGrid[1]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by TransGrid and the modelling methods used.

EY computed the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with five non-network options using input assumptions generally derived from the 2022 Draft Integrated System Plan's (ISP) Progressive Change scenario[2]. The options were defined by TransGrid and are described in detail in the PADR. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[4].

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits on a qualitative basis to maintain the confidentiality of the options. The categories of gross market benefits modelled are changes in:

- capital costs of new generation capacity installed,
- total fixed operation and maintenance (FOM) costs of all generation capacity,
- total variable operation and maintenance (VOM) costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment,
- transmission expansion costs associated with renewable energy zone (REZ) development.
- transmission and storage losses which form part of the demand to be supplied, which are calculated dynamically within the model.

Each category of gross market benefits is computed annually across a 24-year modelling period from 2022-23 to 2045-46. Benefits presented are discounted to June 2021 using a 5.5 % real, pre-tax discount rate as selected by TransGrid. This value is consistent with the value applied by the Australian Energy Market Operator (AEMO) in the draft 2022 ISP[2].

This modelling considers five non-network options as listed in the table below. For more details on each option, refer to the PADR[1].

Table 2: Overview of the BOP non-network options[1]

Option	Commissioning date	Description
Option 5/6	1st July 2026	Large-scale battery at Panorama Large-scale battery at Parkes
Option 7A	1st July 2023	Solar PV and large-scale battery at Parkes Large-scale battery at Panorama
Option 7B	1st July 2023	Solar PV and large-scale battery at Parkes Large-scale battery at Panorama

[4] AER, August 2020, *Application guidelines - Regulatory investment test for transmission.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Regulatory%20investment%20test%20for%20transmission%20application%20guidelines%20-%2025%20August%202020.pdf. Accessed 21 January 2022.

Option	Commissioning date	Description
Option 7C	1st July 2024	Large-scale battery at Parkes Large-scale battery at Panorama
Option 7D	1st July 2023	Large-scale battery at Parkes Large-scale battery at Panorama

The forecast gross market benefits of each option need to be compared to the relevant option cost to determine the forecast net economic benefit for that option. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by TransGrid, by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[4].

The Report is structured as follows:

- Section 3 describes assumptions and scenario inputs modelled in this study.
- Section 4 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.
- Section 5 outlines model design and input data related to representation of the transmission network, transmission losses and demand.
- Section 6 provides an overview of model inputs and methodologies related to supply of energy.
- Section 7 presents the NEM capacity and generation outlook without the BOP options.
- Section 8 presents the forecast gross market benefits for each option. It is focussed on identifying and explaining the key sources of forecast gross market benefits of all options.

3. Scenario assumptions

3.1 Progressive Change Scenario

The options proposed by TransGrid have been assessed under the Progressive Change scenario from the Integrated System Plan[2], as selected by TransGrid. This scenario is summarised in Table 3 and is aligned with AEMO's draft 2022 ISP[2].

Table 3: Overview of key input parameters in the Progressive Change scenario

Key drivers input parameter	Data value and source
Underlying consumption	ESOO 2021 (draft ISP 2022) - Progressive Change[5]
New entrant capital cost for wind, solar SAT, OCGT, CCGT, PSH, and large-scale batteries	2021 Inputs and Assumptions Workbook[6] - Progressive Change
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030
Gas fuel cost	2021 Inputs and Assumptions Workbook - Progressive Change: Lewis Grey Advisory 2020, Central
Coal fuel cost	2021 Inputs and Assumptions Workbook - Progressive Change: Wood Mackenzie, Central
Federal Large-scale Renewable Energy Target (LRET)	33 TWh per annum by 2020 to 2030 (including GreenPower and ACT scheme), accounting for contribution to LRET by Western Australia (WA), Northern Territory (NT) and off grid locations
NEM carbon budget to achieve 2050 emissions levels	2021 Inputs and Assumptions Workbook - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51
Victoria Renewable Energy Target (VRET)	40 % renewable energy by 2025 and 50 % renewable energy by 2030
Queensland Renewable Energy Target (QRET)	50 % by 2030
Tasmanian Renewable Energy Target (TRET)	2021 Inputs and Assumptions Workbook: 200 % Renewable generation by 2040
NSW Electricity Infrastructure Roadmap	2021 Inputs and Assumptions Workbook: 12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the draft 2022 ISP 2 GW Pumped Storage Hydro (PSH) by 2029-30
EnergyConnect	Draft 2022 Integrated System Plan[7] – Progressive Change: EnergyConnect commissioned by July 2025
Western Victoria Transmission Network Project	Draft 2022 Integrated System Plan – Progressive Change: Western Victoria upgrade commissioned by July 2025

[5] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 21 January 2022.

[6] AEMO, *2021 Inputs and Assumptions Workbook*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, Accessed 21 January 2022.

[7] AEMO, *draft 2022 Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 21 January 2022.

Key drivers input parameter	Data value and source
HumeLink	Draft 2022 Integrated System Plan - Progressive Change: HumeLink commissioned by July 2035
Marinus Link	Draft 2022 Integrated System Plan - Progressive Change:1st cable commissioned by July 2029 and 2nd cable by July 2031
Victoria to NSW Interconnector Upgrade (VNI Minor)	Draft 2022 Integrated System Plan - Progressive Change: VNI Minor commissioned by December 2022
NSW to QLD Interconnector Upgrade (QNI Minor)	Draft 2022 Integrated System Plan - Progressive Change: QNI minor commissioned by July 2022
QNI Connect	Draft 2022 Integrated System Plan - Progressive Change: QNI Connect commissioned by July 2036
VNI West	Draft 2022 Integrated System Plan - Progressive Change: VNI West commissioned by July 2038
Victorian SIPS	Draft 2022 Integrated System Plan - Progressive Change: 300 MW/450 MWh, 250 MW for SIPS service and the remaining 50 MW can be deployed in the market by the operator on a commercial basis, November 2021.
New-England REZ Transmission	Draft 2022 Integrated System Plan - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038
Snowy 2.0	Draft 2022 Integrated System Plan -Snowy 2.0 is commissioned by December 2026

4. Methodology

4.1 Long-term investment planning

EY has used linear programming techniques to perform hourly time-sequential, least-cost, long-term NEM development optimisation modelling spanning 24 years from 2022-23 to 2045-46. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[4].

Based on the full set of input assumptions, the Time-Sequential Integrated Resource Planner (TSIRP) model makes decisions that minimise the overall cost to supply the electricity demand for the NEM over the entire modelling period, with respect to:

- capital expenditure for generation and storage (capex),
- FOM,
- VOM,
- fuel usage,
- demand-side participation (DSP) and unserved energy (USE),
- transmission expansion costs associated with REZ development,
- transmission and storage losses which form part of the demand to be supplied and are calculated dynamically within the model.

To determine the least-cost solution, the model makes decisions for each hourly[8] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each trading interval is subject to the modelled availability of power stations in each hour (those that are not on planned or unplanned outages), network limitations and energy limits (e.g., storage levels).

- commissioning new entrant capacity for wind, offshore wind, solar PV SAT[9], CCGT, OCGT, large-scale storage and PSH. We screened nuclear and any other technology options "possible" and found that they would not be a part of the least cost plan.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all trading intervals, while maintaining a reserve margin, with USE costed at the value of customer reliability (VCR)[10],

- minimum loads for some generators,

- transmission interconnector flow limits (between regions),

- intra-regional flow limits (between zones in New South Wales),

- maximum and minimum storage reservoir limits (for conventional storage hydro, PSH and large-scale battery storage),

[8] Whilst the NEM is dispatched on five-minute intervals, the model resolution is hourly as a compromise between managing computation time while still capturing the renewable and storage resources in sufficient detail for the purposes of the modelling.

[9] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined Cycle Gas Turbine, OCGT = Open Cycle Gas Turbine.

[10] AER, December 2019, *Values of Customer Reliability Final report on VCR values.* Available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf. Accessed 21 January 2022.

- new entrant capacity build limits and costs associated with increasing these limits beyond the resource limit for wind and solar in each REZ where applicable, and PSH in each region,

- emission and carbon budget constraints, as defined for the scenario,

- renewable energy targets where applicable by region or NEM-wide.

The model includes key intra-regional constraints in NSW through modelling of zones with intra-regional limits and loss equations. Within these zones and within regions, no further detail of the transmission network is considered.

The model factors in the annual costs, including annualised capital costs, for all new generator capacity and the model decides how much new capacity to build in each region to deliver the least-cost market outcome.

The model meets the specified emissions trajectory at least cost, which may be by either building new lower emissions plant or reducing operation of higher emissions plant, or both.

There are three main types of generation that are scheduled by the model:

- Dispatchable generators, typically coal, gas and liquid fuel which are assumed to have unlimited energy resource in general. An assumed energy limit is placed on coal-fired power stations where specified in the draft 2022 ISP dataset. The running cost for these generators is the sum of the VOM and fuel costs. FOM costs are also modelled, which are another factor in the running cost of generators determining their economic retirements. Coal generators and some CCGTs have minimum loads to reflect operational stability limits and high start-up costs and this ensures they are always online when available. This is consistent with the self-commitment nature of the design of the NEM. On the other hand, peaking generators have no minimum operating level and start whenever their variable costs will be recovered and will operate for a minimum of one hour.

- Wind and solar generators are fully dispatched according to their available variable resource in each hour, unless constrained by oversupply or network limitations.

- Storage plant of all types (conventional hydro generators with storages, PSH, large-scale battery storages and VPPs) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g. when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired, liquid fuel generators. Conversely, at times of low prices, e.g. when there is a surplus of capacity, storage hydro preserves energy and PSH and large-scale battery storage operate in pumping or charging mode.

4.2 Reserve constraint in long-term investment planning

The TSIRP model ensures there is sufficient dispatchable capacity in each region to meet peak demand by enforcing regional minimum reserve levels to allow for generation contingencies, which can occur at any time.

All dispatchable generators in each region are eligible to contribute to reserve (except PSH, VPPs and large-scale battery storages[11]) and headroom that is available from interconnectors. The hourly modelling accounts for load diversity and sharing of reserves across the NEM and so minimises the amount of reserve carried, and provides reserve from the lowest cost providers, including allowing for each region to contribute to its neighbours' reserve requirements through interconnectors.

[11] PSH and large-scale battery storages are usually fully dispatched during the peak demand periods and thus will be unable to contribute to reserve. In the event that they are not dispatched fully, it is likely that they will have insufficient energy in storage.

