Victoria to NSW Interconnector West (VNI West)

Market modelling report forecasting gross market benefits for the PADR

26 July 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 two options for the Victoria to NSW Interconnector West (VNI West) Regulatory Investment Test for Transmission ("VNI West 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 22 September 2021 and was completed on 4 May 2022. Therefore, our Report does not take account of events or circumstances arising after 4 May 2022 and we have no responsibility to update the Report for such events or circumstances.

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

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

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

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.

Table of contents

1. Executive summary

Transgrid has engaged EY to undertake market modelling of system costs and benefits of two options related to the Victoria to NSW Interconnector West (VNI West) network development for the Regulatory Investment Test for Transmission (RIT-T).

The VNI West RIT-T is a joint RIT-T by Transgrid (as the transmission network service provider in NSW) and Australian Energy Market Operator (AEMO) (in its role as Victorian transmission network service provider). Although assumptions and input data sources were selected by both parties, we took instruction from Transgrid as our client. The selection of input assumptions and modelling methodology follows the *Cost benefit analysis guidelines* (CBA guidelines) published by the Australian Energy Regulator (AER)[1] which contain the applicable RIT-T guidelines for actionable ISP projects including VNI West.

This Report forms a supplementary report to the Project Assessment Draft Report (PADR) prepared and published by Transgrid and AEMO[2], and describes the key modelling outcomes and insights as well as the assumptions and input data sources jointly prepared by Transgrid and AEMO in accordance with the CBA guidelines and the modelling methods used. The Report should be read in conjunction with the PADR[2] published by Transgrid and AEMO.

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) associated with two options for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued by the AEMO Draft 2022 Integrated System Plan (ISP)[3]. In addition, based on joint agreement between Transgrid and AEMO, we were requested to incorporate more recent inputs and assumptions updates based on new information since the publication of the Draft 2022 ISP, as follows:

- latest committed and anticipated generators from the AEMO Generation Information, published in February 2022[4].
- recent announced closure dates for Eraring, Bayswater and Loy Yang coal fired generators[4].

The following options have been considered in this modelling:

- Option 1: VNI West via Kerang with scenario-dependent commissioning dates.
- Option 2: virtual transmission line (VTL) from 1 July 2026 to provide network support for Victoria to NSW interconnector (VNI) until the commissioning of Option 1. Note that two batteries (250 MW/125 MWh each) are assumed to switch to market arbitrage operation after the commissioning of Option 1. The batteries are assumed to retire in 2046, based on a 20-year lifetime.

In addition, jointly agreed between Transgrid and AEMO, we were requested to model a sensitivity to assess the impact of excluding the power flow controllers (PFC) on the benefits of Option 1. The

[1] AER, August 2020. *Cost benefit analysis guidelines*. Available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable/final-decision Accessed 12 January 2022

[2] Transgrid and AEMO, *Victoria to NSW Interconnector West PADR*. Available at: https://www.transgrid.com.au/projects-innovation/victoria-to-nsw-interconnector-west. Accessed 22 April 2022.

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

[4] AEMO generation information and expected closure years, February 2022, available at: https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/generation_information/2022/nem-generation-information-feb-2022.xlsx?la=en

sensitivity was run on the Step Change scenario, assuming the import limit of VNI to Victoria without the PFC is reduced by 800 MW compared to the limit assumed in Option 1.

To assess the potential least-cost solution, EY's 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. Generators 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[5], large-scale battery (LS Battery), pumped hydro energy storage (PHES) and hydrogen turbine technology (only applied in the Hydrogen Superpower scenario).
- the withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenarios.

The hourly decisions consider certain 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)[6],
- minimum loads for coal generators,
- interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- intra-regional flow limits for the detailed network modelled in Victoria and Southern NSW through DC load flow (DCLF),
- maximum and minimum storage (conventional storage hydro, PHES and LS battery) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each renewable energy zone (REZ) where applicable, and PHES in each region,
- 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 we computed the following costs, as defined in the RIT-T:

- capital costs of new generation capacity installed (capex),
- total fixed operation and maintenance (FOM) costs of all generation capacity,
- total 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 REZ development.

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

[6] Based on AER, December 2021, *Values of Customer Reliability Final report on VCR values.* These are the same values applied in AEMO's Draft 2022 ISP, available at: https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

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 needs 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 PHES and LS battery between each VNI West option and the counterfactual Base Case.

For each simulation with a VNI West option and in a matched no augmentation counterfactual (referred to as the Base Case), we computed the sum of these cost components and compared the difference between each option and the Base Case. The difference in present values of costs is the forecast gross market benefits[7] 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, consistent with the value applied by AEMO in the Draft 2022 ISP[3] as required by the CBA guidelines[1].

Table 1 summarises the forecast gross market benefits over the modelled 25-year horizon for both options across all scenarios. In addition, the breakdown of gross market benefits by category 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 scenario-specific 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 and AEMO, by incorporating the forecast gross modelled market benefits into the calculation of net economic benefits.

Table 1: Summary of forecast gross market benefits, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Potential gross market benefits ($m)		
			Progressive Change	Step Change	Hydrogen Superpower
Option 1	VNI West via Kerang	▶ 1/07/2030 for Hydrogen Superpower ▶ 1/07/2031 for Step Change ▶ 1/07/2038 for Progressive Change	971	2,795	3,587
Option 2	Interim VTL solution until Option 1 commissioning	▶ 1/07/2026 for VTL, until Option 1 commissioning	1,082	3,002	3,885
Sensitivity 1	Impact of excluding PFC on Option 1	▶ 1/07/2031 for Step Change	NA	2,439	NA

[7] In this Report we use the term *gross market benefit* to mean "market benefit" as defined in the AER's *Cost benefit analysis guidelines*, and "net economic benefit" in the same manner defined in the guidelines.

Figure 1: Composition of forecast total gross market benefits for both options – Step Change

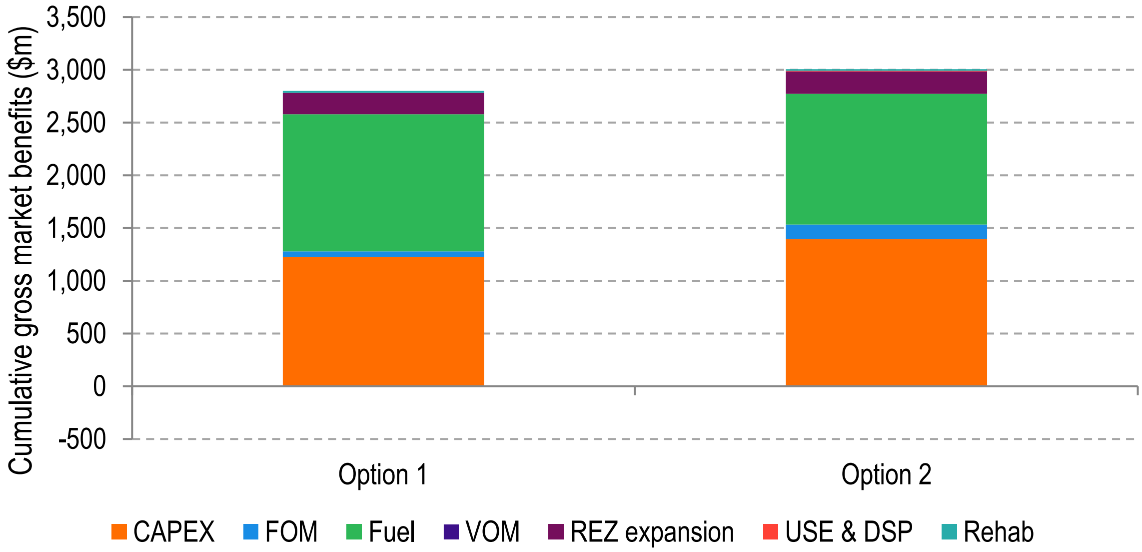


Figure 2: Composition of forecast total gross market benefits for both options – Progressive Change

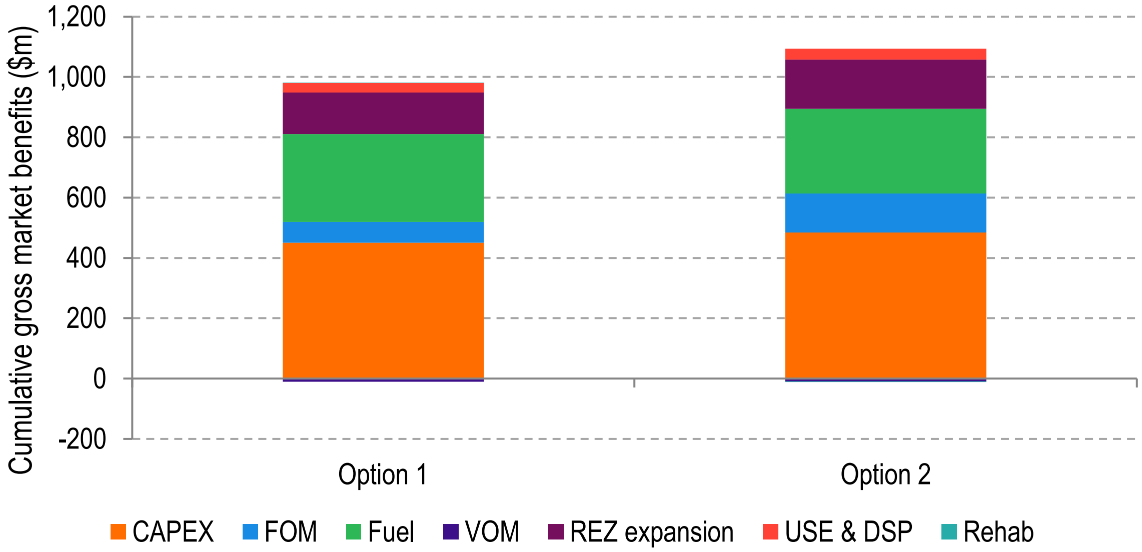
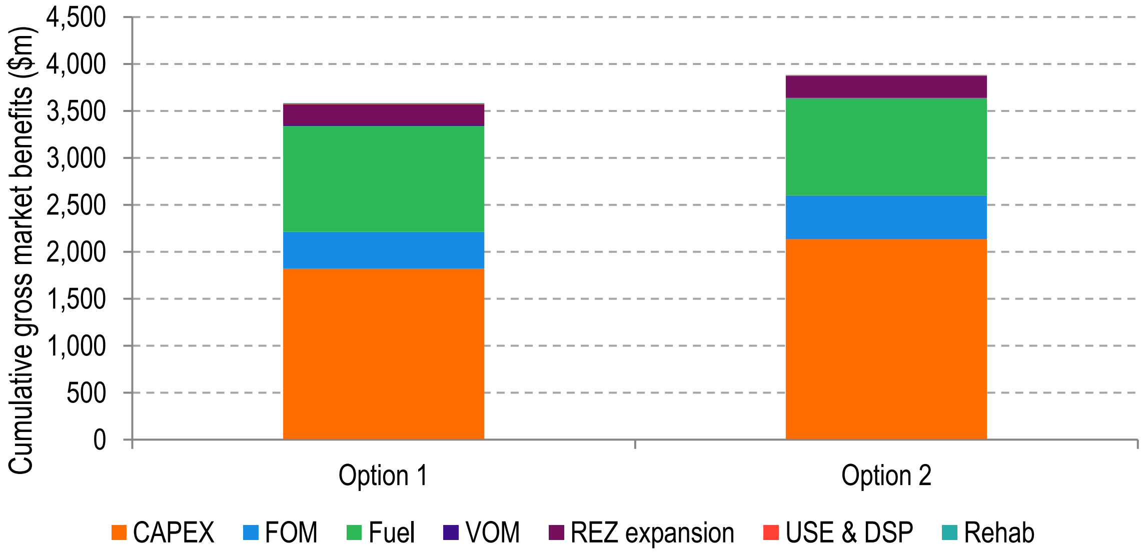


Figure 3: Composition of forecast total gross market benefits for both options – Hydrogen Superpower



Both options are expected to achieve their highest gross market benefits in the Hydrogen Superpower scenario, and their lowest gross market benefits in the modelled Progressive Change scenario. The forecast gross market benefits for Option 1 range between just under $1b in the Progressive Change scenario and just above $3.5b in the Hydrogen Superpower scenario. The gross market benefits for Option 2 are expected to be $111m, $207m and $298m higher than that of Option 1 in the Progressive Change, Step Change and Hydrogen Superpower scenarios, respectively.

The sources of benefits and the key drivers are as follows:

- Across both options, capex, fuel, REZ transmission expansion and FOM are the main categories of benefits in all modelled scenarios.
- The majority of benefits in the Step Change scenario are forecast to come from capex and fuel cost savings with approximately equal shares of around $1.3b, followed by around $200m benefits from REZ expansion savings.
- For the Progressive Change and Hydrogen Superpower scenarios the proportion of benefits from each category is similar. Capex savings account for around 46% of benefits, followed by fuel, REZ expansion and FOM cost savings.
- The increased transfer capacity with both options is forecast to unlock diverse VRE resources and efficient sharing of energy and capacity between southern regions, particularly Victoria, and NSW as well as Queensland. Resource sharing as well as better utilisation of Snowy PHES utilisation, particularly Snowy 2.0, is forecast to allow for more efficient allocation of capex by deferring and reducing investment in new capacity. This is forecast to also deliver fuel cost savings through greater transfer of diverse VRE resources, offsetting thermal generation.

2. Introduction

Transgrid has engaged EY to undertake market modelling of system costs and benefits of two options related to the Victoria to NSW Interconnector West (VNI West) RIT-T.

The VNI West RIT-T is a joint RIT-T by Transgrid (as the transmission network service provider in NSW) and AEMO (in its role as Victorian transmission network service provider). Although assumptions and input data sources were selected by both parties, we took instruction from Transgrid as our client. The selection of input assumptions and modelling methodology follows the CBA guidelines published by the AER[1] which contain the applicable RIT-T guidelines for actionable ISP projects including VNI West.

This Report forms a supplementary report to the broader PADR published by Transgrid and AEMO[2]. It describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by Transgrid and AEMO in accordance with the CBA guidelines and the modelling methods used. The Report should be read in conjunction with the PADR[2] published by Transgrid and AEMO.

EY computed the least-cost generation dispatch and capacity development plan for the NEM associated with options using input assumptions generally derived from the Draft 2022 ISP[3], in accordance with the CBA guidelines[1]. In addition, as jointly agreed between Transgrid and AEMO, we incorporated the most recent input and assumptions since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the AEMO Generation Information, published in February 2022[4].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[4].

The options were defined by Transgrid and AEMO and are described in detail in the PADR. This is an independent study, in which the modelling methodology follows the RIT-T guidelines for actionable ISP projects published by the AER[1].

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 agreed jointly by Transgrid and AEMO. This value is consistent with the value applied by AEMO in the Draft 2022 ISP[3], as required by the CBA guidelines[1].

This modelling considers two options as follows:

- Option 1: VNI West via Kerang. Timing of VNI West is scenario dependent, i.e., 1 July 2030 for the Hydrogen Superpower scenario, 1 July 2031 for the Step Change scenario, and 1 July 2038 for the Progressive Change scenario as assessed as optimal in the Draft 2022 ISP[3].
- Option 2: virtual transmission line (VTL) from 1 July 2026 until the commissioning of Option 1. Note that two batteries (250MW/125MWh each) are assumed to switch to market arbitrage operation after the commissioning of Option 1. The batteries are assumed to retire in 2046.

In addition, based on agreement by Transgrid and AEMO, we were requested to model a sensitivity to assess the impact of removing the PFC on the benefits of Option 1. The sensitivity was run on the Step Change scenario, assuming the import limit of VNI to Victoria without the PFC is reduced by 800 MW compared to the limit assumed in Option 1.

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 and AEMO, 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"[1].

The Report is structured as follows:

- Section 3 describes options, assumptions and scenarios inputs modelled in this analysis.
- 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 VNI West 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. Options and scenario assumptions

3.1 Options

Based on the joint agreement between Transgrid and AEMO, we were requested to model two options as follows:

- Option 1: VNI West via Kerang. Timing of VNI West is scenario dependent, i.e., 1 July 2030 for the Hydrogen Superpower scenario, 1 July 2031 for the Step Change scenario, and 1 July 2038 for the Progressive Change scenario as assessed as optimal in the Draft 2022 ISP[8].
- Option 2: virtual transmission line (VTL) from 1 July 2026 until the commissioning of Option 1. Note that two batteries (250MW/125MWh each) are assumed to switch to market arbitrage operation after the commissioning of Option 1. The batteries are assumed to retire in 2046.

In addition, we modelled a sensitivity to assess the impact of removing the PFC on the benefits of Option 1, as requested by Transgrid and AEMO. The sensitivity was run on the Step Change scenario, assuming the import limit of VNI to Victoria without the PFC is reduced by 800 MW compared to the limit assumed in Option 1.

