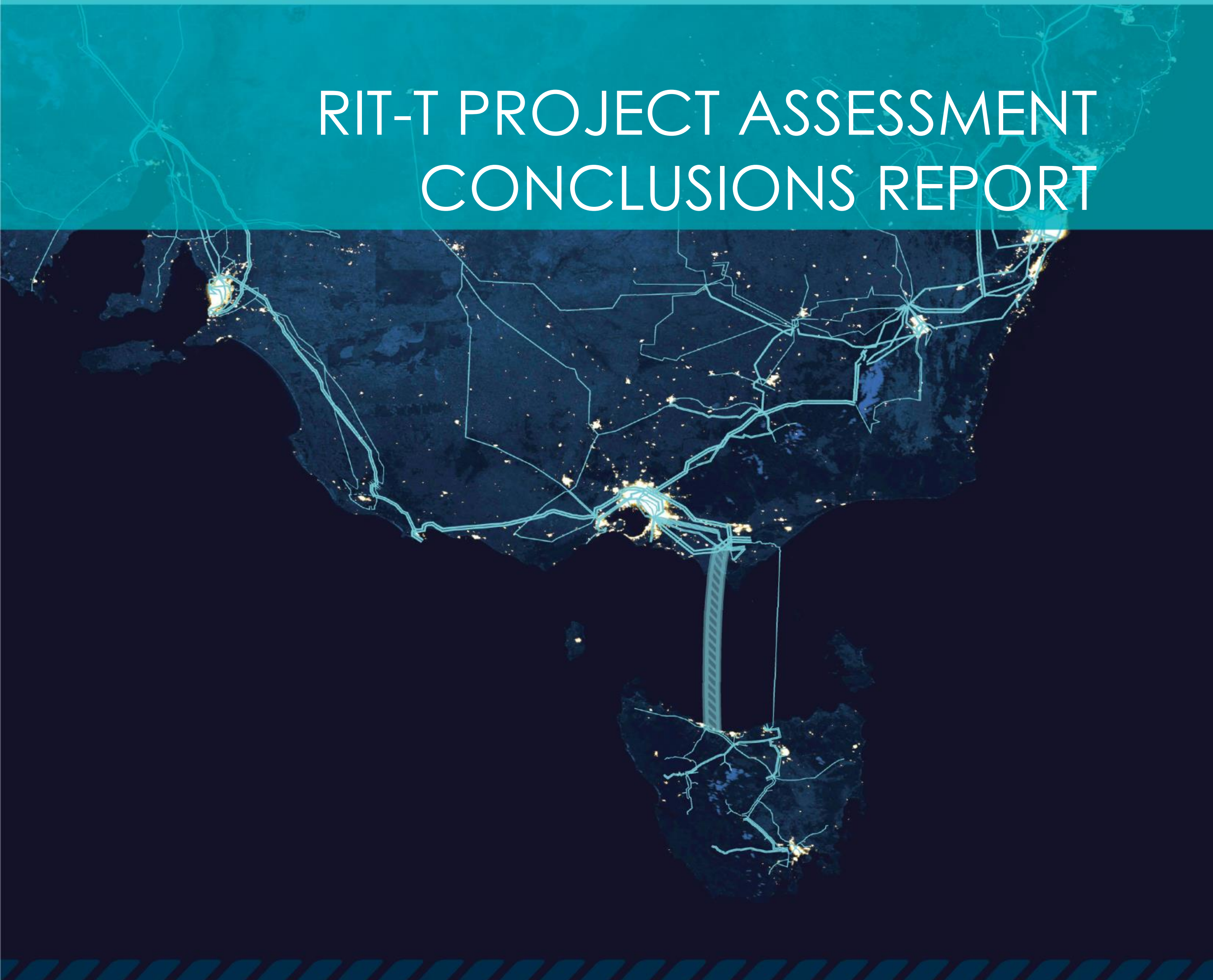
MARINUS
LINK

RIT-T PROJECT ASSESSMENT CONCLUSIONS REPORT



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Executive Summary

Electricity markets around the world are changing rapidly as economies decarbonise in response to global warming and technological change. In Australia, the rapid growth in renewable generation and distributed energy resources (**DER**), combined with the closure of coal plant, are creating significant challenges for market participants, network companies, and customers.

The pace of change appears to be accelerating. Previously held preconceptions regarding the limitations of renewable generation to meet our future energy needs are being challenged, as Renewable Energy Zones (**REZs**) and large scale storage projects obtain support from investors and state government policies. The rapid pace of change is driving the need for network investment to accommodate radically different generation and load flows across the National Electricity Market (**NEM**).

In its role as the national transmission planner, the Australian Energy Market Operator (**AEMO**) is responsible for publishing an Integrated System Plan (**ISP**) every two years. The purpose of the ISP is to coordinate transmission and generation planning to provide for the efficient development of the power system over a planning horizon of at least 20 years. The ISP is a whole-of-system plan that reflects the long-term interests of electricity customers by meeting their needs at the lowest total cost.

In the 2020 ISP, AEMO identified 'actionable ISP projects'. These projects are major transmission investments (or non-network options)[1] that are required to address an identified need and which form part of AEMO's optimal development path. In other words, actionable ISP projects are needed to deliver the lowest cost solution that meets customers' electricity needs. In its 2020 ISP, AEMO identified Project Marinus as an actionable ISP project, as described below:[2]

> "Marinus Link is a multi-staged actionable ISP project to be completed from 2028-29, with early works recommended to start as soon as possible, and with further stages to proceed if their respective decision rules are satisfied."[3]

The purpose of this Project Assessment Conclusions Report (**PACR**) is to further test AEMO's findings in its 2020 ISP by completing the Regulatory Investment Test for transmission (**RIT-T**) in accordance with the new regulatory arrangements for actionable ISP projects, which were introduced in July 2020.

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[1] In accordance with the definition of 'actionable ISP project' in the National Electricity Rules.

[2] AEMO, *2020 Integrated System Plan*, July 2020, page 82.

[3] 2020 Integrated System Plan collectively referred to the HVDC interconnector and North West Transmission Developments as Marinus Link.

Throughout this PACR, 'Project Marinus' refers to the high voltage direct current (HVDC) and converter interconnector assets, known as Marinus Link, and the alternating current (AC) transmission investment in Tasmania, known as the North West Transmission Developments. These investments together constitute the RIT-T project, which is the subject of this PACR.

Inputs, assumptions and scenarios for the market modelling

Our market benefit modelling for Project Marinus, conducted in accordance with the RIT-T, was undertaken principally by Ernst & Young, with GHD being engaged to model the costs of ancillary services. Ernst & Young's modelling approach is closely aligned with AEMO's ISP modelling, as it identifies the lowest cost combination of generation, storage, non-network options, demand side response, and transmission developments, without any preference for particular types of investment solutions or technologies.

To identify the net economic benefit from Project Marinus, Ernst & Young's modelling examines the total costs of meeting customers' future electricity needs 'with' and 'without' Project Marinus, under the five scenarios that AEMO adopted for the 2020 ISP. For the PACR, we have ensured that our inputs and assumptions are aligned with AEMO's current views,[4] as required by the RIT-T.[5]

A key consideration in the ISP and our RIT-T is the treatment of government policy announcements, which include state-based renewable energy targets and, in some instances, contracting arrangements to support these targets. In Tasmania, the Tasmanian Renewable Energy Target (**TRET**) has now been legislated, meeting one of the three decision rules specified in the 2020 ISP related to progressing Stage 1 of Project Marinus to an actionable status.

To ensure that our approach in this PACR is objective, we have adopted AEMO's treatment of government policies as set out in its most recent draft Inputs, Assumptions and Scenarios Report (**IASR**). In adopting AEMO's treatment of government policies, we ensure that our assessment is independent of stakeholders' particular views and preferences regarding certain policies. For example, we note that some stakeholders[6] have raised questions in relation to achievement of the TRET that could equally be made in relation to other

[4] Specifically, we have adopted most of the inputs and assumptions in AEMO's draft 2021 Inputs, Assumptions and Scenarios Report (Draft 2021 IASR). However, we have retained the 2020 ISP scenarios for the purpose of this PACR.

[5] National Electricity Rules, clause 5.15A.3(b)(7)(iv).

[6] For example, submissions made by Bob Brown Foundation and Tasmanian Renewable Energy Alliance (TREA) to the Project Marinus Supplementary Analysis Report.

government policies, which implicitly assume that particular transmission or generation projects proceed, or outcomes eventuate.

To provide stakeholders with an insight into the impact of state government policies on the economic case for Project Marinus, we have conducted sensitivity modelling to examine the effect of replacing state government policies with a NEM-wide emission target. This approach removes distortions that may arise from state government policies that promote projects in particular regions in preference to an optimal NEM-wide solution. This sensitivity analysis shows that Project Marinus would be economically efficient if a Commonwealth 'carbon budget'[7] were adopted and state-based policies removed. The analysis should reassure stakeholders that we have tested Project Marinus against a range of plausible inputs and assumptions in assessing the economic case for the project.

Listening to customers and stakeholders

Customer and stakeholder engagement is an important part of our process and we welcome the feedback we have received. The modelling and analysis undertaken for this PACR takes into account the feedback received from customers and stakeholders over the past three years.

TasNetworks received a total of 40 formal written submissions throughout this RIT-T process. We conducted a total of seven industry forums across three capital cities and held a webinar during the course of this RIT-T assessment. In addition, we held in excess of 50 targeted stakeholder briefings for those consumers and stakeholders who sought further clarification about the economic and technical aspects of the project.

We have extended our consultation process beyond the requirements of the RIT-T, including engagement on our Initial Feasibility Report, which we published in February 2019. The Initial Feasibility Report provided indicative information on the likely costs and benefits of Project Marinus. The feedback we received helped guide our modelling approach and input assumptions, which were reflected in our Project Assessment Draft Report (**PADR**), published in December 2019.

We welcome the significant level of engagement from stakeholders and the feedback received in relation to our PADR. We listened to the feedback from stakeholders that they wanted our analysis to be aligned with the 2020 ISP. To address this issue effectively, we decided to undertake further modelling and to publish the results in our Supplementary Analysis Report in November 2020. The Supplementary Analysis Report also

[7] The carbon budget represents a Representative Concentration Pathway (RCP) of 2.6. An RCP of 2.6 requires that carbon dioxide (CO_2) emissions start declining by 2020 and achieve a net zero status between 2080 and 2100. RCP 2.6 is likely to keep global temperature rises below 2°C by 2100. In comparison, an economy-wide net zero target by 2050 achieves the Paris Agreement's aspirational target to limit global warming to below 1.5 °C. This pathway is typically referred to as RCP 1.9.

responded to stakeholder feedback received on our PADR and adopted the 2020 ISP's updated scenarios, inputs and assumptions.

We also engaged with stakeholders and invited feedback on our Supplementary Analysis Report through a further round of consultation and submissions. By extending the engagement process, we provided stakeholders with an opportunity to review the updated modelling results prior to the publication of this PACR. In preparing this PACR, we have taken account of stakeholder feedback we received on our Supplementary Analysis Report, in addition to the feedback on our PADR. The feedback we have received has been invaluable in identifying specific issues and concerns that we have addressed in this PACR, particularly in the material presented in Chapters 8 and 9, the accompanying appendices and attachments.

1500 megawatts (MW) Project Marinus is the preferred option[8]

On the basis of the modelling undertaken for this PACR, a 1500 MW Project Marinus is the preferred option. This conclusion was reached following the assessment of four credible options for increased interconnection capacity between Tasmania and Victoria:

- **Option A**: A 600 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- **Option B**: A 750 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- **Option C**: A 1200 MW HVDC interconnector, comprising two 600 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.
- **Option D**: A 1500 MW HVDC interconnector, comprising two 750 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.

[8] All values presented in this report are 1 July 2020 real dollars unless stated otherwise. Net Present Value (NPV) outcomes are also discounted back to 1 July 2020 based on the Weighted Average Cost of Capital (WACC) of 4.8 per cent for all scenarios, except Slow Change (WACC of 3.8 per cent). The totals in the tables may not sum precisely due to rounding of the underlying values throughout the report.

The cost-benefit analysis in this PACR shows that each credible option delivers a positive net economic benefit across every scenario. Furthermore, Option D delivers the highest net economic benefit compared to the other credible options. This conclusion is unchanged whether:

- An equal weighting is attributed to each scenario, as shown in the figure below; or
- Whether a one-third Step change scenario, and two-third Central scenario weighting is adopted in accordance with the 2020 ISP, as shown in the figure and table below.

In addition, our sensitivity analysis indicates that the selection of the preferred option is robust against a range of different input assumptions, including project costs (which are discussed shortly).

The results below are reported for the earliest commissioning dates of 2027[9] for the first 750 MW stage and 2029 for the second 750 MW stage. The question of optimal timing is addressed in the next section.

Figure 1: Net economic benefit for all credible options – ISP weighting and averaged across scenarios

[9] All dates in this report are on a financial year basis. The year represents the start of the financial year. For instance, 2027 represents the financial year commencing on 1 July 2027 and ending on 30 June 2028. Unless otherwise stated, all interconnector and capacity expansion occurs at the beginning of the financial year whereas unit retirements occur at the end of the financial year.

Table 1: Net economic benefit for each credible option, using ISP scenario weightings – Project Marinus timing of 2027 (Stage 1) and 2029 (Stage 2) ($ million, NPV)

	Net economic benefit		
Credible Options	**Central Scenario**	**Step Change Scenario**	**2020 ISP weighting (67% - Central & 33% - Step Change)**
600 MW	1,056	2,332	1,482
750 MW	1,367	2,870	1,868
1200 MW	1,353	3,297	2,001
1500 MW	1,416	3,650	2,161

In accordance with the RIT-T, the preferred option is a 1500 MW HVDC interconnector, comprising two 750 MW HVDC interconnector stages, plus associated AC network upgrades for each stage.

The pace of NEM transition and project timing

Since the commencement of the Project Marinus RIT-T in July 2018, the pace of NEM transition has been steadily increasing. Our PACR modelling indicates that the pace of transition away from coal fired generation to variable renewable energy, supported by dispatchable storage and strategic interconnection, is likely to gather significant momentum this decade (Figure 2) with up to 6,500 MW of additional coal-fired power stations expected to retire by 2030, over and above the currently announced retirement schedule outlined in the 2021 Draft IASR.

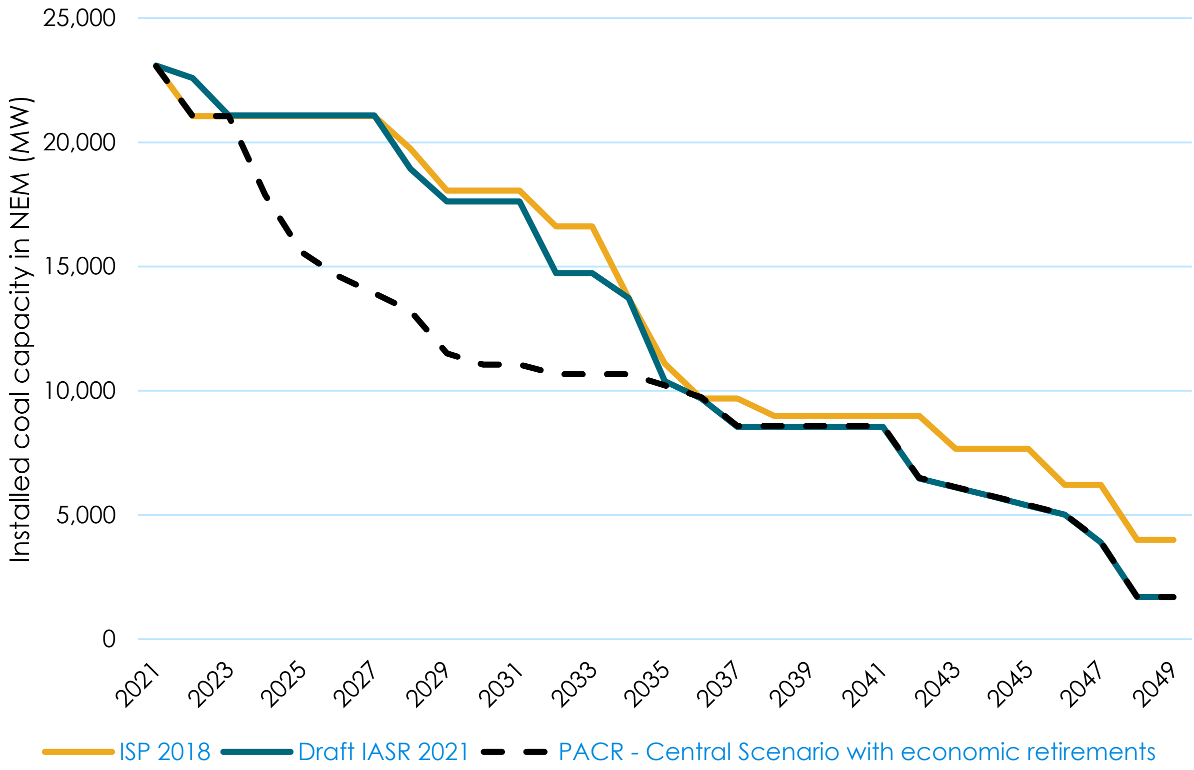

Figure 2: Pace of coal retirement from 2018 ISP, Draft IASR 2021 and Project Marinus PACR (Central scenario with economic retirements)

It is evident from recent company announcements that economic conditions are driving coal fired generation closures. In particular, since the publication of the Draft IASR 2021 in December 2020, the following announcements indicate the increasing pace of change in response to market conditions:

- In March 2021, Yallourn Power Station's (1,480 MW)[10] retirement was advanced by four years to 2028;
- In May 2021, Eraring Power Station (2,880 MW) announced that it would commence closure from 2030[11]. Origin Energy, the operator of Eraring, has indicated that the first of the four units will switch off two years earlier than previously planned; and
- In March 2021, AGL Energy undertook significant asset impairments and restructure plans, including indications that thermal generation units could be mothballed.[12]

[10] EnergyAustralia powers ahead with energy transition, Energy Australia, 10 March 2021.

[11] NSW's Biggest coal plant, Origin's Eraring, starts closure from 2030, The Australian, 18 May 2021.

[12] Slide 29, AGL Energy Investor Day, 30 March 2021.

In addition to these recent announcements, our assessment is that there is mounting evidence that the NEM's current trajectory is consistent with, or exceeding the Step Change scenario as outlined in the 2020 ISP. In particular, we note:

- Policy initiatives and legislation have been proposed or implemented by various state governments to advance renewable development to prepare for the retirement of the ageing thermal generation fleet. The objectives of these initiatives are aligned with, or exceed the Step Change scenario;
- The chair of the Energy Security Board (**ESB**) has expressed views that the power system is already exceeding the Step Change scenario forecast in the ISP in 2020[13] and that the Step Change scenario could now be considered a conservative Central scenario given the ongoing pace of change[14];
- Increased generation from renewables is likely to further exert commercial pressure on coal fired generators as operational inefficiencies arise as output is continually varied to accommodate lower cost renewable generation in the supply stack;
- Sustained pressure from institutional investors and customers on the owners of coal-fired generators to align their business plans with the goals of the Paris Agreement could also lead to early retirement of assets due to environmental considerations.[15] Most recently this was highlighted by the owners of Loy Yang B power station when they flagged the challenges associated with refinancing debt for emission intensive generation assets[16];
- Recent announcements made by the Prime Minister and the Federal Treasurer regarding Australia's ambitions to reach net zero emissions as soon as possible, and preferably by 2050; and
- AEMO has indicated that one of its two Central scenarios for its 2022 ISP will reflect economy-wide net zero emissions by 2050.

In relation to project timing, our analysis confirms the findings in our PADR and Supplementary Analysis Report that the optimal timing of the preferred option depends on the future development of the NEM, which is subject to ongoing unprecedented change. In this context of NEM transition, Project Marinus has the potential to provide significant option value and ensure that wholesale power price increases owing to unexpected coal closure or unplanned maintenance are minimised. TasNetworks has considered the optimal timing based on the scenarios in the 2020 ISP, noting these scenarios are subject to change as AEMO prepares its 2022 ISP.

[13] Post 2025 options paper, ESB, 30 April 2021.

[14] ESB's Kerry Schott at Energy and Investment Conference, Sydney 24 March 2021.

[15] The inputs and assumptions in the Step Change scenarios best capture the electricity market outcomes required to achieve the targets of the Paris climate change agreement.

[16] Alinta calls for Canberra to step in as banks retreat, The Sydney Morning Herald, 11 June 2021.

At this stage, it is appropriate to describe the optimal timing for Stage 1 and Stage 2 of the preferred option as falling within a window, as shown in the table below.

Table 2: Optimal timing window for commissioning 1500 MW Project Marinus

Stage (750 MW each)	Optimal commissioning range across scenarios
Link 1	Between 2027 and 2031
Link 2	Between 2029 and 2034

We note that the new National Electricity Rules (**Rules**)[17] and accompanying guidelines[18] cater for this type of variability in the optimal project timing for a multi-staged actionable ISP project, such as Project Marinus. In particular, AEMO may establish 'decision rules' in its ISP to guide optimal project timing. In addition, the Rules provide for a 'feedback loop' to verify that the project proponent's preferred option accords with AEMO's optimal development path.

In this context, the timing for development of Project Marinus will ultimately depend on the 2022 ISP (including any decision rules in the 2022 ISP for development of Stages 1 and 2) and AEMO's optimal development path at that time. At this stage, however, our assessment is that there is mounting evidence that the NEM's current trajectory is at least consistent with or exceeds the Step Change scenario as outlined in the 2020 ISP.

In most instances, the lead time to withdraw dispatchable capacity from the NEM is much shorter than the timeframe for delivering large transmission projects. Given this observation, and the rapid pace of change in the generation sector, there is a compelling case to proceed on the basis that Project Marinus may be required at the earliest commissioning timeline of 2027 for Stage 1 and 2029 for Stage 2. Nevertheless, AEMO's 2022 ISP will be an important milestone in the context of Project Marinus to determine the optimal timing of the project in light of the latest available information and updated scenarios.

We also note that the significant benefits that Project Marinus will provide to the NEM have been recognised by the Australian and the Tasmanian governments through the execution of the Bilateral Energy and Emissions Reduction Agreement Memorandum of Understanding (**MOU**). This MOU provides funding of Project Marinus through the design and approvals phase to a final investment decision in 2023-24.

[17] Clause 5.16A.

[18] AER, *Cost benefit analysis guidelines: Guidelines to make the Integrated System Plan actionable*, August 2020.

In relation to project timing, TasNetworks will proceed with the early works required for Project Marinus to be able to achieve a final investment decision in 2023-24 and subsequent commissioning of Stage 1 from as early as 2027 and Stage 2 by 2029.

The actual timing of each stage will be determined by the 2022 and subsequent ISPs and AEMO's assessment of the proposed project in accordance with the feedback loop (as required by clause 5.16A.5(b) of the Rules) and its optimal development path at that time.

Project cost estimates

We recognise the concerns raised by stakeholders that the costs of major infrastructure projects can increase substantially from initial estimates. To address these concerns, we engaged engineering consultants, Jacobs, to conduct an independent review of our project cost estimates. Jacobs' report is provided as an attachment to this PACR and should provide stakeholders with confidence that our project cost estimates reflect the best available information and assessment at this time. The expected project cost estimate for this PACR is sourced from the Jacobs report, with the figure calculated on the basis of expected cost of the option under a range of different reasonable cost assumptions.[19]

The Jacobs cost review was conducted on a probabilistic estimation basis that identifies each of the significant cost components; determines the likely range based on previously completed projects and the associated probability distributions of each cost component; and undertakes a sampling process to generate a probability distribution of total project costs. The Association for the Advancement of Cost Engineering recommends utilising the probabilistic estimation basis for all projects over $200 million in value.

Each possible outcome value of the total project cost can be given a 'P' value which indicates its likelihood of occurrence. For instance, a P10 cost is the project cost with sufficient contingency to provide 10 per cent likelihood that this cost would not be exceeded. A P90 cost is the project cost with sufficient contingency to provide 90 per cent likelihood that this cost would not be exceeded. The contingency included in the expected project cost is the median output from a probabilistic analysis of possible outcomes.

The Jacobs report provides an expected project cost for the delivery of Project Marinus of $3,481 million ($2020).[20] This estimate is inclusive of contingency allowance based on a median probabilistic scenario.[21] The report also provides an overall range for the total project estimate of $3.1 billion to $3.8 billion ($2020). This

[19] Uncertainty regarding costs, RIT-T application guidelines, August 2020.

[20] The Jacobs cost estimate is in June 2021 dollars. The modelling undertaken for this PACR is in $2020. Therefore, the Jacobs cost estimate was de-escalated by 1.11 per cent to account for inflation (March 2020 – March 2021, Australian Bureau of Statistics), addition of interest during construction charge and subtraction of $50 million in grant funding received by TasNetworks.

[21] Refer to Project Marinus Cost Estimate Report prepared by Jacobs, released as Attachment 3 with this report.

range is based on P10 and P90 views of the total project contingency allowance. Our sensitivity analysis confirms that the preferred option is expected to deliver a strongly positive net economic benefit, even if the upper cost range estimated by Jacobs eventuates.

Figure 3 shows a comparison of the likely range of costs assumed at the PADR stage, in the 2020 ISP and now, at the PACR stage. The cost estimate for the PADR was based on a "neat" estimate ($2.8 billion, $2020), which excluded accuracy/growth allowances and contingencies, whereas the cost estimate for the 2020 ISP included an accuracy allowance (commonly referred to as the "base estimate"). The 2020 ISP subsequently applied a 30 per cent deterministic contingency on the base estimate of $3.2 billion ($2020).

It can be seen that whilst the underlying cost estimate (i.e. the "neat" estimate before allowances and contingencies) has increased by 10 per cent since the PADR, the contingency amount has reduced such that the expected total project cost is comparable to the PADR. This is explained by the more advanced status of the scope definition, engineering, route alignment and other matters, leading to more certainty.

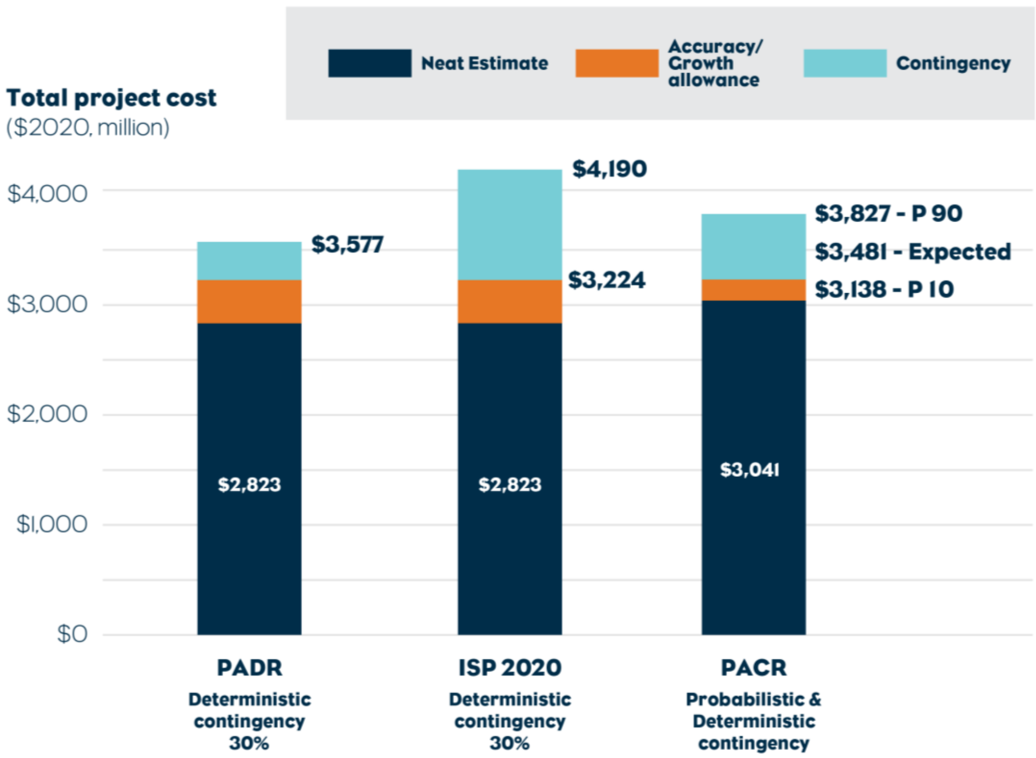

Figure 3: Range of total project cost outcomes comparison ($ million, $2020)[22]

[22] The PADR and ISP costs have been escalated from their original 2019 basis to 2020 prices. Inflation rate of 2.2 per cent based on ABS data for March 2019 to March 2020.

If Project Marinus is completed in two stages spaced no more than 2 to 3 years apart, $600 million in total project cost savings can be achieved compared to two standalone 750 MW links. The savings are derived from streamlining environmental approvals, civil works, horizontal direct drilling and procuring volume discounts from suppliers for cable and converter stations.

In addition to ensuring that our project cost estimates are robust, we have developed competitive tendering and procurement processes that are designed to obtain the best value for money from our contractors and equipment suppliers to achieve the lowest total cost of construction. Our robust project governance arrangements will also ensure that project costs are subject to ongoing management and review.

How does Project Marinus deliver benefits?

It is evident from the feedback we have received from stakeholders that our PACR should go beyond the requirements of the RIT-T to explain the sources of benefits that Project Marinus would unlock. As part of this explanation, stakeholders specifically want to understand why Project Marinus is preferred to solely increasing battery capacity on mainland Australia, and how Project Marinus interacts with the various policy and project announcements in other NEM regions.

In broad terms, Stage 1 of Project Marinus enables customers in the NEM to benefit from spare dispatchable capacity that already exists in Tasmania's hydro system, along with access to some of the best wind resource in the country. Stage 2 is expected to be in service at least two years after Stage 1, at which time our modelling shows that Australian mainland NEM regions would otherwise require additional peaking gas-fired generation and/or deep storage. By staging Project Marinus, investment in lower cost storage capacity and wind generation in Tasmania will provide savings to the mainland NEM by displacing more expensive alternatives.

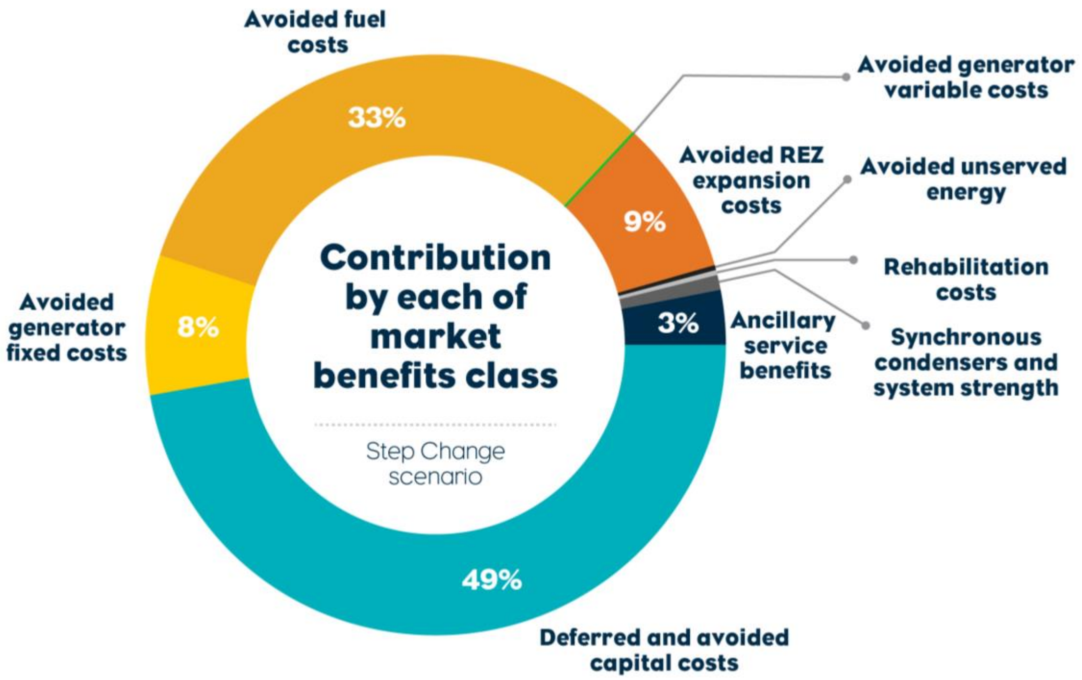

Figure 4: Market benefits provided by Project Marinus, Step Change scenario, 2027 and 2029[23]

Our findings indicate that strategic transmission investment and long-duration energy storage have a key role to play in addressing the risk associated with 'drought' in Variable Renewable Energy (**VRE**). Our analysis also indicates that the benefits of interconnection are underestimated, owing to the computationally intensive nature of system analysis, such that high-level, simplifying assumptions are made to support timely and cost-effective modelling. This means that the complexity of the NEM is understated, including through conducting system studies based on expected outcomes and perfect foresight, undertaking analysis at hourly granularity and utilising separate models for capacity expansion and long-term energy assessment. As explained in this report, these simplifications understate the benefits of interconnection and deep storage to manage variability and VRE drought.

Pricing impact

TasNetworks has received extensive feedback from customers regarding the transmission network pricing impact of Project Marinus, particularly in Tasmania. In principle, the most equitable and efficient pricing arrangement would allocate the costs of Project Marinus in a manner that reflects the beneficiaries. In practice, however, the beneficiaries cannot be determined precisely and will likely change over time. As a consequence, a pragmatic way forward needs to be developed.

[23] Data values for market benefit classes with minimal contribution have not been displayed but included in the analysis.

To progress the discussion, TasNetworks has commissioned analysis by internationally respected consultants, FTI Consulting (**FTI**), to examine how customers in different NEM regions will benefit if Project Marinus proceeds. FTI's analysis demonstrates the following:

- Project Marinus can exert downward pressure on electricity prices across the NEM;
- Project Marinus provides significant benefits to the end-customer;
- The current pricing framework is not consistent with the 'beneficiaries pay' principle; i.e. the principle that end-customers should pay according to the benefits they receive; and
- All customers are better off if Project Marinus proceeds and costs are shared fairly across the NEM.

The ability of Project Marinus to exert downward pressure on power prices in regions not physically connected by the interconnector may not be intuitive to some readers. However, the interconnected nature of the NEM and the ability of an asset to exert pricing impacts across all regions was highlighted by the recent event in Queensland with the unexpected outage at the Callide power station.[24] This incident led to a doubling of wholesale energy prices, compared to the price levels in the previous year, across most of the NEM[25] as the finely balanced supply and demand balance was disrupted. Similar to a power station outage impacting the wholesale energy prices across all jurisdictions, Project Marinus has the ability to put downward pressure on energy prices by introducing additional dispatchable capacity and bringing further diversity to the VRE portfolio in the NEM.

The pricing issue is being progressed by the National Cabinet Energy Reform Committee, building on work undertaken by the ESB and the Australian Energy Market Commission. We are continuing to work with the Commonwealth and state governments to deliver a fair pricing outcome.

Next Steps

The publication of this PACR concludes the RIT-T process. From a regulatory perspective, the next stage of the process is to work with the Australian Energy Regulator (**AER**) and AEMO on the revenue setting arrangements for the project. These arrangements will need to address the two project components, Marinus Link (i.e. the HVDC and converters component) and the North West Transmission Developments component. We will continue to consult with customers and stakeholders on these arrangements as further information becomes available and these processes commence.

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[24] Update on incident at Callide power station, CS Energy, 25 May 2021.

[25] Callide outage feeds power price surge, Australian Financial Review, June 2021.

1 Introduction and Overview

Key messages

Our RIT-T analysis shows that:

- Project Marinus delivers value to NEM customers by providing increased access to the existing hydro capacity in Tasmania. As more solar and wind resources replace coal-fired generation, energy storage will be required to firm the output from these resources. Project Marinus expands the use of existing Tasmanian hydro generation and lower cost pumped hydro to provide energy storage more efficiently than the alternative of gas-fired generation and new storage options on mainland Australia.
- The most significant factors influencing the economic feasibility of Project Marinus are the timing of coal-fired generation retirement in the NEM; load forecasts; the capability and cost of battery storage; and gas prices.
- In accordance with the RIT-T, we have tested alternative capacities for Project Marinus compared to the base case, across a range of different scenarios. The base case examines the costs of meeting customers' demand for electricity if Project Marinus did not proceed. As such the RIT-T compares Project Marinus built at various capacities and staging, to the lowest cost alternative to Project Marinus, which includes the required storage and generation investments on mainland Australia, as well as the additional demand management measures which would be required if Project Marinus does not proceed.
- Our analysis shows that Project Marinus would deliver a net economic benefit for all feasible options and across every scenario. On this basis, Project Marinus should proceed. Our detailed examination of the capacity options indicates that the optimal solution is a staged 1500 MW Project Marinus, comprising early works, Stage 1 (750 MW) and Stage 2 (a further 750 MW).
- In accordance with the new Rules, and in light of the ongoing pace of NEM transition, the timing of each stage of the project will be determined by its inclusion in the optimal development path in the 2022 ISP and subsequent ISPs.

1.1 Purpose of this document

Coal generation continues to be retired with variable renewable generation, such as wind and solar generation, increasingly taking its place. The recent announcements of the early retirement at Yallourn and Eraring power station, and AGL Energy's significant asset impairments and restructure plans[26], are examples of the unprecedented pace of change in the NEM.

To support increasing levels of VRE, the NEM needs 'dispatchable' energy that can be available on-demand, such as batteries, hydro and pumped hydro energy storage resources. The purpose of this PACR is to test the economic case for Project Marinus in meeting these needs by providing greater access to Tasmania's natural advantages in wind resources and long-duration energy storage (**LDES**) capacity.

The PACR is the final stage of the RIT-T process, which is a comprehensive economic cost-benefit analysis, comparing Project Marinus against other credible options to meet the identified need. The objective of the RIT-T is to identify the 'preferred option', which maximises the net economic benefit to all those who produce, consume, and transport electricity in the market compared to all other credible options.[27]

Throughout this PACR, 'Project Marinus' refers to the high voltage direct current (HVDC) and converter interconnector assets, known as Marinus Link, and the alternating current (AC) transmission investment in Tasmania, known as the North West Transmission Developments. These investments together constitute the RIT-T project, which is the subject of this PACR.

1.2 RIT-T analysis supports Project Marinus

The analysis presented in this PACR shows that a 1500 MW Project Marinus, constructed in two 750 MW stages, satisfies the RIT-T. Our analysis shows that Project Marinus constructed in two stages according to its earliest feasible timing of 2027 and 2029 produces an expected net economic benefit of $2,161 million[28] in present value terms compared to the base case, in which Project Marinus does not proceed.

Our modelling approach ensures that Project Marinus is tested against a wide range of alternatives, including generation, storage, demand-side response, and other transmission projects. It is a comprehensive approach

[26] AGL Energy FY21 Half-Year Results Presentation, February 2021.

[27] Clause 5.16.1(b) of the Rules.

[28] This estimate adopts an equal weighting across the 5 scenarios in the 2020 ISP.

that treats all options and technologies on an equal basis, consistent with the approach adopted by AEMO in its 2020 ISP.

1.3 A technology neutral modelling approach

Our RIT-T analysis is underpinned by Ernst & Young's market expansion model, which determines the least cost evolution of the NEM to 2050.

An important aspect of Ernst & Young's market modelling is that it examines the total integrated system costs of meeting customers' future electricity needs. The model selects the lowest cost combination of generation, storage, non-network options, demand-side response and transmission investments. Each option for Project Marinus is therefore accompanied by other investments across the NEM to meet customers' electricity needs, without favouring any particular types of project or response.

Ernst & Young's analysis shows that Project Marinus reduces the total costs of meeting customers' electricity needs compared to the base case under which Project Marinus does not proceed. This outcome is consistent with the 2020 ISP, which also concluded that Project Marinus forms part of the optimal development path.

1.4 Optimal timing and AEMO feedback loop

The Rules allow a transmission network service provider (**TNSP**) to lodge a Contingent Project Application to the AER in relation to an actionable ISP project. The AER's review of a Contingent Project Application will conclude with a decision that amends the TNSP's existing revenue determination to include an annual revenue allowance for the actionable ISP project. As part of the AER's review, the capital and operating expenditure criteria in the Rules will be applied so that only the efficient and prudent project costs are recognised in setting the revenue allowance.

Before lodging a Contingent Project Application, the TNSP must obtain AEMO's confirmation that:

- the preferred option addresses the relevant identified need and aligns with the optimal development path in the ISP;[29] and

[29] National Electricity Rules, Clause 5.16.5(b)(1).

- the cost of the preferred option does not change the status of the actionable ISP project as part of the optimal development path.[30]

The AER has published guidance[31] that clarifies how it expects the 'AEMO feedback loop' to operate in relation to staged ISP projects, such as Project Marinus. In brief, the AER's guidance requires that:

- AEMO assesses the total cost of the proposed project in determining whether it is consistent with the optimal development path.
- AEMO's written confirmation should identify the costs of each project stage that will be subject to a Contingent Project Application.
- Each stage of the project should not exceed the amount specified by AEMO for that stage.
- If the total project costs increase above the amount notified by AEMO, the TNSP is required to seek AEMO's updated confirmation that the project remains aligned with the optimal development path.
- Despite gaining approval through AEMO's feedback loop, the AER will assess the efficiency and prudency of the proposed expenditure for each stage of the project.

For Project Marinus, we will adopt the feedback loop process outlined in the AER's guidance, noting that the project has three potential stages for revenue setting purposes: Early works, Stage 1 and Stage 2. We are particularly conscious of the need to ensure that forecast project costs are reassessed through the feedback loop in accordance with the approach outlined by the AER. We discuss the management of the project costs in further detail in section 9.2 of this PACR, focusing particularly on the regulatory and commercial arrangements that are in place to ensure that the project costs are prudent and efficient.