In the modelling presented in this Report, a consecutive contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g. variability in production from variable renewable energy sources, different forced outage patterns). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.[12]

There are three geographical levels of reserve constraints applied:

- Reserve constraints are applied to each region.
- The model ensures that interconnector headroom is backed by spare capacity in the neighbouring regions through an additional reserve constraint.
- In New South Wales, where the major proportion of load and dispatchable generation is concentrated in the Central New South Wales (NCEN) zone, the same rules are applied as for the New South Wales region except headroom on intra-connectors between adjacent zones does not contribute to reserve. This is because even if there is headroom on the NCEN intra-connectors, it is likely that the flows from the north and south into NCEN reflect the upstream network limits. However, intra-connectors still implicitly contribute to reserve because increased flow can displace dispatchable generators within NCEN allowing them to contribute to reserve.

4.3 Losses in long-term investment planning

Intra and inter-regional losses are captured in the TSIRP model through explicit modelling of dynamic loss equations. More detail on these equations is given in Section 5. Additional losses within New South Wales zones and within the remaining NEM regions are captured through an estimate of loss factors for existing and new entrant generators. To estimate these loss factors, the TSIRP model is interfaced with an AC load flow program. Hourly generation dispatch outcomes from the model are transferred to nodes in a network snapshot.

These estimated loss factors are then returned to the TSIRP model and used in a further refining pass to ensure new entrant developments are least-cost when accounting for changing load and generation patterns. Loss factors are estimated based on hourly outcomes at each five-year interval[13]. This method of estimating and incorporating loss factors is sufficient to give a geographic investment signal related to transmission network utilisation. The reduced energy delivered from generators to serve load as a result of the loss factors is incorporated in the modelling.

4.4 Cost-benefit analysis

From the hourly time-sequential modelling the following categories of costs defined in the RIT-T are computed:

[12] Testing confirmed that this assumption does not affect outcomes as a reserve constraint is unlikely to bind in lower demand intervals.

[13] The final computation of loss factors is in 2030-31 since at around this time significant REZ transmission upgrade costs have been incurred as part of the least-cost generation development plan. There is insufficient detail to reflect these transmission upgrades in the network snapshot to sensibly compute loss factors after this time, and it is therefore assumed that developments occur that are sufficient to maintain loss factors constant from that time.

- capital costs of new generation capacity installed,
- total FOM costs of all generation capacity,
- total VOM costs of all generation capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary and involuntary load curtailment, called DSP and USE,
- transmission expansion costs associated with REZ development.

For each BOP option a matched no BOP option counterfactual (referred to as the Base Case) long term investment plan is simulated. The changes in each of the cost categories are computed as the forecast gross market benefits due to the BOP option, as defined in the RIT-T.

Each component of gross market benefits is computed annually over the 24-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[14], discounted to June 2021 at a 5.5 % real, pre-tax discount rate as selected by TransGrid.

The forecast gross market benefits of each BOP option need to be compared to the relevant option cost to determine whether there is a positive forecast net economic benefit. The determination of the preferred option is also dependent on option costs and was conducted outside of this Report by TransGrid[1]. All references to the preferred option in this Report are in the sense defined in the RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[4], as identified in the PADR[1].

[14] We use the term net present value rather than present value as there are positive and negative components of market benefits captured; however, we do not consider augmentation costs.

5. Transmission and demand

5.1 Regional and zonal definitions

TransGrid elected to split New South Wales into sub-regions or zones in the modelling presented in this Report, with a high resolution of the Canberra zone[15], as listed in Table 4. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 4: Regions, zones and reference nodes

Region	Zone	Zonal Reference Node
Queensland	Queensland (QLD)	South Pine 275 kV
New South Wales	Northern New South Wales (NNS)	Armidale 330 kV
	Central New South Wales (NCEN)	Sydney West 330 kV
	South-West New South Wales (SWNSW)	Darlington Point 330 kV
	Canberra	Canberra 330 kV
	Bannaby	Bannaby 330 kV
	Yass	Yass 330 kV
	Wagga	Wagga 330 kV
	Lower Tumut	Lower Tumut 330 kV
	Snowy (Maragle)	Snowy (Maragle) 330 kV
	Upper Tumut	Upper Tumut 330 kV
Victoria	Murray	Murray 330 kV
	Dederang	Dederang 330 kV
	Victoria (VIC)	Thomastown 66 kV
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The loss factors for generators (as discussed in Section 4.3) are computed with respect to the zonal reference node they are mapped to, which for New South Wales are the reference nodes defined in Table 4 rather than the regional reference node as currently defined in the NEM. Dynamic loss equations are defined between reference nodes across these cut-sets.

The borders of each zone or region are defined by the cut-sets listed in Table 5, as defined by TransGrid.

[15] TransGrid, *HumeLink PACR market modelling*, Available at: https://www.transgrid.com.au/media/vqzdxwl3/humelink-pacr-ey-market-modelling-report.pdf, accessed 21 January 2022.

Table 5: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook – Tamworth Line 84 Liddell – Tamworth Line 96T Hawks Nest – Taree Line 9C8 Stroud – Brandy Hill
NCEN-CAN	Line 61 Gullen Range – Bannaby Line 3W Kangaroo Valley – Capital Line 4/5 Yass – Marulan Line 973 Yass – Cowra Line 999 Yass - Cowra Line 98J Shoalhaven – Evans Lane Line 28P West Tomerong – Evans Lane and new HumeLink lines for each option
CAN/YASS-Bannaby	Line 61 Gullen Range – Bannaby Line 3W Kangaroo Valley – Capital Lines 4 &5 Yass – Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
CAN (WAG)-SWNSW	Line 63 Wagga - Darlington Pt Line 994 Yanco - Wagga Line 99F Yanco - Uranquinty Line 99A Finley - Uranquinty Line 997/1 Corowa – Albury New 330 kV double circuit from Wagga – Dinawan (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Wagga – Dinawan (after assumed commissioning of VNI West)
VIC-CAN	Line 060 Jindera – Wodonga Line 65 Upper Tumut – Murray Line 66 Lower Tumut - Murray
VIC-SWNSW	Line 0X1 Red Cliffs – Buronga New Red Cliffs – Buronga (after assumed commissioning of EnergyConnect) New 500 kV double circuit from Kerang - Dinawan (after assumed commissioning of VNI West)
SWNSW-SA	New 330 kV double circuit from Buronga – Robertstown (after assumed commissioning of EnergyConnect)

Table 6 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by TransGrid.

Table 6: Key cut-set limits (MW)

Options	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
CAN/YASS – Bannaby cut-set	4,900

Options	Bidirectional limit (MW)
CAN-NCEN cut-set	4,500
Bannaby-NCEN	4,500

5.2 Interconnector and intra-connector loss models

Dynamic loss equations are computed for a number of conditions, including:

- when a new link is defined e.g. NNS-NCEN, SA-SWNSW (EnergyConnect), Bannaby-NCEN, Wagga-SWNSW,
- when interconnector definitions change with the addition of new reference nodes e.g. the Victoria to New South Wales interconnector (VNI) now spans VIC-SWNSW and VIC-DED instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled e.g. VNI West, QNI and Marinus Link.
- for Canberra equivalent lines, using their resistance.

The network snapshots to compute the loss equations were provided by TransGrid, and were also used for the estimation of generators loss factors.

5.3 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 7. The following interconnectors are included in the left-hand side of constraints which may restrict them below the notional limits specified in this table:

- Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW. The model will dispatch them to minimise costs.

Table 7: Notional interconnector capabilities used in the modelling (sourced from TransGrid and AEMO draft 2022 ISP[2])

Interconnector (From node – To node)	Import[16] notional limit	Export[17] notional limit
QNI[18]	-1060 MW after QNI minor upgrade -2140MW after QNI connect upgrade	715 MW after QNI minor upgrade 1660 MW after QNI connect upgrade
Terranora (NNS-SQ)	-150 MW	50 MW
VIC-NSW[19] (VIC-CAN)	-250 MW -500 MW after VIC SIPS commissioning	550 MW (Base) 720 MW (after VNI minor upgrade from 1 July 2022)

[16] Import refers to power being transferred from the 'To node' to the 'From node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. import along QNI implies southward flow and import along Heywood implies eastward flow.

[17] Export refers to power being transferred from the 'From node' to the 'To node' and follows NEM convention where the 'From node' is the most southerly or easterly node, and the 'To node' is the most northerly or westerly node. e.g. export along QNI implies northward flow and export along Heywood implies westward flow.

[18] Flow on QNI may be limited due to additional constraints.

[19] The modelling of zones within New South Wales necessitated that VIC-NSW is split across two zones on the New South Wales side of the border. The VIC-NSW transfer path is a combination of VIC-SWNSW and VIC-CAN and have their limits proportioned based on input from TransGrid.

Interconnector (From node – To node)	Import[16] notional limit	Export[17] notional limit
VIC-NSW (VIC-SWNSW)	-150 MW (Base) -500 MW (after EnergyConnect) and -1,950 MW (after VNI West)	150 MW (Base) 500 MW (after EnergyConnect) and 2,250 MW (after VNI West)
EnergyConnect (SWNSW-SA)	-800 MW	800 MW
Heywood (VIC-SA)	-650 MW (before EnergyConnect) -750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	-200 MW	220 MW
Basslink (TAS-VIC)	-478 MW	478 MW
Marinus Link (TAS-VIC)	-750 MW for the first leg and -1,400 MW after the second leg	750 MW for the first leg and 1,400 MW after the second leg

New South Wales has been split into zones with the following limits imposed between the zones defined in Table 8.

Table 8: Intra-connector notional limits imposed in modelling for New South Wales (sourced from TransGrid)

Intra-connector (From node – To node)	Import notional limit	Export notional limit
NCEN-NNS	-1,177 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the 2022 draft ISP	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the 2022 draft ISP
WAG-SWNSW	-300 MW (before EnergyConnect) -1,100 MW (after EnergyConnect) -2,100 (after HumeLink) -3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 (after HumeLink) 3,000 MW (after VNI West)

5.4 Demand

The TSIRP model captures operational demand (energy consumption which is net of rooftop PV and other non-scheduled generation) diversity across regions by basing the overall shape of hourly demand on nine historical financial years ranging from 2010-11 to 2018-19.

Specifically, the key steps in creating the hourly demand forecast are as follows:

- the historical underlying demand has been calculated as the sum of historical operational demand and the estimated rooftop PV generation based on historical monthly rooftop PV capacity and solar insolation,
- the nine-year hourly pattern has been projected forward to meet future forecast annual peak demand and energy in each region (scenario-dependent),
- the nine reference years are repeated sequentially throughout the modelling horizon as shown in Figure 2.
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is

subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles and domestic storage) to get a projection of hourly operational demand.

