# Improving stability in south-western NSW

# PACR

Market modelling report
Forecasting gross market benefits

24 May 2022

Building a better working world

# Release Notice

Ernst & Young ("EY") 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 assess various options for improving stability in south-western New South Wales (SWNSW) Regulatory Investment Test for Transmission ("SWNSW RIT-T").

The results of EY's work are set out in this report ("Report"), including the assumptions and qualifications made in preparing the Report. The Report should be read in its entirety including this release notice, the applicable scope of the work and any limitations. 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.

EY has prepared the Report for the benefit of TransGrid and has considered only the interest of TransGrid. EY has not been engaged to act, and has not acted, as advisor to any other party. Accordingly, EY makes no representations as to the appropriateness, accuracy or completeness of the Report for any other party's purposes. Our work commenced on 19 January 2021 and was completed on 01 April 2022. Therefore, our Report does not take account of events or circumstances arising after 01 April 2022 and we have no responsibility to update the Report for such events or circumstances.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenario, and the key assumptions are described in the Report. These assumptions were selected by TransGrid after public consultation. The modelled scenario represents one possible future option 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.

EY's liability is limited by a scheme approved under Professional Standards Legislation.

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# 1. Executive summary

TransGrid has engaged EY to undertake market modelling of system costs and benefits of various network and non-network options related to "improving stability in south-west New South Wales (SWNSW)" for the Regulatory Investment Test for Transmission (RIT-T).

This Report forms a supplementary report to the Project Assessment Conclusion Report (PACR) prepared and published by TransGrid[1], 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 options for the Step Change, Progressive Change and Hydrogen Superpower scenarios from the 2022 Australian Energy Market Operator (AEMO) Draft Integrated System Plan (ISP)[2].

The following options have been considered in this modelling. Note that Option 1A and Option 1B are included in the PACR[1]. However, TransGrid requested EY to only model Option 1A (which is called Option 1 hereafter in this Report), given their similarities. The modelled options are:

- Option 1: a 330 kV line between Darlington Point and Dinawan (being a new substation as part of Project EnergyConnect (PEC)) to be commissioned from 1 December 2025.
- Option 2: a 330 kV line between Darlington Point and Wagga to be commissioned from 1 July 2026.
- Option 3: a static synchronous compensator (STATCOM) at Darlington Point to be commissioned from 1 December 2025.
- Option 4: Option 1 to be commissioned from 1 December 2025 with a battery near Darlington Point which provides network support from 1 January 2023 to 1 December 2025. TransGrid assumed that the battery has market arbitrage capability from its commissioning date.
- Option 5: a standalone battery to be commissioned from 1 December 2024.

The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[3]. To assess the potential least-cost solution, a Time Sequential Integrated Resource Planner (TSIRP) model is used that makes decisions for each hourly trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Stations and units are assumed to bid at their short-run marginal cost (SRMC), which is derived from their Variable Operation and Maintenance (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 un-planned outages), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, solar PV SAT, CCGT, OCGT[4], large-scale battery storage (LS Battery), pumped hydro and hydrogen turbine technology (only applied in the Hydrogen Superpower scenario).

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[1] TransGrid, *Improving stability in south-western NSW PACR*. Available at: https://www.transgrid.com.au/projects-innovation/improving-stability-in-south-west-nsw. Accessed 1 April 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 February 2022.
[3] AER, *RIT-T and RIT-D application guidelines 2020*. Available at: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision. Accessed March 2022.
[4] PV = photovoltaics, SAT = Single Axis Tracking, CCGT = Combined-Cycle Gas Turbine, OCGT = Open-Cycle Gas Turbine.

The hourly decisions take into account operational constraints that include:

- ► supply must equal demand in each region for all trading intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR)[5],
- ► minimum loads for coal generators,
- ► interconnector flow limits (between regions),
- ► intra-regional flow limits (between zones in NSW),
- ► line 63 stability constraint equation in SWNSW, called N^^N_NIL_2[6] (EY has used the pre-December 2021 constraint equation formulation based on TransGrid advice which does not include temporary impact of proponent funded Special Protection Scheme (SPS) on the constraint equation),
- ► maximum and minimum storage (conventional storage hydro, Pumped Storage Hydro (PSH) and large-scale battery storage) reservoir limits and cyclic efficiency,
- ► new entrant capacity build limits for wind and solar for each REZ where applicable, and PSH in each region,
- ► emission and carbon budget constraints, as defined in the ISP for the modelled scenarios,
- ► renewable energy targets where applicable by region or NEM-wide, and
- ► other constraints such as network thermal and stability constraints, as defined in the Report.

From the hourly time-sequential modelling the following costs were computed, 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.

TransGrid has requested to incorporate the most recent input and assumptions since the publication of the Draft 2022 ISP, as follows:

- ► Latest committed and anticipated generators from the Generation Information Page, published in February 2022[7].
- ► Recent announced closure dates for Eraring, Bayswater and Loy Yang coal fired generators[7].

For each simulation with a SWNSW option and in a matched no augmentation counterfactual (referred to as Base Case), we computed the sum of these cost components and compared the

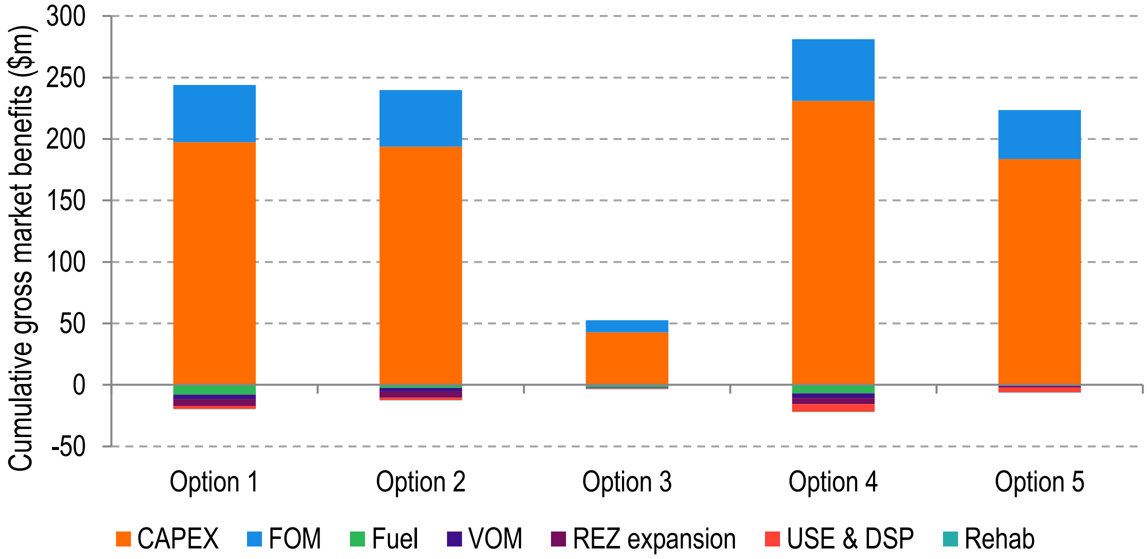
[5] Based on AER, December 2021, *Values of Customer Reliability Final report on VCR values.* Available at:https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/values-of-customer-reliability. Accessed March 2022.
[6] AEMO, *New system normal constraint equation in NSW for voltage collapse at Darlington Point*. Available at: https://aemo.com.au/Market-Notices?marketNoticeQuery=darlington+point&marketNoticeFacets=CONSTRAINTS%2CINTER-REGIONAL+TRANSFER%2CLOR2+FORECAST%2CPRICE+ADJUSTMENT%2CFORCED+MAJEURE%2CLOAD+SHED. Accessed February 2022.
[7] AEMO generation information and expected closure years, February version, available at: AEMO | Generation information, accessed 19 May 2022

difference between each option and the Base Case. The difference in present values of costs is the forecast gross market benefits[8] due to the presence of the corresponding option, as defined in the RIT-T. For all scenarios, benefits presented are discounted to June 2021 using a 5.5% real, pre-tax discount rate as selected by TransGrid.

The forecast gross market benefits capture the impact of 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 PSH and LS battery between each SWNSW option and the counterfactual Base Case.

The composition of the forecast market benefits for all modelled options and scenarios are shown in Figure 1 to Figure 3. The numbers in the chart represent the net present value difference of each option relative to the respective Base Case. 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 – Step Change




[8] 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.

Figure 2: Composition of forecast total gross market benefits for all options – Progressive Change

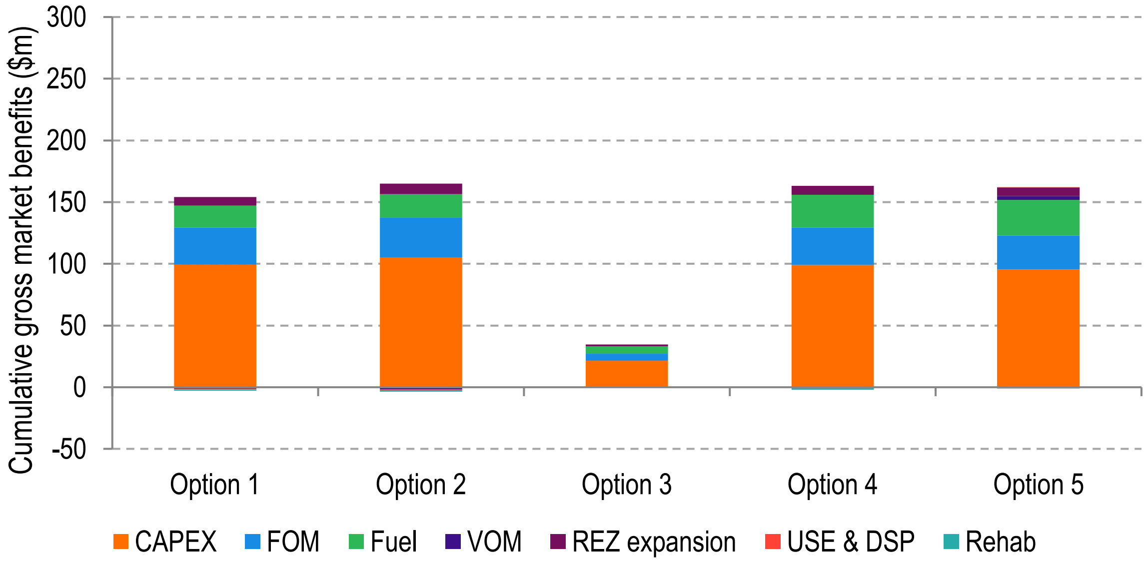
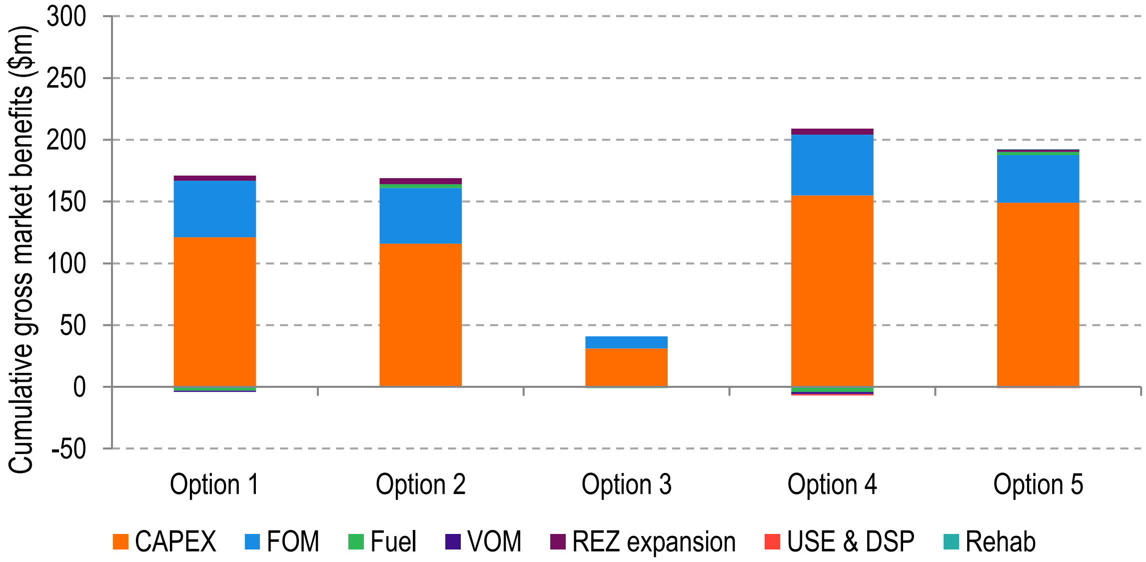



Figure 3: Composition of forecast total gross market benefits for all options – Hydrogen Superpower




From the figures, it is seen that all options are expected to achieve their highest gross market benefits in the Step Change scenario, and their lowest gross market benefits are forecast to be in the modelled Progressive Change scenario. The forecast gross market benefits for Option 4 are the highest amongst all options. On the contrary, Option 3 is forecast to have the lowest forecast gross market benefits with as low as approximately $35m in the Progressive Change scenario. TransGrid's preferred option, i.e. Option 4, has forecast gross market benefits of approximately $259m, $165m, and $203m in the Step Change, Progressive Change and Hydrogen Superpower scenarios, respectively.

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 nature of the proposed option, the level of the option's contribution to the Wagga – SWNSW transfer capacity limit, and whether the option revokes the line 63 stability constraint or reduces the binding frequency of this network limitation. The majority of the gross market benefits are expected to be attributed to capex and FOM savings across all the options in all modelled scenarios. 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 and/or delayed build of new capacity due to the network and non-network options being installed.

- FOM benefits are forecast to generally make up the second highest proportion of the total benefits across all options. Forecast FOM benefits are a result of the expectation that options reduce solar capacity build and enable earlier retirement of coal-fired generation in some cases.
- The gross market benefits are forecast to accumulate across the whole modelled period depending on the timing and scale of the option considered as well as timing of HumeLink and VNI West network augmentations in each scenario. The majority of benefits are forecast to accrue for the period of time between HumeLink commissioning until the commissioning of VNI West.

# 2. Introduction

TransGrid has engaged EY to undertake market modelling of system costs and benefits of various network and non-network options related to "improving stability in SWNSW" for the RIT-T.

This Report forms a supplementary report to the broader PACR 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 NEM associated with options using input assumptions generally derived from the 2022 Draft ISP[2]. TransGrid has requested to incorporate the most recent input and assumptions since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the Generation Information Page, published in February 2022[7].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[7].

The options were defined by TransGrid and are described in detail in the PACR. This is an independent study and the modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[3].

The descriptions of outcomes in this Report are focussed on identifying and explaining the key sources of forecast gross market benefits. The categories of gross market benefits modelled are changes in:

- 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,
- transmission expansion costs associated with 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 25-year modelling period from 2023-24 to 2047-48. 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 AEMO in the Draft 2022 ISP[2].

This modelling considers five network and non-network options to improve stability in SWNSW as followings:

- Option 1: a 330 kV line between Darlington Point and Dinawan (being a new substation as part of Project EnergyConnect) to be commissioned from 1 December 2025.
- Option 2: a 330 kV line between Darlington Point and Wagga to be commissioned from 1 July 2026.
- Option 3: a STATCOM at Darlington Point to be commissioned from 1 December 2025.

- Option 4: Option 1 to be commissioned from 1 December 2025 with a battery near Darlington Point which provides network support from 1 January 2023 to 1 December 2025. TransGrid assumed that the battery has market arbitrage capability from its commissioning date.
- Option 5: a standalone battery to be commissioned from 1 December 2024. TransGrid assumed that the battery has market arbitrage capability from its commissioning date.

A summary of the options is also provided in Table 1.

Table 1: Overview of the SWNSW options[1]

| Option | Commissioning date | Description |
|---|---|---|
| Option 1 | 1/12/2025 | A new 330 kV line between Darlington Point and Dinawan |
| Option 2 | 1/07/2026 | A new 330 kV line between Darlington Point and Wagga |
| Option 3 | 1/12/2025 | STATCOM |
| Option 4 | 1/07/2023 | Option 1 with a battery from 1 July 2023 which provides network support until Option 1 is commissioned |
| Option 5 | 1/12/2024 | A standalone battery |

The forecast gross market benefits of each option need to be compared to the cost of the relevant option 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"[3].

The Report is structured as follows:

- Section 3 describes assumptions and scenarios 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 SWNSW 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 the preferred option, while providing a summary of other options.

# 3. Scenario assumptions

## 3.1 Key assumptions for modelled Scenarios

The options proposed by TransGrid have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from the Integrated System Plan[2], as selected by TransGrid. These scenarios are summarised in Table 2 and are aligned with AEMO's Draft 2022 ISP[11].

TransGrid has requested to incorporate the most recent input and assumptions since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the Generation Information Page, published in February 2022[7].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[7].