1.5 Structure of this PACR

The remainder of this PACR is structured as follows:

- Chapter 2 discusses the 2020 ISP and recent policy developments.
- Chapter 3 discusses the RIT-T process to date; the publication of our Supplementary Analysis Report; and the new ISP Rules.
- Chapter 4 summarises the feedback we received on our PADR and our Supplementary Analysis Report, and explains how we have taken this feedback into account in preparing this PACR.

[30] National Electricity Rules, Clause 5.16.5(b)(2).

[31] AER, *Guidance note, Regulation of actionable ISP projects*, March 2021, pages 29-31.

- Chapter 5 describes the credible options.
- Chapter 6 discusses our modelling approach in detail, including the key input assumptions, scenarios and sensitivity analysis, the discount rate and the planning horizon.
- Chapter 7 presents the results of our net economic benefit analysis, our sensitivity testing and the selection of the preferred option for Project Marinus. This section also sets out the development phases and timeframes for the preferred option.
- Chapter 8 explains Project Marinus' role in the NEM and the benefits it is expected to deliver. This chapter also discusses the economics of pumped storage and batteries, including the value that Project Marinus provides in unlocking long-duration energy storage to the NEM.
- Chapter 9 discusses the issues of transmission pricing and the effective management of project costs, which were raised by stakeholders in their submissions.
- Chapter 10 explains the next steps.

In addition to the above chapters, we have included a number of appendices and attachments which also form part of this PACR. The appendices provide additional detail on the following matters:

- **Appendix 1**: Our response to stakeholders' submissions to our PADR and Supplementary Analysis Report;
- **Appendix 2**: Technical analysis summary for the preferred option;
- **Appendix 3**: Explanation of net economic benefit calculation using a shortened study period; and
- **Appendix 4**: Our compliance checklist, which demonstrates that this PACR meets the Rules requirements.

In addition to the appendices, we also attach three independent expert reports:

- **Attachment 1**: Ernst & Young's market modelling report;
- **Attachment 2:** GHD's assessment of ancillary service costs. This analysis is unchanged from PADR studies; and
- **Attachment 3:** Jacobs' review of the estimated project costs.

2 2020 ISP and recent policy developments

Key messages

- The 2020 ISP provides a comprehensive assessment of the optimal combination of generation, storage, demand-side measures and transmission investments to meet customers' energy needs over a 20 year planning horizon. It therefore provides an important starting point for our assessment of the economic case for Project Marinus.
- The 2020 ISP concluded that Project Marinus is a multi-staged actionable ISP project, which should be subject to a single RIT-T process. It states that early works on both cables should be completed by 2023-24, so that the first cable may be constructed from 2028-29 if the Step Change scenario eventuates.
- Subsequent to the 2020 ISP, the Prime Minister of Australia included Project Marinus as a priority infrastructure project to be accelerated to support Australia's COVID-19 recovery. As a consequence of the accelerated approvals arrangements, the earliest possible timing for Project Marinus Stage 1 to be in service is now forecast to be 2027-28.
- Following the publication of the 2020 ISP, a number of state-based government policy initiatives have been announced that will affect the future development of the electricity sector. In this PACR, we are aligning our treatment of these state-based initiatives with AEMO's proposed approach as outlined in its most recent Inputs, Assumptions and Scenarios Report (**IASR**), which was published in December 2020.
- As a sensitivity analysis, we have modelled the impact of a Commonwealth 'carbon budget' replacing all state-based policy initiatives. While this sensitivity analysis does not necessarily reflect a likely future world, it allows us to assess the merits of Project Marinus' potential contribution to achieving a national target in the absence of state-based policies.

2.1 Australia's complex energy transition

The purpose of the ISP is to coordinate transmission and generation planning to provide for the efficient development of the power system over a planning horizon of at least 20 years. By 2040, the 2020 ISP concludes that the NEM would reflect the following changes:

- **Distributed Energy Resources**: expected to double or triple, providing 13 to 22 per cent of total underlying annual energy consumption.

- **New grid scale renewables**: more than 26 gigawatts (**GW**) is needed to replace coal-fired generation, with 63 per cent of coal-fired generation set to retire.
- **Dispatchable resources**: 6-19 GW of new dispatchable resources are needed to back up renewables, in the form of utility-scale pumped hydro, fast responding gas-fired generation, battery storage, demand response and aggregated DER participating as virtual power plants.
- **Power system services**: the growing need to actively manage power system services (voltage control, system strength, frequency control, inertia, ramping and dispatchability).
- **Transmission**: strategically placed interconnectors and REZs, coupled with firming resources, to add capacity and balance variable resources across the NEM.

AEMO notes that the ISP serves the regulatory purpose of identifying actionable and future ISP projects, as well as the broader purpose of informing market participants, investors, policy decision makers and consumers. AEMO makes the following observations regarding the comprehensive nature of its modelling approach:[32]

> "As a rigorous whole-of-system plan, the ISP is a far more comprehensive and richer analysis than other comparable modelling exercises for Australia's energy future. It takes into account not only the capital and fuel costs of generation but also future network developments and deployment of DER. It includes a degree of sector coupling with the transport and gas sectors. It also takes the first steps towards including insights on the role of hydrogen. It incorporates innovations in consumer-owned DER, virtual power plants, large-scale generation, energy storage, and power-system services. Finally, it ensures the physical limitations and constraints of Australia's energy system are accurately represented."

In relation to its modelling approach, AEMO explains that it uses scenario modelling and cost-benefit analysis to determine the most efficient ways to meet power system needs, in the long-term interests of consumers. The key elements in AEMO's approach for the 2020 ISP are:

- **Consultation on ISP assumptions, scenarios and sensitivities**. AEMO consulted extensively with industry, academia, government, developers and consumer representatives, culminating in its Forecasting and Planning Scenarios, Inputs and Assumptions Report in August 2019. AEMO subsequently updated its inputs and assumptions, drawing on feedback received on the Draft 2020 ISP.

[32] AEMO, *2020 Integrated System Plan*, July 2020, page 10.

- **Five scenarios to trace different speeds of transition**:
    - **Central scenario**, which reflects current Commonwealth and state government policies;
    - **Slow Change scenario** with slower economic growth and emission reductions;
    - **High DER scenario** with more rapid consumer adoption of DER;
    - **Fast Change scenario** with greater investment in grid-scale technology; and
    - **Step Change scenario** where both consumer-led and technology-led transitions occur in the midst of aggressive global decarbonisation.
- **Two new sensitivities to test changes in inputs that could materially alter the optimal development path**: being the legislation of the TRET of 200 per cent by 2040, and updated demand forecasts including the potential impacts of COVID-19 and recent trends in photovoltaic (**PV**) sales. As discussed shortly, the TRET has subsequently been legislated and will be factored into AEMO's 2022 ISP.

In our view, the 2020 ISP provides the most comprehensive analysis of how best to meet customers' energy needs over the next 20 years. The objective of the ISP, which is to identify an optimal development path having regard to all credible options without any preference for technology, is aligned with the RIT-T objective. Given this background, the findings of the 2020 ISP in relation to Project Marinus are of significant importance to this PACR and provide a starting point for our RIT-T analysis. Furthermore, the 2020 ISP provides a point of reference for verifying our modelling results, and should provide stakeholders with confidence that our approach is aligned with the views of the independent national transmission planner.

2.2 ISP findings for Project Marinus

The 2020 ISP identifies the following transmission projects as being most urgently needed (termed 'actionable ISP projects'):

- **VNI Minor**: a minor upgrade to the existing Victoria-NSW Interconnector (**VNI**), which is close to completing its regulatory approval process, with project completion expected in 2022-23.
- **Project EnergyConnect**: a new 330 kilovolt (**kV**) double-circuit interconnector between South Australia and New South Wales, which has completed its regulatory approval process. The project completion is expected by 2024-25.
- **HumeLink**: a 500 kV transmission upgrade to reinforce the NSW southern shared network and increase transfer capacity between the Snowy Mountains hydroelectric scheme and the region's demand centres. This project commenced its regulatory approval process earlier this year, with project completion due by 2025-26.

- **NSW Central-West Orana REZ Transmission Link**: network augmentations to support the development of the Central-West Orana REZ in NSW. The project completion is due in 2024-25.

In addition to these 'actionable ISP projects', the 2020 ISP also identified a category of projects as 'actionable ISP projects with decision rules', which AEMO explains as follows:[33]

> "These projects are also critical to address cost, security and reliability issues. The decision rules for these projects can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate."

Two interconnector projects have been identified as 'actionable ISP projects with decision rules':

- VNI West, a new high voltage alternating current interconnector between Victoria and New South Wales; and
- Project Marinus, which AEMO defines as two new HVDC cables connecting Victoria and Tasmania and the supporting staged Tasmanian AC transmission investment between the Burnie area and Palmerston Substation.[34]

In relation to Project Marinus, AEMO explains that:[35]

> "Marinus Link is a multi-staged actionable ISP project to be completed from 2028-29, with early works recommended to start as soon as possible, and with further stages to proceed if their respective decision rules are satisfied."

AEMO explains that its 2020 ISP analysis recognises 'option value' by recommending that early works commence as soon as possible in anticipation of the first cable being operational by 2028-29, noting that the first link is needed no later than 2031-32. Table 3 shows the 2020 ISP's optimal timing of Project Marinus weighted by the four scenarios in the 2020 ISP where Project Marinus forms part of the optimal development path (i.e. excluding the 'Slow Change' scenario). The decision to fast-track environmental approvals for Project Marinus by the state and commonwealth governments was announced post the release of the 2020 ISP. This decision enabled advancing the commissioning for first stage of Project Marinus to 2027.

[33] AEMO, *2020 Integrated System Plan*, July 2020, page 14.

[34] The Final 2020 ISP Transmission outlook spreadsheet outlines the complete project description and required network augmentation.

[35] AEMO, *2020 Integrated System Plan*, July 2020, page 82.

Table 3: 2020 ISP's commissioning range for Project Marinus

Stage (750 MW each)	2020 ISP's optimal commissioning range[36]
Link 1	Between 2028 and 2031
Link 2	Between 2031 and 2035

The ISP concludes by defining Project Marinus as follows:[37]

> "Marinus Link is therefore specified as a multi-staged actionable ISP project with a single RIT-T process as follows:
>
> - Complete early works on both cables by no later than 2023-24.
> - Stage 1 of the project, as described by TasNetworks in its PADR, is to construct the first cable from 2028-29 should the Step Change scenario eventuate, and by no later than 2031-32, if decision rules are satisfied. The decision rules for Marinus Link to proceed from early works to construct the first cable include:
>   - there is successful resolution as to how the costs of the project will be recovered (from consumers or other sources), and
>   - either TRET is legislated, or, either of the Step Change or Fast Change scenario unfolds.
> - Stage 2 of the project, as described by TasNetworks in its PADR, is to construct the second cable if further decision rules are satisfied. The decision rules for Marinus Link to proceed to construct the second cable will be specified in the 2022 ISP, with the intent that this stage continues to be assessed to deliver value at that time."

[36] The 2020 ISP found that Project Marinus and VNI West are not needed in the Slow Change scenario, so the average timing relates to four of the five scenarios.

[37] AEMO, *2020 Integrated System Plan*, July 2020, page 83.

2.3 Inputs, assumptions and policy developments

2.3.1 Inputs and assumptions

Whilst the 2020 ISP is a key reference point for this PACR, the pace of change across the electricity sector has resulted in a number of subsequent developments and emerging issues that need to be factored into our RIT-T modelling. AEMO is currently in the process of considering these issues in developing its 2021 IASR.[38] At present, AEMO has published a draft version of the 2021 IASR, with the final version expected to be published in July 2021. The data in the final IASR inputs will be applied by AEMO in its draft 2022 ISP and the 2021 Electricity Statement of Opportunities.

In its draft 2021 IASR, AEMO notes that major sectoral uncertainties have been identified through insights developed in the 2020 ISP and recent stakeholder engagement, including: [39]

- The size of consumer energy demand, including the scale of energy avoided and self-generated, and the future outlook for energy intensive large industrial loads.
- Generation and storage technology cost evolution, both grid-scale and distributed energy resources.
- Environmental outcomes, particularly decarbonisation objectives, and the scale and timing of coal-fired generation closures.
- Government policies to support regional economic development, domestic manufacturing and jobs growth, build energy resilience, and keep downward pressure on energy prices.
- The extent of greater electrification and the location of this demand, as other sectors decarbonise and new industries, such as hydrogen production, emerge.

Against this backdrop, AEMO has engaged with stakeholders to develop its future scenarios for use in its 2021-22 forecasting publications. In submissions to our PADR and our Supplementary Analysis Report, stakeholders raised questions regarding input costs that may affect, either positively or negatively, the economic case for Project Marinus. For example, one submitter commented on our assumption that a total replacement of a battery installation is required every 20 years. An alternative view was expressed that the balance of plant infrastructure does not need to be replaced and the cost of repowering battery capacity is the cost of the new cells minus any residual value of the old cells.

[38] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020.

[39] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, page 17.

In responding to stakeholders' diverse views relating to input costs, our view is that the most transparent and objective approach is to rely on AEMO's latest inputs and assumptions in its draft IASR. This approach ensures that our selection of input data cannot be regarded as biased towards estimates that favour Project Marinus. Furthermore, while the draft IASR is not settled it is preferable to adopt this data, rather than rely on older information used by AEMO in the 2020 ISP. In particular, we expect that stakeholders would criticise the use of data that does not reflect AEMO's latest views, particularly where these views reflect stakeholder feedback. For instance, stakeholders' views regarding replacing the battery cell pack, but not the balance of plant equipment, were addressed in the draft 2021 IASR. The draft 2021 IASR also captures a further lowering of battery cost projections and capital costs associated with variable renewable energy generators. For these reasons, we propose to adopt AEMO's draft IASR inputs and assumptions for the purpose of this PACR.

To provide continuity with the 2020 ISP, we propose to retain AEMO's scenarios in this PACR. In taking this approach, we note that stakeholders' submissions to our PADR emphasised the need to align our analysis with the 2020 ISP. This feedback led us to publish our Supplementary Analysis Report, which adopted the 2020 ISP scenarios.

2.3.2 Treatment of government policies

AEMO has explained that it will only adopt a government policy in all its scenarios if the policy is sufficiently developed to enable its impacts on the power system to be identified, and meets at least one of the following conditions:[40]

- A commitment has been made in an international agreement to implement that policy;
- That policy has been enacted in legislation;
- There is a regulatory obligation in relation to that policy;
- There is material funding allocated to that policy in a budget of the relevant participating jurisdiction; or
- The Ministerial Council of Energy has advised AEMO to incorporate the policy.

AEMO has applied the above approach to recent policy developments, as described below. In compiling this summary, we note that AEMO's current position is subject to stakeholder consultation and the status of various initiatives will continue to evolve.[41]

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[40] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, page 42.

[41] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, pages 42 to 46.

- **Australia's 2030 emissions reduction target**

  The Commonwealth Government has set a target to reduce greenhouse gas emissions to 26 per cent below 2005 levels by 2030. In the 2020 ISP, this target was exceeded across all scenarios to varying degrees, and AEMO expects this situation to continue in its future scenarios. As a result, the 2030 emissions reduction target is a non-binding constraint from a modelling perspective.

- **Large-scale Renewable Energy Target (LRET)**

  The national LRET is a legislated policy that provides a form of stimulus to renewable energy development. The LRET is generally considered to have been met, and AEMO notes that it provides minimal further incentive to construct VRE. As such, AEMO does not take account of this policy in its modelling.

- **Victorian Renewable Energy Target (VRET)**

  The VRET mandates 40 per cent of the region's generation be sourced from renewable sources by 2025 and 50 per cent by 2030. The target is measured against Victorian generation, including renewable DER. The VRET is legislated and therefore will be included in AEMO's scenarios.

- **Victorian 2020-21 budget initiatives affecting REZs and energy efficiency**

  In its 2020-21 budget, Victoria has set aside significant funding – a $1.6 billion investment – for the establishment of clean energy initiatives and energy efficiency upgrades to homes. This includes $540 million to establish six REZs.

  In its draft IASR, AEMO comments that currently this policy is not sufficiently detailed to identify the specific impacts on the power system, and therefore it has not been included in all its scenarios. AEMO also notes that the policy may be addressed in the 2022 ISP.

  As explained in further detail below, we propose to follow AEMO's assessment and not factor these potential developments into our PACR modelling. Instead, a sensitivity analysis has been conducted with 10,000 MW of renewable energy projects developed in the Victorian REZs.

- **Queensland Renewable Energy Target (QRET)**

  The Queensland Government has committed to a 50 per cent renewable energy target by 2030. As the Queensland Government has committed material funding to the delivery of the QRET in the 2020-21 Queensland Budget Papers, the policy will be included in all scenarios.

- **Tasmanian Renewable Energy Target (TRET)**

  The Tasmanian Government has recently legislated a 200 per cent renewable energy target by 2040, with an interim target of 150 per cent by 2030. This legislated target extends the Tasmanian Government's existing commitment for 100 per cent renewable energy by 2022. As the targets are legislated, the TRET will be included in all scenarios.

- **New South Wales Electricity Infrastructure Roadmap**

  The New South Wales Government has released an Electricity Infrastructure Roadmap with the objective of delivering an indicative 11 GW of new transmission capacity to the Central-West Orana and New England REZs. These objectives will be progressed through various measures and processes.

  The Electricity Infrastructure Investment Act 2020 recently passed both houses of the New South Wales Parliament. The legislation sets out minimum objectives that, by the end of 2029, the following renewable generation capacity targets will be met:

  - 8 GW of capacity from the New England REZ.
  - 3 GW of capacity from the Central-West Orana REZ.
  - 1 GW of additional generation capacity.
  - 2 GW of dispatchable capacity with a storage duration of at least 8 hours.

  AEMO is therefore proposing to model the policy as a minimum constraint on development of new VRE in New South Wales by 2030. The objective of this policy also suggests that the state is preparing for a Step Change scenario eventuating.

- **National Electricity (Victoria) Act (NEVA) – amendment for expedited approval of transmission upgrades**

  The amendment to the NEVA in February 2020 was made to facilitate the expedited approval of transmission system upgrades. The Act enables the Minister to approve augmentations of the Victorian transmission system. This process was recently used to procure 300 MW/377 MWh of System Integrity Protection Scheme battery storage at Moorabool.

  For the purpose of the ISP, AEMO explains that any Ministerial order that has progressed to the point of approval will be considered as a committed investment, and therefore the merchant energy arbitrage portion of the battery storage is included in all scenarios.[42]

[42] The battery is expected to reserve 250 MW/125 MWh of its capacity during summer months to allow AEMO to increase southerly flow across VNI by increasing the thermal limit so that VNI can operate closer to its current maximum physical capacity.

- **Distributed energy resources policies**

  Various policies and initiatives exist across NEM jurisdictions to support uptake of DER, including:

  - South Australia – Home Battery Scheme.
  - Victoria – Solar Homes Scheme.
  - New South Wales – Clean Energy Initiatives.
  - Emission Reduction Fund and Victorian Energy Saver Incentive Scheme.
  - Australian Capital Territory Next Generation Energy Storage program.
  - Trial programs to integrate virtual power plants and explore how a network of small-scale PV and batteries can be collectively controlled and fed into the grid.

  AEMO intends to incorporate each of these schemes in its DER uptake and behavioural analysis.

- **Energy efficiency policies**

  There are numerous state-based energy efficiency policies that AEMO has taken into account in developing its electricity demand forecasts. A detailed discussion of how AEMO intends to map these policies onto its future scenarios is presented in its draft IASR, noting that this is subject to stakeholder consultation. For the purposes of our PACR, we will account for energy efficiency policies by adopting AEMO's demand forecasts.

While our scenarios in this PACR are unchanged from those adopted in the 2020 ISP, our modelling approach will adopt AEMO's proposed treatment of the policies described above. By replicating AEMO's proposed approach to government policies in our modelling, stakeholders can have confidence that our treatment is unbiased and consistent with AEMO's most recent assessment of these policy initiatives.

We note that AEMO's future approach in its 2022 ISP may vary from the above summary, as policies continue to develop over time. From a practical perspective, however, the best approach is to reflect AEMO's current assessment in our PACR modelling, rather than attempt to anticipate future changes that may, or may not, eventuate. The latter approach would require ad hoc adjustments to AEMO's current position, which may be interpreted as lacking transparency and objectivity.

As discussed in Chapter 8 of this PACR, we have also conducted a sensitivity analysis that adopts a Commonwealth, NEM-wide emissions reductions target (or 'carbon budget') and removes all state-based initiatives. While this sensitivity analysis does not necessarily reflect a likely future world, it captures the economic case for Project Marinus in meeting customers' future electricity needs, absent the influence of state-based policies, including the TRET.

3 RIT-T process and new ISP Rules

Key messages

- The first two stages of the RIT-T for Project Marinus, being the publication of the Project Specification Consultation Report (**PSCR**) and the PADR, have been successfully completed.
- We have engaged with stakeholders on each of these steps in accordance with the Rules requirements. A key theme in response to our PADR was that stakeholders expected us to align our modelling with AEMO's forthcoming 2020 ISP, which had not been published at that time.
- In response to stakeholder feedback, we paused our RIT-T process and published a Supplementary Analysis Report that updated our modelling to account for the latest information in the 2020 ISP. This updated modelling confirmed the 2020 ISP findings that Project Marinus should be a staged, actionable ISP project, subject to satisfying specific decision rules. In addition to consulting on the PADR, we also sought stakeholders' views on our Supplementary Analysis.
- Subsequent to the publication of our PADR, new Rules and guidelines were introduced relating to the application of the RIT-T and revenue setting arrangements for actionable ISP projects, such as Project Marinus. In this PACR, we have elected to adopt these new Rules, which means that Project Marinus will be subject to AEMO's 'feedback loop' before each of the project stages (early works, Stage 1 and Stage 2) can proceed to cost recovery.

3.1 Completed stages of the RIT-T

The RIT-T process commenced with the publication of the PSCR, which we published in July 2018. The PSCR described the 'identified need' that further interconnection between Tasmania and Victoria would address. It also provided details of:

- The assumptions underpinning this need;
- The credible options that would address this need;
- How we intend to evaluate the benefits of these options;
- The likely implementation timetable; and
- The indicative costs.

We received 15 submissions to the PSCR, which covered a wide range of topics.

In preparing our PADR, which was published in December 2019, we ensured that we addressed the feedback from stakeholders, including the comments in relation to our investment assessment and modelling. In particular, to ensure that the cost benefit analysis was robust and independent, we engaged Ernst & Young and GHD to undertake the modelling on our behalf.

This modelling showed that Tasmania's existing hydro capacity is a significant source of value to electricity customers, including mainland NEM customers, given the forecast coal plant closures and the projected growth in renewable generation. Our modelling illustrated that Project Marinus unlocks this benefit by:

- Enabling Tasmania to exploit its natural advantages in terms of topography and wind resources to provide lower cost hydro-electric storage capacity and wind generation to mainland Australia;
- Providing the NEM with access to lower cost, higher capacity, energy storage to 'firm up' variable renewable energy; and
- Displacing expensive gas-fired peaking generation on mainland Australia that would otherwise be required to meet electricity demand.

Our detailed analysis in the PADR concluded that the optimal capacity and indicative timing for Project Marinus is:

- Stage 1: An initial 750 MW HVDC link between Burnie in Tasmania and the Hazelwood area in Victoria, together with AC network augmentations in Tasmania, would be needed as early as 2028; and
- Stage 2: The commissioning of a further 750 MW HVDC link, and AC network augmentations in Tasmania, no later than 2032, but potentially as early as 2030.

We explained that Stage 1 would enable customers in the mainland NEM to benefit from the spare capacity that already exists in Tasmania’s hydro system. The timing of the second stage would be contingent upon the need for dispatchable capacity due to retirement of the thermal generation fleet that would require peaking gas fired generation and mainland storage in the absence of additional interconnector capacity. By aligning the timing of the second stage of the interconnector capacity with the dispatchable capacity needs of the NEM, investment in lower cost storage capacity and wind generation in Tasmania would provide further savings to the mainland NEM by displacing more expensive alternatives.

As part of the PADR, we published reports from Ernst & Young and GHD on their modelling approaches and results. This transparent approach ensured that the independent modelling conducted by Ernst & Young and GHD could be reviewed by stakeholders.

3.2 Supplementary analysis report

In response to the PADR, a key theme raised in stakeholders' submissions was that our cost benefit analysis should be aligned with the 2020 ISP which, at that time, had not been finalised. Given this feedback, we decided to pause our RIT-T process so that we could consider the 2020 ISP. Subsequently, we published a Supplementary Analysis Report[43], which updated our modelling results in light of the 2020 ISP and the feedback from stakeholders.

While the Supplementary Analysis Report is not a formal step in the RIT-T process, we considered it important to update the modelling results we presented in our PADR and provide stakeholders with a further opportunity to make submissions. The Supplementary Analysis Report also provided us with an opportunity to explain how we intended to address stakeholders' feedback on the PADR. By allowing an extra step in the consultation process, we increased the transparency of our process by publishing our updated modelling in advance of this PACR.

Our supplementary cost benefit analysis focused on the preferred option of 1500 MW identified in our PADR and the 2020 ISP. The insights from the Supplementary Analysis Report were broadly consistent with the 2020 ISP. In particular:

- Early works for both stages should be completed by 2023-24;
- Stage 1 of the project should be in-service by no later than 2031-32, with TRET legislated; and
- The timing of Stage 1 would be needed at the earliest possible timing (estimated to be 2027) if the Step Change scenario eventuates and Stage 2 should be in-service shortly after Stage 1 if the Step Change scenario eventuates.

Our Supplementary Analysis Report explained that input assumptions will continue to change as new information becomes available. As explained in the previous chapter, for the purpose of this PACR, we have adopted AEMO's latest inputs and assumptions in its draft IASR and its proposed treatment of the various government policy initiatives. In our view, this approach is consistent with stakeholders' feedback that our RIT-T analysis should be aligned with AEMO's current views. Furthermore, it provides assurance to stakeholders that our modelling is transparent and objective.

[43] TasNetworks, *Regulatory Investment Test for Transmission Supplementary Analysis Report*, 5 November 2020.

3.3 New ISP Rules

On 1 July 2020, new Rules were introduced that establish the ISP in the planning and regulatory framework by:

- defining the roles and responsibilities of AEMO, the TNSPs and the AER;
- explaining how the cost-benefit analysis will work, given the analysis undertaken in the ISP to identify actionable ISP projects and the requirement for TNSPs to undertake the RIT-T; and
- ensuring that TNSPs can obtain cost recovery for actionable ISP projects through streamlined contingent project provisions.

For the purpose of this PACR, it is useful to highlight the following aspects of the new ISP Rules:

- A simplified set of contingent project triggers apply to actionable ISP projects so that the TNSP is able to obtain cost recovery. As part of this process, there is a requirement for TNSPs to obtain confirmation from AEMO that the project meets the identified need in the ISP and the project costs are consistent with the ISP's optimal development path.
- Transitional arrangements apply so that TNSPs can choose whether to apply the new RIT-T arrangements for actionable ISP projects or continue with the previous Rules, if the RIT-T has already commenced or the project was identified as a contingent project in the TNSP's revenue determination.

In accordance with the ISP Rules, the AER published its final ISP guidelines on 25 August 2020. The AER explained that in its view the RIT-T for Project Marinus is 'substantially complete' and should not be updated to apply the new RIT-T guidelines, even if TasNetworks elects to adopt the new Rules.[44] The AER's table below confirms this approach.[45]

[44] AER, *Fact Sheet, Final Guidelines for Integrated System Plan*, August 2020, page 2.

[45] AER, *Final Decision, Guidelines to make the Integrated System Plan actionable*, August 2020, page 19.

Table 4: Transitional arrangements for ISP Projects, AER

Regulatory Process	New ISP rules apply?	Final AER guidelines apply?
VNI Minor RIT–T	Yes – at election of TNSP	No – RIT–T already finalised
Project EnergyConnect RIT–T	Yes – at election of TNSP	No – RIT–T already finalised
HumeLink RIT–T	Yes – at election of TNSP	No – RIT–T past draft report stage*
MarinusLink RIT–T	Yes – at election of TNSP	No – RIT–T past draft report stage
VNI West RIT–T	Yes – at election of TNSP	Yes
Central West REZ RIT–T	Yes	Yes

In explaining the above approach, the AER emphasises the importance of not restarting the RIT-T analysis if the PADR has already been published:[46]

> "It is not appropriate for the guidelines to apply to RIT-T applications where a draft report has been published. Such RIT-T applications are substantively underway and may require re-starting the draft report. For these RIT-T applications, the previous RIT-T instrument and application guidelines continue to apply."

For Project Marinus, our approach is to apply the new ISP Rules so that AEMO has the opportunity to review our proposed project scope and costs at each of the stages (early works, Stage 1 and Stage 2) to verify that these stages are consistent with the optimal development path in the 2020 ISP and subsequent ISPs. In accordance with the AER's observations, we chose not to restart the RIT-T process.

[46] AER, *Final Decision, Guidelines to make the Integrated System Plan actionable*, August 2020, page 19.

4 Listening to stakeholders

Key messages

- We have listened to customers and stakeholders from the inception of Project Marinus, ensuring that their views and feedback have been taken into account. Where stakeholders have commented that further analysis or engagement is required, we have responded positively to these requests.
- The PACR addresses the feedback we received on the PADR and our Supplementary Analysis Report. In this Chapter, we highlight the key themes raised in submissions. Appendix 1 provides a more detailed explanation of how we have taken this feedback into account in this PACR.

4.1 TasNetworks' engagement approach

Customer and stakeholder engagement is an important part of our process and we welcome the feedback we have received. We have extended the consultation process beyond the formal requirements specified in the Rules by publishing the following additional reports:

- Initial Feasibility Report, published in February 2019, to inform the development of our PADR; and
- Supplementary Analysis Report, published in November 2020, to inform the development of our PACR.

These extra steps in our engagement process demonstrate that we have adopted a consultative and transparent approach in assessing the economic case for Project Marinus. In the remainder of this chapter, we explain how we have taken account of the feedback we received on our PADR and the Supplementary Analysis Report in developing this PACR.

In addition to acknowledging the valuable feedback from customers and stakeholders, we are also grateful to AEMO for its assistance throughout the RIT-T process, particularly in relation to market modelling issues. As explained in section 2.3, our approach in this PACR is to align our modelling with AEMO's latest inputs and assumptions as set out in its draft IASR. We are also grateful for AEMO's support in its role as the Victorian jurisdictional transmission planning body.

4.2 Feedback on our PADR

TasNetworks received 15 submissions on the PADR, including two confidential submissions. A full summary of each non-confidential submission is provided in Appendix 1.

We welcome the significant level of engagement from stakeholders and the feedback received in relation to our PADR. A wide range of issues were raised in stakeholders' submissions, with a number of submissions providing detailed observations regarding input assumptions and forecasts that may affect the relative costs and benefits of Project Marinus compared to other options. In addition to the detailed forecasting issues raised by stakeholders, the following themes emerged from stakeholder submissions:

- support for Project Marinus from some stakeholders, challenged by others;
- 'Who pays for Project Marinus?' remains a key issue for stakeholders;
- further consideration needs to be given to uncertainty, including COVID-19;
- some stakeholders support a staged approach to Project Marinus;
- cost-benefit analysis in the PADR queried by some stakeholders; and
- stakeholders expect the RIT-T to align with the 2020 ISP.

In the remainder of this section, we discuss of these themes in turn.

4.2.1 Support for Project Marinus from some stakeholders, challenged by others

The submissions provided a range of views on whether Project Marinus should proceed. Four submissions supported Project Marinus (Clean Energy Council, Hydro Tasmania, Tasmanian Minerals, Manufacturing & Energy Council, UPC Renewables), whilst three submissions strongly challenged the case for Project Marinus (Basslink, Energy Australia, Tasmanian Small Business Council). Other submitters either provided qualified support or made no specific comments in favour or against Project Marinus, but appeared broadly supportive.

We welcome the feedback received and note the range of views expressed. Our view is that the case for Project Marinus should be settled through the application of the RIT-T, in accordance with the Rules and the applicable AER guidelines. The purpose of this PACR is to conduct the final phase of that process to determine if Project Marinus should proceed. As explained in section 2.2, the 2020 ISP concluded that Project Marinus is an 'actionable ISP project with decision rules', which means that it should proceed if these decision rules are satisfied. While this conclusion is to be tested in this PACR, the 2020 ISP provides an important starting point for our assessment.

4.2.2 'Who pays' for Project Marinus

The majority of the submissions we received on the PADR highlighted the 'who pays' issue as a key concern in relation to Project Marinus. This issue was also raised in response to our Supplementary Analysis Report. We discuss this issue in further detail in section 9.1 of this PACR.

4.2.3 Treatment of uncertainty, including impact of COVID-19

A number of submissions raised the issue of uncertainty, with some stakeholders specifically commenting on the potential impact of COVID-19. Stakeholders highlighted uncertainty both in relation to the costs of Project Marinus and the benefits that it is expected to provide over its asset life. Four stakeholders suggested that uncertainty was such a significant issue that Project Marinus should not proceed within the timeframes envisaged by the PADR (Energy Australia, ENGIE, Origin Energy, Tasmanian Small Business Council). In addition, Energy Users Association of Australia (**EUAA**) highlighted concerns with the accuracy of project cost estimates, given ElectraNet's recent experience with Project EnergyConnect.

TasNetworks agrees with stakeholders that uncertainty is an important factor to consider in the RIT-T analysis. This point is highlighted by the AER's RIT-T guidelines, which includes the following commentary on uncertainty and risk:[47]

> "The future will be uncertain when RIT-T proponents apply the RIT-T. Therefore, the expected costs and market benefits of a credible option (and therefore the net economic benefit) should also be uncertain. This uncertainty may have a material impact on the selection of the preferred option."

TasNetworks agrees with the AER's observation that the future will always be uncertain. Whilst deferring an investment decision may be appropriate in some cases, uncertainty will be inherent in most investment decisions. Furthermore, it is incorrect to regard a decision to defer an investment as necessarily being a lower cost or lower risk option.

[47] AER, *Application guidelines, Regulatory investment test for transmission*, August 2020, page 49.

In relation to the impact of COVID-19 and the growth in DER on the case for Project Marinus, AEMO made the following observations in its 2020 ISP:[48]

> "While COVID-19 will have a noticeable impact in the next three to five years, the revised growth in DER has a more lasting impact, leading to much lower minimum demands and operational consumption in Victoria. This variability in operational demand, coupled with the increase in VRE to meet VRET, would increase the need for flexibility (storage and/or interconnection) to help balance demand and supply. This increases the value of early VNI West delivery (DP8),[49] and also favours candidates with earlier Marinus Link development (DP3 and DP5)."

It is evident from the 2020 ISP and AEMO's subsequent draft IASR that input assumptions will continue to change as new information becomes available. The RIT-T provides a robust framework for addressing uncertainty, through the application of scenario analysis and sensitivity testing. Our application of the RIT-T in this PACR, together with the adoption of AEMO's latest forecasts, should address stakeholders' concerns regarding the impact of uncertainty. In relation to project cost estimates, we have undertaken further work to ensure that the risks of unexpected increases are managed effectively. This issue is discussed in further detail in section 9.2.

4.2.4 Staged approach to Project Marinus

A number of stakeholders commented on the proposed staging of Project Marinus in the PADR, highlighting that staging assists in managing uncertainty (EUAA, Hydro Tasmania, Tasmanian Minerals, Manufacturing & Energy Council).

TasNetworks supports the concept of staging Project Marinus. As highlighted by submitters, staging the project is a potentially useful means of addressing the issues of risk and uncertainty, including construction risk. It is also closely related to the issue of option value, where additional value can be obtained by taking action to preserve opportunities to take different courses of action in light of new information.

4.3 Feedback on our Supplementary Analysis Report

In November 2020, we published our Supplementary Analysis Report, which responded to stakeholder feedback received on the PADR and updated the modelling result to reflect the scenarios, inputs and assumptions from the 2020 ISP. The modelling for this report focused on the preferred option identified in our

[48] AEMO, *2020 Integrated System Plan, July 2020*, page 74.

[49] Development path.

PADR and the 2020 ISP of 1500 MW, commissioned in two stages of 750 MW each. This report also highlighted the pace of transition in the NEM and stressed the importance of reaching final investment decision by financial year 2023-24. In addition to holding a webinar, we invited stakeholders to lodge submissions and we received 10 responses. A full summary of all the submissions is provided in Appendix 1.

In addition to raising the issues of 'who pays', stakeholders' submissions covered the following themes, each of which is discussed below:

- Stakeholder consultation;
- Recent state government announcements;
- Batteries as an alternative to Project Marinus;
- TRET and Battery of a Nation;
- Project benefits; and
- Staging of the two links.

4.3.1 Stakeholder consultation

Three submitters provided positive feedback regarding TasNetworks' stakeholder consultation (TMEC, TREA, UPC Renewables). For example, TREA commented that it is highly appreciative of the transparent way in which this process has been conducted, including the release of underlying assumptions, the publication of the material presented at the public consultation forum and the personal briefing and follow up information provided to TREA by Project Marinus staff.

However, the landholders of Buffalo and surrounding area were highly critical of the lack of engagement with landowners in Victoria that will be affected by the proposed project route. In December, we published the proposed route overview[50] and the subsequent unabridged Marinus Link Route Options Report.[51] Public release of these reports provided summary and in-depth evaluations pertinent to the concerns raised by these stakeholders. In addition to these reports, TasNetworks hosted a community webinar and multiple workshops and information sessions in Victoria to work with potentially impacted landowners and communities along the proposed HVDC route.

The submission from landholders was made before the release of the route options reports and we hope that the material released in conjunction with ongoing stakeholder and community engagement activities

[50] Marinus Link Proposed Route Overview, December 2020

[51] Marinus Link Route Options Report, TasNetworks, February 2021

adequately addressed comments raised by the landholders of Buffalo and surrounding area. Further information regarding stakeholder and community engagement undertaken by the Project Marinus team is available on our website.[52]

4.4 Recent Government initiatives

A number of submitters commented on the recent announcements by state governments in support of battery projects and REZs undermining the case for Project Marinus. The timing of these announcements meant that they were not considered in the cost benefit analysis presented in our Supplementary Analysis Report.

For some stakeholders, the recently announced projects are considered to be competitors to Project Marinus and cast doubt on the project's economic viability. In contrast, other submitters viewed the recent project announcements as indicating that the Step Change scenario is more likely to occur, or could possibly be overshot, therefore reinforcing the case for Project Marinus.

We have addressed the treatment of government policy initiatives in this PACR, as explained in section 2.3.2.

4.5 Batteries as an alternative to Project Marinus

The Bob Brown Foundation and TREA argued that batteries are likely to be more cost effective than Project Marinus. In making this case, both referred to a 2020 report from Mountain and Percy of the Victorian Energy Policy Centre. TasCOSS also referred to a recent report by Cornwall Insight Australia, which estimates that approximately 7,000 MW of battery storage projects are proposed or are currently in the planning process in Australia, of which almost 1,000 MW is set to be delivered by 2024. Hydro Tasmania argued that long term storage is required as part of a storage portfolio, but does not expand on this view in its submission.

In this PACR, we anticipate significant uptake of battery storage in a NEM with and without Project Marinus. We have undertaken further analysis to assess whether batteries are able to provide a more cost effective solution than Project Marinus and associated access to cost-effective Tasmanian deep storage. This analysis is presented in Chapter 8.

[52] Community Engagement, Project Marinus

4.6 TRET and Battery of a Nation

Both Bob Brown Foundation and TREA argued that the modelling approach to TRET is inappropriate. TREA describes the approach as creating:[53]

> "[..] a self-reinforcing loop of assumptions: the legislation implicitly assumes that Marinus will be built, the ISP assumes that the generation will be built, the ISP assumption that the generation will be built adds to the business case for building Marinus."

Bob Brown Foundation also criticised the modelling treatment of the costs of Project Marinus and Battery of the Nation, suggesting that the business case for each project assumes that the other one will proceed. The criticism made is that this is a "sleight of hand."

To address the concern raised, we can confirm that our modelling does not assume any Tasmanian pumped hydro investment to be a committed investment (i.e. expected to proceed irrespective of economics). Instead, all pumped hydro development in Tasmania is determined endogenously by the model based on least cost outcomes for the whole of system. We also note that the results in our Supplementary Analysis Report confirmed the findings in the 2020 ISP, which should provide stakeholders with comfort that our modelling approach is aligned with AEMO's independent modelling. The sensitivity analysis outlined in chapter 8 that replaces all the state-based schemes with a Commonwealth target should provide stakeholders with additional confidence on the overall value proposition of Project Marinus, with or without TRET or other state-based schemes.

4.7 Project benefits

The landholders of Buffalo and surrounding area raise concerns that the expected net economic benefits are sensitive to the modelling assumptions. Similar concerns were expressed by a number of other submitters, raising a range of different issues. Bob Brown Foundation and TREA commented that a breakdown of the project benefits should be provided.

We have addressed these comments in this PACR, particularly through the sensitivity analysis and section 7.6, which provides a breakdown of the sources of benefits from Project Marinus. Chapter 8 also explains how Project Marinus unlocks benefits across the NEM in the context of generation, storage and transmission projects in other regions.

[53] Tasmanian Renewable Energy Alliance (TREA) to the Project Marinus Supplementary Analysis Report, 8 December 2020, page 3.

4.8 Staging options for Project Marinus

Given the mixed perspectives on Project Marinus, it is not surprising that a range of views were expressed regarding the project's timing. Origin Energy argued that the project should be deferred until after the 2022 ISP has been published (at the earliest). UPC Renewables, on the other hand, argued that the project should be brought forward to 2026.

