Gross market benefit assessment of Basslink

APT Management Services Pty Ltd

15 September 2023

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Release Notice

Ernst & Young ("EY") was engaged on the instructions of APT Management Services Pty Ltd ("APA" or the "Client") to undertake market modelling of system costs and benefits to forecast the gross benefit of Basslink (the "Project"), in accordance with the contract dated 15 March 2023 ("the Engagement Agreement"). We understand that APA is working with Basslink Pty Ltd in relation to this Project.

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.

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Readers are advised that the outcomes provided are based on many detailed assumptions underpinning the scenarios, and the key assumptions are described in the Report. These assumptions were selected by APA. The modelled scenarios represent three possible future options for the development and operation of the National Electricity Market, and it must be acknowledged that many alternative futures exist. Alternative futures beyond those presented have not been evaluated as part of this Report.

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

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1. Executive summary

APA, working with Basslink Pty Ltd, has engaged EY to undertake market modelling of system costs to forecast the gross market benefits of Basslink from July 2025 (coincident with the timing that APA has advised Basslink may be converted to a regulated asset) to July 2046 (the expected retirement time for Basslink, based on its technical life) (the "Modelling Period"). EY understands that the Report will be used to inform APA's application to convert the Basslink interconnector into a regulated asset in parallel with the revenue determination.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by APA and the modelling methods used.

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the National Electricity Market (NEM) for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued by the Australian Energy Market Operator (AEMO) in the 2022 Integrated System Plan (ISP)[1] under three variants to the size and timing of Marinus Link. Two sensitivities to the size of Basslink were also modelled for the Step Change scenario. In addition, APA requested that the scenarios were updated to incorporate changes to the input assumptions based on the July 2023 AEMO Input, Assumptions and Scenarios Report (IASR)[2]. The input assumptions that have been updated include:

- Energy policy targets
- Carbon budgets
- Costs: capital expenditure (capex), fixed operation and maintenance (FOM), variable operation and maintenance (VOM), fuel, involuntary load curtailment (USE) and Renewable Energy Zone (REZ) resource limit violation penalty factors
- Committed and anticipated generators
- Thermal retirement dates
- Discount rates.

For this modelling, it has not been possible to fully align with the Final 2024 ISP, since the two-yearly ISP process is still ongoing at the time we were undertaking this engagement. For instance, demand scenarios that will be used in the 2024 ISP were only released in the 2023 Electricity Statement of Opportunities (ESOO) at the end of August 2023[3], after the work for this Report was largely complete, and an initial view of the timing of other transmission projects will not be known until the release of the Draft 2024 ISP in December 2023. Due to time restrictions, several other assumption updates from the July 2023 AEMO IASR[2] could not be captured in the modelling, such as changes in REZ transmission limits and renewable capacity factors, as agreed by APA.

[1] Note that while some of the assumptions are from the 2022 Inputs and Assumptions workbook published on 30 June 2021, many assumptions like energy policy targets and costs are from the 2023 Inputs and Assumptions workbook published 28 July 2023. The timing of major upgrades are based on the 2022 ISP outcomes. AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, 2022 ISP assumptions available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, and 2023 ISP assumptions available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023.

[2] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[3] AEMO, *2023 Electricity Statement of Opportunities*, August 2023, available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 3 September 2023.

APA has assumed the following Marinus Link sizes and timings for the three variants of each scenario:

- Marinus Link single-stage: Stage 1 follows the scenario-specific optimal timing from the 2022 ISP [4], but Stage 2 is not commissioned
  - Step Change: Stage 1 commissioned in 2029-30
  - Progressive Change: Stage 1 commissioned in 2030-31
  - Hydrogen Superpower: Stage 1 commissioned in 2029-30
- Marinus Link double-stage, ISP-timing: scenario specific optimal timing from the 2022 ISP[4]
  - Step Change: Stage 1 commissioned in 2029-30 and Stage 2 in 2031-32
  - Progressive Change: Stage 1 commissioned in 2030-31 and Stage 2 in 2032-33
  - Hydrogen Superpower: Stage 1 commissioned in 2029-30 and Stage 2 in 2031-32
- Marinus Link double-stage delay: Stage 1 commissioned 2033-34 and Stage 2 in 2035-36 in all scenarios.

APA have requested that we apply a modelling methodology consistent with the Regulatory Test utilised in the Directlink and Murraylink conversion determination processes with some adjustments to the input assumptions and scenarios advised by APA[5]. As APA is seeking conversion of Basslink from 1 July 2025, APA has assumed the Base Case counterfactual for all scenarios and sensitivities essentially retires Basslink by July 2025, from the beginning of the Modelling Period. The forecast gross market benefit of Basslink is therefore calculated as the difference in the system cost that is forecast with versus without Basslink.

To assess the least-cost solution with and without Basslink, EY's Time Sequential Integrated Resource Planner (TSIRP) model is used. It makes decisions for each hourly dispatch interval in relation to:

- The generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched at their short run marginal cost (SRMC), which is derived from their VOM and fuel costs. The generation for each dispatch 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[6], large-scale battery, pumped hydro energy storage (PHES).
- The withdrawal of existing generation on a least-cost basis, often to meet the emissions budgets assumed in the modelled scenario and sensitivities.

The hourly decisions consider certain operational constraints that include:

- supply must equal demand in each region for all dispatch intervals plus a reserve margin, with unserved energy (USE) costed at the value of customer reliability (VCR),
- minimum loads for coal generators,
- interconnector flow limits (between regions),

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[4] AEMO, *Appendix 5: 2022 Integrated System Plan*, available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 11 September 2023.

[5] Directlink Joint Venture, 6 May 2004, Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005-2014, available at: https://www.aer.gov.au/system/files/Directlink%20application%20%286%20May%202004%29.pdf. Accessed 15 September 2023.

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

- maximum and minimum storage (conventional storage hydro, PHES and large-scale battery) reservoir limits and cyclic efficiency,
- new entrant capacity build limits for wind and solar for each 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 Tasmanian inertia constraints, as defined in the Report.

From the hourly time-sequential modelling we computed the following costs, as defined in the Regulatory investment test for transmission (RIT T) guidelines published by the Australian Energy Regulator (AER)[7]:

- capex costs of new generation and storage capacity installed,
- total FOM costs of all generation and storage capacity,
- total VOM costs of all generation and storage capacity,
- total fuel costs of all generation capacity,
- total cost of voluntary (demand-side participation, DSP) and USE,
- transmission expansion costs associated with REZ development.

The forecast gross market benefits capture the impact of transmission losses to the extent that losses across interconnectors affect the generation that needs to be dispatched in each dispatch interval. The forecast gross market benefits also capture the impact of differences in cyclic efficiency losses in storages, including PHES and large-scale batteries.

For each simulation, we computed the sum of these cost components and compared the difference between with Basslink case and the without Basslink Base Case across the 21-year Modelling Period, from 2025-26 to 2045-46. The difference in present values of costs is the forecast gross market benefits[8] due to Basslink. Benefits presented are discounted to June 2025 using a 7% real, pre-tax discount rate as selected by APA, consistent with the value applied by AEMO in the July 2023 AEMO IASR[9].

On 3 September, a joint media release between the Commonwealth and Tasmanian Governments announced that Marinus Link "will be focused on one cable in the first instance, with negotiations to continue on a second cable, to be considered after final investment decision on cable one"[10]. Table 1 summarises the details of the modelled scenarios and sensitivities with the associated forecast gross market benefits of Basslink under the Marinus Link single-stage variant.

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[7] AER, August 2020. RIT-T 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 4 September 2023

[8] 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.

[9] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[10] Department of Climate Change and Energy, 3 September 2023. Joint media release: Investing in the future of Tasmanian energy with Marinus Link. Available at: https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-investing-future-tasmanian-energy-marinus-link. Accessed 4 September 2023.

Table 1: Overview of scenarios and sensitivities with associated forecast gross market benefits for Basslink; millions real June 2023 dollars discounted to 1 July 2025; Marinus Link single-stage

Scenario/ sensitivity	Description	Basslink gross market benefits ($m)
		Marinus Link single-stage
Step Change	AEMO 2022 ISP Step Change Scenario with changes from 2023 IASR Step Change scenario	3,846
Progressive Change	AEMO 2022 ISP Progressive Change Scenario with changes from 2023 IASR Progressive Change scenario	4,241
Hydrogen Superpower	AEMO 2022 ISP Hydrogen Superpower Scenario with changes from 2023 IASR Green Energy Export scenario	3,268
Step Change with 350 MW Basslink	Step Change scenario with: The original modelled import and export capacity for Basslink is 478 MW; This sensitivity considers a smaller import and export capacity of 350 MW for Basslink.	3,131
Step Change with 150 MW Basslink	Step Change scenario with: The original modelled import and export capacity for Basslink is 478 MW; This sensitivity considers a smaller import and export capacity of 150 MW for Basslink.	1,558

The forecast gross market benefits of each scenario and sensitivity must be compared to the ongoing cost of Basslink to determine the forecast net economic benefit for that case. That evaluation is not part of our scope and hence has not been included in this Report. It is performed by APA outside of this Report using the forecast gross market benefits from this Report and other inputs.

The forecast gross market benefits of Basslink in the double-stage Marinus Link scenario variants are shown in Table 2.

Table 2: Overview of scenarios and sensitivities with associated forecast gross market benefits for Basslink; millions real June 2023 dollars discounted to 1 July 2025; Marinus Link double-stage

Scenario/ sensitivity	Basslink gross market benefits ($m)	
	Marinus Link double-stage, ISP-timing	Marinus Link double stage delay (3 to 4 year delay relative to ISP)
Step Change	2,323	3,823
Progressive Change	2,872	3,579
Hydrogen Superpower	2,634	3,268
Step Change with 350 MW Basslink	1,883	3,121
Step Change with 150 MW Basslink	938	1,499

Overall, the model outcomes demonstrate that the configuration and timing of Marinus Link are key influences on the expected gross market benefits for Basslink. Three possible changes to Marinus Link impact the forecast market benefits:

► The second stage of Marinus Link proceeding reduces benefits

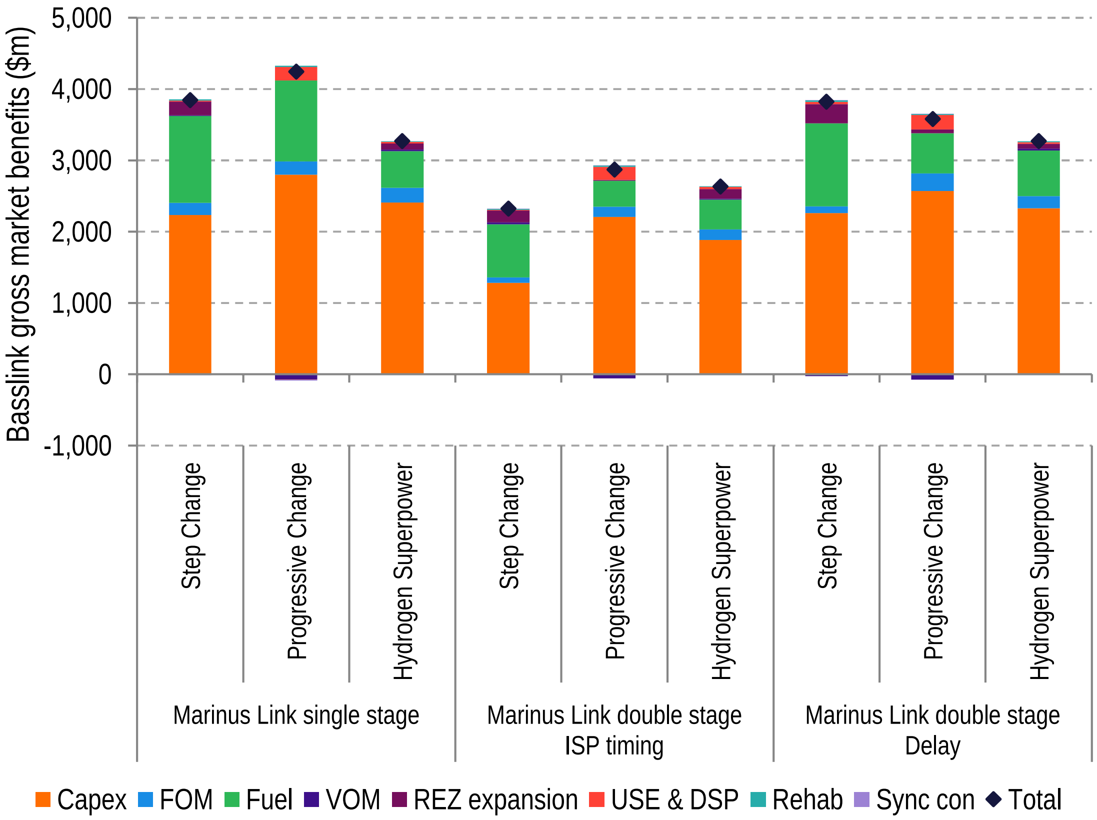
► A delay in the first stage of Marinus Link increases benefits

► A delay in the second stage of Marinus Link (if the second stage is to be commissioned) increases benefits.

The forecast benefits for Basslink benefits prior to 2030 are primarily driven by differences in capacity development to meet NEM-wide emission reduction goals and the federal 82% renewable energy target in 2029-30. As assumed in the July 2023 AEMO IASR[11], interim targets to meet the federal 82% goal are applied before the commissioning of Marinus Link. Without Basslink, Tasmanian generation from capacity built to meet the legislated Tasmanian Renewable Energy Target (TRET) is forecast to be curtailed economically, or spilt, and cannot fully contribute to the federal target. With Basslink, less renewable capacity is forecast to be installed throughout the NEM while achieving the same amount of renewable generation, which result in capex savings.

Post-2030, Basslink is forecast to result in capex and fuel cost savings by enabling better access to existing Tasmanian hydroelectric generators, as a lower cost alternative to the construction and operation of dispatchable gas on the mainland. The extent of these saving varies by scenario, along with the size and timing of Marinus Link, as displayed in Figure 1.

Figure 1: Composition of forecast total gross market benefits of Basslink for the Step Change, Progressive Change and Hydrogen Superpower scenarios across the three Marinus Link size and timing variants; millions real June 2023 dollars discounted to 1 July 2025



The increase in forecast benefits in the Progressive Change scenario with the single-stage and ISP-timing variants of Marinus Link is primarily because Marinus Link is assumed to be commissioned one year later than in the Step Change and Hydrogen Superpower scenarios.

[11] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

2. Introduction

APA has engaged EY to undertake market modelling of system costs and benefits to assist with their application to convert the Basslink interconnector into a regulated asset in parallel with a revenue determination for Basslink.

This Report describes the key modelling outcomes and insights as well as the assumptions and input data sources selected by APA and the modelling methods used.

EY was engaged to compute the least-cost generation dispatch and capacity development plan for the NEM for the Step Change, Progressive Change and Hydrogen Superpower scenarios issued by AEMO in the 2022 ISP[12] under three variants to the size and timing of Marinus Link. Two sensitivities to the size of Basslink were also modelled for the Step Change scenario. In addition, APA has requested that the scenarios be updated to incorporate changes to the input assumptions based on the July 2023 AEMO IASR[13]. The input assumptions that have been updated include:

- Energy policy targets
- Carbon budgets
- Costs: capex, FOM, VOM, fuel, USE and REZ resource limit violation penalty factors
- Committed and anticipated generators
- Thermal retirement dates
- Discount rates.