3.2 Key assumptions for modelled Scenarios

The options proposed by Transgrid and AEMO have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenarios from the Draft 2022 ISP[3,9], indicated in Table 2. We were also requested to incorporate modifications to AEMO's input and assumptions based on updated information since the publication of the Draft 2022 ISP, as follows:

- Latest committed and anticipated generators from the AEMO Generation Information, published in February 2022[4].
- Recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[4].

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[10] (ISP 2022) - Step Change	ESOO 2021[10] (ISP 2022) - Progressive Change	ESOO 2021[10] (ISP 2022) - Hydrogen Superpower
Committed and anticipated generation	Latest committed and anticipated generators from the Generation Information Page, published in February 2022[4].		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2021 Inputs and Assumptions Workbook[11] – Step Change	2021 Inputs and Assumptions Workbook[11] - Progressive Change	2021 Inputs and Assumptions Workbook[11] - Hydrogen Superpower

[8] AEMO, 10 December 2021. *2022 Draft Integrated System Plan*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 5 April 2022.

[9] The AER's *Cost benefit analysis guidelines* requires that the RIT-T proponent of an actionable ISP project adopts the scenarios specified in the AEMO ISP as relevant.

[10] AEMO, *National Electricity and Gas Forecasting*, http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational,

[11] *2021 Inputs and Assumptions Workbook v3.3*, https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed on 5 April 2022.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Retirements of coal-fired power stations	2021 Inputs and Assumptions Workbook[11] - Step Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[3]	2021 Inputs and Assumptions Workbook[11] - Progressive Change: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives beyond 2030. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[3]	2021 Inputs and Assumptions Workbook[11] - Hydrogen Superpower: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives. Updated to reflect recently announced closure dates for Eraring, Bayswater and Loy Yang coal fired power stations[3]
Gas fuel cost	2021 Inputs and Assumptions Workbook[11] - Step Change: Lewis Grey Advisory 2020, Step Change	2021 Inputs and Assumptions Workbook[11] - Progressive Change: Lewis Grey Advisory 2020, Central	2021 Inputs and Assumptions Workbook[11] - Hydrogen Superpower: Lewis Grey Advisory 2020, Step Change
Coal fuel cost	2021 Inputs and Assumptions Workbook[11] - Step Change: Wood Mackenzie, Step Change	2021 Inputs and Assumptions Workbook[11] - Progressive Change: Wood Mackenzie, Central	2021 Inputs and Assumptions Workbook[11] - Hydrogen Superpower: Wood Mackenzie, Step Change
NEM carbon budget	2021 Inputs and Assumptions Workbook[11] - Step Change: 891 Mt CO_2-e 2023-24 to 2050-51	2021 Inputs and Assumptions Workbook[11] - Progressive Change: 932 Mt CO_2-e 2030-31 to 2050-51	2021 Inputs and Assumptions Workbook[11] - 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[11] VRET 2 including 600 MW of renewable capacity by 2025[11]		
Queensland Renewable Energy Target (QRET)	50% by 2030[11]		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, 150% by 2030 and 200% Renewable generation by 2040, excluding hydro[11]		
NSW Electricity Infrastructure Roadmap	12 GW NSW Roadmap, with 3 GW in the Central West Orana (CWO) REZ, modelled as generation constraint per the Draft 2022 ISP and 2 GW of long duration storage (8 hrs or more) by 2029-30[11]		
NSW to Queensland Interconnector Upgrade (QNI Minor)	QNI minor commissioned by July 2022[11]		
Victoria to NSW Interconnector Upgrade (VNI Minor)	VNI Minor commissioned by December 2022[11]		
Victorian SIPS	300 MW/450 MWh, 250 MW for SIPS service during summer. In the summer months the remaining 50 MW can be deployed in the market on a commercial basis, in the winter months the full capacity is available. From April 2032 the full capacity is available to the market.[11]		
EnergyConnect	Draft 2022 ISP anticipated project[3]: EnergyConnect commissioned by July 2025		
Western Victoria Transmission Network Project	Draft 2022 ISP[3] anticipated project: Western Victoria upgrade commissioned by November 2025		
HumeLink	Draft 2022 ISP[3] outcome - Step Change: HumeLink commissioned by July 2028	Draft 2022 ISP[3]. outcome - Progressive Change: HumeLink commissioned by July 2035	Draft 2022 ISP[3]. outcome - Hydrogen Superpower: HumeLink commissioned by July 2027

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
New-England REZ Transmission	Draft 2022 ISP outcome[3] - Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	Draft 2022 ISP outcome[3] - Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	Draft 2022 ISP outcome[3] - 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
Marinus Link	Draft 2022 ISP[3] outcome:1st cable commissioned by July 2029 and 2nd cable by July 2031		
QNI Connect	Draft 2022 ISP[3] outcome - Step Change: QNI Connect commissioned by July 2032	Draft 2022 ISP[3] outcome - Progressive Change: QNI Connect commissioned by July 2036	Draft 2022 ISP[3] outcome - Hydrogen Superpower: QNI Connect commissioned by July 2029 and stage 2 to be commissioned by July 2030
VNI West	Draft 2022 ISP[3] outcome - Progressive Change: VNI West commissioned by July 2031	Draft 2022 ISP[3] outcome - Progressive Change: VNI West commissioned by July 2038	Draft 2022 ISP[3] outcome - Hydrogen Superpower: VNI West commissioned by July 2030
Snowy 2.0	Snowy 2.0 is commissioned by December 2026[11]		

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 for actionable ISP projects published by the AER[1].

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 run 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, LS battery and PHES[5]. 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[6],
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),
- intra-regional flow limits (between zones in NSW),
- intra-regional flow limits for a detailed network modelled in Victoria and Southern NSW through DCLF,
- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES and LS battery),
- 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 PHES 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 and Victoria through modelling of zones with intra-regional limits and losses. Within these zones and within regions, no further detail of the transmission network is considered. More detail on the transmission network representation is given in Section 5.

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

The model meets the specified carbon budget assumed in each scenario 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 another component of the running cost of generators contributing to potential earlier economic withdrawal [13]. 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 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, PHES, LS battery 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 PHES and LS battery 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 PHES, VPPs and LS battery[14]) 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] Note that earlier coal withdrawal in TSIRP is an outcome of the least cost optimisation rather than revenue assessment.

[14] PHES and LS 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, sub-optimal operation of storage). This constraint is applied to only a subset of simulation hours when demand is high to reduce the optimisation problem size.[15]

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 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)[16], discounted to June 2021 at a 5.5% real, pre-tax discount rate as agreed jointly by Transgrid and AEMO. This value is consistent with the value applied by AEMO in the Draft 2022 ISP[3], as required by the CBA guidelines[1].

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 forecast net economic benefit and preferred option was conducted outside of this Report by Transgrid and AEMO[2] using the forecast gross market benefits from this Report and other inputs. All references to the preferred option in this Report are in the sense defined in the RIT-T for actionable ISP projects as "the credible option that maximises the net economic benefit across the market, compared to all other credible options"[1], as identified in the PADR[2].

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

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

5. Transmission and demand

5.1 Regional and zonal definitions

Jointly agreed by Transgrid and AEMO, we were requested to split NSW into sub-regions or zones in the modelling presented in this Report[17], as listed in Table 3. In addition, southern NSW and Victorian networks are modelled with higher resolution through several nodes and an overlayed DC power flow model in TSIRP. This network representation varies from that applied in the Draft 2022 ISP but in Transgrid and AEMO's views, enables better representation of intra-regional network limitations and transmission losses in the relevant parts of the network.

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
	Darlington Point	Darlington Point 330 kV
	Dinawan	Dinawan 330kV
	Buronga	Buronga 330kV
	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
	Southern Victoria	Thomastown 66 kV
	Shepparton	Shepparton 220kV
	Bendigo	Bendigo 220kV
	Kerang	Kerang 220KV
	Red Cliffs	Red Cliffs 220kV
	Horsham	Horsham 220kV
	Ballarat	Ballarat 220kV

[17] 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.

Region	Zone	Zonal Reference Node
South Australia	South Australia (SA)	Torrens Island 66 kV
Tasmania	Tasmania (TAS)	Georgetown 220 kV

The borders of each zone or region are defined by the cut-sets listed in Table 4, as defined by Transgrid. Dynamic loss equations are defined between reference nodes across these cut-sets.

Table 4: Key cut-set definitions

Border	Lines
NNS-NCEN	Line 88 Muswellbrook - Tamworth Line 84 Liddell - Tamworth Line 96T Hawks Nest - Taree Line 9C8 Stroud - Brandy Hill
NCEN- Canberra	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Line 4/5 Yass - Marulan Line 973 Yass - Cowra Line 999 Yass - Cowra Line 98J Shoalhaven - Evans Lane Line 28P West Tomerong - Evans Lane and new HumeLink lines for each option
Canberra/Yass-Bannaby	Line 61 Gullen Range - Bannaby Line 3W Kangaroo Valley - Capital Lines 4 &5 Yass - Marulan and new HumeLink lines from Maragle/Wagga to Bannaby for each option
Snowy cut-set	Line 01 Upper Tumut to Canberra Line 2 Upper Tumut to Yass Line 07 Lower Tumut to Canberra Line 3 Lower Tumut to Yass
Buronga-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.

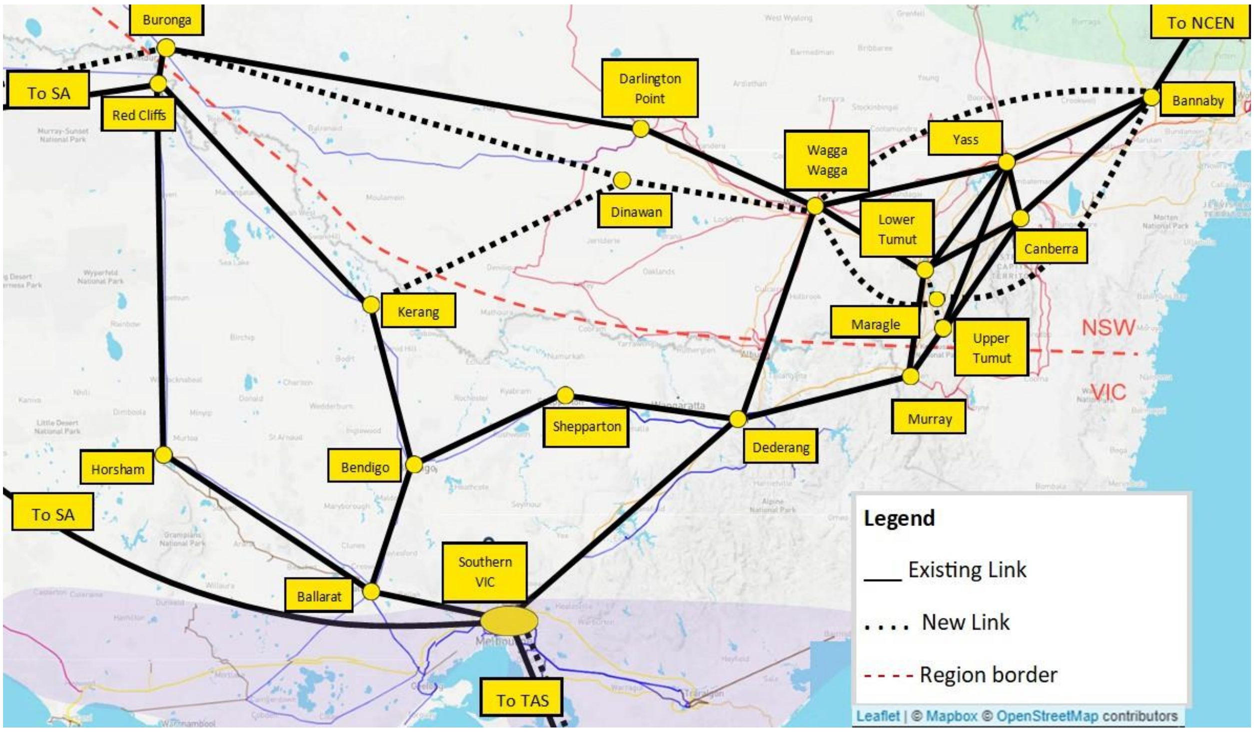
Table 5: Key cut-set limits (MW)

Options	Bidirectional limit (MW)
Snowy cut-set	3,080
Snowy cut-set + HumeLink lines	5,372
Canberra/Yass - Bannaby cut-set	4,900
Canberra-NCEN cut-set	4,500
Bannaby-NCEN	4,500

5.2 Victoria and South NSW network model

Jointly agreed between Transgrid and AEMO, we were requested to model Victoria and southern NSW networks with a higher resolution through modelling several nodes. The network representation is illustrated in Figure 4. Major high-voltage substations in Victoria and southern NSW are modelled as nodes with the equivalenced lines linking between them. The only exception in Victoria is "Southern VIC" node which represents the areas of southern Victoria from Latrobe Valley to Portland. The lines are derived by equivalencing the network connecting the given nodes in the subregion. Demand components are split across the nodes based on their half-hourly proportion of the overall NSW load in 2017-18. Furthermore, generators within this subregion are mapped into the nearest node. TSIRP models the flows and losses for this network using DCLF equations. DCLF is a simplified AC load flow which neglects reactive power flows. The model also captures the losses for the given lines through piecewise linear functions using the equivalent resistance of those lines.

Figure 4: Southern NSW and Victoria DC powerflow network[18,19]



The cut-set definition and limits of the VNI are shown in Table 6 and Table 7.

Table 6: VNI cut-set

Border	Lines
Victoria - NSW	220 kV line between Red Cliffs and Buronga 330 kV lines from Murray to Lower Tumut and Upper Tumut 330 kV line from Wodonga to Jindera (modelled as Dederang to Wagga in DC power flow model) Additional circuit between Red Cliffs and Buronga as part of Energy Connect Double circuit 500 kV line from Kerang to Dinawan, as part of VNI West

[18] This map is a graphical representation of the modelled network, not a map of existing or proposed transmission routes.
[19] AEMO, *AEMO Map*, Available at: https://www.aemo.com.au/aemo/apps/visualisations/map.html, Accessed 16 May 2022.

Table 7: Transfer limits of Victoria to NSW

Description	Import limit (MW)	Export limit (MW)
Original limits	400 all periods	870 peak demand 1,000 summer 1,000 winter
Post Victorian SIPS contract with no Option 1	250 peak demand 400 summer 400 winter	870 peak demand 1,000 summer 1,000 winter
Post Option 1 commissioning with SIPS contract in place	2,200 all periods	2,800 peak demand 2,930 summer 2,930 winter
Post Option 1 commissioning and SIPS contract ended	2,050 peak demand 2,200 summer 2,200 winter	2,800 peak demand 2,930 summer 2,930 winter

PFCs are assumed in Option 1 and Option 2, which are expected to change the reactance of some Victorian transmission lines as shown Table 8. It is assumed that with the PFC, the current reactance of the lines shown in Table 8 increase by the assumed compensation percentage.

Table 8: PFC impact on reactance of Victorian lines

Line	Compensation (%)
Dederang - Murray No.1	60%
Dederang - Murray No.2	60%
Eildon - Thomastown	83%
South Morang - Thomastown	157%

5.3 Interconnector and intra-connector loss models

Dynamic loss equations for the existing network are generally sourced from AEMO's *Regions and Marginal Loss Factors*[20]. New dynamic loss equations are computed for several conditions, including:

- when a new link is defined e.g., NNS-NCEN, SA-Buronga (EnergyConnect), Bannaby-NCEN,
- all the Victorian and southern NSW equivalenced lines between the modelled nodes, through their equivalent resistance, and
- 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 and AEMO.

5.4 Interconnector and intra-connector capabilities

The notional limits imposed on interconnectors are shown in Table 9. The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in this table:

[20] AEMO, *Marginal Loss Factors for the 2018-19 Financial Year*. Available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/market-operations/loss-factors-and-regional-boundaries. Accessed 2 May 2022.

- Heywood + Project EnergyConnect (PEC) has combined transfer export and import limits of 1,300 MW and 1,450 MW. The model will dispatch across the two links to minimise costs.

Table 9: Notional interconnector capabilities used in the modelling (sourced from AEMO Draft 2022 ISP[11])

Interconnector (From node – To node)	Import[21] notional limit	Export[22] notional limit
QNI[23]	1,205 MW peak demand 1,165 MW summer 1,170 MW winter	685 MW peak demand 745 MW summer/winter
QNI Connect 1[24]	2,285 MW peak demand 2,245 MW summer 2,250 MW winter	1,595 MW peak demand 1,655 MW summer/winter
QNI Connect 2[24]	3,085 MW peak demand 3,045 MW summer 3,050 MW winter	2,145 MW peak demand 2,205 MW summer/winter
Terranora (NNS-SQ)	130 MW peak demand 150 MW summer 200 MW winter	0 MW peak demand 50 MW summer/winter
EnergyConnect (Buronga-SA)	800 MW	800 MW
Heywood (VIC-SA)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)	650 MW (before EnergyConnect) 750 MW (after EnergyConnect)
Murraylink (VIC-SA)	200 MW	220 MW
Basslink (TAS-VIC)	478 MW	478 MW
Marinus Link (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage	750 MW for the first leg and 1,500 MW after the second leg

NSW has been split into zones with the following limits imposed between the zones defined in Table 10.