Table 2: Overview of key input parameters in the Step Change, Progressive Change and Hydrogen Superpower scenarios

| Key drivers input parameter | Scenario | | |
|---|---|---|---|
| | Step Change | Progressive Change | Hydrogen Superpower |
| Underlying consumption | ESOO 2021[9] (ISP 2022) - Step Change | ESOO 2021[9] (ISP 2022) - Progressive Change | ESOO 2021[9] (ISP 2022) - Hydrogen Superpower |
| New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PSH, and large-scale batteries | 2021 Inputs and Assumptions Workbook[10] – Step Change | 2021 Inputs and Assumptions Workbook[10] - Progressive Change | 2021 Inputs and Assumptions Workbook[10] - Hydrogen Superpower |
| Retirements of coal-fired power stations | 2021 Inputs and Assumptions Workbook[10]– Step Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives | 2021 Inputs and Assumptions Workbook[10] - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030 | 2021 Inputs and Assumptions Workbook[10] – Hydrogen Superpower: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives |
| Gas fuel cost | 2021 Inputs and Assumptions Workbook[10] - Step Change: Lewis Grey Advisory 2020, Step Change | 2021 Inputs and Assumptions Workbook[10] - Progressive Change: Lewis Grey Advisory 2020, Central | 2021 Inputs and Assumptions Workbook[10] – Hydrogen Superpower: Lewis Grey Advisory 2020, Step Change |
| Coal fuel cost | 2021 Inputs and Assumptions Workbook[10] - Step Change: Wood Mackenzie, Step Change | 2021 Inputs and Assumptions Workbook[10] - Progressive Change: Wood Mackenzie, Central | 2021 Inputs and Assumptions Workbook[10] – Hydrogen Superpower: Wood Mackenzie, Step Change |
| NEM carbon budget to achieve 2050 emissions levels | 2021 Inputs and Assumptions Workbook[10] - Step Change: 891 Mt $CO_2$-e 2023-24 to 2050-51 | 2021 Inputs and Assumptions Workbook[10] - Progressive Change: 932 Mt $CO_2$-e 2030-31 to 2050-51 | 2021 Inputs and Assumptions Workbook[10] – Hydrogen Superpower: 453 Mt $CO_2$-e 2023-24 to 2050-51 |
| Victoria Renewable Energy Target (VRET) | 40 % renewable energy by 2025 and 50 % renewable energy by 2030[10]<br>VRET 2 including 600 MW of renewable capacity by 2025[10] | | |

[9] ESOO 2021 and the April 2022 update are in line with underlying consumption used in this modelling: AEMO | NEM Electricity Statement of Opportunities (ESOO)
[10] https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en

| Key drivers input parameter | Scenario | | |
|---|---|---|---|
| | Step Change | Progressive Change | Hydrogen Superpower |
| Queensland Renewable Energy Target (QRET) | 50 % by 2030[10] | | |
| Tasmanian Renewable Energy Target (TRET) | 2021 Inputs and Assumptions Workbook[10]: 200 % Renewable generation by 2040 | | |
| NSW Electricity Infrastructure Roadmap | 2021 Inputs and Assumptions Workbook[10]: 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 of long duration storage (8 hrs or more) by 2029-30 | | |
| EnergyConnect | Draft 2022 Integrated System Plan[11] - EnergyConnect commissioned by July 2025 | | |
| Western Victoria Transmission Network Project | Draft 2022 Integrated System Plan[11] - Western Victoria upgrade commissioned by November 2025 | | |
| HumeLink | Draft 2022 Integrated System Plan[11] - Step Change: HumeLink commissioned by July 2028 | Draft 2022 Integrated System Plan[11] - Progressive Change: HumeLink commissioned by July 2035 | Draft 2022 Integrated System Plan[11] - Hydrogen Superpower: HumeLink commissioned by July 2027 |
| Marinus Link | Draft 2022 Integrated System Plan[11] -1st cable commissioned by July 2029 and 2nd cable by July 2031 | | |
| Victoria to NSW Interconnector Upgrade (VNI Minor) | Draft 2022 Integrated System Plan[11] - VNI Minor commissioned by December 2022 | | |
| NSW to QLD Interconnector Upgrade (QNI Minor) | Draft 2022 Integrated System Plan[11] - QNI minor commissioned by July 2022 | | |
| QNI Connect | Draft 2022 Integrated System Plan[11] - Step Change: QNI Connect commissioned by July 2032 | Draft 2022 Integrated System Plan[11] - Progressive Change: QNI Connect commissioned by July 2036 | Draft 2022 Integrated System Plan[11] - Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030 |
| VNI West | Draft 2022 Integrated System Plan[11] - Progressive Change: VNI West commissioned by July 2031 | Draft 2022 Integrated System Plan[11] - Progressive Change: VNI West commissioned by July 2038 | Draft 2022 Integrated System Plan[11] - Hydrogen Superpower: VNI West commissioned by July 2030 |
| Victorian SIPS | Draft 2022 Integrated System Plan[11] - 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[11] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035 | Draft 2022 Integrated System Plan[11] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038 | Draft 2022 Integrated System Plan[11] - Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031, and stage 3 by July 2042 |
| Snowy 2.0 | 2021 Inputs and Assumptions Workbook[10] - Snowy 2.0 is commissioned by December 2026 | | |

[11] https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation

# 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 25 years from 2023-24 to 2047-48. The modelling methodology follows the RIT-T guidelines published by the Australian Energy Regulator[3].

Based on the full set of input assumptions, the 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:

- capex,
- FOM,
- VOM,
- fuel usage,
- DSP and 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[12] trading interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators 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, CCGT, OCGT, large-scale storage and PSH[4]. Hydrogen Turbine technology is only modelled as available in the Hydrogen Superpower scenario. Nuclear and other technically feasible technology options were screened 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 VCR[5],
- 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),
- 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,

[12] 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.

- emission and carbon budget constraints, as defined for each 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.

Where included as a factor in scenario assumptions, 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[11]. 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 Virtual Power Plants (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 or liquid fuel generators. Conversely, at times of low supply cost, e.g. when there is a prevailing surplus of renewable generation 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[13]) 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.

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

[13] 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.

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[14].

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.

## 4.4 Cost-benefit analysis

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

- 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 scenario a matched no 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 option, as defined in the RIT-T.

Each component of gross market benefits is computed annually over the 25-year modelling period. In this Report, we summarise the benefit and cost streams using a single value computed as the Net Present Value (NPV)[15], discounted to June 2021 at a 5.5 % real, pre-tax discount rate as selected by TransGrid.

The forecast gross market benefits of each 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

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

[15] 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.

RIT-T as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[3], as identified in the PACR[1].

# 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[16], as listed in Table 3. In TransGrid's view, this enables better representation of intra-regional network limitations and transmission losses.

Table 3: 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 |

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 4, as defined by TransGrid.

Table 4: Key cut-set definitions

| Border | Lines |
|---|---|
| NNS-NCEN | Line 88 Muswellbrook - Tamworth<br>Line 84 Liddell - Tamworth<br>Line 96T Hawks Nest - Taree<br>Line 9C8 Stroud - Brandy Hill |

[16] 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.

| Border | Lines |
|---|---|
| NCEN-CAN | Line 61 Gullen Range – Bannaby<br>Line 3W Kangaroo Valley – Capital<br>Line 4/5 Yass – Marulan<br>Line 973 Yass – Cowra<br>Line 999 Yass – Cowra<br>Line 98J Shoalhaven – Evans Lane<br>Line 28P West Tomerong – Evans Lane and new HumeLink lines for each option |
| CAN/YASS-Bannaby | Line 61 Gullen Range – Bannaby<br>Line 3W Kangaroo Valley – Capital<br>Lines 4 &5 Yass – Marulan<br>and new HumeLink lines from Maragle/Wagga to Bannaby for each option |
| Snowy cut-set | Line 01 Upper Tumut to Canberra<br>Line 2 Upper Tumut to Yass<br>Line 07 Lower Tumut to Canberra<br>Line 3 Lower Tumut to Yass |
| CAN (WAG)-SWNSW | Line 63 Wagga - Darlington Pt<br>Line 994 Yanco - Wagga<br>Line 99F Yanco - Uranquinty<br>Line 99A Finley - Uranquinty<br>Line 997/1 Corowa – Albury<br>New 330 kV double circuit from Wagga – Dinawan (after assumed commissioning of EnergyConnect)<br>New 500 kV double circuit from Wagga – Dinawan (after assumed commissioning of VNI West) |
| VIC-CAN | Line 060 Jindera – Wodonga<br>Line 65 Upper Tumut – Murray<br>Line 66 Lower Tumut - Murray |
| VIC-SWNSW | Line 0X1 Red Cliffs – Buronga<br>New Red Cliffs – Buronga (after assumed commissioning of EnergyConnect)<br>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 5 summarises the key cut-set limits in the Canberra zone and from Canberra to NCEN, as defined by TransGrid.

Table 5: 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 |
| CAN-NCEN cut-set | 4,500 |
| Bannaby-NCEN | 4,500 |

## 5.2 SWNSW constraints

The system normal constraint equation in NSW for voltage collapse at Darlington Point is modelled for the Base Case and SWNSW RIT-T options. TransGrid advised that Option 1 and Option 2 are assumed to fully resolve this constraint, while Option 3 is assumed to alleviate this constraint by 30 MW. Option 4 is also assumed to alleviate this constraint after the commissioning of the proposed battery on 1 July 2023 by 120 MW. Option 5 is also assumed to alleviate the constraint by 120 MW from its commissioning date.

In addition, TransGrid has defined the transfer limits from SWNSW to Wagga for the Base Case and augmentation options, as shown in Table 6.

Table 6: Transfer limits of SWNSW to Wagga

<table>
<tr><th rowspan="3">Case</th><th colspan="10">SWNSW-WAGGA<br>Limit (MW)</th></tr>
<tr><th colspan="2">Initial</th><th colspan="2">Post option</th><th colspan="2">Post PEC</th><th colspan="2">Post HumeLink</th><th colspan="2">Post VNI West</th></tr>
<tr><th>Westerly</th><th>Easterly</th><th>Westerly</th><th>Easterly</th><th>Westerly</th><th>Easterly</th><th>Westerly</th><th>Easterly</th><th>Westerly</th><th>Easterly</th></tr>
<tr><td>Base Case</td><td rowspan="6">500</td><td rowspan="6">300</td><td rowspan="4">-</td><td rowspan="4">-</td><td rowspan="6">1300</td><td rowspan="6">1100</td><td>2100</td><td>1900</td><td rowspan="6">2700</td><td rowspan="6">3000</td></tr>
<tr><td>Option 1<br>(1/12/2025)</td><td>2500</td><td>2500</td></tr>
<tr><td>Option 2<br>(1/7/2026)</td><td>2500</td><td>2500</td></tr>
<tr><td>Option 3<br>(1/12/2025)</td><td>2100</td><td>1930</td></tr>
<tr><td>Option 4<br>(1/7/2023<br>1/12/2025)</td><td>500</td><td>420</td><td>2500</td><td>2500</td></tr>
<tr><td>Option 5<br>(1/12/2024)</td><td>500</td><td>420</td><td>2100</td><td>2020</td></tr>
</table>

## 5.3 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 the eastern flow path instead of VIC-NSW,
- when future upgrades involving conductor changes are modelled e.g. VNI West, QNI and Marinus Link.

The network snapshots to compute the loss equations were provided by TransGrid.

## 5.4 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 AEMO Draft 2022 ISP[2,17])

| Interconnector (From node – To node) | Import[18] notional limit | Export[19] notional limit |
|---|---|---|
| QNI[20] | 1,205 MW peak demand<br>1,165 MW summer<br>1,170 MW winter | 685 MW peak demand<br>745 MW summer/winter |
| QNI Connect 1[21] | 2,285 MW peak demand<br>2,245 MW summer<br>2,250 MW winter | 1,595 MW peak demand<br>1,655 MW summer/winter |
| QNI Connect 2[2121] | 3.085 MW peak demand<br>3,045 MW summer<br>3,050 MW winter | 2,145 MW peak demand<br>2,205 MW summer/winter |
| Terranora (NNS-SQ) | 130 MW peak demand<br>150 MW summer<br>200 MW winter | 0 MW peak demand<br>50 MW summer/winter |
| VIC-NSW | 400 MW pre VNI West<br>2,050 MW peak demand post SIPS (ends March 2032)<br>250 MW post SIPS and pre VNI West<br>2,200 MW post VNI West | 870 MW peak demand pre VNI West<br>1,000 MW summer/winter pre VNI West<br>2,800 MW peak demand post VNI West<br>2,930 MW summer/winter post VNI West |
| EnergyConnect (SWNSW-SA) | 800 MW | 800 MW |
| Heywood (VIC-SA) | 650 MW (before EnergyConnect)<br>750 MW (after EnergyConnect) | 650 MW (before EnergyConnect)<br>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 stage and<br>1,500 MW after the second stage | 750 MW for the first leg and<br>1,500 MW after the second leg |

[17] https://aemo.com.au/-/media/files/major-publications/isp/2021/2021-inputs-and-assumptions-workbook.xlsx?la=en
[18] 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 and EnergyConnect implies eastward flow.
[19] 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 and EnergyConnect implies westward flow.
[20] Flow on QNI may be limited due to additional constraints.
[21] https://aemo.com.au/-/media/files/major-publications/isp/2022/appendix-5-network-investments.pdf?la=en

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 |

## 5.5 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 4.
- 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 4: Sequence of demand reference years applied to forecast

| Modelled year | Reference year | Modelled year | Reference year |
|---|---|---|---|
| 2023-24 | 2014-15 | 2034-35 | 2016-17 |
| 2024-25 | 2015-16 | 2035-36 | 2017-18 |
| 2025-26 | 2016-17 | 2036-37 | 2018-19 |
| 2026-27 | 2017-18 | ... | ... |
| 2027-28 | 2018-19 | 2041-42 | 2014-15 |
| 2028-29 | 2010-11 | 2042-43 | 2015-16 |
| 2029-30 | 2011-12 | 2043-44 | 2016-17 |
| 2030-31 | 2012-13 | 2044-45 | 2017-18 |
| 2031-32 | 2013-14 | 2045-46 | 2018-19 |
| 2032-33 | 2014-15 | 2046-47 | 2010-11 |
| 2033-34 | 2015-16 | 2047-48 | 2011-12 |

This method ensures the timing of high and low demands across regions reflects historical patterns, while accounting for projected changes in distributed 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 distributed 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 distributed PV availability.

TransGrid selected demand forecasts from the ESOO 2021[9], which are used as inputs to the modelling. Figure 5 and Figure 6 show the NEM operational energy and distributed PV for the modelled scenarios.

Figure 5: Annual operational demand in the modelled scenarios for the NEM[9]

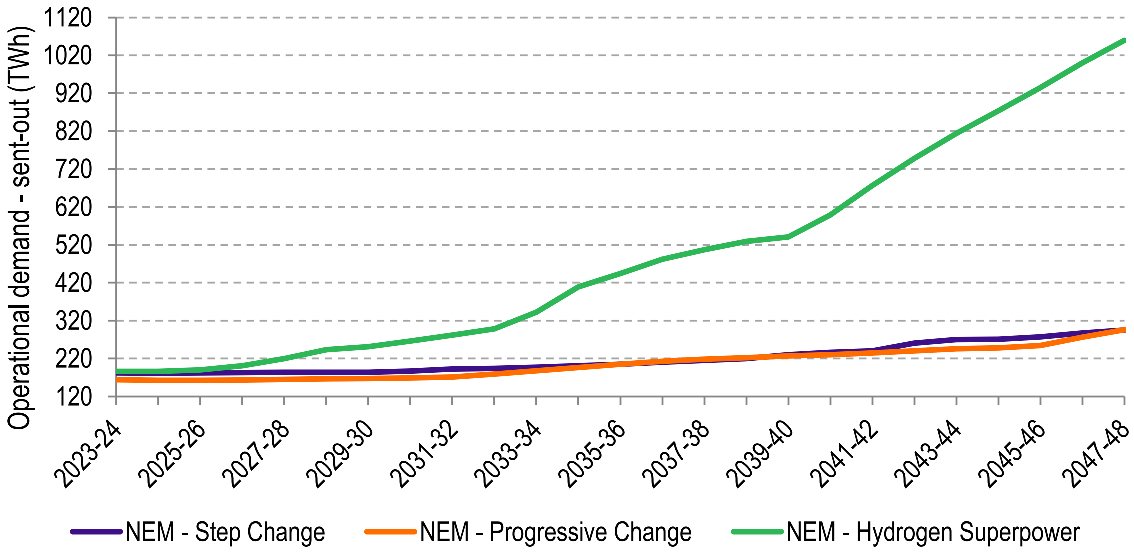
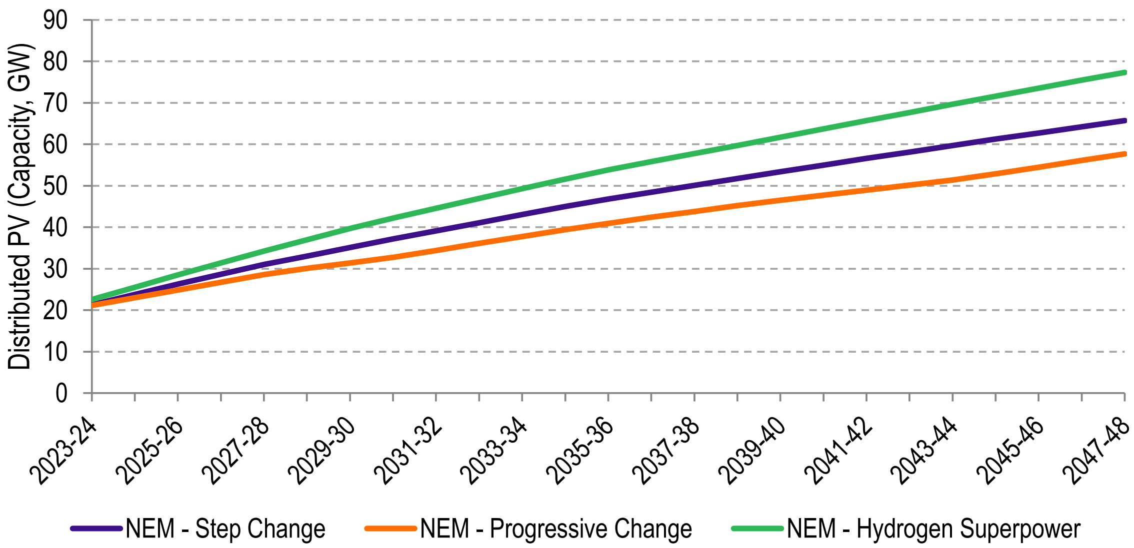



Figure 6: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[9]



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.

# 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 option. The source of this list is based on the AEMO 2021 ISP Inputs and Assumptions workbook[10], existing, committed and anticipated projects as well as batteries are used[7].

Existing and new wind and solar projects are modelled based on nine years of historical weather data[22]. 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 | Specific long-term target based on nine-year average in AEMO ESOO 2019 traces[23] 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 | Reference year specific targets based on capacity factor of nearest REZ, medium quality tranche in AEMO's 2021 Inputs and Assumptions workbook[2]. | |
| | Generic REZ new entrants | Reference year specific 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 | Reference year specific targets based on capacity factor of nearest REZ, in AEMO's 2021 ISP Inputs and Assumptions workbook[2]. | |
| | Generic REZ new entrant | Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[2]. | |
| 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

[22] 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 February 2022.
[23] 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 February 2022.

occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 4.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[24] 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 2019 ESOO[9] and draft 2021 ISP inputs and assumptions[10] 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 target AEMO's capacity factor 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 eleven 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 Orana | 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 % |

[24] 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 February 2022.

| Region | REZ | Wind | | Solar SAT |
|---|---|---|---|---|
| | | High quality | Medium quality | |
| | Western Victoria | 42 % | 37 % | 23 % |
| | South West Victoria | 41 % | 39 % | Tech not available |
| | Gippsland[25] | 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[26] | 51 % | 46 % | 19 % |
| | Central Highlands | 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.