For this modelling, it has not been possible to fully align with the Final 2024 ISP, since the two-yearly ISP process is still ongoing at the time we were undertaking this engagement. For instance, demand scenarios referenced in the July 2023 IASR were only released in the 2023 ESOO at the end of August 2023[14], after the work for this Report was largely complete, and an initial view of the timing of other transmission projects will not be known until the release of the Draft 2024 ISP in December 2023. Due to time restrictions, several other assumption updates from the July 2023 AEMO IASR[13] could not be captured in the modelling, such as changes in REZ transmission limits and renewable capacity factors, as agreed by APA.

APA has assumed the following Marinus Link sizes and timings for the three variants of each scenario:

- Marinus Link single-stage: Stage 1 follows the scenario-specific optimal timing from the 2022 ISP [15], but Stage 2 is not commissioned
  - Step Change: Stage 1 commissioned in 2029-30
  - Progressive Change: Stage 1 commissioned in 2030-31

[12] Note that while some of the assumptions are from the 2022 Inputs and Assumptions workbook published on 30 June 2021, many assumptions like energy policy targets and costs are from the 2023 Inputs and Assumptions workbook published 28 July 2023. The timing of major upgrades are based on the 2022 ISP outcomes. AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, 2022 ISP assumptions available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, and 2023 ISP assumptions available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023.

[13] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[14] AEMO, *2023 Electricity Statement of Opportunities*, August 2023, available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 3 September 2023.

[15] AEMO*, Appendix 5: 2022 Integrated System Plan*, available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 11 September 2023.

- ► Hydrogen Superpower: Stage 1 commissioned in 2029-30

► Marinus Link double-stage, ISP-timing: scenario specific optimal timing from the 2022 ISP[4]

- ► Step Change: Stage 1 commissioned in 2029-30 and Stage 2 in 2031-32
- ► Progressive Change: Stage 1 commissioned in 2030-31 and Stage 2 in 2032-33
- ► Hydrogen Superpower: Stage 1 commissioned in 2029-30 and Stage 2 in 2031-32

► Marinus Link double-stage delay: Stage 1 commissioned 2033-34 and Stage 2 in 2035-36 in all scenarios.

This is an independent study, in which the modelling methodology follows the Regulatory Test utilised in the Directlink and Murraylink conversion determination processes with some adjustments to the input assumptions and scenarios advised by APA[16]. As APA is seeking conversion of Basslink from 1 July 2025, APA has assumed the Base Case counterfactual for all scenarios and sensitivities essentially retires Basslink by July 2025, from the beginning of the Modelling Period. The forecast gross market benefit of Basslink is therefore calculated as the difference in the system cost that is forecast with versus without Basslink.

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 and storage capacity installed,
- ► total FOM costs of all generation and storage capacity,
- ► total VOM costs of all generation and storage 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 the 21-year Modelling Period, from 2025-26 to 2045-46. Benefits presented are discounted to June 2025 using a 7% real, pre-tax discount rate as selected by APA, consistent with the value applied by AEMO in the 2023 IASR[17].

The forecast gross market benefits of each scenario and sensitivity need to be compared to the ongoing cost of Basslink to determine the forecast net economic benefit for that case. That evaluation is not part of our scope and hence has not been included in this Report. It is performed by APA outside of this Report using the forecast gross market benefits from this Report and other inputs.

The Report is structured as follows:

- ► Section 3 describes the assumptions and scenarios inputs modelled in this study.
- ► Section 4 provides an overview of the methodology applied in the modelling and computation of forecast gross market benefits.

[16] Directlink Joint Venture, 6 May 2004, Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005-2014, available at: https://www.aer.gov.au/system/files/Directlink%20application%20%286%20May%202004%29.pdf. Accessed 15 September 2023.
[17] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

- Section 5 outlines model design and input data related to representation of the transmission network and transmission losses.
- Section 6 outlines model design and input data related to demand.
- Section 7 provides an overview of model inputs and methodologies related to supply of energy.
- Section 8 presents the NEM capacity and generation outlook with Basslink for the three scenarios.
- Section 9 presents the forecast gross market benefits associate with Basslink. It is focussed on identifying and explaining the key sources of forecast gross market benefits for the Step Change scenario, while providing a summary of other scenarios and sensitivities and Marinus Link variants.

3. Scenario assumptions

Basslink gross market benefits have been assessed under the Step Change, Progressive Change and Hydrogen Superpower scenario from the 2022 ISP[18], as chosen by APA. As requested by APA modifications were incorporated to reflect the scenarios presented in the July 2023 IASR Assumptions Workbook[19], which include updates to:

- Energy policy targets
- Carbon budgets
- Costs: capex, FOM, VOM, fuel, USE and REZ resource limit violation penalty factors
- Committed and anticipated generators
- Thermal retirement dates
- Discount rates.

For this modelling, it has not been possible to fully align with the Final 2024 ISP, since the two-yearly ISP process is still ongoing. For instance, demand scenarios that will be used in the 2024 ISP were only released in the 2023 ESOO at the end of August 2023[20], after the work for this Report was largely complete, and an initial view of the timing of other transmission projects will not be known until the release of the Draft 2024 ISP in December 2023. Due to time restrictions, several other assumption updates from the July 2023 AEMO IASR[19] could not be captured in the modelling, such as changes in REZ transmission limits and renewable capacity factors, as agreed by APA. The full list of assumptions is summarised in Table 3.

Table 3: 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	2022 ISP[18] – Step Change	2022 ISP[18] – Progressive Change	2022 ISP[18] – Hydrogen Superpower
Committed and anticipated generation	Committed and anticipated generators from the 2023 IASR Assumptions Workbook[19]		
New entrant capital cost for wind, solar PV, SAT, OCGT, CCGT, PHES large-scale batteries and hydrogen turbine	2023 IASR Assumptions Workbook[19] – Step Change	2023 IASR Assumptions Workbook[19] – Progressive Change	2023 IASR Assumptions Workbook[19] – Green Energy Export
Retirements of coal-fired power stations	2023 IASR Assumptions Workbook[19]: In line with expected closure year, or earlier if economic or driven by decarbonisation objectives.		

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[18] Note that while some of the assumptions are from the 2022 Inputs and Assumptions workbook published on 30 June 2021, many assumptions like energy policy targets and costs are from the 2023 Inputs and Assumptions workbook published 28 July 2023. The timing of major upgrades are based on the 2022 ISP outcomes. AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, 2022 ISP assumptions available at https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios, and 2023 ISP assumptions available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023.

[19] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[20] AEMO, *2023 Electricity Statement of Opportunities*, August 2023, available at: https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo. Accessed 3 September 2023.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Gas fuel cost	2023 IASR Assumptions Workbook[21] – Step Change	2023 IASR Assumptions Workbook[21] – Progressive Change	2023 IASR Assumptions Workbook[21] – Green Energy Export
Coal fuel cost	2023 IASR Assumptions Workbook[21] – Step Change	2023 IASR Assumptions Workbook[21] – Progressive Change	2023 IASR Assumptions Workbook[21] – Green Energy Export
NEM carbon budget	2023 IASR Assumptions Workbook[21] – Step Change: 681 Mt CO_2-e 2024-25 to 2051-52	2023 IASR Assumptions Workbook[21] – Progressive Change: 1,203 Mt CO_2-e 2024-25 to 2051-52	2023 IASR Assumptions Workbook[21] – Green Energy Export: 357 Mt CO2-e 2024-25 to 2051-52
Victoria policy	Victoria Renewable Energy Target (VRET) – 40% by 2025, 65% by 2030 and 95% by 2035 Victoria Energy Storage Target – 2.6 GW by 2030 and 6.3 GW by 2035 Victoria Offshore Wind Target – 2 GW by 2032, 4 GW by 2035 and 9 GW by 2040 Consistent with 2023 IASR Assumptions Workbook[21]		
Queensland Renewable Energy Target (QRET)	50% by 2029-30, 70% by 2031-32 and 80% by 2034-35 Consistent with 2023 IASR Assumptions Workbook[21]		
Tasmanian Renewable Energy Target (TRET)	100% by 2022, linear trajectory from the mid-2020s to 150% available renewable generation by 2030 and 200% by 2040 as a percentage of 2020 demand in Tasmania. The trajectory can be exceeded if part of the least cost solution. Consistent with 2023 IASR Assumptions Workbook[21]		
NSW Electricity Infrastructure Roadmap	NSW Roadmap, with at least the same amount of electricity as 8 GW in New England, 3 GW in the Central West Orana (CWO) REZ and 1 GW of additional capacity and 2 GW of long duration storage (8 hrs or more) by 2029-30. Consistent with 2023 IASR Assumptions Workbook[21]		
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. Consistent with 2023 IASR Assumptions Workbook[21]		
EnergyConnect	2022 ISP anticipated project[22]: EnergyConnect commissioned by July 2026		
Western Renewables Link	2022 ISP anticipated project[22]. Western Victoria upgrade commissioned by July 2026		
HumeLink	2022 ISP outcome[22] – Step Change: HumeLink commissioned by July 2028	2022 ISP outcome[22] – Progressive Change: HumeLink commissioned by July 2035	2022 ISP outcome[22] – Hydrogen Superpower: HumeLink commissioned by July 2027
New-England REZ Transmission	2022 ISP outcome[22] – Step Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2035	2022 ISP outcome[22] – Progressive Change: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2038	2022 ISP outcome[22] – Hydrogen Superpower: New England REZ Transmission Link commissioned by July 2027, New England REZ Extension commissioned by July 2031

[21] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[22] AEMO, *Appendix 5: 2022 Integrated System Plan*, available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 11 September 2023.

Key drivers input parameter	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Marinus Link	Changes by scenario variant as per Table 4		
QNI Connect	2022 ISP outcome[23] – Step Change: QNI Connect commissioned by July 2032	2022 ISP outcome[23] – Progressive Change: QNI Connect commissioned by July 2036	2022 ISP outcome[23] – Hydrogen Superpower: QNI Connect commissioned by July 2029
VNI West	2022 ISP outcome[23] – Step Change: VNI West commissioned by July 2031	2022 ISP outcome[23] – Progressive Change: VNI West commissioned by July 2038	2022 ISP outcome[23] – Hydrogen Superpower: VNI West commissioned by July 2030
Snowy 2.0	Snowy 2.0 is commissioned by December 2029 Consistent with the 2023 IASR Assumptions Workbook[24]		
Borumba PHES	Borumba PHES is commissioned by July 2030 Consistent with the nearest financial year in the 2023 IASR Assumptions Workbook[24]		

Table 4 describes the different sizes and timings for Marinus Link across scenarios and scenario variants, as chosen by APA. The single-stage variant was included on request by APA in response to the joint media release Commonwealth and Tasmanian Governments on 3 September which announced that “the project will be focused on one cable in the first instance, with negotiations to continue on a second cable, to be considered after final investment decision on cable one”[25].

Table 4: Timing of Marinus Link across scenarios and scenario variants

Scenario variant	Scenario		
	Step Change	Progressive Change	Hydrogen Superpower
Marinus Link single-stage	2022 ISP outcome[23] (1st cable only) – Step Change: 1st cable commissioned by July 2029	2022 ISP outcome[23] (1st cable only) – Progressive Change: 1st cable commissioned by July 2030	2022 ISP outcome[23] (1st cable only) – Hydrogen Superpower: 1st cable commissioned by July 2029
Marinus Link double-stage, ISP-timing	2022 ISP outcome[23] – Step Change: 1st cable commissioned by July 2029 and 2nd cable by July 2031	2022 ISP outcome[23] – Progressive Change: 1st cable commissioned by July 2030 and 2nd cable by July 2032	2022 ISP outcome[23] – Hydrogen Superpower: 1st cable commissioned by July 2029 and 2nd cable by July 2031
Marinus Link double-stage delay	1st cable commissioned by 2033 and 2nd cable commissioned 2035		

[23] AEMO, *Appendix 5: 2022 Integrated System Plan*, available at https://aemo.com.au/-/media/files/major-publications/isp/2022/2022-documents/a5-network-investments.pdf?la=en. Accessed 11 September 2023.

[24] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[25] Department of Climate Change and Energy, 3 Sep 2023. Joint media release: Investing in the future of Tasmanian energy with Marinus Link. Available at: https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-investing-future-tasmanian-energy-marinus-link. Accessed 4 September 2023.

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 21 years from 2025-26 (coincident with the timing that APA has advised Basslink may be converted to a regulated asset) to 2045-46 (the expected retirement time for Basslink, based on its technical life).

APA have requested that we apply a modelling methodology consistent with the Regulatory Test utilised in the Directlink and Murraylink conversion determination processes with some adjustments to the input assumptions and scenarios advised by APA[26]. As APA is seeking conversion of Basslink from 1 July 2025, APA has assumed the Base Case counterfactual for all scenarios and sensitivities essentially retires Basslink by July 2025, from the beginning of the Modelling Period. The forecast gross market benefit of Basslink is therefore calculated as the difference in the system cost that is forecast with versus without Basslink.

Based on the full set of input assumptions, the 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[27] 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[28] dispatch interval in relation to:

- the generation dispatch level for each power plant along with the charging and discharging of storage. Generators are assumed to be dispatched according to their SRMC, which is derived from their VOM and fuel costs. The generation for each dispatch interval is subject to the modelled availability of power stations in each hour (subject to planned or unplanned outages or variable renewable availability), network limitations and energy limits (e.g., storage levels).
- commissioning new entrant capacity for wind, offshore wind, solar PV SAT, CCGT, OCGT, large-scale battery and PHES.

These hourly decisions take into account constraints that include:

- supply must equal demand in each region for all dispatch intervals, while maintaining a reserve margin, with USE costed at the VCR,
- minimum loads for some generators,
- transmission interconnector flow limits (between regions),

[26] Directlink Joint Venture, 6 May 2004, Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005-2014, available at: https://www.aer.gov.au/system/files/Directlink%20application%20%286%20May%202004%29.pdf. Accessed 15 September 2023.

[27] For the transmission elements modelled, described in Section 5.

[28] 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.

- maximum and minimum storage reservoir limits (for conventional storage hydro, PHES, virtual power plant (VPP) and large-scale battery),
- new entrant capacity transmission and resource limits for wind and solar in each REZ and costs associated with increasing these limits, and PHES in each region,
- emission and carbon budget constraints, as defined for each scenario,
- renewable energy targets where applicable by region or NEM-wide.

The model does not include intra-regional constraints, i.e., it does not contain the detail of the transmission network within a region, only inter-regional transfer limits (between regions).[29]

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 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 2022 ISP dataset[30]. 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 expected earlier economic retirements[31]. 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 the cost of supply is at or above their variable costs 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, large-scale battery and VPPs) are operated to minimise the overall system costs. This means they tend to generate at times of high cost of supply, e.g., when the demand for power is high, and so dispatching energy-limited generation will avoid utilisation of high-cost plant such as gas-fired 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 large-scale batteries operate in pumping or charging mode.

4.2 Reserve constraint in long-term investment planning

As per the AEMO ISP methodology[32] assumed by APA, 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.

[29] It does however include an additional cost for transmission upgrades to facilitate REZ development where this forms part of the input data.

[30] AEMO, *2022 ISP*, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp, and AEMO, 30 June 2022, *Current inputs, assumptions and scenarios v3.4*, 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 11 September 2023.

[31] Note that earlier coal retirements in TSIRP are an outcome of the least cost optimisation rather than revenue assessment.

[32] AEMO, ISP Methodology, June 2023, available at https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/nem-consultations/2023/isp-methodology-2023/isp-methodology_june-2023.pdf?la=en. Accessed 14 September 2023.

All dispatchable generators in each region are eligible to contribute to reserve (except PHES, VPPs and large-scale battery[33]) 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 single contingency reserve requirement was applied with a high penalty cost. This amount of reserve ensures there is sufficient capacity for operational reliability in the event that conditions vary from the perfect-foresight optimisation model (e.g., variability in production from variable renewable energy sources, different forced outage patterns, 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.