Table 10: Intra-connector notional limits imposed in modelling for New South Wales

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 Draft 2022 ISP[3].	1,377 MW (after QNI Minor) Limit will increase after NEW England REZ augmentations as mentioned in the Draft 2022 ISP[3].

21 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.

22 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.

23 Flow on QNI may be limited due to additional constraints.

24 AEMO, 10 December 2021. *Appendix 5: Network Investments (Appendix to Draft 2022 ISP for the National Electricity market)*. Available at: https://aemo.com.au/consultations/current-and-closed-consultations/2022-draft-isp-consultation. Accessed 22 April 2022.

Intra-connector (From node – To node)	Import notional limit	Export notional limit
WAG-SWNSW (provided by Transgrid)	300 MW (before EnergyConnect) 1,100 MW (after EnergyConnect) 1,900 MW (after HumeLink) 3,000 MW (after VNI West)	500 MW (before EnergyConnect) 1,300 MW (after EnergyConnect) 2,100 MW (after HumeLink) 2,700 MW (after VNI West)

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 and historical data for other non-scheduled generation,
- 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 5.
- 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, domestic battery and other small non-scheduled generation) to get a projection of hourly operational demand.

Figure 5: Sequence of demand reference years applied to forecast

Modelled year	Reference year
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19

Modelled year	Reference year
...	...
2041-42	2014-15
2042-43	2015-16
2043-44	2016-17
2044-45	2017-18
2045-46	2018-19
2046-47	2010-11
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 rooftop PV generation and other behind-the-meter loads and generators that may alter the size of peaks and their timing across regions. Overall, due to 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 and AEMO selected demand forecasts from the ESOO 2021[10] consistent with the relevant scenarios in the Draft ISP 2022[11] which are used as inputs to the modelling. Figure 6 and Figure 7 show the NEM operational energy and distributed PV (rooftop PV and small-scale non-scheduled PV) for the modelled scenarios.

Figure 6: Annual operational demand in the modelled scenarios for the NEM[10]

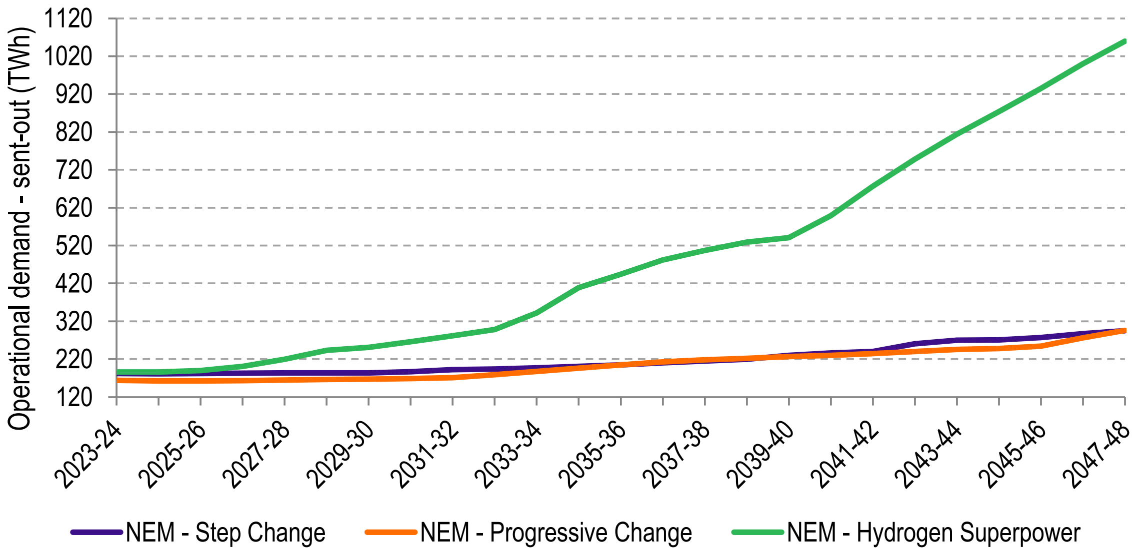
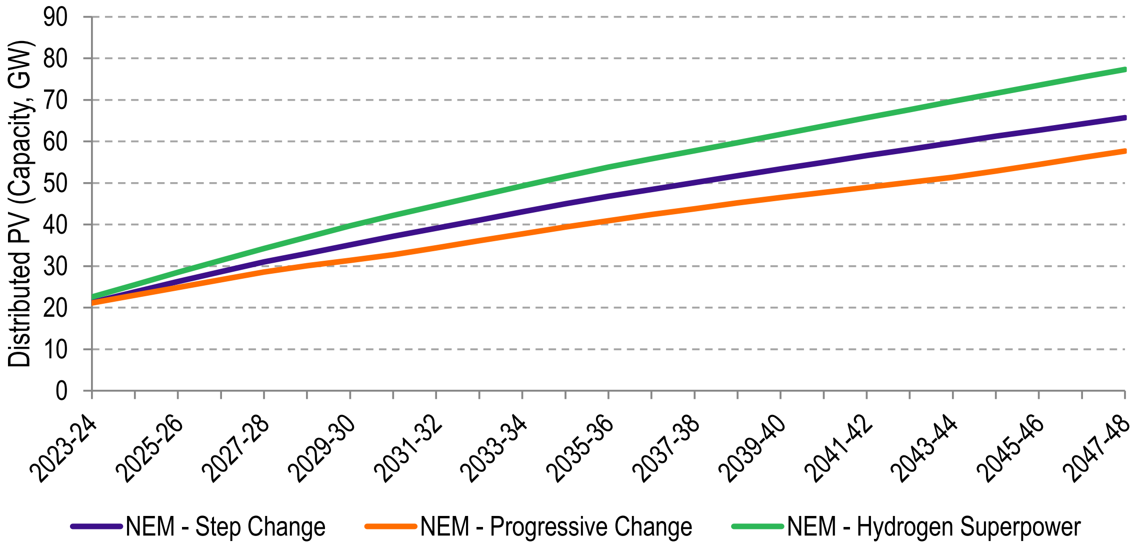


Figure 7: Annual distributed PV (rooftop PV and small non-scheduled PV) uptake in the NEM[10]



The ESOO 2021 demand forecasts for NSW and Victoria are split into the corresponding zones/nodes 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 these regions.

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 the AEMO 2021 ISP Inputs and Assumptions workbook[11], existing, committed and anticipated projects with updates based on new information since the publication of the Draft 2022 ISP[3].

Existing and new wind and solar projects are modelled based on nine years of historical weather data[25]. The methodology for each category of wind and solar project is summarised in Table 11 and explained further in this section of the Report.

Table 11: Summary of wind and solar availability methodology

Technology	Category	Capacity factor methodology	Reference year treatment
Wind	Existing	Specify long-term target based on nine-year average in AEMO ESOO 2019 traces[26] 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 ISP Inputs and Assumptions workbook[11].	
	Generic REZ new entrants	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[11]. 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[11].	
	Generic REZ new entrant	Reference year specific targets based on AEMO 2021 ISP Inputs and Assumptions workbook[11].	
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[11].	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

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

[26] AEMO, *2019 Electricity Statement of Opportunities: 2019 Wind Traces* and *2019 Solar Traces*. Available at: https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo Accessed 21 January 2022.

occurring in the nine historical years, and these generation patterns are repeated throughout the modelling period as shown in Figure 5.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[27] 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 and draft 2021 ISP inputs and assumptions[11] for each REZ (new entrant wind farms, as listed in Table 12).

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 12).

Table 12: Assumed REZ wind and solar average capacity factors over the nine modelled reference years[11]

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
Queensland	Far North Queensland	55%	48%	27%
	North Queensland Clean Energy Hub	44%	37%	30%
	Northern Queensland	Tech not available	Tech not available	28%
	Isaac	37%	32%	28%
	Barcaldine	34%	31%	32%
	Fitzroy	38%	33%	28%
	Wide Bay	32%	31%	26%
	Darling Downs	39%	34%	27%
	Banana	31%	28%	29%
New South Wales	North West NSW	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 NSW	30%	30%	27%
	Wagga Wagga	28%	27%	26%
	Cooma-Monaro	43%	40%	Tech not available
Victoria	Ovens Murray	Tech not available	Tech not available	24%
	Murray River	Tech not available	Tech not available	27%
	Western Victoria	41%	37%	23%

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

Region	REZ	Wind		Solar SAT
		High quality	Medium quality	
	South West Victoria	41%	39%	Tech not available
	Gippsland[28]	39%	34%	20%
	Central North Victoria	33%	31%	26%
South Australia	South East SA	39%	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%	39%	30%
	Roxby Downs	Tech not available	Tech not available	30%
	Eastern Eyre Peninsula	40%	38%	24%
	Western Eyre Peninsula	39%	38%	27%
Tasmania	North East Tasmania	45%	43%	22%
	North West Tasmania[29]	50%	46%	19%
	Central Highlands	56%	54%	20%

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2021 Inputs and Assumptions workbook[11].

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

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

6.2 Generator 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[11].

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

[28] Gippsland has an option for Offshore wind with an average capacity factor of 46%.

[29] North West Tasmania has an option for Offshore wind with an average capacity factor of 50 %.

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

Planned maintenance events for existing generators are scheduled during low demand periods and the number of days required for maintenance is set based on the AEMO 2021 Inputs and Assumptions workbook[10].

6.3 Generator technical parameters

Technical generator parameters applied are as detailed in the AEMO 2021 Inputs and Assumptions workbook[10] for AEMO's long-term planning model, except as 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[10]. 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[10].

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[10], 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, PHES 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[10]. The Tasmanian hydro schemes were modelled using a ten-pond model, with additional information sourced from the TasNetworks Input assumptions and scenario workbook for Project Marinus PACR[30].

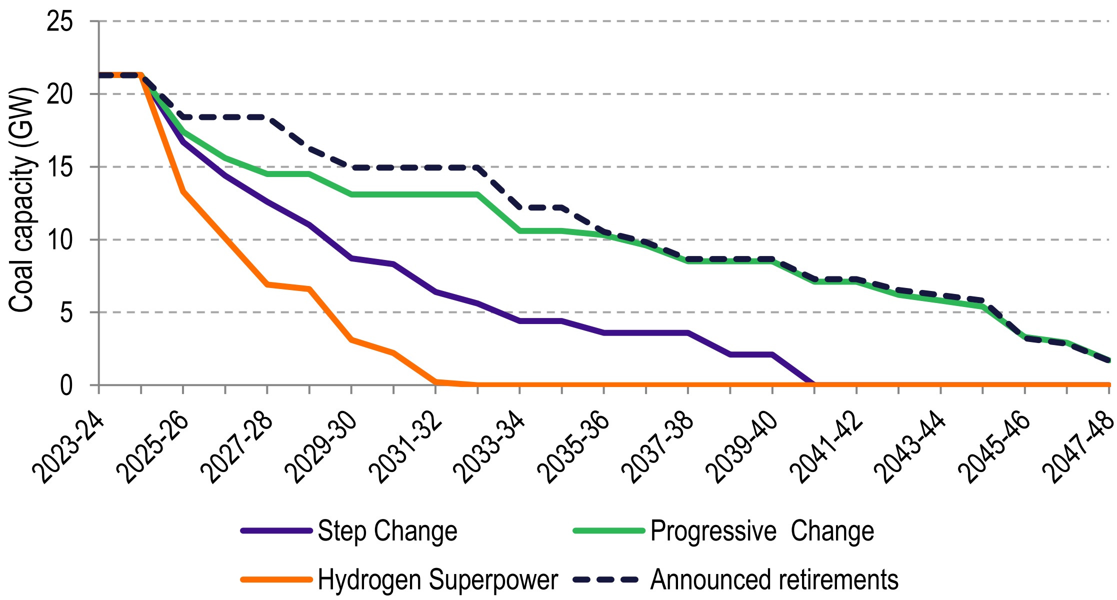
[30] TasNetworks, *Input assumptions and scenario workbook for Project Marinus PACR.* Available at https://www.marinuslink.com.au/rit-t-process/. Accessed on 26 April 2022

7. NEM outlook in the Base Case without VNI West options

Before presenting the forecast benefits of the options, it is useful to understand the expected capacity and generation outlooks in the modelled scenarios, and the underlying input assumptions driving those outlooks in the Base Case.

According to the scenario settings jointly selected by Transgrid and AEMO and in line with the Draft 2022 ISP[11], thermal withdrawal is determined on a least-cost basis. Coal withdrawal dates are at or earlier than their end-of-technical-life or announced withdrawal year. Forecast coal capacity in the Base Case across all scenarios as an output of the modelling is illustrated in Figure 8.

Figure 8: Forecast coal capacity in the NEM by year across all scenarios in the Base Case



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, legislated renewable energy targets (NSW Electricity Infrastructure Roadmap, VRET, QRET and TRET), demand outlook and end-of-life for existing assets in a system developed and dispatched at least cost. The model forecasts the entire coal capacity withdraws by the early 2030s in the Hydrogen Superpower scenario, while this is around 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the modelling period, although earlier withdrawal than AEMO's announced withdrawal is expected until around the mid-2030s.

The NEM-wide capacity mix forecast in the Base Case for the Step Change scenario is shown in Figure 9 and the corresponding generation mix in Figure 10. In the Base Case, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by LS battery, PHES, and gas.

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

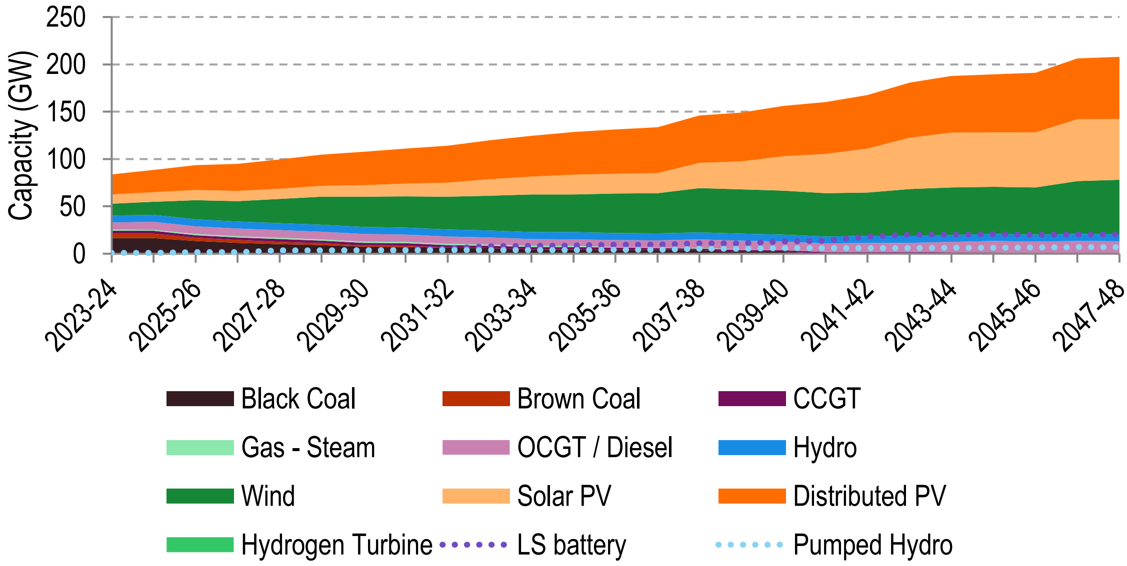
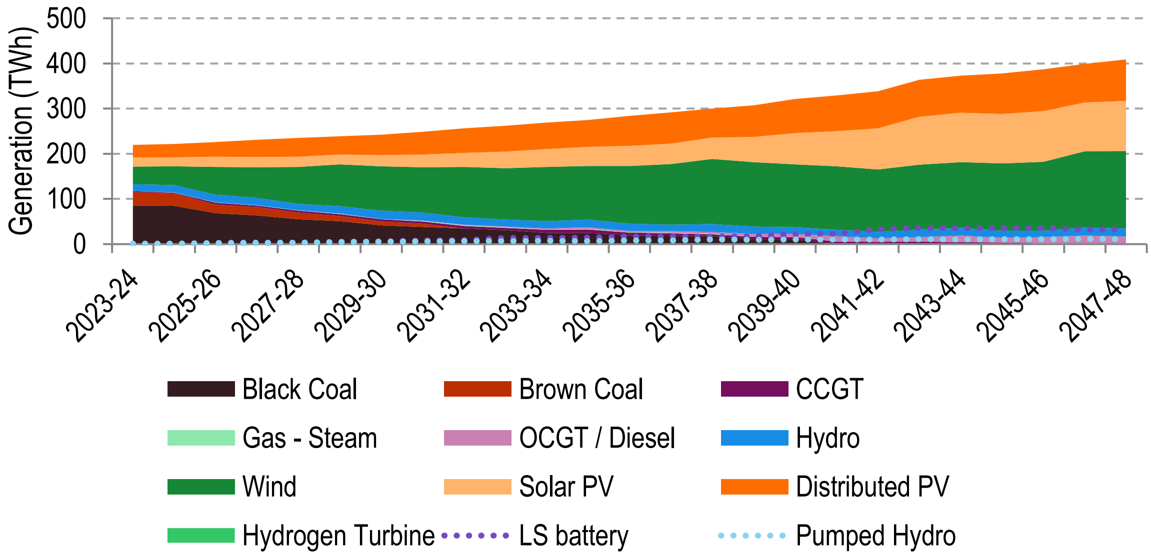


Figure 10: NEM generation mix forecast for the Step Change scenario in the Base Case



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 withdrawal[31] in Queensland and NSW. To replace the retiring capacity, LS battery capacity is forecast to start to increase from the late 2020s, then PHES and wind capacity increases from the 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. Overall, the NEM is forecast to have around 235 GW total capacity by 2047-48 (note that total capacity includes distributed PV, which is an input assumption, and also PHES and LS battery capacities, which are not in the stacked chart). The forecast timing of entry of the majority of new installed capacity coincides with coal-fired generation withdrawal.