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

## 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 on 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 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

Technical generator parameters applied are as detailed in the AEMO 2021 Inputs and Assumptions workbook[10], 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.

## 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 six pond model, with additional information sourced from TasNetwork's Input assumptions and scenario workbook for Project Marinus PACR[27].

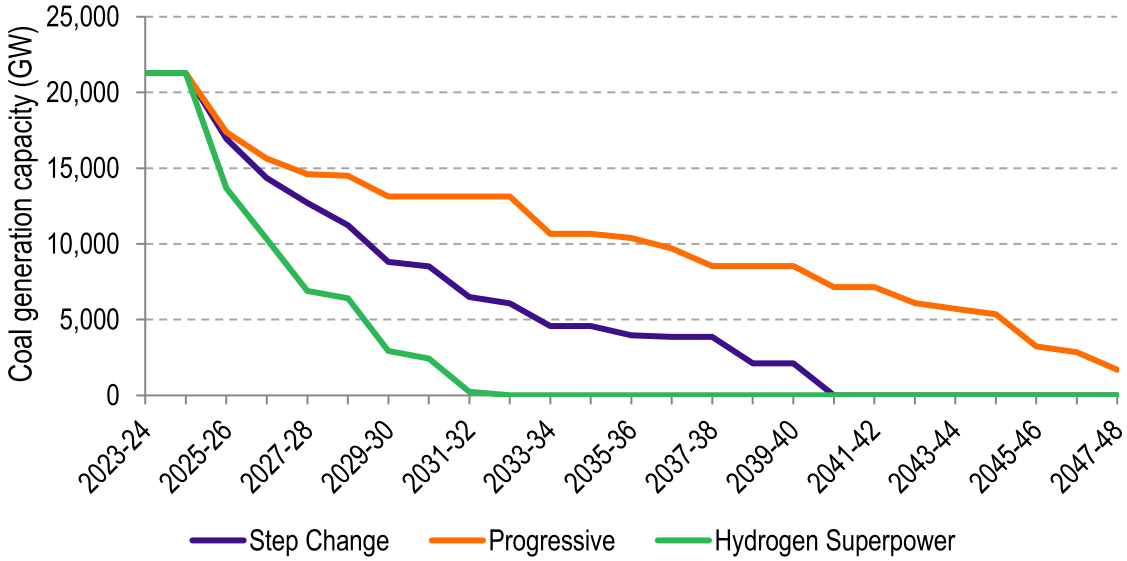
[27] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR*. Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 20 April 2022

# 7. NEM outlook in the Base Case without options

To understand the forecast benefits of the options, it is useful to examine the differences in the expected capacity and generation outlooks in the modelled scenarios, 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 coal generator retirements are determined on an economic or end of life 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 across all scenarios as an output of the modelling is illustrated in Figure 7.

Figure 7: Forecast coal capacity in the NEM by year across all scenarios in the Base Case




The pace of transition is determined by a combination of market forces, federal and state government policies[2] and timing for end of life of existing assets in a system developed and dispatched at least cost. This includes the corresponding demand outlook and capital cost projections, carbon budget constraint, and state-based policy initiatives such as TRET, VRET, QRET and the NSW Electricity Infrastructure Roadmap. The model forecasts the entire coal capacity to retire by early 2030s in the Hydrogen Superpower scenario, while this is the late 2030s for the Step Change scenario and in the Progressive Change scenario, coal is forecast to remain until the end of the modelling period.

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 8 and the corresponding generation mix in Figure 9. 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 8: NEM capacity mix forecast for the Step Change scenario in the Base Case

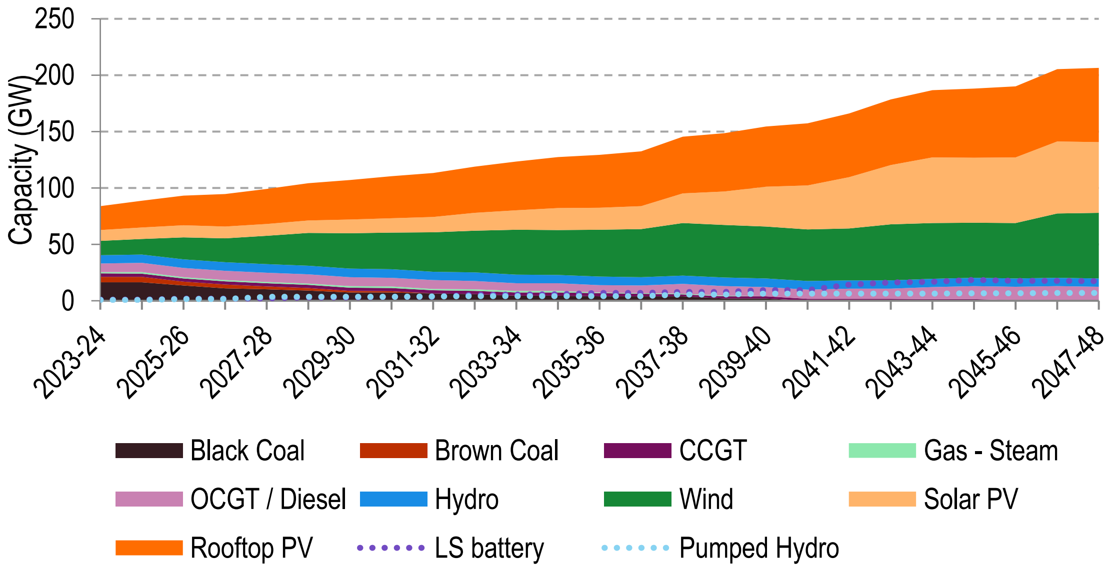
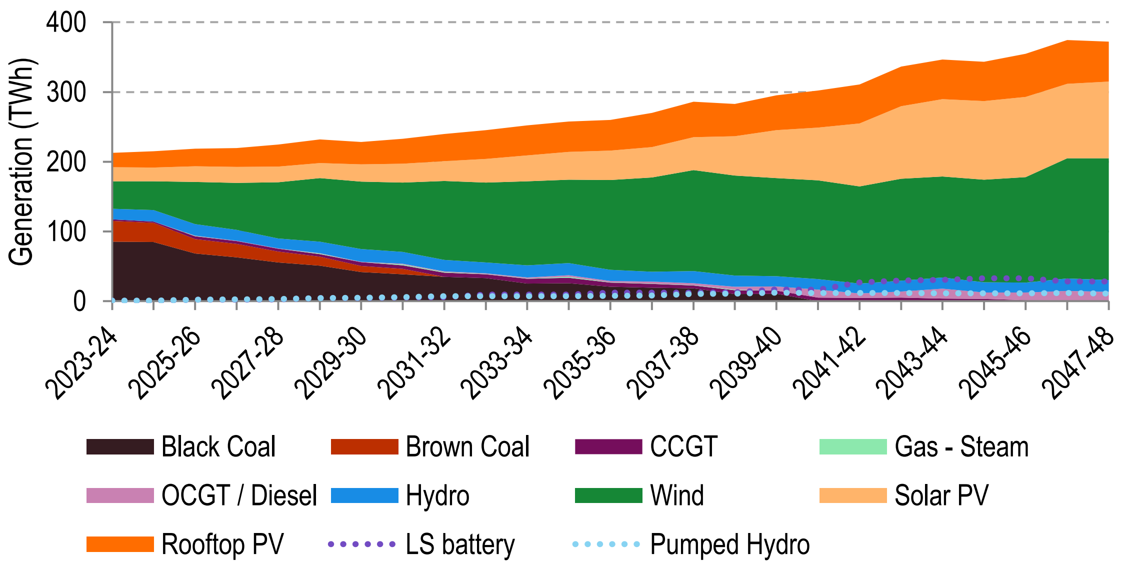



Figure 9: NEM generation mix forecast for the Step Change scenario in the Base Case




Up to 2030, new wind and solar build is largely driven by the assumed state-based renewable energy targets. The forecast increase in renewable capacity leads to some earlier coal generation retirements in Queensland and NSW. To replace the retiring capacity, LS battery capacity is forecast to start to increase from late 2020s, then PSH and wind capacity increases from mid-2030s. Solar PV 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 230 GW total capacity by 2047-48 (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 coincides with coal-fired generation retirements.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 10 and Figure 12 show the differences in the NEM capacity development of other scenarios relative to the Step Change scenario, while Figure 11 and Figure 13 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario, and both capacity and generation differences for each scenario show similar trends. As the figures show, Progressive Change scenario retains higher coal generation and less wind and solar generation compared to the Step Change scenario due to different assumptions such as the carbon budget, demand forecast and underlying input data. The Hydrogen Superpower scenario has higher wind and solar capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario.

Figure 10 Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case (excluding rooftop PV)

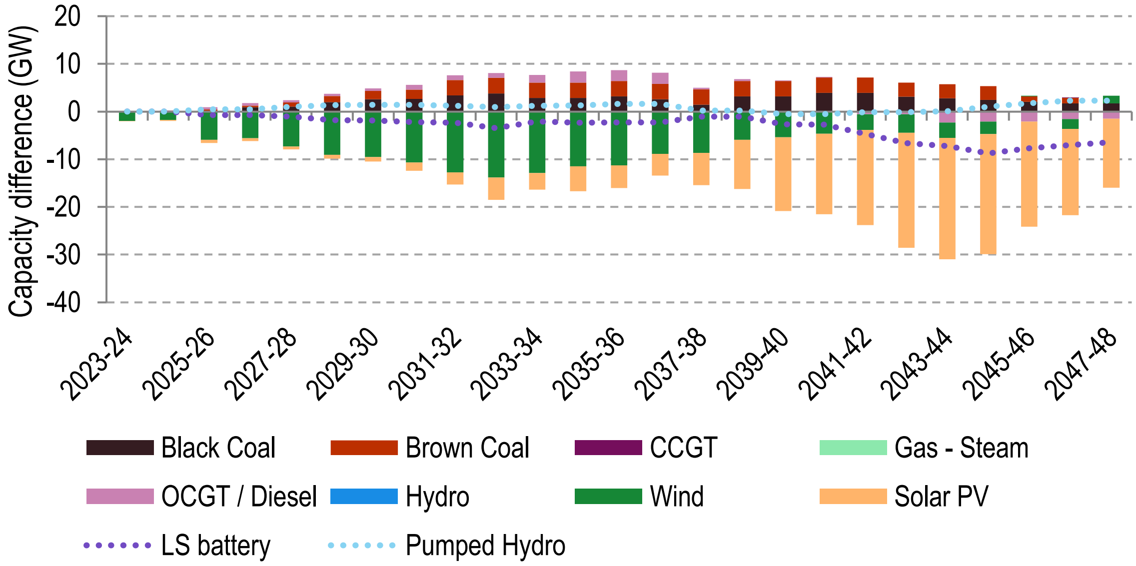



Figure 11 Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios in the Base case (excluding rooftop PV)

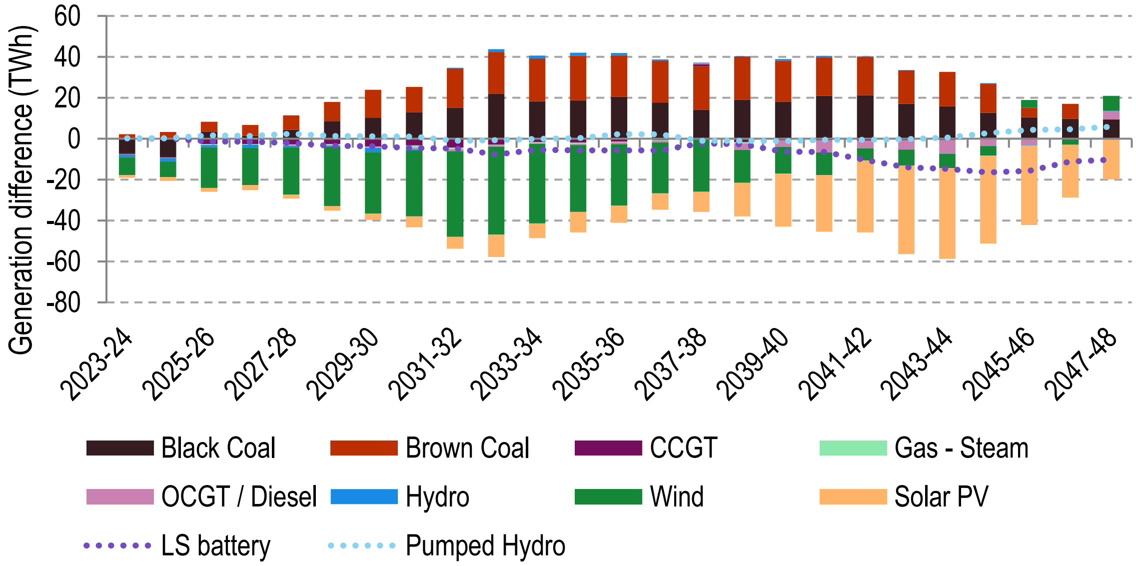


Figure 12 Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding rooftop PV)

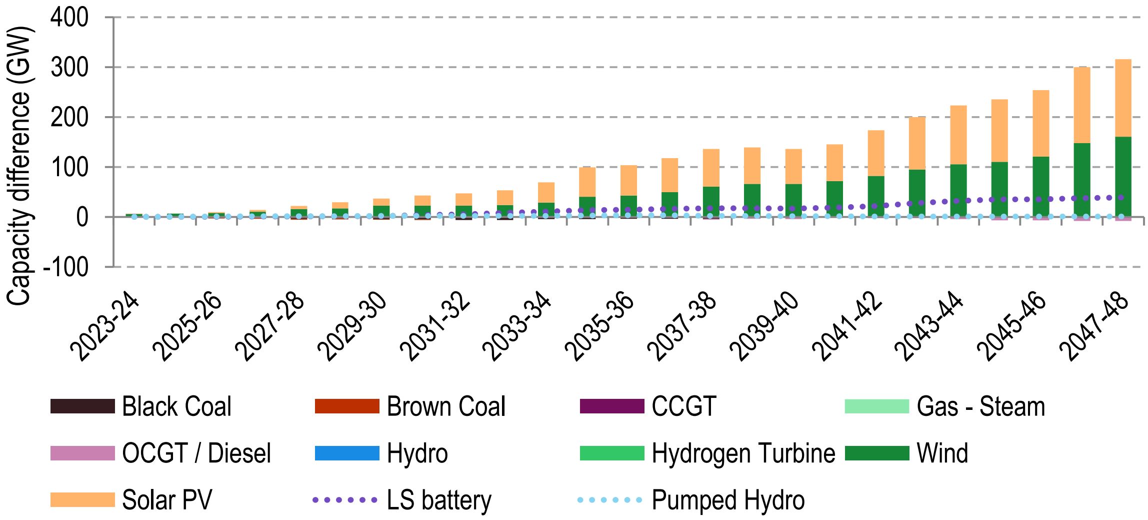
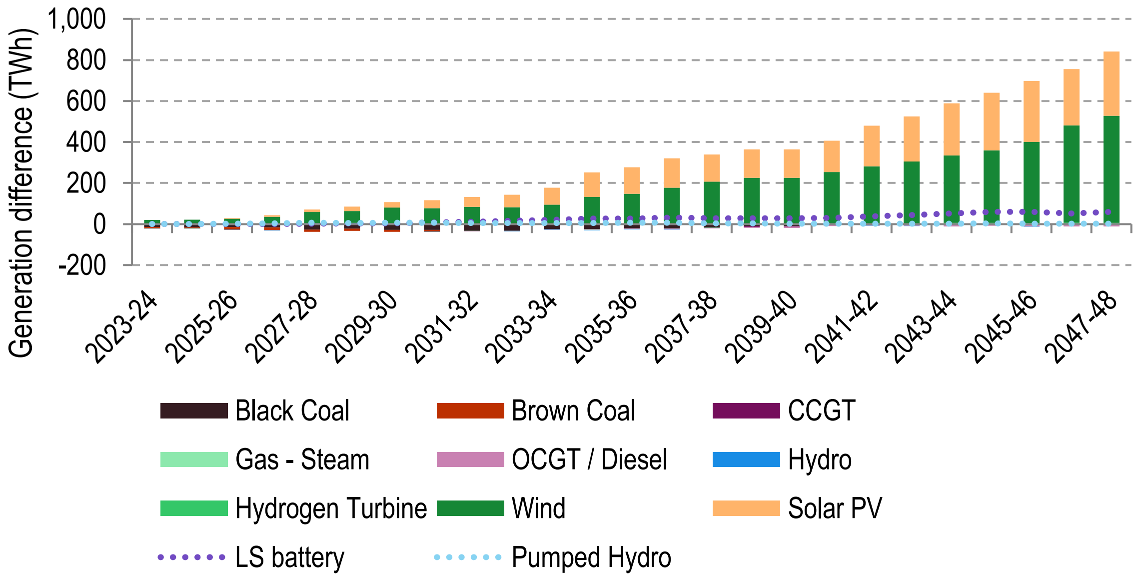



Figure 13 Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding rooftop PV)



# 8. Forecast gross market benefit outcomes

## 8.1 Summary of forecast gross market benefits

Table 11 shows the forecast gross market benefits over the modelled 25-year horizon for all options across all scenarios. TransGrid has concluded that Option 4 is the preferred option based on the forecast net benefits after incorporating forecast gross market benefits and assumed development costs of the options[1]. Option 1 is expected to have the second highest forecast net benefits on a weighted basis, whereas the net benefits of Option 5 are forecast to be the lowest.