As noted previously in the document, we are adopting the new Rules, so the timing of each stage of the project will be determined by its inclusion in the optimal development path in the 2022 ISP and subsequent ISPs.

5 Description of the credible options

This chapter explains the ‘identified need’ that Project Marinus is intended to address, and describes each of the credible options. We also explain the base case against which the credible options are tested. The information presented in this chapter is substantially unchanged from the PADR, apart from providing updated information where appropriate.

Key messages

- The ‘identified need’ complies with the AER’s RIT-T Guidelines and is unchanged from the description we provided in the PADR.
- In accordance with the RIT-T, the credible options for Project Marinus are assessed against a base case. Under the base case, the lowest cost combination of generation, demand-side response, and storage options across the NEM is selected, assuming Project Marinus does not proceed. The base case also includes actionable ISP projects identified in the 2020 ISP and AEMO’s treatment of state government policies as described in section 2.3.2 of this PACR.
- The credible options outlined in the PADR were HVDC links with capacity increments of approximately 600 MW or 750 MW, which means that the credible options are 600 MW, 750 MW, 1200 MW or 1500 MW, with staging options.
- Consistent with the PADR, the preferred route for the HVDC transmission remains between Heybridge in Tasmania and the Latrobe Valley in Victoria, supported by upgrades to the North West Tasmanian AC transmission network.
- Our power system analysis indicates that the preferred option is technically feasible.

5.1 Identified need

The RIT-T requires that we should consider all ‘credible options’ that would meet the ‘identified need’. In the PADR, the identified need was described as follows:[54]

> “The characteristics of customer demand, generation, and storage resources vary significantly between Tasmania and the rest of the NEM. Increased interconnection capacity between Tasmania

[54] TasNetworks, *Project Marinus - Project Assessment Draft Report*, December 2019, section 4.1.

> and the other NEM regions has the potential to realise a net economic benefit by capitalising on this diversity."

The key drivers of benefit for this project, as outlined in the 2020 ISP, include:

- Thermal coal power retirements in Victoria (and the rest of the NEM);
- Access to high-quality wind resources in Tasmania;
- Deep storage capability of Tasmanian hydro generation; and
- Access to low cost pumped storage capability in Tasmania.

We did not receive any specific feedback from stakeholders in relation to the proposed wording of the identified need in the PADR. We have therefore maintained the description of the identified need in this PACR.

5.2 Base case

The AER's RIT-T Guidelines explains that:[55]

> "The base case is where the RIT–T proponent does not implement a credible option to meet the identified need, but rather continues its 'BAU activities'. 'BAU activities' are ongoing, economically prudent activities that occur in absence of a credible option being implemented."

Our market modelling examines the total integrated system costs of meeting customers' future electricity needs to 2050. Under the base case, the model selects the lowest cost combination of generation, storage, and demand-side response across the NEM, on the assumption that Project Marinus does not proceed. Committed and anticipated generation and transmission projects, including actionable ISP projects, also form part of the base case. The model allows for unserved energy, if this results in a lower total cost.

As such, a complete range of investments and operating expenditure options are considered in order to minimise the total costs in present value terms of meeting customers' future electricity requirements. In order for Project Marinus to proceed, it must achieve a lower cost solution in present value terms than the base case.

[55] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, August 2020, p. 21.

5.3 Credible options

We described four credible options in the PADR:

- Option A: A 600 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- Option B: A 750 MW symmetrical monopole HVDC interconnector, including associated AC transmission network augmentation and connection assets.
- Option C: 1200 MW HVDC interconnector, comprising two 600 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.
- Option D. 1500 MW HVDC interconnector, comprising two 750 MW symmetrical monopole HVDC interconnectors, plus associated AC network upgrades.

Table 5 below provides a high-level description of each credible option, noting that there may be variations in the detailed implementation in light of emerging information. A discussion of the technical considerations relating to the scope of the preferred options is provided in Appendix 2.

The development of some AC route sections may be advanced in the light of drivers other than Project Marinus, including Tasmanian customer connection requirements, for example associated with large wind and hydrogen developments proposed to be in service earlier than 2027. Some of this advancement may initially provide unregulated services (for example between Staverton and Hampshire Hills), whilst other elements may provide earlier regulated services (for example between Palmerston and Sheffield).

Each of the Credible options for Project Marinus is being designed with at least 10 to 20 per cent short term overload capability, for a period of at least 15 minutes, enabling it to provide bi-directional Frequency Control Ancillary Services (**FCAS**) even when operating at full nominal power flows.

Table 5: Outline of the credible options

<table>
<tr><th>Credible option</th><th>Main elements of this option</th></tr>
<tr><td>A. 600 MW interconnector</td><td>A single 600 MW HVDC interconnector using voltage source converter technology and symmetrical monopole configuration. Converter stations located at Heybridge (near Burnie) in Tasmania and at Hazelwood area in Victoria. HVDC transmission to use buried cable for the entire route.
AC network augmentations in Tasmania comprise:
• Construction of a new 220 kV switching station at Heybridge adjacent to the converter station;
• Establishment of a new 220 kV switching station at Staverton;
• Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie; and
• Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield.
Limited AC augmentations may be required in Victoria as there is sufficient transmission capacity to accommodate power flows to or from the interconnector. Limited 500 kV connection assets are required to connect the HVDC converter station to the Hazelwood area.</td></tr>
<tr><td>B. 750 MW interconnector</td><td>Like Option A, but with converter stations and HVDC cable rated to 750 MW.
AC network augmentations are identical to Option A.</td></tr>
<tr><td>C. 1200 MW interconnector</td><td>Two parallel 600 MW HVDC interconnectors on the same alignment as Option A.
AC network augmentations in Tasmania to be constructed for the first HVDC interconnector comprise:
• Construction of a new 220 kV switching station at Heybridge adjacent to the converter station;
• Establishment of a new 220 kV switching station at Staverton;
• Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie; and
• Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield.
Additional AC network augmentations in Tasmania to be constructed for the second HVDC interconnector comprise:
• Construction of a new double-circuit 220 kV transmission line from Heybridge to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor; and
As noted for Option A, limited AC augmentations may be required in Victoria.</td></tr>
<tr><td>D. 1500 MW interconnector</td><td>Like Option C, but with converter stations and HVDC cable rated to 750 MW.
AC network augmentations are similar to Option C with enhanced line ratings.</td></tr>
</table>

5.4 Technical feasibility

A credible option must be technically feasible, which means that it is capable of providing the services that the proponent intends it to provide and comply with relevant laws, regulations, and administrative requirements. In addition, it must address the technical requirements of the power system, including the following considerations:

- System strength;
- Maximum contingency size; and
- Inertia.

The technical requirements of the power system may have implications for other characteristics of each credible option, most notably the link capacity and the route selection. A number of technical choices will also need to be made, which will also be influenced by the requirements of the power system, cost and performance considerations, including:

- Converter technology;
- Link configuration; and
- Cable technology.

These matters were discussed in the feasibility stage of the project and further addressed in the PADR. In Appendix 2 of this PACR, we have assessed the technical feasibility for a 1500 MW Project Marinus. By undertaking detailed technical analysis for the option with the greatest interconnection capacity, it demonstrates that the remaining credible options are also technically feasible.

5.5 Costs of each option

Our PADR presented our cost estimates for each credible option in accordance with the RIT-T requirements. A general concern was raised by stakeholders that such cost estimates are prone to significant upward revisions as projects progress through their planning and development phases. In particular, some stakeholders pointed to Project EnergyConnect, which experienced significant cost increases during the planning phase.

To address stakeholders' concerns, we engaged a consortium of independent engineers[56] led by Jacobs to conduct a detailed review of our project cost estimates. While Jacobs' review focused principally on our cost

[56] The consortium of independent engineers include Jacobs, Mott MacDonald and Elia Grid

estimates for the 1500 MW option, the results were also used to inform our cost estimates for the other credible options.

Jacobs has substantial international experience with major transmission projects, including interconnectors. In addition to leveraging this expertise and knowledge, our terms of reference required Jacobs' review to have regard to and comment on (without limitation):

- the principles governing the establishment of sound expenditure forecasts for project planning purposes;
- the current status of the project and the extent to which the forecasts may be subject to revision, for example to reflect the outcomes from competitive tendering;
- the appropriateness of TasNetworks' proposed scope of works and project schedule;
- the consistency and reasonableness of TasNetworks' forecasting assumptions;
- the identification and inclusion of all relevant proposed in-house and outsourced costs to ensure that all activities are included in the expenditure forecasts without any double-counting or omissions;
- the completeness and accuracy of TasNetworks' financial models that have been used to combine the various input data and assumptions in the production of the expenditure forecasts;
- appropriate allowances for project risk; and
- the application of external benchmark information to our cost estimates.

The Jacobs cost review was conducted on a probabilistic estimation basis that identifies each of the significant cost components; determines the likely range based on previously completed projects and the associated probability distribution of each component; and undertakes a sampling process to generate a probability distribution of the total project costs. The Association for the Advancement of Cost Engineering recommends utilising the probabilistic estimation basis for all projects over $200 million in value.

Each possible outcome value of the total project cost can be given a 'P' value which indicates its likelihood of occurrence. For instance, a P10 cost is the project cost with sufficient contingency to provide 10 per cent likelihood that this cost would not be exceeded. A P90 cost is the project cost with sufficient contingency to provide 90 per cent likelihood that this cost would not be exceeded. The contingency included in the expected project cost is the median output from a probabilistic analysis of possible outcomes.

The Jacobs reports provides an expected project cost for the delivery of Project Marinus of $3,481 million ($2020).[57] This estimate is inclusive of contingency allowance based on a median probabilistic scenario.[58] The report also provides an overall range for the total project estimate of $3.1 billion to $3.8 billion ($2020). This range is based on P10 and P90 views of the total project contingency allowance. Our sensitivity analysis confirms that the preferred option is expected to deliver a strongly positive net economic benefit, even if the upper cost range estimated by Jacobs eventuates (section 7.5.5).

Figure 5 shows a comparison of the likely range of costs assumed at the PADR stage, in the 2020 ISP and now, at the PACR stage. The cost estimate for the PADR was based on a “neat” estimate ($2.8 billion, $2020), whereas the cost estimate for the 2020 ISP was expanded to include an accuracy allowance (commonly referred as the base estimate). The 2020 ISP subsequently applied a 30 per cent deterministic contingency on the base estimate of $3.2 billion ($2020).

[57] The Jacobs cost estimate is in June 2021 dollars. The modelling undertaken for this PACR is in $2020. Therefore, the Jacobs cost estimate was de-escalated by 1.11 per cent to account for inflation (March 2020 – March 2021, Australian Bureau of Statistics), addition of interest during construction charge and subtraction of $50 million in grant funding received by TasNetworks.

[58] Refer to Project Marinus Cost Estimate Report prepared by Jacobs, released as Attachment 3 with this report.

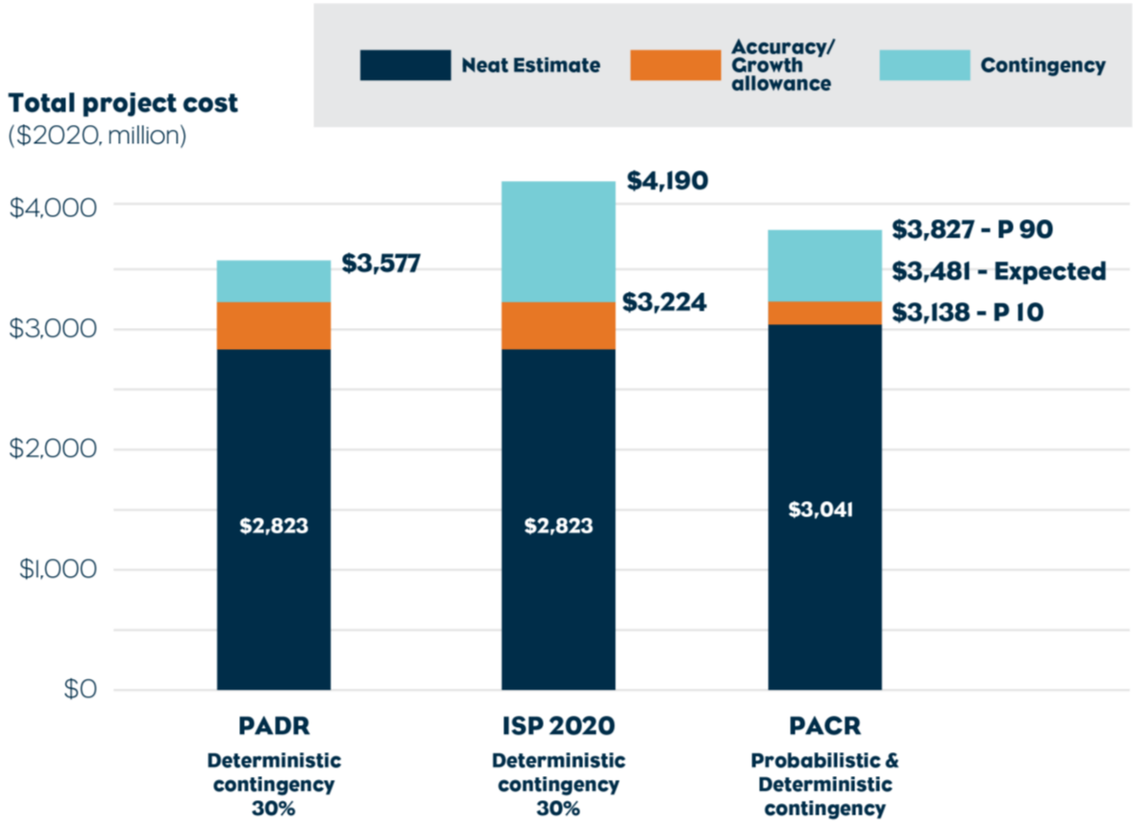

Figure 5: Range of total project cost outcomes comparison ($ million, $2020)[59]

It can be seen that whilst the underlying cost estimate (i.e. the "neat" estimate before allowances and contingencies) has increased by 10 per cent since the PADR, the contingency amount has reduced such that the expected cost is comparable to the PADR estimate of around $3.5 billion. This is explained by the more advanced status of the scope definition, engineering, route alignment and other matters, leading to more certainty.

The cost estimate for the remaining three credible options are scaled, based on quotes received from cable and converter station suppliers, AC transmission cost estimators, and the detailed review undertaken by Jacobs. Table 6 provides a summary of the expected cost estimate for each credible option.

[59] The PADR and ISP costs have been escalated from their original 2019 basis to 2020 prices. Inflation rate of 2.2 per cent based on ABS data for March 2019 to March 2020.

Table 6: Estimated costs of each option ($ million, 2020 dollars)

Project Marinus Option	600 MW	750 MW	1200 MW	1500 MW
Capital cost	2,034	2,185	3,284	3,481
Annual operating cost	27.7	27.7	36.4	36.4
Annualised cost (WACC – 4.8%)[60]	135	143	211	221
Annualised cost (WACC – 3.8%)	120	127	187	197

In the case of the 1200 MW and 1500 MW options, which are built in two stages, the cost of the second stage is materially lower than the first stage, as shown in the table below.

Table 7: Estimated cost breakdown for each stage of 1200 MW and 1500 MW option ($ million, 2020 dollars)

Project Marinus two-stage options	1200 MW			1500 MW		
Stage (Total capacity)	Early works	Stage 1 (600 MW)	Stage 2 (1200 MW)	Early works	Stage 1 (750 MW)	Stage 2 (1500 MW)
Stage cost	189	1,931	1,164	189	2,081	1,210
Stage cost as percentage of total project cost (%)	6%	59%	35%	5%	60%	35%

The second stage of the project benefits from economies of scale as the expenditure incurred with the following activities remains largely unchanged for a single or a multi-stage interconnector project:

- community engagement and environmental approvals in Victoria and Tasmania;
- undertaking detailed technical system studies and economic analysis;
- easement acquisition and compensation along the preferred corridor;
- project management costs (including tendering activities);

[60] Consistent with the 2021 Draft IASR, the WACC of 4.8 per cent is used for all scenarios, except Slow Change. Slow Change uses a WACC of 3.8 per cent.

- supplier costs for major components due to common design;
- undertaking horizontal directional drilling for shore crossings at the Tasmanian and Victorian coasts; and,
- common civil works activities.

Our discussions with the converter and cable suppliers also highlight the importance of the spacing between the commissioning of the two links, which can be up to 2-3 years apart without incurring any additional expenditure. On the basis of this advice, the PACR modelling tests the earliest possible commissioning timeline of 2027 (Stage 1) and 2029 (Stage 2). It is estimated that Project Marinus completed as a two-staged project spaced no more than 2-3 years apart provides up to $600 million in total project cost savings as compared to two standalone 750 MW links. These savings are realised from procuring volume discount from cable and converter station manufacturers and avoiding the need to remobilise workforce related to project planning and delivery.

Given the comprehensive nature of the terms of reference for Jacobs' review and their substantial experience, stakeholders should have confidence that our project cost estimates are robust. Jacobs' independent expert report is provided as Attachment 3 to this PACR. The effective management of project costs is discussed in further detail in section 9.2 of this PACR.

5.6 Options considered but not assessed further

The PSCR raised the possibility of adding a second pole to Basslink, thereby converting it from a monopole to a bipole link. From an engineering perspective this would involve:

- Constructing a second HVDC converter at each end;
- Augmenting the overhead DC transmission sections to carry an additional conductor, adding a second high-voltage DC cable (in both the undersea and underground sections); and
- Augmenting the transmission network into George Town to increase its capacity.

After examining this option more closely, we have found that this option is infeasible on the following technical grounds:

- Due to system strength constraints, the second pole must use Voltage Source Converter technology. The existing Basslink converters use line commutated converter technology. Adding a Voltage Source Converter second pole to an existing line commutated converter link has only been done once (the Skagerrak 3/4 Norway to Denmark interconnector) and proved technically very challenging.

- Engaging HVDC equipment vendors to provide a bespoke solution, at a time when HVDC is in high demand globally, would likely prove very difficult and far more expensive than a greenfield 600 MW or 750 MW link.
- Increasing the capacity of Basslink by a further 600 MW or 750 MW does not offer any route diversity. Therefore, a single event could render the entire upgraded Bass Strait interconnector inoperable.
- Completing the works would require extensive outages of the existing Basslink interconnector.

In addition to these technical reasons, an agreement would need to be reached with Basslink's owners. Furthermore, a range of regulatory and commercial issues, stemming from the fact Basslink Pty Ltd is a Market Network Service Provider, would need to be resolved.

For these reasons, the option of adding a second pole to Basslink was not evaluated further.

6 PACR modelling

Key messages

- In developing our PADR, we engaged Ernst & Young to conduct the market modelling, which is a key element of the RIT-T process.
- Following the publication of the PADR, Ernst & Young updated its market modelling to adopt the scenarios and input assumptions in the 2020 ISP. The updated model results, which were presented in our Supplementary Analysis Report, were consistent with AEMO's findings in the 2020 ISP that Project Marinus forms part of the optimal development path. Furthermore, our modelling also confirmed that the optimal timing for Project Marinus should be brought forward if the Step Change scenario eventuated.
- In this PACR, we build on the modelling that we undertook in the Supplementary Analysis Report by adopting AEMO's latest input assumptions. As explained in section 2.3.2, our modelling also adopts AEMO's current treatment of the various government policy initiatives, some of which have been announced since the publication of our Supplementary Analysis Report.
- To augment our cost-benefit analysis, we have undertaken a range of sensitivity studies to understand the impact of key variables on the net economic benefit attributable to Project Marinus. This sensitivity testing essentially provides a 'what if' analysis, to determine whether the investment signal provided by the RIT-T is sensitive to particular assumptions.
- By continuing to engage Ernst & Young to conduct the modelling on our behalf, stakeholders should be confident that the methodology is robust, transparent and independent. To assist in this regard, the report from Ernst & Young is provided as Attachment 1 to this PACR as well as a comprehensive inputs assumptions workbook.
- The recent market notices related to Tasmanian FCAS are likely to increase the benefits provided by Project Marinus. However, the GHD market analysis for the ancillary services benefits was not updated from the PADR modelling. The GHD report is republished as Attachment 2 to this PACR for convenience.

6.1 Modelling approach

6.1.1 Overview

The RIT-T requires a number of different classes of market benefits to be considered:[61]

(a) Changes in fuel consumption arising through different patterns of generation dispatch;

(b) Changes in voluntary load curtailment;

(c) Changes in involuntary load shedding, with the market benefit to be considered using a reasonable forecast of the value of electricity to consumers;

(d) Changes in costs for parties, other than the transmission network service provider, due to:

(i) Differences in the timing of new plant;

(ii) Differences in capital costs; and

(iii) Differences in the operational and maintenance costs;

(e) Differences in the timing of transmission investment;

(f) Changes in network losses;

(g) Changes in ancillary services costs;

(h) Competition benefits being net changes in market benefit arising from the impact of the credible option on participant bidding behaviour;

(i) Any additional option value (meaning any option value that has not already been included in other classes of market benefits) gained or foregone from implementing the credible option with respect to the likely future investment needs of the market;

(j) Negative of any penalty paid or payable (meaning the penalty price multiplied by the shortfall) for not meeting the renewable energy target, grossed-up if not tax deductible to its value if it were deductible; and

(k) Other benefits that the TNSP determines to be relevant and are agreed to by the AER in writing.

Our PADR for Project Marinus explained that Ernst & Young's market modelling examines the total integrated system costs of meeting customers' future electricity needs. We explained that the model selects the lowest cost combination of generation, storage, and demand-side response, in addition to considering the optimal timing and capacity of other interconnector options apart from Project Marinus. As a consequence, therefore,

[61] AER, *Final Regulatory Investment Test for Transmission*, June 2010, Clause (5).

each option for Project Marinus was accompanied by different investments across the NEM, without favouring any particular type of solution or technology.

In broad terms, the modelling approach in the PADR for Project Marinus is therefore aligned with the ISP's objective, which is to identify the combination of investments that will address customers' needs at the lowest cost. As already noted, we updated the PADR results in our Supplementary Analysis Report in response to stakeholder feedback that our modelling should be aligned with the 2020 ISP and AEMO's latest inputs and assumptions. As explained in section 2.3.1, in this PACR we have adopted the same modelling approach but updated our inputs to reflect AEMO's draft IASR while maintaining scenarios aligned with the 2020 ISP.

We have maintained our earlier decision not to assess two categories of market benefits, being competition benefits and option value. As explained in the PADR, our view is that the inclusion of these market benefits would not affect the ranking of the credible options or have a material impact on the estimated net economic benefit. Stakeholders did not comment on this issue. The remaining benefits have been modelled using the assessment tools set out in Figure 6 below.

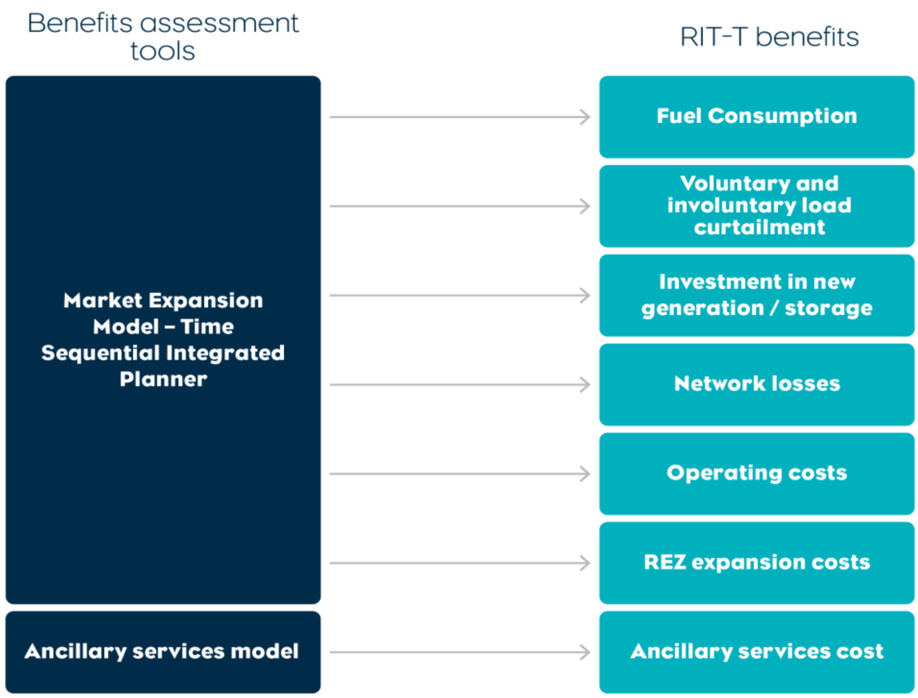

Figure 6: Assessment tools for estimating the RIT-T benefits

Typically, market benefits are estimated by combining the output from separate models.[62] In contrast, Ernst & Young's 'Time Sequential Integrated Resource Planner' is a market expansion model that adopts an integrated approach to estimating market benefits. This approach is more efficient and comprehensive from a modelling perspective, as it avoids the need to ensure consistency across separate models.

Ernst & Young's model considers changes in network losses on interconnectors, but not intra-regional network losses. Our assessment is that the impact of Project Marinus on intra-regional network losses is likely to be modest and will not affect the modelling outcomes. On this basis, the additional modelling required to estimate intra-regional network losses 'with' and 'without' Project Marinus was not warranted. Instead, intra-regional changes are accounted for by modelling the REZ transmission limits their associated network expansion costs.

In relation to ancillary services modelling, we engaged GHD to undertake an independent assessment of the impact of Project Marinus. Ancillary services perform an essential role of ensuring stable power system operation on a second-by-second basis, especially when subjected to unforeseen contingency events. While generators and other network devices directly provide ancillary services, interconnectors offer the ability to transfer some types of ancillary services between regions, thereby lowering the overall cost of ancillary services within the NEM.

Stakeholders did not raise concerns regarding GHD's modelling of ancillary service costs. While we have retained GHD's earlier assessment of the ancillary service benefits provided by Project Marinus, recent market experience suggests that these benefits may be higher than GHD estimated. In particular, AEMO's market notices[63] issued on 1 March 2021 regarding the reduction in Tasmanian load relief factor and the reclassification of a non-credible contingency event in Tasmania, illustrate the potential value of Project Marinus through enhanced sharing of FCAS with mainland Australia. For this PACR, however, GHD's ancillary services benefits modelling methodology has not been updated since December 2019 and is republished as Attachment 2.

6.1.2 Model description

The market expansion model takes the projected NEM demand over the study period as an input to determine the optimal generation and transmission interconnector investments to supply this demand, such that the overall cost of supply to the entire NEM is minimised. The optimal generation mix may consist of both existing generation and assumed new generation.[64]

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[62] Refer to section 6.4.3.

[63] AEMO Market Notices, 83867 and 83081.

[64] New generation types include traditional generation technologies, as well as large-scale solar and wind generation, pumped hydro storage, and grid-scale batteries.

Voluntary load reduction (i.e. demand-side participation) is also included in the model and will be adopted when this results in a lower cost of supply. In addition to ensuring customer load is supplied, the model also applies simplified operational constraints to ensure there are sufficient reserves of dispatchable generation during high demand periods, and to ensure that the NEM's inertia requirements are met.

Taking all these factors into account, the model will determine the most appropriate timing of new generation and energy storage investments, and the retirement of existing generation that reaches end-of-life or is uneconomic, across all NEM regions, to yield the overall least cost outcome over the entire study period. The model expresses the total cost of supply in present value terms.

For a particular scenario, the model is run multiple times: the first run is to determine the NEM-wide costs which would occur without Project Marinus, and then subsequent model runs are undertaken with alternative credible options in place. Each model run will optimise the generation and storage investments to minimise supply costs, i.e. the different projects will be identified assuming different capacities and timings for Project Marinus. The difference in NEM-wide resource costs between these two states of the market represents the net economic benefit resulting from that Project Marinus option.

Further detail of the market expansion model can be found in Attachment 1.

6.2 Assumptions and input data

6.2.1 Model input data

As noted in section 2.3.1, we have adopted AEMO's draft IASR for the purposes of this PACR. TasNetworks will release a detailed inputs and assumptions workbook that outlines all the inputs that are used in the PACR modelling.

6.2.2 Hydro Tasmania's expansion projects

Consistent with the 2020 ISP, our PADR and Supplementary Analysis Report, we have considered Hydro Tasmania's proposed capacity expansion projects discussed in its series of White Papers.[65] Although these capacity expansions are not committed projects, they relate to the need to replace ageing turbine runners; expenditure which Hydro Tasmania will incur regardless of Project Marinus. Hydro Tasmania has advised that if Project Marinus does not proceed, it will undertake like-for-like turbine runner replacements. If Project Marinus does proceed, it will replace the existing turbine runners with runners of higher capacity, at

[65] For example, Hydro Tasmania's Battery of the Nation, Unlocking Tasmania's energy capacity, December 2018.

essentially the same cost. This would result in 100 MW of additional generation capacity in the West Coast region of Tasmania, at no incremental cost.

Hydro Tasmania presents an argument in the same paper that Tarraleah Power Station requires substantial remedial works and a viable option is to replace the station with one of substantially higher capacity (220 MW versus current 70 MW) at a similar cost to refurbishing the existing station.

Therefore, we have introduced changes to Hydro Tasmania's power schemes in our modelling, for simulations in which Project Marinus is implemented:

- West Coast power schemes' capacities are increased by a total of 100 MW; and
- the Tarraleah's capacity is increased by 150 MW.

Simulations of the base case (i.e. Project Marinus does not proceed) assume existing capacities, on the basis that Hydro Tasmania has advised it would not proceed with capacity upgrades in the absence of Project Marinus.

Hydro Tasmania's White Paper also discusses 400 MW of latent existing hydro capacity in the Tasmanian system through greater interconnection and 90 MW of additional capacity that could be gained from Gordon Power Station by maintaining Lake Gordon at a higher storage level. These effects, which are representative of the existing hydro system, are already included in Ernst & Young's model. This modelling of the Tasmanian hydro scheme in the case where Project Marinus proceeds is consistent with the approach adopted by the 2020 ISP.

6.2.3 Timing of other actionable ISP projects

Noting that the ISP considered in excess of 100 different network and non-network augmentation before determining its optimal development path, we have assumed that interconnector projects identified in the 2020 ISP will proceed, as set out in the following table.

Table 8: Timing of 2020 ISP interconnector projects[66]

Proposed upgrade	RIT-T status	Our modelling assumption
VNI Minor	RIT-T Complete	Treated as a committed project, assumed to be commissioned in 2022.
EnergyConnect	RIT-T Complete	Treated as a committed project, assumed to be commissioned in 2024.
HumeLink (formerly SnowyLink North)	PADR complete	Treated as a committed project, assumed to be commissioned in 2025.
Central-West Orana REZ Transmission Link	RIT-T not commenced	Treated as a committed project, assumed to be commissioned in 2024.
VNI West	PSCR Complete Pending PADR (December 2021)[67]	Treated as an anticipated project, assumed to be commissioned in 2027.[68]

6.2.4 Assessment period

The RIT-T analysis has been undertaken over a 30-year period, from financial years 2020-21 to 2049-50. We consider that this assessment period is consistent with the principles set out in section 3.12 of the RIT-T Application Guidelines, which state:[69]

> "The duration of modelling periods should take into account the size, complexity, and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the credible option. This means that by the end of the modelling period, the network is in a 'similar state' in relation to needing to meet a similar identified need to where it is at the time of the investment.
>
> […] In the case of very long-lived and high-cost investments, it may be necessary to adopt a modelling period of 20 years or more."

[66] AEMO, *2020 ISP, July 2020*, Table 14, page 88.

[67] VNI West Regulatory Investment Test for Transmission – progress update, AEMO communications, March 25 2021.

[68] Consistent with 2020 ISP findings, VNI West is not commissioned in the Slow Change scenario.

[69] AER, *Application Guidelines, Regulatory Investment Test for Transmission*, August 2020.

It is noted that the credible options have asset lives that extend beyond the end of the assessment period. To ensure that the long-lived capital costs of these assets are captured appropriately in the 30-year assessment period, the modelling employs annualised capital costs, calculated as annuities over the full expected life of the relevant assets.

A number of stakeholder submissions raised questions in relation to this approach, particularly the implicit assumption that the benefits beyond the assessment period at least cover the remaining cost of the asset. In response to these questions, we published an explanatory paper and accompanying spreadsheet which explained that in order to ensure that the net economic benefit of all options are compared on a like-for-like basis, the evaluation of long-lived capital projects can be undertaken in one of three ways:

A. Examine the costs and benefits over the entire life of the project.

B. Adopt a shorter study period, say 30 years, and attribute a terminal value to the assets at the end of the period.

C. Adopt a shorter study period, say 30 years, recognising the annualised cost of the assets employed.

We have updated this explanatory paper and included it as Appendix 3 to this PACR. It explains that the approach we have adopted obviates the need for a terminal value, and is consistent with good practice in relation to conducting economic evaluations. The updated explanatory note also demonstrates that the net economic benefit of the project using a terminal value calculation is closely aligned with the annualised cost benefit method.

6.2.5 Discount rate

In relation to the discount rate or cost of capital, paragraph 14 of the RIT–T specifies that:

> “The discount rate in the RIT–T must be appropriate for the analysis of a private enterprise investment in the electricity sector and must be consistent with the cash flows that the RIT-T proponent is discounting. The lower boundary should be the regulated cost of capital.”

For the purpose of the analysis presented in this PACR, we have adopted the discount rates proposed in AEMO’s draft IASR:[70]

- 4.8 per cent real pre-tax has been adopted for all scenarios, except the Slow Change scenario; and
- 3.8 per cent for the Slow Change scenario.

[70] AEMO, *Draft 2021 Inputs, Assumptions and Scenarios Report*, December 2020, page 105.

We note that stakeholders, in their response to the draft IASR, provided a diverse opinion on the appropriate discount rate. Given the stakeholders views, we have applied sensitivity analysis to the discount rate, in accordance with the AER's RIT-T Guidelines.

6.3 Scenarios and weighting

In our PADR, we adopted the following four scenarios which were closely aligned with AEMO's scenarios in 2019, as explained below:

- **Global slowdown.** This scenario essentially represented a future in which there is a sustained global economic slowdown, resulting in reduced demand for both commodities and energy. This scenario included reduced national energy demand, including the loss of all mainland aluminium smelters; a 25 per cent reduction in gas prices; and termination of all emissions reduction schemes. This scenario was closely aligned with AEMO's 2019 'Slow Change' scenario.
- **Status quo/current policy**. This scenario represented the median-projection NEM demand profile and a continuation of existing policies. Under this scenario, the Mandatory Renewable Energy Target was included in its current form and state-based renewable energy targets were assumed to be implemented. This scenario was closely aligned with AEMO's 2019 'Central' scenario.
- **Sustained renewables uptake**. This scenario assumed that the recent momentum in renewable investment would be sustained and, consequently, a number of coal-fired generators retire three to five years earlier than the nominated closure dates. This scenario was closely aligned with AEMO's 2019 'Fast Change' scenario.
- **Accelerated Transition to a Low Emissions Future**. This scenario represented a future in which there is a concerted international effort to meet the objectives of the Paris Climate Accord. Under this scenario, load was assumed to increase due predominantly to the accelerated transition to electrification of the transport sector to support a lower emissions trajectory. This scenario was aligned with AEMO's 2019 'Step Change' scenario.

We explained that AEMO subsequently developed a fifth scenario, 'High DER', for which we had no direct equivalent. This scenario essentially involved a more rapid consumer-led transformation of the energy sector, leading to increased adoption of DER and accelerated change in the generation sector. In our PADR, we applied an equal weight to each of the four scenarios, but did not include the 'High DER' scenario as it had not been developed at that time. In our Supplementary Analysis Report, we extended our assessment of Project Marinus to include the 'High DER' scenario and thereby ensured that our modelling was aligned with AEMO's 2020 ISP.

In terms of scenario weightings, we consider equal weighting to AEMO's five scenarios, as this analysis will provide a useful comparison with our analysis in the PADR. In addition, AEMO's 2020 ISP indicates that a

67 per cent Central scenario and 33 per cent Step Change scenario weighting would be appropriate, as shown in the table below.

Table 9: 2020 ISP's Proposed Scenario Weightings for Project Marinus[71]

Project	Responsible TNSP(s)	Identified need	ISP candidate option†	Scenarios of relevance for TNSP under ISP Framework
Marinus Link (with decision rules) ‡ **PADR completed in December 2019**	TasNetworks and AEMO Victorian Planning	The characteristics of customer demand, generation and storage resources vary significantly between Tasmania and the rest of the NEM. Increased interconnection capacity between Tasmania the other NEM regions has the potential to realise a net economic benefit by capitalising on this diversity.	Marinus Link is a second, and potentially third, HVDC cable interconnection between Tasmania and Victoria. It is proposed with a transfer capability of 750 MW (one cable) or 1,500 MW (two cables).	Central with TRET (67%), and Step Change (33%)

† Indicative outline of the recommended option for project delivery
‡ These requirements can be assessed during the RIT-T process and will be confirmed by AEMO during an ISP feedback loop process with the TNSP once the decision rules eventuate. These projects are also critical to address cost, security and reliability issues.

As explained in section 3.3, we are adopting the new ISP Rules for the final stage of the RIT-T process for Project Marinus. Given this approach, it is appropriate to consider AEMO's focus on the Central and Step Change scenarios and their likely weightings, in addition to presenting the modelling results using an equal weighting across all five scenarios.

6.4 Input and assumptions deviations from 2020 ISP

As noted in previous chapters, a key purpose of this PACR is to update the modelling in light of stakeholder feedback and AEMO's latest inputs and assumptions. In accordance with the Rules, this section explains the rationale for inputs and assumptions that diverge from the 2020 ISP. The modelling for this PACR commenced shortly after the final submissions were received from stakeholders in January 2021. Therefore, the early closure of Yallourn Power Station, announced in early March 2021, is not explicitly modelled in this PACR.[72]

[71] AEMO, *2020 Integrated System Plan*, July 2020, Table 12, page 87.

[72] The latest retirement for the Yallourn Power Station retirement assumed for the studies is a unit by unit retirement commencing in 2029 and concluding in 2032.

6.4.1 2021 draft IASR

As already noted, for the purpose of this PACR, we have updated the inputs and assumptions adopted in the 2020 ISP to reflect AEMO's draft IASR. In our view, adopting AEMO's latest inputs and assumptions is preferable to retaining the inputs and assumptions that were adopted in the 2020 ISP, or partially updating the 2020 ISP data. By adopting the latest AEMO data, we ensure that our modelling is as transparent and objective as possible.

In comparison to the Slow Change scenario of the 2020 ISP, the draft IASR proposes that the Slow Change scenario include the continued growth in uptake of distributed PV, particularly in the short-term in response to a number of incentives assumed to be implemented as part of a COVID-19 recovery plan. The updated scenario narrative also suggests that the extension of technical life of coal-fired generators will not be pursued – instead allowing market forces and reduction in operational demand to determine the scenario outcomes. The PACR modelling adopts the updated narrative associated with the Slow Change scenario. Therefore, the modelling for this report allows economic retirements of coal fired generators to occur in all scenarios. Economic retirements are permitted from 2024 onwards, on the basis of the three year notice of closure Rule.[73]

6.4.2 State-based renewable energy schemes

As explained in section 2.3, AEMO proposes to adopt the TRET and the New South Wales Electricity Infrastructure Roadmap across each of its scenarios.[74] To align our modelling with AEMO's current views, our modelling assumes that these schemes will be achieved. We note that these targets may appear to be ambitious today, but recent experience illustrates the rapid pace of change across the sector and the rate of growth of renewable generation.

6.4.3 Modelling refinements

The modelling for this PACR leverages the proprietary modelling resources of Ernst & Young for renewable energy traces, inertia and reserve constraints.

The Tasmanian hydro system continues to be represented as a 10-pond system in the modelling for this PACR in contrast to the 2020 ISP modelling, which is based on a 7-pond system. In addition, the reserve and inertia

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[73] Australian Energy Market Commission, *Generator three year notice of closure, Rule determination*, 8 November 2018.

[74] Consistent with the Draft IASR, the Slow Change scenario assumes achieving a slightly reduced target of 29 TWh in the financial year of 2031-32.

constraints detailed in the Ernst & Young attachment released with our PADR continue to be used. The 2020 ISP's market modelling paper indicates that a more iterative process was followed wherein market modelling results are investigated through power system analysis to ensure that the reliability and system security needs of the power system will be met.[75] In contrast, Ernst & Young's time sequential resource planning for capacity expansion ensures the power system needs are met on an hourly basis.

The modelling for this PACR also uses Ernst & Young's proprietary renewable energy resource traces for each of the 35 REZs and data from AEMO's January 2021 generator information paper[76]. This data has been updated from that adopted in the 2020 ISP, and therefore it is appropriate to adopt it in this PACR. The inputs, assumptions and scenario worksheet outlining the modelling information is released in conjunction with this PACR.

[75] AEMO, *2020 ISP*, Appendix 9.

[76] NEM Generator Information, AEMO, January 2021.

7 Economic benefit results

This chapter presents the results of the cost-benefit analysis for Project Marinus. The cost benefit analysis employs the modelling approach described in the previous chapter.

Key messages

- We have updated our modelling to assess the economic case for Project Marinus using the 2020 ISP scenarios and AEMO's latest inputs and assumptions. It shows that each credible option delivers a net economic benefit across all scenarios.
- The preferred option is a 1500 MW HVDC interconnector, comprising two 750 MW HVDC interconnectors, plus associated AC network upgrades.
- Our analysis of recent changes in the NEM suggests that the current trajectory is consistent with the Step Change scenario. The rapid rate of change and Project Marinus' potential value in smoothing the transition as coal plant retires, provides the backdrop for pursuing the earliest commissioning of the project in 2027 and 2029.
- The timing of each stage of the project will be determined by its inclusion in the optimal development path in the 2022 ISP and subsequent ISPs.
- Our sensitivity analysis does not raise any issues in relation to the adoption of the preferred option. Our analysis shows, for example, that the net economic benefit of the project is unchanged despite a further 30 per cent reduction in battery costs.