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 11 and Figure 13 show the differences in the NEM capacity development of other scenarios relative to the Step Change scenario, while Figure 12 and Figure 14 show generation

[31] Note that the earlier coal withdrawal in TSIRP is based on the least cost optimisation, rather than revenue assessment.

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 less restrictive carbon budget, demand forecast and other underlying input data. The Hydrogen Superpower scenario has higher wind, solar and LS battery while less OCGT capacity and generation compared to the Step Change scenario, mainly due to the significant hydrogen demand uptake in this scenario, along with a more restrictive carbon budget.

Figure 11 Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios in the Base case (excluding distributed PV)

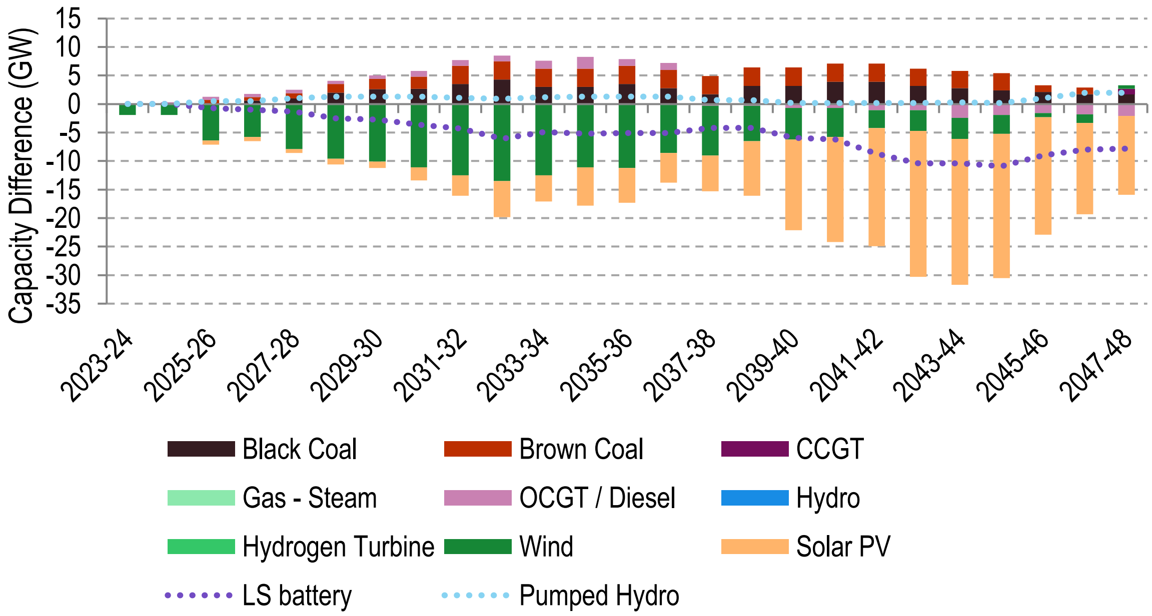


Figure 12 Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios in the Base case (excluding distributed PV)

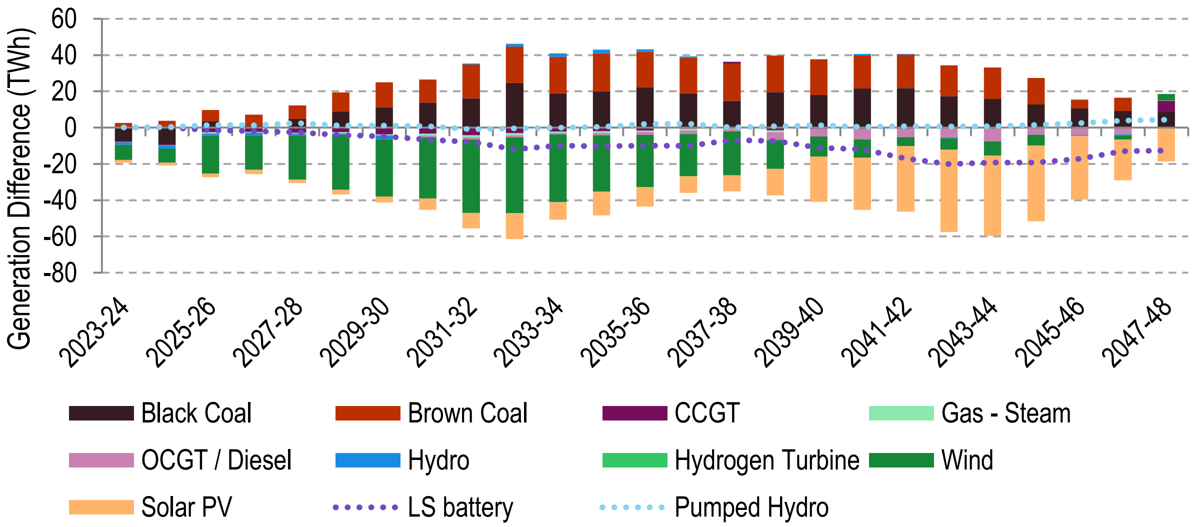


Figure 13 Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding distributed PV)

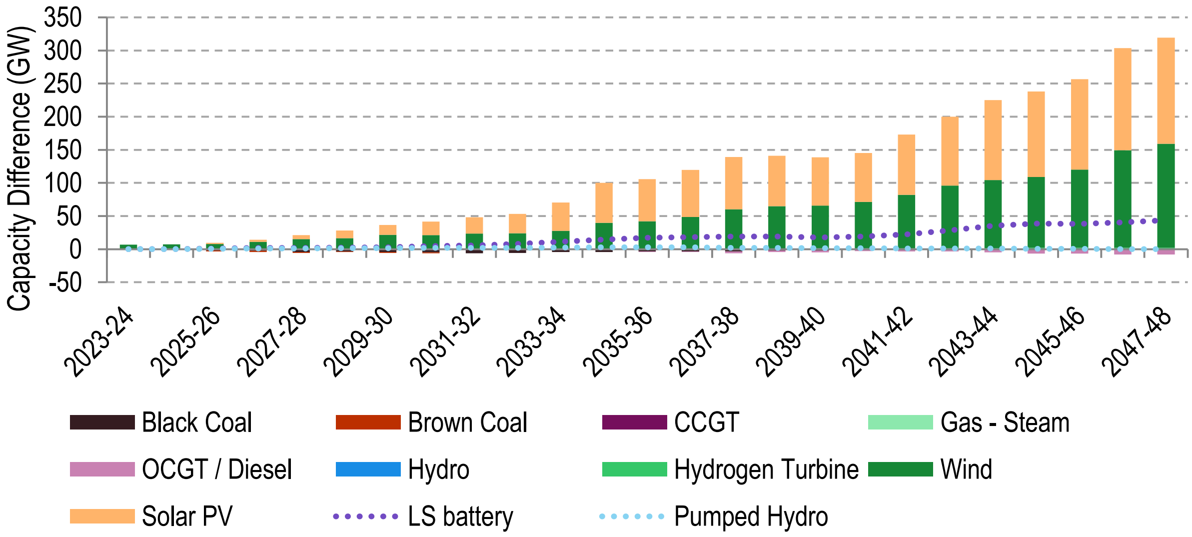
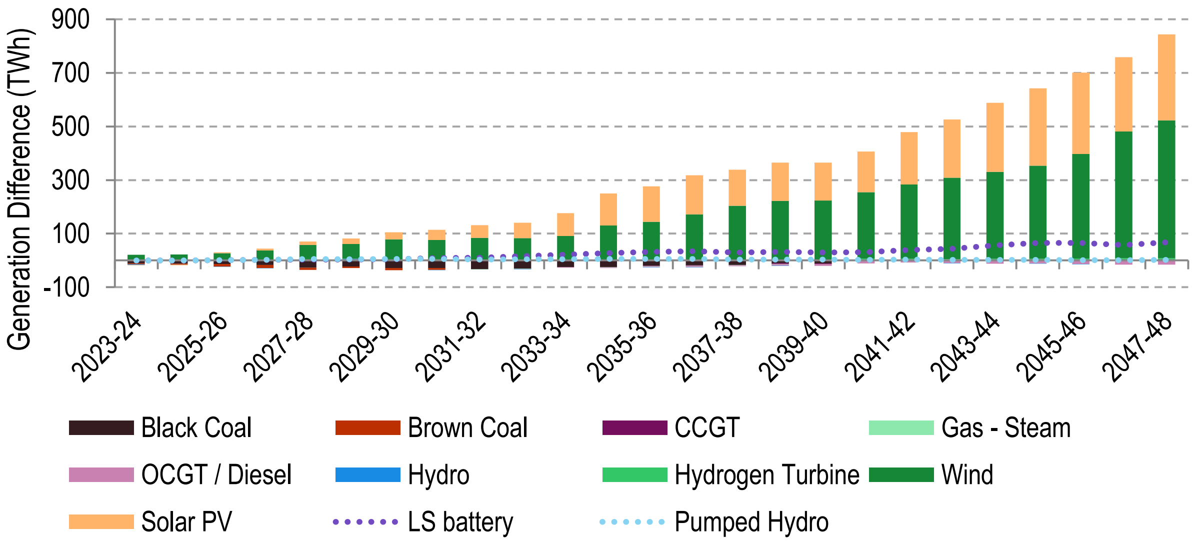


Figure 14 Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios in the Base case (excluding distributed PV)



8. Forecast gross market benefit outcomes

8.1 Summary of forecast gross market benefits

Table 13 shows the forecast gross market benefits over the modelled 25-year horizon for both options across all scenarios.

Jointly agreed between Transgrid and AEMO, we were also requested to conduct a sensitivity to assess the impact of the PFC on Option 1's gross market benefits. The modelling forecasts that excluding PFC will reduce the benefits of Option 1 by $357m in the Step Change scenario.

Table 13: Summary of forecast gross market benefits, millions real June 2021 dollars discounted to June 2021 dollars

Option	Description	Timing	Potential gross market benefits ($m)		
			Progressive Change	Step Change	Hydrogen Superpower
Option 1	VNI West via Kerang	▶ 1/07/2030 for Hydrogen Superpower ▶ 1/07/2031 for Step Change ▶ 1/07/2038 for Progressive Change	971	2,795	3,587
Option 2	Interim VTL solution until Option 1 commissioning	▶ 1/07/2026 for VTL, until Option 1 commissioning	1,082	3,002	3,885
Sensitivity 1	Impact of excluding PFC on Option 1	▶ 1/07/2031 for Step Change	NA	2,439	NA

The rest of Section 8 explores the timing and sources of these forecast benefits.

8.2 Market modelling results for Option 1

In this section, the modelling outcomes for Option 1 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 1 in the Step Change scenario are depicted in Figure 15. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 1 and the Base Case in the same scenario are shown in Figure 16 and Figure 17, respectively.

Figure 15: Forecast cumulative gross market benefit[32] for Option 1 under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

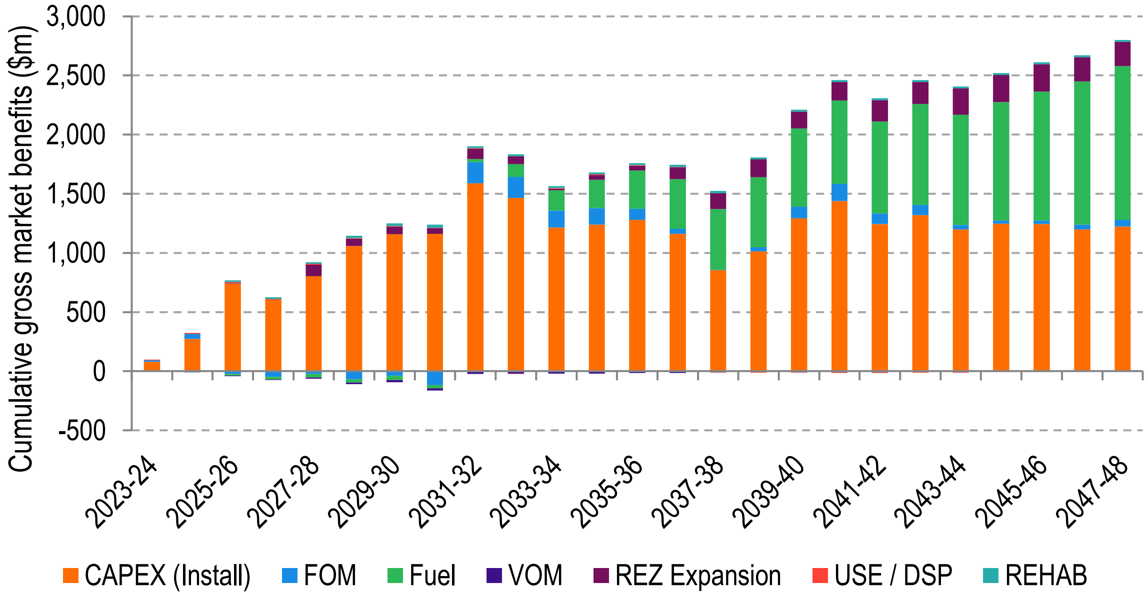
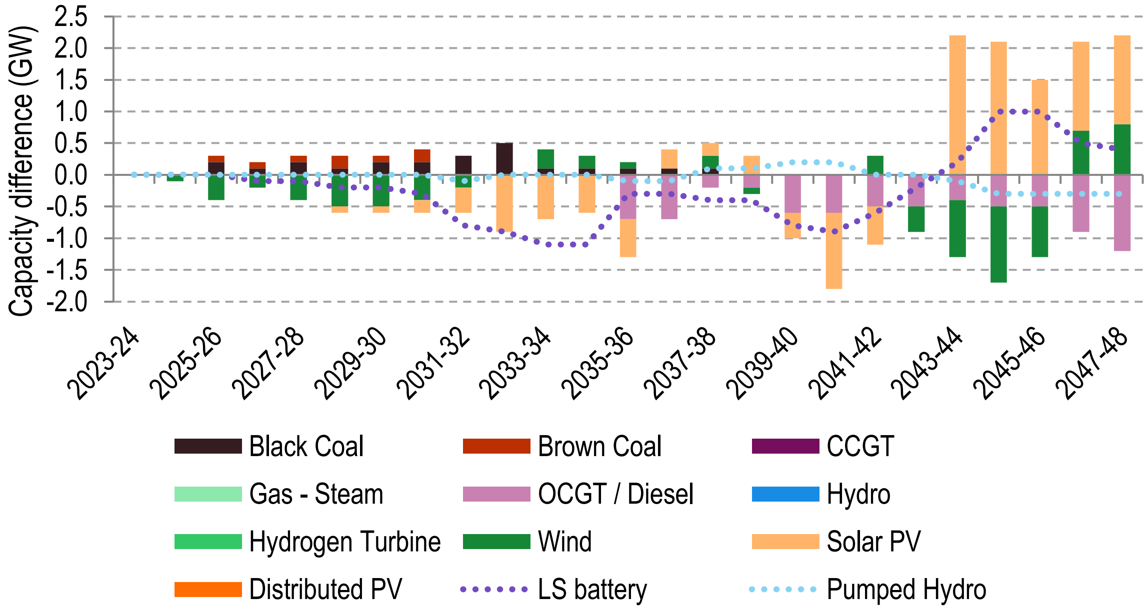
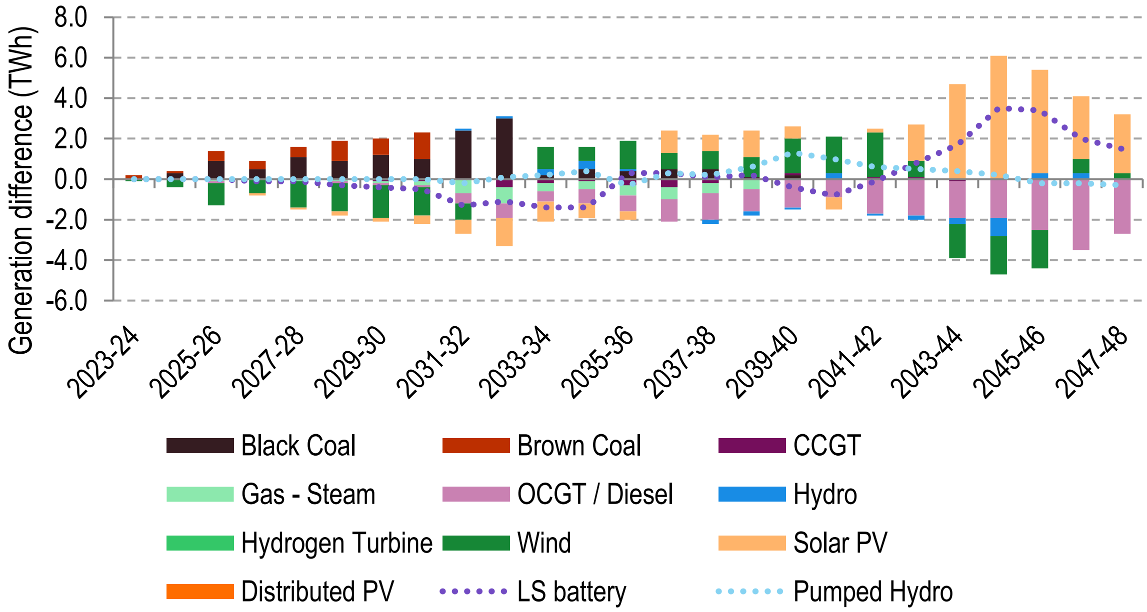