There are two 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.

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 and storage capacity installed,
- total FOM costs of all generation and storage capacity,
- total VOM costs of all generation and storage 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 and sensitivity with Basslink, a matched without Basslink 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 Basslink.

Each component of forecast gross market benefits is computed annually over the 21-year Modelling Period. In this Report, we summarise the forecast benefit and cost streams using a single value computed as the net present value (NPV)[34], discounted to June 2025 at a 7% real, pre-tax discount rate as selected by APA, consistent with the 2023 IASR[35].

The forecast gross market benefits of each scenario and sensitivity need to be compared to the cost in the relevant case to determine whether there is a positive forecast net economic benefit. That evaluation is not part of our scope and hence has not been included in this Report. It is performed by APA outside of this Report using the forecast gross market benefits from this Report and other inputs.

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

34 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.

35 AEMO, *2023 IASR*, available at https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023.

5. Transmission

5.1 Regional definitions

A five-node setup was implemented in the modelling presented in this Report to represent the inter-regional network limitations and transmission losses. The regions and regional reference nodes are listed in Table 5.

Table 5: Regions, zones and reference nodes

Region	Regional Reference Node (RRN)
Queensland (QLD)	South Pine 275 kV
New South Wales (NSW)	Sydney West 330 kV
Victoria (VIC)	Thomastown 66 kV
South Australia (SA)	Torrens Island 66 kV
Tasmania (TAS)	Georgetown 220 kV

5.2 Interconnector loss models

Dynamic loss equations for the existing network are sourced from AEMO's 2022 ISP assumptions[36]; however, losses across Basslink are attributed to the sending end of the interconnector, as per AEMO's Forward Looking Loss Factor (FLLF) methodology[37].

5.3 Interconnector capabilities

The notional limits imposed on interconnectors are shown in Table 6.

Table 6: Notional interconnector capabilities used in the modelling (sourced from AEMO 2022 ISP36)

Interconnector (From node – To node)	Import[38] notional limit	Export[39] notional limit
QNI[40]	1,165 MW summer 1,170 MW winter	745 MW summer/winter
QNI Connect[41]	2,245 MW summer 2,250 MW winter	1,655 MW summer/winter

[36] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 11 September 2023.

[37] AEMO, March 2023, *Marginal Loss Factors: Financial Year 2023-24*, available at: https://aemo.com.au/-/media/files/electricity/nem/security_and_reliability/loss_factors_and_regional_boundaries/2023-24/marginal-loss-factors-for-the-2023-24-financia-year-pdf.pdf?la=en. Accessed 5 September 2023.

[38] 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.

[39] 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.

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

[41] 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 11 September 2023.

Interconnector (From node – To node)	Import[38] notional limit	Export[39] notional limit
Terranora	150 MW summer 200 MW winter	50 MW summer/winter
EnergyConnect (NSW-SA)	800 MW	800 MW
VIC-NSW	400 MW 2,200 MW (after VNI West)	1,000 MW 2,930 MW (after VNI West)
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 (most simulations) 150 MW (sensitivity) 350 MW (sensitivity)	478 MW (most simulations) 150 MW (sensitivity) 350 MW (sensitivity)
Marinus Link[42] (TAS-VIC)	750 MW for the first stage and 1,500 MW after the second stage (for applicable variants)	750 MW for the first stage and 1,500 MW after the second stage (for applicable variants)

The following interconnectors are included in the left-hand side of constraint equations which may restrict them below the notional limits specified in Table 6:

- Heywood + Project EnergyConnect has combined transfer export and import limits of 1,300 MW and 1,450 MW, respectively. The model will dispatch across the two links to minimise costs.
- Basslink and Marinus Link are included in the Tasmania inertia constraints described in Section 5.3.1.

5.3.1 Tasmania inertia constraints

An inertia constraint was included in the generation development plan to ensure the aggregate level of inertia in Tasmania in each dispatch interval is sufficient to meet minimum requirements.

A linear inertia requirement described in the Marinus Link PACR by TasNetworks[43] was imposed, which accounts for the effect of Tasmanian demand, interconnector flows, seasonal differences in hydro minimum loads and the effect of variable wind production and PHES development. The set of inertia constraints account for the contribution of Tasmanian generator to inertia with different requirements varying with import, export and Tasmania demand conditions. Applicable hydroelectric generators are also able to operate in synchronous condenser mode at a cost of $0.17/MW.s, as per the Marinus Link PACR[43].

[42] The 2022 ISP imposes a combined Basslink + Marinus Link constraint on import limits as the ISP model does not consider Tasmanian inertia requirements. As this Report explicitly models inertia constraints the import limit constraints are not imposed.

[43] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*, available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 11 September 2023.

6. Demand

The TSIRP model captures forecast demand 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 historical 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 assumed annual peak demand and energy in each region,
- the nine reference years are repeated sequentially throughout the Modelling Period as shown in Figure 2.
- the future hourly rooftop PV generation has been estimated based on insolation in the corresponding reference year and the projection of future rooftop PV capacity, which is subtracted from the forecast underlying demand along with other behind-the-meter components (e.g., electric vehicles, domestic battery and other small non-scheduled generation) to get a projection of hourly operational demand.

Figure 2: Sequence of demand reference years applied to forecast

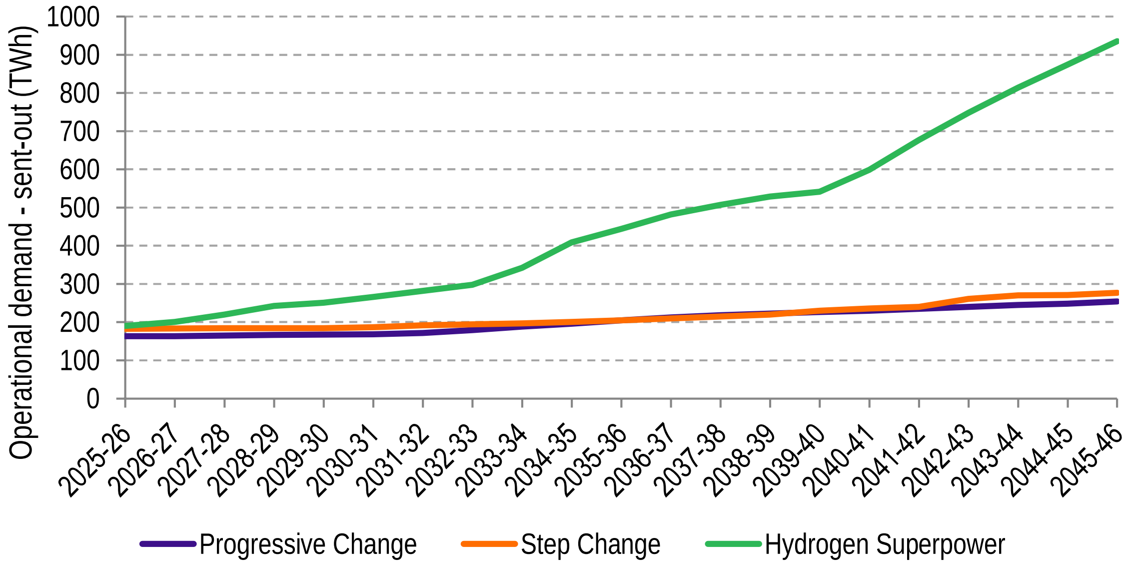
Modelled year	Reference year
2023-24	2014-15
2024-25	2015-16
2025-26	2016-17
2026-27	2017-18
2027-28	2018-19
2028-29	2010-11
2029-30	2011-12
2030-31	2012-13
2031-32	2013-14
2032-33	2014-15
2033-34	2015-16
2034-35	2016-17
2035-36	2017-18
2036-37	2018-19
...	...
2043-44	2016-17
2044-45	2017-18
2045-46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

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 dispatch 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 7.1) and hydro inflows. This maintains correlations between weather patterns, demand, wind, large-scale solar and distributed PV availability.

APA selected demand forecasts from the ESOO 2021[44] consistent with the relevant scenarios in the ISP 2022[45] which are used as inputs to the modelling. Figure 3 shows the NEM operational demand for the modelled scenarios, inclusive of hydrogen demand.

Figure 3: Annual operational demand in the modelled scenarios for the NEM



[44] AEMO, *National Electricity and Gas Forecasting*. Available at: http://forecasting.aemo.com.au/Electricity/AnnualConsumption/Operational. Accessed 11 September 2023.

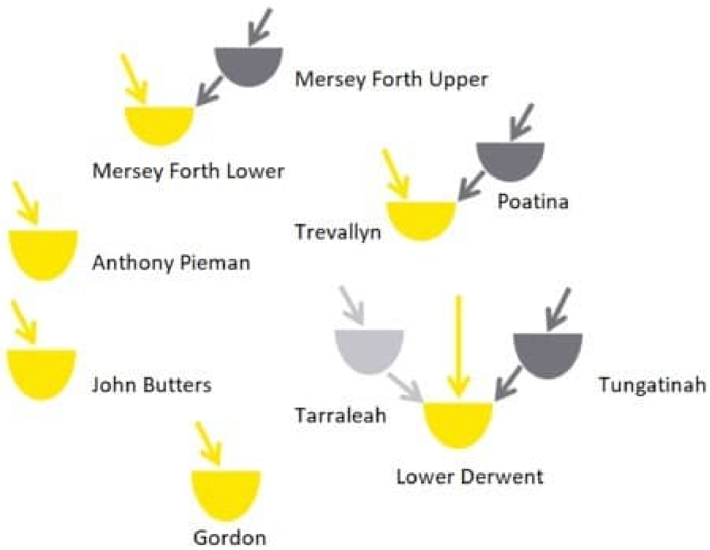
[45] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 11 September 2023.

7. Supply

7.1 Tasmanian hydroelectric generators

Most of Hydro Tasmania's generators are part of connected systems or cascades of multiple generators and variously-sized storages along various Tasmanian river systems. Consistent with the Marinus Link PACR by TasNetworks[46], we used a ten-pond model of the schemes which aggregated some generators within schemes. Figure 4 shows the structure of the cascades modelled. Monthly data for modelling of the Hydro Tasmania generators is included in the assumptions workbook for the Marinus Link PACR by TasNetworks[46].

Figure 4: Cascades modelled



The hourly generation profile of each scheme is determined by the model, which maximises the value of energy available. Water use in each scheme over the 21-year Modelling Period is optimised subject to reservoir levels at the start of the study, hourly inflows (derived from monthly data) and minimum monthly whole-of-system reservoir levels.

The whole-of-Tasmanian system reservoir volume is known as Total Energy in Storage and the monthly minimums are the prudent storage level (PSL) profile. The PSL is imposed as part of Tasmania's energy security plan mandated by the Tasmanian Government to manage the consequences of an extended Basslink outage[47].These levels vary throughout the year to match long-term seasonal rainfall patterns as shown in Figure 5. In the model, these minimums from the Marinus Link PACR by TasNetworks[46] were imposed on the first of each month.

Upon entry of Marinus Link, there is a ten percentage point decrease in the PSL profile, which represents a reversion to values that were applied prior to energy security review that followed the extended outage of Basslink in 2016. The decrease in PSL profile with Marinus Link was selected by APA, consistent with the Marinus Link PACR by TasNetworks[46]. This was selected on the basis that the assumptions detailed in the Tasmanian Energy Security Taskforce Final Report[48], upon which the PSL is based, would no longer be valid with the introduction of Marinus Link, and a revision to

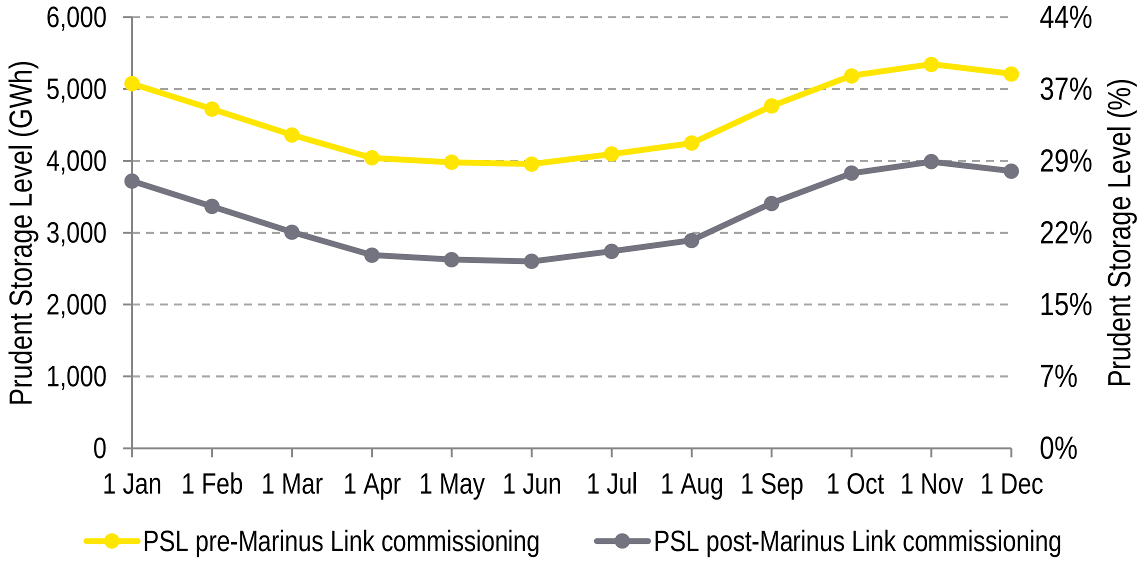
[46] TasNetworks, 24 June 2021, *Input assumptions and scenario workbook for Project Marinus PACR*, available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 5 September 2023.

[47] Hydro Tasmania, *Secure Energy,* Available at: https://www.hydro.com.au/clean-energy/secure-energy. Accessed 11 September 2023.

[48] Tasmanian Government, *Tasmanian Energy Security Taskforce Final Report.* Available at: https://www.stategrowth.tas.gov.au/energy_and_resources/tasmanian_energy_security_taskforce/final_report. Accessed 11 September 2023.

the former PSL profile could be justified. As we understand, this PSL reduction does not represent Tasmanian Government policy. This decrease delivers a one-off quantity of additional water for generation and ongoing greater flexibility in use of Hydro Tasmania's storages.

Figure 5: PSL Profile for Hydro Tasmania's reservoirs



7.2 Wind and solar energy projects and REZ representation

Several generators not yet built are committed in all simulations. The source of this list is AEMO's 2023 IASR Assumptions Workbook[49] for existing, committed and anticipated projects.

Existing and new wind and solar projects are modelled based on nine years of historical weather data[50] and the methodology for each category of wind and solar project is summarised in Table 7.

Table 7: 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[51] 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[52].	

[49] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[50] 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 11 September 2023.

[51] 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 11 September 2023.

[52] AEMO, 10 December 2021, *Input and Assumptions Workbook v3.3*, available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 5 September 2023.

Technology	Category	Capacity factor methodology	Reference year treatment
	Generic REZ new entrants	Reference year specific targets based on AEMO's 2021 ISP Inputs and Assumptions workbook[53]. One high quality option and one medium quality option per REZ.	
Solar PV Fixed Flat Plate	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[53].	
	Generic REZ new entrant	Reference year specific targets based on AEMO's 2021 ISP Inputs and Assumptions workbook[53].	
Rooftop PV and small non-scheduled solar PV	Existing and new entrant	Long-term average capacity factor based on AEMO's 2022 ISP Inputs and Assumptions workbook[54].	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 demand profile. Wind and solar availability profiles used in the modelling reflect generation patterns occurring in the nine historical years, and these generation patterns are repeated throughout the Modelling Period as shown in Figure 4.