7.1 Net economic benefit results

The net economic benefit is calculated in present value terms as the difference in total NEM costs with and without various Project Marinus options, minus the costs of the relevant option. The 'without Project Marinus' case is modelled to identify the lowest costs of meeting customers' future demand for electricity, assuming that Project Marinus does not proceed.

The credible options for Project Marinus are summarised in the table below, noting the detailed implementation may introduce some changes at the margin.

Table 10: Summary of the credible options[77]

Credible option	Main elements of this option
A. 600 MW interconnector	A 600 MW HVDC interconnector utilising voltage source converter technology and symmetrical monopole configuration. AC network augmentations in Tasmania. Limited AC augmentations and connections may be required in the Hazelwood area as there is sufficient transmission capacity to accommodate power flows to or from the interconnector.
B. 750 MW interconnector	As per Option A, with converter stations and HVDC cable rated to 750 MW. AC network augmentations as per Option A.
C. 1200 MW interconnector	Two parallel 600 MW HVDC symmetrical monopole interconnectors as per option A. AC network augmentations in Tasmania, in addition to those identified in Options A and B. As noted for Option A, limited AC augmentations may be required in Victoria.
D. 1500 MW interconnector	As per Option C, with converter stations and HVDC cable rated to 750 MW. AC network augmentations are the same as Option C.

In order to assess the preferred option we adopted a step-wise approach to evaluating the competing credible options through a series of questions. Stakeholders did not raise any concerns with a similar approach in their submissions to our PADR, and therefore it has been maintained in this PACR.[78]

Our first step is to focus our modelling effort on addressing the following two questions:

1. Would Project Marinus provide a net economic benefit if it were commissioned at the earliest possible date, being 2027?
2. Is the optimal initial capacity for Project Marinus 600 MW or 750 MW?

These two questions are addressed in Table 11 below. For ease of reference, the highest net economic benefit is shaded.

[77] A more detailed description of the credible options is provided in Table 5 of this document.

[78] In this PACR, we have changed the earliest commissioning date to 2027, rather than 2026. In addition, we have expanded the analysis to include the 'High DER' scenario and aligned the scenario definitions with the 2020 ISP. Otherwise, the approach is unchanged from the PADR, although the model inputs and assumptions have been updated in accordance with the draft IASR, as explained in section 2.3.

Table 11: Net economic benefit of 600 MW versus 750 MW commissioned in 2027 ($ million, NPV)

Credible option	Commissioning year	Net economic benefit by scenario					
		Slow Change	Central	High DER	Fast Change	Step Change	Weighted average
600 MW	2027	1,028	1,056	1,053	1,200	2,332	1,334
750 MW	2027	1,461	1,367	1,367	1,530	2,870	1,719
Additional value provided by the 750 MW option		433	311	314	330	538	385

Based on the results presented in Table 11, our findings are as follows:

1. For all five scenarios, Project Marinus delivers a net economic benefit compared to the 'without Project Marinus' base case. The weighted average net economic benefit ranges from $1,334 million for the 600 MW option to $1,719 million for 750 MW of capacity.[79]
2. For all five scenarios, Project Marinus delivers a greater net economic benefit for a 750 MW capacity compared to a 600 MW capacity. The weighted average shows a 750 MW interconnector delivers $385 million or 28 per cent additional value compared to the 600 MW option.

These findings are important because they demonstrate that Project Marinus commissioned at the earliest possible date, delivers a significant net economic benefit to the NEM under all five scenarios. It is therefore reasonable to conclude that the NEM is better off with Project Marinus compared to a base case under which Project Marinus does not proceed. This is a significant finding.

Furthermore, the net economic benefit analysis indicates that there are significant economies of scale in constructing a 750 MW interconnector compared to a 600 MW option, with the larger option consistently outperforming the smaller interconnector across all five scenarios. The magnitude of the outperformance ($385 million or 28 per cent) is highly material as compared to the incremental cost increase ($150 million or 7 per cent). As such, it is reasonable to conclude that the optimal initial interconnector capacity is 750 MW, rather than 600 MW. Therefore, Option B is preferred to Option A.

[79] It should be noted that if the Central and Step change scenarios are weighted two-thirds and one-third as indicated by the 2020 ISP, the net economic benefit are $1,868 million and $1,482 million for the 750 MW and 600 MW options respectively.

We now turn our attention to the following question:

3. What is the preferred option from the three remaining credible options for Project Marinus 750 MW; 1200 MW or 1500 MW?[80]

To address this question, we extend the above analysis to examine the net economic benefit if a second increment of capacity is added in 2029. Table 12 presents the net economic benefit, which shows that the staged 1500 MW option (Option D) is preferred to the 1200 MW option (Option C), across all five scenarios.

Table 12: Net economic benefit for 1500 MW or 1200 MW Project Marinus options

Credible option	Commissioning year	Net economic benefit by scenario					
		Slow Change	Central	High DER	Fast Change	Step Change	Weighted average
1200 MW	2027 and 2029	2,027	1,353	1,364	1,583	3,297	1,925
1500 MW	2027 and 2029	2,336	1,416	1,420	1,674	3,650	2,099
Additional value provided by the 1500 MW option		310	63	56	91	353	175

To complete the analysis, the table below compares the net economic benefit of the 1500 MW option (Option D) in 2027 and 2029 with a 750 MW interconnector in 2027 (Option B).

Table 13: Net economic benefit for 1500 MW or 750 MW Project Marinus options

Credible option	Commissioning year	Net economic benefit by scenario					
		Slow Change	Central	High DER	Fast Change	Step Change	Weighted average
750 MW	2027	1,461	1,367	1,367	1,530	2,870	1,719
1500 MW	2027 and 2029	2,336	1,416	1,420	1,674	3,650	2,099
Additional value provided by the 1500 MW option		875	49	54	144	781	380

[80] The previous discussion eliminated 600 MW as the optimal capacity, which means that we are now considering 750 MW, 1200 MW and 1500 MW.

Table 13 shows that the 1500 MW interconnector delivers a higher net economic benefit in all of the five scenarios, with the weighted average across all five scenarios producing an additional net economic benefit of $380 million for the staged 1500 MW capacity (Option D).

The table below presents the results using the 2020 ISP weighting, which show that the 1500 MW option outperforms the other credible options. Applying the 2020 ISP's weighting of two thirds Central scenario and one third Step Change scenario produces a net economic benefit of $2,161 million for 1500 MW compared to $1,868 million for 750 MW. On this basis, we conclude that the 1500 MW capacity (Option D) is preferred to a single interconnector of 750 MW (Option B).

Table 14: Net economic benefit for each credible option (2027 and 2029), using ISP scenario weightings ($ million, NPV)

	Net economic benefit		
Credible Options	**Central Scenario**	**Step Change Scenario**	**2020 ISP weighting (67% - Central & 33% - Step Change)**
600 MW	1,056	2,332	1,482
750 MW	1,367	2,870	1,868
1200 MW	1,353	3,297	2,001
1500 MW	1,416	3,650	2,161

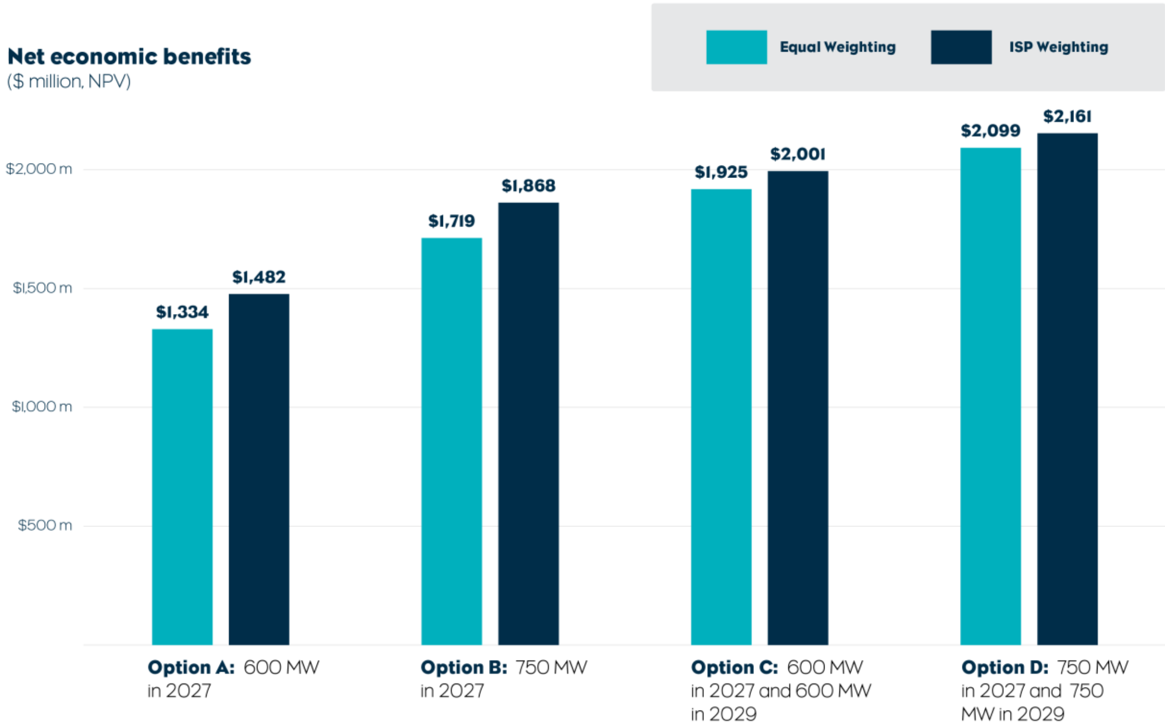

Figure 7: Net economic benefit for all credible options (2027 and 2029), averaged across all scenarios

7.2 Preferred option

On the basis of the analysis presented in the previous section, the staged 1500 MW option maximises the net economic benefit when compared with the 600 MW, 750 MW and 1200 MW options. This conclusion is unchanged whether:

- An equal weighting is attributed to each scenario, as shown in the figure below; or
- The 2020 ISP's weighting is adopted, which is a weighting of one-third Step Change scenario and two-thirds Central scenario, as shown in the figure and table below.

The summary information shows the results for the earliest commissioning date of 2027 and 2029 for ease of presentation. Project timing is addressed separately in the next section.

In accordance with the RIT-T, the preferred option is a 1500 MW HVDC interconnector, comprising two 750 MW HVDC links, plus associated AC network upgrades.

7.3 Project timing and scope

In relation to project timing, our analysis confirms the findings in our PADR and Supplementary Analysis Report that the optimal timing of the preferred option depends on the future development of the NEM, which is continuing to experience unprecedented transition. The table below shows how the net economic benefit provided by the preferred option varies for different commissioning dates and scenarios.

Table 15: Net economic benefit by scenario of the preferred option ($ million, NPV)

	Commissioning Years				
Scenarios	**2027 & 2029**	**2027 & 2030**	**2028 & 2031**	**2031 & 2034**	**2034 & 2037**
Central	1,416	1,466	1,575	1,814	1,807
Slow Change	2,336	2,370	2,389	2,366	2,235
High DER	1,420	1,471	1,578	1,809	1,779
Fast Change	1,674	1,723	1,820	2,005	1,944
Step Change	3,650	3,677	3,680	3,586	3,240

The above analysis is based on the scenarios in the 2020 ISP, but these scenarios are subject to change as AEMO prepares its 2022 ISP. At this stage, it is appropriate to describe the optimal timing for Stage 1 and Stage 2 of the preferred option as falling within a window, as shown in the table below.

Table 16: Optimal timing of Project Marinus based on PACR modelling

Stage (750 MW each)	Optimal commissioning year range across the scenarios
Link 1	Between 2027 and 2031
Link 2	Between 2029 and 2034

The new Rules and accompanying guidelines cater for this type of variability in the optimal timing for a multi-staged actionable ISP project, such as Project Marinus. In particular, AEMO may establish 'decision rules' to guide the optimal project timing. In addition, the Rules provide a 'feedback loop' to verify that the proposed preferred option accords with AEMO's optimal development path.

In this context, the timing for development of Project Marinus will ultimately depend on the 2022 ISP (including any decision rules in the 2022 ISP for development of Stages 1 and 2) and AEMO's optimal development path at that time. At this stage, however, our assessment is that there is mounting evidence that the NEM's current trajectory is at least consistent with or exceeds the Step Change scenario as outlined in the 2020 ISP. In particular, we note:

- Policy initiatives and legislation have been proposed or implemented by various state governments to advance renewable development to prepare for the retirement of the ageing thermal generation fleet. The objectives of these initiatives are aligned with, or exceed the Step Change scenario;
- The chair of the Energy Security Board has expressed views that the power system is already exceeding the step change scenario forecast in the ISP in 2020[81] and that the Step Change scenario could now be considered a conservative Central scenario given the ongoing pace of change[82];
- Increased generation from renewables is likely to exert increasing commercial pressure on coal fired generators as operational inefficiencies arise as output is continually varied to accommodate lower cost renewable generation in the supply stack;
- Sustained pressure from institutional investors and customers on the owners of coal-fired generators to align their business plans with the goals of the Paris Agreement could also lead to early retirement of assets due to environmental considerations. [83] Most recently this was highlighted by the owners of Loy Yang B power station when they flagged the challenges associated with refinancing debt for emission intensive generation assets[84];
- Recent announcements made by the Prime Minister and the Federal Treasurer regarding Australia's ambitions to reach net zero emissions as soon as possible, and preferably by 2050; and
- AEMO has indicated that one of its two Central scenarios for its 2022 ISP may reflect economy-wide net zero emissions by 2050.

In most instances, the lead time to withdraw dispatchable capacity from the NEM is much shorter than the timeframe for delivering large transmission projects. Given this observation, and the rapid pace of change in the generation sector, there is a compelling case to proceed on the basis that Project Marinus may be required at the earliest commissioning timeline of 2027 and 2029. Nevertheless, AEMO's 2022 ISP will be an important

[81] Post 2025 options paper, ESB, 30 April 2021.

[82] ESB's Kerry Schott at Energy and Investment Conference, Sydney 24 March 2021.

[83] The inputs and assumptions in the Step Change scenarios best capture the electricity market outcomes required to achieve the targets of the Paris climate change agreement.

[84] Alinta calls for Canberra to step in as banks retreat, The Sydney Morning Herald, 11 June 2021.

milestone in the context of Project Marinus to determine the optimal timing of the project in light of the latest available information and updated scenarios.

In relation to project timing, TasNetworks will proceed with the early works required for Project Marinus to be able to achieve a final investment decision in 2023-24 and subsequent commissioning of Stage 1 from as early as 2027 and Stage 2 by 2029. The actual timing of each stage will be determined by the 2022 ISP and subsequent ISPs and AEMO's assessment of the proposed project in accordance with the feedback loop (as required by clause 5.16A.5(b) of the Rules) and its optimal development path at that time.

Figure 8 shows the indicative development phases and timeframes for the preferred option, while Table 17 provides an overview of the required scope of work.

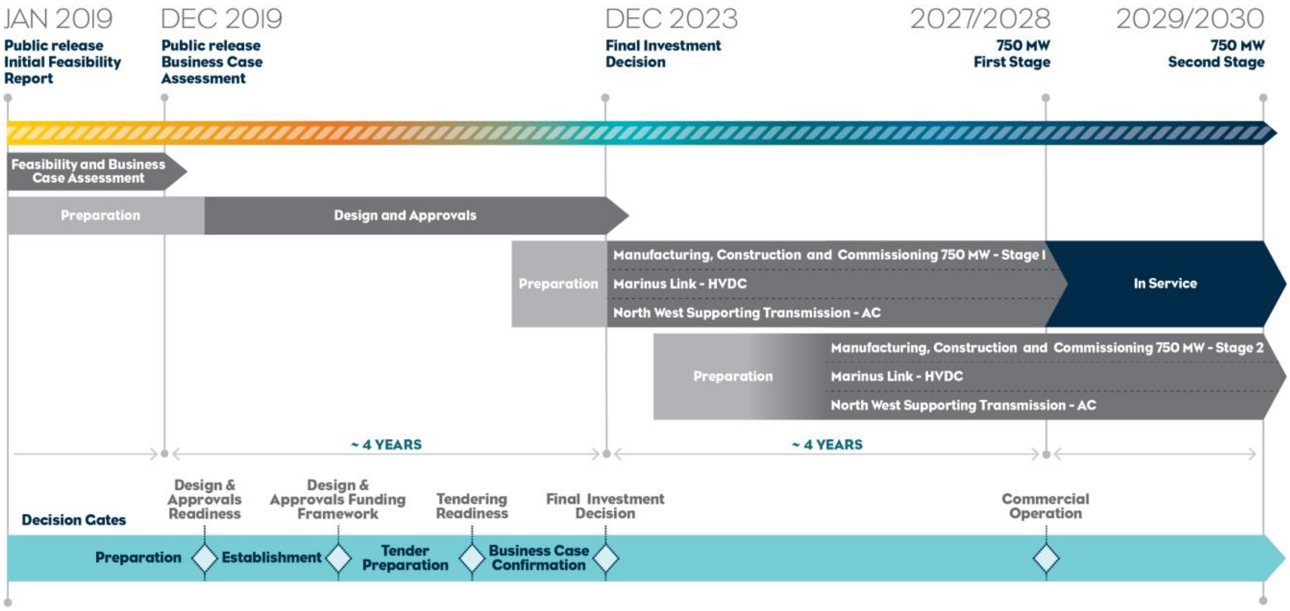

Figure 8: Development phases and timeframes for the preferred RIT-T option

Table 17: Scope of work for the preferred RIT-T option

Investment type	Development
DC assets	Two parallel 750 MW HVDC interconnectors using voltage source converter technology and symmetrical monopole configuration. The first 750 MW interconnector is targeted for commissioning, as early as 2027 and the second as early as 2029. Converter stations located at Heybridge in Tasmania and the Hazelwood area in Victoria. HVDC transmission to use buried cable for the entire route.
AC assets	AC network augmentations in Tasmania: • Construction of a new 220 kV switching station at Heybridge adjacent to the converter station; • Establishment of a new 220 kV switching station at Staverton; • Construction of a new double-circuit 220 kV transmission line from Staverton to Heybridge via Hampshire and Burnie; • Construction of a new double-circuit 220 kV transmission line from Palmerston to Sheffield; and • Construction of a new double-circuit 220 kV transmission line from Heybridge to Sheffield and the decommissioning of the existing 220 kV single-circuit transmission line in this corridor. Limited AC augmentations may be required in Victoria as there is sufficient transmission capacity to accommodate power flows to or from the interconnector. Limited 500 kV connection assets are required to connect the HVDC converter station to the Hazelwood area.

7.4 Robustness of net economic benefit

Table 18 compares the net economic benefit of the PACR with our earlier results in the PADR and the Supplementary Analysis report. The modelling period for the PADR and PACR extends to 2050, but the Supplementary Analysis Report considered an abridged modelling study period of 2042, due to the limited availability of inputs at that time. For comparison purposes, the results below for the PADR and the PACR have been abridged to 2042 to align with the Supplementary Analysis report.

Table 18: Comparison of the net market benefits between PADR, Supplementary Analysis and PACR ($ million, NPV)[85]

	PADR	Supplementary Analysis Report	PACR
Average (No Slow Change)	1,027	972	1,023
Commissioning year	2028 and 2032	2028 and 2031	2027 and 2029
Modelling study period	2020 – 2050 (abridged to 2042)	2020 - 2042	2020 – 2050 (abridged to 2042)

The table shows that despite the changes in project costs, scenarios, inputs and assumptions since the commencement of the RIT-T, the net market benefits provided by Project Marinus remain largely unchanged. This further demonstrates the robustness of the Project Marinus value proposition for the NEM, despite the continued evolution of information.

7.5 Sensitivity analysis

This section explains the various sensitivity analyses undertaken based on the issues raised by stakeholders in their submissions to our PADR and Supplementary Analysis Report.

In addition to modelling scenarios, the RIT-T application guidelines require the proponent to undertake sensitivity analysis. Sensitivity analysis entails varying one or multiple inputs to test how the output of a model is affected by changes in its input assumptions.

Our sensitivity analysis has been informed by a combination of stakeholder feedback and application of the RIT-T Application Guidelines. The sensitivity analyses considered in this PACR are described below. The sensitivity analysis has been conducted under the earliest timing of Project Marinus in 2027 and 2029. The specific scenario under which each of the sensitivity tests is conducted is guided by the narrative or rationale for that sensitivity.

[85] This comparison is similar to section 7.3 of the Supplementary Analysis report. The numbers for the PACR and the Supplementary Analysis Report are sourced from that section for consistency.

7.5.1 Hydrogen Load Growth

Hydrogen is increasingly being discussed as a promising fuel that could reduce the amount of fossil fuels burnt in several sectors, such as transportation and heavy industry, and help achieve a net zero carbon emissions target by 2050, which is a target set by the majority of state governments and territories in Australia and by a number of countries.

The Supplementary Analysis Report contained a hydrogen load growth sensitivity in Tasmania to 500 MW by 2035 and 1,000 MW by 2040. Subsequent to the publication of this report, as part of the Tasmanian Government's Renewable Hydrogen Industry Development Funding program, various participants announced detailed feasibility studies into processing hydrogen and green ammonia in Tasmania. Therefore, for this PACR we have expanded the hydrogen load growth sensitivity in Tasmania to include an additional 300 MW by 2030, while retaining a load increase of 500 MW by 2035 and 1,000 MW by 2040. This load growth is assumed to occur under the Step Change scenario, since it aligns with the decarbonisation objectives needed for the growth of the hydrogen industry.

It is assumed that hydrogen load will have a capacity factor of 80 per cent[86], with consumption reduced during periods of high electricity demand. For the purpose of this PACR, we assume that hydrogen production will primarily absorb excess renewable energy, and will not increase the firming requirement on the system.

7.5.2 Sustained Low Gas Price

The gas price projections in the draft IASR suggest an average gas price for a new entrant CCGT in Victoria is approximately $13.3/GJ (real 2020 dollars for a period of 2025 to 2050)[87].

As a means of driving economic recovery from the COVID-19 pandemic, several business experts are calling on the Commonwealth Government to provide financial underwriting to ensure a sustained reduction in gas price. This sensitivity assumes that the underwriting support is for up to $5.3/GJ, thereby lowering the gas price to $8/GJ. The 2020 Gas Statement of Opportunities estimates the demand for eastern and south-eastern Australia to be approximately 600 PJ (excluding LNG exports). This level of underwriting therefore provides for a potential annual financial assistance of up to $3.2 billion. The sensitivity is conducted with inputs and assumptions associated with the Central scenario.

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[86] Based on industry journals, a capacity factor of at least 70-80 per cent is needed to justify the capital cost investment associated with hydrogen production.

[87] AEMO, *draft 2020-21 inputs, assumptions and scenarios report*, December 2020.

7.5.3 750 MW of committed pumped hydro in Tasmania

Hydro Tasmania, in its submission to our PADR, indicated lower capital costs for Tasmanian pumped hydro projects as compared to those in mainland Australia. The estimate provided suggested a reduction of 20-25 per cent below the 2020 ISP costs. This sensitivity assumes 750 MW of pumped hydro is committed in Tasmania with the second stage of Project Marinus.

As noted in our PADR, pumped hydro development typically occurs in conjunction with the retirement of dispatchable thermal generation capacity. We have therefore incorporated this sensitivity in the Step Change scenario.

7.5.4 Variation in battery cost (+/- 30 per cent)

This sensitivity examines the impact if battery costs in 2030 are 30 per cent higher or lower than the draft IASR 2021 forecasts for batteries with a 4 hour storage duration, as shown below. The sensitivity is conducted with inputs and assumptions associated with the Central scenario.

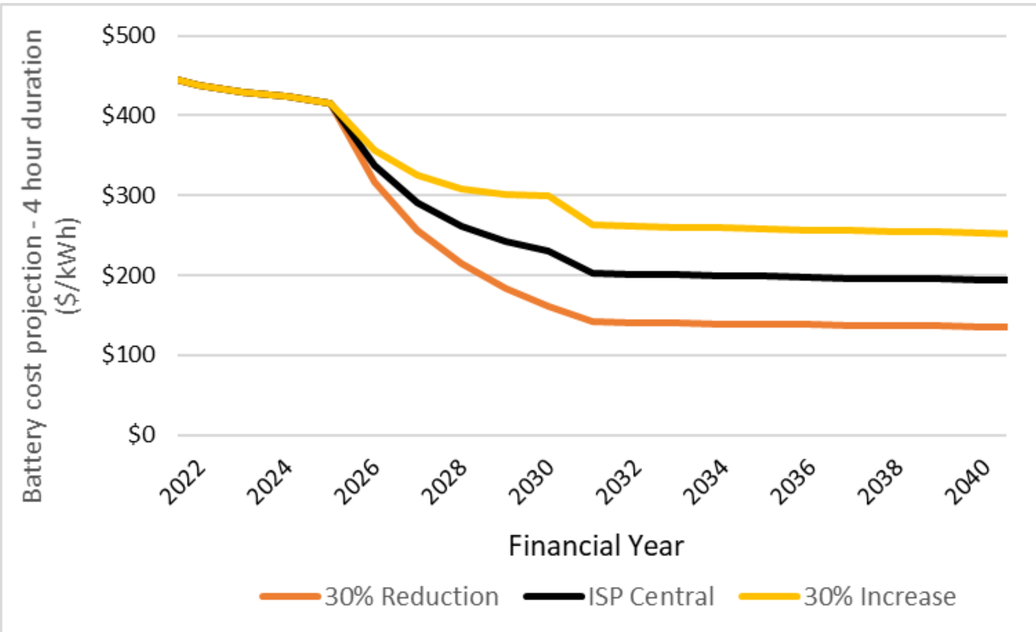

Figure 9: Battery cost sensitivity – 4 hour storage ($2020/kWh)

7.5.5 Total project cost estimate sensitivity – P10 and P90

As outlined in section 5.5, each possible outcome value of the total project cost can be given a ‘P’ value which indicates the likelihood of the occurrence of that total project cost. For instance, a P10 cost is the project cost with sufficient contingency to provide 10 per cent likelihood that this cost would not be exceeded. A P90 cost is the project cost with sufficient contingency to provide 90 per cent likelihood that this cost would not be exceeded.

The table below summarises the reasonable lower bound (P10 estimate) and upper bound cost range (P90 estimate) as outlined in the Jacobs report. This sensitivity tests the robustness of the net economic benefit of Project Marinus to this lower and upper bound project cost estimate.

Table 19: Summary of total project cost estimate for preferred option ($ million, 2020 dollars)

Cost sensitivity	P10 Estimate	Expected Cost	P90 Estimate
Total project cost estimate	3,138	3,481	3,827

7.5.6 Development of Victorian REZs

The Victorian Government released a directions paper on the Victorian Renewable Energy Zones Development Plan in February 2021. The plan outlined in the Directions Paper sets out an objective of unlocking 10 GW of new renewable energy capacity in Victoria. The plan is enabled by the Victorian Government's $540 million REZ Fund to invest in the required REZ network infrastructure and the establishment of a new body, VicGrid, to actively plan and develop Victorian REZs.

While the plan does not provide a specific date to unlock 10 GW of renewable capacity, on the basis of the delivery timeframe for Stage 2 Projects, it is assumed that this additional renewable capacity will be available by 2032. Noting the decarbonisation objective outlined in the plan and the Victorian Government’s net zero emission target, this sensitivity is assessed under the Step Change scenario.

7.5.7 Weighted Average Cost of Capital (WACC)

As outlined in section 6.2.5, consistent with the Draft 2021 IASR, the discount rate of 4.8 per cent (real, pre-tax) is used for all scenarios, except Slow Change. Slow Change uses a WACC of 3.8 per cent. This sensitivity tests the net economic benefit of the project across all scenarios under a lower discount rate of 3.8 per cent and a higher discount rate of 6.8 per cent.

7.5.8 Hydro Tasmania generation capacity remains unchanged

As outlined in section 6.2.2, it is currently assumed that the Tasmanian hydro scheme will be repurposed to increase dispatchable capacity to firm variable renewable energy. In this context, it is highly likely that

Tasmanian hydro will be retrofitted for capacity upgrades if, as stated by Hydro Tasmania, this can be achieved at minimal incremental cost to the required refurbishment works. Nevertheless, this sensitivity test considers the case where the hydro capacity upgrades did not proceed. The sensitivity is conducted with inputs and assumptions associated with the Central scenario.

7.5.9 Testing import capacity on Project Marinus for procurement of System Protection Scheme (SPS) services

Basslink's ability to achieve 478 MW of power transfer between Tasmania and Victoria, relative to the median Tasmanian load of 1,100 MW, relies on the existence of a Frequency Control System Protection Scheme (**FCSPS**). In the event of Basslink tripping during conditions of moderate to high power flows into Tasmania, the loss of supply would result in an immediate excessive Tasmanian supply/demand imbalance condition. This would lead to the Tasmanian power system frequency falling at an uncontrollable rate, and ultimately lead to widespread blackouts. The FCSPS scheme acts to prevent this situation by rapidly tripping selected industrial loads following loss of Basslink under import conditions. This acts to rapidly re-establish a supply/demand balance and maintain power system frequency within controllable levels. The industrial loads which are tripped have agreed to participate in the scheme, through non-regulated commercial arrangements.

The operation of Marinus Link, the HVDC assets, at high Tasmanian import capacity will also rely on the implementation of a similar frequency control special protection scheme, which rapidly trips pre-determined loads in the event that Marinus Link trips. The cost estimate for Project Marinus includes an allowance for the implementation of a similar FCSPS. The FCSPS cost comprises two components: the capital cost of implementing the required hardware, and the ongoing cost of commercial arrangements with load customers who elect to participate in the scheme.

The question should be considered whether the incremental market benefit from Marinus Link having an increased import capacity would exceed the cost of implementing the FCSPS to enable this import capacity. In this sensitivity, we do not allow any additional increase in transfer capability from Victoria to Tasmania. This implies that the combined import limit with Stage 1 of Marinus Link commissioned remains unchanged at 478 MW and the import limit is increased to 1,228 MW once both stages of the links are commissioned. The outcome of this sensitivity provides an insight into the ceiling for the cost of procuring FCSPS services with Marinus Link. The import limit is allowed to increase proportionally with incremental economic development of pumped hydro storage in Tasmania. This assumption is consistent with the assumption that pumped hydro load would need to be FCSPS enabled to ensure secure operation of the Tasmanian power system. The sensitivity is conducted with inputs and assumptions associated with the Step Change scenario.

7.5.10 Optimising the conductor size for HVDC cable

The HVDC conductor size determines the transmission losses associated with the interconnector. Optimisation of the conductor size of HVDC power cables for the Marinus Link interconnector requires estimation of the value of losses over the life of the scheme. By increasing the size of cable conductors, HVDC cables losses can be reduced; this sensitivity therefore assists in assessing the optimal size of the conductor.

The current cost estimate of the HVDC assets is based on a conductor size of up to 1400mm^2 for land cable and a slightly smaller size for the submarine cable. However, the conductor size could potentially be reduced (subject to detailed design and technical specifications) for the cable. This reduction in conductor size may enable a reduced capital cost for the project, but would lead to higher transmission losses for the remainder of the project. This sensitivity assesses the cost benefit impact of conductor size and potential transmission losses. This sensitivity is conducted with inputs and assumptions associated with the Step Change scenario, where the link utilisation is the highest.

7.5.11 Economic retirement of gas fired generation permitted

The PACR modelling allows for the economic retirement of only coal-fired generation (and not gas-fired generation) since it is assumed that gas powered generators can play a transitionary role in the NEM. For this sensitivity, it is assumed that gas powered generation can also retire based on least cost economic modelling outcomes. This sensitivity is conducted with inputs and assumptions associated with the Central scenario.

7.5.12 Summary of sensitivity results

Our sensitivity analysis indicates that the preferred option is robust against a range of different outcomes. The outcomes of the sensitivities analysed are outlined in Table 20.

Table 20: Summary of sensitivity analysis ($ million, NPV)

Sensitivity	Net market impact	Revised net market benefit with sensitivity	Relevant Scenario
Hydrogen Load Growth (300 MW by 2030, 500 MW by 2035 and 1,000 MW by 2040)	-1,744	1,933	Step Change
Development of Victorian REZs	-134	3,543	Step Change
750 MW committed pumped hydro in Tasmania	887	4,563	Step Change
SPS sensitivity - limiting transfer capability to Tasmania	-6	3,671	Step Change
Reducing the HVDC conductor size	-19	3,658	Step Change
Sustained Low Gas Price ($8/GJ – flat)	-721	745	Central
Battery costs higher by 30% (ISP costs)	1	1,467	Central
Battery costs lower by 30% (ISP costs)	11	1,477	Central
Optional retirement of gas permitted	62	1,528	Central
Tasmanian hydro capacity remains unchanged	-283	1,183	Central
WACC analysis (-1% & + 2%)	2,537 (3.8%); 2,141 (4.8%); 1,236 (6.8%)		Average of all scenarios

In relation to total capital costs, our analysis shows that the preferred option remains unaffected for the P10 and P90 cost estimate as provided by Jacobs. Table 21 shows the net economic benefit of the preferred option for the total cost range sensitivity.

Table 21: Net economic benefit for total cost range sensitivity for 2027 and 2029 ($ million, NPV)

Sensitivity	Total Project Cost ($ 2020)	Net economic benefit by scenario					
		Slow Change	Central	High DER	Fast Change	Step Change	Weighted average
P10 estimate	3,138	2,516	1,592	1,850	1,597	3,827	2,276
Base Case (expected cost)	3,481	2,336	1,416	1,420	1,674	3,650	2,099
P90 estimate	3,827	2,154	1,236	1,495	1,241	3,471	1,919
Impact of P10 cost estimate to preferred option (scenario average)							+177
Impact of P90 cost estimate to preferred option (scenario average)							-180

The above analysis provides comfort that the preferred option is expected to deliver a strongly positive net economic benefit, even if the upper cost range estimated by Jacobs eventuates. In addition, arrangements are in place to ensure that project costs are closely controlled and monitored, as discussed in further detail in section 9.2.

7.6 High-level summary of benefits

Table 22 provides a breakdown of the net economic benefit for the preferred option of a 1500 MW interconnector, for each scenario, as calculated by Ernst & Young's market expansion model and GHD's assessment of ancillary service benefits.

Table 22: Details of market benefits of the preferred RIT-T option under each scenario (2027 and 2029), ($ million, NPV)

Market benefit category	Value of each benefit category for the scenarios				
	Central	Slow Change	High DER	Fast Change	Step Change
Deferred and avoided capital costs	1,399	737	1,064	1,817	2,844
Avoided generator fixed costs	451	2,955	476	551	468
Avoided fuel costs	1,481	873	1,682	1,115	1,915
Avoided generator variable costs	-90	-164	-80	-128	-153
Avoided REZ expansion costs	174	159	260	292	524
Avoided unserved energy	15	1	26	36	8
Rehabilitation costs	-14	-88	-18	-18	4
Synchronous condensers and system strength	4	-69	15	14	45
Ancillary service benefits	172	202	172	172	172
Gross Benefits [1]	3,592	4,606	3,597	3,851	5,827
Project Marinus Costs [2]	2,177	2,270	2,177	2,177	2,177
Net economic benefit	1,415	2,337	1,420	1,674	3,650

Notes:

1. Totals may not sum precisely due to rounding of the underlying values in this table.
2. Project Marinus estimated costs are less than the estimated capital cost of the 1500 MW option presented in Section 5.5 because the market benefit calculation considers only the annualised costs which occur during the modelling period (to 2050), whereas Project Marinus has an asset life of 40 and 60 years for HVDC and AC assets respectively.

The figure below shows the breakdown of the net economic benefit for the preferred option of a 1500 MW interconnector under the Step Change scenario.

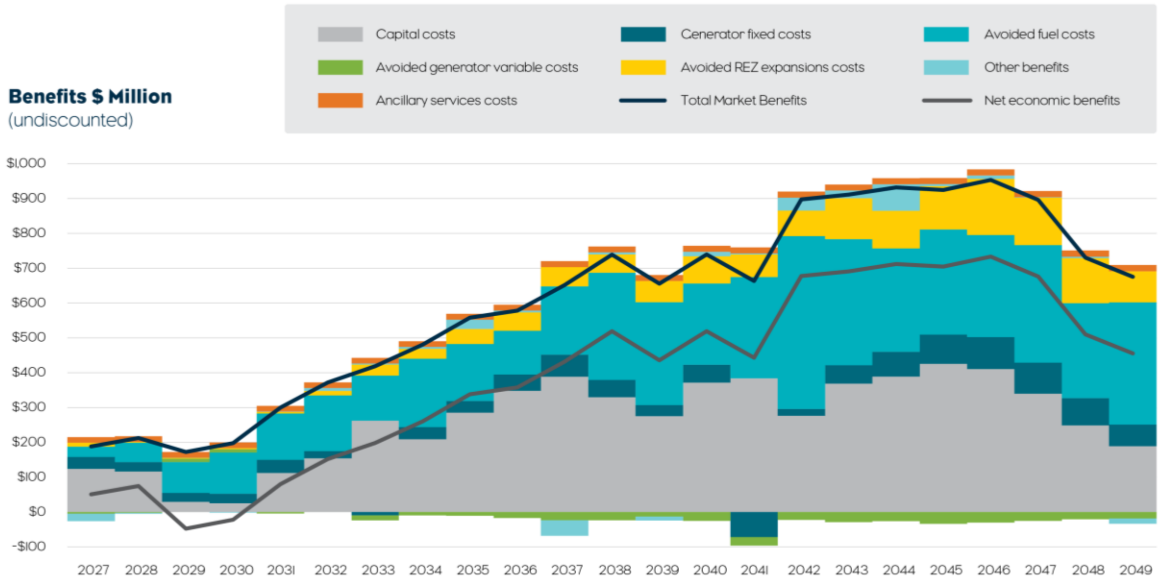

Figure 10: Annual average net economic benefit, 1500 MW Project Marinus with first stage commissioned in 2027 and second stage in 2029 (Step Change scenario)

In the next chapter, we explore in further detail why Project Marinus provides a net economic benefit, given the developments across the NEM and the expected growth in VRE and battery capacity outside Tasmania.

8 Why does Project Marinus provide a net economic benefit?

The purpose of this chapter is to provide further information on the benefits that Project Marinus is able to unlock for the NEM, with a particular focus on the benefits of long duration storage.

Key messages

- Over the coming decades, there is expected to be further significant increases in the amount of energy provided by VRE sources, with a corresponding increase in the need for energy storage facilities across the NEM.
- As the energy contribution from VRE sources progressively increases, the role played by dispatchable capacity will become critical in maintaining the security and reliability of the NEM.
- Project Marinus will provide the NEM with increased access to Tasmania's cost-effective dispatchable hydro and pumped hydro resources. Pumped hydro is a cost-effective source of long duration energy storage, which can provide the dispatchable capacity needed to maintain the security and reliability of the NEM as ageing coal plant is retired, and the contribution of VRE continues to increase.

8.1 Introduction

The NEM is currently transitioning from a centralised coal-fired baseload generation system to a decentralised system with significant contribution from DER, utility-scale VRE sources backed by dispatchable generation from batteries, gas-powered generators, hydro and pumped hydro schemes. This transition requires investment in transmission infrastructure to ensure that customers' energy needs can continue to be met at the lowest costs.

The modelling undertaken for this PACR demonstrates that Project Marinus is part of the lowest cost solution across a diverse range of scenarios. This chapter explains how and why Project Marinus provides this value in a Step Change scenario. For other scenarios, although a longer time horizon is required to achieve the same benefits, the nature of these benefits is essentially unchanged. The report from Ernst & Young, which is provided as Attachment 1 to this PACR, provides a more detailed explanation of the source of benefits for Project Marinus across each of the scenarios.

8.2 The scale of NEM transition

The scale of transition that the NEM is projected to experience over the coming decades is unprecedented. In addition to sourcing up to three times more energy from DER, the installed capacity of the NEM is expected to almost triple by 2050, as shown in Figure 11 below. This fundamental transition of the NEM, based on least-cost economics, is likely to lead to sourcing significant amounts of generation from VRE sources and storing excess energy in dispatchable sources, such as batteries and pumped hydro facilities for energy shifting purposes.

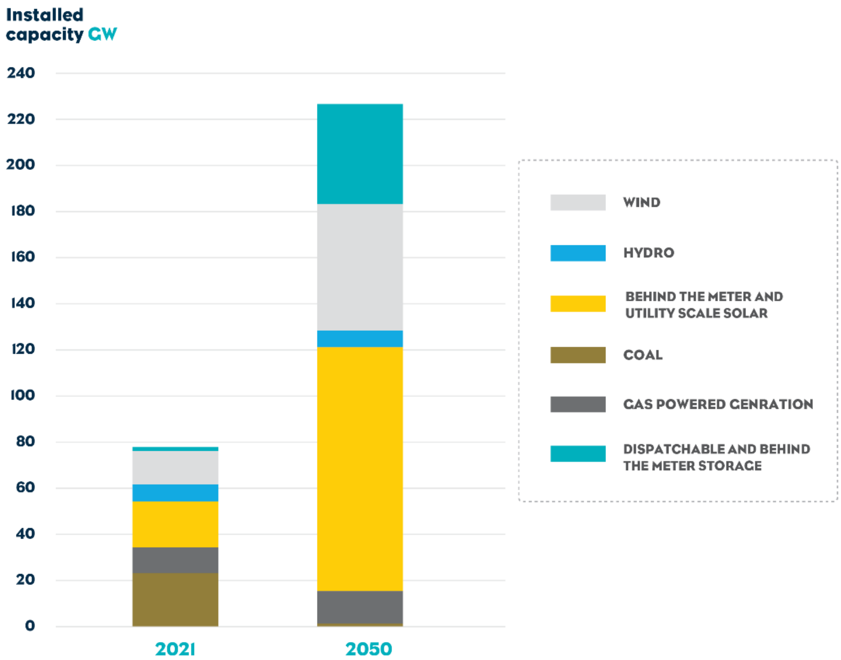

Figure 11: Installed capacity in NEM 2021 & 2050 (Step Change scenario)

Figure 12 below depicts the potential change in the contribution of each of the technology types between 2021 and 2050 in a Step Change scenario. The contribution from VRE sources, including utility-scale and behind the meter generation, is expected to more than double to over 80 per cent by 2050. In contrast, the thermal generation contribution reduces from about 55 per cent to around 5 per cent over the same period.