Figure 16: Difference in NEM capacity forecast between Option 1 and Base Case in the Step Change scenario



[32] 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 withdraws) and does not affect the overall gross benefits of the options.

Figure 17: Difference in NEM generation forecast between Option 1 and Base Case in the Step Change scenario



It is forecast that capex and fuel cost savings account for the major share of benefits with an approximately equal share, followed by some REZ transmission expansion savings. The timing and source of these benefits are attributable to the following:

- Option 1 is forecast to initially result in wind capacity deferral, then LS battery and solar capacity deferral until the mid-2030s. More black and brown coal generation is forecast through the early to mid-2030s, which reduces the need for new capacity that would otherwise be needed without this augmentation. The whole-of-study optimisation means that even with higher forecast coal generation in those years, the allocated carbon budget is met with Option 1, as it enables increased renewable generation in the years following the augmentation. This is achieved through increased resource sharing and locational diversity of renewable resources as well as enabling higher utilisation of Snowy Hydro hydroelectric generation, particularly Snowy 2.0, when this option is in place. The increased renewable generation after the augmentation ultimately replaces gas generation in the no augmentation case.
- Specifically, wind builds are expected to be deferred in Central West Orana, Darling Downs and Gippsland REZs. Up to around 1.3 GW LS battery in Victoria is also deferred in the early to mid-2030s, while solar capacity deferral is mostly seen in Victoria, South Australia and Queensland.
- From the mid-2030s, Option 1 is forecast to avoid OCGT build in Victoria by building solar and LS battery in NSW, while also building some of the earlier deferred LS battery in Victoria. New OCGT is required in the no augmentation case to supply demand and maintain reserve requirements as several gas generators are expected to withdraw in Victoria and South Australia in the mid-2030s. However, with Option 1, the VNI limit is expected to increase and as such a cheaper generation mix in NSW is utilised and imported to Victoria to meet demand and maintain the reserve requirements in the region.
- By the end of study period, Option 1 is forecast to unlock more wind and solar capacity (and energy) as well as LS battery in NSW, South Australia and Queensland (wind being the only exception). At the same time Option 1 is forecast to result in a reduced need for LS battery in Victoria (in addition to OCGT), and a significant capacity of wind and solar in Tasmania which is required without the augmentation.
- By 2047-48, it is expected that more renewables are built in NSW REZs such as Central West Orana, South West NSW, and Wagga Wagga while up to around 1 GW of wind and solar is avoided in Tasmania REZs such as Central highlands, North West and North East Tasmania.

- Option 1 provides transmission capacity for Murray River and Western Victoria REZs, resulting in a significant increase in renewables in these REZs which replace the required wind in Gippsland and solar in Ovens Murray for the no augmentation case. Note that Option 1 is forecast to result in wind and solar deferral/being brought forward in several REZs throughout the study period.
- Overall, the change in capacity outlook translates into an accumulation of capex savings from the mid-2020s to a maximum in the early 2030s. Thereafter, capex savings are forecast to fluctuate until the mid-2040s, then remain steady at around $1.3b.
- Forecast fuel cost savings are predominantly due to reduced use of gas with Option 1. These savings are expected to increase as more OCGT investment is avoided until the last year of the study period. However, there is a slight increase in fuel costs forecast with Option 1 in the early years due to more coal generation relative to the Base Case. As discussed earlier, this is mainly due to Option 1 allowing for more renewable generation in the NEM when commissioned, which reduces the emissions compared to the Base Case so that the carbon budget constraint is still met.
- REZ transmission expansion cost savings are expected to be around $200m by the end of the study period, which mostly accrue from the late 2030s. Major REZ transmission expansion savings are forecast to be in REZs such as Ovens Murray, Central North Victoria, Tasmania's Central Highland, although some REZs such as Central West Orana, Darling Downs, Banana and South East South Australia are expected to require more transmission expansion relative to the Base Case.

8.2.2 Progressive Change scenario

The forecast cumulative gross market benefits for Option 1 in the Progressive Change scenario are shown in Figure 18. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 1 and the Base Case are shown in Figure 19 and Figure 20.

Figure 18: Forecast cumulative gross market benefit for Option 1 under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

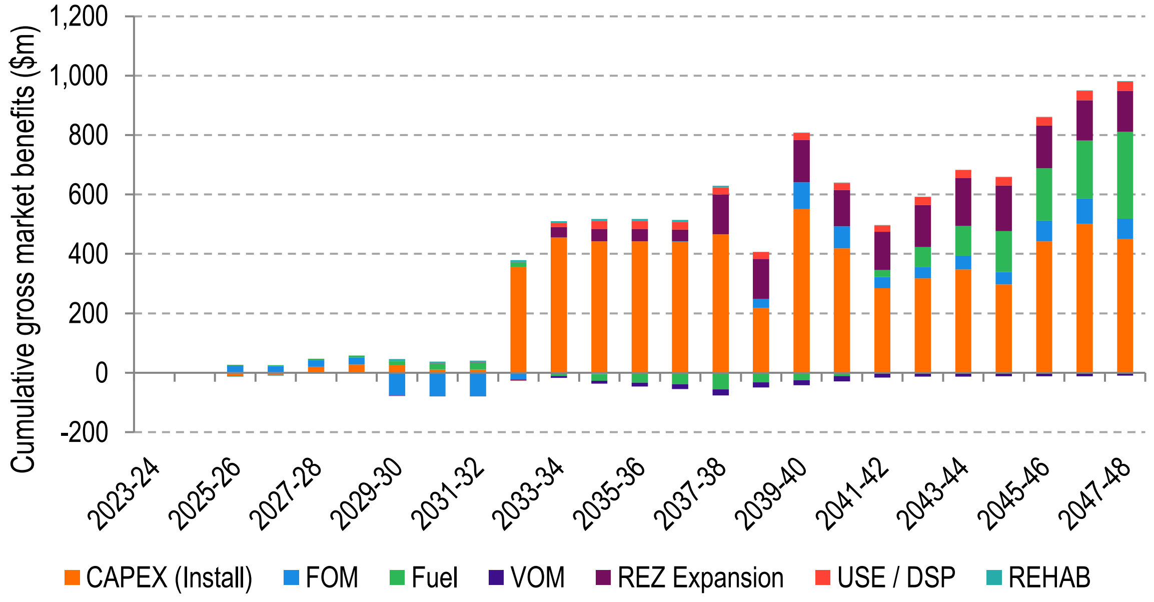


Figure 19: Difference in NEM capacity forecast between Option 1 and Base Case in the Progressive Change scenario

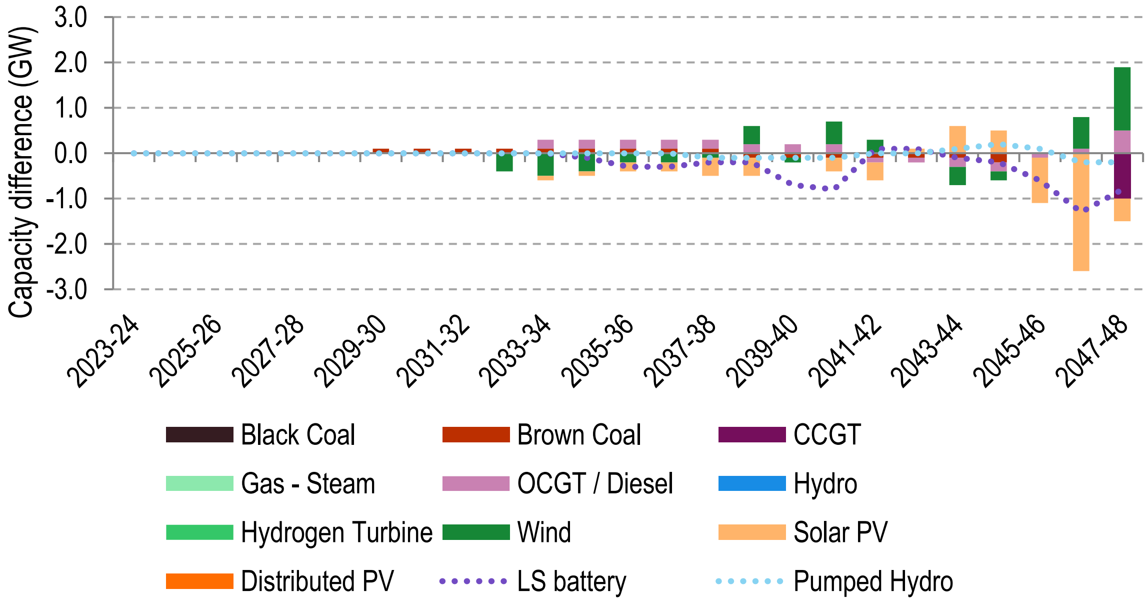
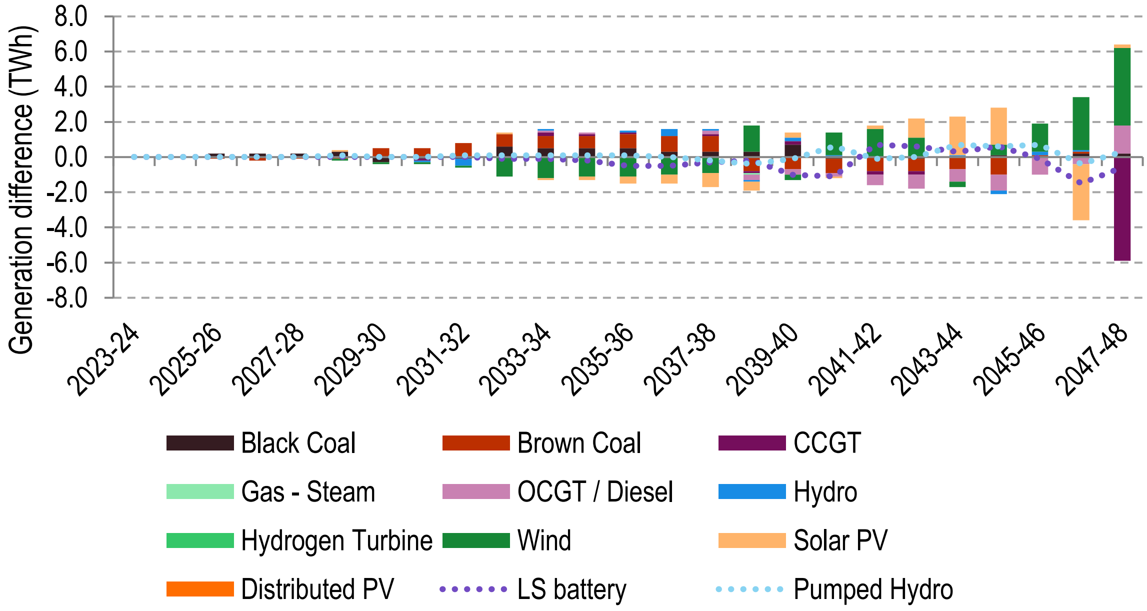


Figure 20: Difference in NEM generation forecast between Option 1 and Base Case in the Progressive Change scenario



The largest proportion of forecast gross market benefits in this scenario are made up of capex savings from deferred and avoided capacity build, reduced fuel costs as well as reduced REZ transmission expansion costs. A summary of the drivers as well as timing and sources of benefits for this option is as follows.

- Option 1 augmentation is assumed to be commissioned in 2038-39 in the Progressive Change scenario, which is seven years later than the date assumed in the Step Change scenario. As such benefits of this option in this scenario are not expected until the early to mid-2030s.
- In addition, benefits in this scenario are significantly lower than the Step Change scenario due to other underlying assumptions, particularly a less restrictive carbon budget assumption. This is expected to result in slower coal withdrawal and significantly less renewable and LS battery investments in the NEM (as shown in Figure 11), which reduces the need for more interconnection through Option 1.

- Option 1 is expected to result in capex savings by changing capacity mix in different regions. Similar to the Step Change scenario, better resource sharing and to a lesser extent enabling more utilisation of Snowy PHES are the main drivers for accruing benefits with Option 1's upgrade in the Progressive Change scenario. This option reduces the need for LS battery and gas in Victoria, while more renewables, particularly wind, are built in this region by the end of the study period. On the other hand, significantly more wind is expected to be built in NSW, while Queensland solar investment is forecast to be significantly less with Option 1 in place. In addition, this option reduces the need for wind investment in Tasmania while enabling more solar investment in South Australia.
- Fuel cost savings are mostly expected in the early 2040s, though prior to those years there are some increased fuel costs incurred in Option 1 to the NEM relative to the Base Case. The fuel costs incurred during 2030s are mainly due to increased coal generation, particularly brown coal in advance of Option 1 commissioning. Coal generation can increase before Option 1's commissioning while the whole-of-study emissions remain within the budget due to renewable generation being unlocked after Option 1 entry. In the later years fuel cost savings are mostly due to reductions in OCGT in Victoria (because Option 1 improves sharing of capacity between regions), though the reduction in CCGT generation also contributes to this in the last year.
- By the final year of modelling, it is expected that Option 1 unlocks more renewables mainly in REZs such as Murray River, Western Victoria and South West NSW while reducing the need for renewables in Ovens Murray, Wagga Wagga, Gippsland as well as Fitzroy and Central Highlands REZs.
- Forecast REZ expansion cost savings are expected from the mid-2030s and remain stable after an increase in 2037-38, being around $140m by the end of the study period. Major REZ expansion savings are expected in all northern Queensland REZs (and their relevant group REZ transmission constraints), and to a lesser extent in other REZs such as Cooma Monaro, Central Highlands, Ovens Murray and Central North Victoria.
- FOM and USE / DSP cost savings are other categories of benefits. USE / DSP savings are expected from around the mid-2030s, largely in NSW. FOM cost savings are mostly expected in Victoria and Tasmania, primarily in later years. During the same period NSW is expected to incur higher FOM costs due to building more renewables with VNI West Option 1. FOM cost savings contribute generally from avoided capacities in Victoria and Tasmania.

8.2.3 Hydrogen Superpower scenario

The forecast cumulative gross market benefits for Option 1 in the Hydrogen Superpower scenario are shown in Figure 21. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 1 and the Base Case in this scenario are shown in Figure 22 and Figure 23.