The availability profiles for wind generation are derived from simulated wind speeds from the Australian Bureau of Meteorology's Numerical Weather Prediction systems[55] 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 2021 ISP inputs and assumptions[53] for each REZ.

The availability profiles for solar are derived using solar irradiation data 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.

[53] AEMO, 10 December 2021, *Input and Assumptions Workbook v3.3*, available at: https://aemo.com.au/consultations/current-and-closed-consultations/2021-planning-and-forecasting-consultation-on-inputs-assumptions-and-scenarios. Accessed 5 September 2023.

[54] AEMO, 30 June 2022, *Current inputs, assumptions and scenarios v3.4*, 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 5 September 2023.

[55] As described by Australian Government Bureau of Meteorology, *ACCESS NWP Data* Information. Available at: http://www.bom.gov.au/nwp/doc/access/NWPData.shtml. 11 September 2023.

Wind and solar capacity expansion in each REZ is limited by four parameters based on AEMO's 2022 ISP Inputs and Assumptions workbook[56].

- 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, and potentially beyond the limit at cost, if it is part of the least-cost development plan.

7.3 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 2022 ISP Inputs and Assumptions workbook[56].

All unplanned forced outage patterns are set by a random number generator for each existing generator. The seed for the random number generator is set such that the same forced outage pattern exists between the Base Case and the with Basslink case. 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 2022 ISP Inputs and Assumptions workbook[57].

7.4 Generator technical parameters

Technical generator parameters applied are as detailed in the 2023 IASR Assumptions Workbook[58] for AEMO's long-term planning model, except as noted in the Report.

7.5 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 2023 IASR Assumptions Workbook[58], 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 2022 ISP Inputs and Assumptions workbook[57].

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[56] AEMO, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 11 September 2023.

[57] AEMO,30 June 2022, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 11 September 2023.

[58] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

7.6 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 2023 IASR Assumptions Workbook[58], 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.

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

Intermittent renewables, in particular solar PV, wind and run-of-river hydro have their dispatch capped at 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 7.2.

Solar PV and wind generation are dispatched at their available resource limit unless curtailed economically (when sufficient sources of must-run generation and generation with cost at or below their VOM are available) or by other constraints such as transmission limits.

7.8 Storage-limited generators

Conventional hydro with storages, PHES and batteries are dispatched in each 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 2022 ISP Inputs and Assumptions workbook and the median hydro climate factor trajectory for the respective scenario applied[59]. The Tasmanian hydro schemes, including run-of-river plants, were modelled using a ten-pond model, with additional information for monthly inflow data from the Marinus Link PACR by TasNetworks[60] (see Section 7.1 for more detail). The monthly inflow data was used to calculate hourly inflows for each reservoir.

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[59] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 11 September 2023.

[60] TasNetworks, Input assumptions and scenario workbook for Project Marinus PACR, available at: https://www.marinuslink.com.au/rit-t-process/. Accessed 11 September 2023.

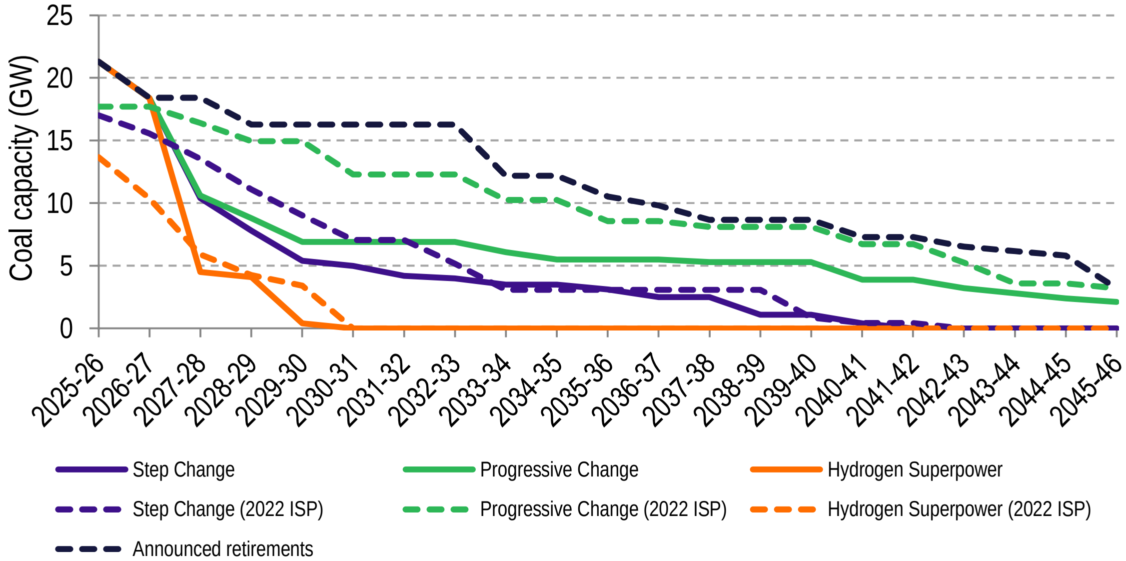
8. NEM outlook in the with Basslink case

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 case where Basslink continues its service until 2045-46. Charts in this section are based on simulations with Basslink and two stages of Marinus Link commissioned at 2022 ISP timings, since the majority of this report was drafted before 1 September 2023. On 3 September, a joint media release between the Commonwealth and Tasmanian Governments announced that “the project will be focused on one cable in the first instance, with negotiations to continue on a second cable, to be considered after final investment decision on cable one”[61]. As a result of this announcement, APA requested that we complete additional simulations with a single-stage of Marinus Link. However, the overall scenario descriptions in this section remains the same with other modelled variants of Marinus Link size and timing.

8.1 Coal power plants withdrawal

Based on the scenario settings described in Section 3, and in line with the 2024 ISP methodology, thermal retirements are determined on a least-cost basis. Coal generator retirements are assumed to occur at or earlier than their end-of-technical-life or announced retirement year. The announced retirement schedules for coal units are based on the July 2023 IASR Assumptions Workbook[62]. Forecast coal capacity in the with Basslink case across all scenarios as an output of the modelling is illustrated in Figure 6.

Figure 6: Forecast coal capacity in the NEM by year across all scenarios in the with Basslink case[63] (solid lines and dashed lines demonstrated the coal capacity changes in this model and ISP 2022 outcomes, respectively)



The forecast pace of the transition is predominantly determined by a combination of assumed carbon budgets, renewable energy targets (federal, 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

[61] Department of Climate Change and Energy, 3 Sep 2023. Joint media release: Investing in the future of Tasmanian energy with Marinus Link. Available at: https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-investing-future-tasmanian-energy-marinus-link. Accessed 4 September 2023.

[62] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

[63] In the model 2,880 MW from the four units of Eraring retires in August 2025 (after the beginning of the 2025-26 financial year).

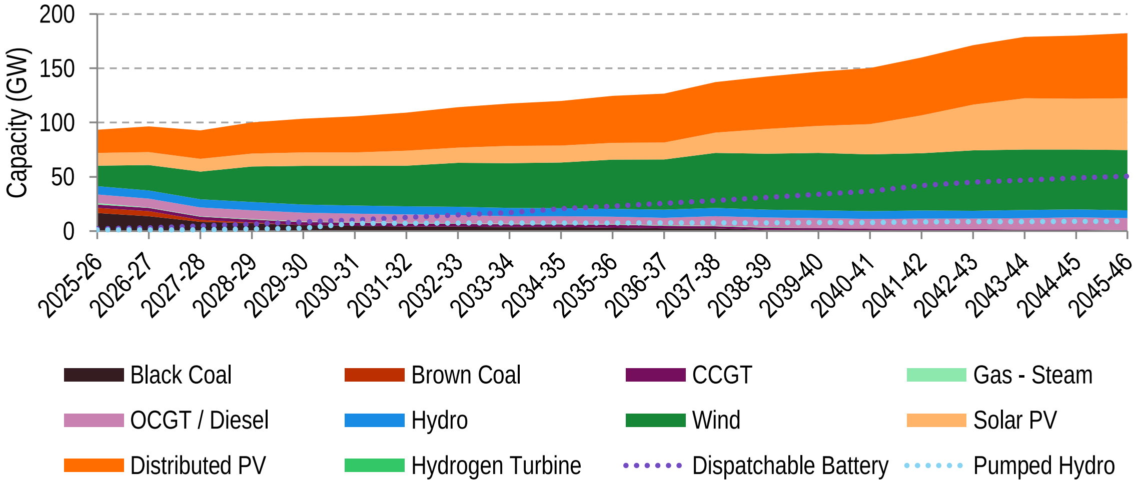
in the Hydrogen Superpower scenario, while this is around 2040 for the Step Change scenario. In the Progressive Change scenario, coal-fired generation is forecast to remain until the end of the Modelling Period, although earlier withdrawals than AEMO's announced withdrawal dates are expected.

The National Electricity Rules require generators to provide three years notice of closure. As such, the coal capacity forecast at the beginning of 2025-26 is higher in this Report compared to the 2022 ISP outcomes, which allowed coal retirements from the beginning of 2025-26. From the late 2020s, the scenarios in this Report are forecast to have less coal capacity than their corresponding 2022 ISP scenario outcomes due to faster pace renewable energy target from the July 2023 IASR Assumptions Workbook[64]. This is particularly relevant for the Progressive Change scenario where earlier withdrawals occur due to the assumed 82% federal renewable generation target.

8.2 NEM capacity and generation outlook

The NEM-wide capacity mix forecast in the Step Change scenario with Basslink is shown in Figure 7 and the corresponding generation mix in Figure 8. In this scenario, the forecast generation capacity of the NEM shifts towards increasing capacity of wind and solar, complemented by large-scale battery, PHES, and gas.

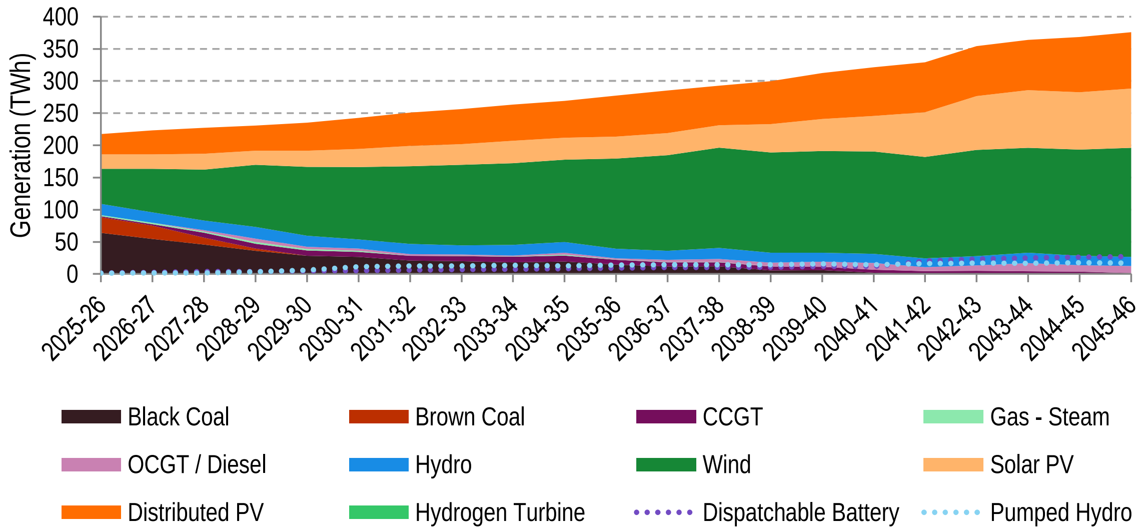
Figure 7: NEM capacity mix forecast for the Step Change scenario in Basslink[65]



64 AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

65 Dispatchable battery includes both large-scale battery and VPP.

Figure 8: NEM generation mix forecast for the Step Change scenario with Basslink



Up to 2030, new wind and solar build is largely driven by the assumed federal renewable energy target. During this time period, the federal renewable energy policy drives outcomes ahead of state-based renewable energy targets and entry of renewable capacity to replace coal retirements to achieve the assumed carbon budget. To replace the retiring capacity, wind capacity is predominantly forecast to be installed throughout the mid-to-late 2020s, along with large-scale battery and pumped hydro storage capacity in line with the assumed state-based storage targets. Solar PV and OCGT capacity are also forecast to increase from the late 2030s complementing other technologies. The forecast new gas-fired capacity also supports reserve requirements. Overall, the NEM is forecast to have roughly 242 GW total capacity by 2045-46 (note that total capacity includes distributed PV, which is an input assumption, and also PHES and large-scale battery capacities, which are not in the stacked chart).

The other selected scenarios vary in the pace of the energy transition from the Step Change scenario. Figure 9 and Figure 11 show the differences in the NEM capacity development of other two scenarios relative to the Step Change scenario, while Figure 10 and Figure 12 show generation differences. The differences are presented as alternative scenario minus the Step Change scenario, and both capacity and generation differences for each scenario show similar trends.

Figure 9 and Figure 10 show that the Progressive Change scenario is forecast to retain coal generation and install less wind and solar generation compared to the Step Change scenario due to different assumptions such as the less restrictive carbon budget, lower demand forecast and other underlying input data.

Figure 9: Difference in NEM capacity forecast between the Progressive Change and Step Change scenarios with Basslink

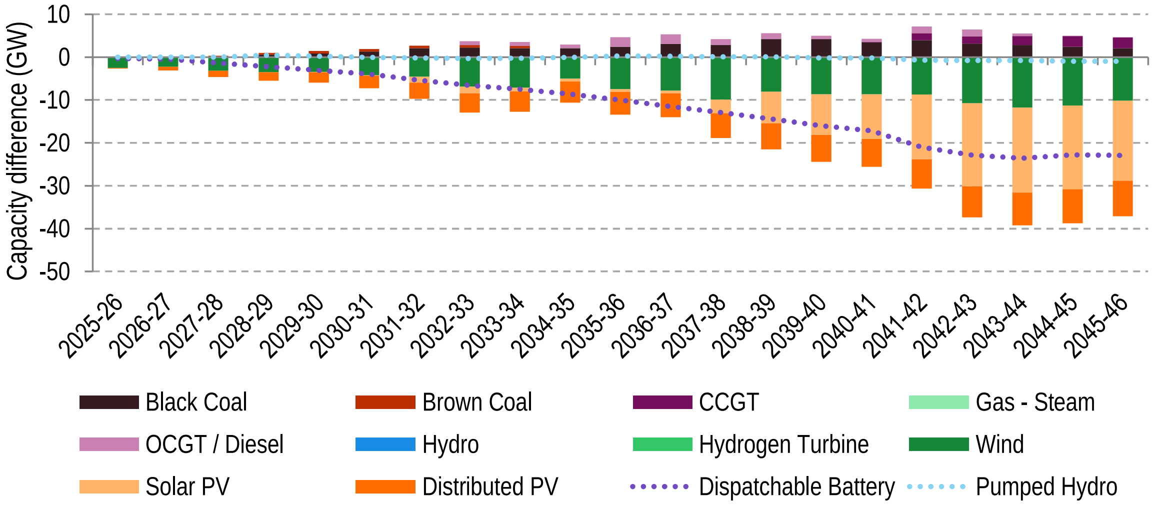


Figure 10: Difference in NEM generation forecast between the Progressive Change and Step Changes scenarios with Basslink

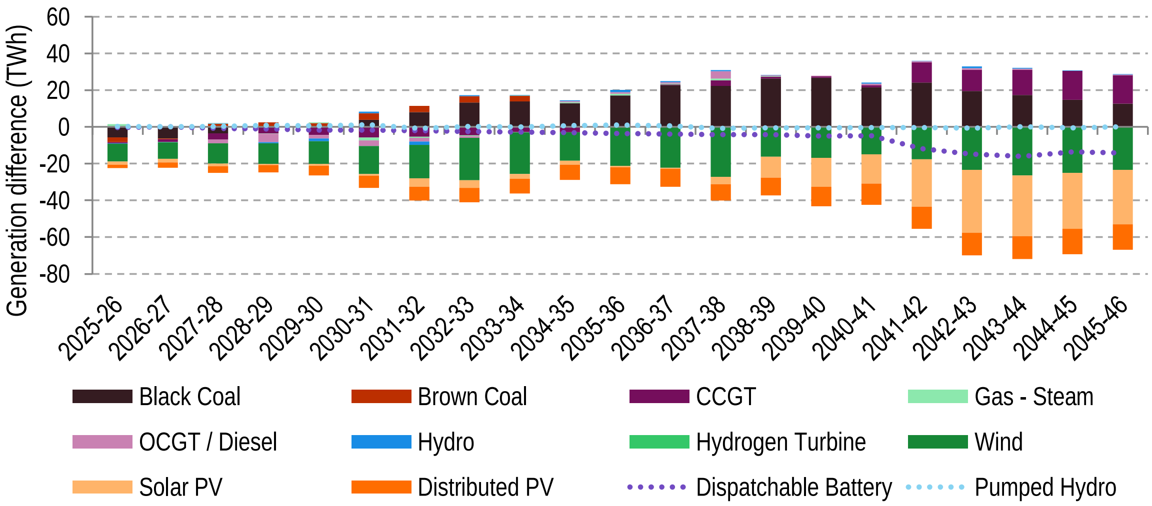


Figure 11 and Figure 12 show that the Hydrogen Superpower scenario is forecast to withdraw coal generation and install wind and solar generation more rapidly than the Step Change scenario due to different assumptions such as the more restrictive carbon budget and higher demand forecast.