Table 11: Summary of forecast gross market benefits, millions real June 2021 dollars discounted to June 2021 dollars

| Option | Description | Timing | Potential gross market benefits ($m) | | |
|---|---|---|---|---|---|
| | | | Step Change | Progressive Change | Hydrogen Superpower |
| Option 1 | A new 330 kV line between Darlington Point and Dinawan | 1/12/2025 | 224 | 155 | 167 |
| Option 2 | A new 330 kV line between Darlington Point and Wagga | 1/7/2026 | 227 | 165 | 168 |
| Option 3 | STATCOM | 1/12/2025 | 49 | 35 | 40 |
| Option 4 | Option 1 with interim battery from July 2023 which provides network support until Option 1 is commissioned | 1/07/2023 | 259 | 165 | 203 |
| Option 5 | A standalone battery | 1/12/2024 | 217 | 161 | 191 |

The rest of Section 8 explores the timing and sources of these forecast benefits, with a focus on TransGrid's preferred option, i.e. Option 4.

## 8.2 Market modelling results for Option 4

In this section, the modelling outcomes for TransGrid's preferred option for all scenarios are depicted and analysed. The outcomes include gross market benefit of this option, capacity mix, and generation mix compared to the Base Case.

### 8.2.1 Step Change scenario

The forecast cumulative gross market benefits for Option 4 in the Step Change scenario are shown in Figure 14. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 4 and the Base Case in this scenario are shown in Figure 15 and Figure 16, respectively.

Figure 14: Forecast cumulative gross market benefit[28] for Option 4 under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

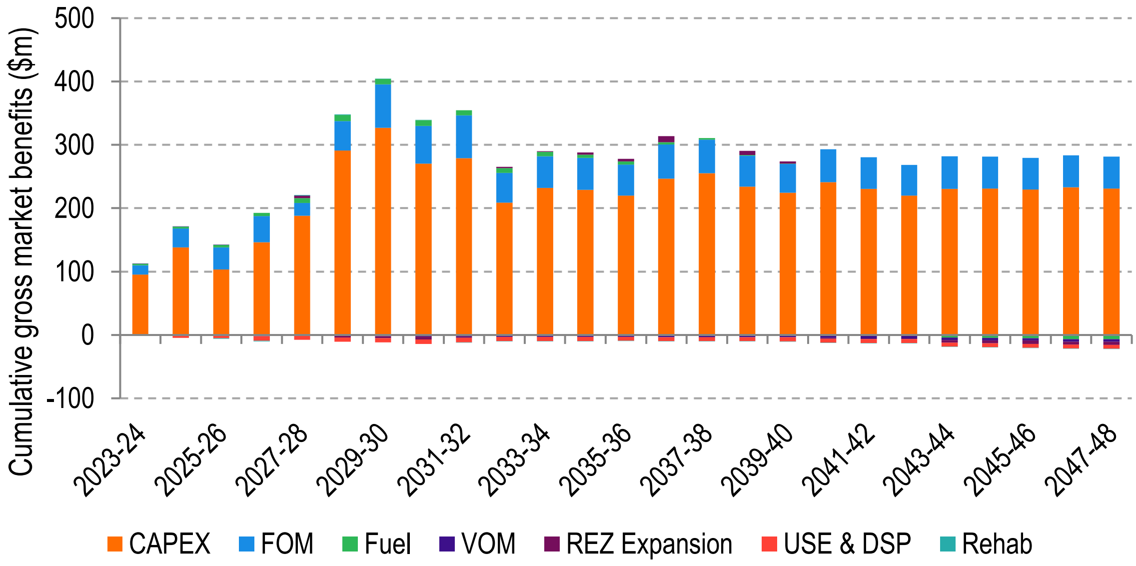
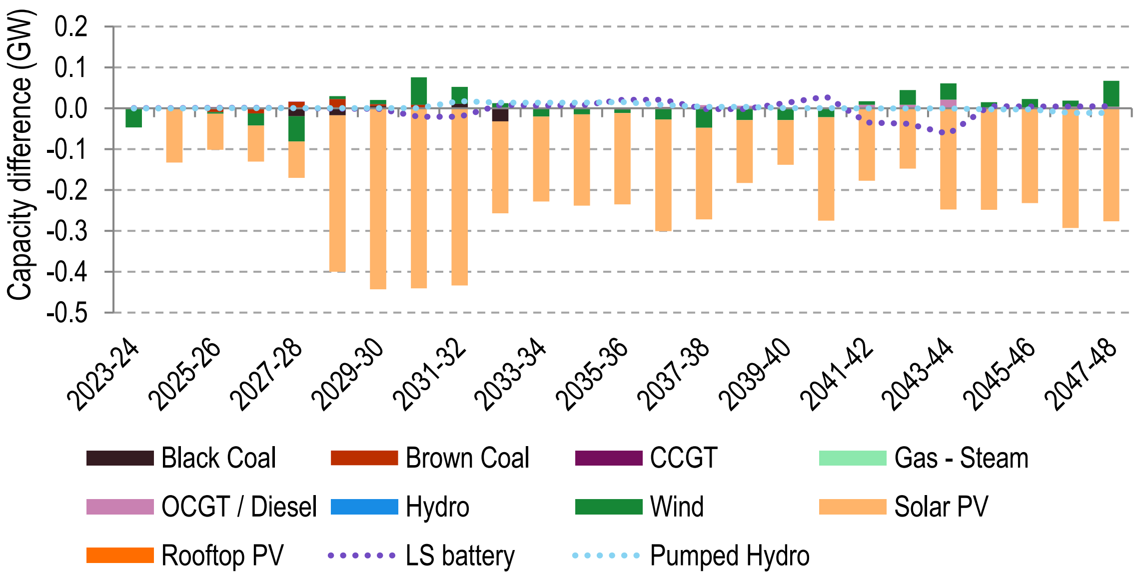
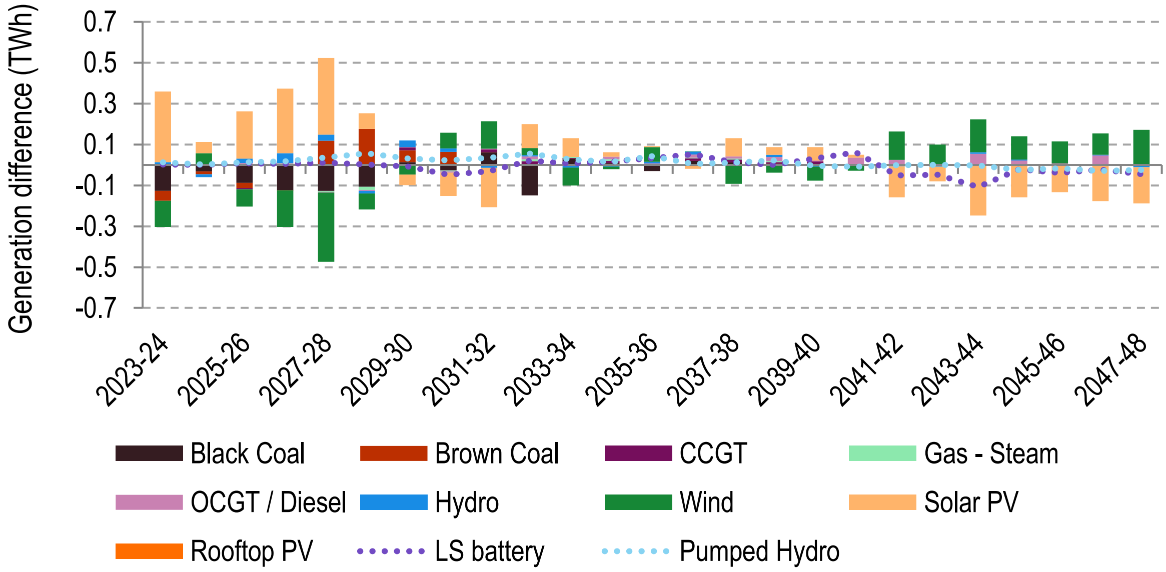



Figure 15: Difference in NEM capacity forecast between Option 4 and Base Case in the Step Change scenario




[28] 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 16: Difference in NEM generation forecast between Option 4 and Base Case in the Step Change scenario




The primary sources of forecast market benefits are avoided and deferred solar and wind capacity build and early retirement of coal. The timing and source of these benefits are attributable to the following:

- Capex and FOM savings are forecast to accrue from the first year of modelling which is due to the deferred solar and wind capacity build. The major capex saving is forecast around late-2020s to early-2030s and remains stable at around $250m until the last modelled year. This is due to commissioning of HumeLink which results in a significantly higher transfer limit between SWNSW and Wagga in Option 4.

- The reduced capex in Option 4 is mainly due to the solar deferral and avoidance, where around 280 MW of solar capacity is avoided by the end of study. This is partially offset by 60 MW of additional wind capacity build relative to the Base Case. Most of the avoided solar capacity is forecast to be in the Wagga and CWO REZs from the start of the modelling up to the mid-2030s. This is a result of less curtailment of existing solar PV generation in SWNSW as a result of this option which leads to more solar energy transfer from SWNSW to Wagga and less need for additional solar capacity build to the east of the SWNSW-WAGGA transmission cut set. Then there is approximately 250 MW of avoided solar capacity build in SWNSW from the early-2040s which coincides with the retirement of some of the existing solar projects in SWNSW.
- FOM cost saving is expected to accumulate as soon as Option 4 is in place and increases until the early-2030s and remains stable until the end of the study period resulting in approximately $50m overall FOM cost saving by 2047-48.
- The reduced FOM cost is mainly due to the wind capacity deferral from the first year and early black coal withdrawal and wind and solar capacity avoidance and deferral throughout the modelled years.

### 8.2.2 Progressive Change scenario

The forecast cumulative gross market benefits for Option 4 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 4 and the Base Case are shown in Figure 18 and Figure 19.

Figure 17: Forecast cumulative gross market benefit[28] for Option 4 under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

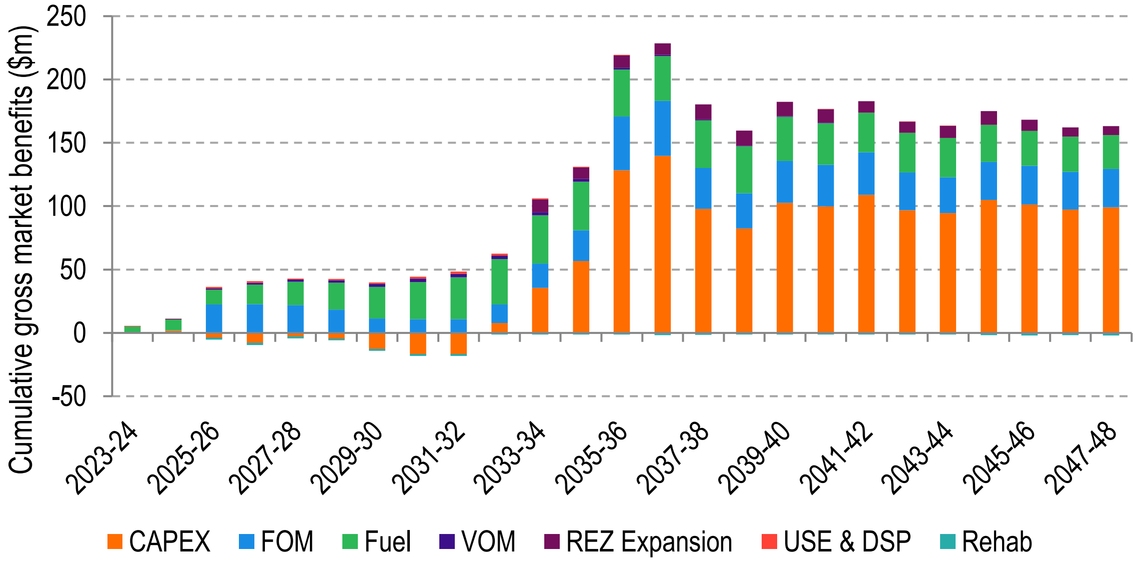



Figure 18: Difference in NEM capacity forecast between Option 4 and Base Case in the Progressive Change scenario

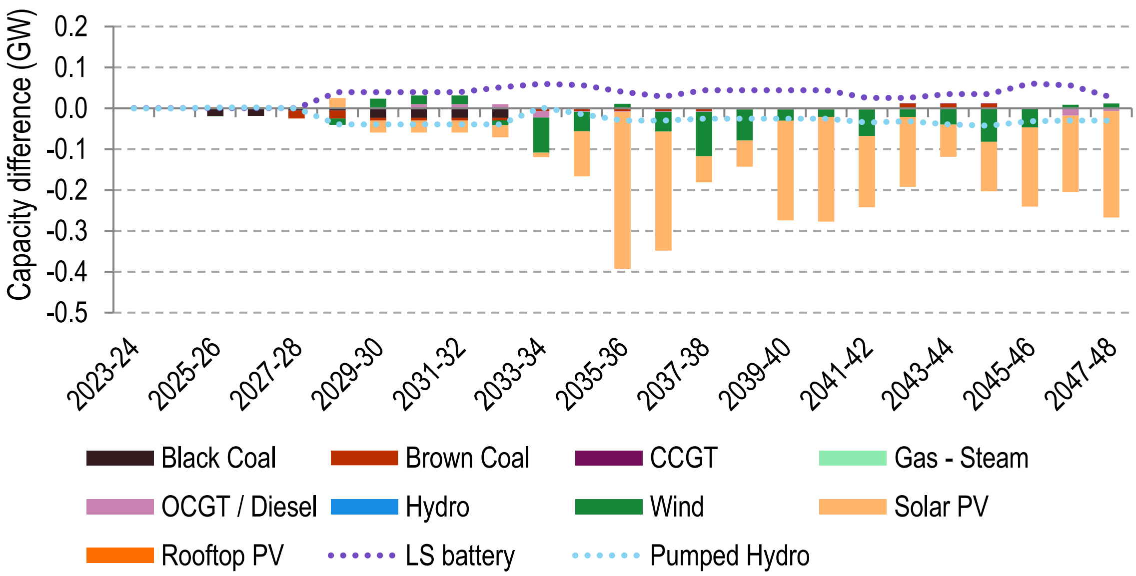
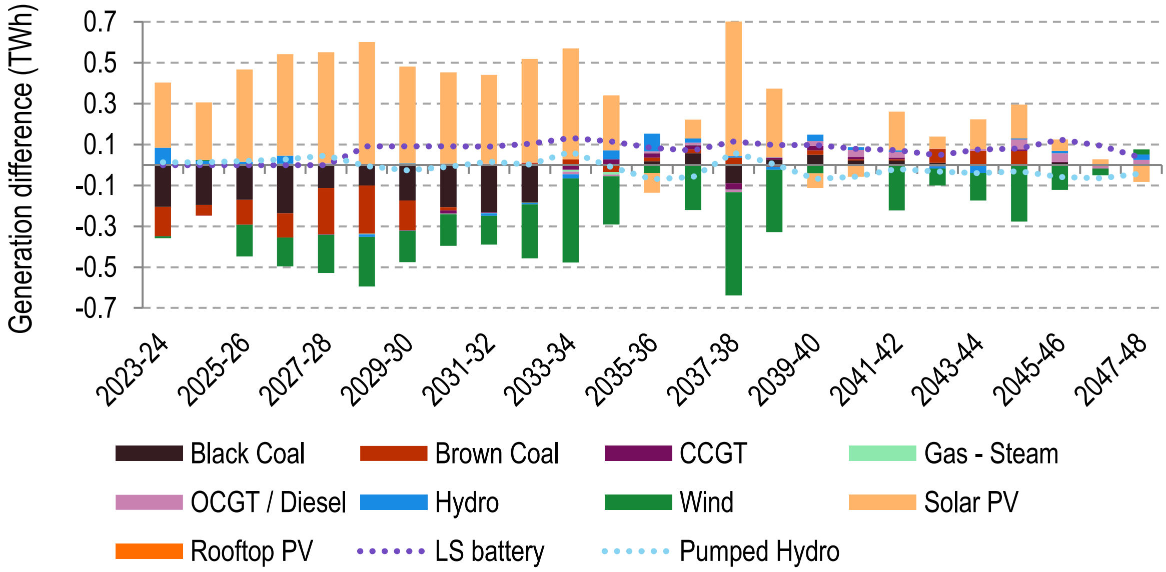


Figure 19: Difference in NEM generation forecast between Option 4 and Base Case in the Progressive Change scenario




The largest sources of forecast gross market benefits in this scenario are capex saving from deferred and avoided capacity build and reduced fuel and FOM costs. The timing and source of the benefits from Option 4 are attributable to the following:

- Forecast capex savings mainly occur between 2033-34 to 2037-38 and are attributed to the deferred or avoided solar and wind capacity build within NSW by this option. The capex saving then remains stable over the modelled years.
- Forecast fuel and FOM cost savings occur from the first year and increase between the early-2030s and the mid-2030s. These cost savings are attributed to reduced black and brown coal generation and forecast earlier black and brown coal withdrawals due to the presence of the Option 4. In this scenario, this option reduces curtailment of existing SWNSW solar generation and is supplemented with some large scale battery capacity to replace coal generation.
- Forecast REZ expansion cost saving of $1.7m is also observed in this scenario which is mainly in NSW as a result of less need for REZ transmission expansion in the region by the addition of this option compared to the Base Case.

### 8.2.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits for Option 4 in the Hydrogen Superpower scenario are shown in Figure 20. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 4 and the Base Case in this scenario are shown in Figure 21 and Figure 22.