Figure 21: Forecast cumulative gross market benefit for Option 1 under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

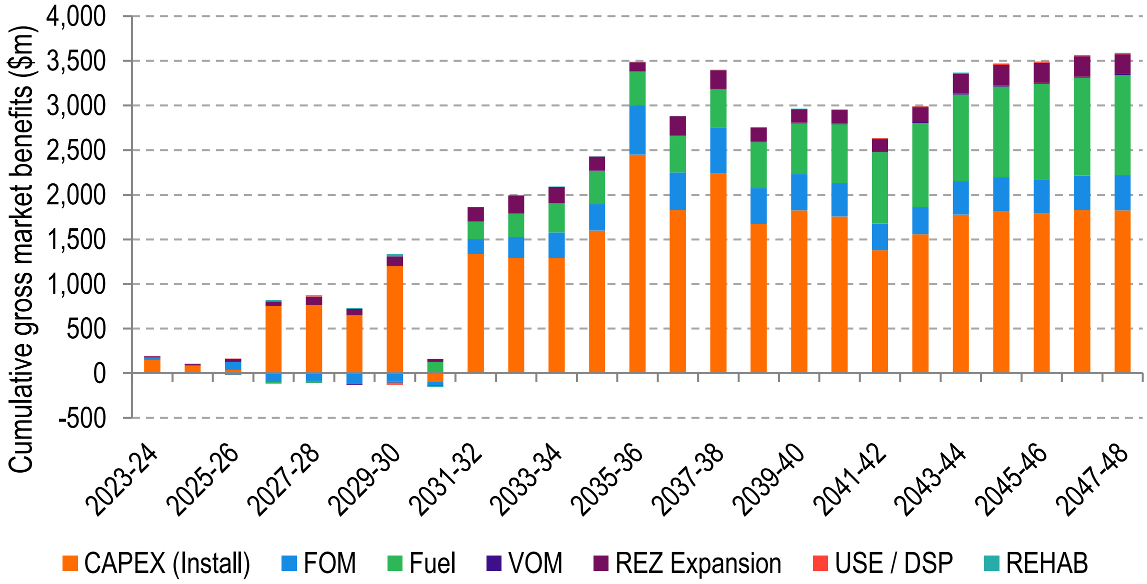


Figure 22: Difference in the NEM capacity forecast between Option 1 and Base Case in the Hydrogen Superpower scenario

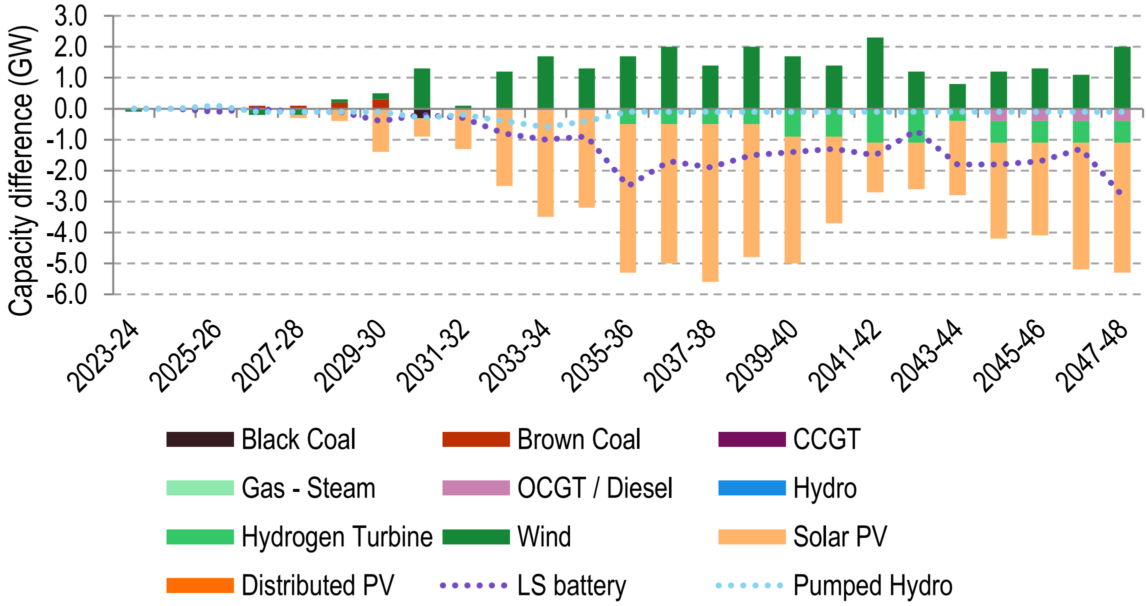
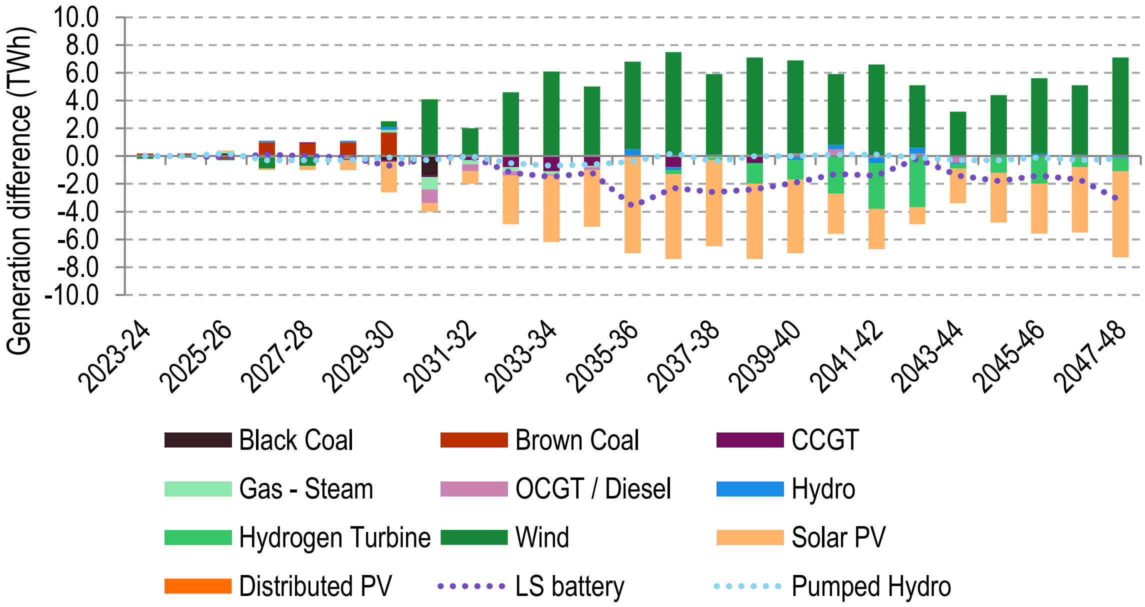


Figure 23: Difference in NEM generation forecast between Option 1 and Base Case in the Hydrogen Superpower scenario



The primary contributing factors of forecast gross market benefits in this scenario are derived from capex and fuel savings, followed by FOM savings as well as REZ transmission expansion cost savings. The timing and source of these benefits are attributable to the following:

- Forecast benefits of Option 1 in this scenario are around $800m higher than the Step Change scenario, mainly due to the assumed significantly higher demand and more restrictive carbon budget leading to increased benefits through improved sharing of diverse resources.
- It is forecast that this option results in significantly less investment in solar, LS battery and to some extent hydrogen turbine and OCGT relative to the Base Case, while it is more favourable for wind investment in the NEM. Similar to the other scenarios, with Option 1 in place, the lower capacity investment is mainly in Victoria as well as South Australia and Tasmania, while there is a significant increase in wind capacity build in NSW.
- By the end of the study period, significant solar capacity is avoided in Victorian REZs such as Gippsland, Central North Victoria and Ovens Murray, while more solar is built in Murray River and more solar and wind are built in Western Victoria with Option 1. This option results in a significant wind and solar build in the Central West Orana REZ, though solar build is offset by lower investment in Wagga Wagga and North West NSW. In addition, significant solar capacity is avoided in North East Tasmania resulting from Option 1 augmentation.
- Forecast fuel cost savings with Option 1 are predominantly due to reduced use of hydrogen in the initial years and gas in later years. These savings are expected to increase over the study period as OCGT investment and thus generation is avoided in last few years of the study period. However, there is a slight increase in fuel costs forecast with Option 1 in the early years relative to the Base Case due to more coal generation.
- FOM cost savings are expected to steadily increase starting from the early 2030s, mainly in Victoria and to a lesser extent in Tasmania, as new capacity is avoided, though FOM costs are expected in NSW with more capacity build as a result of Option 1 augmentation.

8.2.4 VNI flow

This section summarises flow duration curves for the VNI in the Base Case and Option 1. For detail on the inputs and assumptions used to model Option 1 refer to Section 5.2. The forecast flow duration curves for the Base Case and Option 1 in the Step Change scenario are shown in Figure 24 and Figure 25.

Figure 24: Forecast flow duration curve of VNI in the Base Case for the Step Change scenario

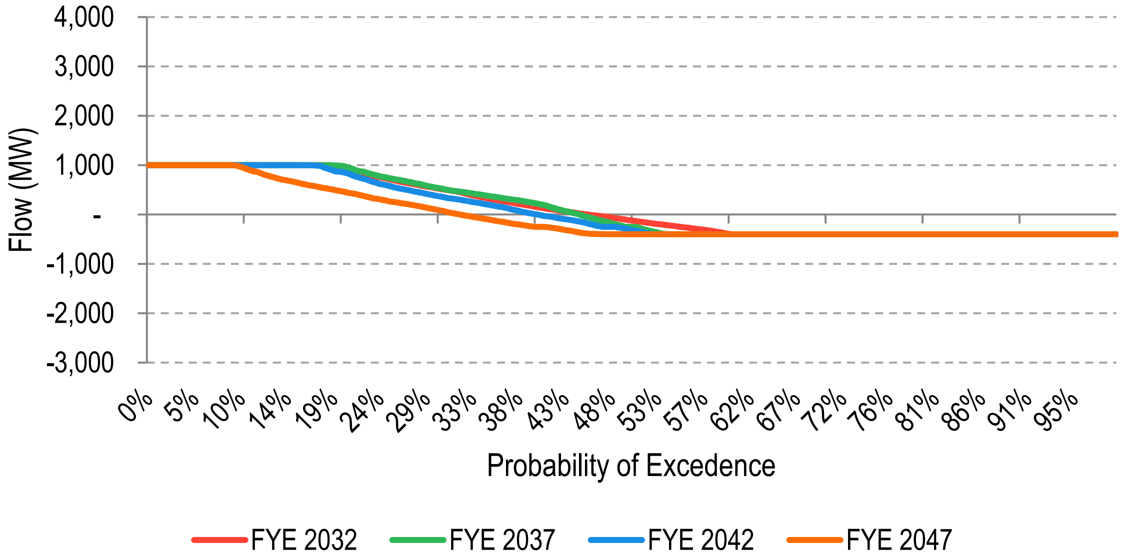
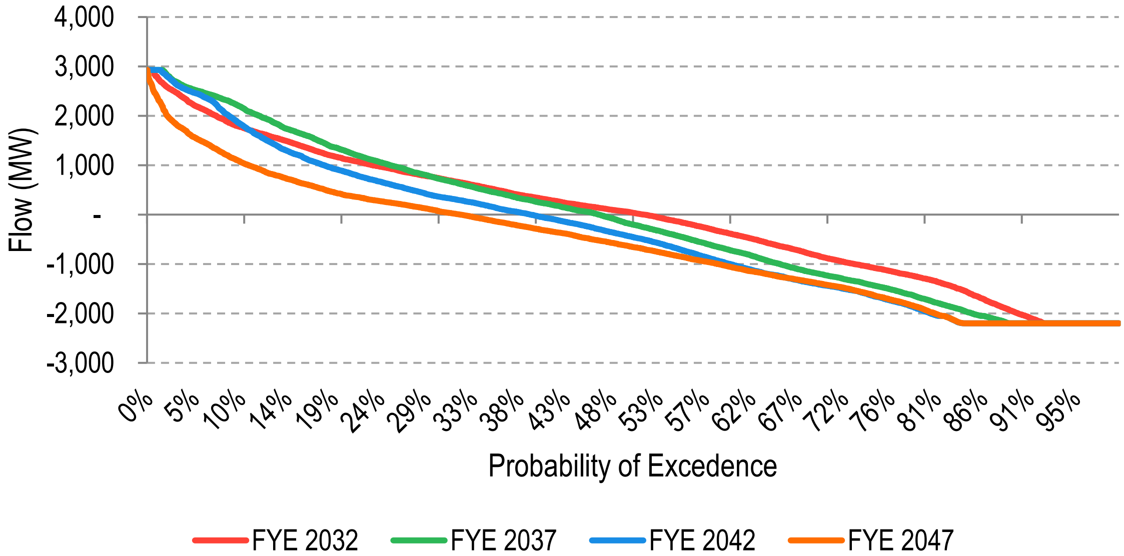


Figure 25: Forecast flow duration curve of VNI in Option 1 for the Step Change scenario



The forecast flow duration curves in the Base Case indicate significant binding in both the import and export directions in all sample years. In the import direction, across multiple years, VNI is forecast to be at its modelled limit, greater than 50% of the time, while in the export direction, VNI flow is forecast to be at its modelled limit, between 10% to 25%. The above figure indicates that as time progresses the flow gradually shifts in the import direction (increased flow from NSW to Victoria). This is caused by increased generation in NSW and Queensland to meet Victorian demand.

With Option 1 in place the modelled limits of the VNI are increased as detailed in Section 5.2. Option 1 significantly increases the transfer capacity between Victoria and NSW allowing for greater resource sharing between the regions. The probability that the VNI cut-set will be binding is reduced compared to the Base Case. Over time it is forecast that Victoria imports more from NSW, similar to the Base Case. It is seen that the export limit is generally high enough for VNI to be infrequently capped in the northward direction. However, while the binding percentage in the export direction is reduced in Option 1 relative to the Base Case, southward flow is still capped for some time, particularly in the later years of the study period.

8.3 Market modelling results for Option 2

This section provides market modelling results for Option 2 across all three modelled scenarios.

8.3.1 Step Change Scenario

The forecast cumulative gross market benefits for Option 2 in the Step Change scenario are shown in Figure 26. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 2 and Option 1 in this scenario are shown in Figure 27 and Figure 28, respectively. The following capacity and generation graphs include the VTL battery pair in NSW and Victoria. Note that it is assumed the VTL batteries have arbitrage capability after the commissioning of Option 1.

Figure 26: Forecast additional cumulative gross market benefits for Option 2 relative to Option 1 under the Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

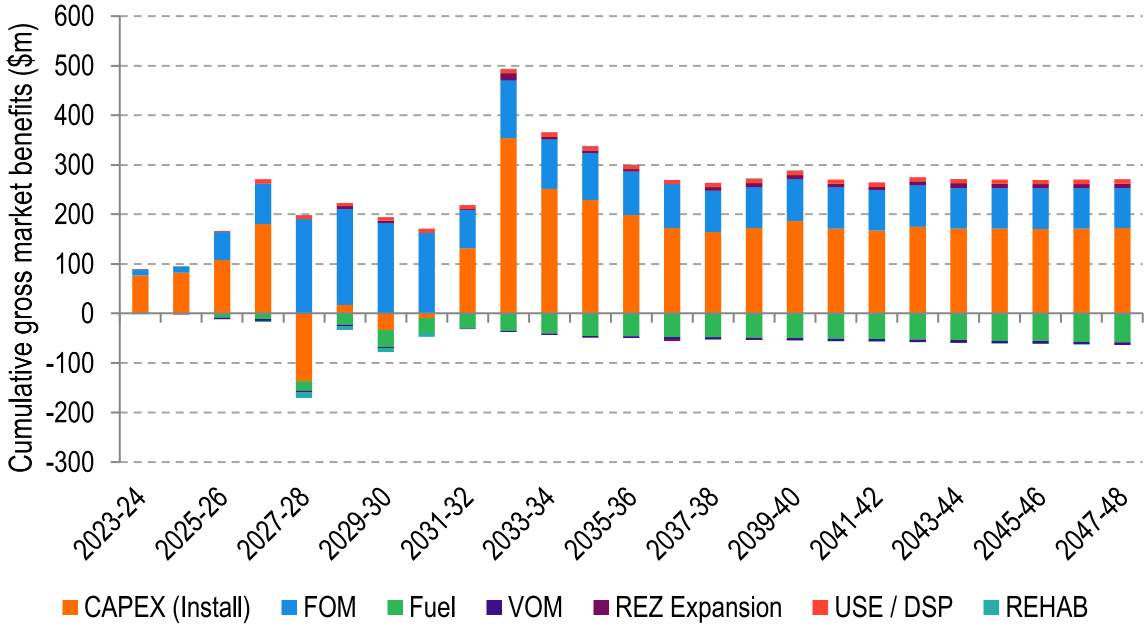


Figure 27: Difference in NEM capacity forecast between Option 2 and Option 1 in the Step Change scenario