Figure 11: Difference in NEM capacity forecast between the Hydrogen Superpower and Step Change scenarios with Basslink

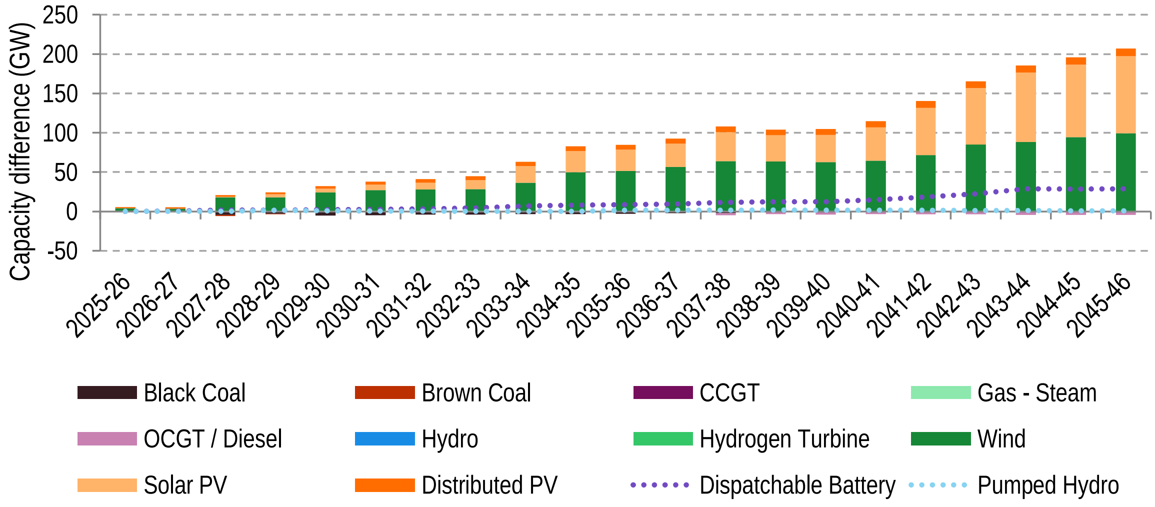
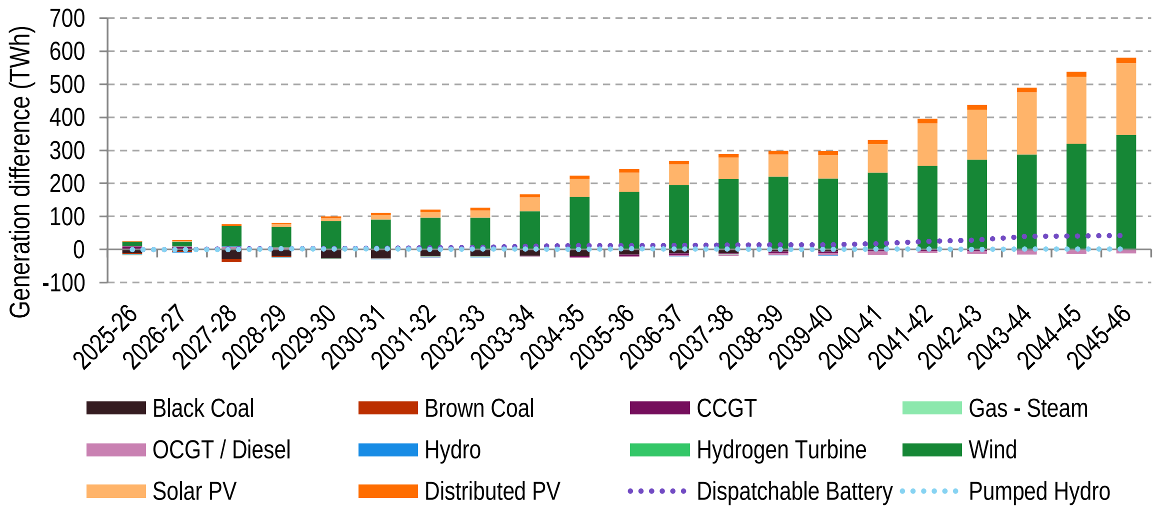


Figure 12: Difference in NEM generation forecast between the Hydrogen Superpower and Step Change scenarios with Basslink



9. Forecast gross market benefit outcomes

9.1 Summary of outcomes

On 3 September, a joint media release between the Commonwealth and Tasmanian Governments announced that Marinus Link "will be focused on one cable in the first instance, with negotiations to continue on a second cable, to be considered after final investment decision on cable one"[66].Table 8 shows the forecast gross market benefits of Basslink over the 21-year Modelling Period from 2025-26 to 2045-46 for the Step Change, Progressive Change and Hydrogen Superpower scenarios and Basslink size sensitivities in the single-stage Marinus Link variant.

Table 8: Overview of scenarios and sensitivities with associated forecast gross market benefits for Basslink; millions real June 2023 dollars discounted to 1 July 2025; Marinus Link single-stage

Scenario/ sensitivity	Description	Basslink gross market benefits ($m)
		Marinus Link single-stage
Step Change	AEMO 2022 ISP Step Change Scenario with changes from 2023 IASR Step Change scenario	3,846
Progressive Change	AEMO 2022 ISP Progressive Change Scenario with changes from 2023 IASR Progressive Change scenario	4,241
Hydrogen Superpower	AEMO 2022 ISP Hydrogen Superpower Scenario with changes from 2023 IASR Green Energy Export scenario	3,268
Step Change with 350 MW Basslink	Step Change scenario with: The original modelled import and export capacity for Basslink is 478 MW; This sensitivity considers a smaller import and export capacity of 350 MW for Basslink.	3,131
Step Change with 150 MW Basslink	Step Change scenario with: The original modelled import and export capacity for Basslink is 478 MW; This sensitivity considers a smaller import and export capacity of 150 MW for Basslink.	1,558

The forecast gross market benefits of each scenario and sensitivity must be compared to the ongoing cost of Basslink to determine the forecast net economic benefit for that case. That evaluation is not contained in this Report. It is performed by APA outside of this Report using the forecast gross market benefits from this Report and other inputs.

The forecast gross market benefits of Basslink in the double-stage Marinus Link scenario variants are shown in Table 2.

Table 9: Overview of scenarios and sensitivities with associated forecast gross market benefits for Basslink; millions real June 2023 dollars discounted to 1 July 2025; Marinus Link double-stage

Scenario/ sensitivity	Basslink gross market benefits ($m)	
	Marinus Link double-stage ISP timing	Marinus Link double-stage delay (3 to 4 year delay relative to ISP)
Step Change	2,323	3,823
Progressive Change	2,872	3,579

[66] Department of Climate Change and Energy, 3 Sep 2023. Joint media release: Investing in the future of Tasmanian energy with Marinus Link. Available at: https://minister.dcceew.gov.au/bowen/media-releases/joint-media-release-investing-future-tasmanian-energy-marinus-link. Accessed 4 Sep 2023.

Scenario/ sensitivity	Basslink gross market benefits ($m)	
	Marinus Link double-stage ISP timing	Marinus Link double-stage delay (3 to 4 year delay relative to ISP)
Hydrogen Superpower	2,634	3,268
Step Change with 350 MW Basslink	1,883	3,121
Step Change with 150 MW Basslink	938	1,499

Marinus Link's size and timing are key drivers of forecast gross market benefits of Basslink. Overall, the model outcomes demonstrate that three possible changes to Marinus Link would impact the forecast market benefits of Basslink:

- The second stage of Marinus Link proceeding reduces benefits
- A delay in the first stage of Marinus Link increases benefits
- A delay in the second stage of Marinus Link (if the second stage is to be commissioned) increases benefits.

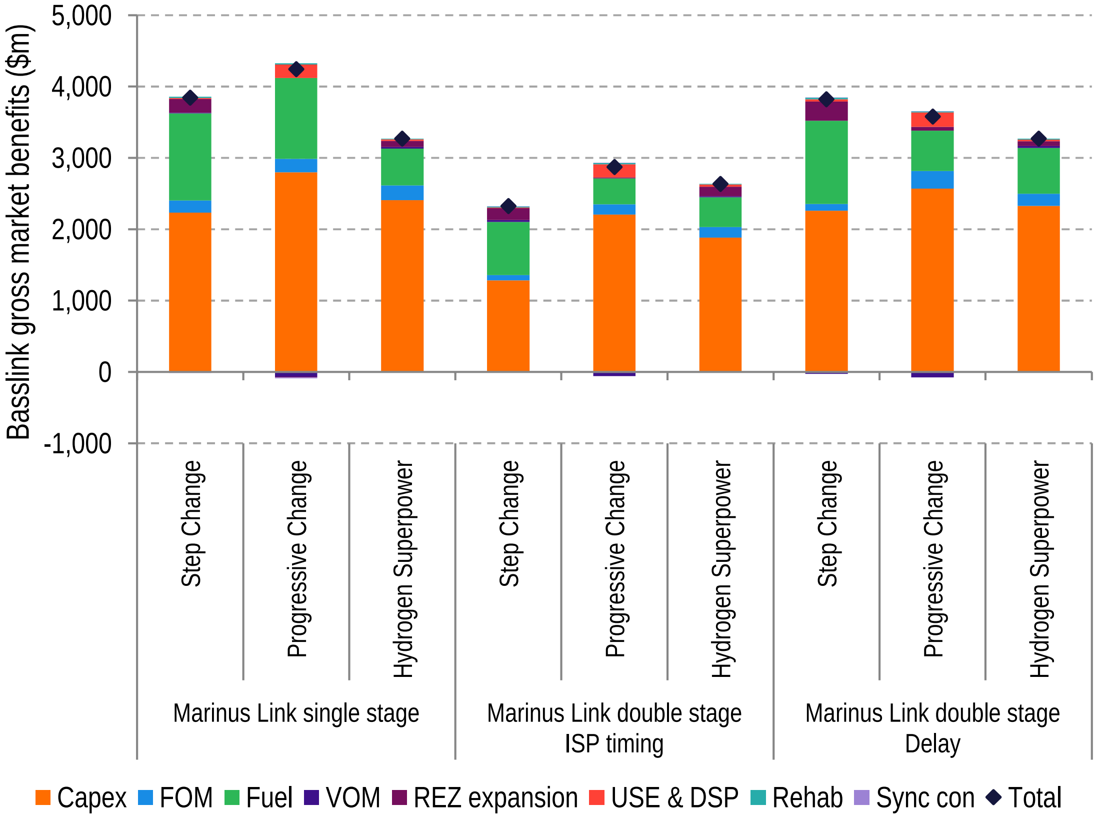
Prior to 2030, for both the Step Change and Progressive Change scenarios, the forecast benefits for Basslink are primarily driven by differences in capacity development to meet the federal 82% renewable energy target in 2029-30 (for a given state of Marinus Link size and timing variants). As most of the annual checkpoints to meet this target (as assumed in the July 2023 AEMO IASR[67]) occur before the assumed commissioning of Marinus Link, Marinus Link is not available to help meet this policy in most years. Without Basslink, in the years prior to Marinus Link commissioning, Tasmanian renewable energy available from capacity built to meet the TRET is spilt and cannot contribute to the federal target. More wind capacity needs to be built on the mainland instead. With Basslink, Tasmanian renewable energy can instead be exported to contribute to serving mainland demand and the federal target. Investment in mainland wind capacity is avoided, leading to capex savings. Overall, Basslink helps meet the federal 82% target at lower cost through efficient use of existing Tasmanian renewable capacity and new renewable capacity built to meet the TRET in the years prior to Marinus Link's entry.

Similar trends to the Step Change and Progressive Change scenarios are forecast for the Hydrogen Superpower scenario. However, capacity differences throughout the 2020s, with and without Basslink, are driven by the restrictive carbon budget of 357 Mt CO_2-e 2024-25 to 2051-52, which is more constraining than the 82% federal target.

Post-2030, Basslink is forecast to result in capex and fuel cost savings by enabling better access to existing Tasmanian hydroelectric generators, as a lower cost alternative to the construction and operation of dispatchable gas. The extent of these saving varies by scenario, along with the size and timing of Marinus Link, as displayed in, Figure 13.

[67] AEMO, July 2023, *2023 IASR Assumptions Workbook v5.0*, previously available at: https://aemo.com.au/consultations/current-and-closed-consultations/2023-inputs-assumptions-and-scenarios-consultation. Accessed 3 September 2023. The July 2023 IASR Assumptions Workbook can be made available on request.

Figure 13: Composition of forecast total gross market benefits of Basslink for the Step Change, Progressive Change and Hydrogen Superpower scenarios across the three Marinus Link size and timing variants; millions real June 2023 dollars discounted to 1 July 2025



In the remainder of this section:

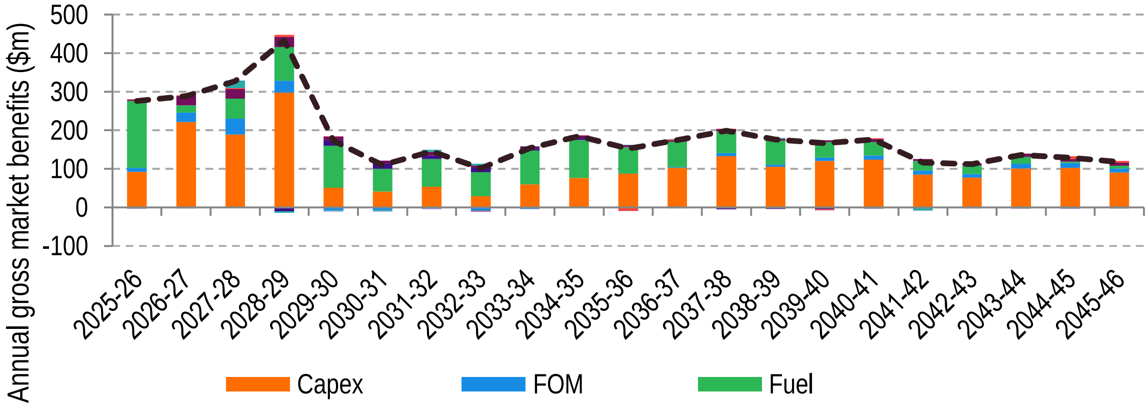
- Sections 9.2 to 9.4 describe the market dynamics for each of the three scenarios with assumed commissioning of a single-stage of Marinus Link as per the ISP timing.
- Section 9.5 outlines differences in the two-stage Marinus Link double-stage, ISP-timing scenario variants.
- Section 9.6 then outlines differences in the two-stage Marinus Link double-stage delay scenario variants.
- The forecast benefits of Basslink in the smaller transfer limit size sensitivities are described in Section 9.7.