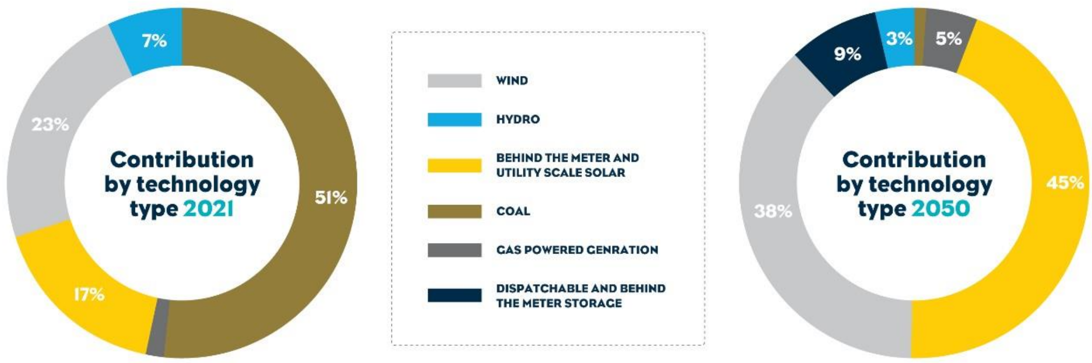

Figure 12: Energy contribution by technology type (2021 and 2050, Step Change scenario)

The figure above indicates a significant increase in dispatchable and behind the meter storage by 2050, including storage from pumped hydro. This outcome is not surprising as reliable 'on-demand' capacity is needed to support the continued expansion of variable renewable generation.

Our modelling shows that the first stage of Project Marinus enables the cost of new dispatchable capacity to be avoided by providing the opportunity to access available and repurposed hydro capacity in the existing Tasmanian hydro system. The prospect of utilising existing Tasmanian hydro capacity allows the NEM to defer the need for investment in shorter duration dispatchable storage options on mainland Australia, which would also require system redundancy in the form of gas-powered generation.

In addition to low emission dispatchable hydro and pumped hydro energy, Tasmania has some of the country's best wind resources. The presence of excellent wind resources results in high capacity factors (i.e. higher average energy output), which means that the cost of generating a unit of wind energy could be up to 25 per cent lower in Tasmania compared to elsewhere in Australia. Project Marinus unlocks this wind generation potential and enables the delivery of higher value generation to the broader NEM. A 1500 MW Project Marinus unlocks the potential for up to 2,500 MW of additional wind development in Tasmania.

The wind development associated with the first 750 MW of Project Marinus complements the existing hydro storage potential, while wind development associated with the second 750 MW of Project Marinus complements long-duration energy storage (**LDES**) in the form of cost-effective Tasmanian pumped hydro energy storage (**PHES**).

As explained in Chapters 6 and 7 of this PACR, our modelling shows that a 1500 MW Project Marinus contributes to achieving the transition to a lower carbon future at the lowest total cost.

8.3 Categories of benefits provided by Project Marinus

Before assessing the various categories of market benefits provided by Project Marinus, it is valuable to understand the current Tasmanian power system and the role of hydro generation in meeting the system's baseload energy demands. As explained in Ernst & Young's report (Attachment 1), the economic modelling for Project Marinus is based on nine years of historical weather and demand traces from the financial year commencing in July 2011 through to June 2020. During these nine years, Tasmanian hydro generation met over 80 per cent of the Tasmanian demand, with wind generation the next highest energy source at 9 per cent.

Figure 13 (below) shows that over the same period, a combination of brown and black coal met 78 per cent of the customer demand in the mainland NEM. The next highest energy source is gas-powered generation that met slightly over 11 per cent of the demand.[88] The comparison between the Tasmanian and mainland NEM system indicates that the significant role played by coal fired generation on mainland Australia is similar to hydro's dominant role in Tasmania. It is this difference in the composition of the generation that creates for scope for Project Marinus to deliver benefits, as the NEM transitions to a lower carbon future.

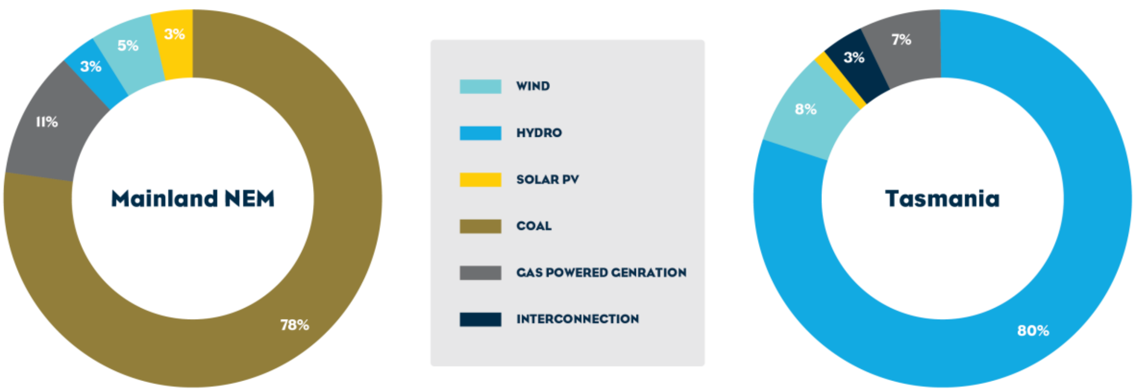

Figure 13: Generation by technology type to meet customer demand in Tasmania and mainland NEM (2011 – 2020)

[88] It must be noted that gas generation in the NEM has been progressively decreasing as the commodity price of gas began increasing from 2015 as the legacy gas contracts commenced expiring and the East Coast became a major gas exporter with prices increasing towards world parity. In the most recently concluded financial year, wind and solar generation sources provided as much energy as gas-powered generation.

In the coming years and decades, as the system transitions away from thermal fired generation to more variable sources of generation along with dispatchable storage, our modelling shows that Tasmania's energy system can contribute to mainland Australia's energy needs, with interconnectors providing mainland Australia with access to dispatchable Tasmanian generation. The figure below shows the percentage contribution for each category of market benefits provided by Project Marinus under the Step Change scenario.

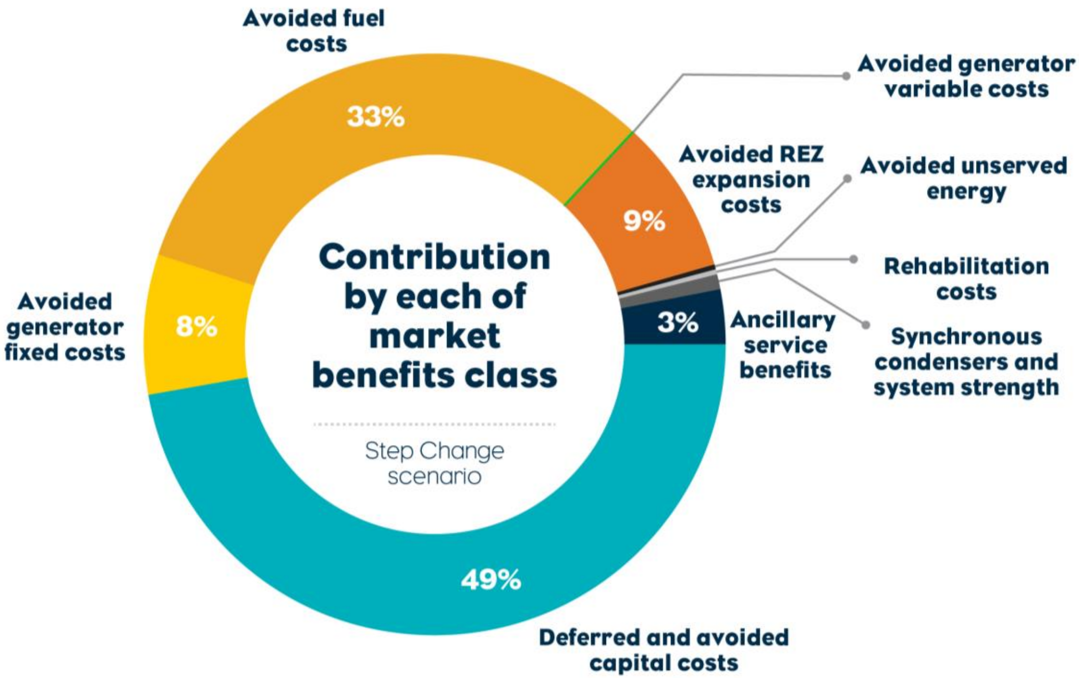

Figure 14: Market benefits provided by Project Marinus, Step Change scenario, 2027 and 2029[89]

As shown in the above figure, the largest source of the benefits from Project Marinus is deferred and avoided capital costs. This benefit arises from the ability of the existing and repurposed Tasmanian hydro capacity along with the development of longer duration cost-effective pumped hydro in Tasmania to cost-effectively meet the dispatchable energy needs of the transitioning NEM.

The second largest source of benefit is the avoided fuel costs that are achieved by utilising the existing hydro generation and forecast pumped hydro generation as an on-demand dispatchable generator that is generating to firm the variability of renewable sources. In the absence of an additional 1500 MW of dispatchable capacity enabled by Project Marinus, gas-powered generation plays a more critical role as a provider of dispatchable capacity. With Project Marinus in service, the reduced need for gas-fired generation manifests itself as avoided fuel costs in our modelling. The use of the lower cost pumped hydro instead of gas-fired generation also

[89] Data values for market benefit classes with minimal contribution have not been displayed but included in the analysis.

contributes to reduced curtailment of variable renewables and a contribution to emissions reduction, which is not explicitly valued under the RIT-T.

In summary, the benefits of Project Marinus arise from:

- Assisting the mainland NEM in replacing carbon intensive generation with variable renewable generation that is correlated with demand, supported by clean dispatchable sources of capacity in the form of Tasmania's cost-effective conventional hydro and pumped hydro resources; and
- Enabling a combination of wind and interconnection to meet the 'baseload' energy needs of the Tasmanian system, so the Tasmanian hydro scheme can work as 'peaking' or dispatchable generation to manage the intermittency of wind and solar generation in Tasmania and beyond.

8.4 Impact of state-based renewable energy policies on least-cost outcomes

In accordance with the AER cost-benefit guidelines, all state legislated renewable energy targets are considered as committed investments in Ernst & Young's economic modelling. It is assumed that the various state governments will develop 'outside of the electricity market' mechanisms to ensure achievement of the targets, including through measures to support the financial viability of the projects commissioned to achieve state legislation.

The purpose of this section is to respond to stakeholders' comments in relation to the TRET by considering three questions:

- Is the TRET policy viable if Project Marinus does not proceed?
- Would Project Marinus be viable without the TRET?
- How would Project Marinus be affected if state-based policies were replaced by a hypothetical NEM-wide emissions reduction target?

In considering these questions, we note that our modelling approach in relation to the treatment of energy policies is consistent with the AER guidelines and the draft IASR. The validity of our modelling approach, therefore, is not dependent on the analysis presented below.

8.4.1 Viability of the TRET if Project Marinus did not proceed

The Energy Co-ordination and Planning Amendment (Tasmanian Renewable Energy Target) Act 2020, as legislated by the Tasmanian parliament states:

1. "… before 31 December 2030, 15,750 GWh of electricity that is generated in that calendar year by NEM connected equipment is to be generated by utilising renewable energy sources or by converting renewable energy sources into electricity; and
2. … before 31 December 2040, 21,000 GWh of electricity that is generated in that calendar year by NEM connected equipment is to be generated by utilising renewable energy sources or by converting renewable energy sources into electricity.
3. Renewable energy sources consist of solar, wind and water (which includes hydro) – which will contribute towards achievement of the TRET."

The modelling of TRET for the Supplementary Analysis Report, in both the base case and Project Marinus case, is consistent with the passage of this legislation.

If Project Marinus does not proceed, we recognise that renewable generation would be curtailed in the absence of any increase in Tasmanian demand. As the short-run marginal cost of curtailed renewable generation would be close to zero in the 'without Project Marinus' case, we would expect electricity demand to increase in response to lower energy prices.

In these circumstances, the state could consider accelerating its renewable hydrogen ambitions, thereby increasing the Tasmanian system demand. Over 1,200 MW of renewable hydrogen projects applied for assessment as part of the Tasmanian Government's Renewable Hydrogen Industry Development Funding program – and may support the TRET in the absence of Project Marinus. These potential developments, however, are somewhat preliminary and therefore have not been explicitly modelled, apart from through sensitivity analysis.

8.4.2 Viability of Project Marinus without the TRET

The next question to consider is whether Project Marinus would be viable in the absence of the TRET. As already noted, this situation does not arise as the TRET has been legislated. Nevertheless, the achievement of the TRET and impact of the TRET on the economic case for Project Marinus is a question that will be of interest to some stakeholders.

To examine this question, we undertook additional modelling assuming that the TRET policy is removed, while retaining all remaining Commonwealth and state-based schemes in the modelling. The figure below depicts the average net economic benefit of Project Marinus for the Step Change and Central scenario, with and without the TRET.

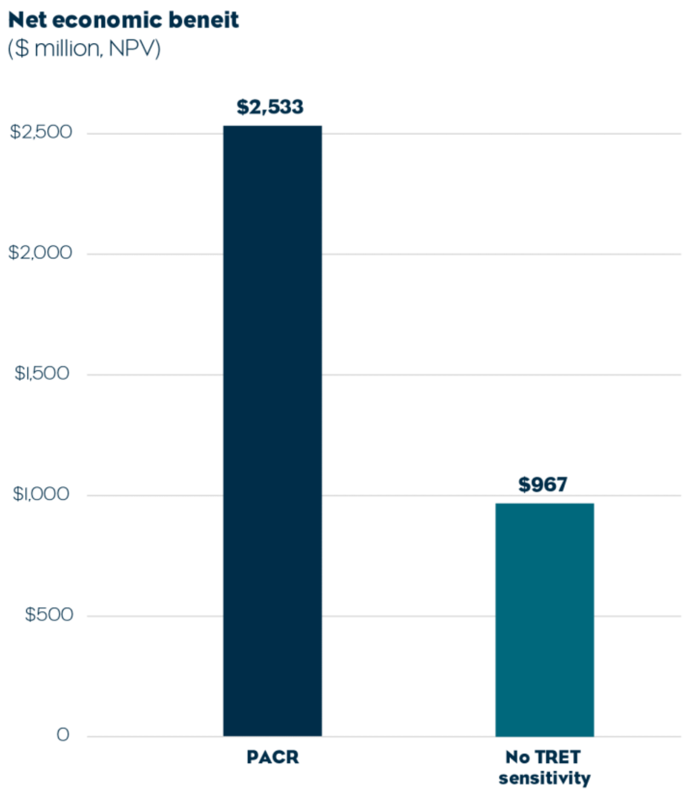

Figure 15: Average net economic benefit for Project Marinus – with and without TRET (Central and Step Change scenario, 2027 & 2029, $ million, NPV)

The modelling indicates that the impact of removing the TRET policy while retaining the other policy initiatives is approximately $1,550 million. However, the overall net economic benefit of Project Marinus is still almost $970 million. In other words, the net economic benefit provided by Project Marinus would be substantially reduced if the TRET were no longer government policy, but the project would still provide material net benefits to the NEM and remain viable. The reason for the reduction in net economic benefit for Project Marinus is due to the following:

- The inclusion of all renewable energy schemes, except TRET, leads to the model choosing to utilise sub-optimal but committed variable renewable energy generation and dispatchable storage on mainland Australia, therefore diminishing the need for cost-effective renewable generation from Tasmania. In reality, if Project Marinus were to proceed, the renewable developers are likely to commission projects in Tasmania owing to the competitive advantages outlined in section 8.3.

- Additionally, in the 'No TRET' sensitivity, wind capacity installed in Tasmania is lower in the 'No Marinus' scenario. Accordingly, the net economic benefit of Project Marinus accounts for the capital cost of Project Marinus and additional capital costs of wind generation installed in Tasmania.

The combination of these two factors results in lower deferred and avoided capital costs for this sensitivity, as compared to Figure 14. As depicted in

Figure 16, the benefits provided by deferred and avoided capital costs and avoided fuel costs benefits are similar in the 'No TRET' sensitivity.

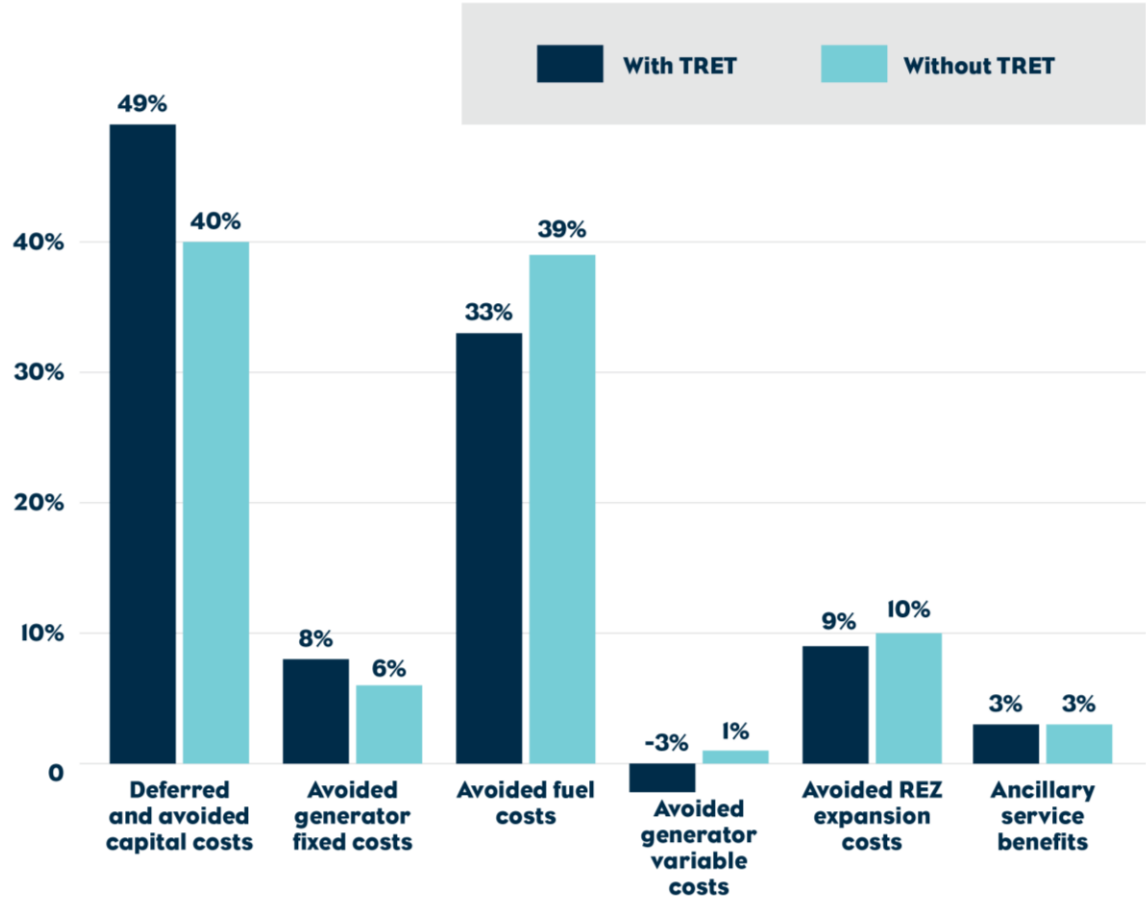

Figure 16: Market benefits comparison with and without TRET, Step Change scenario, 2027 and 2029[90]

[90] Data values for market benefit classes with minimal contribution have not been displayed but included in the analysis.

8.4.3 Conducting a national emission policy sensitivity

It is not appropriate for TasNetworks to challenge the legitimacy of any particular state-based renewable energy legislation. However, it is instructive to consider the effect if all state-based renewable energy schemes were removed and replaced with a Commonwealth, NEM-wide emissions reduction target or carbon budget.[91] Although this is a theoretical exercise (essentially a sensitivity), it provides insight into the least cost solution for the NEM that is not distorted by state-based renewable energy policies. The outcomes for this sensitivity indicate that the net economic benefit of Project Marinus would be almost $1,850 million if a national carbon budget were established in place of state-based policies.

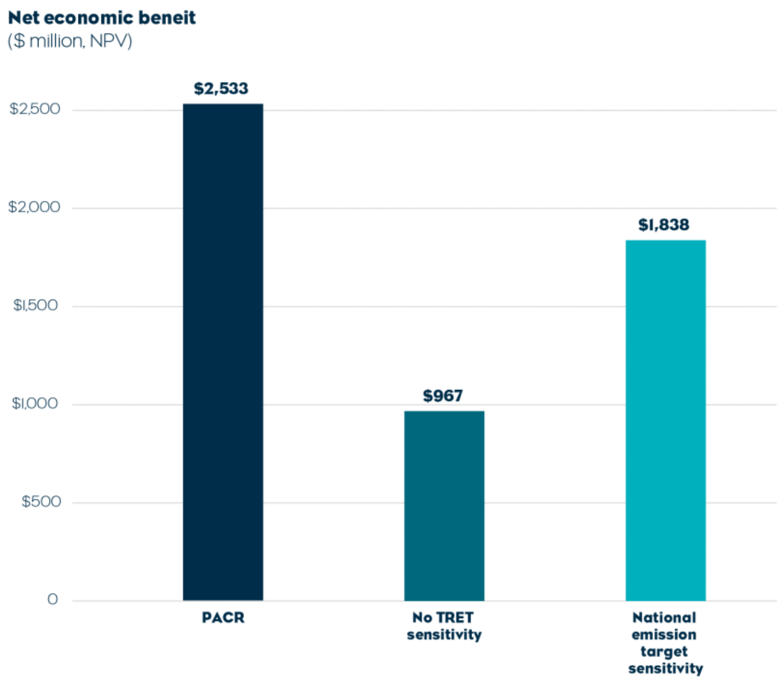

Figure 17: Average net economic benefit for Project Marinus – TRET and national emission sensitivities (Central and Step Change scenario, 2027 and 2029, $ million, NPV)

The analysis demonstrates that Project Marinus will play an important role in meeting a NEM carbon budget if state-based policies were replaced by a National Emission Target. The net economic benefit provided by Project Marinus in this case would be almost double the net economic benefit compared to the 'No TRET' case. As shown above in Figure 17, Project Marinus would have an important role to play in both cases. It is

[91] The carbon budget represents a Representative Concentration Pathway (RCP) of 2.6. An RCP 2.6 requires that carbon dioxide (CO_2) emissions start declining by 2020 and achieve a net zero status between 2080 and 2100. RCP 2.6 is likely to keep global temperature rise below 2°C by 2100. In comparison, an economy-wide net zero target by 2050 achieves the Paris Agreement's aspirational target to limit global warming to below 1.5°C. This pathway is typically referred to as RCP 1.9.

important to highlight that this sensitivity merely aims to decarbonise the electricity sector by 2050 – with emissions reducing by up to 80 per cent from the current levels.

8.4.4 Role of the NEM in a net zero emission scenario (high electrification sensitivity)

Experts estimate that the economic impacts of not appropriately addressing climate change range from 2 to 20 per cent of the total global Gross Domestic Product (GDP) per annum.[92] The immense socio-economic costs, sea level rise, increased frequency and severity of extreme weather, and the projected loss of bio-diversity led countries to come together in signing the 2015 Paris Agreement. Under this legally binding international treaty on climate change, the governments agreed to keep global warming 'well below' 2ºC, and to 'make efforts' to keep it below 1.5ºC. The signatories to this agreement recognised that the eventual extent of global warming is proportional to the total amount of carbon dioxide that human activities add to the atmosphere. So, in order to stabilise climate change, CO_2 emissions need to fall to zero. The longer it takes to do so, the more the climate will change.

Based on Australia's emissions projections 2020 report[93], the emissions in the electricity sector peaked at 212 Mt CO_2-e (equivalent) in 2009 and are projected to reduce to 111 Mt CO_2-e by 2030. The reason for this reduction is the ongoing transition in the electricity sector, with the adoption of utility-scale renewable developments and strong uptake of the distributed energy resources such as rooftop solar.

The same projections indicate that by 2030, the electricity sector will generate 23 per cent of total emissions produced by the Australian economy – effectively one quarter of the Australian economy's emissions. The NEM contributes 80 per cent of this share. More importantly, while the emissions in the electricity sector are trending lower, the emissions from some of the other sectors are remaining unchanged or even increasing, as the figure below shows.

[92] Global Development And Environment Institute, Tuft University, *The economics of Global Climate Change*, 2017.

[93] Department of Industry, Science, Energy and Resources, *Australia's emissions projections 2020*, December 2020.

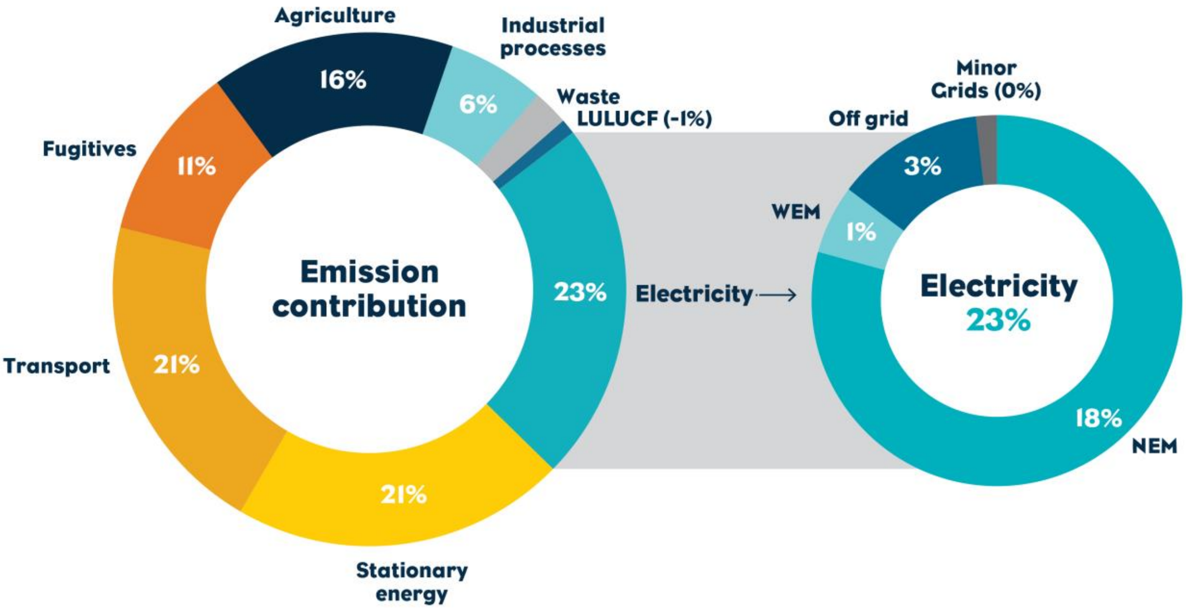

Figure 18: Emission contribution from each sector, with subsectors highlighted for electricity

The National Emission Target sensitivity, as discussed in the previous section, assesses emissions reduction only in the electricity generation sector. However, the momentum is building in achieving net zero emissions across the entire economy.

The sentiment of achieving net zero emissions was echoed by Australia's Prime Minster in his address to the National Press Club on 1 February 2021 where he stated that his government's goal is "… to reach net zero emissions as soon as possible, and preferably by 2050".[94] Similarly, the Federal Treasurer in his budget speech earlier this year stated that "Australia is on the pathway to net zero and our goal is to get there as soon as we possibly can, preferably by 2050."[95] This commitment requires ensuring that every ton of emission produced is effectively offset by a process that reduces the same amount of greenhouse gases already in the atmosphere. On the basis of projections by IPCC, achieving a global net zero emission target by 2050 provides the best pathway to limit the global warming to 1.5°C above pre-industrial levels by 2100.[96] In addition to the

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[94] Prime Minister Scott Morrison, National Press Club address, 1 February 2021.

[95] Treasurer Josh Frydenberg, Federal Budget 2021-22, 11 May 2021.

[96] Global Warming of 1.5°C, an IPCC special report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty, October 2018.

Australian Government intentions, all Australian states and territories have either legislated or made a commitment to a net zero emissions target by 2050, inclusive of state-based renewable energy targets.

Based on studies undertaken by various preeminent organisations[97], in order to achieve a net zero emission target by 2050, a combination of technological pathways are needed. The pathways generally include increasing energy efficiency standards, decarbonisation of the electricity generation sector, electrification of the end-use sectors like building, industry and transportation, and expanded production of green hydrogen.

Most of these studies estimate that in order to achieve the net zero emission target our electricity consumption will need to increase by double to triple the current levels, as a pathway to reduce emissions attributable to some 'harder to decarbonise' sectors[98]. Electrification allows for the use of carbon-free electricity in place of fossil fuels in end-use applications, and significantly improves the overall efficiency of the energy service supply. Electric vehicles, for instance, are more efficient than internal combustion engines. Similarly, in a net zero scenario, technology shifts can also lead to the relocation of industrial processes, for instance, the shift from traditional carbon and energy-intensive steel production methods to green steel production methods with green hydrogen. Moreover, electricity generation will predominantly need to be from renewable generation.

On a global scale, similar emission reduction commitments have been made by most of Australia's major trading partners, with the European Union – the world's largest single market – introducing legislation likely to result in additional costs on products imported from countries without a strong decarbonisation commitment.[99]

In the interests of due diligence, we have expanded the National Emission Target sensitivity to test the net economic benefit that Project Marinus would provide in a scenario where underlying demand on the electricity grid doubles from current levels to achieve a net zero emission target by 2050. This implies that the energy consumption in the Central and Step Change scenario reaches 315 GWh and 385 GWh respectively by 2050. This sensitivity can be described as a high-electrification of the economy with a national emission reduction policy.

In comparison, based on the 2020 Electricity Statement of Opportunities demand forecasts for the Central and Step Change scenario, underlying demand is expected to increase to 250 GWh (35 per cent increase from current levels) and 343 GWh (78 per cent increase) by 2050 respectively.

Results from this sensitivity (shown in Figure 19 below) indicate that the net economic benefit from Project Marinus, in a net zero sensitivity, are greater than the current PACR modelling outcomes. Consistent with the outcome of the Step Change scenario, this sensitivity indicates that having Project Marinus in service in the

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[97] Organisations including IEA, IRENA, IPCC, BP, Equinor, Shell, DNVGL-ETO, Tenske and Greenpeace.

[98] World Energy Transitions Outlook: 1.5°C Pathway, International Renewable Energy Agency (**IRENA**)

[99] Carbon Border Adjustment Mechanism as part of the European Green Deal, European parliament

NEM is necessary as soon as possible. The outcome from this sensitivity also indicates that renewable energy, supported by investments in strategic transmission, dispatchable generation and storage capacity, will dominate the mix of power generation in the medium to long term future. The role of fossil fuels in power generation will be greatly diminished, with natural gas to play a transitionary role in achieving the net zero target by 2050. The need for Tasmanian long-duration pumped hydro assets is also brought forward in this sensitivity.

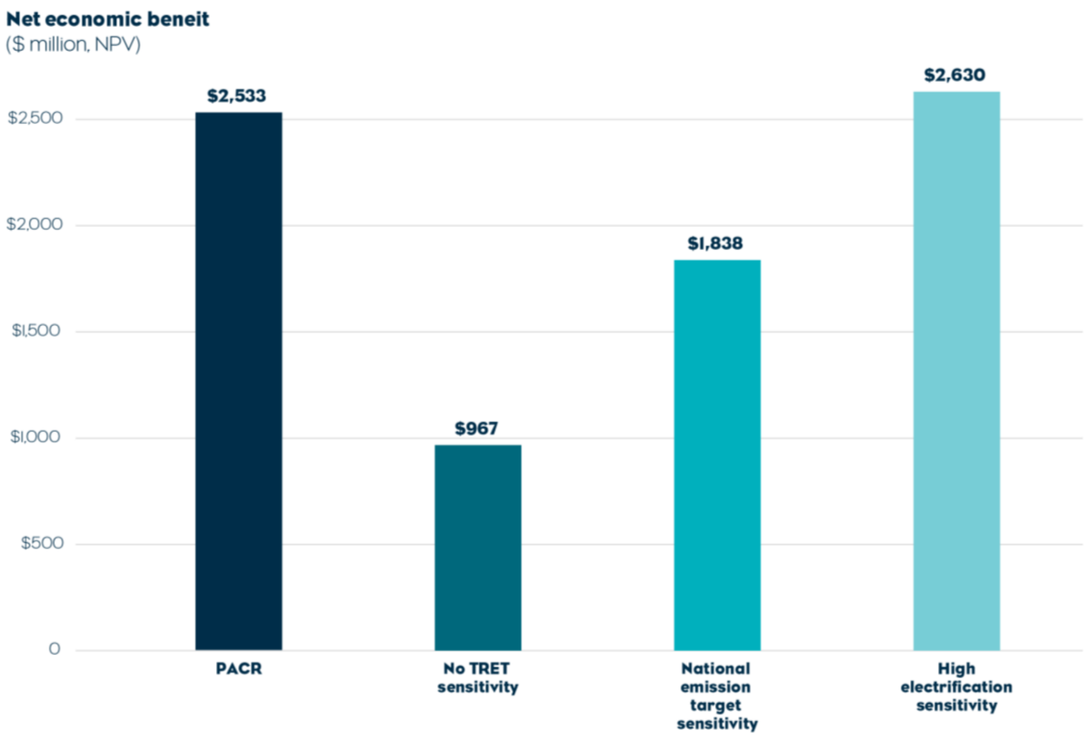

Figure 19: Net economic benefit for Project Marinus – PACR and various emission sensitivities (average of Central and Step Change scenario, 2027 and 2029, $ million, NPV)

8.5 The case for long-duration energy storage (LDES)

The planning studies undertaken by system operators worldwide indicate that the penetration of variable renewable energy generators is likely to increase significantly in coming years and decades. The pace of this transition typically depends on government climate change objectives, the availability of cost-effective renewable resources, and the relative age of the thermal generation fleet in the country. Most system studies also conclude that LDES will be critical to ensure sufficient dispatchable capacity is available to manage the intermittent nature of renewable generation.

For the NEM, the extensive modelling undertaken by CSIRO for the Gencost studies, and market modelling undertaken by AEMO for the ISP, arrive at a similar conclusion, which is that a combination of short and long duration storage will be needed to provide resilience to the transitioning power system.

Importantly, some of the latest system modelling studies also find that the traditional least-cost modelling approach undervalues the role of transmission and LDES. This conclusion is based on assumptions surrounding the perfect foresight[100] nature of system modelling that tends to underestimate the role of LDES, by intrinsically attributing greater 'dispatchability' to the variable renewable energy generators.

In a NEM context, the least cost modelling is typically conducted on an hourly basis that simplifies the load and the renewable generation to an hourly granularity. In the real-time market, the variable renewable energy generation rarely remains unchanged for an entire hour. In fact, a comparison between day-ahead forecasts and the actual wind generation for a few days suggest that the variation between actual 5-minute dispatch and the forecasts can vary significantly, as much as 50 per cent within the hour, as shown in the figure below.

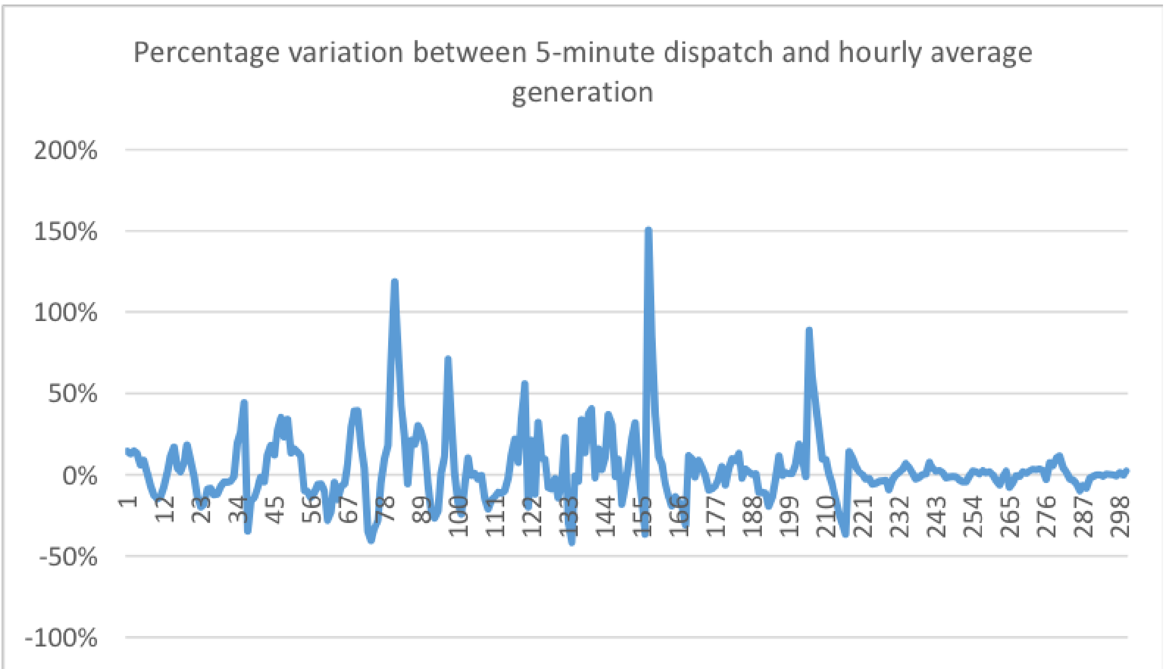

Figure 20: Variation between 5 minute dispatch and hourly average generation

It is conceivable that, as the penetration of renewables continues to increase, the management of intra-hour variability will result in some of the shallower storage and existing generators incurring additional costs associated with continually varying their output and unit cycling. In contrast, the total cost of the interconnector is already reflected in analysis, and is not increased by such cycling patterns of shallower storage and generation. Further, interconnectors provide increased resource sharing to the available dispatchable and variable energy resources between regions and therefore contribute to more efficient operation of the

[100] One of the principal tenets of economic equilibrium theory, the basis for majority of long-term economic modelling, is the assumption that all persons concerned correctly foresee the relevant events in the future, and this foresight includes not only the change in objective data but also the behaviour of all other persons.

generation fleet (providing greater net economic benefit). Some of the pre-eminent research institutes are looking to develop more sophisticated tools that better assess the integrated and strategic planning outcomes that interconnectors help achieve across all decision making horizons (i.e. yearly from a capacity perspective but granular to a few seconds for ancillary services markets).[101] At present, the existing modelling tools are likely to understate the net economic benefit provided by interconnectors as a result of the loss of granularity in defining the system needs.

8.5.1 Ideal duration of storage

A number of stakeholders (Bob Brown Foundation, Tasmanian Renewable Energy Alliance and TasCoss) questioned the validity of commissioning long-duration storage. They indicated that batteries should be sufficient to manage such events. Some stakeholders referred to the work undertaken by the Victorian Energy Policy Centre (**VEPC**) that concluded four-hour storage duration is sufficient for the NEM.

The VEPC report reached this conclusion based on the results shown in

Figure 21 below that represents the average demand (residual demand) that needs to be met from dispatchable sources once variable renewable energy generation is subtracted from the system's operational demand for 2022 and 2039. The study focused on 2020 ISP outcomes for the Victorian region.

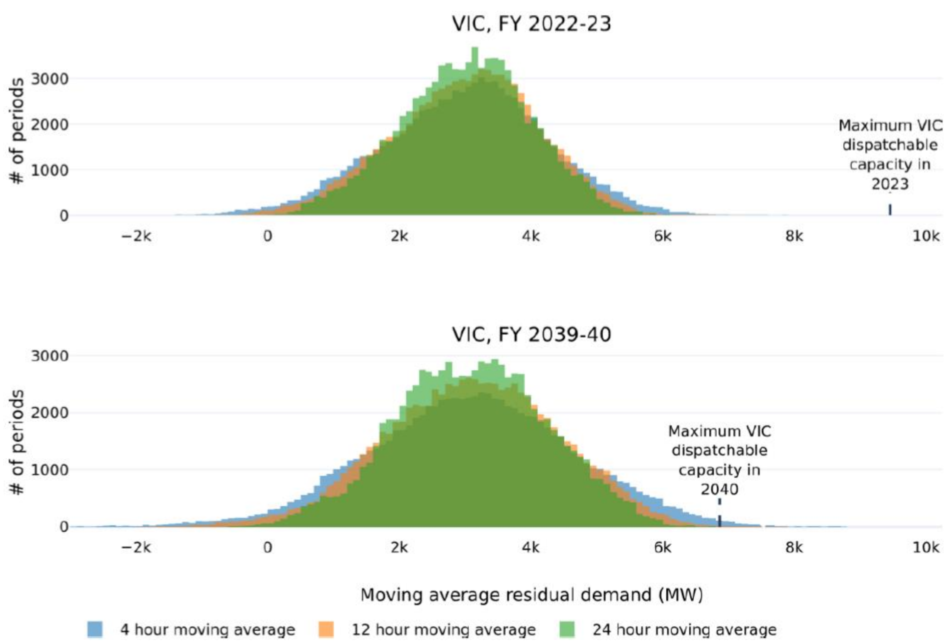

Figure 21: Residual demand graphic from VEPC report[102]

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[101] Electric Power Research Institute, integrated resilience and strategic planning initiative.