Figure 20: Forecast cumulative gross market benefit[28] for Option 4 under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

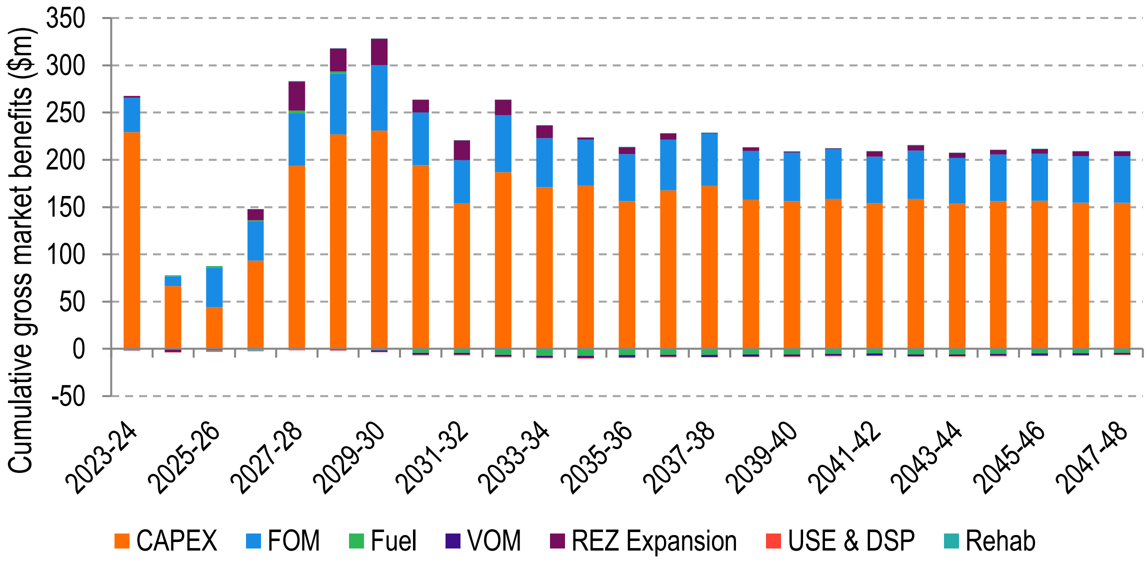



Figure 21: Difference in the NEM capacity forecast between Option 4 and Base Case in the Hydrogen Superpower scenario

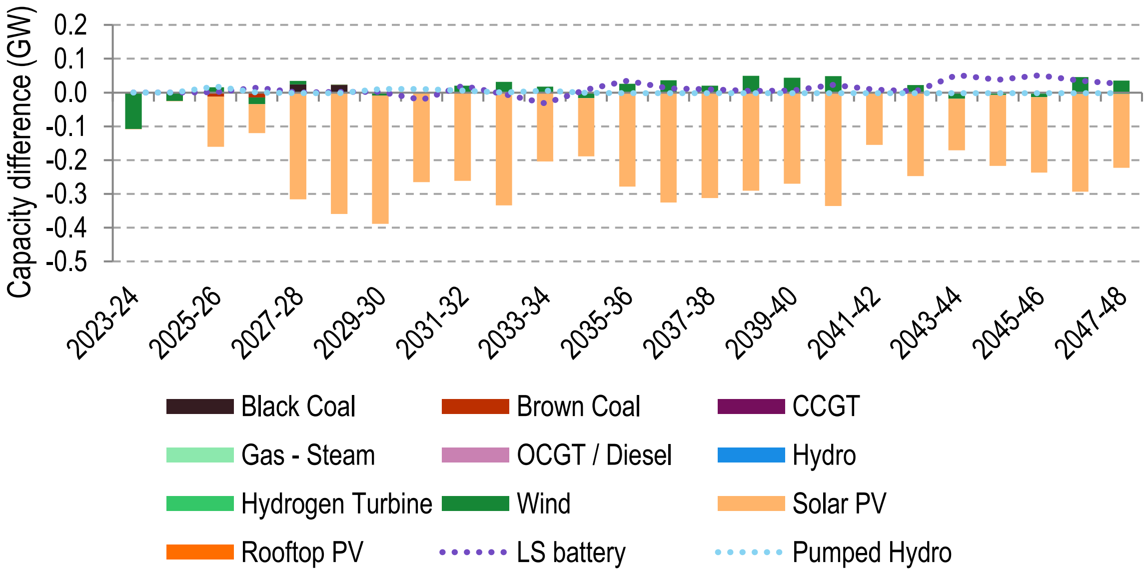
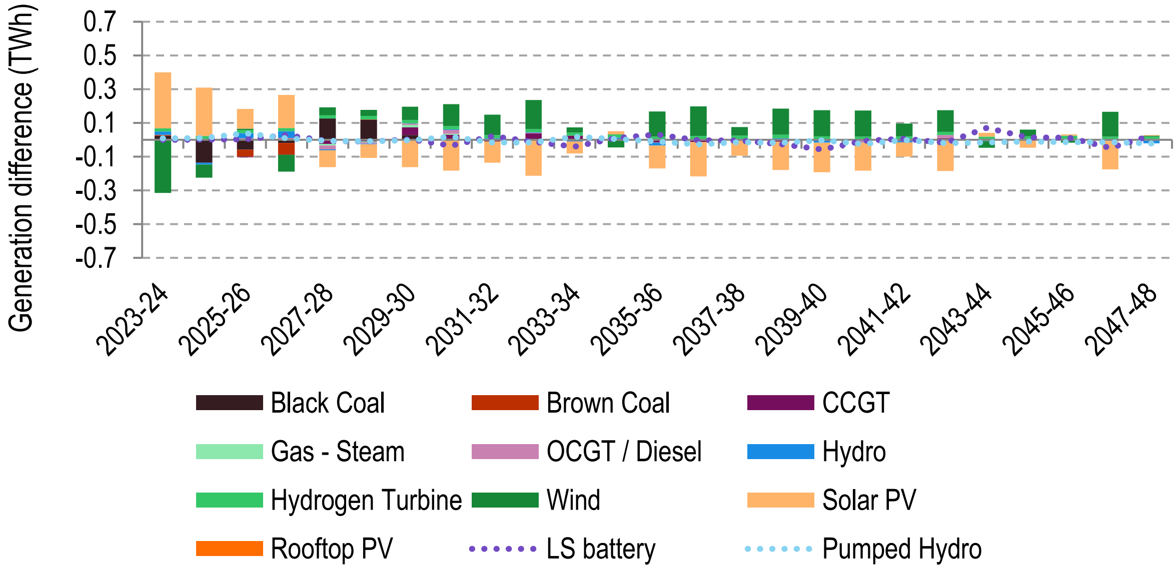


Figure 22: Difference in NEM generation forecast between Option 4 and Base Case in the Hydrogen Superpower scenario



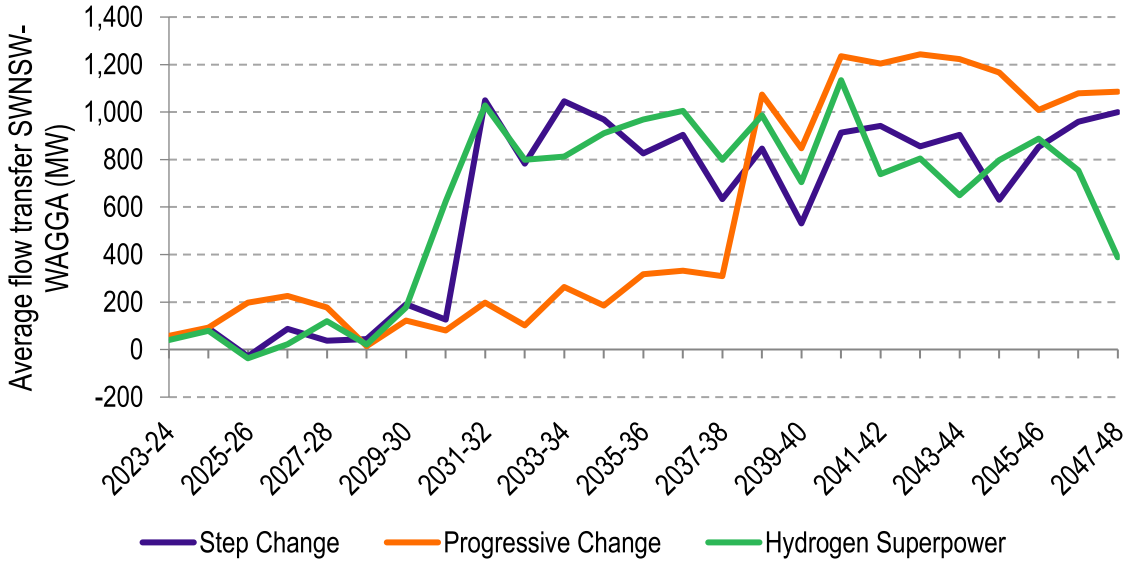

Capex and FOM savings are forecast to be the main sources of cost savings in this scenario. Avoided and deferred solar capex are the major source of forecast gross market benefits. The timing and sources of these benefits are attributable to the following:

- Capex benefits are forecast from the first year and are expected to increase from 2027-28 to 2030-31 between HumeLink and VNI West augmentation years in the model. In these years Option 4 adds more capacity to the SWNSW to Wagga transfer limit and increases RHS of line 63 stability constraint equation which result in reduced curtailment of existing solar generation in SWNSW. This leads to more solar energy transfer from SWNSW to Wagga and less need for additional solar capacity build to the east of the SWNSW-WAGGA transmission cut set. The capex saving then remains stable at $150m approximately by the end of the study.
- Throughout the 2020s there are forecast FOM savings as a result of deferred or avoided solar and wind capacity build due to the presence of the Option 4.
- Hydrogen Superpower scenario is forecast to have lower gross market benefits compared to the Step Change scenario. The main reason for the comparatively lower gross market benefits is that demand has a significantly increasing trend in this scenario and Victoria demand appears with a positive coefficient on the RHS of the line 63 stability constraint equation. Increasing Victoria demand from early 2030s in the Hydrogen Superpower scenario results in less binding of this constraint equation in the Base Case. This means Option 4 will have relatively less impact on the generation mix and capacity deferral and avoidance in this scenario. Therefore, market benefits in the Hydrogen Superpower scenario are not as high as in the Step Change scenario

### 8.2.4 SWNSW to WAGGA flow

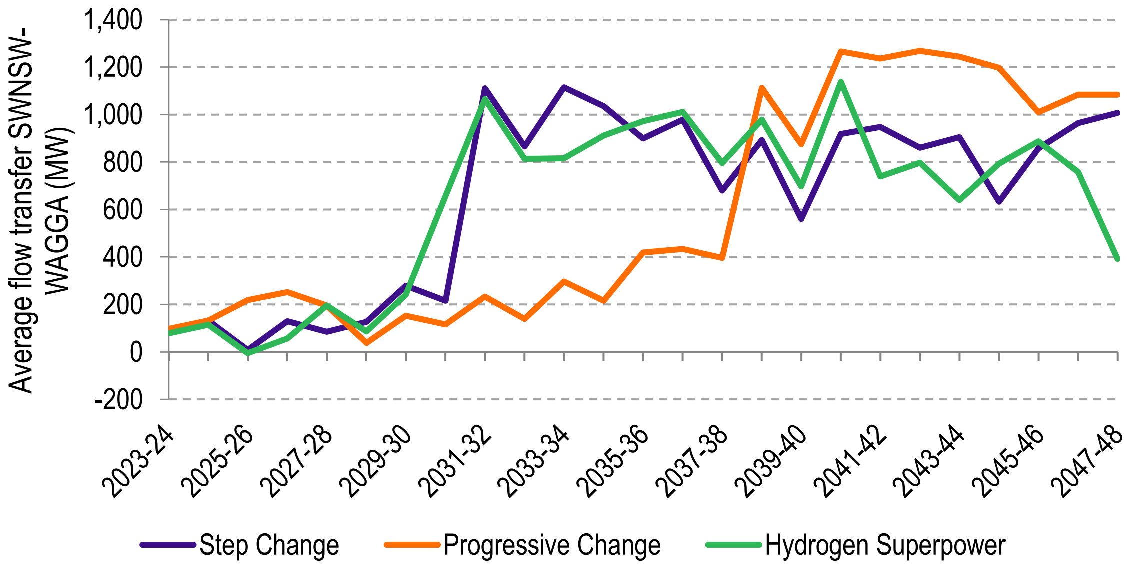
This section summarises the outcomes for the transmission network flows from SWNSW to Wagga. Figure 23 shows this flow on an annual average basis for the Base Case in all scenarios. It is seen that the flow has an increasing trend over the study period. The Step Change and Hydrogen Superpower scenarios show a significant increase in the flow in 2031-32 and 2030-31, respectively, and the Progressive Change scenario shows a similar increase in 2038-39 in line with the assumed VNI West timing in these scenarios. In addition, lower flow in the early years in the Step Change and Hydrogen Superpower scenarios is mainly due to lower brown coal generation in these scenarios, which is partly a result of the carbon budget assumption.

Figure 23: Forecast average flow transfer of SWNSW-WAGGA in the Base Case




Annual average flow transfer in the preferred option for all scenarios is shown in Figure 24. In comparison to the Base Case, generally higher flow transfers from SWNSW to Wagga are expected in the preferred option. This is more evident for the years between the commissioning of HumeLink and VNI West for each scenario. Note that the flow limit of SWNSW to Wagga is 3,000 MW after VNI West entry, regardless of the modelled options.

Figure 24: Forecast average flow transfer of SWNSW-WAGGA in the preferred option




Flow duration curves of SWNSW-WAGGA for the modelled scenarios in the Base Case are provided in Figure 25, Figure 26 and Figure 27.

It is seen that the flow transfer towards Wagga is expected to be significantly limited most years in all scenarios. In comparison, the flow duration curves of SWNSW-WAGGA in the preferred option are shown in Figure 28, Figure 29, and Figure 30. It is seen that the preferred option is expected to have higher flow towards Wagga, mostly after HumeLink commissioning until VNI West commissioning.

As the figures show, the power flow across SWNSW-WAGGA transmission tends to be capped at the limits prior PEC and post VNI West commissioning. More market benefits would be expected from the options if the flow is capped at limit in the Base Case without options between PEC and VNI West commissioning.

Figure 25: Duration curve of forecast flow for SWNSW-WAGGA in the Base Case – Step Change

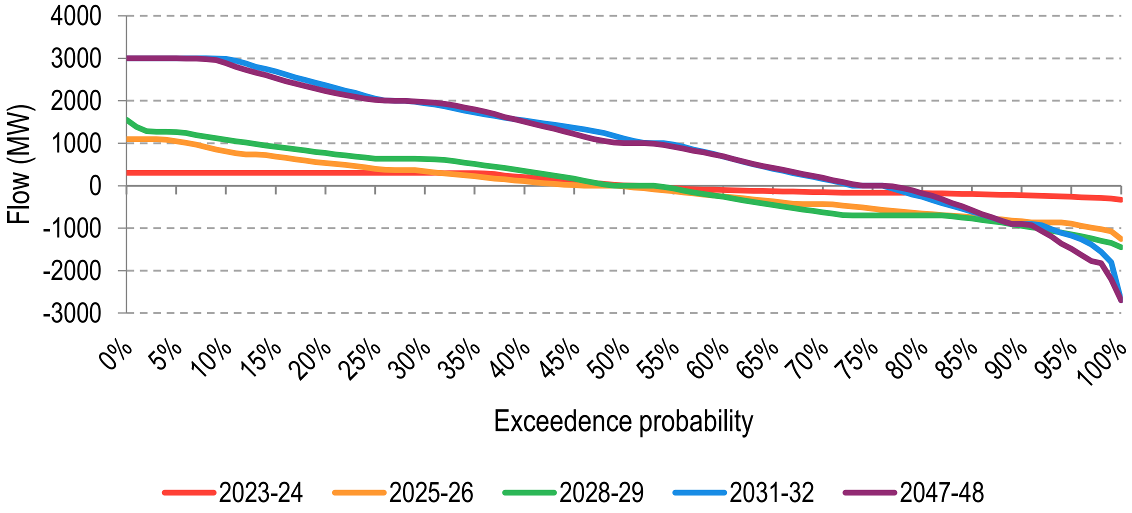



Figure 26: Duration curve of forecast flow for SWNSW-WAGGA in the Base Case – Progressive Change scenario

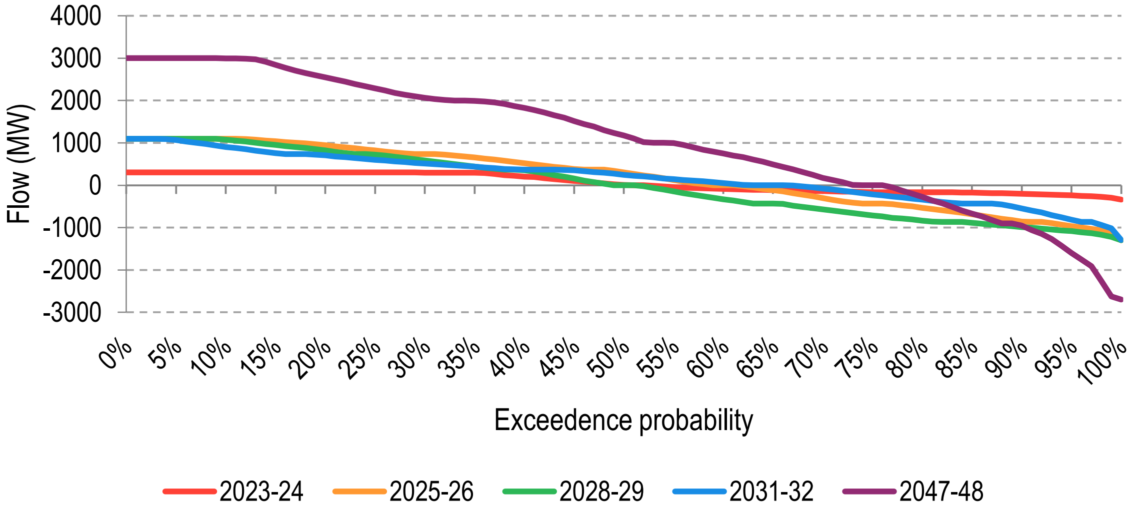


Figure 27: Duration curve of forecast flow for SWNSW-WAGGA in the Base Case – Hydrogen Superpower scenario