9.2 Market modelling outcomes for Step Change scenario for the Marinus Link single-stage variant

9.2.1 Forecast gross market benefits, Step Change scenario

The annual gross market benefit forecast for the inclusion of Basslink in Step Change scenario are depicted in Figure 14 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Basslink results in $3,846m in gross market benefits.

Figure 14: Annual Basslink market benefit forecast for Step Change scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing



The largest individual year benefits of Basslink are forecast to accrue before the assumed commissioning of Marinus Link Stage 1 in 2029-30. This is primarily driven by the capacity development forecast to meet the federal 82 % renewable energy target.

Most of the benefit with the inclusion of Basslink is forecast to be from the reduction in expected capex and fuel costs. Without Basslink, in the years prior to Marinus Link commissioning, Tasmanian renewable energy available from capacity built to meet the TRET is spilt and cannot contribute to the federal target. More wind capacity is forecast to be built on the mainland instead. With Basslink, Tasmanian renewable energy can instead be exported to contribute to serving mainland demand and the federal target. Investment in mainland wind capacity is avoided, leading to capital savings. In 2029-30, there are benefits associated with greater interconnection to Tasmania to meet the federal target, but these are shared between Basslink and Marinus Link.

From 2030-31, Basslink is still forecast to accrue further gross market benefits. This is primarily because the generation from existing Tasmanian hydroelectric power stations can be exported to the mainland to avoid the operation and construction of mainland gas, which results in fuel cost and further capex savings.

With a single stage of Marinus Link, as assumed by APA for this scenario variant, renewable spill is forecast to occur in Tasmania. For this scenario, the modelling forecasts that Basslink (in combination with at least one stage of Marinus Link), is required for TRET generation to be sufficiently exported to the mainland or consumed locally within Tasmania.

9.2.2 Forecast NEM generation development plan, Step Change scenario

The differences in the forecast capacity and generation outlooks in Step Change scenario across the NEM with and without Basslink are shown in Figure 15 and Figure 16, respectively.

Figure 15: Capacity difference with and without Basslink for Step Change scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing

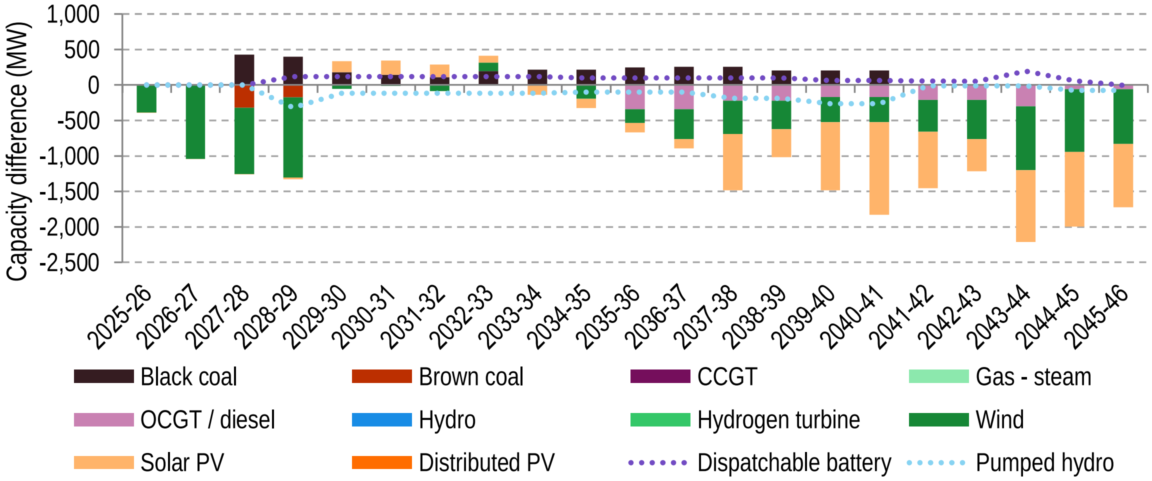


Figure 16: Generation difference with and without Basslink for Step Change scenario, Basslink 478 MW, Marinus Link double-stage, ISP 2022 timing

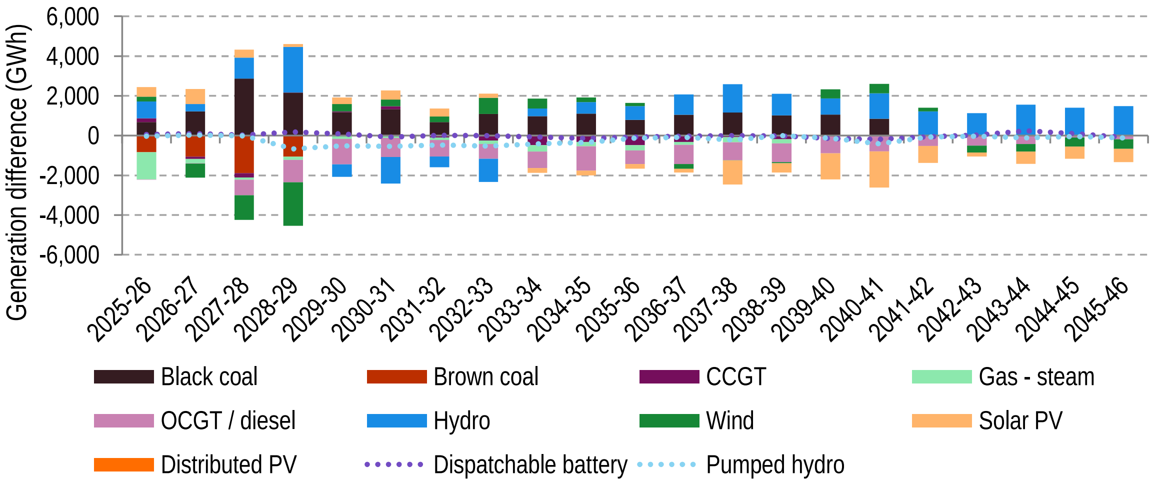


Figure 15 shows that a large amount of forecast wind investment is avoided with inclusion of Basslink before 2029-30. The high requirement for wind investment without Basslink is primarily due to the state-based renewable targets and the federal renewable target 82 % in 2029-30. This wind capacity is forecast to be built on the mainland.

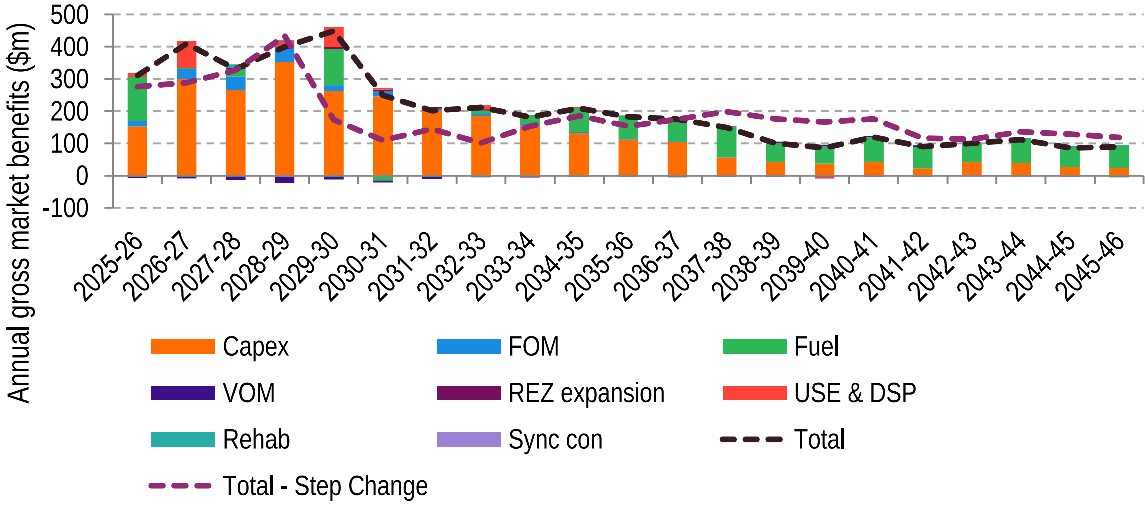
Figure 16 shows that not only the wind generation is avoided, but also the thermal operation of brown coal and OCGTs in Victoria is reduced materially with inclusion of Basslink. Instead, with inclusion of Basslink the dispatch of Tasmania hydro is increased. Black coal is also forecast to increase output with Basslink, while still meeting the assumed emissions budget over the full 21-year period. This is achieved because Basslink is forecast to decrease reliance on gas generation in later years by improving diversity in generation sources and load.

9.3 Market modelling outcomes for Progressive Change scenario for the Marinus Link single-stage variant

9.3.1 Forecast gross market benefits, Progressive Change scenario

The annual gross market benefit forecast for the inclusion of Basslink in Progressive Change scenario are depicted in Figure 17 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Basslink results in $4,241m in gross market benefits.

Figure 17: Annual market benefit forecast for Progressive Change scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing



Similar to the Step Change scenario, the highest annual benefits of Basslink are forecast to accrue early in the Modelling Period. In Progressive Change scenario, Marinus Link's commissioning is assumed to be delayed one year relative to the Step Change scenario (Stage 1 in 2030-31 compared to 2029-30), as selected by APA to align with the 2022 ISP outcomes. Consequently, the Progressive Change scenario is forecast to have higher benefit than the Step Change scenario since Marinus Link is not commissioned until after the 82% NEM-wide federal renewable target is required to be met and the benefits of access to Tasmania to meet the target in 2029-30 are not shared between Basslink and Marinus Link.

As discussed in Section 8.2, the Progressive Change scenario is forecast to retain coal capacity longer than the Step Change scenario due to different assumptions, such as the less restrictive carbon budget. As such, Basslink is forecast to have lower benefits in the Progressive Change scenario from the late-2030s onward, since there is less benefit associated with offsetting mainland wind and solar while coal remains operational.

9.3.2 Forecast NEM generation development plan, Progressive Change scenario

The differences in the forecast capacity and generation outlooks in Progressive Change scenario across the NEM with and without Basslink are shown in Figure 18 and Figure 19, respectively.

Figure 18: Capacity difference with and without Basslink for Progressive Change scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing

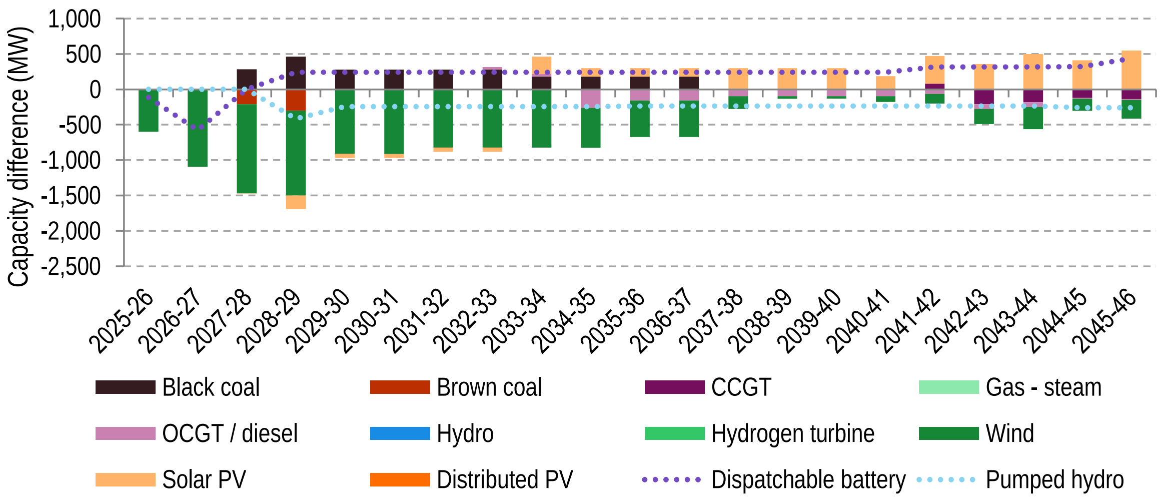


Figure 19: Generation difference with and without Basslink for Progressive Change scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing

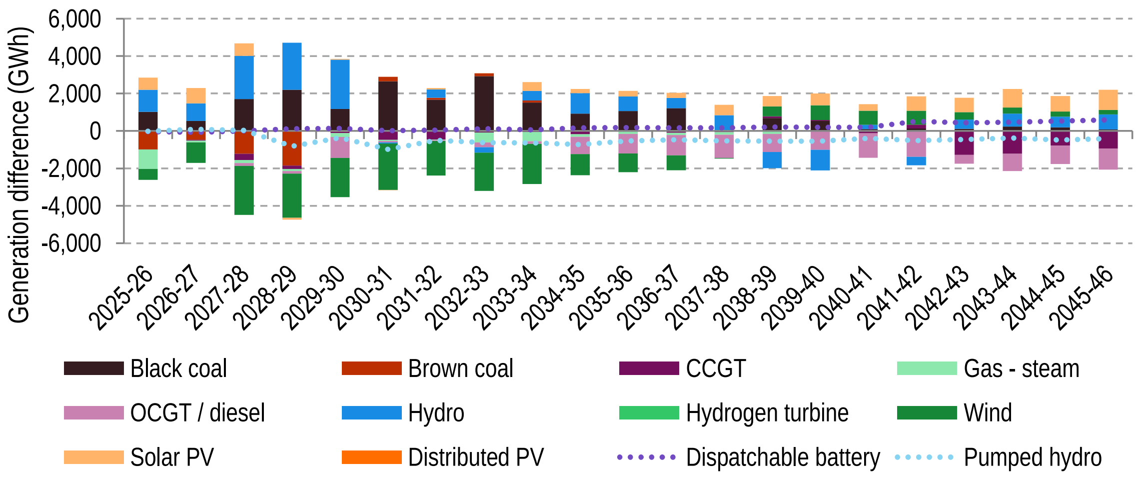


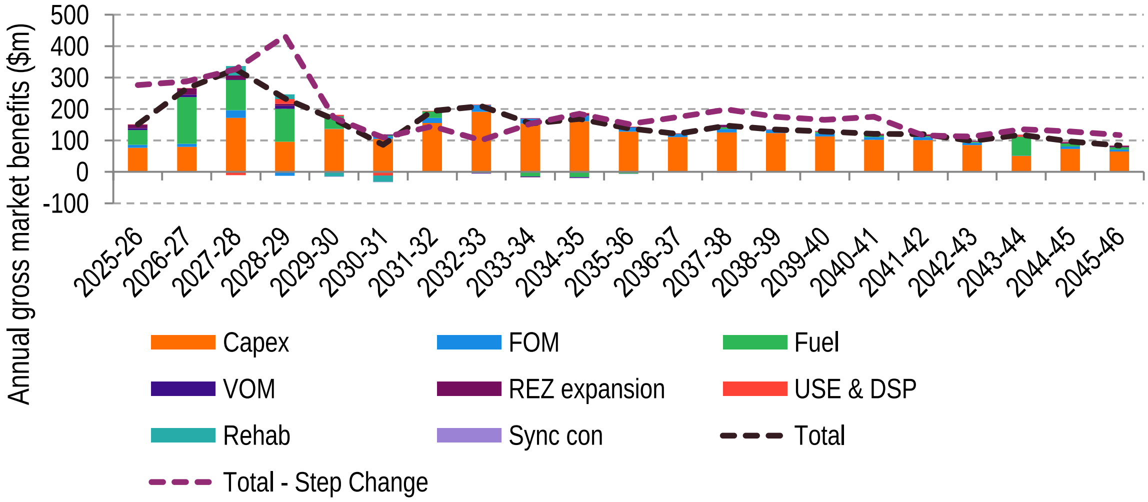
Figure 18 and Figure 19 show that a significant amount of wind investment is forecast to be avoided before 2034-35 with inclusion of Basslink. From the mid-2030s onward, Basslink is forecast to avoid mainland dispatchable gas generation by better connecting existing Tasmanian hydroelectric generators and new Tasmanian wind to the mainland as a lower cost alternative.