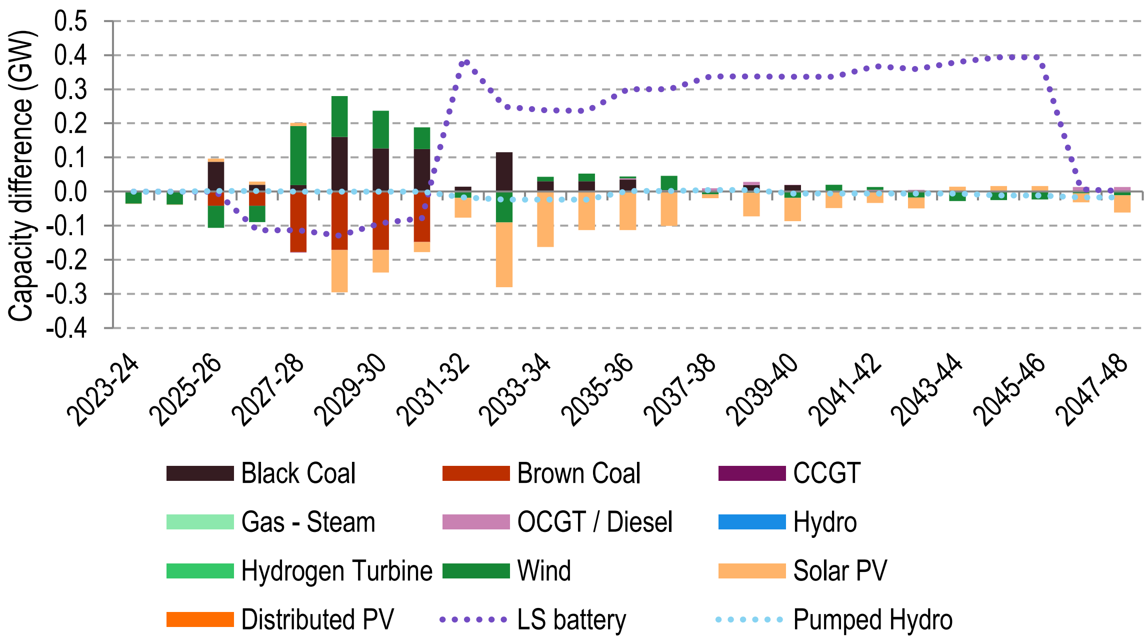
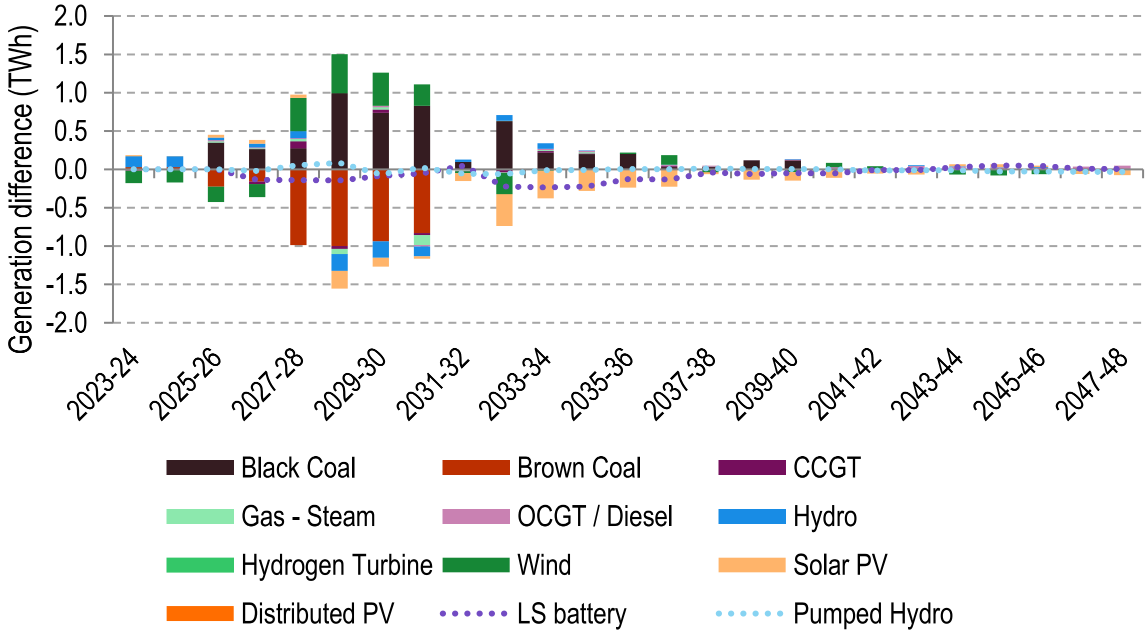


Figure 28: Difference in NEM generation forecast between Option 2 and Option 1 in the Step Change scenario



Option 2 is forecast to provide $207m additional gross market benefits compared to Option 1. The benefits are expected to come from savings in capex and FOM costs. The timing and source of the additional benefits in comparison to Option 1 are attributable to the following:

- Option 2 differs from Option 1 in enabling an additional 250 MW transfer limit between Victoria and NSW from 2026-27 until the commissioning of Option 1, and thereafter the VTL batteries are assumed to provide energy arbitrage in the NEM until they retire in June 2046.
- The additional transfer capacity between Victoria and NSW in Option 2 allows black coal generation in NSW and Queensland to displace brown coal generation in Victoria. This creates FOM cost savings, due to avoiding high fixed costs of brown coal generation while also reducing emissions. The reduction in emissions in the late 2020s to early 2030s allows for extended generation of black coal into the 2030s, resulting in some increased fuel cost with Option 2 relative to Option 1.
- In addition, this extra transfer limit as well as the arbitrage availability of VTL batteries after the commissioning of Option 1 results in expected deferral of some LS battery build, solar and wind deriving extra capex savings in this option relative to Option 1.
- LS Battery capacity is forecast to be deferred in Victoria from the mid-late 2020s through to the late 2040s, and in NSW from the early 2030s through to the end of the study period.
- Solar capacity is forecast to be deferred in NSW from the late 2020s through to the late 2030s. Some solar capacity is also deferred in Queensland through the 2030s.
- FOM savings are forecast to accrue in the late 2020s due to the early withdrawal of some brown coal capacity in Victoria, which is replaced by delaying black coal withdrawal in NSW and Queensland.

8.3.2 Progressive Change Scenario

The forecast cumulative gross market benefits for Option 2 in the Progressive Change scenario are shown in Figure 29. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 2 and Option 1 in this scenario are shown in Figure 30 and Figure 31, respectively.

Figure 29: Forecast additional cumulative gross market benefit for Option 2 relative to Option 1 under the Progressive Change scenario, millions real June 2021 dollars discounted to June 2021 dollars

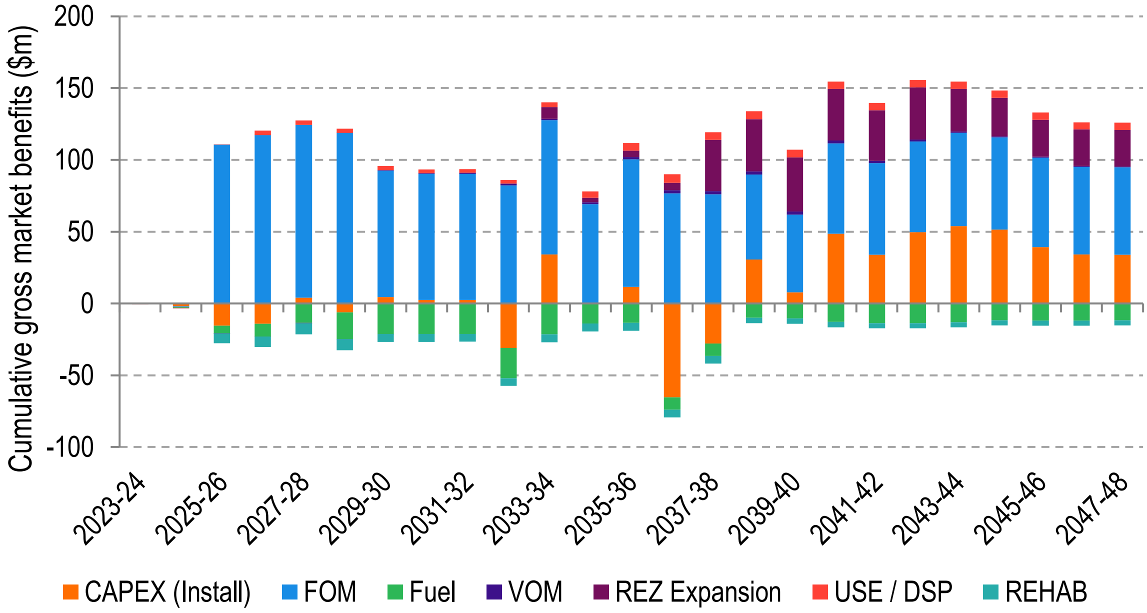


Figure 30: Difference in NEM capacity forecast between Option 2 and Option 1 in the Progressive Change scenario

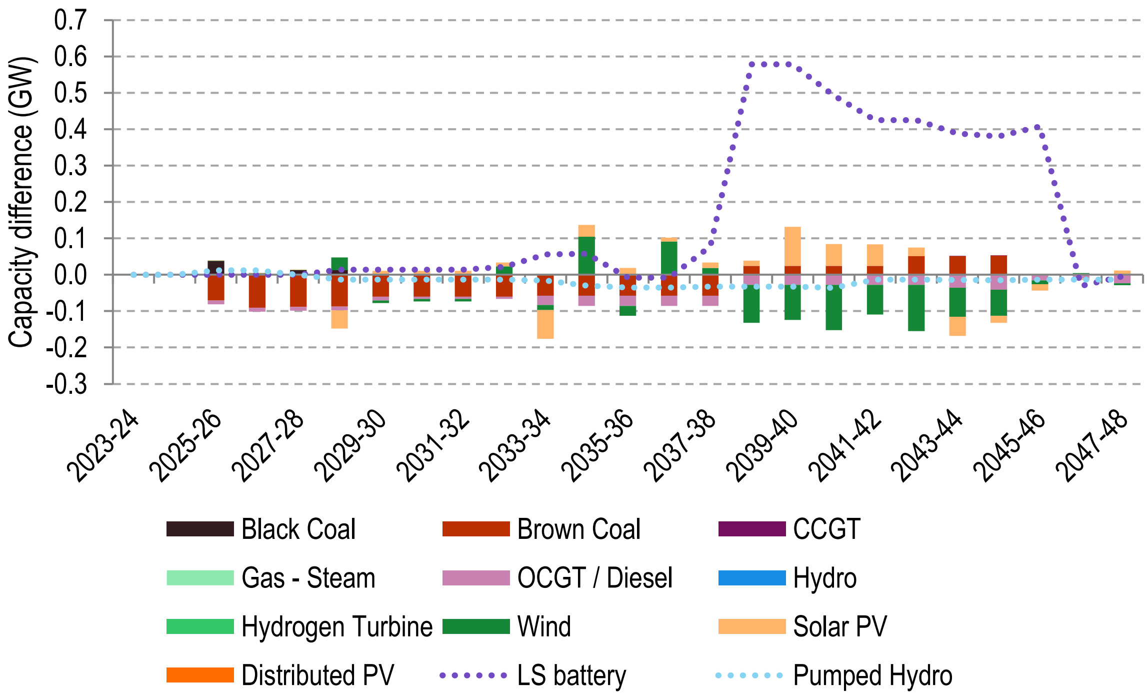
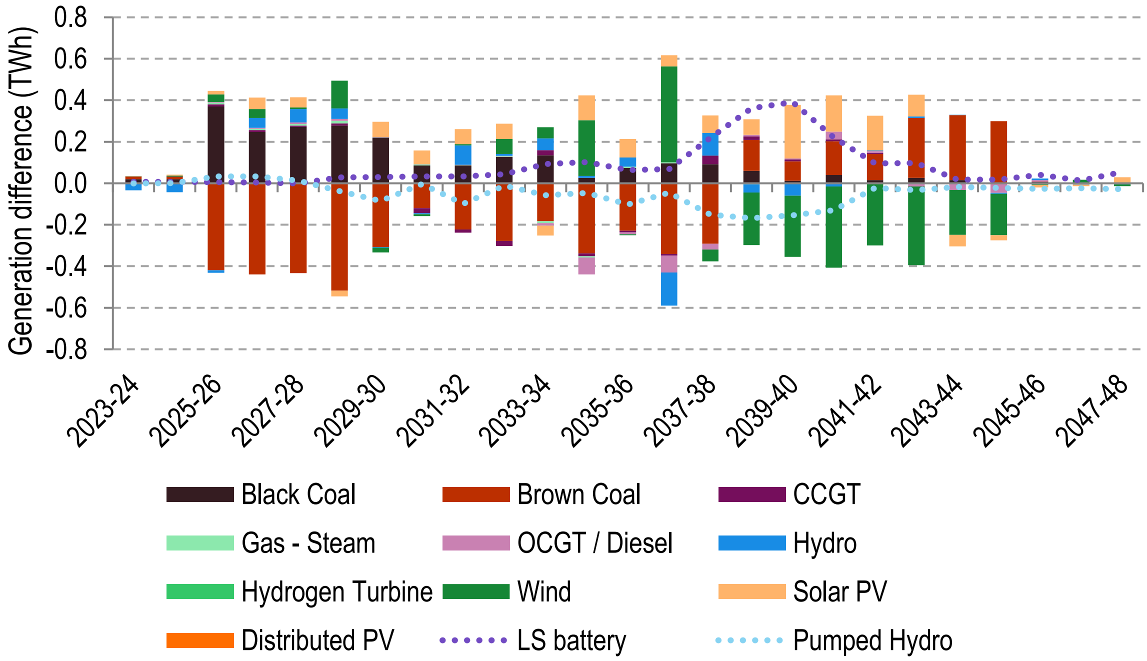


Figure 31: Difference in NEM generation forecast between Option 2 and Option 1 in the Progressive Change scenario



Option 2 provides $111m additional forecast gross market benefits compared to Option 1. With interim VTL batteries, it is expected that Option 2 results in earlier brown coal withdrawal of service relative to Option 1 alone until Option 1 is commissioned in 2038-39. After commissioning of Option 1, some brown coal withdrawal is forecast to be delayed along with some solar capacity brought forward, resulting in some OCGT avoidance and wind deferral. This results in up to around $130m FOM cost savings, although it reduces to around $60m by the end of study period. In addition, wind capacity deferral as well as OCGT avoidance is expected to result in extra capex savings in Option 2 relative to Option 1 in this scenario.

Additional forecast REZ Transmission savings begin to accrue from the early to mid-2030s through the early 2040s. These additional savings are largely in the North Queensland Clean Energy Hub REZs and the north Queensland group constraints.

8.3.3 Hydrogen Superpower Scenario

The forecast cumulative gross market benefits for Option 2 in the Hydrogen Superpower scenario are shown in Figure 32. Furthermore, the differences in the forecast capacity and generation outlooks across the NEM between Option 2 and Option 1 in this scenario are shown in Figure 33 and Figure 34, respectively.