Figure 2: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2021-22	2012-13
2022-23	2013-14
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2034-35	2017-18
2035-36	2018-19
…	…
2041-42	2015-16
2042-43	2016-17
2043-44	2017-18
2044-45	2018-19
2045-46	2010-11

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to rooftop PV uptake, we generally see the peak operational demand intervals shifting later in the day throughout the forecast.

The reference year pattern is also consistent with site-specific hourly large-scale wind and solar availability (see Section 6.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and rooftop PV availability.

TransGrid selected demand forecasts from the ESOO 2021[20], which are used as inputs to the modelling. Figure 3 and Figure 4. shows the NEM operational energy and distributed PV for the Progressive Change scenario.

Figure 3: Annual operational demand in the Progressive Change scenario for the NEM[20]

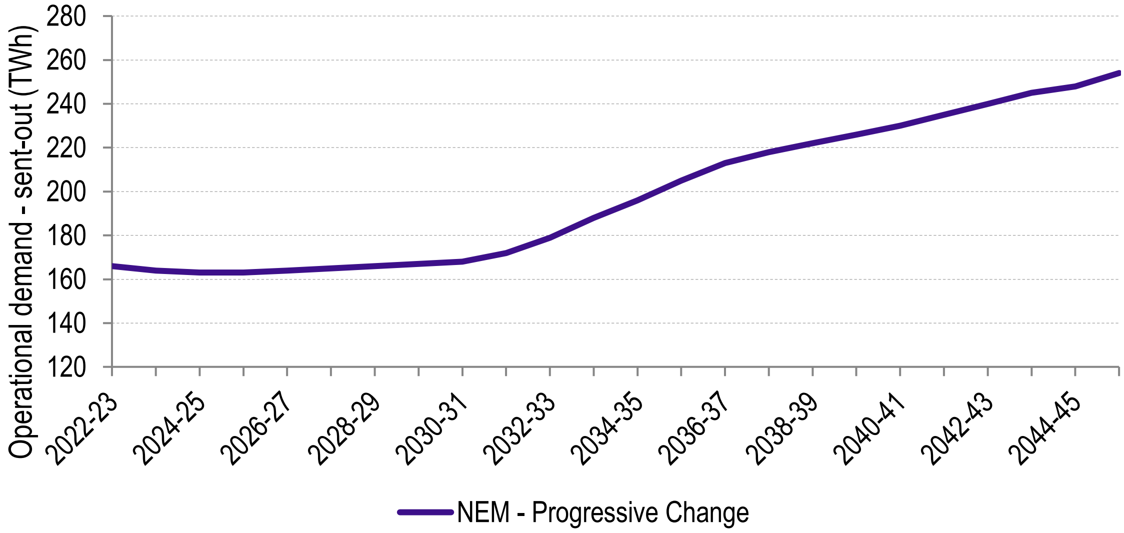
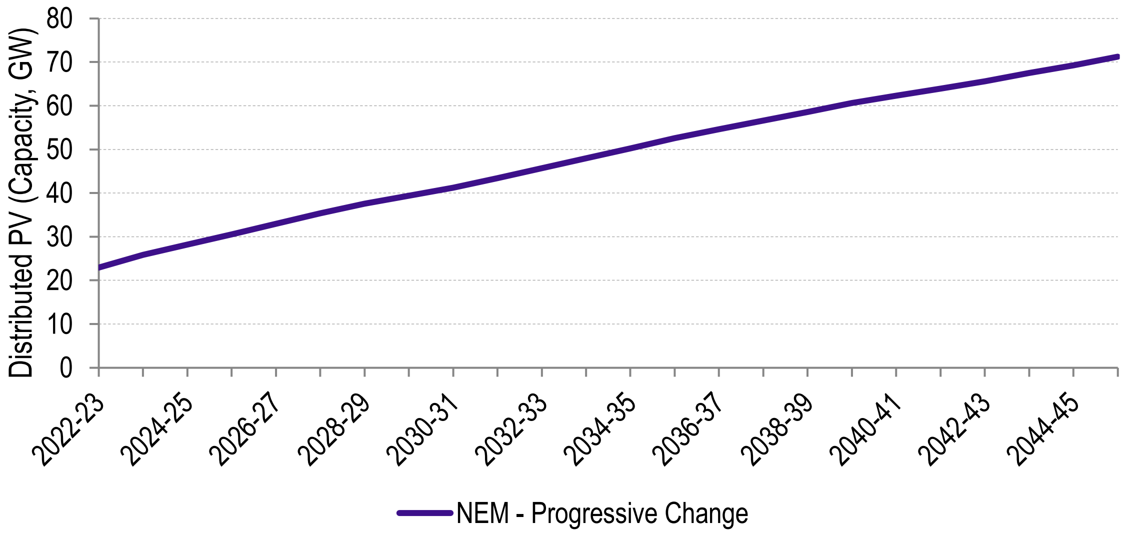


Figure 4: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[20]



The ESOO 2021 demand forecasts for NSW are split into the various NSW zones that have been defined, as described in Section 5.1. TransGrid obtained from AEMO half-hourly scaling factors to convert regional load to connection point loads which are used to split the regional demand into the zones. Doing so captures the diversity of demand profiles between the different zones in NSW.

The load forecasts used in the market modelling do not include the changes in mining loads in the BOP areas modelled by TransGrid as these are immaterial in scale relative to NEM demand, whole-of-NSW and zonal NSW demand.

[20] AEMO, August 2021, *NEM Electricity Statement of Opportunities (ESOO)*, Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 21 January 2022.

6. Supply

6.1 Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations, including the Base Case and each non-network option. The source of this list is based on the AEMO 2021 ISP Inputs and Assumptions workbook[2], existing, committed and anticipated projects as well as batteries are used.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[21]. The methodology for each category of wind and solar project is summarised in Table 9 and explained further in this section of the Report.

Table 9: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[22] where available, otherwise past meteorological performance.	Capacity factor varies with reference year based on site-specific, historical, near-term wind speed forecasts.
	Committed new entrant	Specify long-term target based on average of AEMO ESOO 2019 traces of nearest REZ, medium quality tranche.	
	Generic REZ new entrants	Specify long-term target based on AEMO 2021 ISP Inputs and Assumptions workbook[2]. One high quality option and one medium quality trace per REZ.	
Solar PV FFP	Existing	Annual capacity factor based on technology and site-specific solar insolation measurements.	Capacity factor varies with reference year based on historical, site-specific insolation measurements.
Solar PV SAT	Existing		
	Committed new entrant		
	Generic REZ new entrant		
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO 2021 ISP Inputs and Assumptions workbook[2].	Capacity factor varies with reference year based on historical insolation measurements.

All existing and committed large-scale wind and solar farms in the NEM are modelled on an individual basis. Each project has a location-specific availability profile based on historical resource availability. The availability profiles are derived using nine years of historical weather data covering financial years between 2010-11 and 2018-19 (inclusive), and synchronised with the hourly shape of demand. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 2.

[21] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 21 January 2022.

[22] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/NEM-Electricity-Statement-of-Opportunities. Accessed 21 January 2022.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[23] at a representative hub height. Wind speeds are converted into power using a generic wind farm power curve. The wind speed profiles are scaled to achieve the average target capacity factor across the nine historical years. The profiles reflect inter-annual variations, but at the same time achieve long-term capacity factors in line with historical performance (existing wind farms) or the values used in the AEMO 2021 ESOO and draft 2022 ISP assumptions[2,5] for each REZ (new entrant wind farms, as listed in Table 10).

The availability profiles for solar are derived using solar irradiation data downloaded from satellite imagery processed by the Australian Bureau of Meteorology. As for wind profiles, the solar profiles reflect inter-annual variations over nine historical years, but at the same time achieve long-term capacity factors in line with historical performance (existing solar farms) or close to AEMO's approximation for each REZ (generic new entrant solar farms as listed in Table 10).

Table 10: 2021 IASR REZ wind and solar approximate average capacity factors over nine reference years[2]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	54 %	48 %	27 %
	North Queensland Clean Energy Hub	43 %	36 %	30 %
	Northern Queensland	Tech not available	Tech not available	28 %
	Isaac	37 %	31 %	29 %
	Barcaldine	33 %	31 %	32 %
	Fitzroy	38 %	33 %	28 %
	Wide Bay	32 %	30 %	27 %
	Darling Downs	39 %	34 %	28 %
	Banana	31 %	28 %	29 %
New South Wales	North West New South Wales	Tech not available	Tech not available	29 %
	New England	39 %	38 %	26 %
	Central West New South Wales	37 %	34 %	27 %
	Broken Hill	33 %	31 %	30 %
	South West New South Wales	30 %	30 %	27 %
	Wagga Wagga	28 %	27 %	26 %
	Cooma-Monaro	43 %	41 %	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24 %
	Murray River	Tech not available	Tech not available	27 %
	Western Victoria	42 %	37 %	23 %
	South West Victoria	41 %	39 %	Tech not available

23 As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. Accessed 21 January 2022.

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	Gippsland[24]	40 %	35 %	20 %
	Central North Victoria	33 %	31 %	26 %
South Australia	South East SA	40 %	37 %	23 %
	Riverland	29 %	28 %	27 %
	Mid-North SA	39 %	37 %	26 %
	Yorke Peninsula	37 %	36 %	Tech not available
	Northern SA	37 %	35 %	28 %
	Leigh Creek	41 %	40 %	31 %
	Roxby Downs	Tech not available	Tech not available	30 %
	Eastern Eyre Peninsula	40 %	38 %	25 %
	Western Eyre Peninsula	40 %	38 %	27 %
Tasmania	North East Tasmania	46 %	44 %	22 %
	North West Tasmania[25]	51 %	46 %	19 %
	Tasmania Midlands	56 %	54 %	21 %

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[2].

- Transmission-limited total build limit (MW) representing the amount of dispatch supported by current intra-regional transmission infrastructure.
- A transmission expansion cost ($/MW) representing an indicative linear network expansion cost to develop a REZ beyond current capabilities and connect the REZ to the nearest major load centre.
- Resource limits (MW) representing the maximum amount of capacity expected to be feasibly developed in a REZ based on topography, land use etc at the given capex.
- A resource limit violation penalty factor ($/MW) to build additional capacity beyond the resource limit. This represents additional capex to build on sites with higher land costs.