[102] Mountain, B.R., S.D. Percy (2020). An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation. A report prepared for the Bob Brown Foundation. Victoria Energy Policy Centre, Victoria University, Melbourne, Page 25.

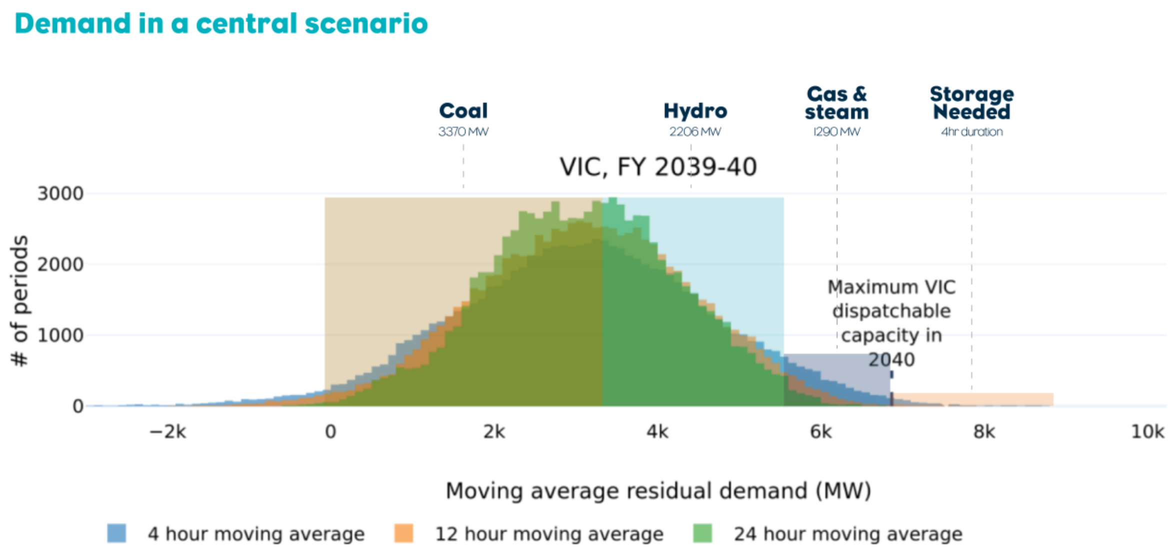

Figure 22: Residual demand graphic from VEPC report with dispatchable capacity overlay (Central scenario for 2039)

Figure 22 focuses on the year 2039 and provides an overlay of each dispatchable capacity source available in accordance with the 2020 ISP. In reaching the conclusion that four-hour storage duration is sufficient (the blue section of the 4 hour moving average that exceeds the Maximum VIC dispatchable capacity in 2040), the VEPC report only considered the Central scenario's outcomes and ignored the high fixed and operating costs associated with some dispatchable generators. Further, VEPC’s analysis assumes that generators like diesel and open cycle gas-turbine units that typically run for less than a few hours in a year (historical capacity factor of less than 5 per cent) owing to their high costs, are expected to perform the role of a dispatchable generator that is continuously generating for at least 24 hours (based on 24-hour moving average) and for an extended period (over 3,000 instances on the y axis). This is very unlikely to lead to a least-cost system outcome for customers.

Project Marinus provides dispatchable capacity, and access to some of the best renewable zones in the NEM as the ageing coal-fired generation fleet retires. Therefore, it is instructive to assess the value and typical storage duration in a Step Change scenario. The maximum dispatchable capacity in Victoria in a Step Change scenario is less than 4,100 MW. This is inclusive of 563 MW of Demand Side Participation that is assumed to be available for at least 24 hours.[103] Based on the average residual demand analysis conducted by VEPC, almost 3,000 MW of at least 24 hour duration dispatchable capacity would be needed to ensure that the system

[103] This is an extremely aggressive assumption since the dominant source of Demand Side Participation in Victoria is the Portland aluminium smelter. The operator of this smelter has stated that power supply to the smelter cannot be curtailed for more than 3 hours as it can otherwise lead to significant damage to the potlines.

can be operated reliably. TasNetworks encourages VEPC to reassess the need for long-duration storage across various potential evolutions of the NEM, including the Step Change scenario. The figure below shows the various sources of dispatchable capacity and their available capacity.

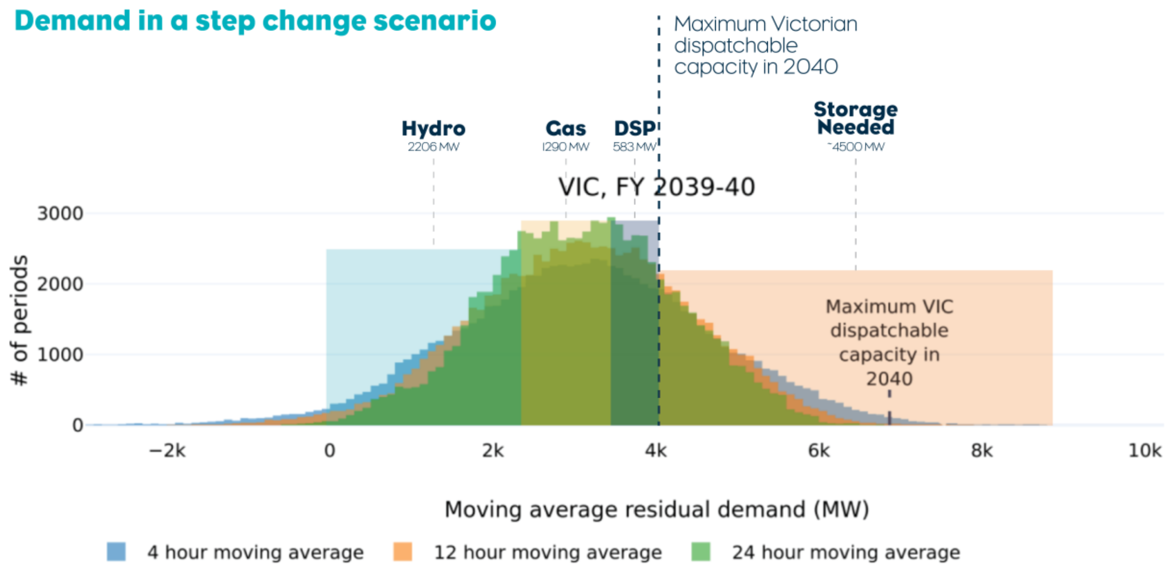

Figure 23: Residual demand graphic from VEPC report with dispatchable capacity overlay (Step Change scenario)

We also note that the CSIRO's GenCost 2020-21 consultation draft reached a similar outcome to our Supplementary Analysis Report that batteries tend to be more competitive in short storage duration applications, while PHES is more competitive in long-duration applications. Figure 24 (below) shows that the long-duration storage in Tasmania is at least 2 to 4 times more cost-effective than equivalent long-duration storage provided by batteries.[104]

[104] Graham, P., Hayward, J., Foster J. and Havas, L.2020, GenCost 2020-21: Consultation draft, Australia.

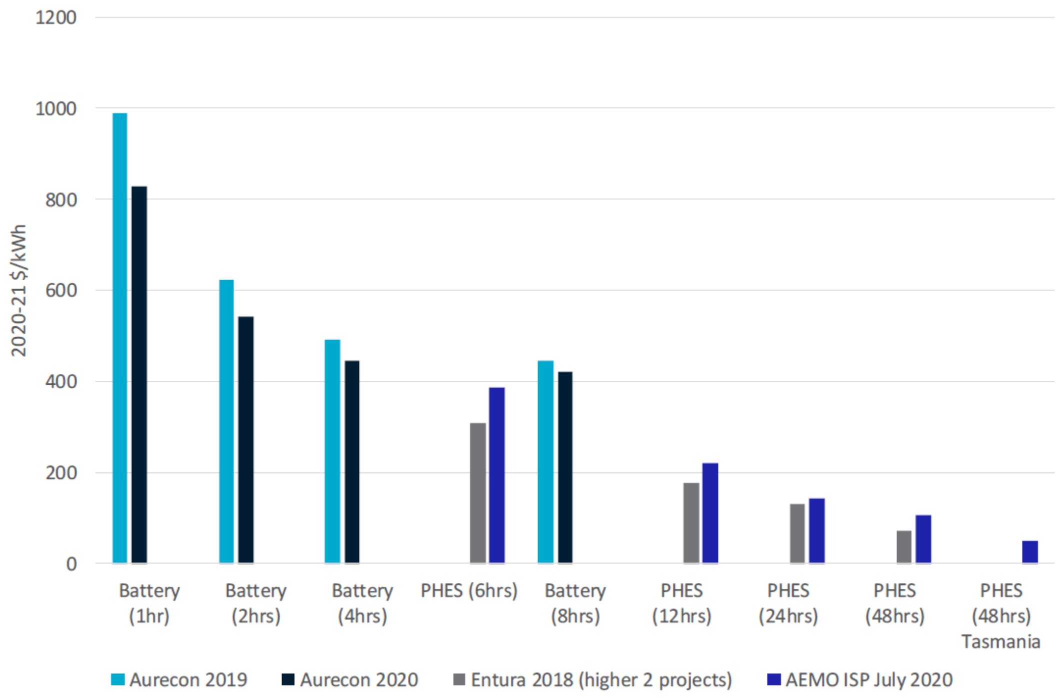

Figure 24: Cost summary of various storage technologies (CSIRO Gencost studies 2020-21)

8.5.2 Modelling insights on batteries and pumped hydro energy storage

Some stakeholders have suggested that recent announcements related to potential commissioning of battery projects indicate a trend that long duration storage unlocked by Project Marinus may not be needed. As previously noted in the Supplementary Analysis Report, even with the latest draft IASR inputs (that indicate a further reduction in battery costs) our modelling continues to indicate that shallow and LDES will play a complementary role in this energy transition.

The latest load forecasts indicate a further acceleration in this trend, with the operational load profile evolving such that:

- the minimum system demand is coincident with the daylight hours (the period with rooftop and utility scale solar generation); while
- the maximum operational system demand is forecast to occur during the hours following the sunset.

This places an enormous operational strain on the generators to modulate their output to match the needs of the system. In the future, this strain on generators can be reduced with the installation of shallow storage technology that assists in peak-shifting/shaving across the day.

With the assumption of perfect foresight, the least cost modelling optimises the system need for short term and long duration storage over the modelling period. With the continued electrification of the economy, peak demand on the system is managed through a combination of solutions like energy efficiency measures, behind the meter storage, demand side participation, and the residual super-peak requirements of the system are met through the installation of batteries, with assistance from pumped hydro.

This observation is validated by the modelled installation of over 31,000 MW of battery capacity by 2050, with the total available energy from this resource being approximately 70,000 MWh, as shown in Figure 25 below. This implies an average total storage duration of slightly over 2 hours.[105] This storage depth is an average across all the behind the meter storage and utility scale batteries, with behind the meter options tending to be of a shorter duration (typically 1 hour) and utility scale solutions lasting up to 8 hours.

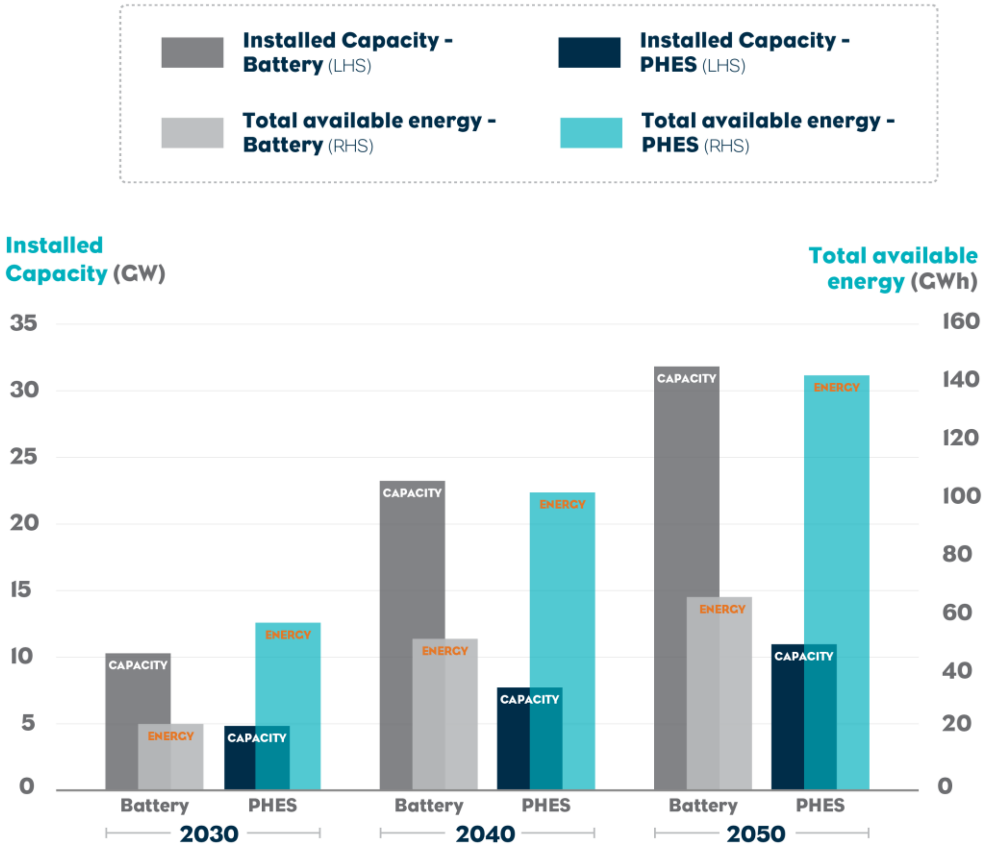

Figure 25: Projected installed capacity and energy for batteries and PHES

[105] This is typically referred to as an energy to power ratio.

In comparison, the pumped hydro storage option while only providing about a quarter of the installed capacity needs of the system (10,000 MW), provides on average at least 12 hours of storage. In aggregate, by 2050, pumped hydro would provide more than double the energy compared to installed battery capacity.

The capacity and energy contribution of both short-duration storage options like Lithium-ion batteries and LDES like pumped hydro is summarised in the figure below. The capacity and energy mix between short-duration storage technology and long-duration energy storage systems is consistent with a recent system-level decarbonisation research paper published by the MIT Energy Initiative.[106] The paper goes on to suggest that diverse transmission and traditional LDES options (like pumped hydro) must be pursued as some of the other LDES technology types like vanadium redox flow batteries, aqueous sulphur flow batteries, and firebrick resistance-heated thermal storage may not be able to achieve the required technological breakthroughs in time to facilitate the energy transition.

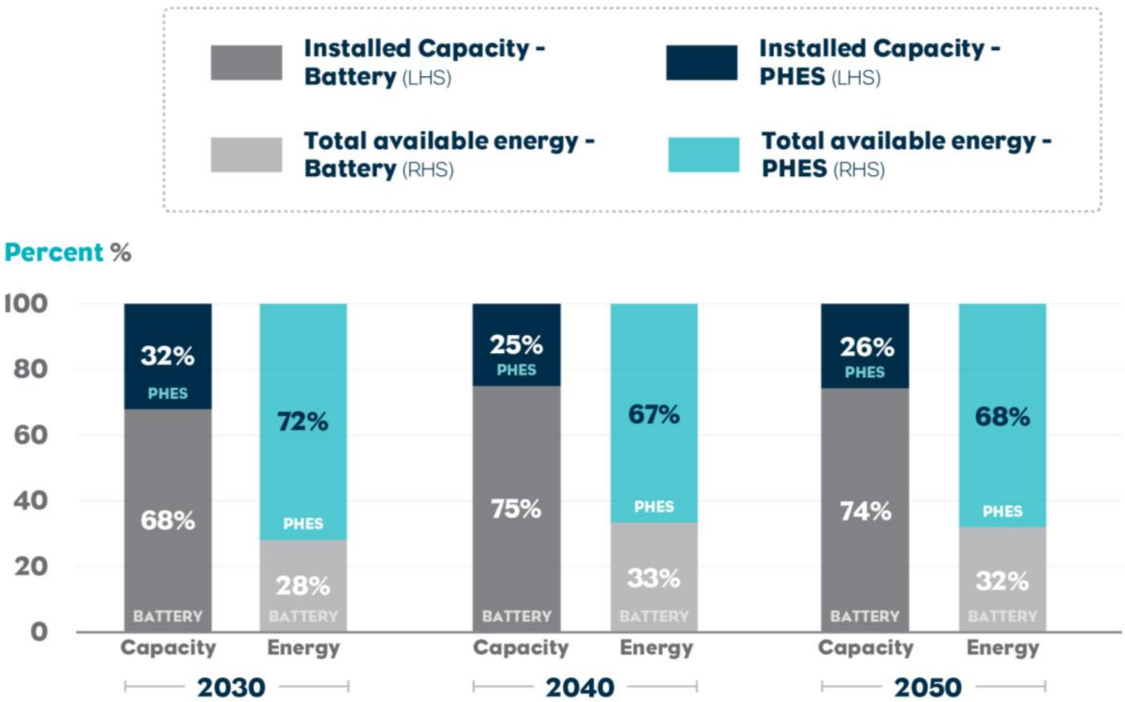

Figure 26: Projected installed capacity for batteries and PHES

[106] Sepulveda, N.A., Jenkins, J.D., Edington, A. et al. The design space for long-duration energy storage in decarbonized power systems. Nature Energy (2021).

The pace of transition in the NEM is best compared to the Californian grid in the United States and some of the European power systems with high renewable penetration. A recently published landmark study into California's grid to achieve a reliable supply of 100 per cent renewable energy and zero-carbon resources for electric retail sales to end-use customers by 2045, also found an unequivocal and urgent need for significant deployments of LDES between now and 2045 to achieve the decarbonisation objectives of the state.[107] These examples from overseas jurisdictions reinforce the findings in this PACR that Project Marinus has an important role to play, given the future needs of a low carbon NEM.

8.5.3 Frequency of VRE droughts in the NEM

In response to the VRE drought analysis presented in the Supplementary Analysis Report, stakeholders sought additional information regarding the frequency of such a drought occurring in the NEM. Before addressing this issue, it is worth reiterating that the value provided by Project Marinus is not limited to assisting the management of renewable energy droughts. More broadly, Project Marinus also provides benefits in managing seasonal storage of energy, contributing to the lowest cost integrated energy solution of generation and absorbing mainland Australia's excess renewable energy, as explained in section 8.3.

Turning to the issue of the frequency of VRE droughts, two factors suggest our modelling approach will tend to understate the system challenges they are likely to create:

- The perfect foresight nature of market modelling leads to the optimum development of generation to minimise VRE droughts, in contrast to the real-world conditions in which the incidence and extent of VRE droughts cannot be predicted.
- The model uses weather data from a nine-year period, which is unlikely to capture 'tail' events that expose the system to the impact of extreme events. These tail events may include the coincident impact of low wind and solar generation, which will exacerbate the pressures on the system.

These factors mean that the actual costs of managing VRE droughts is likely to be greater than indicated in the model. In the 'without Project Marinus' case, it means that additional gas fired generation and battery storage will be required to meet these needs. In contrast, the 'with Project Marinus' case is likely to be able to address these additional system requirements without any increase in costs. In other words, Project Marinus provides additional 'insurance cover' against VRE droughts, which is not appropriately valued in the cost benefit analysis.

To demonstrate the frequency of VRE drought influenced by lack of wind output, the figure below shows the frequency of wind generation in Victoria being reduced by 95 per cent compared to the total installed capacity

[107] Long Duration Energy Storage for California's Clean, Reliable Grid, December 2020.

of the available resource. For instance, even though almost 10,000 MW of wind capacity is installed in Victoria by 2050, during a wind drought, only 500 MW is generating to meet customer demand. The data below shows the frequency of wind droughts lasting from between 6 hours and 42 hours on average in a year. The figure demonstrates that despite the perfect foresight nature of modelling, sustained periods of wind droughts are not an uncommon outcome. In addition, the analysis was replicated in a counterfactual case with no transmission expansion permitted, including projects classified as committed in section 6.2.3, with the same threshold of 5 per cent wind generation.[108] The outcomes for this analysis indicate that the frequency of wind drought increases up to fourfold, since the diversity of wind generation from various REZs is curtailed due to a lack of transmission development. Moreover, each NEM region would have to build its own generation/system redundancies to manage wind drought.

The analysis of wind generation patterns provide critical insights, namely that:

- Investment in strategic transmission infrastructure significantly reduces the need for long-duration energy storage by allowing better sharing of renewable resources across the NEM; and
- The alternative to investing in transmission infrastructure involves incurring material expenditure on long-duration energy storage at locations where it may not be suitable.

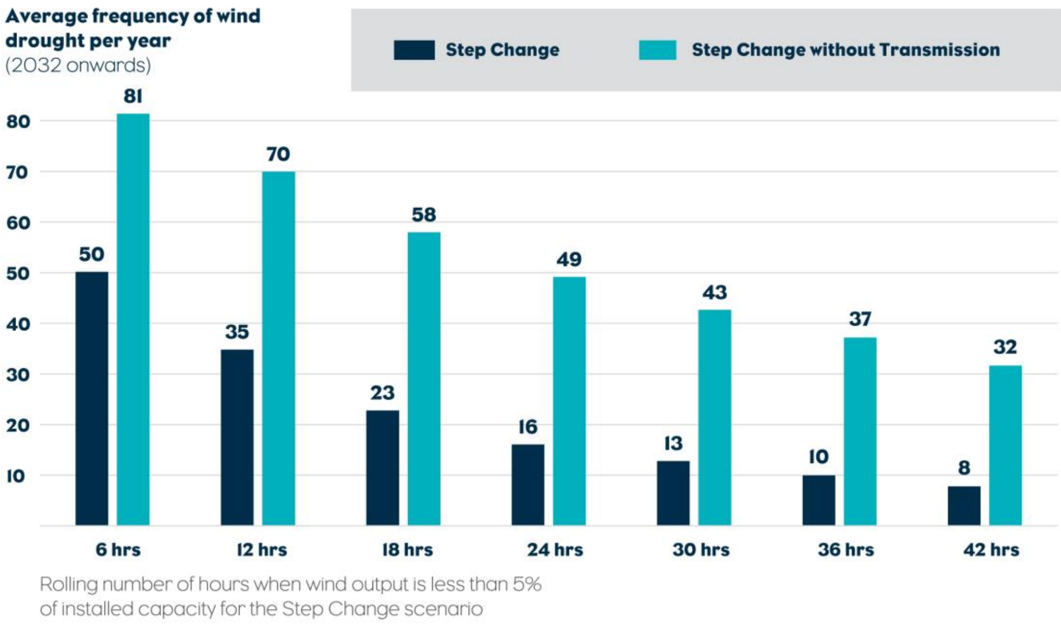

Figure 27: Frequency of annual wind drought for Victoria – with and without transmission[109]

[108] The installed capacity of wind in the no transmission case is one-third of the with transmission case.

[109] Rolling average 6 – 42 hours with wind output less than 5 per cent of installed capacity, Step Change scenario with Project Marinus installed in 2027 (Stage 1) & 2029 (Stage 2) for the modelling period from July 2032 until June 2050.

The analysis above shows the frequency of wind drought, noting that the impact on the system may be exacerbated by a coincident reduction in solar generation. As already noted, our modelling approach tends to downplay the challenges and costs of addressing VRE droughts.

In summary, our assessment is that the current treatment of VRE droughts in our modelling is likely to understate the net economic benefit provided by Project Marinus. In particular, Project Marinus enables access to existing spare hydro capacity in the Tasmanian system, along with the development of long-duration pumped hydro and access to one of the best wind resources in the NEM. It is likely that Project Marinus will be able to help to manage the risks of VRE drought not captured in our modelling, at zero incremental cost.

9 Other project considerations

Key messages

- Stakeholders have raised other considerations that are not strictly to be addressed in the RIT-T process, but nevertheless raise important issues. These considerations are transmission pricing, i.e. who pays for Project Marinus' services, and the effective management of project costs, which experience shows are often under-estimated.
- In relation to transmission pricing, we have conducted further work which shows that the benefits of Project Marinus are fairly evenly spread across the NEM regions, on a $/MWh basis. Our view is that this analysis supports a simple 'fair sharing' method for major interconnectors such as Project Marinus.
- In relation to the management of project costs, there are a number of regulatory safeguards to ensure that Project Marinus will only proceed if it is consistent with AEMO's optimal development path. In addition, we have robust tendering processes, and project management and governance arrangements, which should provide stakeholders with confidence that we will deliver the project efficiently.

9.1 Transmission pricing

Stakeholders have highlighted the importance of the 'who pays' question in relation to Project Marinus. The focus on this question has arisen from TasNetworks' and the Tasmanian Government's concern that the current transmission pricing arrangements would recover approximately 50 per cent of the project costs from Tasmanian customers, while the benefit from the project will be shared more broadly across the NEM regions.

To address this matter, the Energy National Cabinet Reform Committee has agreed that the Commonwealth should take the lead on progressing work on the fair cost allocation for major transmission infrastructure, in consultation with interested jurisdictions. TasNetworks is encouraged that the Commonwealth is progressing the issue of fair transmission pricing and we look forward to continuing to work with all stakeholders to find a workable resolution.

As a further contribution to the debate, we published a report titled 'How Do Customers Benefit from Project Marinus?'[110] that presents the results of modelling undertaken by FTI consultants[111] on behalf of TasNetworks.

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[110] TasNetworks, How do customers benefit from Project Marinus? - Summary Report.

[111] FTI Consulting is an independent global business advisory firm.

FTI's modelling approach differs in two respects from the modelling undertaken by Ernst & Young and GHD, which is the subject of this PACR:

- FTI focuses exclusively on the impact of Project Marinus on customers, rather than considering the net economic benefit across the NEM; and
- FTI's modelling takes account of generators' likely bidding behaviour, rather than assuming that generators' bids will always reflect their marginal costs.

By focusing specifically on customer benefits, FTI's modelling approach addresses the question of whether customers can expect to be better off if Project Marinus proceeds compared to a situation in which it does not. This analysis differs from the RIT-T, which is required to consider the net economic benefit to all those who produce, consume and transport electricity, without specifically considering how the proposed project will affect customers.

Our Summary Report explains that Project Marinus has the ability to put downward pressure on wholesale energy prices by introducing an additional 1500 MW of dispatchable capacity into the NEM, accessing the existing spare and refurbished dispatchable capacity in the Tasmanian hydro-electric system for the first stage of the link, and enabling the development of long-duration pumped hydro facilities with the second stage. This lower cost dispatchable energy helps to suppress price rises from more expensive solutions that would otherwise be required in the NEM.

The figure below summarises a key finding from FTI's modelling of customer benefits. It shows that customer benefits vary modestly between regions if we examine the impact on wholesale generation prices, with four regions benefitting by either $4/MWh or $5/MWh.[112] Therefore, the differences between the total customer benefits for each region are driven principally by the differences in the total volume of energy consumed in each region, rather than the differences in the expected price reductions per unit of energy.

[112] It should be noted that the results presented here are based on the data used in our Supplementary Analysis Report rather than the updated modelling in this PACR. Nevertheless, we consider that the conclusions are unlikely to be affected if the report were updated for the latest modelling results.

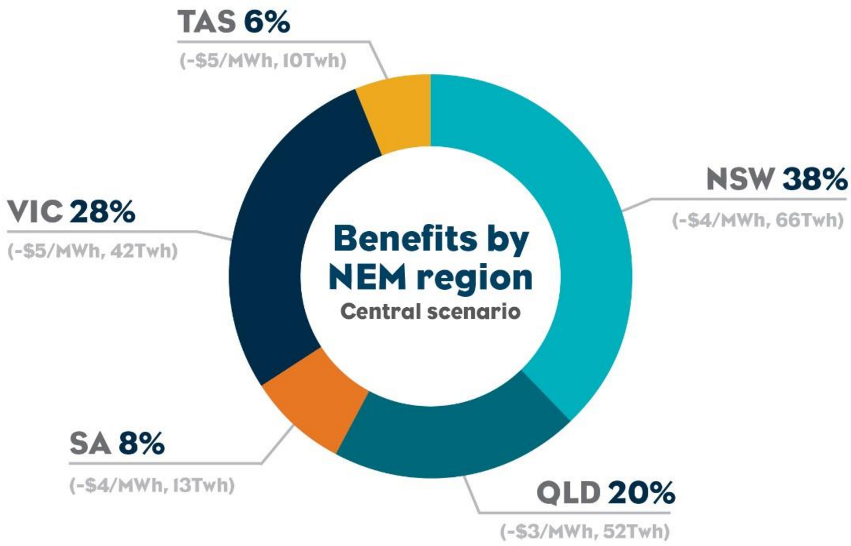

Figure 28: Gross benefits by NEM region for Central Scenario based on projected reduction in wholesale electricity price and annual energy consumption[113]

The above analysis reinforces our earlier view that it would be unfair and inefficient for Tasmanian and Victorian customers to each pay, say, 50 per cent of the costs of Project Marinus, but only receive 6 per cent and 28 per cent respectively of the total customer benefits. By the same token, however, the analysis also shows that a simple pricing method that shared the costs of Project Marinus across the regions according to the volume of energy consumed would deliver a much fairer and efficient outcome for customers.

TasNetworks supports the development of a pragmatic solution to the fair pricing issue, so that Project Marinus can obtain broad support from customers across the NEM, all of whom should benefit if the project proceeds.

9.2 Management of project costs

A number of stakeholders raised concerns regarding the possibility that project costs will increase above the forecasts presented in our RIT-T assessment, particularly given recent experiences in relation to Project EnergyConnect.

[113] The FTI analysis relies upon the efficient-market hypothesis and prevalence of a free market system with supply and demand determining the electricity market price with minimal government control. However, in instances of extreme price volatility, governments do intervene in the market to protect customers from excessive price increases. For instance, the analysis assumes that Tasmanian consumers pay the Tasmanian contract price, which is assumed to equal the Victorian price. The Tasmanian regulatory instrument that this assumption relies on is currently under review and this may reduce the level of modelled benefits received by Tasmanian customers.

Against this background, TasNetworks considers it important that stakeholders understand the safeguards that are in place to protect them from unexpected or inefficient increases in project costs. As explained in section 1.4, AEMO's feedback loop and the AER's revenue setting process ensures that:

- the project will only proceed if it is consistent with AEMO's optimal development path; and
- the amount of revenue to be recovered reflects the prudent and efficient costs of delivering the project and cannot exceed the amount specified by AEMO through its feedback loop.

In addition, the sensitivity analysis that we have undertaken in this PACR shows that even if the project costs increase to $3.8 billion ($2020), Project Marinus remains justified in terms of maximising net economic benefit in accordance with the RIT-T. Furthermore, stakeholders should have confidence in our project cost estimates presented in this PACR, which have been reviewed by Jacobs. As already noted, the Jacobs report is provided as Attachment 3, so that their review and findings are transparent.

In addition to the regulatory checks and balances that are in place to ensure that only efficient projects proceed, and only efficient costs are recovered from customers, TasNetworks is implementing project management and governance arrangements that are designed to drive an optimal outcome for customers. In particular, a rigorous tender and procurement process has been developed that will ensure that the project is delivered in an efficient and timely manner, in accordance with our project plans.

TasNetworks expects to engage with the AER in relation to its tender process and broader project governance arrangements as part of the revenue setting process for Project Marinus. While the specific details of the revenue setting process for Project Marinus are yet to be finalised, we envisage that these arrangements will include transparent cost forecasting arrangements and consumer engagement with a view to ensuring cost allowances are efficient and project risks are able to be managed effectively.

10 Next steps

This PACR concludes the RIT-T process for Project Marinus and, therefore, the formal consultation process has also been concluded. We thank all stakeholders that have engaged in the process. All enquiries relating to this document or requests for information should be directed to:

Stephen Clark
Project Director, Marinus Link
PO Box 606, Moonah TAS 7009
Email: team@marinuslink.com.au

From a regulatory perspective, the next stage of the process is to work with the AER and AEMO on the revenue setting arrangements for early works and Stage 1 of the project. A key part of this process will be the application of AEMO's feedback loop, which will verify that each stage of the project is consistent with AEMO's optimal development path in terms of its scope and forecast cost. Our expectation is that Stage 1 of the project will be assessed following the publication of the 2022 ISP. Stage 2 will be assessed either alongside or subsequent to the assessment of Stage 1 (depending on the findings of the 2022 ISP).

We will continue to consult with customers and stakeholders on the progress of the project and the revenue setting arrangements, as further information becomes available.

Appendices and attachments

Attachments are located on our website alongside this PACR.

Appendices:

Appendix 1: Our response to stakeholders' submissions to our PADR and Supplementary Analysis Report;

Appendix 2: Technical analysis summary for the preferred option;

Appendix 3: Explanation of net economic benefit calculation using a shortened study period; and

Appendix 4: Our compliance checklist, which demonstrates that this PACR meets the Rules requirements.

Independent expert reports:

Attachment 1: Ernst & Young's market modelling report;

Attachment 2: GHD's assessment of ancillary service costs (unchanged from PADR studies); and

Attachment 3: Jacobs' review of the estimated project costs

Appendix 1 – Summary of submissions to the PADR and Supplementary Analysis Report

(a) Submissions to the Project Assessment Draft Report (PADR)

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
AEMO	• The market modelling and supplementary information papers published alongside the PADR, including the hourly data relating to generation, demand and interconnector flows, are a positive initiative in delivering transparency for those interested in participating in this RIT-T process. • In the Draft 2020 ISP, AEMO recommended progressing with the design and regulatory approvals process for Marinus Link, with the intent of making the project 'shovel- ready'. The ISP identified this as a low-regret approach that will allow time for further assessment and certainty before the 2022 ISP, while ensuring project delivery remains possible by as early as 2027-28 if a decision to proceed is made by 2023-24. • AEMO has worked co-operatively with TasNetworks to ensure that any impacts of Marinus Link on the Victorian transmission network are well understood and factored into the analysis. This has included an understanding of network impacts across a range of possible Victorian landing points, and the broader implications for network utilisation and Victorian interconnections with other States. These impacts have been shared with the Project Marinus team and summarised in AEMO's Victorian Annual Planning Report.	• TasNetworks welcomes AEMO's observations regarding the transparency of the information we provided alongside the PADR. Our view is that the Supplementary Analysis Report and the PACR will further advance the transparency of the RIT-T process and encourage stakeholder engagement. • TasNetworks notes AEMO's comments in relation to the draft 2020 ISP and the rationale for requiring Marinus Link to be 'shovel ready' as a low-regret approach. As explained in chapter 4 of the Supplementary Analysis Report and section 4.8 of this PACR, the 2020 ISP has provided additional clarity regarding the staging of Marinus Link and the application of decision rules to determine the timing for the completion of Stage 1 and 2 of the project. The further analysis in this PACR broadly supports the conclusions in the 2020 ISP. • TasNetworks welcomes the assistance provided by AEMO throughout the RIT-T process for Marinus Link, in addition to AEMO's engagement in the development of the 2020 ISP. We look forward to continuing to work with AEMO in the next phases of Marinus Link.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Basslink Pty Ltd (BPL) and ACIL Allen for BPL	• BPL refers to the findings in ACIL Allen's report (summarised below). BPL comments that Basslink has capacity for expansion in a bipolar configuration, but has not been engaged on this option (which could double existing capacity). • The estimated gross market benefits in the PADR scenarios are between 45 per cent and 200 per cent higher than gross market benefits in the earlier IFS Neutral scenario. • ACIL Allen conclude that the new investment in CCGTs projected by EY is highly unlikely and the projected operation of these CCGT at high capacity factors would also be highly unlikely. The estimated gross benefits are dependent on these projections and therefore are 'fundamentally flawed'. • ACIL Allen considers the demand forecasts utilised in three of the four main PADR scenarios unreasonable and likely to overstate the market benefits of Project Marinus. • ACIL Allen also raise concerns that cost benefit analysis is only conducted to 2049-50, with assumptions made about the remaining 20 years of the asset life. ACIL Allen consider these assumptions to be unrealistic (because they rely on gas fuel savings post 2050) and they overstate the total benefits from the project. • BPL also comment that many issues still need to be resolved in relation to the location, configuration and environmental issues associated with Marinus Link. BPL is happy to contribute to exploring these issues with Project Marinus.	• The expansion of Basslink was discussed in section 4.8 of the PADR, but found to be technically infeasible and therefore was not considered further. One issue of concern is that increasing the capacity of Basslink does not offer any route diversity and, therefore, a single event could render the entire interconnector inoperable. The proximity to the North West Tasmanian REZ is also a factor in selecting the Tasmanian connection and transmission upgrade options, as it allows existing and new generation resources in the region to access the interconnector capacity. • The Initial Feasibility Study (IFS) concluded that there are plausible circumstances where Marinus Link could be economically feasible from the mid-2020s. Following the completion of the IFS and consultation on its findings, TasNetworks completed the cost benefit analysis in accordance with the RIT-T requirements and published the PADR. The net economic benefits of Marinus Link have remained robust between the PADR and this PACR. • In relation to ACIL Allen's comments regarding the new investment in CCGTs, the modelling in this PACR principally relies on AEMO's input data and assumptions, including those relating to CCGT performance. • ACIL Allen is correct that our analysis has been limited to 30 years from 2020/21 to 2049/50. The shortening of the study period is a standard approach, which has been adopted in other recent RIT-Ts and the ISP. Appendix 3 of this PACR examines this issue in further detail. • TasNetworks agrees with BPL that many issues need to be resolved in relation to the location, configuration and environmental issues. TasNetworks looks forward to working with stakeholders in resolving these issues.
Clean Energy Council (CEC)	• The CEC strongly supports new transmission investment in the National Electricity Market (NEM) that demonstrates rigorously tested	• TasNetworks agrees with CEC that efficient investment in transmission can deliver substantial benefits, including lower total electricity costs for customers and improved system strength and resilience. This is one of the key findings of the 2020 ISP. For regulated transmission

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Clean Energy Council (CEC) (continued)	benefits to consumers. The lack of transmission is now one of the most critical challenges facing the transition of Australia's energy system. • While robust and thorough scrutiny of large-scale transmission investments should occur, we believe that TasNetworks has adequately demonstrated the significant benefits that Marinus Link can deliver, alongside other interconnection investments. • CEC identifies three key benefits from Marinus Link: (1) Facilitating the benefits of the Battery of the Nation project; (2) Contributing to the achievement of Victoria's VRET ambitions; and (3) Obtaining the benefit of diversity in wind generation between Victoria and Tasmania. • The CEC supports the significant potential that Tasmania presents to the energy system through the storage assets that would be unlocked through Marinus Link.	investments that are financed by electricity customers, it is essential that the case for investment is warranted on efficiency grounds in accordance with the RIT-T. • TasNetworks welcomes CEC's observations regarding the likely benefits that Marinus Link can provide alongside other interconnector investments. Chapter 7 of this PACR confirms that the expected net economic benefits from Marinus Link are significant. • TasNetworks agrees with CEC's observations in relation to the types of benefits that Marinus Link will deliver. Table 16 of the PADR quantifies the different categories of benefits from Marinus Link. An updated table is provided in Chapter 7 of this PACR. • TasNetworks welcomes CEC's support and shares its view that Tasmania has material value to provide in relation to storage assets, as the share of renewable generation across the NEM increases. The analysis presented in chapter 8 of this PACR confirms this view.
Energy Australia	• The optimal timing of Marinus Link appears to be considerably uncertain. Our view is that the evidence currently before stakeholders, in addition to the uncertainty posed by COVID-19 impacts, justifies a delay in considering this project for regulatory purposes. • TasNetworks should be clearer where its analysis of government subsidies reflects modelling requests from governments or other stakeholders, and clearly call out where possible policy interventions would result in departures from optimal project scope or timing and added costs for consumers. • The allocation of costs of transmission interconnection is an important issue. TasNetworks should ensure its RIT-T produces relevant and robust data to inform consultation on this issue (which is being led by the Energy Security Board). • Least cost optimisation and perfect foresight modelling relied on by TasNetworks has inherent shortcomings which over-state the value of	• TasNetworks agrees with Energy Australia that there is uncertainty regarding the optimal timing of Marinus Link. In part, this reflects the unprecedented transformational changes that are taking place across the NEM as we move towards a lower carbon future. COVID-19 is a factor to consider in our scenarios and sensitivity analysis as part of the RIT-T process. As noted in section 3.3 of this PACR, we have adopted the ISP Rules to ensure that Marinus Link is subject to AEMO's feedback loop before proceeding. • TasNetworks concurs with Energy Australia's comments regarding Government subsidies and policy positions. Section 6.3.1 of the PADR discussed the possibility of Government supporting early delivery of the project. TasNetworks will continue to adopt a transparent approach in relation to such matters, in accordance with the RIT-T requirements. • TasNetworks also agrees with Energy Australia's comments in relation to transmission pricing. We will continue to work with the regulatory