Figure 32: Forecast cumulative gross market benefit for Option 2 relative to Option 1 under the Hydrogen Superpower scenario, millions real June 2021 dollars discounted to June 2021 dollars

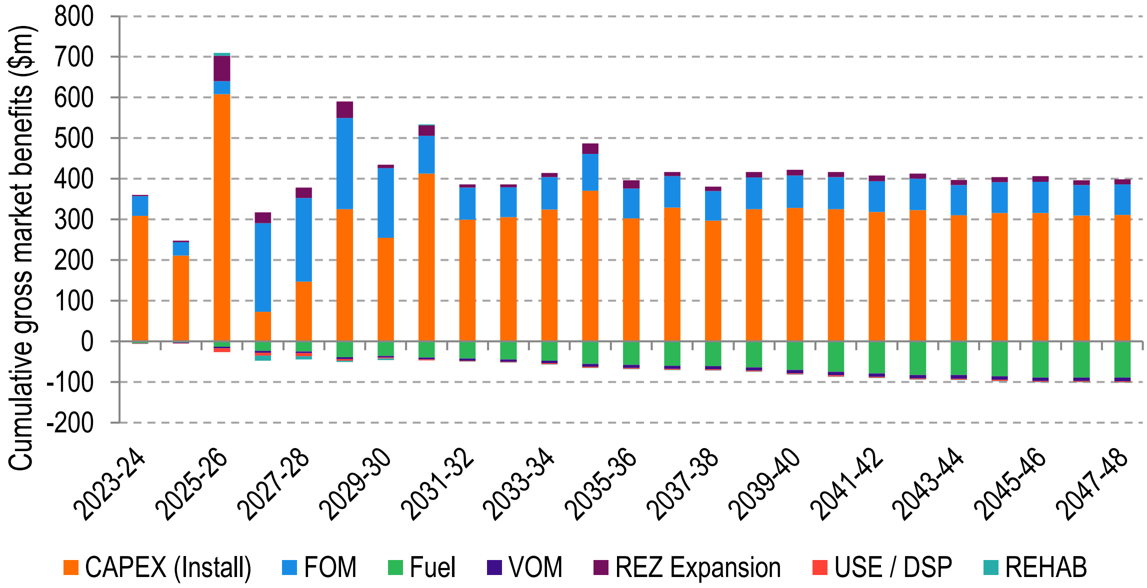


Figure 33: Difference in NEM capacity forecast between Option 2 and Option 1 in the Hydrogen Superpower scenario

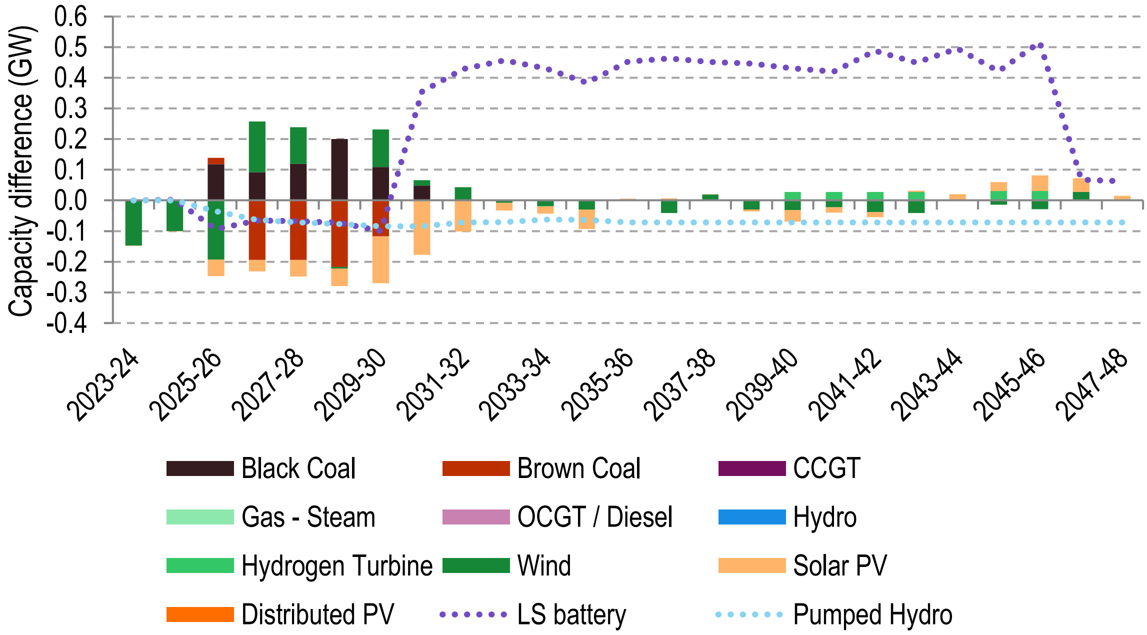
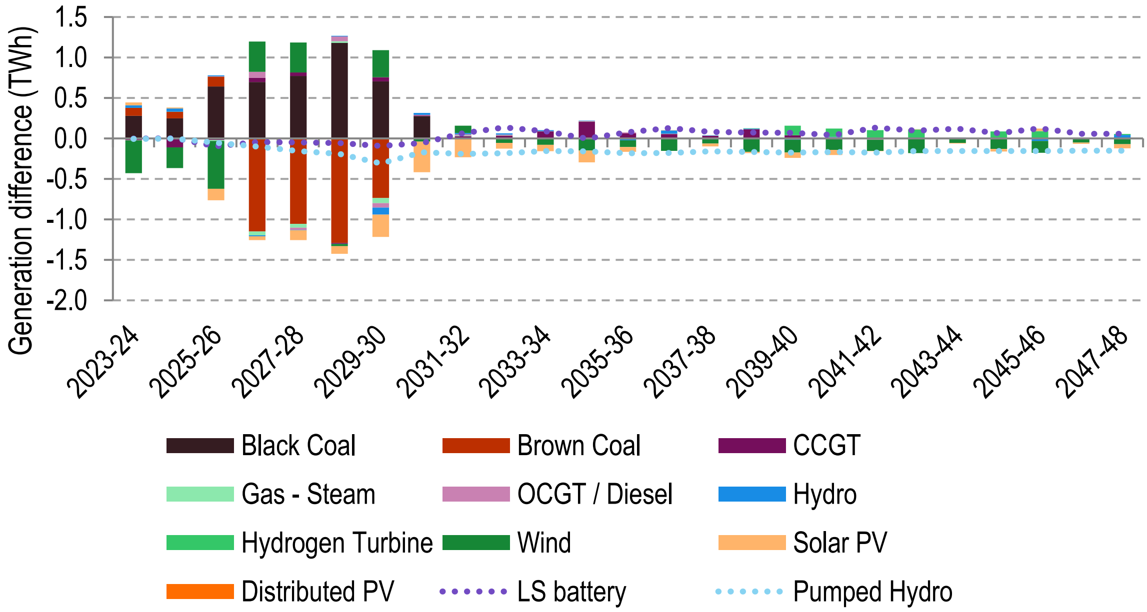


Figure 34: Difference in NEM generation forecast between Option 2 and Option 1 in the Hydrogen Superpower scenario



Option 2 provides $298m additional forecast gross market benefits compared to Option 1. The benefits in order of magnitude are forecast to come from savings in capex and FOM cost savings. The timing and source of the identified additional benefits are attributable to the following:

- The major share of additional capex benefits is forecast to result from avoided capacity build of PHES in Queensland and Victoria in the late 2020s.
- Additional capex benefits are forecast to accrue from the deferral of LS battery capacity from the mid-2020 in NSW and Victoria.
- FOM cost savings are forecast to accrue from 2026-27 through to 2029-30 due to early withdrawal of service by brown coal in Victoria. The early withdrawal of brown coal service is forecast to be replaced by increased black coal generation in NSW and Queensland. The reduced emissions intensity of black coal allows for additional black coal generation in the early 2020s while still adhering to the strict carbon budget which allows for some additional capacity deferral in these early years.

8.4 Market modelling outcomes for sensitivities

One sensitivity has been modelled to assess the impact of PFC on Option 1's market benefits in the Step Change scenario. Jointly agreed between Transgrid and AEMO, we were advised that excluding PFC will change the import limit of VNI to Victoria to 1,400 MW in summer and winter periods, and 1,250 MW in peak demand periods, reduced by 800 MW from the assumed limits in Option 1, as summarised in Table 14. In addition, the reactance of existing Victorian lines is used in the equivalenced network, instead of the compensation due to the PFC, as shown in Table 8.

Table 14: VNI Limits without PFC (comparable with Option 1 limits in Table 7)

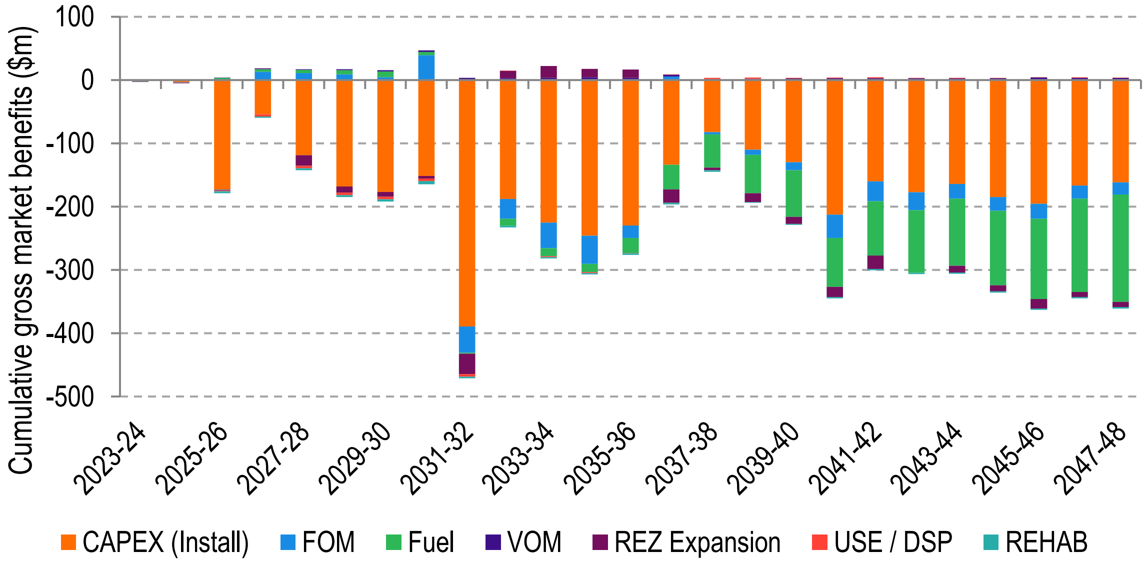
Description	Import limit (MW)	Export limit (MW)
Original limits	400 all periods	870 peak demand 1,000 summer 1,000 winter
Post Victorian SIPS contract with no Option 1	250 peak demand 400 summer 400 winter	870 peak demand 1,000 summer 1,000 winter

Description	Import limit (MW)	Export limit (MW)
Post Option 1 commissioning with SIPS contract in place	1,400 all periods *(as opposed to 2,200 in Option 1)*	2,800 peak demand 2,930 summer 2,930 winter
Post Option 1 commissioning and SIPS contract ended	1,250 peak demand *(as opposed to 2,050 in Option 1)* 1,400 summer *(as opposed to 2,200 in Option 1)* 1,400 winter *(as opposed to 2,200 in Option 1)*	2,800 peak demand 2,930 summer 2,930 winter

8.4.1 Impact of excluding PFC on Option 1

The forecast cumulative gross market benefits for Option 1 excluding the PFC (the PFC sensitivity) with respect to Option 1 (core case) are shown in Figure 35, indicating that the total forecast gross market benefits decrease by $357m when the PFC is excluded from Option 1. Furthermore, the differences in capacity and generation outlook across the NEM between the sensitivity and the core case are shown in Figure 36 and Figure 37, respectively.

Figure 35: Forecast cumulative gross market benefit[33] for the PFC sensitivity relative to Option 1 in Step Change scenario, millions real June 2021 dollars discounted to June 2021 dollars



[33] 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 withdraws) and does not affect the overall gross benefits of the options.

Figure 36: Difference in NEM capacity forecast between the PFC sensitivity relative to Option 1 in the Step Change scenario

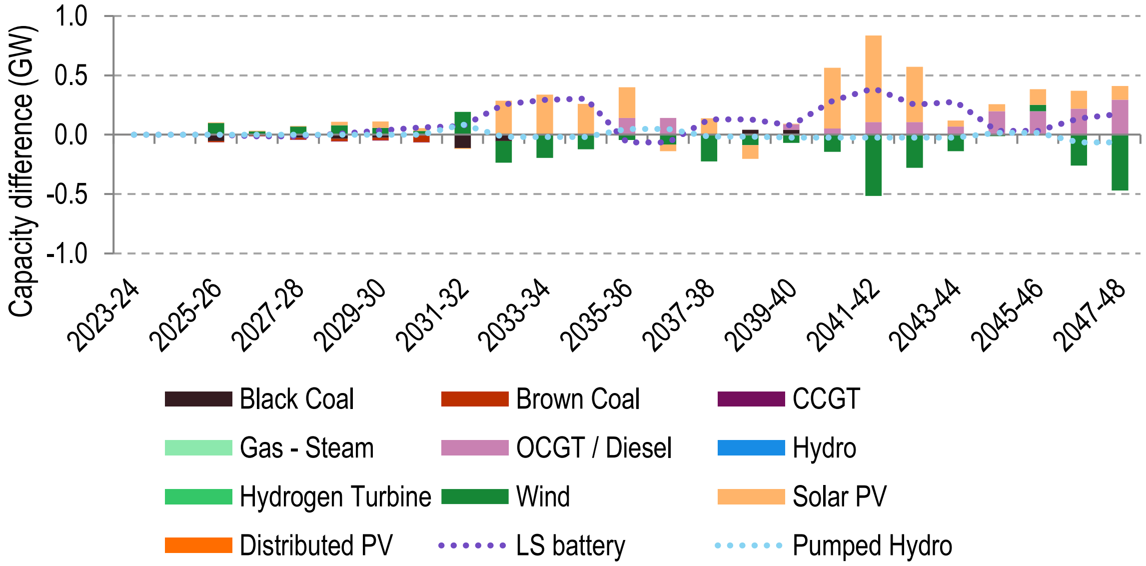
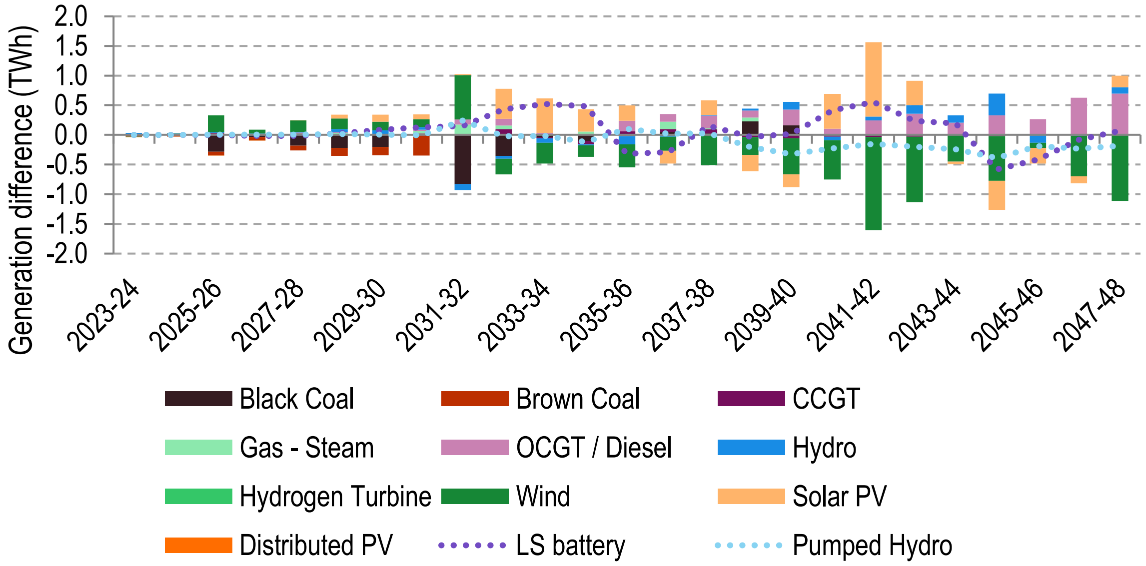


Figure 37: Difference in NEM generation forecast between the PFC sensitivity relative to Option 1 in the Step Change scenario



The primary sources of the reductions in forecast gross market benefits in the PFC sensitivity are increased capex and fuel costs. The timing and sources of the increased capex and fuel costs can be attributed to the following:

- A decrease in capex savings is forecast from the mid-2020s through to the 2040s. In the mid-2020s this is a result of wind capacity in Victoria and Queensland being brought forward. In the early to mid-2030s there is a forecast increase in capacity of solar and LS storage as well as OCGT primarily in Victoria. This is a result of the VNI import limit decreasing without the PFC, and so a larger proportion of Victorian demand is required to be met locally. The increased solar capacity is located across Western Victoria, Ovens Murray, Central North Victoria and Murray River REZs.
- Increased fuel costs are forecast in all mainland NEM regions, with the highest proportion being in Victoria. Increased fuel costs are mostly attributable to increased OCGT generation resulting from the decreased ability to share generation resources between NSW and Victoria.

Appendix A Glossary of terms

Abbreviation	Meaning
AC	Alternating Current
AEMO	Australian Energy Market Operator
AER	Australia Energy Regulator
$b	Billion dollars
CAN	Canberra (NEM zone)
CAPEX	Capital Expenditure
CBA guidelines	Cost benefit analysis guidelines
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
CWO	Central West Orana
DC	Direct Current
DSP	Demand side participation
ESOO	Electricity Statement of Opportunities
FFP	Fixed Flat Plate
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
LHS	Left Hand Side
LS Battery	Large-Scale battery storage (as distinct from behind-the-meter battery storage)
$m	Million dollars
Mt	Mega Ton
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

Abbreviation	Meaning
PADR	Project Assessment Draft Report
PEC	Project EnergyConnect
PFC	Power Flow Controller
PHES	Pumped Hydro Energy Storage
PV	Photovoltaic
PV	Present Value
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QNI Minor	NSW to QLD Interconnector Upgrade
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
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
VOM	Variable Operation and Maintenance
VRE	Variable Renewable Energy
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant
VTL	Virtual Transmission Line

EY | Building a better working world

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

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

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

ey.com