The TSIRP model incurs the additional transmission expansion cost to build more capacity up to the resource limit if it is part of the least-cost development plan.

6.2 Forced outage rates and maintenance

Full and partial forced outage rates for all generators as well as mean time to repair used in the modelling are based the AEMO 2021 Inputs and Assumptions workbook[2].

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage

[24] Gippsland has an option for Offshore wind with an average capacity factor of 46 %.
[25] North West Tasmania has an option for Offshore wind with an average capacity factor of 50 %.

pattern exists between the Base Case and the various upgrade options. New entrant generators are de-rated by their equivalent forced outage rate.

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2021 Inputs and Assumptions workbook[2].

6.3 Generator technical parameters

All technical parameters are as detailed in the AEMO 2021 Inputs and Assumptions workbook[2], except where noted in the Report.

6.4 Coal-fired generators

Coal-fired generators are treated as dispatchable between minimum load and maximum load. Must run generation is dispatched whenever available at least at its minimum load. In line with the AEMO 2021 Inputs and Assumptions workbook[2]. Maximum loads vary seasonally. This materially reduces the amount of available capacity in the summer periods.

A maximum capacity factor of 75 % is assumed for NSW coal, as per the AEMO 2021 Inputs and Assumptions workbook[2].

6.5 Gas-fired generators

Gas-fired CCGT plant also typically have a must-run component and so are dispatched at or above their minimum load to deliver efficient fuel consumption.

In line with the AEMO 2021 Inputs and Assumptions workbook[2], a minimum load of 46 % of capacity for all new CCGTs has been applied to reflect minimum load conditions for assumed efficient use of gas and steam turbines in CCGT operating mode.

OCGTs are assumed to operate with no minimum load. As a result, they start and are dispatched for a minimum of one hour when the cost of supply is at or above their SRMC.

A minimum stable load is assumed for some gas generators including Condamine, Darling Downs, Swanbank E, Tallawarra, Yabulu and Yarwun as described in the 2021 Inputs and Assumptions workbook[2].

6.6 Wind, solar and run-of-river hydro generators

Intermittent renewables, in particular solar PV, wind and run-of-river hydro are dispatched according to their resource availability as they cannot store energy. Intermittent renewable production levels are based on nine years of hourly measurements and weather observations across the NEM including all REZ zones. Using historical reference years preserves correlations in weather patterns, resource availability and demand. Modelling of wind and solar PV is covered in more detail in Section 6.1.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically, when the marginal cost of supply falls to less than their VOM, or by other constraints such as transmission limits.

6.7 Storage-limited generators

Conventional hydro with storages, PSH and batteries are dispatched in each trading interval such that they are most effective in reducing the costs of generation up to the limits of their storage capacity.

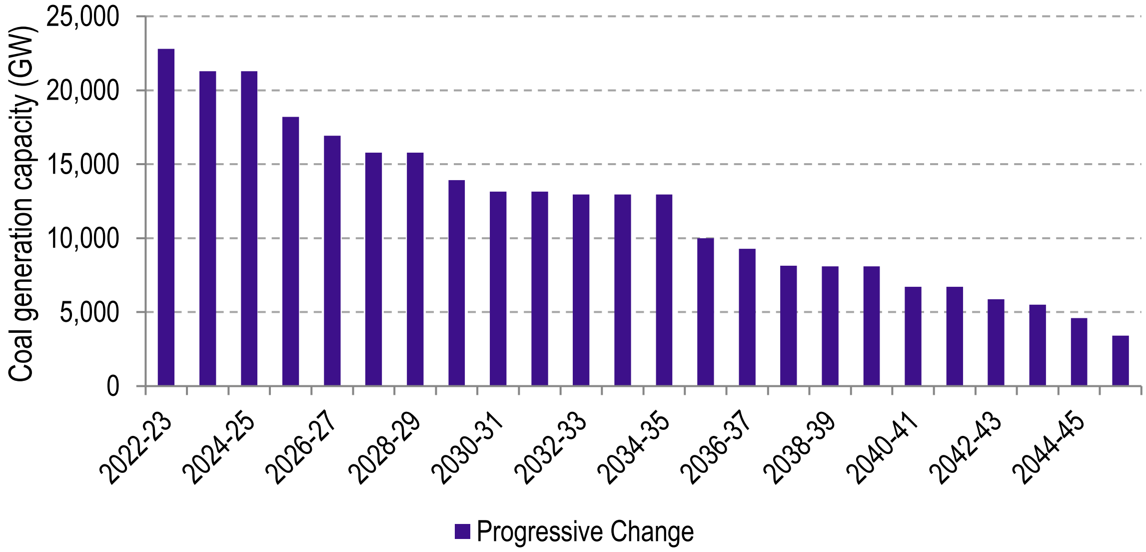
Hourly hydro inflows to the reservoirs and ponds are computed from monthly values sourced from the AEMO 2021 Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[2]. The Tasmanian hydro schemes were modelled using a simplified six pond model.

7. NEM outlook without BOP options

To understand the forecast benefits of the BOP options, it is useful to examine the differences in the expected capacity and generation outlooks in the modelled scenario, and the underlying input assumptions driving those differences in the Base Case.

According to the scenario settings selected by TransGrid and in line with the draft 2022 ISP, thermal retirements in the model are on an economic basis. Coal retirement dates are at or earlier than their end-of-technical life or announced retirement year. Forecast coal capacity in the Base Case as an output of the modelling is illustrated in Figure 5.

Figure 5: Coal capacity in the NEM by year in the Base Case



The pace of transition is determined by market forces under current federal and state government policies[2] in a system developed and dispatched at least cost. This includes a central demand outlook and capital cost projections, neutral fuel cost prices, net zero emissions target by 2050, and state-based policy initiatives such as TRET, VRET, QRET and the NSW Electricity Infrastructure Roadmap. Considered transmission augmentations include Marinus Link first cable assumed commissioned in 2029-30 and second cable in 2031-32, HumeLink in 2035-36, VNI West in 2038-39 and QNI connect in 2036-37.

The NEM-wide capacity mix forecast in the Base Case is shown in Figure 6 and the corresponding generation mix in Figure 7. In the Base Case, the forecast generation capacity of the NEM gradually shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PSH, and gas.

Figure 6: NEM capacity mix forecast for the Progressive Change scenario in the Base Case

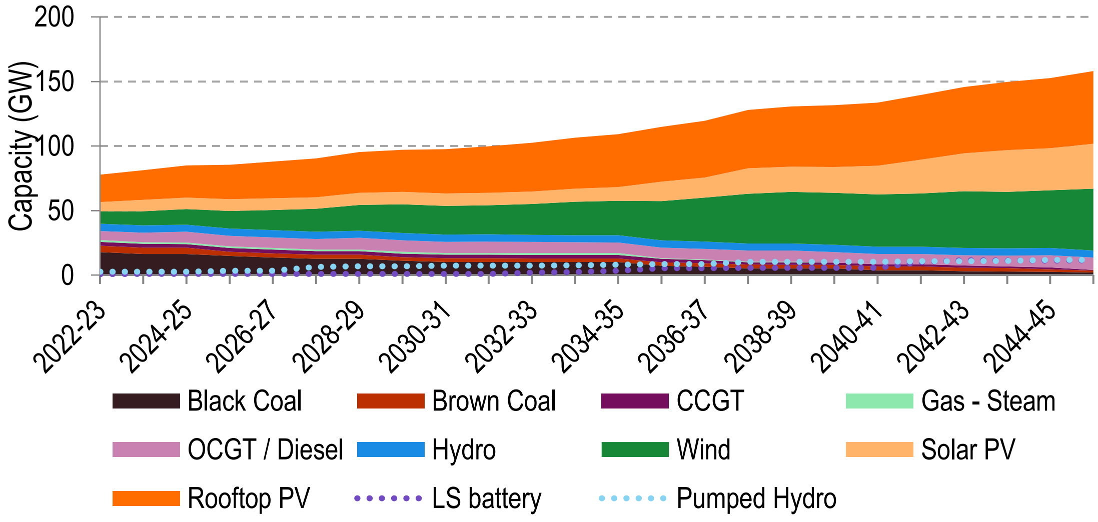
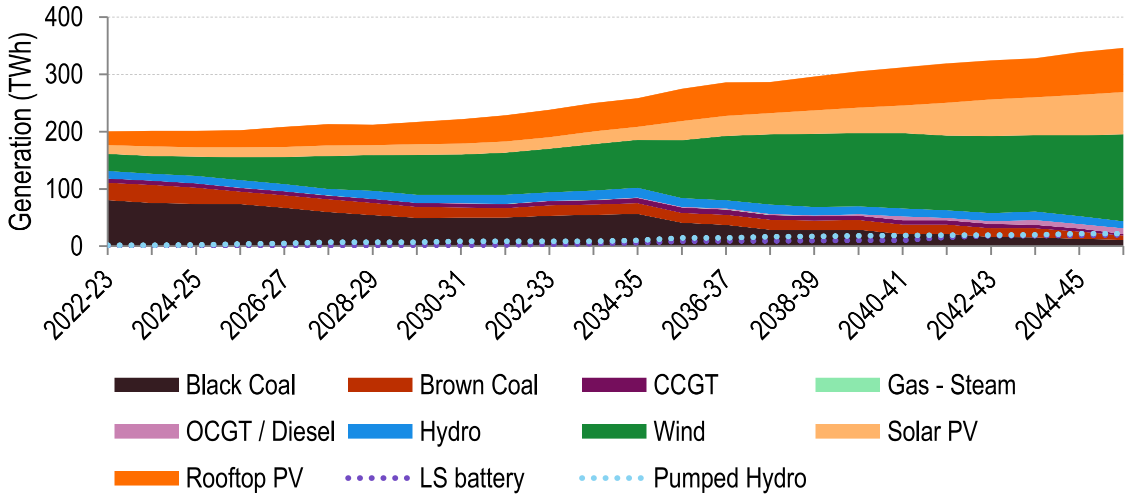


Figure 7: NEM generation mix forecast for the Progressive Change scenario in the Base Case



Up to 2030, new wind and solar build is driven by the assumed state-based renewable energy targets. The forecast increase in renewable capacity leads to some economically driven black and brown coal retirements before their currently advised closure date[6]. From 2030-31, with further expected coal retirements, large-scale battery capacity is forecast to start to increase, and from 2035-36 PSH and wind, to replace the retiring capacity. Solar and OCGT capacity is also forecast to increase from the late 2030s complementing other technologies. The forecast gas-fired capacity also supports reserve requirements during peak demand times. Overall, the NEM is forecast to have around 181 GW total capacity by 2045-46 (note that total capacity includes PSH and large-scale battery capacities, which are not in the stacked chart), and the forecast timing of the majority of new installed capacity is coincident with coal-fired generation retirements.