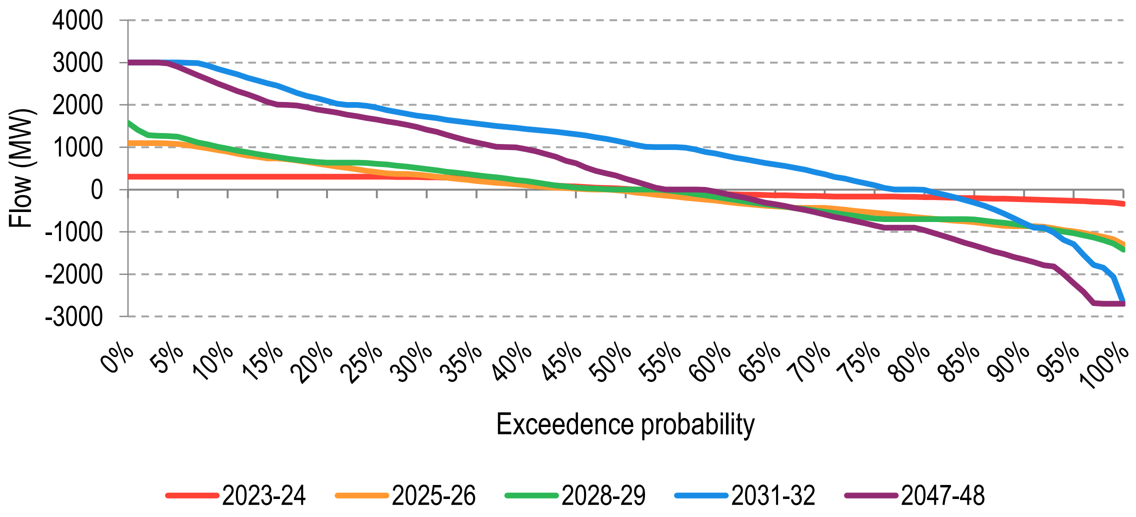



Figure 28: Duration curve of forecast flow for SWNSW-WAGGA in the preferred option – Step Change scenario

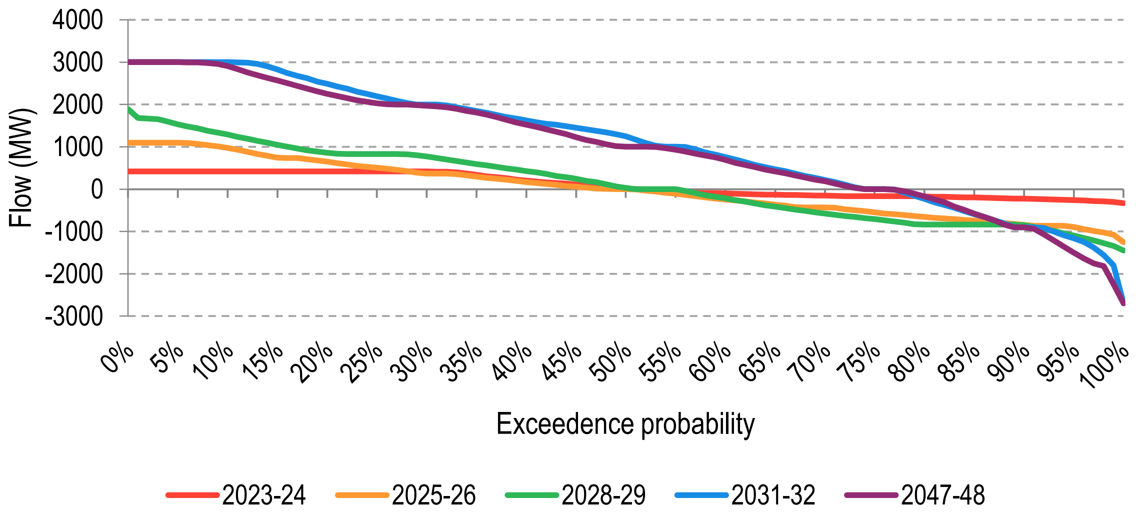


Figure 29: Duration curve of forecast flow for SWNSW-WAGGA in the preferred option – Progressive Change scenario

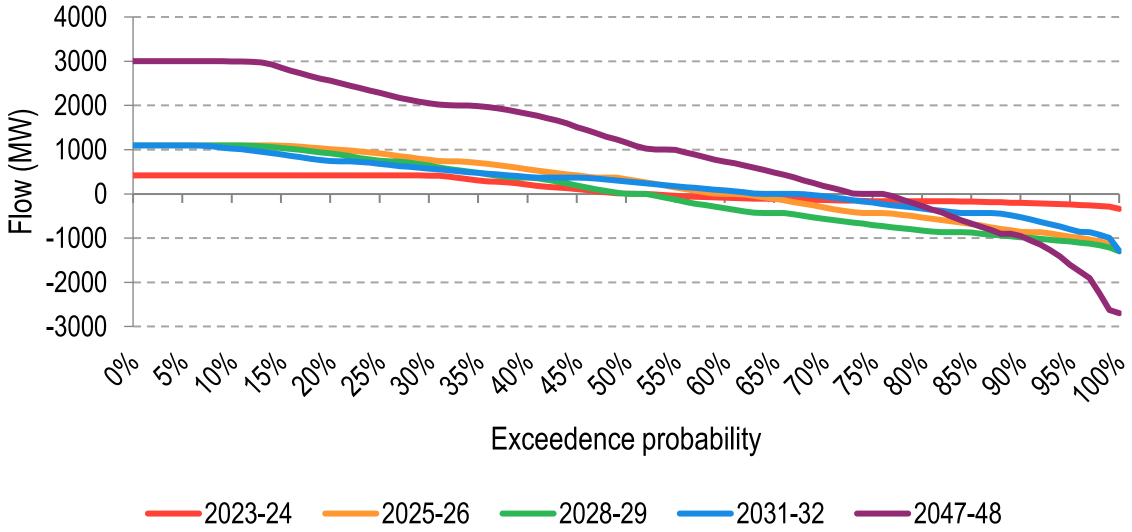
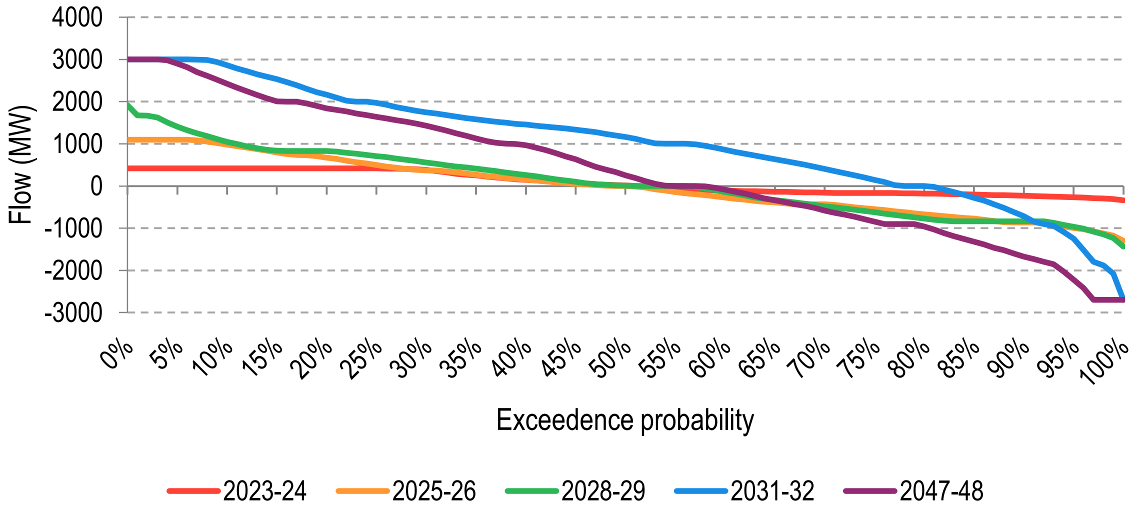



Figure 30: Duration curve of forecast flow for SWNSW-WAGGA in the preferred option – Hydrogen Superpower scenario




## 8.3 Other options outcomes

This section provides market modelling results for other options for the Step Change scenario.

### 8.3.1 Option 1

The forecast cumulative gross market benefits for Option 1 are shown in Figure 31, indicating that the total forecast gross market benefit reaches around $224m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 1 and the Base Case are shown in Figure 32 and Figure 33, respectively.

Figure 31: Forecast cumulative gross market benefits[28,29] for Option 1, millions real June 2021 dollars discounted to June 2021 dollars

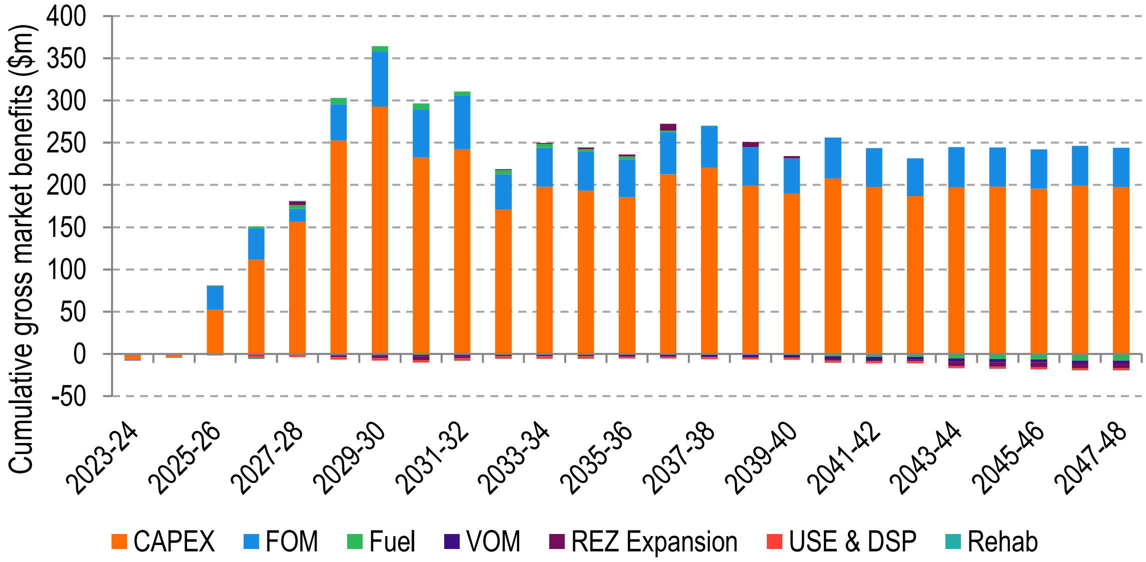
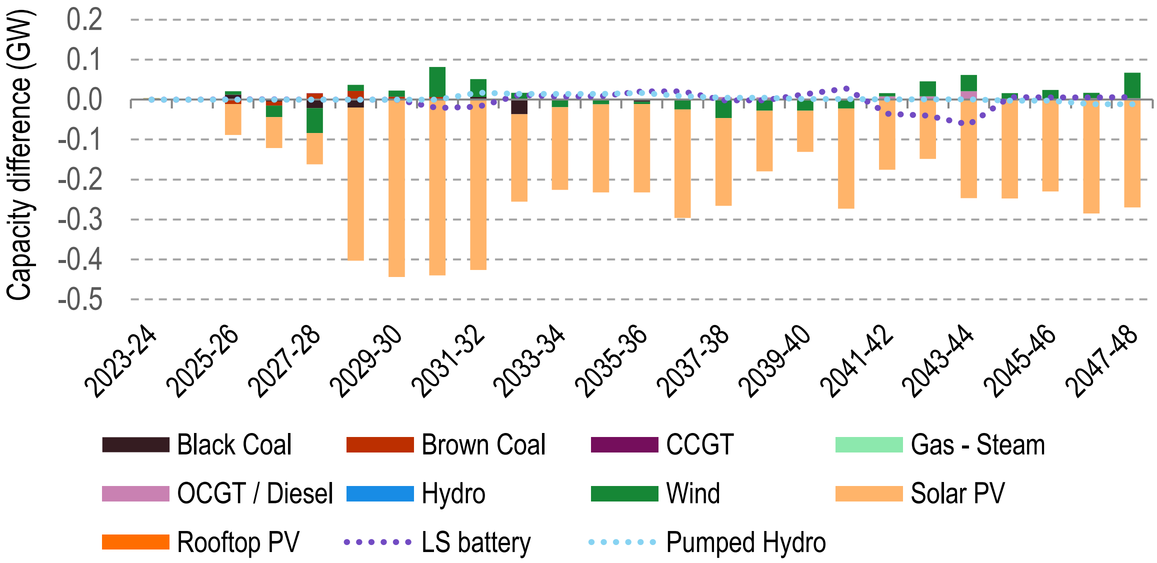
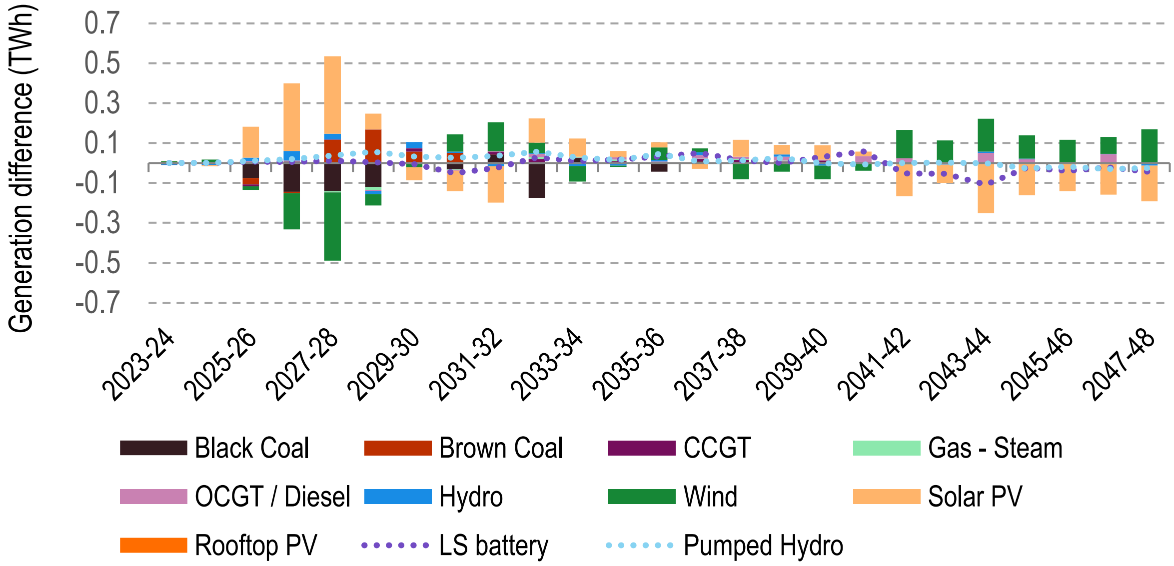



Figure 32: Difference in NEM capacity forecast between Option 1 and the Base Case




[29] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2047-48 equates to the gross benefits for Option 1 shown in Table 11.

Figure 33: Difference in NEM generation forecast between Option 1 and the Base Case




The modelling outcomes for Option 1 are similar to Option 4, with around $35m less benefits. The lower forecast benefit is due to the additional benefits from the battery connected to Darlington Point substation in option 4 from July 2023. The primary sources of forecast gross market benefits in Option 1 are capex and FOM cost savings as a result of avoided and deferred solar and wind capacity. The timing and source of these benefits are attributable to the following:

- Capex and FOM savings are expected from 2025-26 due to deferred solar and wind capacity build. The major capex saving is forecast around the late 2020s until the early2030s and remains stable at around $200m until the last year of the study.
- The reduced capex in Option 2 is mainly due to solar deferral and avoidance, where study around 270 MW solar build is avoided by the end of the study. This is partially offset by 60 MW of additional wind capacity build relative to the Base Case.
- The reduced FOM cost is mainly due to early coal withdrawal and solar and wind capacity deferral and avoidance throughout the study.

## 8.3.2 Option 2

The forecast cumulative gross market benefits for Option 2 are shown in Figure 34, indicating that the total forecast gross market benefit reaches $227m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 2 and the Base Case are shown in Figure 35 and Figure 36 respectively.