9.4 Market modelling outcomes for Hydrogen Superpower scenario for the Marinus Link single-stage variant

9.4.1 Forecast gross market benefits, Hydrogen Superpower scenario

The forecast gross market benefits for the inclusion of Basslink in the Hydrogen Superpower scenario are depicted in Figure 20 on an annual basis. Over the Modelling Period, it is forecast that the inclusion of Basslink will result in $3,268m in gross market benefits.

Figure 20: Annual market benefit forecast for Hydrogen Superpower scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing



Under this scenario, Basslink is forecast to accrue less benefit throughout the Modelling Period, relative to the Step Change scenario. While the forecast capex benefits are similar between the two scenarios, there are less fuel cost savings from the 2030s onward, since the constraining carbon budget significantly restricts the amount of coal and gas generation that can occur in the Hydrogen Superpower scenario.

9.4.2 Forecast NEM generation development plan, Hydrogen Superpower scenario

The differences in the forecast capacity and generation outlooks in Hydrogen Superpower scenario across the NEM with and without Basslink are shown in Figure 21 and Figure 22, respectively. In the 2020s, the benefit of Basslink is driven by the forecast reduction in new entrant installation across NEM (Figure 21) and reduced thermal operation in Victoria (Figure 22). After the federal renewable target is met in 2029-30, the majority of benefit associated with Basslink is forecast to be from the reduced uptake of new entrants. With Basslink, Tasmanian renewable generation, including existing hydro, is forecast to be utilised to meet the assumed emission target, reducing the requirement for new entrant capacity in the mainland.

Figure 21: Capacity difference with and without Basslink for Hydrogen Superpower scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing

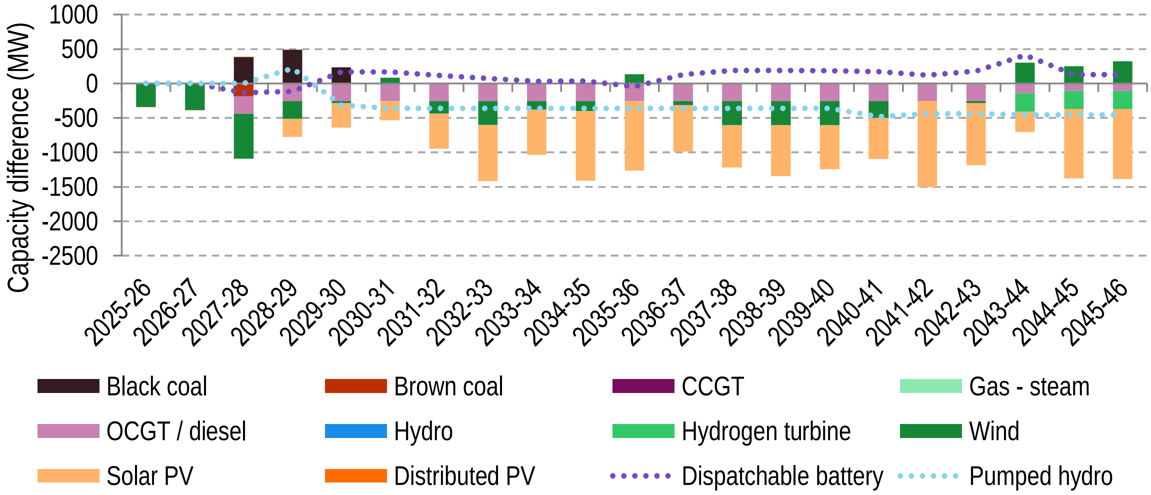


Figure 22: Generation difference with and without Basslink for Hydrogen Superpower scenario, Basslink 478 MW, Marinus Link single-stage, ISP 2022 timing

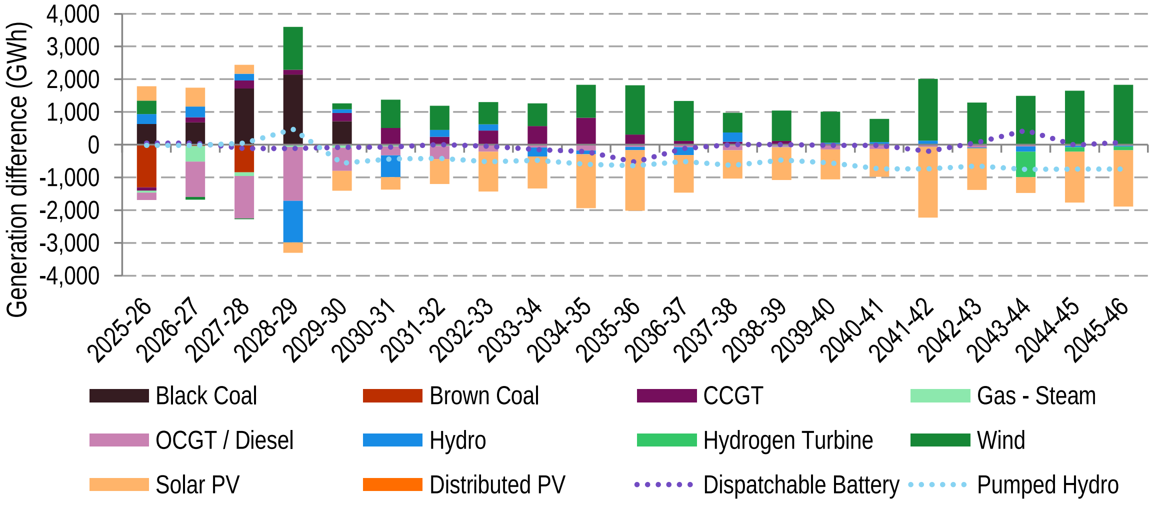


Figure 21 shows the forecast reduction new entrant capacities is primarily a reduction in solar PV, wind and OCGTs. Figure 22 shows that Basslink is forecast to reduce solar operation across the NEM as a result of having better access to high capacity factor Tasmanian wind generation instead.

9.5 Market modelling outcomes for the Marinus Link double-stage ISP-timing variants

This section presents the forecast market benefits for Basslink across each scenario for the Marinus Link ISP 2022 timing variants. These variants assume the following commissioning dates for the second 750 MW stage of Marinus Link, as chosen by APA, consistent with the 2022 ISP scenario-specific optimal development paths:

- Step Change: second stage commissioned by 2031-32
- Progressive Change: second stage commissioned by 2032-33
- Hydrogen Superpower: second stage commissioned by 2031-32.

Figure 23, Figure 24 and Figure 25 display the forecast gross market benefits across each of the scenarios, respectively. Annual benefits by category are presented alongside Basslink's forecast benefit from the relevant Marinus Link single-stage variant.

Figure 23: Annual market benefit forecast for Step Change scenario, Basslink 478 MW, Marinus Link double-stage, ISP 2022 timing (compared to annual market benefit forecast for Step Change scenario with Marinus Link single-stage)

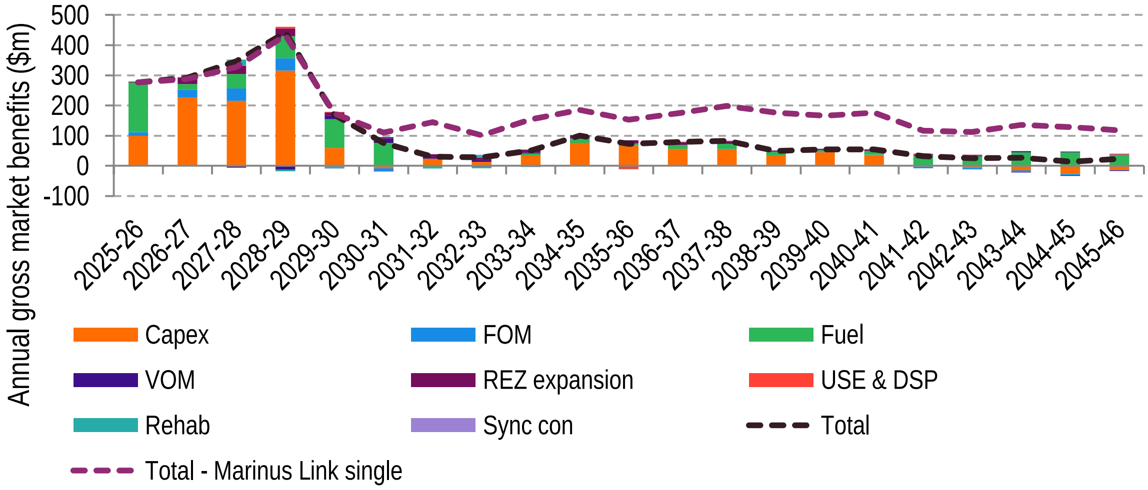


Figure 24: Annual market benefit forecast for Progressive Change scenario, Basslink 478 MW, Marinus Link double-stage, ISP 2022 timing (compared to annual market benefit forecast for Progressive Change scenario with Marinus Link single-stage)

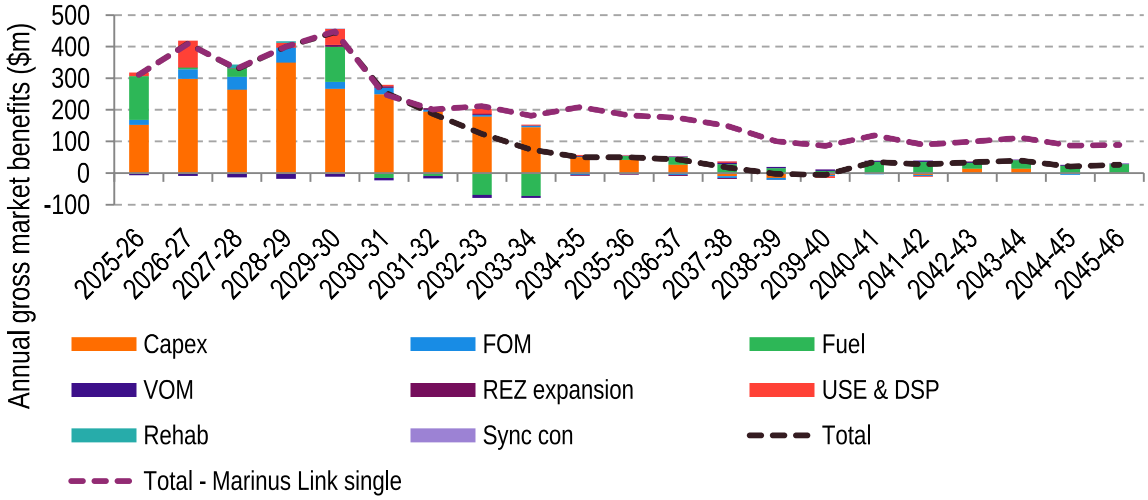
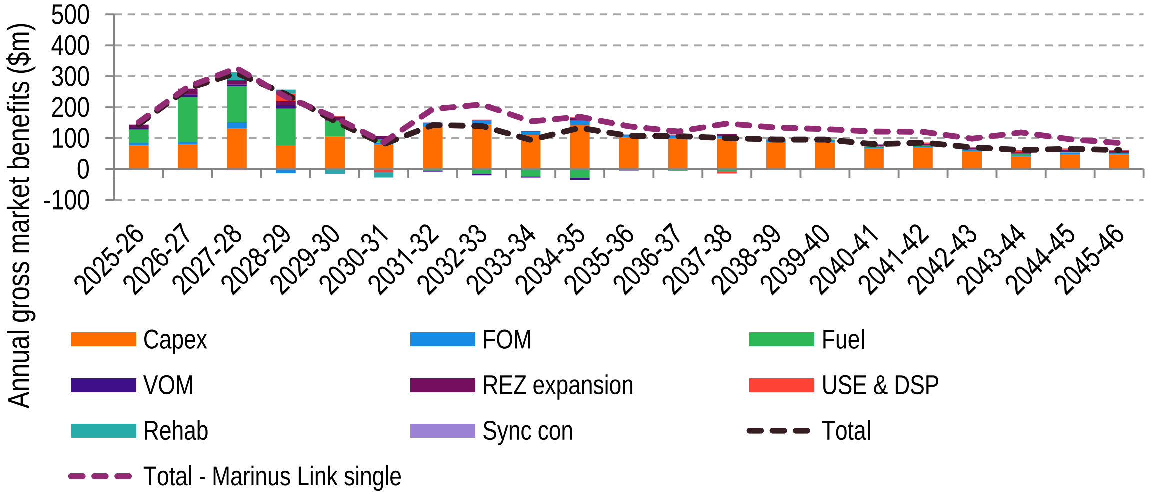


Figure 25: Annual market benefit forecast for Hydrogen Superpower scenario, Basslink 478 MW, Marinus Link double-stage, ISP 2022 timing (compared to annual market benefit forecast for Hydrogen Superpower scenario with Marinus Link single-stage)



Once the second stage of Marinus Link is assumed to be installed, the forecast benefits for Basslink begin to diverge for the single-stage variant. The annual benefits for Basslink are forecast to be lower if both stages of Marinus Link are commissioned, since the second stage of Marinus Link provides and additional transfer path between Tasmania and the mainland.

9.6 Market modelling outcomes for the Marinus Link double-stage delay variants

APA requested that the benefits of Basslink be forecast under a third scenario variant, which assumes the commissioning date for Stage 1 of Marinus Link is delayed until 2033-34 and the second stage is commissioned by 2035-36 in all scenarios.

Figure 26, Figure 27 and Figure 28 display the forecast gross market benefits across each of the scenarios, respectively. Annual benefits by category are presented alongside Basslink's forecast benefit from the relevant Marinus Link ISP timing variant to isolate the effect of the delay in Marinus Link timing.