8. Forecast gross market benefit outcomes

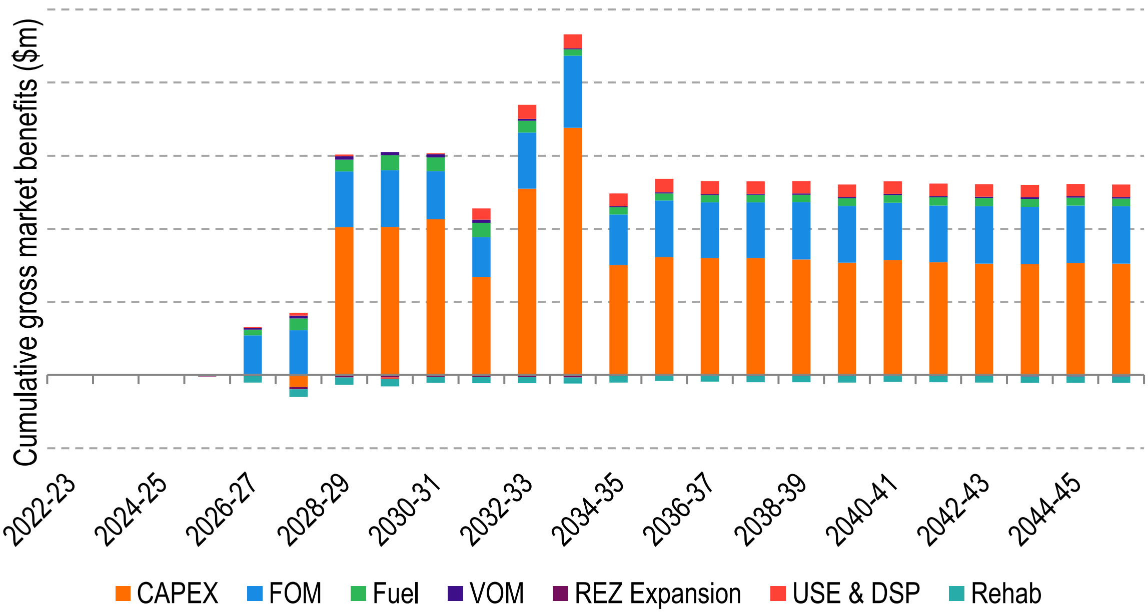
8.1 Market modelling results

Throughout this section, the y-axis in all the comparison charts is removed to maintain the confidentiality of the modelled options as requested by TransGrid. This includes Option 5/6; although these are TransGrid-owned battery options with non-confidential costs, if numbers were included the costs of other battery options could be inferred through comparison to this option.

8.1.1 Option 5/6

The forecast cumulative gross market benefits for Option 5/6 in the Progressive Change scenario are shown in Figure 8. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 5/6 and the Base Case in this scenario are shown in Figure 9 and Figure 10, respectively.

Figure 8: Forecast cumulative gross market benefit[26] for Option 5/6 under the Progressive Change scenario



[26] Note that all generator and storage capital costs have been included in the market modelling on an annualised basis. However, this chart and all charts of this nature in the Report present the entire capital costs of these plants in the year avoided to highlight the timing of capacity changes that drive expected capex benefits. This is purely a presentational choice that TransGrid has made to assist with relaying the timing of expected benefits (i.e., when thermal plant retires) and does not affect the overall gross benefits of the options.

Figure 9: Difference in NEM capacity forecast between Option 5/6 and Base Case in the Progressive Change scenario (including assumed capacity of Option 5/6)

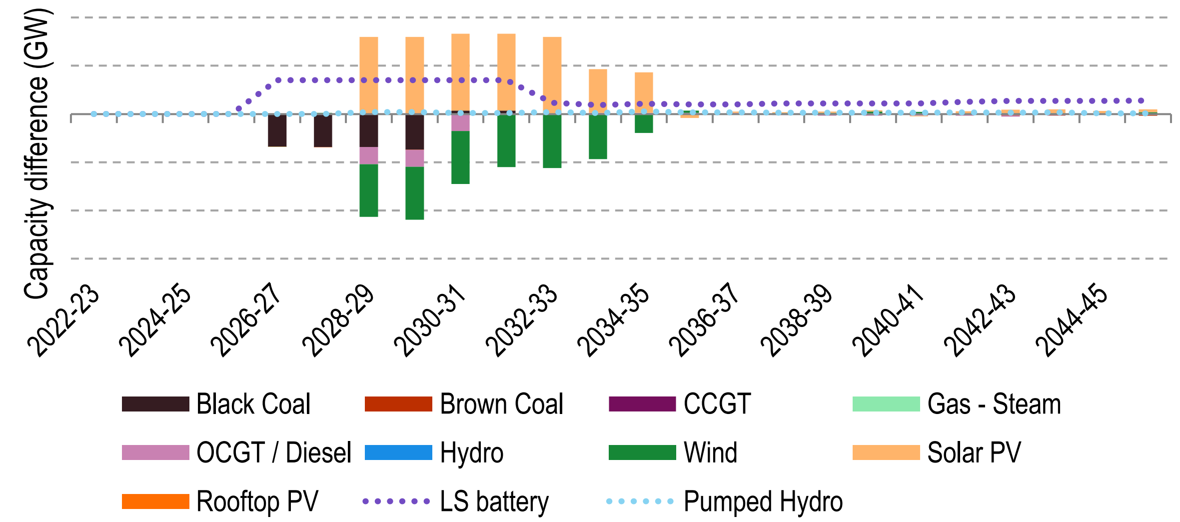
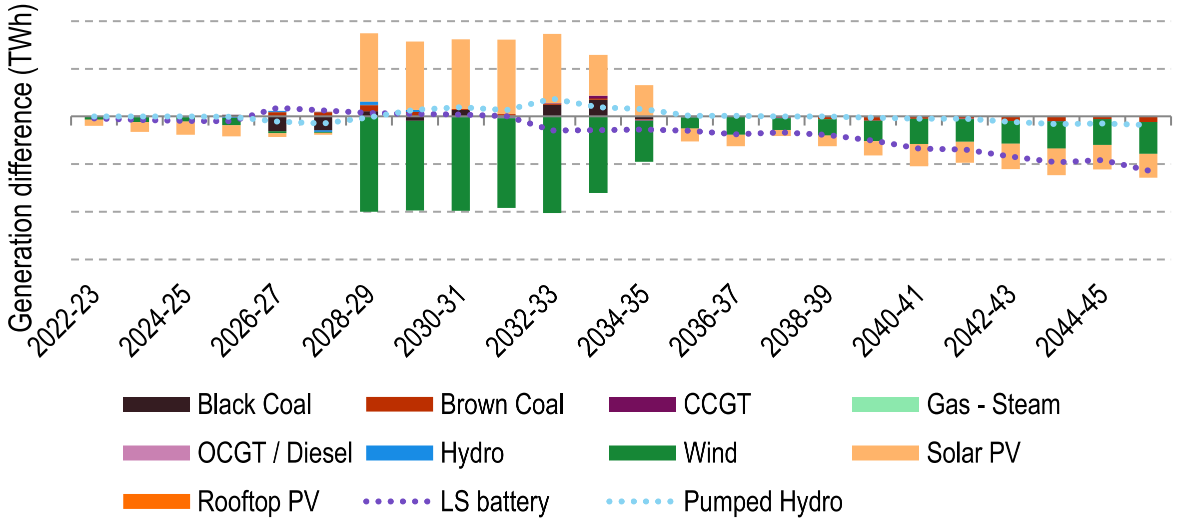


Figure 10: Difference in NEM generation forecast between Option 5/6 and Base Case in the Progressive Change scenario (including forecast generation of Option 5/6)



The primary sources of forecast market benefits are from avoided capex for new generators as well as FOM and fuel cost savings from reduced black coal and OCGT generation, followed by USE savings. The timing and source of these benefits are attributable to the following:

- Benefits are forecast to accrue from 2026-27, largely due to FOM and fuel savings as some NSW black coal capacity is forecast to retire earlier than the Base Case. Forecast fuel benefits in early years are due to the Option 5/6 battery operation replacing higher cost black coal generation.
- From 2028-29, solar capacity build in the NEM (specifically NSW) is forecast to be brought forward, while wind capacity build is forecast to be delayed with respect to the Base case.
- Capex benefits are forecast to increase in 2028-29 due to deferral of build of gas-fired generation to 2031-32.
- The capex benefits are then forecast to fluctuate when the deferred gas generation is built in 2031-32, economic build of large-scale battery storage is avoided from 2032-33 to 2033-34

(due to assumed earlier inclusion of Option 5/6), and deferred wind capacity is built from 2033-34 to 2035-36.

- From 2035-36 the capex benefits are expected to remain stable until the end of the study.
- Fuel cost savings are forecast to accrue from 2026-27, gradually increasing due to less black coal generation until around 2030.

8.1.2 Option 7A

The forecast cumulative gross market benefits for Option 7A in the Progressive Change scenario are shown in Figure 11. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 7A and the Base Case are shown in Figure 12 and Figure 13.