Figure 34: Forecast cumulative gross market benefit[28,30] for Option 2, millions real June 2021 dollars discounted to June 2021 dollars

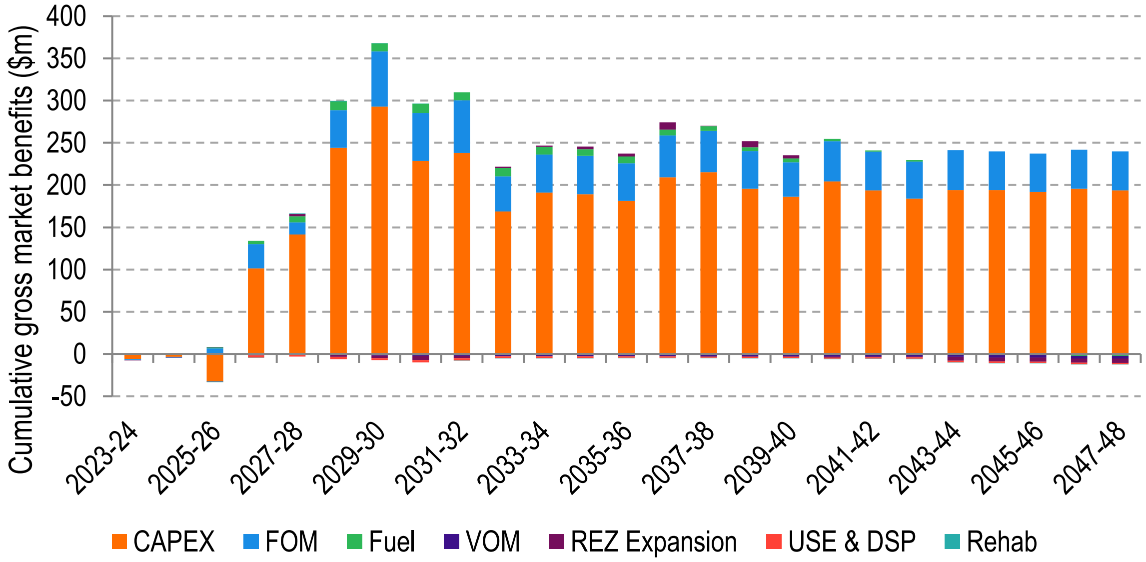
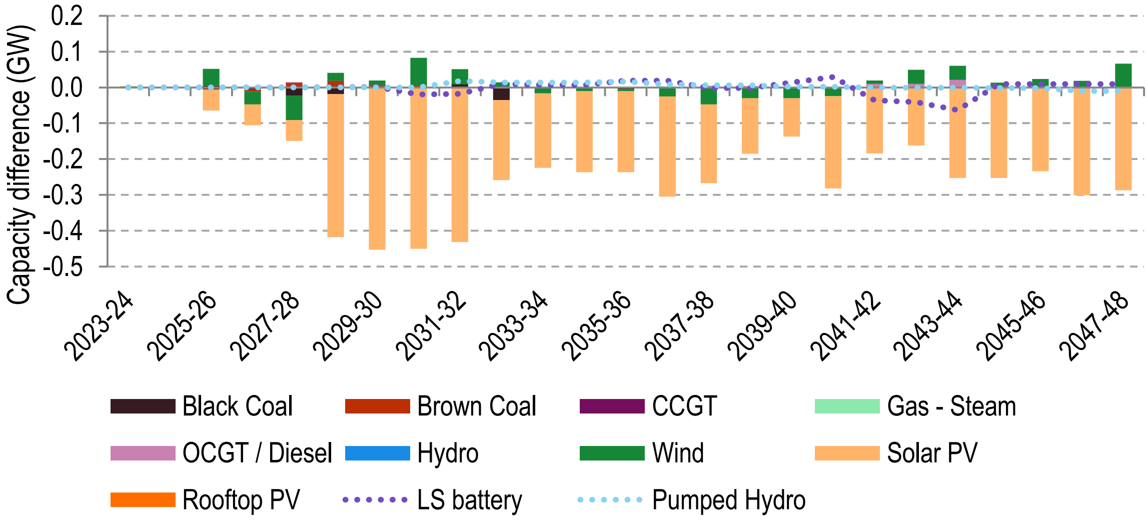
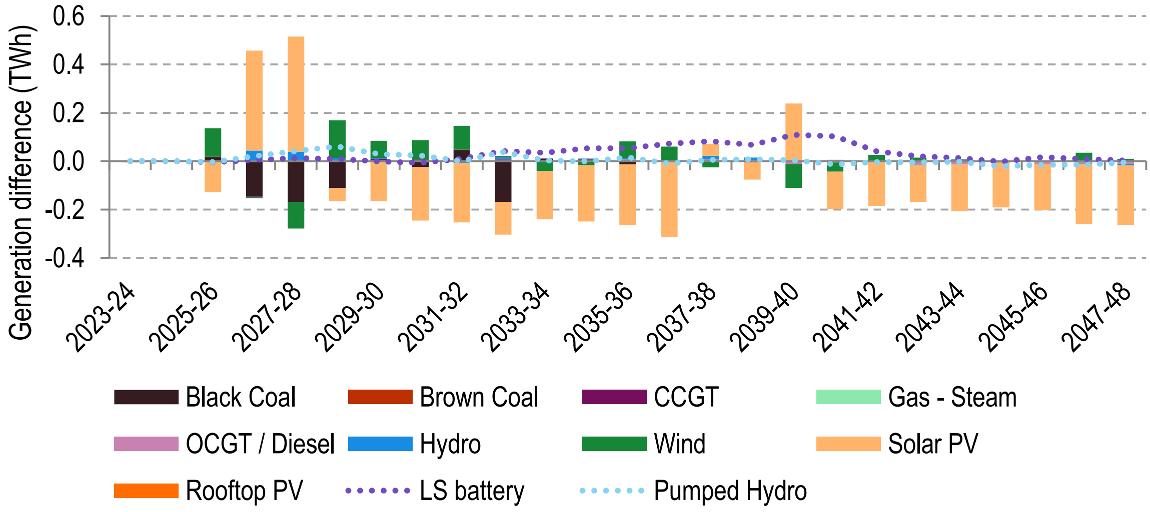



Figure 35: Difference in NEM capacity forecast between Option 2 and the Base Case




[30] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2047-48 equates to the gross benefits for Option 2 shown in Table 11.

Figure 36: Difference in NEM generation forecast between Option 2 and the Base Case




The modelling outcomes for Option 2 are similar to Option 1, with around $3m more market benefits. The increase in the forecast benefits is due to the reduced losses from SWNSW to Wagga as a result of a new 330 kV line between Darlington Point and Wagga substations in this option. The primary sources of forecast gross market benefits in Option 2 are avoided and deferred solar and wind capacity build and early retirement of coal. The timing and source of these benefits are attributable to the following:

- Capex saving is expected from 2026-27, due to deferred and avoided wind and solar capacity build. The major capex saving occurs around the late 2020s and remains stable at around $190m until the last year of the study.
- The reduced capex in Option 2 is mainly due to deferred and avoided solar and wind capacity build, where at the end of the study around 290 MW solar build is avoided. This is partially offset by 60 MW of additional wind capacity build relative to the Base Case.
- FOM cost savings are expected to accumulate as soon as Option 2 is in place, and increase until the early-2030s. FOM cost saving forecast then stabilizes over the rest of the modelled years and end up at approximately $46m in the last modelled year.
- The reduced FOM cost is mainly due to the solar and wind capacity build deferral and avoidance throughout the study.

### 8.3.3 Option 3

The forecast cumulative gross market benefits for Option 3 are shown in Figure 37, indicating that the total forecast gross market benefit reaches $49m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 3 and the Base Case are shown in Figure 38 and Figure 39 respectively.

Figure 37: Forecast cumulative gross market benefit[28,31] for Option 3, millions real June 2021 dollars discounted to June 2021 dollars

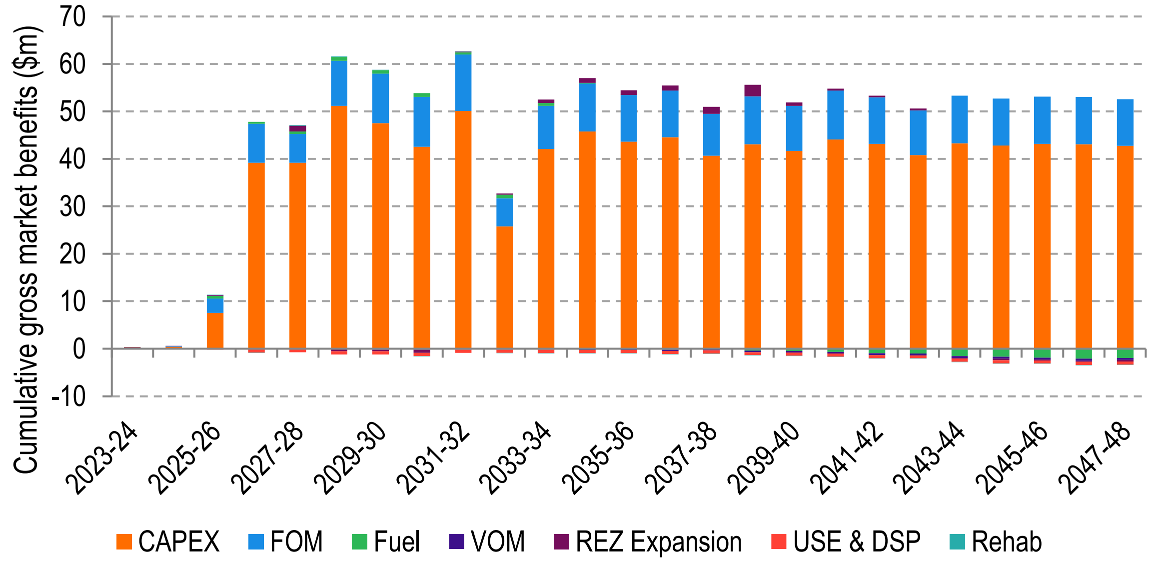
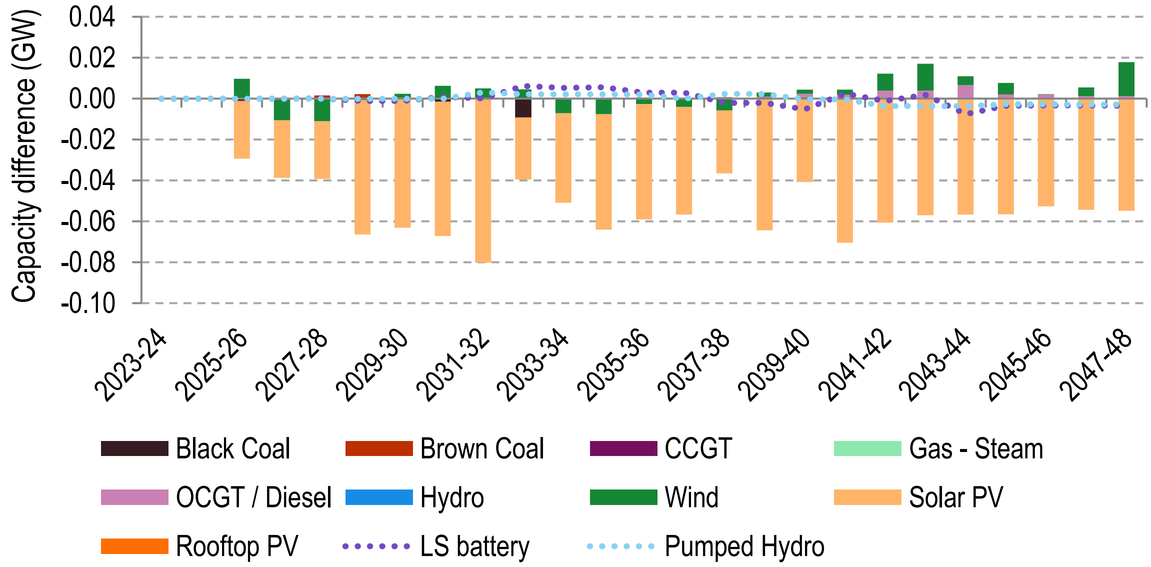
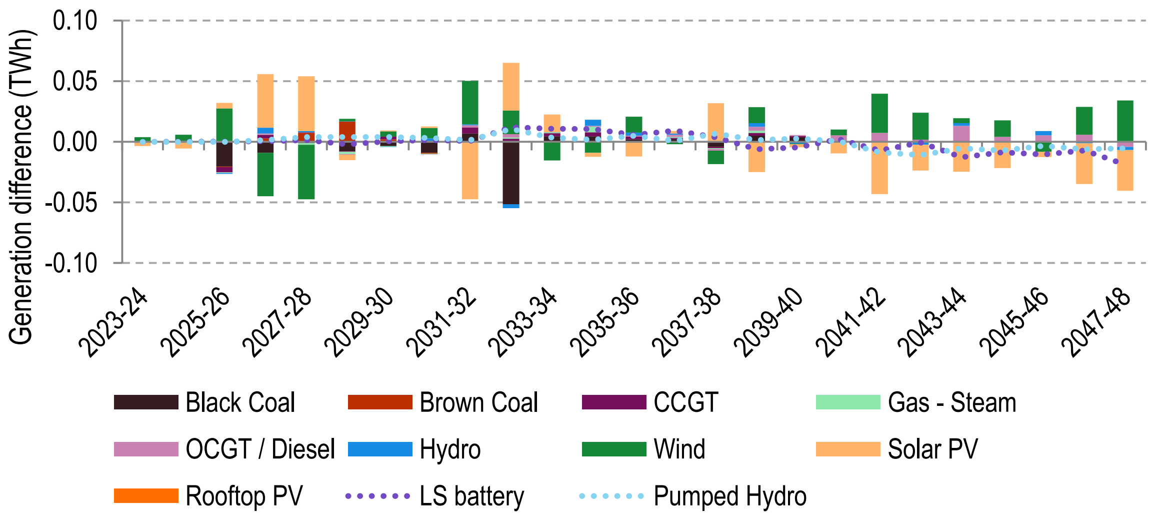



Figure 38: Difference in NEM capacity forecast between Option 3 and the Base Case




[31] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2047-48 equates to the gross benefits for Option 3 shown in Table 11.

Figure 39: Difference in NEM generation forecast between Option 3 and the Base Case




The primary sources of forecast gross market benefits in Option 3 are avoided and deferred solar and wind capacity build. The timing and source of these benefits are attributable to the following:

- Capex saving is due to deferred solar and wind capacity build throughout the study. However, the major capex saving occurs around the late 2020s and remains stable at just under $43m until the last year of the study.
- The reduced capex in Option 3 is mainly due to deferred and avoided solar capacity build, where at the end of the study around 50MW solar build is avoided, which is partially offset by 20 MW of additional wind capacity build relative to the Base Case.
- FOM cost savings are expected to accumulate from 2025-26 and increase until the late-2020s. Thereafter, no more FOM cost savings are expected which results in approximately $10m overall FOM cost saving.
- Similar to Option 2, the reduced FOM cost is mainly due to avoided and deferred solar and wind capacity build in this option.

### 8.3.4 Option 5

The forecast cumulative gross market benefits for Option 5 are shown in Figure 40, indicating that the total forecast gross market benefit reaches $217m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 5 and the Base Case are shown in Figure 41 and Figure 42 respectively.

Figure 40: Forecast cumulative gross market benefit[28,32] for Option 5, millions real June 2021 dollars discounted to June 2021 dollars

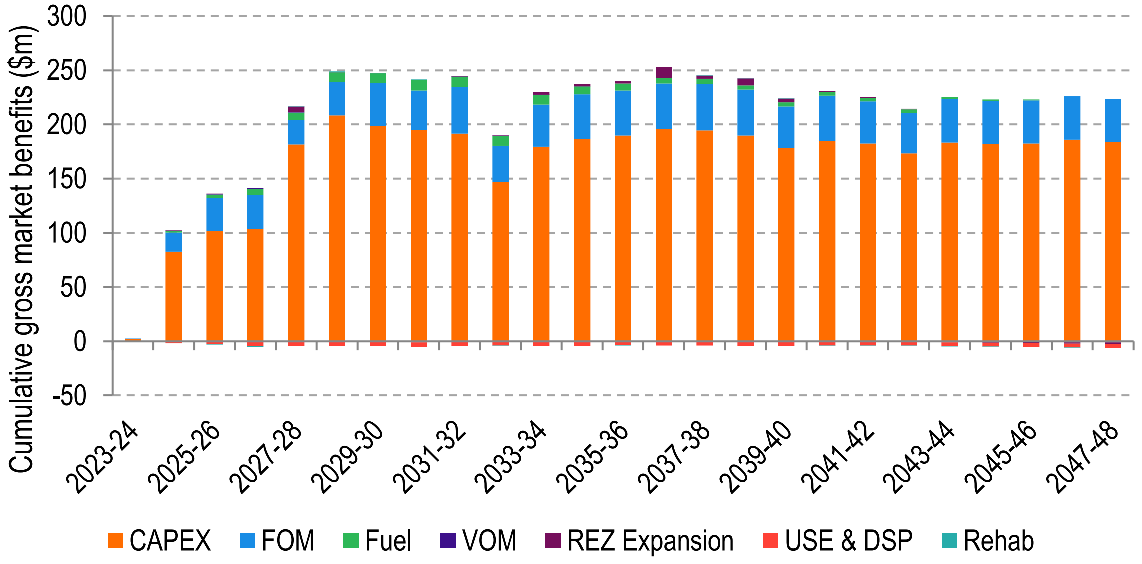
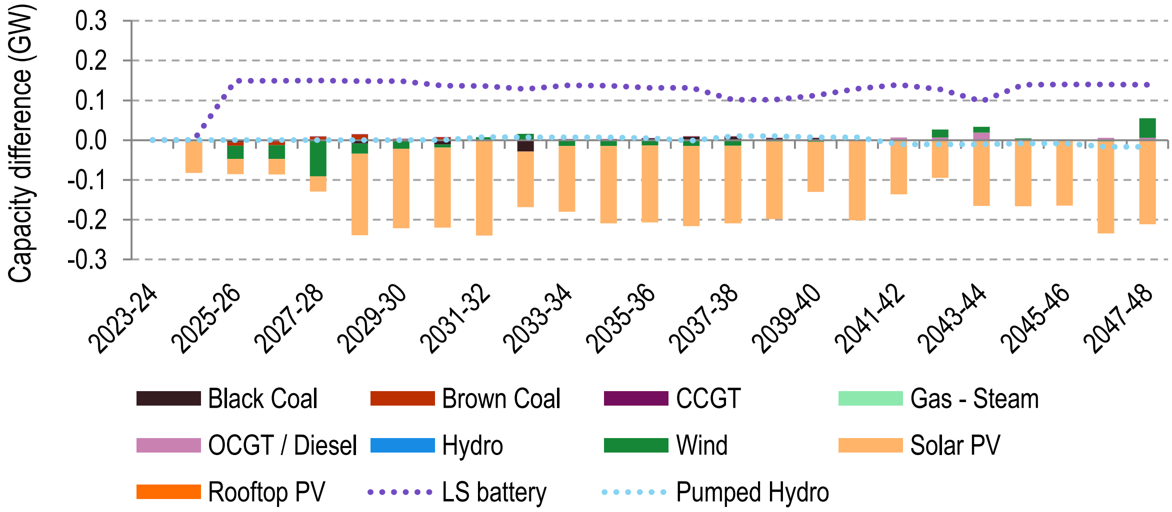
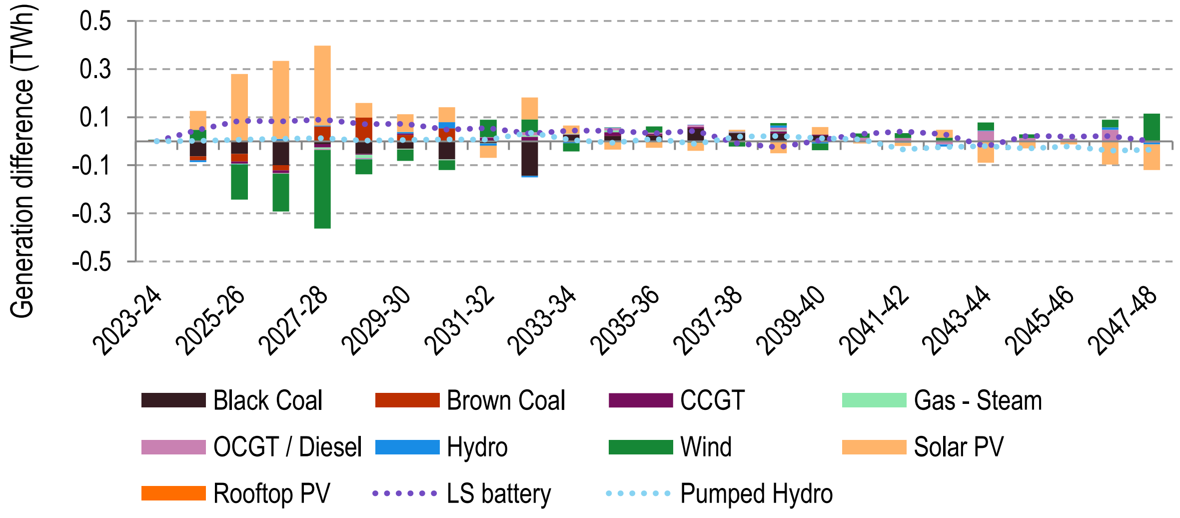



Figure 41: Difference in NEM capacity forecast between Option 5 and the Base Case




[32] Since this figure shows the cumulative forecast gross market benefits in present value terms, the height of the bar in 2047-48 equates to the gross benefits for Option 5 shown in Table 11.

Figure 42: Difference in NEM generation forecast between Option 5 and the Base Case




The primary sources of forecast gross market benefits in Option 5 are avoided and deferred solar and wind capacity build. The timing and source of these benefits are attributable to the following:

- Capex saving is expected from 2024--25 due to deferred solar capacity build and increases in later years due to differed and avoided wind and solar capacity build and early retirement of coal. The major capex saving occurs around the late 2020s and remains stable at around $183m by the end of the study.
- The reduced capex in Option 5 is mainly due to solar deferral and avoidance, where at the end of the study around 210MW solar build is avoided, although approximately 50 MW more wind is built in this option.
- FOM cost savings are expected to accumulate from 2024--25 and increase until the late-2020s. Thereafter, no more FOM cost savings are expected which results in approximately $40m overall FOM cost saving.
- Similar to other options, the reduced FOM cost is mainly due to avoided and deferred solar and wind capacity build in this option due to opening of the transfer limit from Victoria and SWNSW to NSW load centres.
- Compared to Option 4, this option has lower network support, however, additional 150 MW standalone battery has been assumed as a committed project at no capex which adds more market benefits to this option.

## 8.4 Sensitivity test to evaluate impact of interim protection scheme

As per TransGrid's request, a sensitivity case has been modelled for the Step Change scenario to assess the impact of 200 MW additional transfer capacity from SWNSW to Wagga in the Base Case as a result of an interim protection scheme from the beginning of the study period until 1 December 2025. The sensitivity Base Case which is called the Alternative Base Case hereafter, also includes an additional 200 MW constant value to the RHS of the line 63 stability constraint equation for the period through to 1 December 2025. As part of this sensitivity test, Option 1 and Option 4 have also been tested on the Alternative Base Case to evaluate the market benefit forecast of these options compared to the Alternative Base Case. This section summarises market modelling results for this sensitivity test in the Step Change scenario.

### 8.4.1 Option 1

The forecast cumulative gross market benefits for the Option 1 compared to the Alternative Base Case are shown in Figure 45. The total forecast gross market benefit of this option is $224m by the end of the study period. The differences in capacity and generation outlook across the NEM between Option 1 and the Alternative Base Case are shown in Figure 44 and Figure 45, respectively.

Figure 43: Forecast cumulative gross market benefit[28] for Option 1 in Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

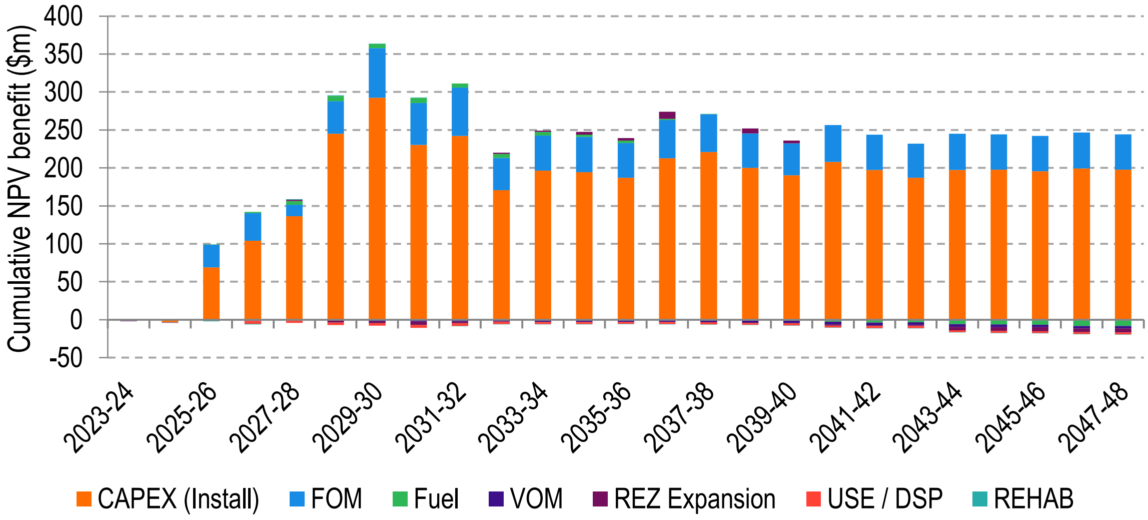



Figure 44: Difference in NEM capacity forecast between Option 1 and Alternative Base Case in the Step Change scenario

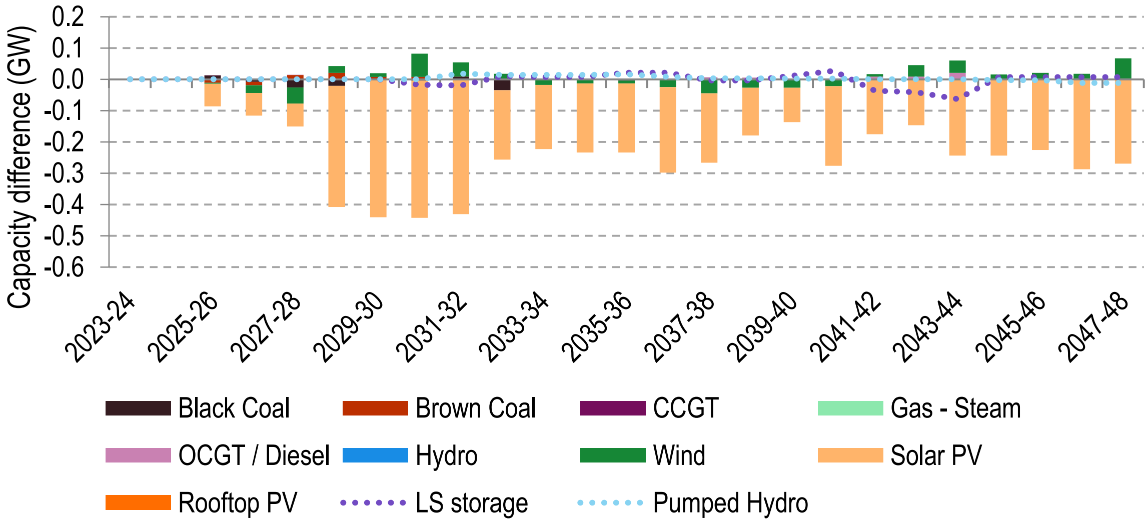
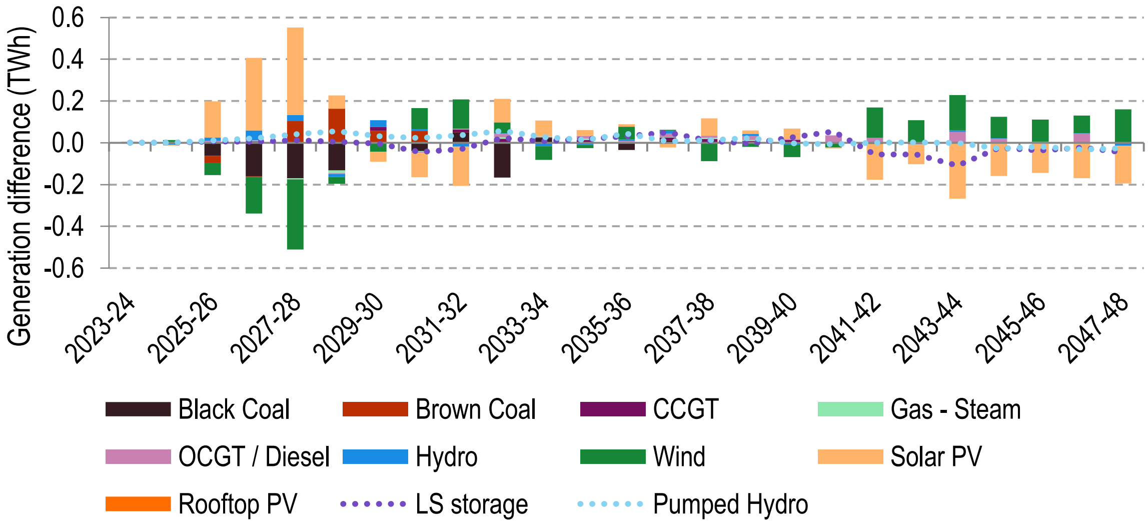


Figure 45: Difference in NEM generation forecast between Option 1 and Alternative Base Case in the Step Change scenario




The primary sources and overall forecast gross market benefits in this sensitivity are similar to the core scenario modelling, being primarily from capex and FOM savings due to avoided and deferred capex for new generators. This sensitivity case results in the same gross market benefits as the core scenario modelling. The interim protection scheme is assumed to be in place until the commissioning of Option 1, and as such it is forecast that its impact on the benefit of this option is marginal.

### 8.4.2 Option 4

The forecast cumulative gross market benefits for Option 4 compared to the Alternative Base Case are shown in Figure 46, indicating that the total forecast gross market benefit of this option is $244m by the end of the study period. Furthermore, the differences in capacity and generation outlook across the NEM between Option 4 and the Alternative Base Case are shown in Figure 47 and Figure 48, respectively.

Figure 46: Forecast cumulative gross market benefit[28] for Option 4 in Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

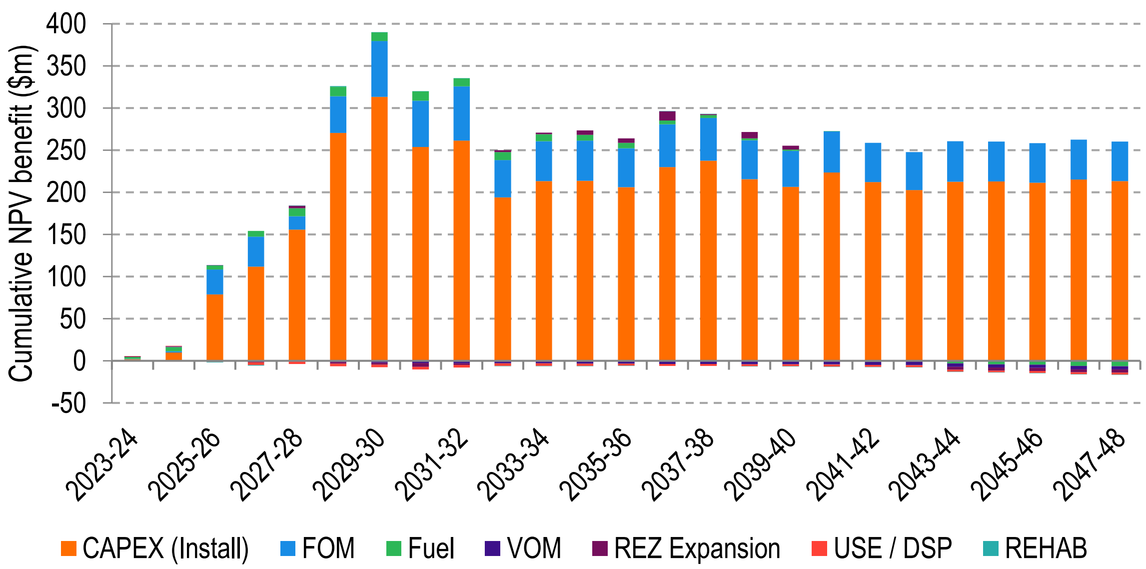


Figure 47: Difference in NEM capacity forecast between Option 4 and Alternative Base Case in the Step Change scenario

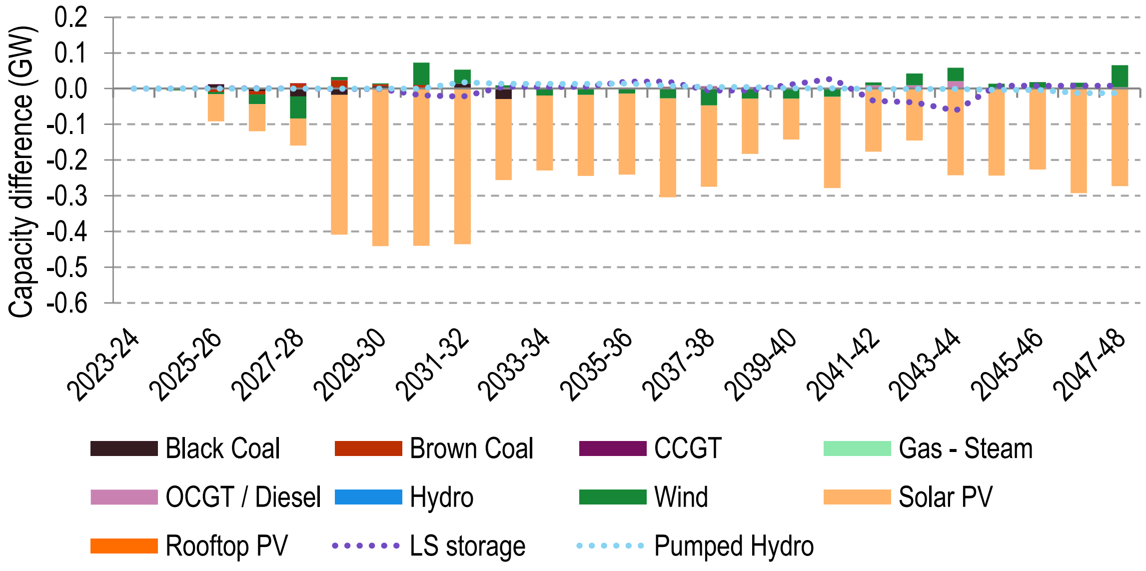
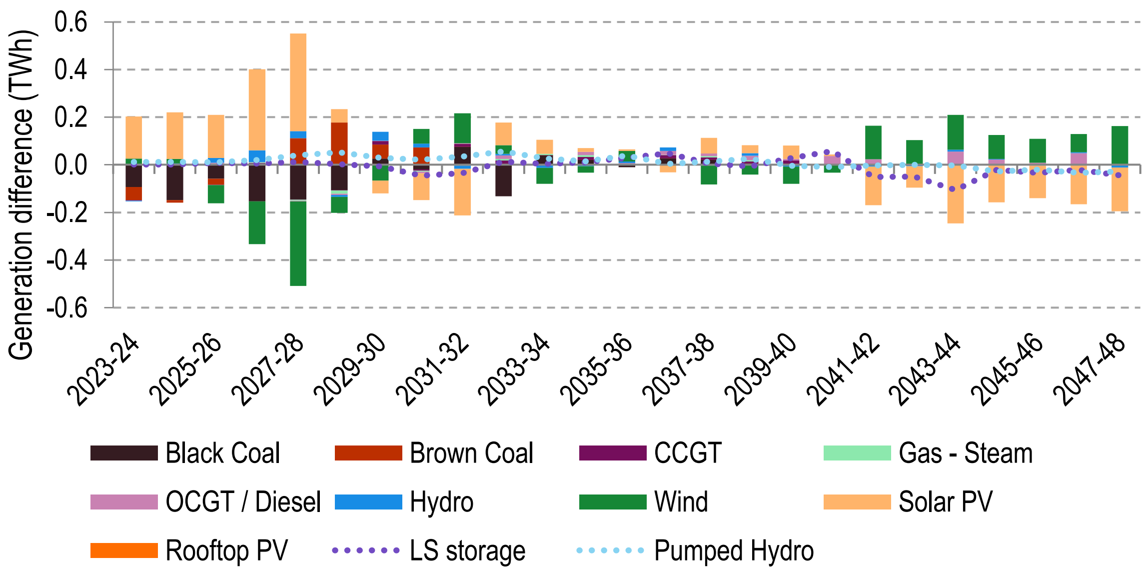



Figure 48: Difference in NEM generation forecast between Option 4 and Alternative Base Case in the Step Change scenario




The primary sources and overall forecast gross market benefits in this sensitivity are very similar to the core scenario modelling, being primarily from capex and FOM savings due to avoided and deferred capex for new generators. This sensitivity case results in approximately $15m lower gross market benefits relative to the core scenario modelling. The main driver of lower gross market benefits in this sensitivity case is reduced solar and wind capex saving in the first two years of modelling due to the increased interim limit in the Alternative Base Case.

# 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 |
| CWO | Central West Orana |
| DSP | Demand side participation |
| FFP | Fixed Flat Plate |
| FOM | Fixed Operation and Maintenance |
| GW | Gigawatt |
| GWh | Gigawatt-hour |
| ISP | Integrated System Plan |
| 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 |
| PACR | Project Assessment Conclusion Report |
| PEC | Project EnergyConnect |
| PSH | Pumped Storage Hydro |
| PV | Photovoltaic |
| QLD | Queensland |
| QNI | Queensland-New South Wales interconnector |
| QNI Minor | NSW to QLD Interconnector Upgrade |
| QRET | Queensland Renewable Energy Target |
| REZ | Renewable Energy Zone |

| Abbreviation | Meaning |
|---|---|
| RIT-T | Regulatory Investment Test for Transmission |
| RHS | Right Hand Side |
| SA | South Australia |
| SAT | Single Axis Tracking |
| STATCOM | Static Synchronous Compensator |
| SRMC | Short-Run Marginal Cost |
| SWNSW | South West New South Wales (NEM zone) |
| TAS | Tasmania |
| TRET | Tasmanian Renewable Energy Target |
| 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 |
| VNI Minor | Victoria to NSW Interconnector Upgrade |
| VOM | Variable Operation and Maintenance |
| VRET | Victoria Renewable Energy Target |
| VPP | Virtual Power Plant |

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