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Energy Australia (continued)	interconnection and pumped hydro over the modelling period. Modelling may assume that the cost of this capacity is sunk and therefore always bid into the market at zero cost, whereas other bidding assumptions are likely to be more realistic. • As we have separately stated to AEMO in its draft ISP consultation, we seek further justification for progressing Marinus Link to a 'shovel ready' status ahead of the 2022 ISP. In particular, we would like to see a demonstration that the project would stall for an extended period if not progressed now, including the inability to achieve an earlier commissioning date e.g. 2028 if this is subsequently found to be prudent given changing market conditions. • The resolution of the 'who pays' question will be assisted if TasNetworks, AEMO and other RIT-T proponents produce estimates of regional costs and benefits. • We have concerns that TasNetworks' analysis has accommodated the potential for government interventions that would result in suboptimal investment timing. • We also have some detailed suggestions for TasNetworks in improving its modelling, including the treatment of Snowy 2.0, scrutinising the heavy reliance on Tasmanian wind capacity, and a possible accelerated timing of VNI West.	bodies and other stakeholders to find a workable solution, having regard to the expected distribution of benefits across the NEM regions. • As explained in the PADR and chapter 6 of this PACR, Ernst & Young's market modelling examines the total integrated system costs of meeting customers' future electricity needs. The model selects the lowest cost combination of generation, storage, and demand-side response. It also considers the optimal timing and capacity of other interconnector options. TasNetworks recognises that this modelling approach assumes that bidding is cost reflective, which is a reasonable assumption for the purpose of assessing optimal transmission projects. • The 2020 ISP concluded that early works for Marinus Link should be an actionable project without decision rules. As explained in chapter 2 of this PACR, the possibility that Marinus Link may be required by 2027 supports the progress of early works for the reasons outlined in the ISP. • TasNetworks agrees with Energy Australia that the 'who pays' question may be informed by providing estimates on the regional costs and benefits. We provide further information on this issue in section 9.1 of this PACR. • The PADR explains that a government may want to bring forward the timing of Marinus Link, but would need to make an appropriate financial contribution in order to satisfy the RIT-T. TasNetworks considers this approach to be appropriate and transparent. • TasNetworks welcomes the feedback on the treatment of Snowy 2.0. As explained in section 2.3 of this PACR, we have adopted AEMO's latest input assumptions for the purposes of this PACR.
ENGIE	• ENGIE is concerned that the scenarios used to quantify project benefits are not sufficiently stretching and are not sufficient to correctly assess proposed benefits. Specifically, in this time of uncertainty and pandemic a scenario capturing the potential impacts of the COVID-19 on the	• The PADR explained that our modelling approach relied on AEMO's 2019 Planning and Forecasting Consultation Paper assumptions published in February 2019 (at the time of commencing our RIT-T assessment) as a starting point, recognising we must explain any deviation from AEMO's forecasts. The PADR noted that AEMO's

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
ENGIE (continued)	economy and the energy sector must be developed and used to properly assess the benefits of the Marinus Link. • Given the recent media coverage of commentary on the impacts on the economy, employment, manufacturing, and business and commerce in general, the impacts of COVID-19 on the electricity sector are likely to be profound. • ENGIE recommends that the RIT-T process must be repeated and include the potential impacts of a COVID-19 pandemic-like scenario. • The benefits are risky and occur way into the future, so the project should be delayed until an acceptable risk profile is obtained (or is funded by Tasmanian generators and customers without a need for a RIT-T assessment).	position would continue to evolve in response to stakeholder feedback and new information. In this PACR, we have adopted the scenarios developed for the 2020 ISP and AEMO's latest input assumptions. • COVID-19 is a significant national and international crisis, which has undoubtedly led to unprecedented shocks to economic activity. As a major infrastructure project with an asset life in excess of 40 years, careful consideration needs to be given to the impact of COVID-19 on the cost-benefit assessment for Marinus Link. At this stage, the most appropriate approach is to adopt AEMO's latest input assumptions. • As explained in section 3.3 of this PACR, we do not consider that there is a case for restarting the RIT-T analysis, as suggested by ENGIE. • In relation to the riskiness of the benefits from Marinus Link, TasNetworks notes that the purpose of the RIT-T is to identify the option that maximises the present value of net economic benefits. As such, the RIT-T has been designed to take account of risk and uncertainty in selecting the preferred option. The RIT-T analysis shows that the 'do nothing' option is more costly than Marinus Link. As a consequence, a decision to defer the project would not be the most economic option. The updated cost-benefit assessment in this PACR confirms that conclusion.
Energy Users Association of Australia (EUAA)	• We caution that during this time of significant change and uncertainty it will be vital to remain flexible regarding project scope including capacity and timing. We also urge you to consider new approaches to cost recovery that seek to spread the cost and inevitable risks over a broader group of stakeholders, including generators, than is currently the case. • While we note that TasNetworks have modelled a number of key sensitivities. We would encourage you to keep reviewing not only these sensitivities, as they can change in nature and impact, but also new risks and sensitivities as they emerge.	• TasNetworks agrees with EUAA that change and uncertainty must be factored into the assessment of Marinus Link. This PACR has reviewed the case for Marinus Link, based on the latest AEMO scenarios, inputs and assumptions. Based on findings of the 2020 ISP and this PACR, we hope to complete the early works and reach Final Investment Decision for Project Marinus by 2023-24. In relation to cost recovery, we will discuss this issue with the AER and other stakeholders to develop a workable approach that is equitable and efficient. • TasNetworks concurs with EUAA's comments in relation to the importance of sensitivity analysis.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
EUAA (continued)	• EUAA highlights the significant uncertainty in relation to the cost estimates for Energy Connect. We strongly suggest that TasNetworks maintains a close watch on this situation and to take a conservative approach to capex assumptions given they are highly likely to trend toward the upper boundary of expectations if not beyond. • The recent decisions at COAG Energy Council (including in relation to Retailer Reliability Obligations (**ROO**) and other energy market initiatives) and the outcome of the post 2025 Market Review may have significant implications for Marinus Link, which should be included in the sensitivity analysis to the extent possible. • EUAA support a staged approach to Marinus Link, similar to TransGrid's approach to its project 'Powering Sydney's Future'. • A case could be reasonably made that due to the impacts of COVID-19 that the "Global Slowdown" scenario is likely to occur, significantly reducing net market benefits. When combined with higher capex and a weak Australian dollar, charging ahead with a 1500 MW link may be optimistic. • We believe that if you are going to broaden the concept of who pays to go beyond consumers in the two regions connected by Marinus Link (because it is argued that the benefits go beyond those jurisdictions) then the same rationale must hold true for the expansion of the concept of who is a beneficiary. • We are concerned that the rapid rate of change in technology, fundamental changes in end user behaviour and significant political and regulatory uncertainty make the benefits from future investments such as Project Marinus difficult to assess from a consumer perspective. The EUAA are of the view that where there are multiple beneficiaries of new energy assets like Project Marinus then the costs and risks should be equitably shared.	• TasNetworks agrees with EUAA's comments in relation to uncertainty in the cost estimates for major capital projects. This issue is discussed in section 9.2 of this PACR. • TasNetworks notes that the COAG Energy Council reforms are focused on co-optimising generation and transmission investments, in addition to promoting non-network solutions. The RIT-T modelling for Marinus Link implicitly assumes that the market arrangements will support co-optimisation to deliver the lowest cost outcomes for customers. Accordingly, any reforms introduced by the COAG Energy Council are likely to support our modelled outcomes. At this stage, therefore, we do not anticipate that the RRO or post 2025 Market Reform initiatives will affect the cost-benefit assessment for Marinus Link. We will, however, continue to monitor these developments. • This PACR has reconsidered the staging options for the project, which should address the points raised by EUAA. • As already noted, COVID-19 is a significant shock to the national and international economy. Our view is that the issue is best addressed by adopting AEMO's latest input assumptions and applying its feedback loop prior to the commencement of Stage 1 of the project. • The question of 'who benefits' from Marinus Link and the pricing arrangements is being progressed by ESB and the Energy National Cabinet Reform Committee. As outlined in section 9.1, TasNetworks supports a practical resolution of these issues that is acceptable to all parties. • In relation to the RIT-T, the Rules require the assessment of the project to be made on behalf of all those who produce, transport and consume electricity. TasNetworks notes that the RIT-T does not require the sharing of the benefits across the sectors to be identified.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Hydro Tasmania	• Hydro Tasmania supports a 1500 MW Marinus Link delivered progressively as two cables in 2027 and 2028. This provides the greatest resilience to the NEM and in particular to the Victorian region. It will support the development of further wind and solar by providing a customer for this energy during high generation periods. • Marinus Link will complement the other strategic Group 1 and 2 investments outlined in the ISP including those currently going through the RIT-T process. It is Hydro Tasmania's view that Marinus Link will enhance the energy security of the NEM, particularly the Victorian region; increase competition; and support the development of wind and solar resources both in Tasmania and Victoria. • TasNetworks should continue to progress the RIT-T, design work and approvals for Marinus Link to ensure that it can be available as soon as is technically feasible. Maintaining current momentum will be critical to ensure optionality and can provide additional resilience to AEMO NEM-wide planning processes. • It is of paramount importance that TasNetworks, the AER and AEMO continue working together so that these benefits can be realised. Hydro Tasmania strongly supports maintaining current progress and optionality for Marinus Link (targeting delivery of 1500 MW by 2028) and examining an appropriate cost-allocation methodology for this strategic interconnection. • The competitive advantage of the Tasmanian pumped hydro development opportunity must be accurately reflected in the next round of Marinus Link and ISP modelling. Further, confidential evidence can be provided to both TasNetworks and AEMO if necessary. • Long-duration pumped hydro storage will be hard to find in Australia and sites identified through desk-top studies can experience significant challenges when progressing to full feasibility, mainly due to geological challenges. AEMO's ISP has identified the strong future system demand for deep energy storage. Sites in later stages of development,	• TasNetworks notes Hydro Tasmania's support for Marinus Link and the benefits it expects the project to deliver to Victoria and the NEM. • As explained in the PADR, Ernst & Young's modelling assumed that the 'Group 1' and 'Group 2' projects will proceed. In addition, where specific projects have progressed, such as Western Victoria RIT-T and project EnergyConnect, these projects were also included in the market modelling. As explained in section 2.3 of this PACR, we have aligned our project assumptions with AEMO's latest views. • TasNetworks notes Hydro Tasmania's comments that the project should continue so that momentum can be maintained and the benefits achieved. From a RIT-T perspective, it is important that the project is justified on economic grounds. In this regard, the benefits of completing early works of the project by 2023-24 has been noted in chapter 7 of this PACR, in addition to other staging options. • TasNetworks agrees with Hydro Tasmania that the resolution of the pricing issues requires close collaboration between a number of stakeholders, including the ESB and other stakeholders. TasNetworks is continuing to work with all stakeholders to reach a resolution on these issues. • TasNetworks agrees with Hydro Tasmania that assumptions regarding the costs of pumped storage in Tasmania compared to alternatives in mainland Australia is an important element in understanding the benefits that Marinus Link can provide. Further work has been undertaken in conjunction with AEMO to ensure that the assumptions adopted in this PACR reflect the best available information. In addition, section 7.5 contains a sensitivity regarding a commitment of 750 MW of pumped hydro in Tasmania. • TasNetworks notes Hydro Tasmania's comments in relation to long-duration pumped storage options in Australia. It should be noted that Ernst & Young's modelling approach does not require similar pumped storage options to be adopted on mainland Australia if Marinus Link does not proceed. Instead, the modelling seeks the lowest cost solution

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Hydro Tasmania (continued)	with studies confirming cost competitiveness, with technically and environmentally feasible outcomes should be prioritised.	to meeting the energy requirements of customers, without any preference for a particular technology mix or storage type. Nevertheless, the natural cost advantage of long duration pumped storage in Tasmania is a factor that is reflected in the model outcomes.
Origin Energy	• Delay the RIT-T until the outcomes of the 2022 Integrated System Plan (ISP) are known. We consider that it is inappropriate to finalise the RIT-T now for a project that is not required until at least 2028. In our view, for the RIT-T to be robust to potential futures, it is best carried out as close as possible to when the project is likely to be required. • We are concerned about the inconsistency between the outcomes of the draft 2020 ISP and the Marinus Link PADR. Our understanding of the draft 2020 ISP is that Marinus Link is not an actionable ISP project and does not yet form part of the optimal development path. • Assuming the RIT-T is not delayed, TasNetworks should at a minimum update its inputs and assumptions to reflect the 2020 ISP and consider re-issuing the PADR if the outcomes are materially different. • TasNetworks should reconsider its SA-related assumptions in light of the AER's findings in relation to Energy Connect, to the extent that they are relevant. • Origin Energy suggest additional sensitivity analysis including giving zero weight to the accelerated transition scenario; the impact of Government underwriting generation projects in Victoria and Queensland; and the impact of smelter closures in NSW and Victoria.	• TasNetworks appreciates the concerns raised by Origin Energy in relation to the desirability of ensuring that the RIT-T is robust to potential futures, particularly as the PADR indicated that the project may not be required until 2028. Chapter 7 of this PACR has re-examined the case for staging the project and its optimal timing. • TasNetworks recognises the importance of aligning the RIT-T with AEMO's latest forecasts and scenarios. A key purpose of the Supplementary Analysis Report was to address the concerns raised by Origin Energy and other stakeholders regarding the need for consistency between the RIT-T and the 2020 ISP. • TasNetworks agrees with Origin Energy's observations regarding the need to adopt updated inputs and assumptions. As explained in chapters 3 and 6 of this PACR, we have adopted AEMO's latest views. • TasNetworks notes the assessment of Project Energy Connect by the AER and the need to ensure that the cost estimates for the project are robust. This issue is discussed in section 9.2 of this PACR. • TasNetworks recognises the importance of sensitivity analysis as part of the RIT-T process. The impact of smelter closure is addressed in the Slow Change scenario. As explained in section 2.3 of this PACR, we have adopted AEMO's treatment of Government policies and projects.
Phil Bayley	• Private sector participation in funding the project, particularly equity, would highlight Tasmania's success in global capital markets and its potential as a place to invest in the future. There should be little difficulty in securing the private sector capital required to build Marinus Link.	• TasNetworks notes Mr Bayley's comments in relation to attracting private sector funding for the project. At this stage, the ownership and funding arrangements for Marinus Link have not been settled. It is a matter for the Tasmanian Government and others to determine the future funding arrangements.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Phil Bayley (continued)	• Economic and capital market conditions will affect the appropriate discount rate to apply in the next stage of the RIT-T, but this will be affected by the COVID-19 pandemic which is contributing to uncertainty in the wholesale market. Inflows to the hydro system and energy storage, particularly the price of batteries, also have the potential to change the economics of Marinus Link. • Snowy 2.0 will have a material impact on the optimal timing of Marinus, but it is neither a regulated project nor is the final investment decision likely to be solely based on a fully commercial and risk-weighted WACC given its political support. Tasmania's projects could be stranded by this re-ranking, particularly if Victoria and other states resist contributing through the price re-allocations in favour of their own preferred projects.	• TasNetworks agrees with Mr Bayley's comments in relation to the potential impact of COVID-19. Section 5.3 of our Supplementary Analysis Report considered the impact of COVID-19 on the project, noting that there remains considerable uncertainty regarding the longer term impact of the pandemic. Investment decisions – including assessment of 'do nothing' options – must be made in the context of the uncertainties that have resulted from COVID-19. • TasNetworks agrees with the observation that the economic case for Marinus Link depends, both positively and negatively, on other projects that are expected to proceed. TasNetworks' approach is to adopt AEMO's treatment of Government policies and projects.
TasCOSS	• TasCOSS acknowledges the great potential inherent in Project Marinus. A project of this size and scope has the potential to benefit many aspects of Tasmanian life, including through increased investment, boosting the local workforce and their communities, increased returns to government and importantly, supporting Australia to transition to a low-emissions, renewable energy future. • Our core concern is that the costs of Marinus Link also have the potential for detrimental consequences for Tasmanian consumers, in particular, residential consumers. • The illusive question of 'who pays' for the Marinus Link remains unanswered. Yet it is critical that Tasmanian households are not burdened with increased costs to fund an infrastructure project that principally benefits mainland customers and Tasmanian generators. • TasCOSS is not aware of a commitment by the Tasmanian Government that prices in Tasmania will not increase as a consequence of Marinus Link. If it can be confirmed by the Government, such a commitment would provide comfort to TasCOSS in our assessment of Project Marinus.	• TasNetworks notes TasCOSS' comments in relation to the potential benefits of Marinus Link. It should be noted that a number of the benefits mentioned cannot be included in the RIT-T analysis, which is focused solely on the benefits to those that consume, transport and produce electricity. Nevertheless, it is useful to note the wide benefits highlighted by TasCOSS. • TasNetworks notes TasCOSS' concerns regarding the potential cost consequences for Tasmanian customers if Marinus Link proceeds. The Tasmanian Government has highlighted this issue as a matter that will need to be addressed. TasNetworks has been working closely with regulatory bodies and other stakeholders to assist in resolving this issue. • TasNetworks concurs with the views expressed by TasCOSS in relation to the 'who pays' question. As noted in section 9.1, TasNetworks will continue to work collaboratively with relevant stakeholders for a satisfactory resolution of this issue. • TasNetworks notes TasCOSS' observations in relation to commitments made by the Tasmanian Government in relation to prices in Tasmania.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
TasCOSS (continued)	• We support changes to the National Electricity Rules (NER) that will deliver network cost allocations for interconnectors that are reflective of the benefits that those interconnectors provide across the NEM. In this regard, we welcome moves to implement a 'fair cost methodology' that are being progressed through the Energy Minister's COAG. • TasCOSS is yet to be convinced Tasmanian households will be net-beneficiaries of the Marinus Link, or that it will benefit Tasmania in general to the extent that it has the potential to, including delivering lower wholesale electricity prices to Tasmanian consumers and returns on investment that provide long-term benefits to the state as a whole.	Such commitments are outside the scope of the RIT-T and are matters for the Tasmanian Government. • ESB is currently considering the case for changing the existing transmission pricing arrangements, which may result in a change to the National Electricity Rules. TasNetworks will continue to work with regulatory bodies and other stakeholders to identify a workable solution. • TasNetworks notes TasCOSS' concern that Tasmanian households may not be net beneficiaries if Marinus Link proceeds. TasNetworks recognises that this is an important issue for Tasmanians. From a RIT-T perspective, TasNetworks notes that the investment decision considers the net economic benefits across the NEM, rather than the regional distribution of benefits to customers in each region.
Tasmanian Minerals, Manufacturing & Energy Council (TMEC)	• TMEC would like to acknowledge and commend TasNetworks for the work gone into this PADR. It is pleasing to read that both the documented feedback, verbal feedback and forum feedback has been taken seriously. • TMEC supports the two-staged proposal of a staged 1500 MW Marinus Link, constructed in 750 MW increments in 2028 and 2032. • TMEC is concerned about the question of 'who pays' for Marinus Link, noting that the link does not benefit Tasmanian customers. • TMEC is also concerned that imports from mainland Australia may not be renewable energy, damaging the Tasmanian renewable energy brand that the Tasmanian Government has committed to. • It is unclear why the reduction in 'prudent storage levels' has been included in the PADR when the levels are set by the Tasmanian Government and Hydro Tasmania. Assuming the levels will be reduced as part of a justification for Project Marinus is not considered in the best interests of TMEC members.	• TasNetworks welcomes the positive feedback from TMEC regarding the PADR and our consultative approach. TasNetworks is committed to effective engagement with its stakeholders to ensure that we understand and respond to our customers' views. • TasNetworks notes TMEC's support for the two-staged 1500 MW Marinus Link in 2028 and 2032, which was the preferred option in the PADR. This PACR provides a detailed reconsideration of the options in light of the latest available information. • TasNetworks notes TMEC's concerns in relation to the 'who pays' question. This issue is discussed in section 9.1 of this PACR. • The RIT-T does not consider the potential damage to Tasmania's 'renewable energy brand'. Nevertheless, TasNetworks does not share TMEC's concern in this regard, as Marinus Link would capture the benefits of Tasmania's natural advantage in renewable energy for the benefit of the wider NEM. • In relation to 'prudent storage levels', it is important to recognise that Marinus Link will provide additional energy security to Tasmania and

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
TMEC (continued)	• Project Marinus may provide a real alternative to the current FCAS market service providers for which customers will benefit from reduced charges in the market. TMEC has some concerns about what it will do to network system strengths, and welcomes TasNetworks openly discussing this in the PADR and understanding it must be addressed.	therefore a less conservative approach to storage for energy security purposes may be adopted. TasNetworks notes that a sensitivity was also conducted in the PADR with the prudent storage levels left unchanged. • TasNetworks notes TMEC's feedback in relation to the importance of network system strength.
Tasmanian Small Business Council	• TSBC submission was supported by two reports from its consultants, Goanna Energy and SavvyPlus Consulting, with financial support from Energy Consumers Australia. • There are very large risks to consumers in progressing with the investment in or evaluation of very expensive interconnectors, which are part of a future scenario as envisaged by AEMO, ahead of the ESB's assessment of future scenarios for the NEM design/framework. • The RIT-T in its current form is adequate for the assessment of "traditional" network assets such as a zone substation required to meet expected load growth, but it is not appropriate for interconnector projects. • The ESB should undertake an extensive review of the RIT-T and require that the RIT-T clearly identifies all parties who will benefit from interconnector investments, in all applicable jurisdictions of the NEM, the value of those benefits, and that the resulting cost allocations and changes to transmission prices are directly aligned to those benefits. • Tasmania should not pay higher transmission charges in order to provide surety of supply and/or lower prices in mainland jurisdictions. • It is not yet clear who would build and own Marinus. The Tasmanian government could be expected to be under considerable pressure to take an ownership position, which would see Tasmanian taxpayers taking on the associated project, investment and operating risks. • We are unconvinced that proceeding with the proposed Marinus Link is in the best interests of consumers. If consumers were regarded as	• TasNetworks welcomes the detailed feedback and analysis provided by TSBS and its consultants, Goanna Energy and SavvyPlus Consulting. • TasNetworks notes the comments regarding the 'very large risks' to consumers in progressing the investment, given the possible changes to the NEM. Equally, however, there are risks to consumers in terms of higher prices if interconnector projects, such as Marinus Link, do not proceed. The purpose of the RIT-T is to undertake a balanced assessment of the competing options (including the 'do nothing' option), and to make an appropriate investment decision given the prevailing uncertainties and risks. • TasNetworks notes TSBC's views and extensive analysis regarding the appropriateness of the RIT-T. The RIT-T has been reviewed on a number of occasions. TasNetworks' role is to apply the test as it currently stands. • TasNetworks agrees with TSBC that there is potential value in proponents explaining how the benefits from a proposed project would be distributed across the different parties in the NEM. TasNetworks notes that the AER has recognised the benefit of this approach in its final Cost Benefit Analysis guidelines that would apply to AEMO in identifying the optimal development path in its ISP. • TasNetworks notes TSBC's comments in relation to transmission charges. As discussed in section 9.1, this is an important issue that TasNetworks is engaging collaboratively with the relevant regulatory bodies and other stakeholders.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
Tasmanian Small Business Council (continued)	being investors in this project, it is our opinion that the risks have been understated. • We question TasNetworks' discounting of the capital costs of the project, from $2.762 billion to $1.271 billion, in order to derive the figure for net market benefits of $1.674 billion, and we suggest that the $3.5 billion total capital costs, including accuracy and contingencies, should be used. • The modelled Market Benefits arising from the PADR are considered unreliable. Given Marinus Link is a 'big bang' solution with a 40-year legacy, it fails to meet the internationally accepted principles of smaller and nimble investments being more appropriate at times of high uncertainty. • Given the ISP modelling has a systematic bias of under-playing the role of batteries (large and small), then the conclusion that pump-storage and the associated interconnectors are the best Least Regret solution can be regarded as questionable. • We tested an alternative which we called Battery Link that is based on fast-tracking behind-the-meter storage using the same annual expenditure as proposed for Marinus Link, and concluded that, when complemented with gas-powered generation in Victoria's Latrobe Valley (at a much lower capital cost than the Battery of the Nation and Marinus Link), there are greater comparable consumer benefits.	• TasNetworks concurs with TSBC's observation that the ownership and construction of Marinus Link has not yet been settled. It is a matter for the Tasmanian Government and others to determine the preferred position on these questions. • TasNetworks notes that the PADR shows that Marinus Link can be expected to provide very significant benefits to customers. This PACR confirms that finding. • TasNetworks' modelling approach is consistent with practice in other RIT-Ts, where the study period is truncated so that it is shorter than the technical life of the assets. To assist stakeholders in understanding this issue, we have prepared Appendix 3 to explain the different approaches that could be adopted. It explains why the approach adopted by TasNetworks is reasonable. • TasNetworks notes the comments in relation to modelling benefits beyond the ISP horizon. TasNetworks' view is that it has adopted a reasonable study period given TasNetworks recognises the concern that Marinus Link may be regarded as a relatively inflexible solution, given the size of the investment and its asset life. However, the analysis presented in chapters 7 and 8 of this PACR shows that it delivers substantial benefits by harnessing the renewable and storage capacity in Tasmania. The analysis has not identified alternative options that deliver greater net economic benefits. • TasNetworks does not accept that the ISP modelling has demonstrated a systematic bias of underplaying the role of batteries. A discussion of the role of batteries is provided in Chapter 8 of this PACR.
UPC Renewables	• UPC considers that TasNetworks has provided an extensive analysis of the market benefits that Marinus Link can provide, but also as part of the business case, highlights the significant value proposition through jobs and economic activity Marinus Link can deliver for both Tasmania and Victoria.	• TasNetworks notes UPC's comments in relation to the analysis presented in the PADR and welcomes the positive feedback. • TasNetworks concurs with UPC's views in relation to the importance of resolving the pricing issues discussed in the PADR.

	Key points raised by submitter on the PADR	TasNetworks' consideration of the issues raised
UPC Renewables (continued)	• We see the process of achieving a successful RIT-T outcome and finalising the "who pays" question are key to realising the development of Marinus Link. • We consider Marinus Link being developed earlier provides both risk mitigation and option value to managing some of the high impact events that may materialise earlier than the central/base case analysis. • The concept of "shovel ready" as indicated in AEMO draft 2020 ISP should be progressed as fast as possible so that Marinus Link is closer to being ready to be built if circumstances change. As a developer, we consider that early 2025/2026 is very achievable for the first 750 MW and that TasNetworks should aim to deliver the link on this timing. • UPC is concerned that the cost estimates for Marinus Link are conservatively high. These estimates should be revisited. • A key concern is the current misalignment with both the outcomes and assumptions in the draft 2020 ISP, which UPC believes is caused by AEMO discounting the Tasmanian opportunities. • UPC advocates a more coordinated modelling of Tasmanian development as it is clear once Marinus Link is built, wind development will occur and pumped hydro development is likely to coincide with Marinus Link being operational. • The timing of Snowy 2.0 seems optimistic for such a large and complex project based on recent budget increases and challenges. • UPC would strongly advocate the beneficiaries pays principle is adopted to ensure a fair and equitable approach for cost allocation of interconnectors. It is understood that one issue raised on this is the potential for the beneficiaries to change over time. This issue could be managed similar to the current AER regulatory revenue approach by continual review or review on material change in circumstances (i.e. new interconnectors developed, material change in flows on interconnectors, etc.).	• TasNetworks notes UPC's comments that developing the project early will mitigate risk and create option value. As noted in relation to feedback from other stakeholders that indicated the project should be delayed, it is important that the RIT-T assesses the optimal timing, given the uncertainties and risks. The analysis should take a balanced approach, which means neither favouring bringing forward nor deferring the project from its optimal timing. • As envisioned by the 2020 ISP, TasNetworks agrees that the early works for Marinus Link should be completed by 2023-24 in case Step Change scenario eventuates. • TasNetworks notes UPC's comments regarding the project cost estimates. As noted earlier, TasNetworks has given careful consideration to the cost estimates in this PACR. • In relation to consistency with AEMO's ISP, as explained in chapters 2 and 6, this PACR aligns the RIT-T analysis with the 2020 ISP scenarios and AEMO's latest inputs and assumptions. • TasNetworks agrees with UPC's comments that Marinus Link will encourage developments of wind projects and pumped storage in Tasmania. These linkages between the developments is captured in Ernst & Young's market modelling. • TasNetworks notes UPC's comments in relation to the closure of Yallourn and the possible benefits of bringing forward Marinus Link to 2027. As already noted, it is important that the RIT-T takes a balanced approach, having regard to the uncertainties that exist and the range of possible outcomes that may emerge. TasNetworks has updated its modelling and cost-benefit analysis in light of the best available information. • TasNetworks welcomes UPC's comments in support of the beneficiaries pay principle. We continue to work with relevant authorities and other stakeholders to develop a workable solution to this issue.

(b) Submissions to the Supplementary Analysis Report

	Key points raised by submitter on the Supplementary Analysis Report	TasNetworks' consideration of the issues raised
Bob Brown Foundation (BBF)	• The trend is towards smaller, more flexible, distributed solutions which pose a far lower risk in this rapidly changing environment than large, centralised, long-lived assets. The risk of being leapfrogged and left stranded is high. • Since the justification for Project Marinus is that it delivers the firming benefits of Battery of the Nation to the NEM, the project must be seen as integrated and costings should incorporate the full cost of both Marinus and Battery of the Nation. It is sleight of hand to assume the full benefit up front but stage the costs. Table 11 in the report, which shows a comparison of battery costs with Battery of the Nation, is misleading and demonstrates why the Project should refer to both components. • The RIT-T fails to capture the following costs (in addition to the ecological costs): ○ Upgrades of existing and construction of new transmission infrastructure in Tasmania; ○ Upgrades of existing and construction of new hydro assets in Tasmania; and ○ Facilitation via subsidies of new wind energy generation in Tasmania to meet Tasmanian demand even though Tasmanians have already paid for existing hydro generation assets to meet that same demand. • The answer is 'a resounding no' to the following questions that Tasmanians need to ask: ○ Whether Marinus Link is necessary for Tasmania's energy security; and	• TasNetworks recognises the advantages of smaller scale, flexible solutions, especially in a rapidly changing environment. By the same token, large transmission investments have a role to play in delivering the lowest cost solution to customers, as highlighted by the 2020 ISP. The best approach is to conduct comprehensive market modelling, using AEMO's latest input assumptions to identify the optimal mix of solutions, without any preference for particular types of solutions or remedies. TasNetworks has reflected feedback from Bob Brown Foundation by adopting the updated assumptions from Draft IASR that indicate DER uptake will remain strong even in the Slow Change scenario. • The inputs, assumption and intention of the High DER scenario is to reflect the shift towards smaller, more flexible and distributed solutions. We note that the net economic benefit and the need for Marinus Link remains unchanged in this scenario too. • As explained in section 4.6 of this PACR, the analysis does not assume that Battery of the Nation will proceed. Any pumped hydro development in Tasmania is commissioned on a least cost basis by the model. As highlighted in the PADR and section 4.6 of this PACR, the first stage of Marinus Link is not contingent upon any pumped hydro development in Tasmania. • The scope and role of the RIT-T has been reviewed on numerous occasions, including its treatment of environmental costs. Our view is that the RIT-T is the appropriate test to apply to Marinus Link, and we have applied it in accordance with the AER's application guidelines. As explained in section 5.5, the costs of transmission upgrades that form part of Marinus Link have been included in the cost-benefit analysis that underpins this PACR. As explained in sections 2.3.1 and 6.1 of this PACR and chapter 7 of our Supplementary Analysis Report, our

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
Bob Brown Foundation (BBF) (continued)	○ Whether Marinus Link is necessary or the most effective method for mainland Australia to achieve 100 per cent renewable energy; and ○ Whether Marinus Link will reduce emissions; and ○ Whether Marinus Link is economically viable or the least cost solution. • The whole premise of the project is to provide deep energy storage to the NEM. But where is the evidence that the NEM will need storage of more than eight hours on a regular basis rather than a short period and even if it does that, will Tasmania's Battery of the Nation be the most cost-effective solution? • Why did AEMO assume that TRET would result in 10,500GWh VRE being available to the NEM? AEMO's inclusion of the 10,500GWh, which has then been used by the Tasmanian Government and TasNetworks to underpin the business case for the project amounts to a "revolving door subterfuge based on announcements and an artificial feedback loop." • BBF refers to a report from Victoria Energy Policy Centre which argues that batteries would be much cheaper than Marinus Link. BBF also comments that the financing of the project is its 'Achilles' heel' as a cost sharing agreement with Victoria has not been reached. • On the issue of benefits, BBF asks which capital costs or fuel costs are being deferred or avoided given that the Supplementary Analysis does not assume construction of new gas-fired power plants? BBF recommends that the avoided and deferred costs assumed in the Supplementary Analysis should be itemised.	modelling results are closely aligned with the 2020 ISP, which should provide stakeholders with confidence that the analysis has been undertaken appropriately. • TasNetworks notes that BBF does not support Marinus Link. As shown in chapters 7 and 8 of this PACR, however, Marinus Link delivers a significant net economic benefit, which means that the costs of meeting customers' electricity needs will be lower if Marinus Link proceeds. • We note BBF's comments in relation to deep storage. In Chapter 8 of this PACR, we have examined why Marinus Link is able to deliver value compared to battery storage. • In relation to the TRET, as explained in AEMO's draft IASR, AEMO has adopted a framework for determining whether to take account of government policy initiatives in their market modelling. The approach to the TRET is consistent with AEMO's application of its framework. As explained in section 2.3 of this PACR, TasNetworks' approach is to adopt AEMO's latest position on each government policy as set out in its draft IASR. • As noted above, Chapter 8 of this PACR addresses the issue of whether batteries provide a cost effective alternative to Marinus Link. Section 9.1 of the PACR discusses the pricing issues raised by BBF. • Chapter 7 provides a breakdown of the sources of benefits from Marinus Link, as requested by BBF. • In the interest of transparency with the stakeholders, Chapter 8 provides the net economic benefits of Marinus Link without TRET. The chapter also outlines modelling differences undertaken by VEPC. • Similar to pumped hydro in Tasmania, the construction of gas powered generation is based on least cost economics. The only committed storage capacity built in the model, besides Snowy 2.0, is another 2

	Key points raised by submitter on the Supplementary Analysis Report	TasNetworks' consideration of the issues raised
		GW of 8 hour storage in NSW in accordance with the NSW Energy Infrastructure Roadmap.
Clean Energy Council (CEC)	• The lack of transmission is now one of the most critical challenges facing the transition of Australia's energy system. • The ISP sets out the least cost development pathway for the NEM. It confirms there is a clear need for a strongly interconnected NEM and that there is a need to continue progressing Marinus Link as a multi-staged actionable ISP project with decision rules. • It is possible that government commitments subsequent to the ISP, such as the passage of the legislation to give effect to Tasmania's 200 per cent renewable energy target and the NSW Electricity Infrastructure Investment Roadmap, are already setting us on a path that overshoots the Step Change scenario. • The CEC supports the significant potential that Tasmania presents to the NEM through its storage assets and therefore the continued need for Marinus Link to unlock this deep storage potential.	• TasNetworks notes CEC's comments regarding the lack of transmission. As noted in section 1.3 of this PACR, TasNetworks' approach is to assess the case for Marinus Link on its merits, without favouring any particular type of solution or technology. • TasNetworks notes CEC's comments in relation to the 2020 ISP's position on Marinus Link. The analysis in this PACR broadly confirms the conclusions of the 2020 ISP in relation to Marinus Link. • In chapter 7 of this PACR, we note that the NEM may be on a Step Change trajectory, which reinforces the case for proceeding with Marinus Link so that it can be commissioned in 2027 if that scenario eventuates. • TasNetworks notes CEC's support for Marinus Link.
COTA Tasmania	• Heating and cooling are essential to older Tasmanians' health and that those on fixed incomes are particularly vulnerable to electricity price rises. Maintaining or reducing electricity prices is crucial to supporting older Tasmanians and we acknowledge that TasNetworks is working to ensure that Marinus Link does not financially disadvantage Tasmanians. • The barriers to older jobseekers are greater than ever in the current COVID-19 environment as people across a wide range of ages and sectors have lost work. COTA Tasmania encourages TasNetworks and their partners to consider strategies to reskill, employ, and retain older workers (aged over 45 years) as part of Project Marinus. We are keen	• TasNetworks strongly agrees with the observations made by COTA in relation to affordability. Our analysis shows that Marinus Link will deliver lower prices compared to the case where it does not proceed. • TasNetworks notes the feedback in relation to older jobseekers. Our recruitment policy is to treat all job seekers on their merits, without any preference in relation to the applicant's age. • Additionally, the current demographics of the Project Marinus team indicate that two-third of the team is above the age of 40. We look forward to working continued engagement with COTA.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
	to be part of these discussions as the project progresses and encourage TasNetworks to view our Work45+ website.	
Hydro Tasmania	• Hydro Tasmania strongly agrees that customers' best interests will be served by continuing to retain the flexibility for the earliest possible delivery of Project Marinus. TasNetworks should continue its Design and Approval work and continue engaging with the Commonwealth and Tasmanian Governments to allow an investment decision to be made by 2023/24. Given the dependence of Pumped Hydro Energy Storage (PHES) investment and the newly legislated TRET on Project Marinus, it is critical that TasNetworks continue to progress an accelerated timeframe preserving the earliest feasible delivery date of 2027. • Given the substantial differences between the outcomes of scenarios, it is important to continually examine the probability of different scenarios eventuating. While termed the 'central' scenario, there is a weight of evidence that the Australian energy mix is transitioning at a faster pace than this. Actual and forecast renewable energy development data from the Clean Energy Regulator suggests that of the scenarios examined in the 2020 ISP, the Australian energy sector may already be in a 'Step Change' scenario. • Given the interrelated nature of NEM transmission projects (mainly interconnectors), a key question facing any analysis is what energy resources and transmission infrastructure to include as 'committed'. Our reading of the TasNetworks analysis is that the modelling has included some development of interconnection that are not yet actionable ISP projects. Hydro Tasmania supports further consideration of which future investments to include in future TasNetworks analysis. • The Commonwealth Government's Technology Investment Roadmap: First Low Emissions Technology Statement, released September 2020, names Energy Storage as a Priority Low Emissions Technology,	• TasNetworks notes Hydro Tasmania's comments regarding the benefits of retaining flexibility to deliver the project at the earliest possible date. The analysis presented in this PACR supports Hydro Tasmania's position. • TasNetworks agrees with Hydro Tasmania's observations. In relation to the weighting of the scenarios, we have adopted an equal weighting in addition to a one-third 'Step Change' and two-thirds 'Central' in accordance with the 2020 ISP. • In relation to committed projects, our approach in this PACR is aligned with AEMO's latest position in the draft IASR. Our view is that the most appropriate approach is to align our analysis with AEMO's latest views, unless there are strong reasons for taking a different approach (which would need to be explained to stakeholders). • TasNetworks notes Hydro Tasmania's comments in relation to the cost of pumped storage in Tasmania. The assumptions adopted in our modelling reflect AEMO's draft IASR. • TasNetworks notes Hydro Tasmania's views on long duration storage and contingency costs. We have discussed the cost comparison with battery storage in Chapter 8 of this PACR. • In relation to the higher capacity factor for Tasmanian wind resources, this has been taken into account in Ernst & Young's market modelling (which is described in chapter 6). As such, Marinus Link's potential role in unlocking these benefits has been recognised in this PACR. • We note Hydro Tasmania's comments regarding the potential changes to FCAS benefits. This is noted in section 6.1.1 of this PACR.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
Hydro Tasmania (continued)	adopting a stretch goal for energy storage of "electricity from storage for firming under $100 per MWh." In the case of pumped hydro, the lowest cost resource will be in Tasmania. • Hydro Tasmania strongly believes that a portfolio of energy storage technologies and durations will be needed for the future high renewables NEM. This includes a critical role for longer-duration storage such as pumped hydro to underpin system resilience. Section 8.4 of the Supplementary Analysis Report provides a strong assessment of the 'Economic comparison between batteries and long duration pumped hydro'. As noted, the present value cost of Tasmanian pumped hydro is less than half that of a comparable battery installation cost. • Contingency costs should be treated consistently across technologies. It is not clear that these costs have been included for batteries. • As noted in the Supplementary Analysis Report, even with very low battery costs, the "net market benefits [are] only negatively impacted by $40 million". This demonstrates that the market need for long duration storage will not be easily filled by other technologies and provides a grounding for investment in both transmission and PHES. • Our updated feasibility studies provide additional confidence in the cost estimates of PHES in Tasmania as well as a greater indication of the capacity and storage options available. Cost estimates are markedly lower than the cost of developing an equivalent site on the Australian mainland, which reinforces TasNetworks' cost/benefit modelling. • Tasmanian wind resources are expected to have a higher capacity factor output than mainland options. Project Marinus will be essential to unlock this resource diversity and high-class wind resource. • Load relief factors have changed in Tasmania, potentially increasing local FCAS requirements. This phenomenon could occur in other	[See previous page for our responses to the issues raised]