Figure 11: Forecast cumulative gross market benefit for Option 7A under the Progressive Change scenario

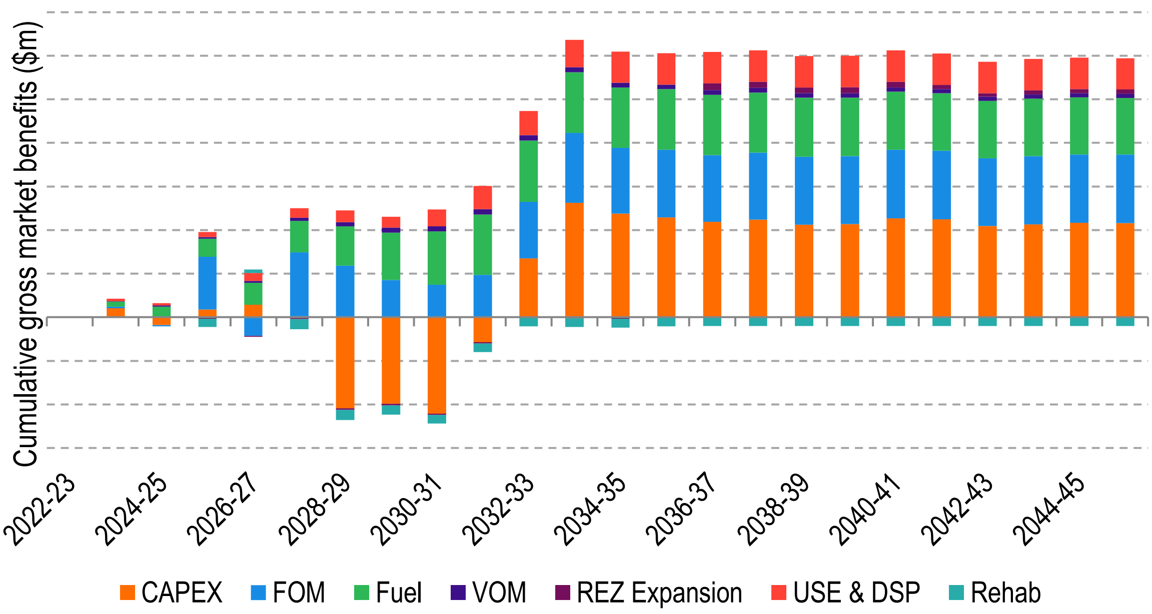


Figure 12: Difference in NEM capacity forecast between Option 7A and Base Case in the Progressive Change scenario (including assumed capacity of Option 7A)

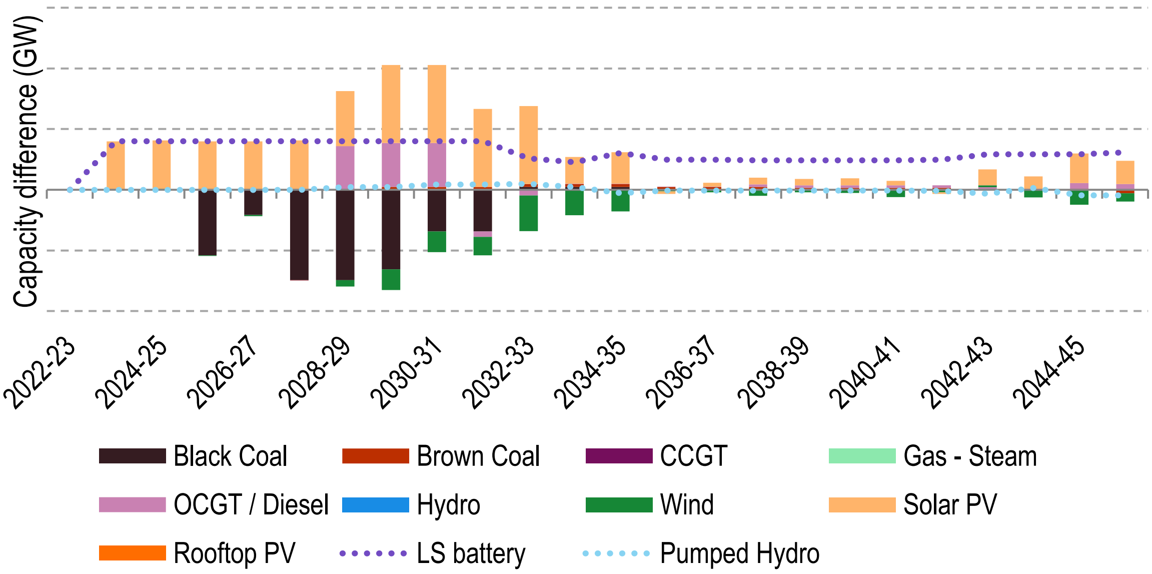
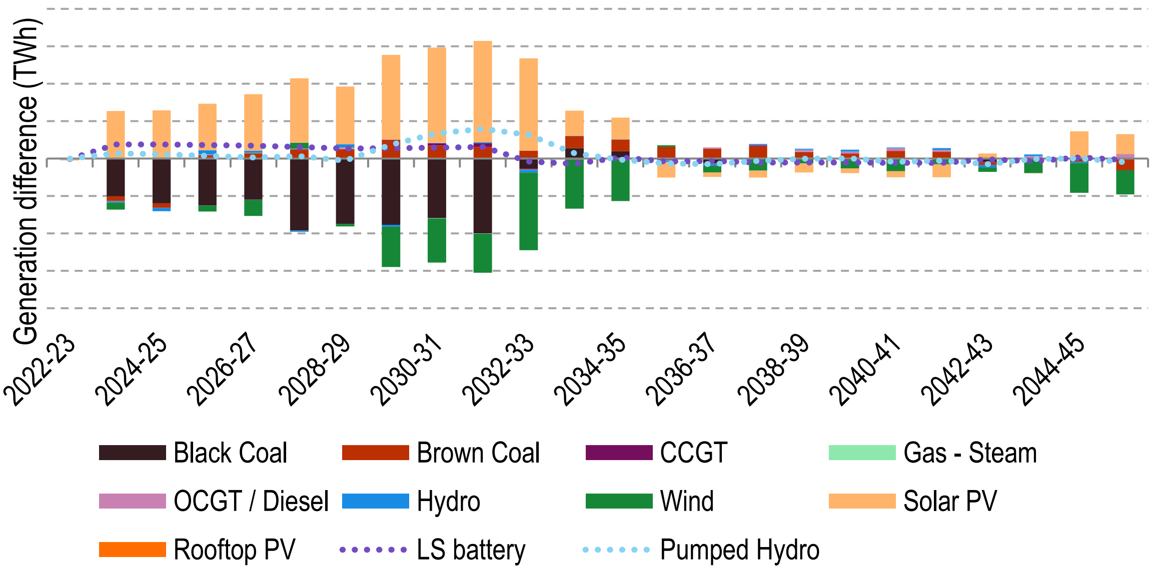


Figure 13: Difference in NEM generation forecast between Option 7A and Base Case in the Progressive Change scenario (including forecast generation of Option 7A)



The largest sources of forecast gross market benefits are reduced fuel and FOM costs and avoided and deferred capex. The timing and source of the benefits from Option 7A are attributable to the following:

- Forecast fuel and FOM cost savings occur between 2025-26 to 2031-32 and are attributed to reduced black coal generation and forecast earlier black coal withdrawals due to the presence of the Option 7A solar farm and batteries.
- The overall capex benefits are forecast to occur from the avoidance of building large-scale battery and solar within NSW. These benefits are mainly forecast between 2032-33 and 2033-34. In this case OCGT capacity is forecast to be brought forward which results in negative capex benefits from 2028-29 to 2030-31.
- Savings from reduced USE and DSP are forecast to accrue over the late 2020s to early 2030s.

8.1.3 Option 7B

The forecast cumulative gross market benefits for Option 7B in the Progressive Change scenario are shown in Figure 14. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 7B and the Base Case in this scenario are shown in Figure 15 and Figure 16.

Figure 14: Forecast cumulative gross market benefit for Option 7B under the Progressive Change scenario

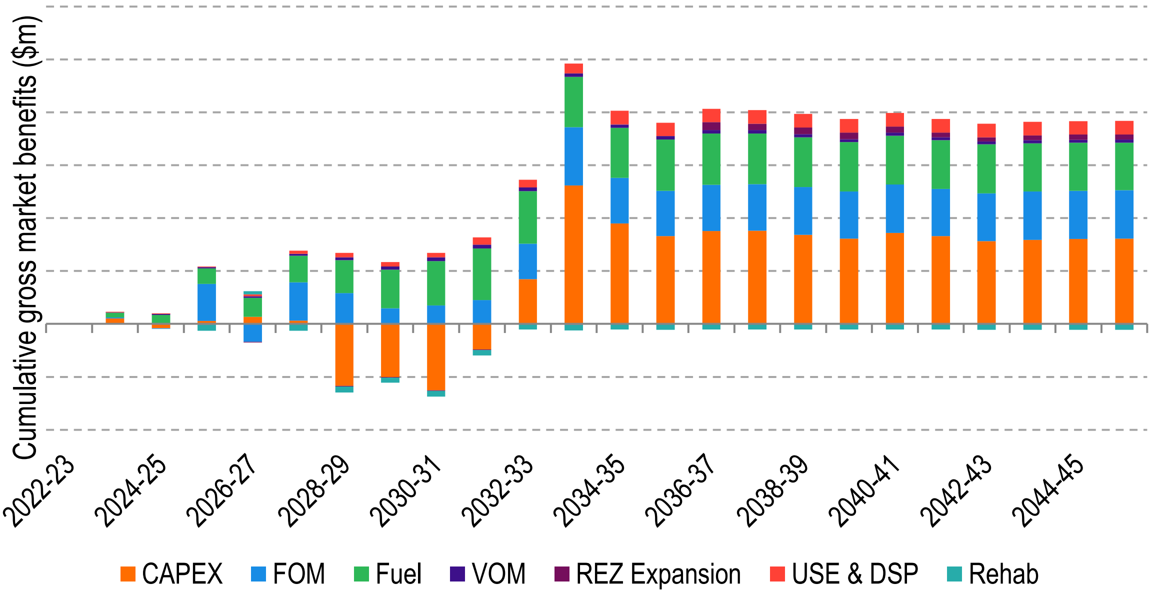


Figure 15: Difference in the NEM capacity forecast between Option 7B and Base Case in the Progressive Change scenario (including assumed capacity of Option 7B)

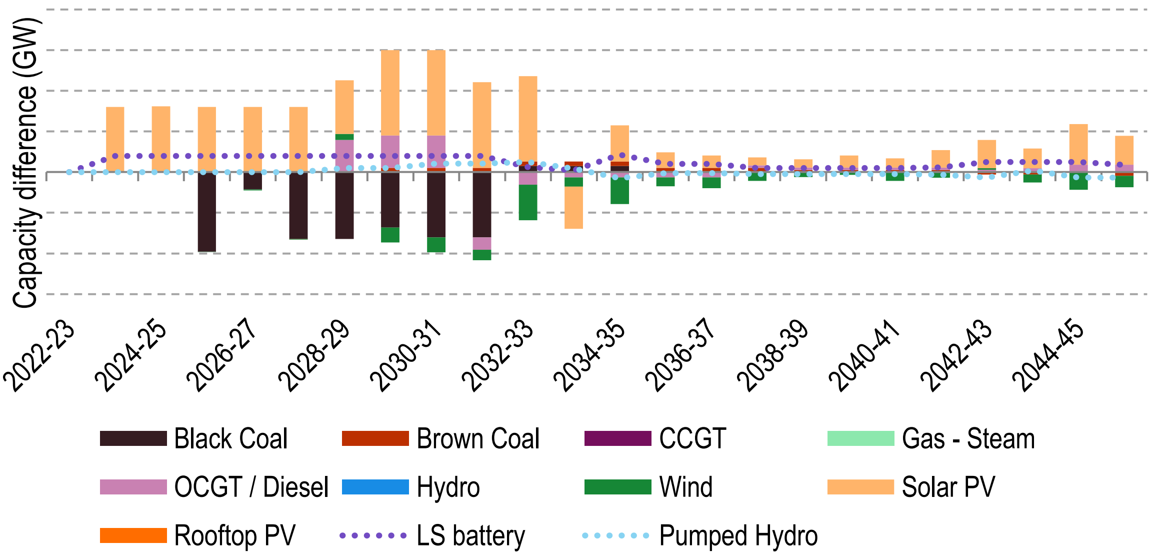
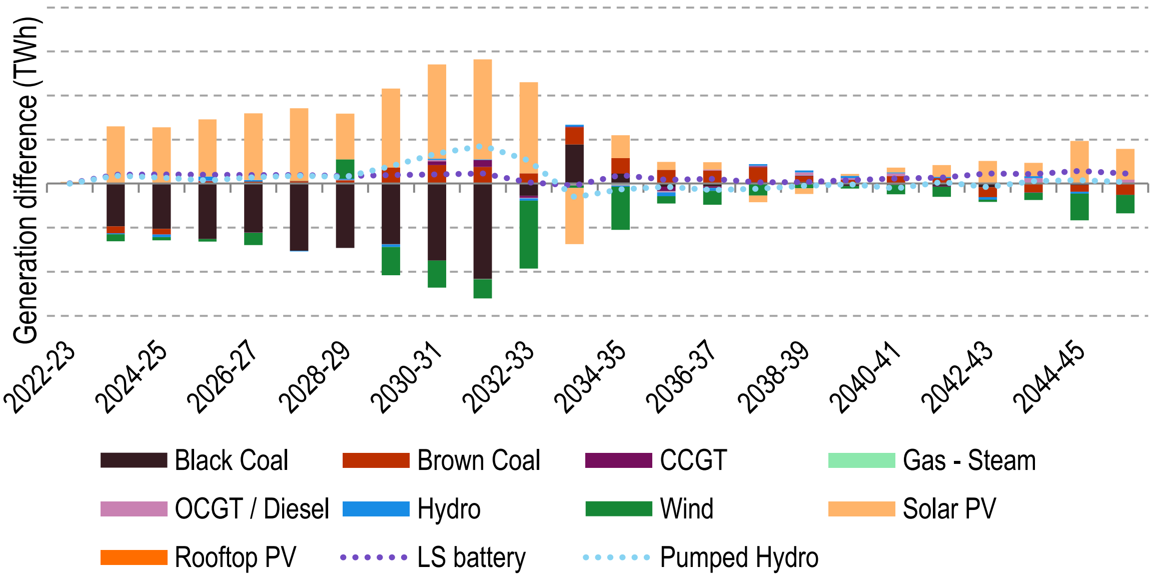


Figure 16: Difference in NEM generation forecast between Option 7B and Base Case in the Progressive Change scenario (including forecast generation of Option 7B)



As for the other options, fuel and FOM savings as well as avoided and deferred capex are the major source of forecast gross market benefits. The timing and sources of these benefits are attributable to the following:

- Throughout the 2020s there are forecast fuel and FOM savings as a result of a reduction in forecast black coal generation and earlier black coal withdrawals due to the presence of the Option 7B solar farm and large-scale batteries.
- Capex benefits are forecast to increase in 2032-33 from avoiding the build of solar and large-scale battery storage due to the earlier assumed build of the Option 7B solar farm and large-scale batteries. In this case OCGT capacity is forecast to be brought forward which results in negative capex benefits from 2028-29 to 2031-32.
- Savings from reduced USE and DSP are forecast to accrue over the late 2020s to early 2030s.

8.1.4 Option 7C

The forecast cumulative gross market benefits for Option 7C in the Progressive Change scenario are shown in Figure 17. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 7C and the Base Case in this scenario are shown in Figure 18 and Figure 19, respectively.

Figure 17: Forecast cumulative gross market benefit for Option 7C under the Progressive Change scenario

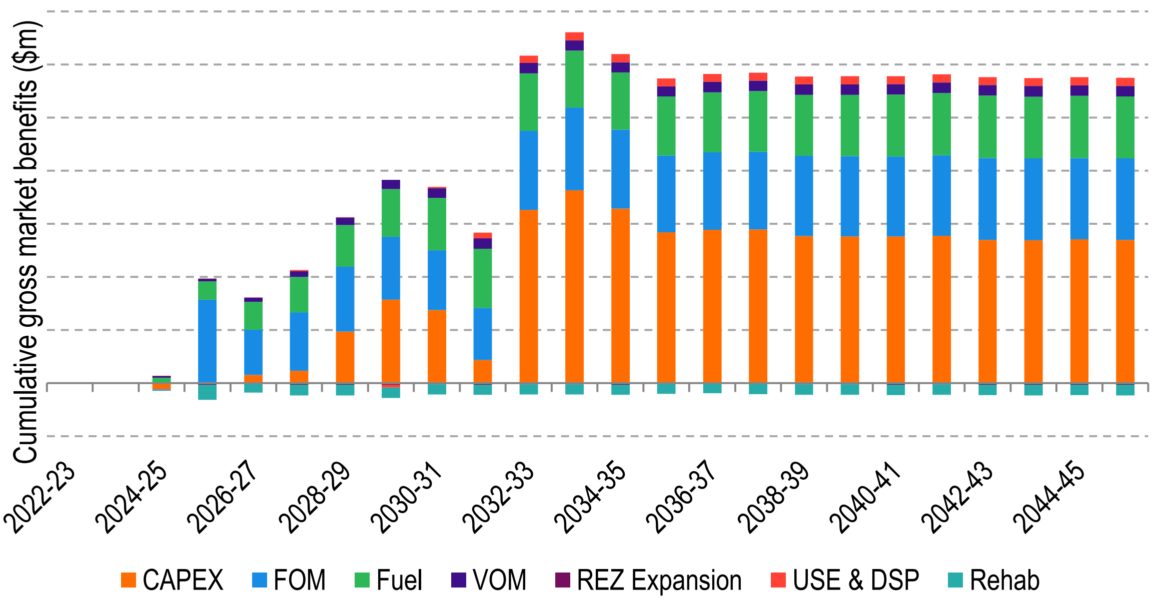


Figure 18: Difference in NEM capacity forecast between Option 7C and Base Case in the Progressive Change scenario (including assumed capacity of Option 7C)

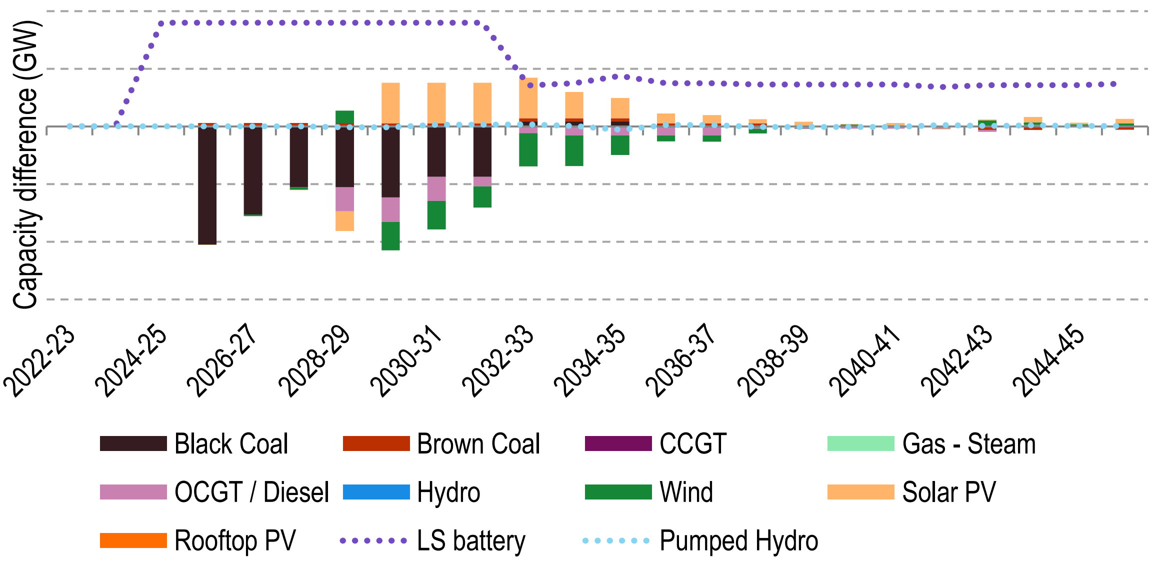
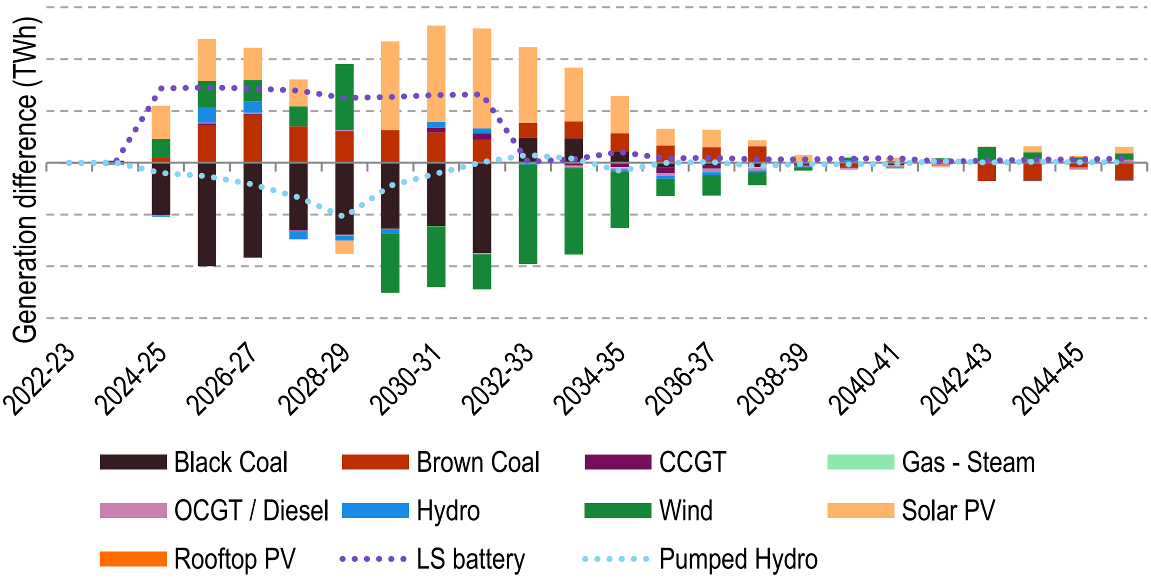


Figure 19: Difference in NEM generation forecast between Option 7C and Base Case in the Progressive Change scenario (including forecast generation of Option 7C)



As for the other options, fuel and FOM savings as well as avoided and deferred capex are the major sources of forecast gross market benefits. The timing and sources of these benefits are attributable to the following:

- Throughout the 2020s there are forecast fuel and FOM savings as a result of a reduction in forecast black coal generation and early black coal withdrawals as a result of the presence of the Option 7C large-scale batteries. The presence of the Option 7C batteries is forecast to unlock the build of more solar generation in the late 2020s, further offsetting black coal generation and capacity.

- Capex benefits are forecast to increase in 2032-33 from avoiding the build of large-scale battery storage due to the earlier assumed build of the Option 7C large-scale batteries. There is also an increase in capex benefits in 2028-29 from OCGT being deferred for three years.

8.1.5 Option 7D

The forecast cumulative gross market benefits for Option 7D in the Progressive Change scenario are shown in Figure 17. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 7D and the Base Case in this scenario are shown in Figure 18 and Figure 19, respectively.

Figure 20: Forecast cumulative gross market benefit for Option 7D under the Progressive Change scenario

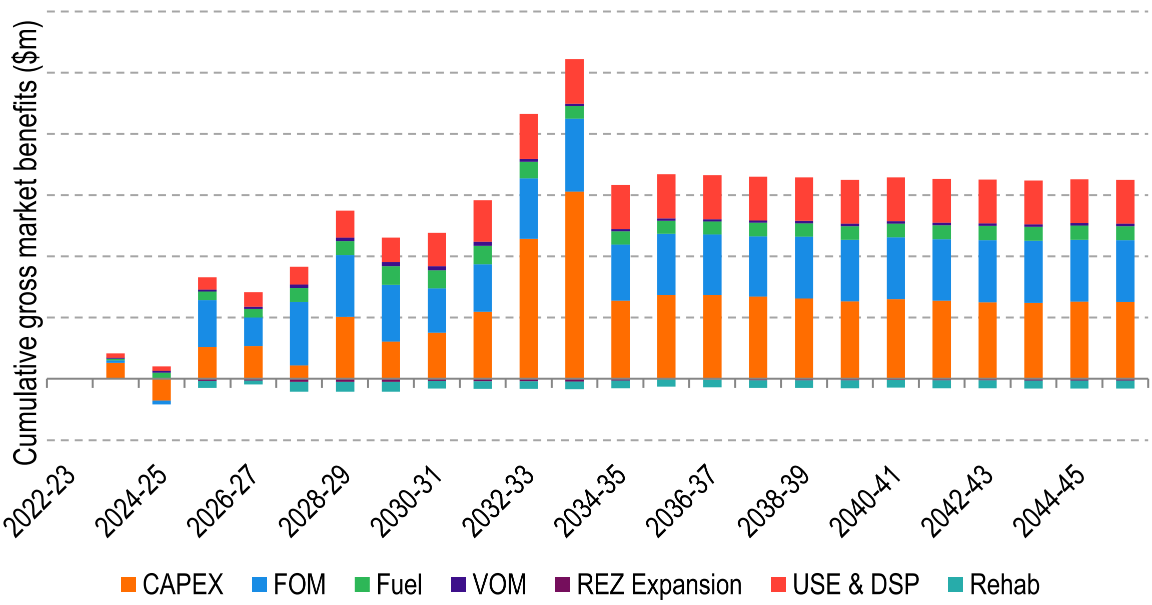


Figure 21: Difference in the NEM capacity forecast between Option 7D and Base Case in the Progressive Change scenario (including assumed capacity of Option 7D)

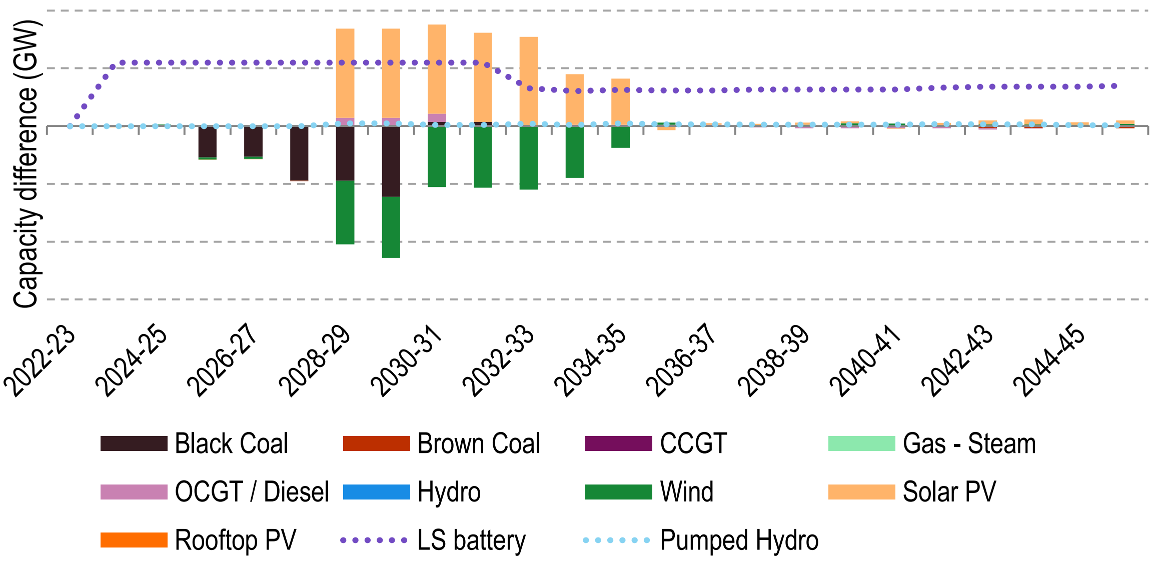
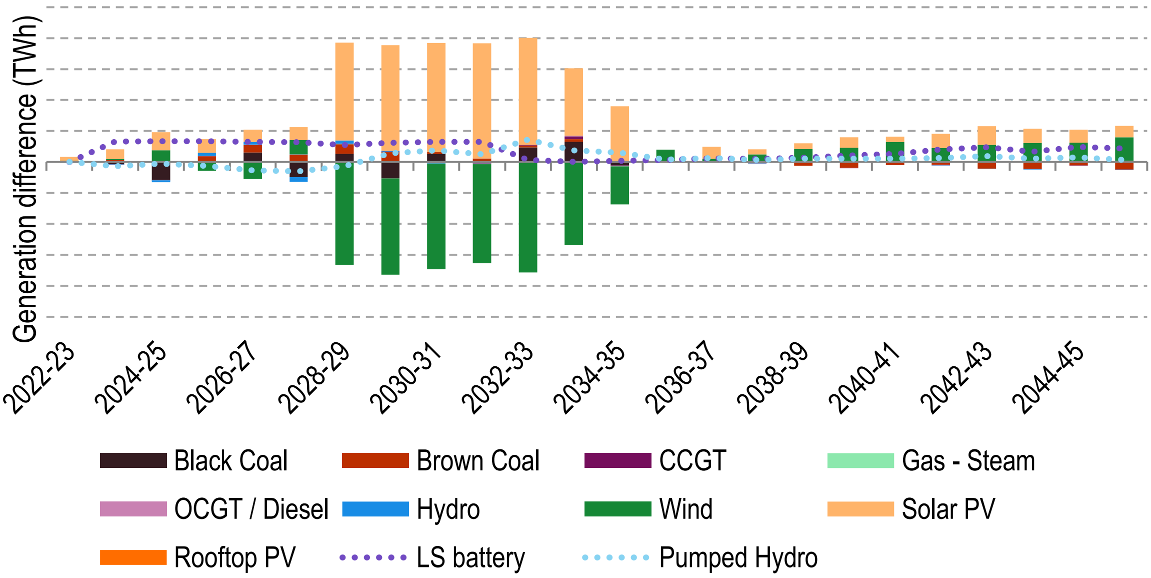


Figure 22: Difference in NEM generation forecast between Option 7D and Base Case in the Progressive Change scenario (including forecast generation of Option 7D)



This option is forecast to have similar market benefit outcomes to Option 5/6, and the key differences are in the timing of this option and also its energy arbitrage capability. FOM savings as well as avoided and deferred capex are the major source of forecast gross market benefits. The timing and sources of these benefits are attributable to the following:

- Throughout the 2020s there are forecast fuel and FOM savings as a result of a reduction in forecast black coal generation and early black coal withdrawals as a result of the presence of the Option 7D large-scale batteries. The presence of the Option 7D batteries unlocks the build of more solar generation in the late 2020s and early 2030s, further offsetting black coal generation and capacity.
- Capex benefits are forecast to increase in 2032-33 from avoiding the build of large-scale battery storage due to the earlier assumed build of the Option 7D large-scale batteries. There is also an increase in capex benefits in 2028-29 from OCGT being deferred for three years.
- Savings from reduced USE and DSP are forecast to accrue over the late 2020s to early 2030s.

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AC	Alternating Current
CAN	Canberra (NEM zone)
CAPEX	Capital Expenditure
CCGT	Combined-Cycle Gas Turbine
DCLF	DC Load Flow
DER	Distributed Energy Resources
DSP	Demand side participation
DUID	Dispatchable Unit Identifier
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LRET	Large-scale Renewable Energy Target
LS Battery	Large-Scale battery storage (as distinct from behind-the-meter battery storage)
MW	Megawatt
MWh	Megawatt-hour
NCEN	Central New South Wales (NEM zone)
NEM	National Electricity Market
NNS	Northern New South Wales (NEM zone)
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PADR	Project Assessment Draft Report
POE	Probability of Exceedence
PSCR	Project Specification Consultation Report
PSH	Pumped Storage Hydro
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector

Abbreviation	Meaning
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking
SRMC	Short-Run Marginal Cost
SWNSW	South West New South Wales (NEM zone)
SWVIC	South West Victoria (REZ)
TAS	Tasmania
TSIRP	Time-sequential integrated resource planner
TW	Terawatt
TWh	Terawatt-hour
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant

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