Figure 26: Annual market benefit forecast for Step Change scenario, Basslink 478 MW, Marinus Link double-stage, delay timing (compared to annual market benefit forecast for Step Change scenario with Marinus Link double-stage ISP 2022 timing)

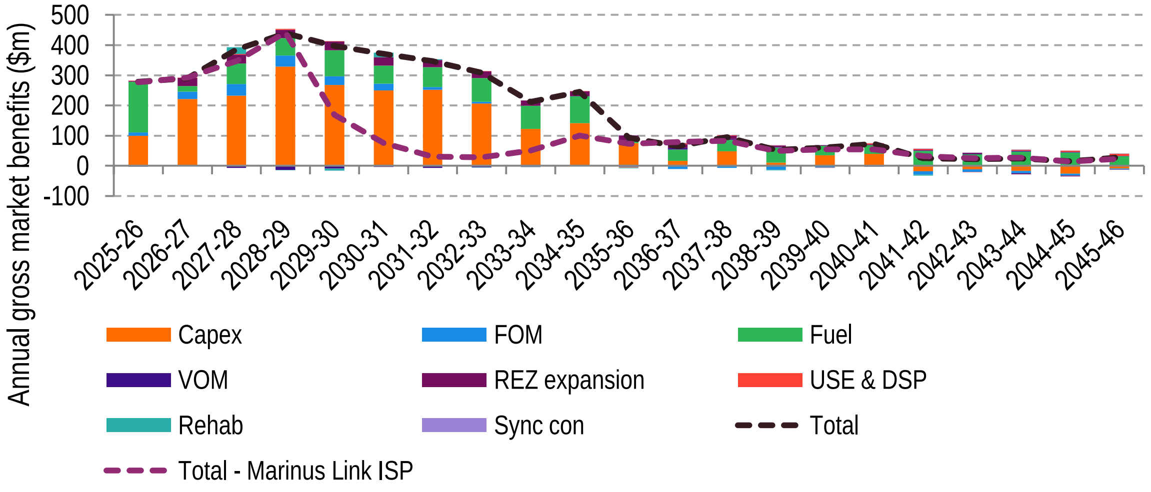


Figure 27: Annual market benefit forecast for Progressive Change scenario, Basslink 478 MW, Marinus Link double-stage, delay timing (compared to annual market benefit forecast for Progressive Change scenario with Marinus Link double-stage ISP 2022 timing)

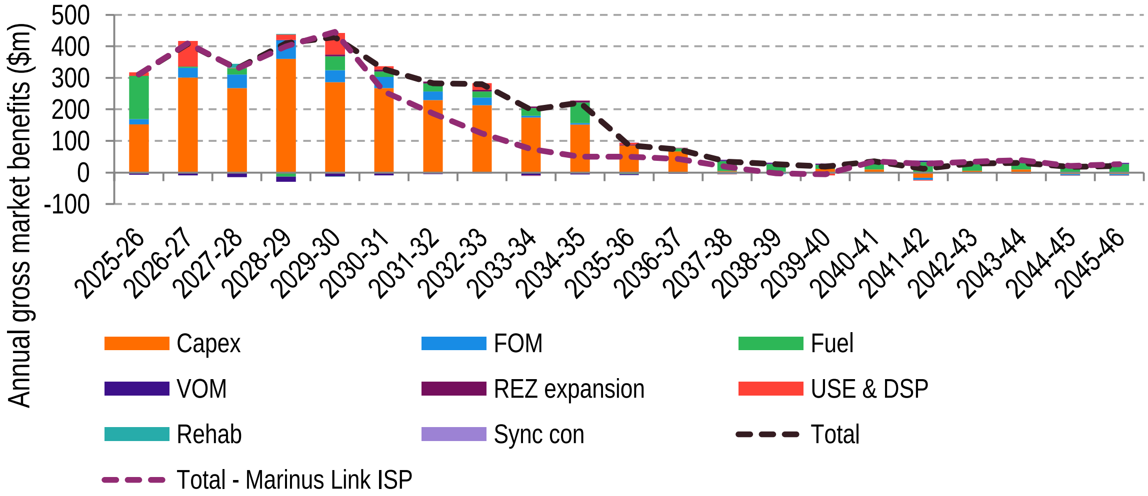
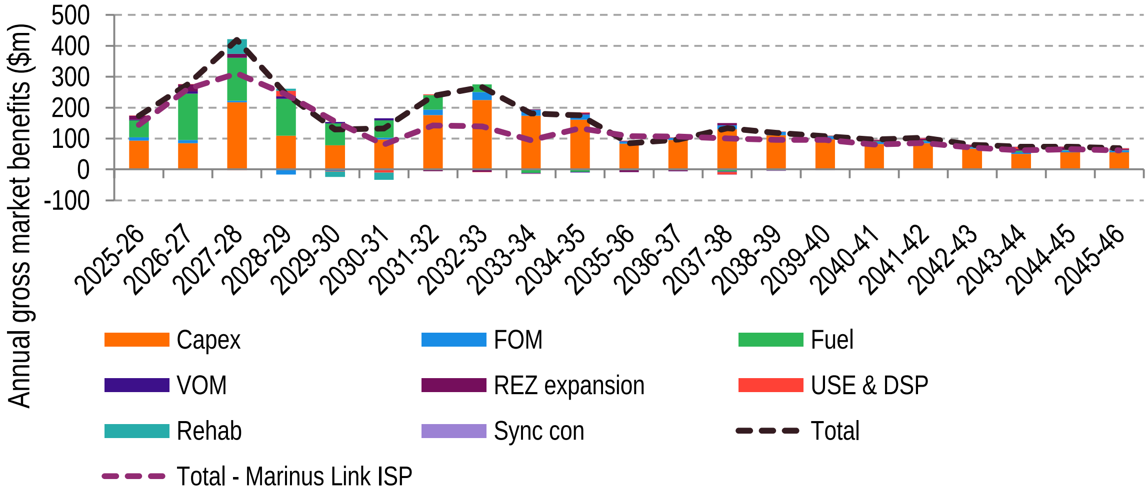


Figure 28: Annual market benefit forecast for Hydrogen Superpower scenario, Basslink 478 MW, Marinus Link double-stage, delay timing (compared to annual market benefit forecast for Hydrogen Superpower scenario with Marinus Link double-stage ISP 2022 timing)



Across each of the scenarios, a delay in the timing of Marinus Link is forecast to increase the annual benefits of Basslink in the years that these delays occur. For the Hydrogen Superpower scenario, additional benefits for Basslink are forecast to occur in years prior to the commissioning of Marinus Link due to the restrictive 30-year carbon budget. Since Marinus Link cannot be relied on as heavily during the early 2030s in this variant, it is forecast that there is a greater benefit associated with having an existing connection between Tasmania and the mainland to assist in the energy transition required to achieve such an extreme carbon reduction goal.

9.7 Basslink capacity sensitivities

The existing Basslink interconnector has a nominal transfer limit of 478 MW[68]. APA requested that EY undertake two sensitivities for forecast gross market benefits where Basslink is assumed to have

[68] AEMO, 30 June 2022, *Input and Assumptions Workbook v3.4*, available at: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp/current-inputs-assumptions-and-scenarios. Accessed 16 June 2023.

a maximum bi-directional transfer capacity of 350 MW and 150 MW, respectively. Forecast gross market benefits for these sensitivities are presented in Table 10.

Table 10: Overview of forecast gross market benefits in Basslink sizing sensitivities; millions real June 2023 dollars discounted to 1 July 2025

Scenario/ sensitivity	Basslink gross market benefits ($m)		
	Marinus Link single-stage	Marinus Link double-stage, ISP timing	Marinus Link double-stage delay
Step Change (478 MW Basslink)	3,846	2,323	3,823
Step Change with 350 MW Basslink	3,131	1,883	3,121
Step Change with 150 MW Basslink	1,558	938	1,499

Forecast gross market benefits are lower for smaller sizes of Basslink. However, the forecast gross market benefits of Basslink do not include the ongoing cost of Basslink, since evaluation is not part of our scope and hence has not been included in this Report. The timing of annual benefits is forecast to be similar across Basslink sizes. This is shown in Figure 29, Figure 30, Figure 31, which present the forecast benefit of Basslink for the Marinus Link single-stage, Marinus Link ISP timing and Marinus Link delay scenario variants.

Figure 29: Annual market benefit forecast for Basslink size sensitivities: Step Change scenario, Marinus Link single-stage, ISP timing

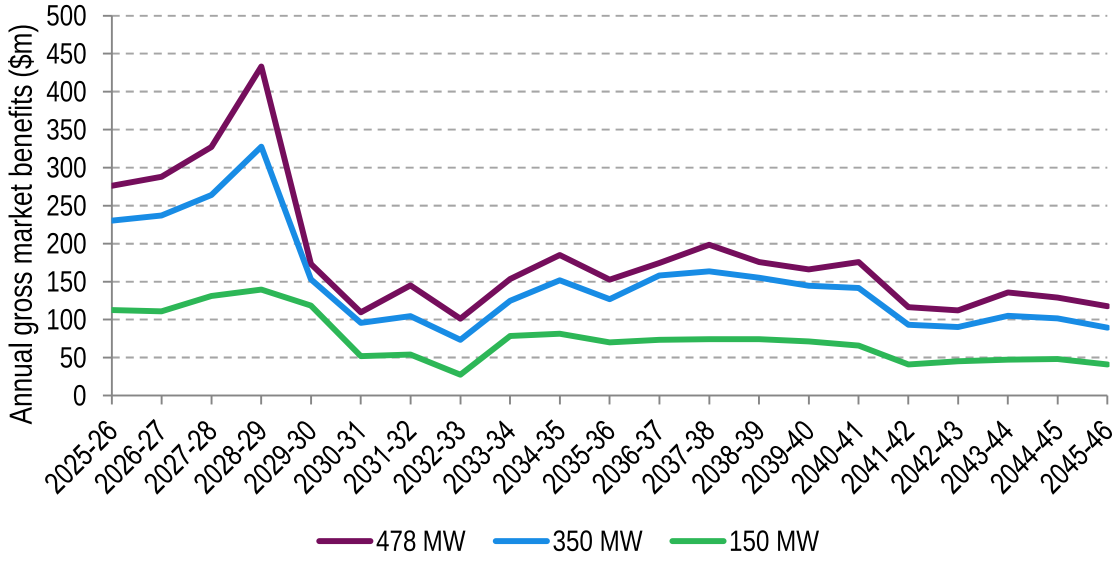


Figure 30: Annual market benefit forecast for Basslink size sensitivities: Step Change scenario, Marinus Link double-stage, ISP-timing

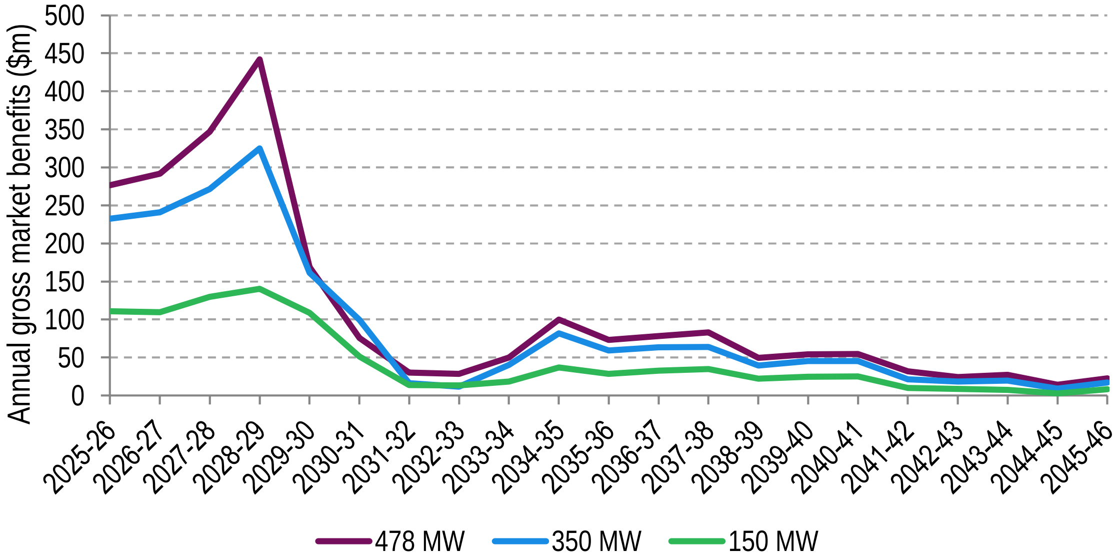
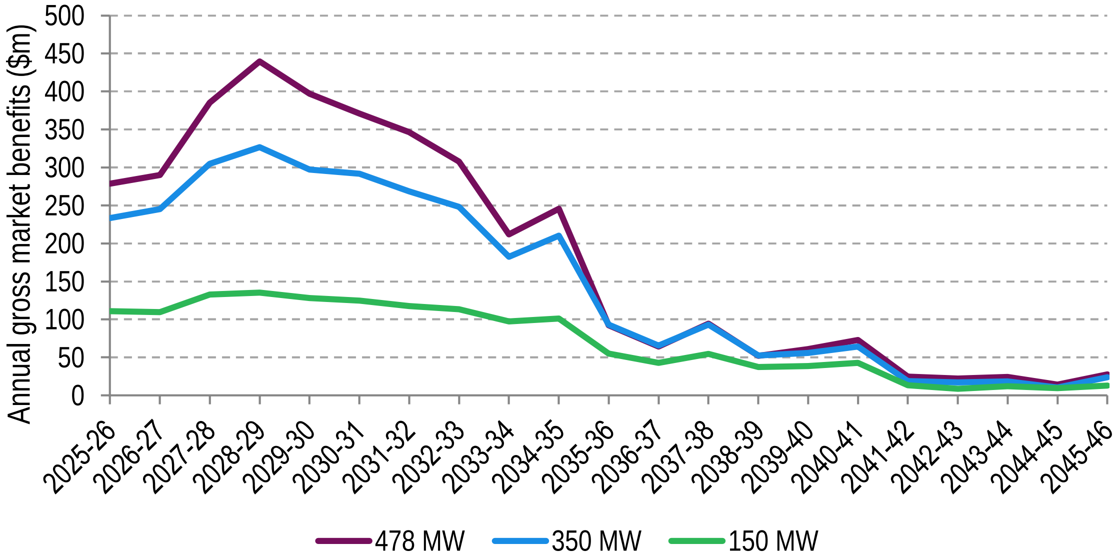


Figure 31: Annual market benefit forecast for Basslink size sensitivities: Step Change scenario, Marinus Link double-stage, delay timing



Across the three Marinus Link size and timing variants, the forecast gross market benefit of the 350 MW sized Basslink is approximately 80% of the existing 478 MW size. Benefits of the 150 MW sized Basslink are forecast to be approximately 40% of the 478 MW size.

Appendix A Glossary of terms

Abbreviation	Meaning
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Capex	Capital Expenditure
CO_2	Carbon Dioxide
CCGT	Combined-Cycle Gas Turbine
DC	Direct Current
DSP	Demand side participation
ESOO	Electricity Statement of Opportunities
FOM	Fixed Operation and Maintenance
GW	Gigawatt
GWh	Gigawatt-hour
ISP	Integrated System Plan
IASR	Inputs, Assumptions and Scenarios Report
$m	Million dollars
Mt	Mega Ton
MW	Megawatt
MWh	Megawatt-hour
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
OCGT	Open-Cycle Gas Turbine
PHES	Pumped Hydro Energy Storage
PSL	Prudent Storage Level
PV	Photovoltaic
QLD	Queensland
QNI	Queensland-New South Wales interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
SA	South Australia
SAT	Single Axis Tracking

Abbreviation	Meaning
SRMC	Short-Run Marginal Cost
TAS	Tasmania
TRET	Tasmanian Renewable Energy Target
TSIRP	Time-sequential integrated resource planner
USE	Unserved Energy
VCR	Value of Customer Reliability
VIC	Victoria
VNI	Victoria-New South Wales Interconnector
VOM	Variable Operation and Maintenance
VRET	Victoria Renewable Energy Target
VPP	Virtual Power Plant

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