	Key points raised by submitter on the Supplementary Analysis Report	TasNetworks' consideration of the issues raised
Hydro Tasmania (continued	regions of the NEM. Hydro Tasmania suggests that TasNetworks updates its FCAS benefits analysis to consider such possible changes to NEM operations.	
Landholders of Buffalo and surrounds	This group of landowners raised the following concerns: • **The uncertainty regarding the net market benefit of $1.5 billion**, particularly given the prospect of higher than expected costs and the reliance of the net benefit estimate on the step change scenario eventuating. The group noted that AEMO requires an additional 30 per cent should be added to the estimated project costs, while the RIT-T has only considered an additional 15 per cent. AEMO's 67/33 weighting of the central and step change scenarios should be adopted. The group also raised concerns that battery costs could be lower than expected and the benefits from Marinus Link could be undermined by drought. • **The lack of costing of other routes compared to the proposed route**. The group proposed an undersea cable to Portland or to Cranbourne terminal station, arguing that each may have significant advantages compared to the proposed route. • **The fast-tracking of environmental impact assessments**, which may lead to an incomplete assessment of these costs. • **The lack of community consultation**, raising strong concerns that the affected landowners have not been properly consulted.	• This PACR has addressed the issue of project costs and the scenario weightings. As already noted, Chapter 8 discusses the costs of batteries. • TasNetworks notes the concerns raised by landowners regarding the consultation process. This issue has been addressed in section 4.3.1 of this PACR. • The fast-tracking of the environmental approvals does not mean that the assessment will be incomplete. Instead, the fast-tracking will enable the project to be delivered sooner, if there is an economic case for doing so. • TasNetworks notes the concerns raised in relation to community consultation. Further work in that regard has been undertaken since the publication of our Supplementary Analysis Report. • TasNetworks hopes the questions raised by the landowners have been addressed through the various community engagement initiatives undertaken. We look forward to continued engagement with the stakeholders and community throughout the project.
Origin Energy	• We consider that TasNetworks should delay the regulatory investment test for transmission (RIT-T) until at least the 2022 ISP outcomes are known because: ○ The need for Marinus Link remains uncertain – recently announced government policies are likely to affect optimal	• TasNetworks notes the comments in relation to delaying the project. As explained in chapter 7 of this PACR, delaying the project is likely to lead to a higher cost outcome for customers. The better approach is to adopt the optimal timing as indicated by the application of the RIT-T, which takes account of uncertainty.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
Origin Energy (continued)	transmission build and should be factored into the analysis through the 2022 ISP before any decision is made. ○ Cost recovery issues are not yet resolved – this needs to be settled before the project can progress. ○ Uncertainty around future costs remains – it would be premature to conclude the regulatory process now for a project that may not be needed until the late 2020s at the earliest. • In relation to uncertainty, Origin notes that recently announced government policies (such as the NSW infrastructure roadmap and Victorian REZ announcements) will have implications for the location and competitiveness of generation in the system. Given the significance of the recent government announcements, we consider that the emergence of the step change scenario is no longer an appropriate indicator of when the link may be required. • The cost recovery issues are yet to be resolved, with consultation on options to address the problems having yet to commence. We understand that changes might involve mainland consumers, especially from Victoria and NSW, bearing most of the costs of Marinus Link as they were previously identified as the main beneficiaries. However, in light of the recent government announcements, it is unclear who the main beneficiaries would be and how this would affect cost recovery issues. • TasNetworks should delay the RIT-T and re-issue the project assessment draft report (PADR) once better information is available. • Project EnergyConnect RIT-T found net benefits of $924 million, which were revised down to $269 million at the approval stage due to changed inputs and assumptions. Given growing concerns around transmission costs, particularly for large projects such as Marinus Link, we urge TasNetworks to be transparent about any potential cost	• In relation to government policies, as already noted, we have aligned our approach to AEMO's latest assessment in its draft IASR. We note Origin's comments in relation to the Step Change scenario. Despite the inclusion of the latest state-based policy settings, our analysis continue to shows that Marinus Link is required sooner if this scenario eventuates. In fact, as outlined in Chapter 8, in case a Net Zero emission target then the benefits of Marinus Link are likely to be even higher. • Section 9.1 of this PACR provides further information on the pricing issue and the distribution of customer benefits across the NEM. • In relation to delaying the RIT-T, our view is that this approach would be inconsistent with the purpose of identifying actionable ISP projects in the 2020 ISP, which is to deliver transmission investments in a timely manner. • We note Origin's concerns in relation to project costs and the importance of effective cost management. Section 9.2 of this PACR discusses this issue in further detail.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
	increases to ensure that a robust determination of net benefits can be made. Delaying the RIT-T until closer to when the project is needed would help address some of the uncertainty around costs.	
TasCOSS	• It is imperative that households are not burdened with Marinus Link costs through higher electricity bills and Tasmanian consumers are net-beneficiaries from this project. • Marinus Link is not required to provide Tasmanian residential customers with a low-cost, renewable, energy supply. The Tasmanian Government has recently announced that our state is now 100 per cent self-sufficient in renewable energy generation. Tasmanians have achieved this by investing in our renewable energy assets for over a century through our power bills and taxes. Tasmanian households should not be penalised for our 100 years of investment in renewable energy, nor be expected to pay a further premium for a project that will deliver most benefit to mainland NEM customers and developers of renewable energy projects. • There is no clear indication from the Tasmanian Government or TasNetworks on what constitutes our fair share or any indicator for measuring a satisfactory resolution to the "who pays" question. TasCOSS wants to understand what is meant by Tasmania's "fair share". In the absence of other reasonable measures offered by TasNetworks or the Government, TasCOSS suggests that Tasmanian customers should pay no more than 6 per cent of the project costs (6 per cent reflects Tasmania's share of NEM energy consumption). • Three large-scale battery projects, totaling 1,500MW, were announced after the release of the Supplementary Analysis Report and therefore would not have been taken into accounted in the updated scenarios, inputs and assumptions. Additionally, a recent report by Cornwall Insight Australia estimates there is around 7,000MW of battery storage projects proposed or currently in the planning process in Australia, of	• TasNetworks strongly agrees that affordability is a significant concern for electricity customers. This PACR shows Marinus Link reduces the total costs of meeting customers electricity needs compared to the case where Marinus Link does not proceed. According to this analysis, therefore, Marinus Link reduces the burden on customers. • TasNetworks has noted the importance of fair pricing to ensure that Tasmanian customers do not pay a disproportionate contribution to the costs of Marinus Link. Providing that the pricing issues are resolved, Marinus Link will benefit Tasmanian customers. Further information on the benefit to customers is provided in section 9.1 of this PACR. • As noted above, section 9.1 of this PACR addresses the issue of 'fair sharing', having regard to the estimated customer benefits in each region. • The release of the accompanying wholesale pricing impacts from the commissioning of Marinus Link should provide further insights to all stakeholders regarding the consumer benefits of Marinus Link. • As explained in section 2.3.1, the assumptions regarding battery costs have been updated in this PACR to reflect AEMO's latest view. The market modelling undertaken by Ernst & Young adopts the lowest cost solutions, which includes growth in battery capacity. • Chapter 8 of this PACR discusses the role of batteries in meeting customers' electricity needs and the value provided by Marinus Link in this context.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
TasCOSS (continued)	which almost 1,000MW is set to be delivered by 2024 – before Marinus Link design and approvals are finalised or a final investment decision is made (2024), let alone construction commenced or the first link operational (2027). • The ability to plan and install mega-batteries must be a serious threat to the Marinus Link business case and project viability. Large-scale batteries on mainland Australia will also support the energy grid's transition away from fossil fuels, support new investment in solar and wind projects and help the transition to a low-carbon economy. These batteries also have the advantage of doing so relatively rapidly when compared to the construction of a subsea cable.	
Tasmanian Minerals, Manufacturing and Energy Council (TMEC)	• TMEC is fully supportive of the transformative undertaking to create an entirely new export sector to contribute further economic and social benefits to the state of Tasmania for generations to come. Legislating the TRET at 200 per cent makes a very clear decree as to the State's ambition. Tasmania will be a much more vibrant and self-sufficient State when the two needs from the energy assets are delivered. • TMEC's principles are that: ○ Any changes and additions to the energy assets in Tasmania contribute to ensuring on-island users of energy are provided with internationally competitively priced and reliable delivered energy; and ○ Any downside risks which occur with Marinus Link (and the subsequent additional generation capacity) are contained within the electricity export asset group (Marinus Link / Battery of the Nation / new generation assets). • Future financial modelling should consider the actual cost performance of major transmission asset upgrades from the NEM given there are	• TasNetworks notes TMEC's support for the TRET. For the purpose of this PACR, our treatment of the TRET is aligned with AEMO's draft IASR, as explained in section 2.3. • We note TMEC's principles in relation to transmission investments and risk allocation. As a regulated transmission asset, however, the economic assessment of Marinus Link must be conducted in accordance with the RIT-T and the revenue recovery would be determined by Chapter 6A of the National Electricity Rules. • We note TMEC's concerns regarding the potential for project cost increases. This issue is discussed in section 9.2 of this PACR. • As noted in chapter 7 of this PACR, the staged introduction of Marinus Link is supported by the cost-benefit assessment. We also note that the 2020 ISP identified the staging of Marinus Link as the optimal approach. • We note TMEC's comments in relation to the growth in hydrogen production. As noted in section 7.4.1, to address this issue this PACR has examined the impact on Marinus Link of a hydrogen extraction plant constructed in Northern Tasmania.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
TMEC (continued)	examples where final costs were up to 50 per cent greater than the planned amount. • Supports the multi-stage approach to Marinus Link as a means of balancing the timeframes involved with having a functional asset in service and the accuracy of forecasting the multi-variants which feature in the business case. • The ever-increasing prospect of Tasmania becoming an exporter of hydrogen, in several forms as stored energy will be an on-island competitor for Marinus Link in the energy export market. • TMEC takes some comfort from the recognition the updates contained in the 2020 ISP continue to align with the strategic assumptions which make up the Marinus Link business case. The potential obsolescence of Marinus Link by "new technology" exists with all substantive infrastructure investments. • The transparency with which TasNetworks applies counterarguments from submissions for Marinus Link and models the effects is to be commended. This will continue to be a complex business case and ensuring scenarios are kept to up to date is critical to build broad support.	• We welcome TMEC's comments on the updates provided in the Supplementary Analysis Report and the transparency with which TasNetworks has conducted its assessment of Marinus Link.
Tasmanian Renewable Energy Alliance (TREA)	• We are highly appreciative of the transparent way in which this process has been conducted, including the release of underlying assumptions, the publication of the public consultation forum and the personal briefing and follow up information provided to TREA by Marinus staff. • We are concerned that assumptions still favour traditional technologies and large projects in a world which is rapidly moving towards more flexible and decentralised technology and smarter controls to match electricity supply and demand. In order to test the benefits of the very large long term commitments required for Marinus Link and Battery of	• TasNetworks welcomes TREA's positive feedback on our transparent approach to the RIT-T assessment. • TasNetworks notes the concerns expressed regarding a preference for traditional technologies. As explained in section 1.3 of this PACR, the modelling approach does not favour any particular types of solutions or technologies. In chapter 8 of this PACR, we provide the additional analysis in relation to the costs of battery storage. The treatment of government policies is addressed in section 2.3 of this PACR.

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
TREA (continued)	the Nation we are requesting additional modelling to test the business case for Marinus taking into account: ○ the initiatives being taken by state governments to progress renewable electricity generation and storage within their own jurisdictions; ○ the potential for demand response initiatives to match electricity supply and demand in a NEM with much greater penetration of variable renewable energy; and ○ the possibility that costs of large scale battery storage continues to be overstated (particularly in relation to replacement costs over decades). • We are also requesting that more information be provided on: ○ the sensitivity of the business case to possibilities outlined below that are outside the current 'step change' assumptions; ○ the modelled demand for storage over durations longer than 8 hours; and ○ the detailed make-up of the components of the modelled benefits of Marinus. • The TRET legislation does not provide any mechanism (other than sharing information and reporting) for ensuring that the anticipated extra renewable electricity generation is built. This creates a self-reinforcing loop of assumptions: the legislation implicitly assumes that Marinus will be built; the ISP assumes that the generation will be built; the ISP assumption that the generation will be built adds to the business case for building Marinus. • As far as we are aware, the cost of building additional wind generation in Tasmania is not factored into the business case for Marinus.	• The additional information requested by TREA is provided in this PACR. In particular, sensitivity analysis is provided in chapter 7; demand side response is addressed in the modelling; and the make-up of the benefits is also provided in chapter 7. • In relation to the TRET, our treatment of this policy is aligned with AEMO's approach, which is applied consistently across all government policies. Furthermore, the analysis provided in Chapter 8 shows that Marinus Link would provide a significant net economic benefit if a Commonwealth carbon budget were adopted instead of state-based government policies. • The modelling assumes that the TRET will be satisfied, which is consistent with the legislated commitment and AEMO's current treatment of the TRET. We consider this approach to be appropriate, so that the TRET is treated on a consistent basis with other government policies. • As noted in section 2.3.2, the treatment of government policy announcements in this PACR is consistent with AEMO's current approach in its draft IASR. • We discuss the issue of batteries as an alternative to Marinus Link in Chapter 8 of this PACR. Our assumptions regarding asset lives and costs is consistent with AEMO's latest input assumptions. • Ernst & Young model has been reconciled with AEMO's model results in its 2020 ISP. The proximity of the results from these models should provide stakeholders with comfort that Ernst & Young's model is fit for purpose. • The adoption of the Draft IASR assumption that includes replacement of battery pack rather than the entire battery infrastructure should further reassure TREA that modelling is undertaken in a technology agnostic manner. • By aligning the timing of each stage of Marinus Link with future ISP outcomes, we hope it provides TREA assurance that net economic

Key points raised by submitter on the Supplementary Analysis Report		TasNetworks' consideration of the issues raised
TREA (continued)	• The NSW state government has recently announced an ambitious energy plan with a budget of $50 million to support up to 3 GW of pumped hydro projects. This is in addition to the 2 GW anticipated to be available from Snowy 2.0. The first of three priority REZs (Central-West Orana) is anticipated to support 3 GW of new generation. The modelling of the business case for Marinus should be updated to reflect these announcements. • We would like to understand the basis of the difference between the Marinus business case set out in the Supplementary Analysis Report and the apparently contradictory finding in Mountain and Percy (2020, p.5) that: "*1,500 MW of four-hour battery can be provided for less than half the cost of Marinus Link. The same capacity of six-hour battery can be provided for 79 per cent of the cost of Marinus Link and 1,500 MW of eight-hour battery storage is still cheaper than Marinus Link.*" The key difference appears to be in the modelled need for greater than 8 hours storage. • TREA queries the assumption that a total replacement of a battery installation is required every 20 years. • It would be desirable for EY's modelling (including the assumptions and the detailed outputs) to be independently reviewed by AEMO to check for consistency and highlight any unanticipated outputs	benefit of Marinus will be tested against continually evolving inputs, assumptions and stakeholder review.
UPC Renewables	• UPC congratulates TasNetworks on the effort to address concerns raised by numerous submissions and to align the analysis with the 2020 ISP. • The key remaining questions relate to the timing of Marinus Link and the cost allocation methodology. UPC supports the beneficiary pays model.	• TasNetworks welcomes UPC's comments regarding our efforts to align the analysis with the 2020 ISP. • TasNetworks agrees with UPC that transmission pricing remains an important issue to be resolved. This issue is discussed in further detail in section 9.1. • In relation to the possible early delivery of Marinus Link, this PACR supports the views expressed by UPC.

	Key points raised by submitter on the Supplementary Analysis Report	TasNetworks' consideration of the issues raised
UPC Renewables (continued)	• UPC advocates that Marinus Link is developed as soon as possible, as UPC believes that the market benefits will be realised earlier of Marinus Link is operational. Being able to deliver Marinus Link early will promote the achievement of TRET. • UPC considers that the recent policy announcements in NSW (NSW roadmap), and in the Victorian and Queensland budgets will bring the NEM closer to the step change scenario and accelerate the closure of coal plant – leading to the need for Marinus Link sooner. • UPC considers that Marinus Link can be delivered by 2026, based on recent HVDC interconnectors in Europe. UPC encourages TasNetworks to look at ways to progress the development at a faster pace and bring it on line as early as possible, preferably before 2027.	• TasNetworks notes UPC's comments that the recent market developments indicate that the NEM is on a 'Step Change' trajectory. As explained in chapter 7 of this PACR, TasNetworks considers that there is evidence to support UPC's position. • We note UPC's comments regarding the potential early delivery of Marinus Link. At the present time, we consider that 2027 is the earliest feasible delivery date.

Appendix 2 – Technical analysis summary

TasNetworks has undertaken detailed analysis of the technical feasibility of Marinus Link. The analysis demonstrates that the preferred option for Project Marinus is technically viable, regardless of which scenario (or combination of scenario outcomes) eventuates. The following is a summary of that analysis.

Methodology

Our methodology in conducting this assessment was as follows:

NEM wide simulations were conducted initially using the power system simulation software PSS®E, to enable us to identify potential stability issues, any areas in which power system operational limits may be exceeded, and assess impacts on transfer limits across the wider network.

Performance under weaker power system conditions was further checked using electromagnetic transient simulation tools.

A large number of NEM load and generation dispatch cases were considered in this process, which included possible retirement of coal generating units, different quantities of future renewable generation and battery systems, and the consequent impact on system strength and inertia. Simulations also considered a variety of future network configurations, including future ISP projects, the presence of only the first 750 MW stage of Marinus Link, and the presence of both 750 MW stages.

The key criteria against which simulation outcomes were assessed were the System Standards defined in the Rules Schedule S5.1a, the technical requirements of Network Service Providers in the Rules Schedule S5.1, relevant requirements for secure operation of the power system in the Rules Chapter 4, and Tasmanian jurisdiction planning requirements in the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007.*

On the basis of these criteria, the key issues, and our resulting assessment of these, are described in the following paragraphs.

Marinus Link can maintain stable operation, despite decreasing system strength

The reduction in system strength as fossil fuel powered synchronous generation is displaced by inverter based resources has been widely acknowledged as a key area to be dealt with in the evolving NEM. Marinus Link will be capable of maintaining stable operation even when all coal fired generation in Victoria has retired, assuming future mainland wind generation is accompanied by some synchronous condenser capability.

Increased contingency size can be accommodated

The commissioning of Marinus Link will increase the maximum credible contingency size in both Victoria and Tasmania. The maximum effective generator contingency size in Victoria will increase from 600 MW (the previous maximum output of Basslink) to 750 MW. Inter-regional transfer limits from New South Wales to Victoria will be impacted as a result of this increased contingency size, but the reduction of transfer limits is less than the added power transfer capacity of Marinus Link.

The maximum Tasmanian contingency size is presently the loss of Basslink. The loss of up to 480 MW import to Tasmania, or 630 MW export (currently limited to 500 MW) from Tasmania, via Basslink, can be managed with an existing system protection scheme. This scheme can be extended to accommodate the loss of up to 780 MW export.[114] If commercial agreements can be reached with suitable load customers, then the system protection scheme can be extended to cater for the loss of up to 750 MW import from Marinus Link. If commercial agreements cannot be reached, the worst case outcome would be Marinus Link plus Basslink combined import to Tasmania being restricted to 480 MW (during the first 750 MW stage of Marinus Link) or 1230 MW (once the second stage is commissioned). This limit was examined as a sensitivity study in the PACR, and found to reduce the net market benefit by $6 million over the life of Marinus Link.

Marinus Link does not adversely impact upon power system security

The operation of Marinus Link does not affect the ability to dispatch the power system in a secure operating state.

Following a credible contingency event affecting either Marinus Link directly, or elsewhere in the Tasmanian or Victorian networks, operation of the power system in a satisfactory operating state is maintained. Power system voltage, frequency and rate of change of frequency can be maintained within required limits.

The present limitation of northwards flow across the Victoria to New South Wales interconnector, due to transient stability following the loss of the Hazelwood to South Morang line, is improved with the addition of Marinus Link.

Damping of inter-area oscillations was not degraded by Marinus Link.

Post-contingent power flows in the Victorian network are within equipment ratings. Post-contingent power flows in the Tasmanian network are either within short-term equipment ratings, and thus can be managed by AEMO generator re-dispatch, or can be accommodated by modifications to existing special protection schemes. The

[114] Marinus Link's 750 MW capacity is at the receiving end. Due to resistive losses of the cable, transferring 750 MW into Victoria will require approximately 780 MW export from Tasmania.

Tasmanian network control special protection scheme will require modification to accommodate the presence of Marinus Link, but the scheme does not need to be extended to protect the new transmission lines which support the connection of Marinus Link as these will be rated appropriately.

Secure operation of Marinus Link during planned network outage conditions can be accommodated by the use of constraints within AEMO's dispatch process, or – if economic to do so – by extension of special protection schemes to protect against credible contingencies occurring during planned outage conditions.

Conceivable non-credible contingencies can be adequately managed

Whilst the Rules allow for loss of supply to customer load following non-credible contingency events, it is prudent to ensure loss of customer supply in the event of readily conceivable non-credible contingencies can effectively be managed with the existing (or modified) backup protection schemes. Jurisdictional requirements in Tasmania also limit the permissible load loss following some non-credible contingencies.

We have examined the operation of the power system following readily conceivable non-credible contingency events which are likely to be impacted by Marinus Link. With one exception, the loss of load was contained by appropriate emergency protection schemes (assuming these would be appropriately modified as future renewable generation is integrated) and relevant voltage and frequency limits were maintained.

The exception occurs during the period when only the first stage of Marinus Link has been commissioned, and only at times of both high wind generation and high Marinus Link import into Tasmania. During these times, a non-credible contingency which would disconnect all north-west Tasmanian wind generation and Marinus Link may not be able to be contained by under-frequency load shedding schemes. This can be mitigated by reducing Marinus Link import in such cases, and economic analysis has shown such an import restriction is an unlikely operational dispatch and makes negligible difference to the net market benefit of Marinus.

Tasmanian jurisdictional requirements relating to loss of load following non-credible contingencies were satisfied.

Marinus Link can operate in parallel with Basslink

No adverse interactions between Marinus Link and Basslink have been observed when both interconnectors are operating, assuming the required setting changes are implemented to resolve the issue which causes Basslink to trip as a result of some credible network contingencies.

The supporting AC transmission upgrades in Tasmania are necessary for Marinus Link to be able to operate securely

The Palmerston to Sheffield 220 kV transmission upgrade must be constructed to coincide with the first 750 MW stage of Marinus Link in order to ensure compliance with the *Electricity Supply Industry (Network Planning Requirements) Regulations 2007*. Without this upgrade, the possibility of a single asset failure in other transmission corridors could potentially lead to a system black event, which would be in breach of these regulations. Other developments separate from Marinus Link may result in the need for this augmentation to be brought forward ahead of Marinus Link.

With the commissioning of the second stage of Marinus Link, construction of the Palmerston to Sheffield 220 kV transmission upgrade has a positive net market benefit in its own right, due to reduced network losses and reduced constraints which would occur without this augmentation.

Without the supporting AC transmission upgrades to form the Sheffield-Heybridge-Burnie-Hampshire Hills-Staverton-Sheffield 220 kV loop, Marinus Link export would be constrained to between 80 MW and 40 MW, depending on wind generation and power system conditions, in order to maintain power system security. The 50th percentile export constraint is approximately 270 MW. With such constraints, Marinus Link would no longer have a positive net market benefit. The supporting AC transmission upgrades are therefore an essential part of the overall Project Marinus interconnector development.

Limitation of the scope of studies

The aim of our technical studies is to demonstrate that Project Marinus is technically viable under a range of future NEM network evolution pathways, and that Marinus Link does not have a detrimental impact on power system operations. In undertaking the studies, we have made reasonable assumptions regarding the connection of future renewable generation and large-scale batteries. The analysis does not set out to demonstrate how the anticipated large quantity of future renewable generation can be integrated into the NEM, nor does it attempt to precisely quantify future NEM operating limits. This can only be done as actual technical data for future network and generation projects becomes available, and is beyond the scope of Project Marinus.

Appendix 3 – Explanation of net economic benefit calculation using a shortened study period

Background and overview

The cost-benefit analysis presented in this PACR is conducted over a study period from 2020 to 2050, whereas the life of Project Marinus' AC and DC assets are 60 and 40 years respectively. A truncated study period is a standard approach in cost-benefit analysis with long-lived assets, as input data becomes increasingly uncertain over an extended time horizon. In this case, AEMO's forecast data is only available to 2050, whereas the assets will remain in service well beyond that date. Some of the other resources 'planted' by the model (such as batteries, gas fired generators, wind and solar generation assets) may also have asset lives that extend beyond the study period.

A truncated study period raises the issue of how the residual costs and benefits of the assets should be assessed at the end of the period. Our modelling approach in this PACR is to annualise the cost of the assets and calculate annual benefits to the end of the study period. The assumption with this annualised cost-benefit computation is that the net present value of the project's costs and benefits beyond the study period is zero.

An alternative approach is to recognise the cash outflow when the asset is first constructed and a cash inflow (called a 'terminal value') at the end of the study period. We have discussed these alternative methods in an explanatory paper[115] and accompanying spreadsheet, as part of our response to the Marinus Link PADR.

Although we did not receive any further stakeholder comments on the explanatory paper, in the interests of transparency, we consider it useful to provide additional analysis on terminal value calculations in this appendix. In particular, the purpose of this appendix is to examine how our modelling results would be affected if we adopted a terminal value approach instead of our annualised cost approach. Before setting out this analysis, we briefly discuss the AER's commentary on terminal values in its Cost Benefit Guidelines.[116]

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[115] https://www.marinuslink.com.au/wp-content/uploads/2021/02/Explanation-of-net-market-benefits-calculation-using-truncated-study-period.pdf

[116] AER, Cost benefit analysis guidelines - Guidelines to make the Integrated System Plan actionable, August 2020, section 4.3.9. As explained in section 4.2.2 of the AER's accompanying Final Decision, these guidelines do not apply to this PACR. Nevertheless, we have had regard to the guidelines in preparing this PACR.

AER's guidance on terminal values

In its Cost Benefit Analysis Guidelines, the AER explains that a shorter modelling period may require a terminal value to be included in the analysis to account for the remaining life of the asset:[117]

> "Where the modelling period is shorter than the expected life of a credible option, the RIT-T proponent is required to include any relevant and material terminal values in its discounted cash flow analysis. The RIT–T proponent is required to explain and justify the assumptions underpinning its approach to calculating the terminal value, which represents the credible option's expected cost and benefits over the remaining years of its economic life."

It is helpful to comment on two specific aspects of this guidance:

- The requirement is for the proponent to include any relevant and material terminal values. As noted in our earlier explanatory paper, an annualised cost approach obviates the need to include a terminal value in the cashflows. If this method is applied, therefore, it is reasonable to say that there are no relevant terminal values to be included in the cashflows. It is an open question whether the AER was contemplating this possibility in referring to 'relevant' terminal values.
- The Guidelines state that the terminal value represents the credible option's expected cost and benefits over the remaining years of its economic life. The reference to expected costs and benefits is open to different interpretations, but it would be incorrect to interpret the guideline as referring to the net economic benefit (i.e. benefits minus costs) over the remaining life of the asset.[118]

In principle, the terminal value may reflect either the residual (or unexpired) cost of the asset at the end of the study period or the present value of the future benefits over the remaining life of the asset. A cost-based terminal value will implicitly make an assumption that the future benefits beyond the study period will equal the unexpired cost of the asset in present value terms. We note that a straight line approach to depreciating the asset's costs is often used to determine the terminal value (even though it assumes a declining profile of benefits, which may not be valid).

Alternatively, if the terminal value is based on the future benefits, an explicit projection of benefits beyond the end of the study period must be made. Any such projection inherently assumes that the benefits accrued in the final few years extend for the remainder of the asset life. This methodology is routinely used in valuing corporations with steady cash flows that extend over a long time horizon.

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117 AER, Cost Benefit Analysis Guidelines, August 2020, section 4.3.9.

118 To illustrate this point, imagine an asset where the benefits exactly match the costs over its life, but the study period covers only half of the asset's life. In this case, the terminal value would be 50 per cent of the asset's original costs whether we have regard to the asset's future costs or its future benefits beyond the study period. Evidently, the terminal value is not the present value of the net economic benefit (costs minus benefits) over the asset's remaining life, which would be zero in this example.

In summary, our interpretation of the AER's Cost Benefit Analysis Guidelines is that it does not mandate a particular approach to modelling when a truncated study period is adopted. Instead, it requires the RIT–T proponent to *explain and justify* its approach. Given this requirement, we consider it appropriate to explain how our modelling would be affected if a terminal value approach were adopted.

Terminal value calculations

The terminal value method requires an estimate of the terminal value of the assets at the end of the study period. The use of terminal values ensures that options with differing asset lives (and different mixes of capital and operating expenditure) are assessed on the same basis.

The calculation of a terminal value could reflect:

- the remaining cost of the asset using a standard depreciation method, such as straight line depreciation; or
- the present value of the projected benefits for the remaining life of the asset.

In relation to the projected benefits, it is useful to consider the profile of benefits modelled over the study period. Figure 1 presents summary information on the costs and benefits of Marinus Link, assuming a 1500 MW capacity with the first stage commissioned in 2027 and second stage in 2029.

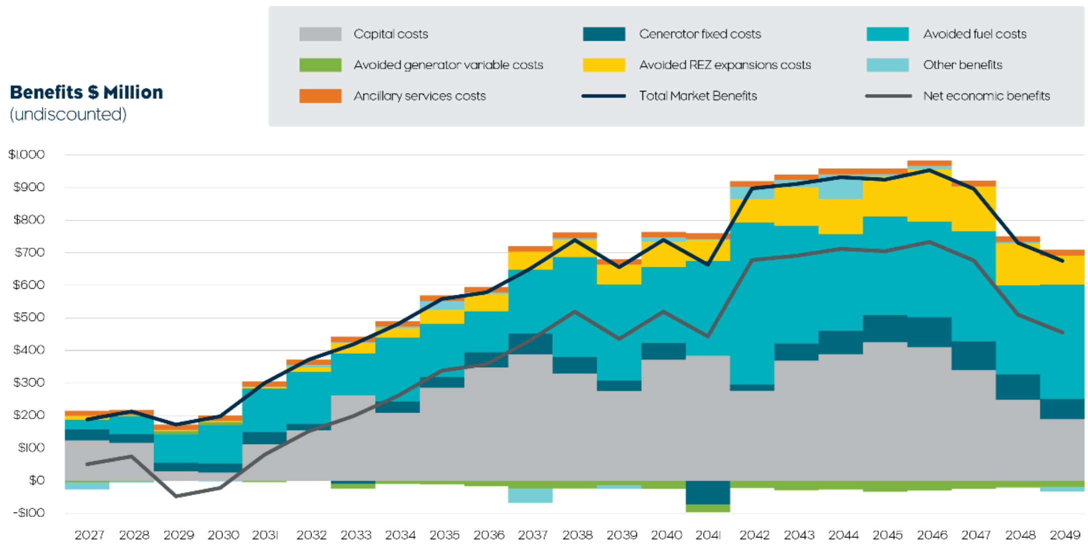

Figure 1: Overview of Marinus Link's costs and benefits (Step Change scenario, 2027 and 2029)

The grey line shows the gross benefits, which should be the focus of our attention for determining a benefit-based terminal value. The benefits remain relatively stable over the last 10 years of the modelling period (2040's). In these circumstances, one approach is to project the future benefits according to the average benefits obtained during the final few years of the study period.

The chart below shows the net economic benefits for 1500 MW of capacity with the first stage commissioned in 2027 and second stage in 2029 using a benefit-based and cost-based approach, alongside the annualised approach used in the PACR.

The cost-based approach depreciates the assets on a straight line basis and the benefit-based approach utilises average gross market benefits for the period of 2043 - 2048[119]. The computation of each of these approaches can be found in the economic evaluation spreadsheet for reference.

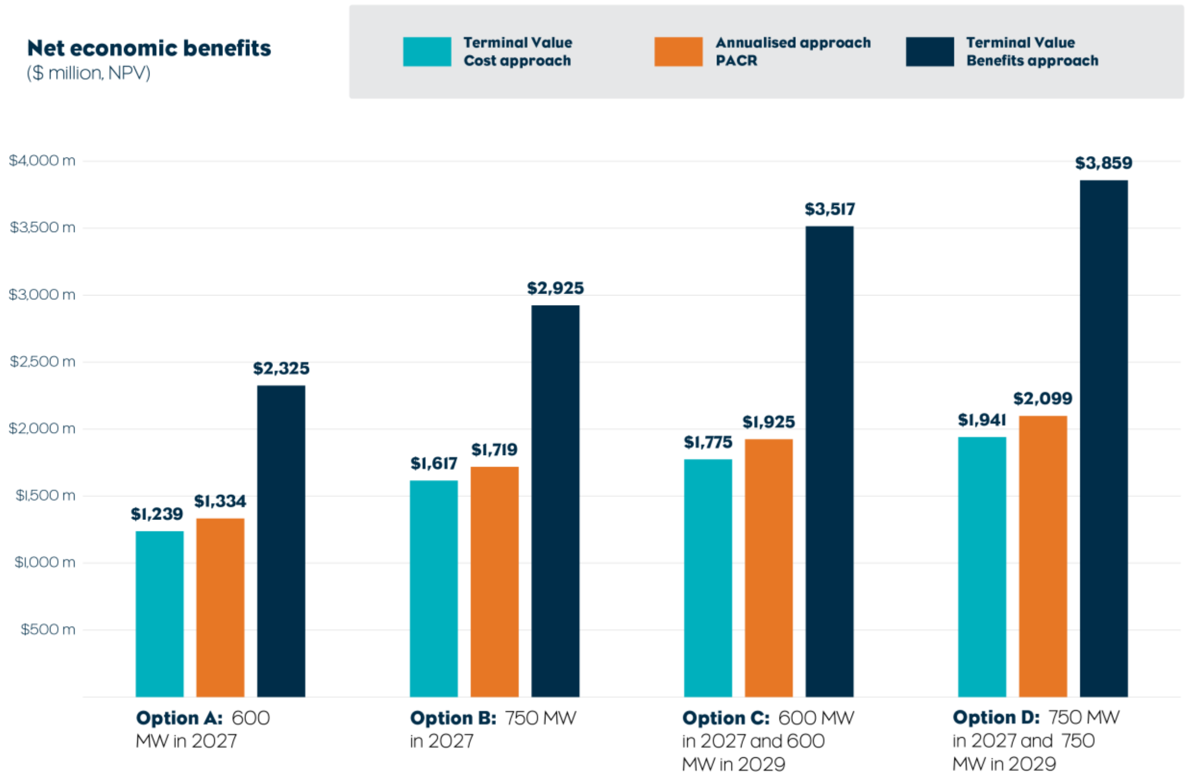

Figure 2: Net economic benefit for terminal value and annualised valuation approach (Scenario weighted, 1500 MW Marinus Link, 2027 and 2029)

[119] Owing to end-effects of modelling, the last two modelling years are avoided.

Discussion and conclusion

Applying straight line depreciation to derive a terminal value (the cost-based approach) results in a small decrease in the net economic benefit of all options compared to the estimate obtained using the annualised cost approach. Importantly however, the reduction in the net economic benefit does not affect the selection of the preferred option.[120]

Applying a benefit-based estimate of the terminal value would result in a material increase in the net economic benefit of all options compared to the annualised cost approach. In our view, the increased terminal value derived from a benefit-based approach may be justified, given the expected level of benefits towards the end of the study period and the likelihood that these will continue. In relation to the RIT-T, the key issue is that this method also does not affect the selection of the preferred option.

As explained in this appendix, there are different approaches that may be taken to allow for the terminal values of long-lived assets when the study period is shorter than the lives of the assets. The annualised cost approach enables the evaluation of costs and benefits on a consistent basis when the study period is shorter than the asset lives, without the need to derive a terminal value.

The application of a cost-based or a benefit-based approach to estimating terminal values does not affect the conclusions set out in this PACR, which are based on an annualised cost approach. The annualised cost approach estimates the net economic benefit to be slightly above the cost-based terminal value and substantially below the benefit-based approach. Furthermore, the selection of the preferred option is the same for each of the three methods. On that basis, we consider our modelling approach to be appropriate and the implied terminal value to be reasonable having regard to the costs and benefits for the remaining life of the asset, in accordance with the Cost Benefit Guidelines.

[120] In addition to the net economic benefit remaining substantially positive with the reduced terminal value, our analysis shows that the preferred option continues to be ranked first amongst the credible options.

Appendix 4 - Checklist of Compliance Clauses

This appendix sets out a compliance checklist which demonstrates the compliance of this PACR with the requirements of clauses 5.16A.4 ‘Application of the RIT-T to actionable ISP Projects’ of the National Electricity Rules version 162.

NER clause	Summary of requirements	Relevant section(s) in PACR
5.16A.4(i)	**Project assessment conclusions report** As soon as practicable after the end of the consultation period on the project assessment draft report referred to in paragraph (g), the RIT-T proponent must, having regard to the submissions received, if any, under paragraph (f) and the matters discussed at any meetings held, if any, under paragraph (h), prepare and make available to all Registered Participants, AEMO and interested parties and publish a report (the project assessment conclusions report).	This PACR has been prepared in accordance with this requirement. As explained in section 3.2 of this PACR, we extended the consultation period by publishing a Supplementary Analysis Report in response to stakeholder feedback on our PADR.
5.16A.4(j)	The project assessment conclusions report must set out:	
	(1) the matters detailed in the project assessment draft report as required under paragraph (d); and	See detailed responses in relation paragraph (d) below
	(2) a summary of, and the RIT-T proponent's response to, submissions received, if any, from interested parties sought under paragraph (f).	Section 4 and Appendix 1 of this PACR.
5.16A.4(d) [to address 5.16A.4(j)(1)]	The project assessment draft report must include:	
	(1) include the matters required by the Cost Benefit Assessment Guidelines;	TasNetworks has ensured that the PACR and the accompanying cost benefit modeling complies with the requirements of the Cost Benefit Assessment Guidelines.
	(2) adopt the identified need set out in the Integrated System Plan (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	Section 5.1 sets out the identified need, which is consistent with the 2020 ISP, Table 12, page 87.
	(3) describe each credible option assessed;	Section 5.3.

NER clause	Summary of requirements	Relevant section(s) in PACR
	(4) include a quantification of the costs, including a breakdown of operating and capital expenditure for each credible option;	Section 5.5.
	(5) assess market benefits with and without each credible option and provide accompanying explanatory statements regarding the results;	Section 7.1 and Chapter 8.
	(6) if the RIT-T proponent has varied the ISP parameters, provide demonstrable reasons in accordance with 5.15A.3(b)(7)(iv);	Section 2.3 explains that we have adopted the draft IASR parameter values, being the latest available data developed by AEMO in light of stakeholders' views.
	(7) identify the proposed preferred option that the RIT-T proponent proposes to adopt;	Sections 7.1 and 7.2.
	(8) For the proposed preferred option identified under subparagraph (7), the RIT-T proponent must provide:	
	(i) details of the technical characteristics;	Appendix 2.
	(ii) the estimated construction timetable and commissioning date;	Section 7.3.
5A.16.4(k)	The RIT-T proponent must publish on its website the project conclusions report within 5 business days of the project assessment conclusions report being made. The RIT-T proponent must promptly provide the project assessment conclusions report to AEMO after it is made and AEMO must publish on its website the report within 5 business days of receipt.	TasNetworks intends to publish the PACR and provide it to AEMO as required by this provision.
5A.16.4(l)	A RIT-T proponent may discharge its obligation under paragraph (i) to make the project assessment conclusions report available by including the project assessment conclusions report as part of its Transmission Annual Planning Report provided that the report is published within 4 weeks from the date of publishing the project assessment conclusions report under paragraph (i).	Not applicable.

Glossary

Terms	Description
Ancillary services	Ancillary services perform the essential role of ensuring a continuously stable power system operation, especially when subjected to unforeseen contingency events. Examples include a device which can rapidly alter the network voltage to correct for voltage disturbances (caused, for example, by a lightning strike), or the ability of a generator to rapidly change its power output in response to a sudden change in customer demand.
Battery of the Nation	An initiative by Hydro Tasmania, supported by funding from the Australian Renewable Energy Agency, investigating and developing a pathway of future development opportunities for Tasmania to make a greater contribution to the NEM.
Capex	Capital expenditure; the expenditure required to develop and construct an asset
Dispatchable on-demand	A generator, such as a hydroelectric, gas- or coal-fired generator, in which the electrical output can be increased or decreased as required in order to meet varying customer demand. This contrasts with non-dispatchable generators, such as solar and wind, the output of which will fluctuate depending on the input power source. e.g., how strongly the wind is blowing or the sun is shining.
Energy security	Refers to the certainty of being able to supply customers' energy needs in the medium and long-term
Final Investment Decision	Relates to the stage in a project where everything is in place to execute the project (contracts are signed). Getting to this stage involves arranging all financing, permits, approvals and any other requirements that are needed prior to construction starting. It is the point where contracts for all major equipment can be placed, allowing procurement and construction to proceed and engineering to be completed
Firming	Firming, in relation to variable generation sources such as solar or wind, is the action of adding additional power from a separate dispatchable on-demand source that can compensate for the potential lack of output from a variable generator when the power is needed.
Load shedding	Reducing or disconnecting load from the power system. (Rules chapter 10).

Terms	Description
Marinus Link	A proposed second transmission interconnector linking Tasmania and Victoria
Net present value	The difference between the present value of benefits and the present value of costs over a period of time.
On-demand	Available when requested or required.
Opex	Operational expenditure; the ongoing expenditure required to operate and maintain assets and the supporting activities to provide services.
Power system security	Operation of the power system within its technical limits (for frequency, voltage, etc.) such that it will maintain stable operation including after a contingency event.
Supply reliability	Maintaining sufficient capacity (generation, network, and demand response) to meet customer power demands in the short-term
Unserved energy	The volume of energy that customers desired but could not supplied (e.g. due to a blackout). The technical definition of unserved energy is set out in chapter 10 of the Rules.

Acronym	
AC	alternating current
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
DER	distributed energy resources
ESB	Energy Security Board
EUAA	Energy Users Association of Australia
FCAS	frequency control ancillary services
FCSPS	frequency control system protection scheme
FTI	FTI Consulting
GW	gigawatts
HVDC	high voltage direct current
IASR	Inputs, Assumptions and Scenarios Report
ISP	Integrated System Plan
kV	kilovolt
LDES	long-duration energy storage
LRET	Large-scale Renewable Energy Target
MW	megawatts
NEM	National Electricity Market
NEVA	National Electricity (Victoria) Act

Acronym	
NPV	net present value
PACR	Project Assessment Consultations Report
PADR	Project Assessment Draft Report
PHES	pumped hydro energy storage
PSCR	Project Specification Consultation Report
PV	photovoltaic
QRET	Queensland Renewable Energy Target
REZs	renewable energy zones
RIT-T	regulatory investment test for transmission
Rules	National Electricity Rules
SPS	System Protection Scheme
TNSP	transmission network service provider
TRET	Tasmanian Renewable Energy Target
VEPC	Victorian Energy Policy Centre
VNI	Victoria-NSW Interconnector
VRE	Variable Renewable Energy
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital