29 JUNE 2020

BENEFITS OF PROJECT ENERGYCONNECT

A REPORT FOR TRANSGRID

FINAL REPORT

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Project EnergyConnect: Key Findings

This report is an independent analysis on the gross benefits of Project EnergyConnect ("EnergyConnect"), a proposed 800MW electricity interconnector between New South Wales ("NSW") and South Australia ("SA"). EnergyConnect is due to become operational between 2022 and 2024 and has been identified by AEMO as a critical project. One of the project developers, TransGrid, will shortly submit a Contingent Project Application ("CPA") for EnergyConnect to the Australian Energy Regulator and this report is intended to inform that submission.

Our report first presents the expected gross benefits of EnergyConnect in accordance with the standard evaluation framework – known as the Regulatory Investment Test for Transmission ("RIT-T") – and drawing on the latest available Draft Integrated System Plan ("ISP") 2020 information from AEMO (published in December 2019); it then outlines the potential wider benefits of EnergyConnect, including non-monetary benefits, currently not captured by the RIT-T approach; and finally we present an alternative consumer-focused perspective to calculating benefits, which differs from the RIT-T approach but is common in some other jurisdictions.

Using the standard RIT-T, we estimate that EnergyConnect will create gross benefits of **$1.6 billion in Net Present Value ("NPV") terms over the 2020 to 2040 modelled period**. In practice, we believe that this is a conservative estimate of the benefits EnergyConnect is likely to bring to the NEM over its lifetime, for the three reasons set out below and discussed in detail in the report.

First, FTI expanded its research based on its experience of how authorities in other jurisdictions typically assess the benefits of a proposed interconnector. In this context, we find that other regulators (or relevant decision-makers) commonly consider wider qualitative benefits of interconnector investments that cannot be easily evaluated in monetary terms. **For EnergyConnect we would expect incremental non-monetary benefits to arise as a result of integrating renewable generation, connecting two regions with complementary generation mixes, improving security of supply and providing optionality in the face of uncertain future policies or circumstances.** These incremental non-monetary benefits are relevant in the context of the security and reliability of supply aims within the National Electricity Objective ("NEO"). Moreover, the Australian Energy Market Operator ("AEMO") has identified EnergyConnect as crucial to the security of South Australia's system.

Second, we also consider that **an additional $0.8 to $1.0 billion of gross benefits, relating to the remaining life of EnergyConnect beyond 2040, is likely to accrue to consumers in Australia.** This benefit is not included in the definition of benefits under the RIT-T, nor is it included in the assessment of interconnectors in other jurisdictions, although the primary assessment period in some jurisdictions (e.g. Ofgem in Great Britain) is 25 years - longer than the period assessed for EnergyConnect under its RIT-T. Our view is that it is reasonable to assume that some benefits will continue to accrue beyond 2040.

Finally, from a **purely consumer-focused perspective, which differs from the approach adopted in the RIT-T, we estimate that, as a result of lower wholesale prices, EnergyConnect will deliver $7.1 billion to $11.9 billion of net economic benefits to the NEM's energy consumers.** This benefit is driven by improved access to cheaper sources of generation. Consumers also benefit from enhanced competition, as the greater access to distant electricity markets that EnergyConnect facilitates means generators located in neighbouring regions can inhibit the ability of locally sited generators to bid in a strategic manner. For NSW and SA consumers specifically, EnergyConnect may bring **net savings** of **between $34 to $110 per year for NSW households**, and [redacted]

Executive summary

The National Electricity Market ("NEM") is currently undergoing a rapid transition as it seeks to move towards an electricity system with high levels of renewable generation, which is creating new challenges for the production, transmission, storage and consumption of electricity. In response to these challenges, the Australian Energy Market Operator ("AEMO") has developed the Integrated System Plan ("ISP") as a tool for informing the market about the NEM system and its future development, including the need for future transmission investments.

The most recent Draft ISP 2020 outlines a series of proposed transmission investments that AEMO considers critical.[1] Project EnergyConnect ("EnergyConnect"), a proposed 800MW interconnector between New South Wales ("NSW") and South Australia ("SA"), due to be operational between 2022 and 2024, has been identified as one of these critical projects.

EnergyConnect satisfied the Australian Energy Regulator's ("AER's") formal regulatory assessment, known as the Regulatory Investment Test for Transmission ("RIT-T"), in January 2020. As a next step, the project promoters TransGrid and ElectraNet are expected to submit a joint Contingent Project Application ("CPA") for regulatory approval of the efficiently incurred costs of the project.

To help inform the CPA, TransGrid has engaged FTI Consulting ("FTI") to undertake independent analysis of the expected gross benefits of EnergyConnect. This report presents FTI's findings on both the benefit of the project under the RIT-T approach as well as other wider project benefits not captured in the RIT-T assessment.

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1 These projects are *"Group 1 – Priority grid projects"*, which are *"critical to address cost, security and reliability issues"* in the NEM. Source: AEMO, Draft Integrated System Plan 2020, December 2019 (link), page 11.

Modelling methodology and approach

The gross benefit of EnergyConnect is modelled using FTI's in-house NEM power market model (that runs on the Plexos® Market Simulation Software). The impact of EnergyConnect over the 2020 to 2040 modelling period (i.e. the first 17 years of the project's lifetime), is estimated by comparing an assumed evolution of the NEM with EnergyConnect relative to a counterfactual scenario without EnergyConnect.

In our modelling we have adopted the most recent input assumptions from AEMO's Draft ISP 2020[2] and we also impose specific stability constraints from ESOO 2019, which seek to reflect "*stability limits that currently constrain dispatch in the NEM*".[3,4]

We have estimated four categories of benefit from EnergyConnect, each in-line with the RIT-methodology, for the 2020 to 2040 period.[5] The categories of benefits we have estimated are:

- **Avoided variable costs**, which is the benefit that is derived because EnergyConnect enables cheaper generation sources to displace more expensive generation sources, saving fuel cost, variable operating and maintenance cost and start-up cost.
- **Avoided fixed costs**, which is the benefit derived as EnergyConnect allows certain generators to retire early or commence operating later than would otherwise be the case and, in so doing, saves fixed operating costs.
- **Avoided Renewable Energy Zone Transmission costs**, which is the benefit derived when there are cost savings due to changes to the timings or configuration of investment in transmission to meet a different "identified need" that arises as a result of the investment in EnergyConnect.

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2 We use the most recent input assumptions available at the time of modelling, which were the Draft ISP 2020 input assumptions published in December 2019. This is different to the input assumptions used in the Project Assessment Conclusions Report ("PACR").

3 These stability constraints are critical in understanding the benefit of EnergyConnect. Given the uncertainty about how system conditions in the NEM will evolve in the future, we have modelled three different variations of the constraints.

4 AEMO's main ESOO scenarios do not include QNI and VNI upgrades. However, as part of ESOO 2019, AEMO tested the potential impact of these interconnector augmentations as a sensitivity. Source: AEMO, Electricity Statement of Opportunities, August 2019 (link), page 70.

5 For example, using Short-Run Marginal Cost bidding methodology.

- **New build generator capital cost**, which are the incremental changes in generator capital costs that are incurred due to new capacity being built, or the timing of new capacity being brought forward as a result of EnergyConnect.

A recognised key benefit of EnergyConnect is that it will replace the current need for SA gas plants to operate so frequently (particularly at times of low renewable output and for system security purposes). Instead of incurring the cost of gas in these plants, EnergyConnect would enable SA to draw on cheaper electricity from neighbouring regions. Therefore, a key area of our analysis has been a detailed examination of how SA gas generators are likely to operate both with and without EnergyConnect.

The AER concurred in its Determination with this view, identifying the displacement of SA gas plant fuel use (and retirements) as the most important driver of the estimated benefits of EnergyConnect.[6]

The avoided cost of gas by SA gas plants, arising as a result of EnergyConnect, has been a key area of contention. One approach is to assume that, in the absence of EnergyConnect, SA gas plants would operate over the forecast period in line with an assumed **Minimum Capacity Factor**, which is determined primarily on the basis of historical operating patterns.[7] In its Determination, the AER was critical of this approach.[8] Therefore, in line with the AER's guidance, we did not apply this assumption and instead used other assumptions to reflect reasonable generator behaviour over the forecast period.

To reflect such behaviour, we have refined the specific inputs and assumptions in our Plexos® model such that we reflect the **costs, technical limitations and operating decisions** faced by generators in a credible manner. In particular, we carefully defined appropriate assumptions on the gas generators' minimum on/off times, minimum stable load and start-up cost assumptions.

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6 Underpinning this analysis, AER identified the Minimum Capacity Factor, generator characteristics, system security and generator new build/retirement as the four assumptions that are critical to the evaluation of the project's benefits. Source: AER, Decision: South Australian Energy Transformation, January 2020 (link), pages 26-29.

7 This assumption specifies a minimum percentage of hours that a generator must be online and proxies for various commercial and operational factors such as take or pay contracts, system security requirements or reasonable operating patterns.

8 The AER were not satisfied that MCF should be applied on the basis of historical gas usage. Furthermore, these assumptions were found to have a significant impact on the capacity and generation of SA gas units in the counterfactual scenario without EnergyConnect, and hence the estimated project benefits.

In addition to the assumptions underpinning gas plant generator behaviour, we also focused on two additional sets of assumptions, as set out below:

- **System security**: The transition to a more intermittent based resource mix (and the coincidental decline in the share of generation from synchronous sources) has progressively led to a reduction in system strength and inertia (in particular in SA). EnergyConnect is expected to improve system stability and to remove the existing requirement for some synchronous generators, notably SA gas plant, to be online at all times. To capture this benefit, system security constraints are included in the counterfactual to assess how SA gas plant might need to continue to operate in the absence of EnergyConnect and a relevant subset of these constraints are relaxed (or removed) in our modelling of the system with EnergyConnect.
- **Generator retirements and new build capacity**: We vary our approach over the forecast horizon:
  - in the short term, we use pre-committed investment and retirement decisions of generators as inputs into our modelling;[9] and
  - in the longer term, our approach differs by region. For SA, we estimate in our modelling when SA gas plant will close and when new generator capacity will come online. For other regions of the NEM, thermal plant closures are inputs into the model.[10]

9 The owners of Torrens Island A have announced their intentions to retire this plant, in-line with the Australian Energy Market Commission's requirement to give three years notice for any planned retirement. The owners of Osborne are expected to imminently formally announce their intentions to retire all Osborne units in 2023. Sources: AGL, Schedule for the closure of AGL plants in NSW and SA, August 2019 (link); Australian Energy Council, South Australia's surprise RRO, January 2020 (link).

10 Due to practical modelling limitations, we were not able to allow the model to decide when all thermal capacity across the NEM should be retired. Taking into account this limitation, the approach of allowing the model to decide SA gas plant retirements and new build capacity is broadly consistent with the AER's observation that Plexos® model has the capability to model generator build-out and retirement endogenously.

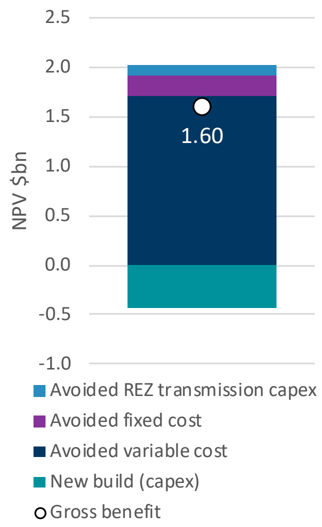
Gross benefits of EnergyConnect calculated under the RIT-T methodology

Using the methodology set out above, we estimate **gross project benefits to be $1.6 billion** in Net Present Value ("NPV") terms over the 2020 to 2040 modelled period.[11] As illustrated in Figure 1 below, this estimate is composed of:

- **$2.0 billion in positive benefits**, arising from a combination of reduced: (i) variable costs; (ii) fixed costs; and (iii) Renewable Energy Zone ("REZ") transmission capex; and
- **$0.4 billion in disbenefits** (that is, negative benefits), arising from an increase in new generator build capex across the NEM.

This estimate of gross benefits is materially higher than the $1.2 to $1.3 billion value estimated in the Determination using AER's preferred set of assumptions.[12]

Figure 1: Gross benefit of EnergyConnect (NPV, 2020 to 2040)



Source: FTI analysis.
Note: The quantum of gross benefit is dependent on the stability constraints imposed (here shown for the model run with all NEM stability constraints).

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11 Values discounted to the start of financial year 2020 (i.e. 1 July 2019) at AEMO's Draft ISP 2020 central scenario discount rate of 5.9%. All monetary input values in real 2019 dollar terms.

12 The AER's preferred set of assumptions were informed by the work of its economic advisers, Frontier Economics. Source: AER, Decision: South Australian Energy Transformation, January 2020 (link), page 30.

Avoided variable cost

The reduction in variable costs across the NEM is estimated to be the biggest driver of benefit from EnergyConnect, accounting for **$1.7 billion** of the total estimated gross benefits accrued between 2020 and 2040. There are two main mechanisms through which EnergyConnect enables a net reduction in variable costs.

Firstly, EnergyConnect allows for **NEM dispatch to be optimised over a larger geographical area**, enabling relatively less expensive generation from one region (this can sometimes be SA and sometimes NSW) to displace relatively more expensive generation in the connected region. With EnergyConnect, SA gas generation (which is no longer required to be online at all times) is replaced by an increase in SA renewable generation and increased imports to SA from Victoria of brown coal generation on existing interconnectors. Furthermore, on days when renewable generation in SA exceeds local demand, excess generation can be exported to NSW via EnergyConnect.

Secondly, EnergyConnect **reinforces SA system security** and relaxes the existing requirement for certain SA gas generators to be online at all times.[13] This supports the displacement of SA gas generation by less expensive generation sources (e.g. renewable generation) without compromising system security.

Avoided fixed cost

Our modelling indicates that EnergyConnect enables certain SA gas units to retire earlier than they otherwise would in the absence of the interconnector, and allows new capacity to be built (or its timing to be brought forward). The early retirement of SA gas units with high fixed cost represents a significant benefit (i.e. cost saving) which outweighs the additional fixed cost incurred on incremental generation capacity.

The net impact of the change in capacity mix with EnergyConnect is a cost saving of **$0.2 billion**.

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13 Investment in synchronous condensers in SA also contributes to reinforcing system security. Our modelling considers the four approved synchronous condensers as ‘committed’ both in the baseline and in the scenario with EnergyConnect, so the estimated impact of EnergyConnect is additional.

Avoided Renewable Energy Zone Transmission Capex

This benefit category reflects the extent to which EnergyConnect changes the timings of, or need for, investment in other transmission designed to meet a different 'need'. Although material, this is not a key driver of the overall cost-benefit analysis (accounting for only a small percentage of the total gross benefits). We have therefore not undertaken detailed analysis of this benefit and instead use the value of **$0.1 billion** calculated in the Project Assessment Conclusions Report ("PACR").[14]

Capex from new build capacity

EnergyConnect has an impact on the evolution of the NEM generation capacity, with our modelling indicating that, as a result of EnergyConnect coming online, there is a net decrease of **$0.4 billion** during the modelling period (i.e. this is an incremental cost). With EnergyConnect, some capacity will retire earlier than it otherwise would (e.g. Torrens Island B), the commissioning of some new plant will be brought forward and some incremental capacity will be built that otherwise would not (in particular in response to the retirement of Torrens Island B).

Wider benefits of EnergyConnect

Our modelling finds significant positive benefits of EnergyConnect under the RIT-T methodology. However, based on our experience in other jurisdictions, we consider that this is not the only valid approach that can be taken. Other regulators (or relevant decision-makers) may, from time to time, take into account wider quantitative and qualitative benefits of interconnector investments. In Europe, for example, a wide range of qualitative criteria is included in the formal evaluation process, to ensure that potentially "*the full range of costs and benefits can be represented*" [15] when evaluating potential investments.

Our analysis has identified additional economic benefits that would accrue to consumers in Australia, that are not included in the definition of benefits under the RIT-T. Relative to approaches adopted in other jurisdictions, the RIT-T may therefore undervalue total project benefits, as there are likely to be benefits that cannot be monetised or are project-specific, and do not fall into one of the allowed benefit categories. These additional benefits include:

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14 AER, Decision: South Australian Energy Transformation, January 2020 (link), page 73.

15 ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Project, Draft Version, October 2019 (link), page 18.

- **Post-2040 benefits.** Gross benefits arising from EnergyConnect continuing to operate beyond the 2020 to 2040 modelling horizon are estimated to be in the range **$0.8 to $1.0 billion** on an NPV basis.[16] While we recognise that there is a greater level uncertainty regarding the quantum of this gross benefit,[17] it is reasonable to consider that EnergyConnect will continue providing benefit to the NEM over its remaining expected life post-2040.[18] Based on the information currently available, we consider the quantum of benefit to be reasonable.

16 The lower bound of this range assumes that the annual benefit from 2041 is equal to the average of the annual benefit over the 2020 to 2040 modelling period, while the upper bound of this range assumes that the annual benefit from 2041 is equal to the average of the annual benefit from the final three modelled year (i.e. 2038 to 2040 inclusive).

17 This quantum of benefit is more uncertain compared to the pre-2040 period because there is currently less visibility on what the generation mix, volume of additional interconnection, commodity prices and electricity demand will look like beyond 2040.

18 For example, Interconnexion France-Angleterre, a 2,000MW interconnector between GB and France, has been operational for over 30 years and has provided benefit to GB consumers from lower wholesale prices over its operational life. The interconnector remains operational (with no plans for operation to cease) as of May 2020. Source: Ofgem, IFA Use of Revenue framework, 22 August 2016 (link), page 1.

- **Non-monetary benefits** arising from the contribution of EnergyConnect towards renewables integration, connection of complementary energy mixes, security of supply and optionality for uncertain future policies and circumstances. For example, EnergyConnect is expected to improve system security, which will help mitigate high impact, low probability system stress events – such as the two week SA separation event in early 2020 – that are not explicitly prepared for but have been occurring with greater frequency in the last few years. EnergyConnect is also likely drive down the cost of procuring ancillary services through (i) decreasing the frequency at which such services are needed in the context of system stress events; and (ii) improving access to cheaper ancillary services in other regions. These benefits are not able to be fully captured under the RIT-T methodology (as they cannot be fully monetised) but would commonly be taken into account by regulators and/or policy makers in other jurisdictions, including Great Britain ("GB"), the United States ("US") and European Union ("EU"), as part of 'standard' regulatory assessment.[19]

These non-monetary effects are however considered important in the context of the NEM as a whole, and appear to be directly relevant to the National Electricity Objective ("NEO"). The NEO governs the manner in which the AEMC applies economic regulation to the transmission network in the NEM.

Among other matters, the NEO is specifically concerned with the reliability and security of supply.[20] EnergyConnect is expected to help prevent SA from being 'islanded' during system stress events, which will contribute directly to a more reliable and secure system.

In addition, AEMO has recently identified that the completion of EnergyConnect under the current proposed timelines *"should be considered crucial for the ongoing security of South Australia's power system"*.[21]

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19 For example, The European Network of Transmission System Operators for Electricity ("ENTSO-E") argues that "*both qualitative assessments and quantified, monetised assessments are included* [in its assessment]. *In such a way the full range of costs and benefits can be represented.*" ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Project, Draft Version, 15 Oct 2019 (link), pages 17-18.

20 AEMC, Applying the Energy Market Objectives, July 2019(link), pages 7 and 8.

21 AEMO, Minimum operational demand thresholds in South Australia, May 2020 (link), page 55.

On Australia's wider climate change objectives, the NEO emphasises the need to ensure they are met efficiently and in such a manner that preserves reliability and security.[22] As the first link between NSW and SA, EnergyConnect is well equipped to assist in achieving this objective, by creating an option for excess renewable generation from one region to be exported to another.

In addition, from a purely consumer perspective, which differs from the RIT-T,[23] we have estimated the net economic benefits that would accrue to energy consumers as a result of EnergyConnect to be between **$7.1 and $11.9 billion**, in NPV terms.[24] For NSW and SA consumers specifically, EnergyConnect may bring **net savings** of **between $34 to $110 per year for NSW households**, and [redacted].[25]

This quantum of benefit is not incremental to that estimated under the RIT-T methodology,[26] but does provide an alternative perspective commonly considered by regulators in some other jurisdictions, notably Ofgem in GB. In-line with its principal objective to protect the interest of future and current consumers in GB, Ofgem primary focus is on assessing the impact of new interconnector investment from the perspective of consumers in GB, as opposed to society as a whole. We further note that the NEO is specifically concerned with the *"long term interests of consumers of electricity"*.[27]

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22 AEMC, Applying the Energy Market Objectives, July 2019 (link), pages 7 and 8.

23 The consumer-only approach places a greater weight on consumer welfare relative to other stakeholders when assessing the merits of interconnector investment.

24 This estimate includes the increase in consumer surplus, less interconnector residues and less an assumed annuitised cost of EnergyConnect falling within the modelling period.

25 Assuming that: (i) wholesale price savings are fully passed on to retailers; and (ii) the cost of EnergyConnect and the change in interconnector rent are fully passed on to consumers.

26 For example, the reduction in fuel cost captured under the RIT-T methodology is also captured in net consumer surplus.

27 AEMC, Applying the Energy Market Objectives, July 2019(link), pages 7 and 8.

The benefit of EnergyConnect to consumers is driven by two factors: first, an improved access to cheaper sources of generation from neighbouring regions, as identified previously. However, the interconnector also has a secondary impact of enhancing competition in the NEM.[28] This arises because the strategic bidding behaviour of local generators becomes more limited as the new interconnector would enable other, more distant generators sited in neighbouring regions, to compete to meet local demand. In turn, as a result of EnergyConnect, the wholesale electricity price that feeds into customer bills will be significantly lower – materially improving the welfare of electricity consumers in the NEM.

[28] We recognise that the RIT-T methodology allows for 'competition benefits' to be included in the calculation of gross benefits, to reflect the impact that the credible option is likely to have on the bidding behaviour of generators. The AER outlines two possible methodologies that could be used to isolate the benefit of competition on the cost of dispatch. Our consumer-focused approach considers the impact of increased competition on the wholesale electricity price, by estimating prices using the "Bertrand" methodology, as explained in footnote 155. This approach enables us to estimate the benefit of EnergyConnect in terms of constraining generators' bidding behaviour, to the benefit of consumers. Source: AER, Application guidelines: Regulatory investment test for transmission, December 2018 (link) pages 91 to 95.

1. Introduction

1.1 As with many electricity markets in the world, the Australian National Electricity Market ("NEM") has entered a period of transition, driven by concerns over climate change, in which the share of generation from renewable intermittent sources, notably solar and wind, is increasing rapidly.[29] In this context, further investment in transmission infrastructure to convey power from generators (or storage/injection points) to consumers or other networks for onwards transmission is often cited as one of the crucial elements required to support this transition towards renewables and to improve reliability and security of supply in a cost-efficient way.[30]

1.2 To address these challenges, the Australian Energy Market Operator ("AEMO") publishes its Integrated System Plan ("ISP"), which aims to take a coordinated approach to planning a cost-efficient evolution of the transmission network. The inaugural ISP report, published in 2018, projected *"substantial amounts of geographically dispersed renewable generation, placing a greater reliance on the role of the transmission network."*[31] It identified the need for *"a much larger network footprint with transmission investment […] to efficiently connect and share these low fuel cost resources."* [32]

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29 AEMO, Electricity Statement of Opportunities, August 2019 (link).

30 See for example: Dr Alan Finkel AO, Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future ("Finkel Review") June 2017 (link); AEMO, Integrated System Plan, July 2018 (link); AEMO, Draft 2020 Integrated System Plan, December 2019 (link).

31 AEMO, Integrated System Plan, July 2018 (link), page 6.

32 AEMO, Integrated System Plan, July 2018 (link), page 6.

1.3 The Draft Integrated System Plan 2020 ("Draft ISP 2020"),[33] re-affirmed the need for increased electricity transmission investment in the NEM. It identified 15 projects to augment the transmission grid, which would contribute to the "*optimal development path"* towards affordable, secure and reliable energy supply in the NEM.[34]

1.4 Project EnergyConnect ("EnergyConnect"), a proposed interconnector between New South Wales ("NSW") and South Australia ("SA"), has been identified as one of these projects on the "*optimal development path*". EnergyConnect has been classified as one of the *"Group 1 – Priority grid projects"*, which are *"critical to address cost, security and reliability issues"* in the NEM.[35,36] EnergyConnect is being jointly developed by ElectraNet and TransGrid, the Transmission Network Service Providers ("TNSPs") in SA and NSW respectively.

1.5 EnergyConnect recently satisfied the Australian Energy Regulator's ("AER") Regulatory Investment Test for Transmission ("RIT-T").[37] As part of its determination, the AER critiqued a number of key modelling assumptions and requested that ElectraNet update its Project Assessment Conclusions Report ("PACR") modelling with these amended. In this context, FTI has been asked to re-evaluate the benefits of EnergyConnect from a 'first principles' approach in light of the concerns raised by the AER about some aspects of the key modelling assumptions.

1.6 Following the RIT-T Determination, TransGrid and ElectraNet are expected to submit a joint contingent project application ("CPA") for regulatory approval of efficiently incurred costs for the project.

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33 The Draft ISP 2020 was published in December 2019. The Final ISP 2020 is expected in mid-2020.

34 AEMO, Draft 2020 Integrated System Plan, December 2019 (link), page 11.

35 AEMO, Draft 2020 Integrated System Plan, December 2019 (link), page 11.

36 Victoria-New South Wales Interconnector ("VNI") and Queensland-New South Wales Interconnector ("QNI") upgrades, which are modelled in the counterfactual without EnergyConnect and in the scenario with EnergyConnect, have also been classified as Group 1 projects.

37 AER, Decision: South Australian Energy Transformation, January 2020 (link).

Purpose and objectives of this report

1.7 FTI Consulting ("FTI") has been engaged by TransGrid to provide an independent view on the gross benefits of EnergyConnect, to help inform the CPA submission.[38]

1.8 This report evaluates and presents:

- the expected gross benefits of EnergyConnect under the RIT-T framework, using the latest available Draft ISP 2020 information from AEMO (published in December 2019); and
- potential wider benefits of EnergyConnect, including non-monetary benefits, currently not captured by the RIT-T approach.

Restrictions

1.9 This report has been prepared solely for the benefit of TransGrid for the purpose described in this introduction.

1.10 FTI Consulting accepts no liability or duty of care to any person other than TransGrid for the content of the report and disclaims all responsibility for the consequences of any person other than TransGrid acting or refraining to act in reliance on the report or for any decisions made or not made which are based upon the report.

Limitations to the scope of our work

1.11 This report contains information obtained or derived from a variety of sources. FTI Consulting has not sought to establish the reliability of those sources or verified the information provided.

1.12 No representation or warranty of any kind (whether express or implied) is given by FTI Consulting to any person (except to TransGrid under the relevant terms of our engagement) as to the accuracy or completeness of this report.

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[38] FTI previously examined the net benefits of the Draft ISP 2020 Group 1 interconnectors between NSW and the neighbouring states. However, the previous analysis, undertaken in 2018 and 2019, assessed the benefits from the perspective of consumers, which departs from the RIT-T methodology.

1.13 This report is based on information available to FTI Consulting at the time of writing of the report and does not take into account any new information which becomes known to us after the date of the report. We accept no responsibility for updating the report or informing any recipient of the report of any such new information.

Structure of this report

1.14 The following sections in this report are set out as follows:

- **Section 2** describes the modelling methodology used to evaluate the expected gross benefits of EnergyConnect.
- **Section 3** calculates the gross benefit of EnergyConnect in line with the RIT-T framework, compares this estimate of gross benefit to previous estimates, considers total project costs that support positive societal benefits and analyses the sensitivity of benefits and costs to the discount rate.
- **Section 4** discusses the wider benefits of EnergyConnect outside of the RIT-T framework.

1.15 The report includes the following appendices:

- **Appendix 1** provides further details on our modelling methodology, including an overview of the software used and the key inputs.
- **Appendix 2** presents further details on our modelling results.
- **Appendix 3** presents further details on some of the wider quantitative benefits of EnergyConnect not captured by the RIT-T framework.
- **Appendix 4** presents the approach taken by regulators in other jurisdictions to account for non-monetary benefits of transmission investments.

1.16 A **glossary** of key terms is also attached at the end of this report.

2. Modelling methodology

2.1 In this section, we present the modelling methodology applied to estimating the gross benefits of EnergyConnect.

2.2 We first provide an overview of our modelling methodology (Section A) and the main modelling inputs and assumptions (Section B). We then set out our approach to calculating the gross benefit of EnergyConnect, focusing on the scenarios assessed (Section C) and on the cost-benefit methodology (Section D). Finally, we elaborate on the treatment of selected key assumptions, which were discussed in detail as part of the AER's RIT-T Determination process (Section E).

A. Overall approach

2.3 We use FTI's in-house power market model (that runs on Plexos® Market Simulation Software), calibrated with a detailed representation of the NEM, to model the period 2020 to 2040.[39,40] The model is based on the Draft ISP 2020 central scenario assumptions (published in December 2019),[41] which were the most recent available assumptions from AEMO at the time of modelling.

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39 For further detail on how Plexos® Market Simulation Software optimises dispatch, see Appendix 1.

40 All years in this report refer to fiscal years. Fiscal year 2020 runs from 1 July 2019 to 30 June 2020.

41 For further detail of the Draft ISP 2020 assumptions used in our model, see Section 2B and Appendix 1.

2.4 The counterfactual model (i.e. the model without EnergyConnect) has been calibrated with the existing topology of the NEM (i.e. modelling each of the five NEM regions). In addition to modelling the existing interconnectors,[42] we treat the Victoria-New South Wales Interconnector ("VNI") and Queensland-New South Wales Interconnector ("QNI") upgrades as committed investments.[43] Both the existing interconnectors and the committed investments are included in the counterfactual model (i.e. are included in all model runs with and without EnergyConnect).

2.5 To estimate the incremental impact of EnergyConnect, we model the NEM with EnergyConnect and then compare it to the counterfactual of the NEM without EnergyConnect. The model assumes that EnergyConnect will be online from 1 July 2023.

2.6 The modelled topology of the NEM is illustrated in Figure 2-1 below:

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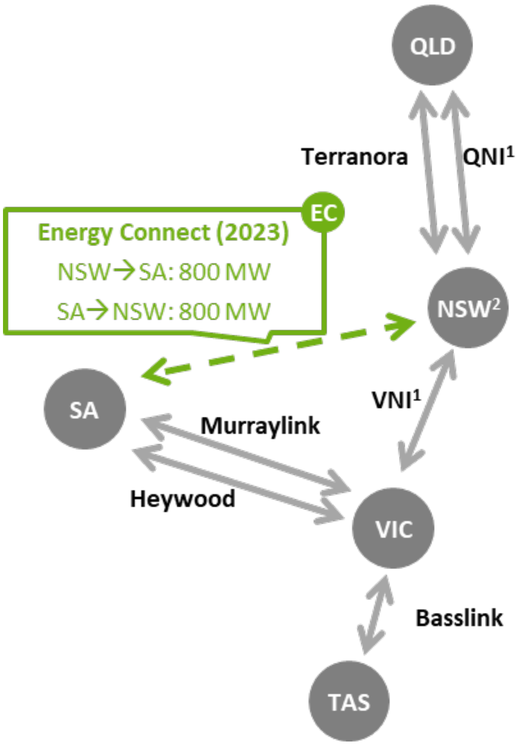
42 Existing NEM interconnectors are Terranova, QNI (both between NSW and Qld), VNI (between Vic and NSW), Heywood, Murraylink (both between SA and Vic) and Basslink (between Vic and Tas).

43 For further detail on existing and committed interconnector modelling assumptions, see Appendix 1.

Figure 2-1: Modelled NEM topology



Source: FTI

Note: 1) Includes VNI and QNI upgrades.

2) Humelink, a proposed interconnector between NSW and Vic is implicitly modelled by assuming that there is no congestion between Snowy 2.0 and NSW demand centres once Snowy 2.0 comes online.

2.7 Our main analysis (presented in Section 3 of this report), is based on Short-Run Marginal Cost ("SRMC") bidding methodology (as required by the RIT-T methodology)[44] over a 21-year modelling horizon (2020 to 2040 inclusive).[45] Total gross benefit is calculated by discounting the annual gross benefit for each modelled year to the start of fiscal year 2020[46] at 5.9%.[47]

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44 AER, Application guidelines: Regulatory investment test for transmission, December 2018 (link) page 91.

45 We consider the potential gross benefits arising beyond 2040 as part of the wider benefit of EnergyConnect in Section 4A.

46 Fiscal year 2020 runs from 1 July 2019 to 30 June 2020.

47 Draft ISP 2020 central WACC estimate. Source: AEMO, Draft 2020 Integrated System Plan, December 2019 (link), page 30.

B. Modelling inputs and assumptions

2.8 Our model uses input assumptions, such as electricity demand, commodity prices and generator specific cost and technical parameters, to forecast the evolution of the NEM to 2040. These inputs are sourced from AEMO's Draft ISP 2020 central scenario, published in December 2019. These were the most recent assumptions available at the time of modelling.

2.9 In addition, we also use assumptions from AEMO's Electricity Statement of Opportunities 2019 ("ESOO 2019") for unit specific information not covered by the ISP assumptions workbook[48] and stability constraints. Stability constraints are discussed further in the Section 2C below.

2.10 Further detail on the modelling assumptions is provided in Appendix 1.

C. Modelling of stability constraints

2.11 AEMO, as the system operator, is responsible for maintaining system security and reliability across the NEM. Modelling a realistic representation of the current conditions impacting system security (across the NEM, but particularly in SA) is critical in understanding the benefit of EnergyConnect.

2.12 We have sought to reflect existing and future system conditions through modelling stability constraints, which represent "*stability limits that currently constrain dispatch in the NEM*"[49] for voltage stability and transient stability purposes. We use AEMO's ESOO 2019 'ISP sensitivity' stability constraints as these include VNI and QNI upgrades.[50]

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48 For example, forced outage rates, rating and heat rate adjustments.

49 AEMO's main ESOO scenarios do not include QNI and VNI upgrades. However, as part of ESOO 2019, AEMO tested the potential impact of these interconnector augmentations as a sensitivity.
Source: AEMO, Electricity Statement of Opportunities, August 2019 (link), page 70.

50 Thermal constraints and transmission outage constraints are not included in our modelling.

2.13 The ESOO modelling assesses the reliability of electricity supply on a forward-looking basis over a 10-year period.[51] The ESOO considers electricity supply and network capabilities that are existing or meet AEMO's commitment criteria.[52] Therefore, the ESOO stability constraints assume that there will be no further network augmentation (generation or transmission) from that already known or "committed", over the 10-year modelling horizon.

2.14 In reality, there may be other new projects developed in the NEM that may impact the system (and therefore the constraints that should be modelled) either during the 10-year period or in the following years. Some of these new projects may not have been conceived yet. However, in the absence of further information about how the constraints may change as the network develops over time, particularly after the 10-year forecast horizon of the ESOO, we consider the ESOO constraints represent the best currently available information. We therefore consider that the best approach is to apply the ESOO constraints throughout the 10-year horizon to 2029 and assume that most remain constant to 2040.[53]

2.15 EnergyConnect did not meet the 'commitment criteria' for ESOO 2019 (i.e. it had not progressed sufficiently far) and is thus not considered in the stability constraint set. However, EnergyConnect is expected to improve system stability, and so to capture this impact we have made assumptions, informed by discussions with AEMO and ElectraNet, as well as material published by the AER as part of its RIT-T Determination, as to what constraints may be relaxed following its introduction.[54]

2.16 Given the uncertainty about how stability constraints may evolve in the future, we have modelled three different variations (called "Model Runs") of ESOO stability constraints to test the robustness of benefits derived from EnergyConnect:[55]

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51 ESOO 2019 uses a 10-year modelling horizon (2020 to 2029 inclusive), but we model a 21-year period (2020 to 2040 inclusive).

52 These commitment criteria assess whether a given project has made a formal commitment to proceed to construction. These are based on *"site acquisition, contracts for major components, planning and other approvals, financial, and commissioning date"*. See AEMO, Electricity Statement of Opportunities, August 2019 (link), page 9.

53 We make some adjustments to the stability constraints to reflect (i) the installation of four synchronous condensers; and (ii) EnergyConnect. See Appendix 1 for further detail.

54 See Appendix 1, Table A1- 5 for details of the amendments that we have made to stability constraints following the commissioning of EnergyConnect.

55 For further detail on the combinations of constraints imposed, see Appendix 1, Table A1-5.

- **Model Run 1**: In this variant, we model three constraints relevant for SA system stability. These are:
  - A requirement for synchronous generation to be online at all times in the absence of EnergyConnect (previously referred to by AER as the "*two unit constraint*"[56]). Prior to the installation of four synchronous condensers,[57] we assume that four units of SA gas plants[58] must be online at all times. Following the installation of the four synchronous condensers, this requirement is relaxed to two units of SA gas plants without EnergyConnect, and removed with EnergyConnect as synchronous generation can now be provided by NSW generators.
  - Cap on SA non-synchronous generation. We impose a limit on SA non-synchronous generation equal to 2,000 MW plus the flow on Heywood interconnector. This reflects existing limits imposed for system security reasons. This cap is removed once EnergyConnect is commissioned.
  - Heywood Rate of Change of Frequency ("ROCOF") constraint. This constraint ensures that there is sufficient inertia to prevent ROCOF exceeding 3Hz/sec following an unexpected loss of Heywood. This constraint is removed once EnergyConnect is commissioned.
- **Model Run 2:** We include all of the constraints above in Model Run 1, as well as all other SA constraints modelled by AEMO in its ESOO 2019 'ISP sensitivity' scenario.
- **Model Run 3:** We model all NEM constraints modelled by AEMO in its ESOO 2019 'ISP sensitivity' scenario (i.e. all constraints included in Model Run 2), as well as additional constraints that apply to the remaining NEM regions.

2.17 In the main body of this report, we present the results from Model Run 3, which includes the full suite of constraints articulated in ESOO 2019. We consider that Model Run 3 is most representative of the likely benefits of EnergyConnect for the NEM. However, we have tested the additional Model Runs to verify the robustness of the findings to different combinations of system constraints applied to the NEM. The full spectrum of results for Model Runs 1 to 3 are presented in Appendices 2 and 3.

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[56] AER, Decision: South Australian Energy Transformation, January 2020 (link).

[57] Four synchronous condensers are assumed to be online as of 1 January 2021.

[58] These units must be from Torrens Island B, Osborne GT or Pelican Point GT.

D. Cost-benefit methodology

2.18 In estimating the gross benefits of EnergyConnect, we have followed AER's RIT-T methodology. The AER's RIT-T guidelines set out the classes of benefits that should be taken into consideration when evaluating all proposed transmission investments. In these guidelines, AER also provide guidance on the selection of reasonable inputs, discount rate and scenarios.

2.19 While our approach is in line with the RIT-T methodology, we do not perform a full RIT-T analysis as we only consider the preferred credible option[59] under a central scenario in this report. In particular, we have not considered any other (potentially) credible options that might need to be considered as part of the RIT-T, nor the preferred credible option under a 'high' or 'low' scenario.

2.20 Table 2-1 below outlines the benefit categories that we estimate for EnergyConnect:

Table 2-1: Benefits calculated for EnergyConnect

Benefit category	Description
Avoided variable costs	An interconnector increases transmission capacity between connected regions, which enables capacity mix and dispatch across the NEM to re-optimise to meet demand. The extent to which the interconnector allows cheaper generation sources to displace more expensive generation sources on a variable cost basis is captured in this category. Avoided fuel cost, variable operating and maintenance and start-up costs[60] of generators are included in this category and are driven by the volume of electricity generated (by contrast, fixed costs are, by definition, not dependent on the volume of generation).

59 Option C.3, the preferred option which received AER RIT-T approval on 24 January 2020. Sources: ElectraNet, SA Energy Transformation RIT-T - PACR, February 2019 (link), page 5; AER, Decision: South Australian Energy Transformation, January 2020 (link), page 5.

60 Modelled start-up costs are the average of the cold, warm and hot start values outlined by ACIL Allen in its 2014 Fuel and Technology Cost Review. For further detail, see Appendix 1.

Benefit category	Description
Avoided fixed costs	Commissioning an interconnector (i.e. increasing cross-border transmission capacity) can have an impact on the capacity mix in the NEM. The extent to which the interconnector affects decisions such that certain generators retire early (or commence operating later) and hence save fixed operating costs, is captured in this category. Avoided generator fixed operating and maintenance cost is included in this category. Fixed costs are independent of generation volume.
Avoided Renewable Energy Zone Transmission costs	A new interconnector may change the timings or configuration of investment in transmission to meet a different "identified need", which can result in a reduction in the total cost.
Capital expenditure ("capex") from new build capacity	A new interconnector may change the timing of capital investment in new generation capacity, or the volume of new generation capacity. This changes the profile of generation capex investment across the NEM, which is captured in this category.

2.21 Each of the benefits described in Table 2-1 above is estimated on an annual basis for the 2020 to 2040 modelling period. The estimate for each year is then discounted to 2020 at a discount rate of 5.9%, and the discounted annual estimates are summed to calculate a total gross benefit for the modelled period.

2.22 The RIT-T methodology is prescriptive in the benefit categories that can be included and takes a cost-based approach. Based on our experience in other jurisdictions, we consider that this is not the only valid approach that can be taken. Other regulators (or relevant decision-makers) may, from time to time, take into account wider quantitative and qualitative benefits of interconnector investments. In this report we therefore follow a dual approach:

- We first set out the gross benefits of EnergyConnect, in line with the RIT-T methodology, in Section 3.
- We also discuss the potential wider benefits of EnergyConnect in Section 4.

E. Treatment of selected assumptions

2.23 As is the case with any power market modelling of this type, modelling assumptions and constraints are used to approximate the real-world system characteristics and behaviours of market participants, in order to provide a credible estimate of the impact of new investments on the overall system.

2.24 In the context of EnergyConnect, AER identified four specific assumptions as critical, given their impact on the estimated gross benefits of the project. These critical assumptions are:

- minimum capacity factors ("MCF") imposed on specific SA gas units;
- SA gas unit operating characteristics, such as minimum stable load and cycling;
- system security constraints; and
- generator retirements.

2.25 Our understanding is that these assumptions have been identified as critical because they impact the capacity and generation of SA gas units in the counterfactual scenario without EnergyConnect. This, in turn, is important because one of the main drivers of the quantum of EnergyConnect benefit is the extent to which the project facilitates the displacement of SA gas generation by less expensive alternatives.[61]

2.26 In this subsection, we present an overview of ElectraNet and the AER's position on the four critical assumptions, and outline FTI's approach to modelling these.

E.1 Minimum Capacity Factor

<u>Overview of the AER position</u>

The PACR modelling applied MCF on three SA gas generators (Torrens Island B 25%, Pelican Point 50% and Osborne 60%).

ElectraNet expressed the following views in support of MCFs on these SA gas generators:

[61] In simplified terms, AER's analysis identified that the more gas used in SA in the counterfactual scenario without EnergyConnect, the greater the potential for the interconnector to help avoid these gas fuel costs.

- Applying an MCF assumption aligns with the ISP 2018 assumptions. AEMO notes that its ISP 2018 MCFs are used to (i) take into account generator technical limits; (ii) draw on historical gas usage as a predictor of future dispatch; (iii) take into account generator contracts; and (iv) ensure sufficient synchronous generation is online for system security. In its submission to the AER on this matter, AEMO comments that *"ignoring these operational limitations could lead to models which are unachievable in practice or at least increase operating costs."*[62]
- Applying an MCF assumption provides a better reflection of the historical operating characteristics of SA gas generators.

AER expressed that MCF should not be used for the following reasons:

- The MCFs at times force mid merit SA gas generators to be dispatched 'out of merit', displacing lower cost renewable generation.
- Generator technical limits are already taken into consideration with minimum stable operating level assumptions.
- A separate assumption that forces synchronous generation online already takes into consideration system security requirements.

2.27 Applying a MCF to a generating unit forces it to run at least at minimum stable load for the specified percentage of hours in a year. AEMO use MCFs "*to reflect typical dispatch* [to ensure] *that minimum operating levels* [are] *observed*" for Osborne, Pelican Point and Torrens Island B units.[63,64] The MCF outlined by AEMO in ISP 2018 and Draft ISP 2020 respectively are outlined in Table 2-2 below:

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62 AER, Decision: South Australian Energy Transformation, January 2020 (link).

63 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, (link) page 9.

64 AEMO also required that all four units of Torrens Island B be online at least at minimum stable load (40 MW per unit) at all times (prior to the installation of four synchronous condensers in SA) as the least-cost option for satisfying the SA system security constraint.

Table 2-2: MCFs of SA gas generators

SA Generator	MCF ISP 2018	MCF Draft ISP 2020
Pelican Point	50%	50%
Osborne	60%	50%
Torrens Island A	15%	-
Torrens Island B	20%[1]	20%

Source: AEMO ISP 2018, AEMO Draft ISP 2020.
Note: 1) No MCF is imposed on Torrens Island B in AEMO's ISP 2018 modelling, but Torrens Island B is modelled as the least-cost method of meeting the 4 unit constraint. This constraint requires all four units to be online at least at 40MW, which equates to an MCF of 20%.

2.28 We have compared modelled load factor for Torrens Island B, Osborne and Pelican Point with MCF applied, and without MCF applied. Unsurprisingly, we find that the load factor of these units increases by about 20% to 40% in most years when MCF is applied.

2.29 MCF could in theory be used as a proxy for various commercial and operational factors, for example take-or-pay gas contracts, system security requirements or reasonable operating patterns. However, we have not identified sufficient information to support the application of MCFs in the long run on the basis of take-or-pay gas contracts.

2.30 Indeed, we have followed the AER's guidance in not applying an MCF. Instead, we use other assumptions relating to generator behaviour (for example, unit minimum on/off times and minimum operating load) to reflect generator specific operational factors.

E.2 Generator characteristics

Overview of the AER position

In its Determination, the AER discussed the application of certain key generator inputs and assumptions in the PACR modelling.

ElectraNet expressed the following views on its use of generator assumptions:

- The cycling constraints and minimum operating loads imposed in the PACR modelling reflect reasonable estimates based on historic behaviour and the physical limitations of generators.

- Start-up costs were not incorporated due to modelling limitations. ElectraNet also note that "*these costs, whilst significant for a commercially minded operator are not currently major costs in the NEM. The operation of the plant is captured by the minimum up and down time constraints.*"[65]

The AER expressed the following views on generator operating assumptions:

- The ACIL Allen input data for generator minimum up/down time should be adopted as there is not enough supporting evidence in favour of the alternative inputs used in the PACR modelling.
- It is reasonable to include start-up costs.

2.31 We have sought to reflect generator specific inputs and assumptions in our Plexos® model in such a way that reflects the costs, technical limitations and operating decisions faced by generators in a credible manner. Some of the specific inputs include:

- **Minimum stable load**: The minimum level of generation that must be produced by a unit when its online.
- **Minimum up/down time:** Minimum up time is the minimum number of hours that a unit must be on once online and minimum down time is minimum number of hours that a unit must be off after being shutdown.
- **Start-up cost:** Cost incurred each time a generator turns on. Cost incurred depends on whether unit starting from cold (>40 hours since last start), warm (5-40 hours since last start) or hot (<5 hours since last start). However, due to limitations in the modelling, we only model one type of start (i.e. we do not distinguish between cold, warm and hot starts and instead use an average of the three start costs).

2.32 The values modelled for these inputs are outlined in Table 2-3 below:

65 AER, Decision: South Australian Energy Transformation, January 2020 (link), page 58.

Table 2-3: Minimum stable load and min on/off times for Osborne, Pelican Point, Torrens Island B

Generator	Minimum stable load *(MW per unit)*	Minimum on/off time *(hours)*	Start-up cost *($/unit)*
Osborne GT	90	4	1,770
Pelican Point GT	110	4	2,400
Torrens Island B	40	1	2,000

Source: Draft ISP 2020 (minimum stable load); ACIL Allen, Fuel and Technology Cost Review, 2014 (minimum on/off time and start-up cost).
Note: Single start-up cost value for a given generator is based on the average of ACIL Allen's cold, warm and hot start.

2.33 The shorter the modelled minimum on/off times, the more frequently units are allowed to 'cycle' on and off in the model. In our view, both the technical and commercial aspects of generator cycling behaviour are relevant to develop an appropriate modelling assumption. Whether the model produces a realistic representation of generator cycling behaviour would need to be evaluated *ex-post* to assess whether the values outlined by AEMO are reasonable.

2.34 We have not performed such analysis as part of this report. Rather, we have modelled generator start-up costs in a simplified manner by not differentiating between cold, warm and hot starts. A more accurate representation of start-up costs would be possible by making this differentiation, but given start-up costs are a small proportion of avoided variable costs from EnergyConnect,[66] we consider that making this differentiation is unlikely to have a material impact on total gross benefits.

E.3 System security

Overview of the AER position

66 Avoided fuel cost is the main source of cost saving (96% of total avoided variable cost), with avoided variable operating and maintenance and start-up cost being comparatively much smaller (2% of total avoided variable cost respectively). Source: FTI analysis.

The PACR modelling included a number of system security related obligations designed to mimic the current system conditions in SA. This includes (i) a requirement for SA synchronous generation to run; (ii) a cap on SA non-synchronous generation; and (iii) a constraint on Heywood flows to manage the rate of frequency of change in the case of an outage on the Heywood interconnector.

The PACR modelled two synchronous condensers as it was undertaken before the installation of four synchronous condensers was approved.

Following consultation with AEMO, AER accepted the above system security constraints. AER also noted that four synchronous condensers should be modelled as this is what has been approved.

2.35 The SA generation mix is increasingly dominated by inverter-based resources, while at the same time synchronous generators (i.e. gas) are generating less frequently. This transition has progressively led to a reduction in system strength[67] and a reduction in inertia.[68] For the stability of the SA system, it is essential that there are sufficient levels of system strength and inertia at all times. Historically, system strength and inertia have been provided by maintaining sufficient levels of synchronous generation online at any given time.

2.36 In response to the aforementioned shortfalls, ElectraNet undertook an economic evaluation that identified installing four high inertia synchronous condensers (with flywheels) as the preferred solution to meeting the identified system strength and inertia gaps. On 18 February 2019, the AER provided regulatory approval for the installation of these four synchronous condensers, and on 20 August 2019 the AER provided approval of project funding. These synchronous condensers are expected to provide 4,400 MW of inertia once installed by the end of 2020.[69]

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67 A shortfall in system strength was declared by AEMO on 13 October 2017. Source: ElectraNet, Strengthening South Australia's Power System (link).

68 A shortfall in inertia was declared by AEMO on 24 December 2018. Source: ElectraNet, Strengthening South Australia's Power System (link).

69 ElectraNet, Addressing the System Strength Gap in SA: Economic Evaluation Report, 18 February 2019 (link), page 15.

2.37 AEMO note that the four synchronous condensers do not address all of the SA system security requirements and therefore additional intervention or reinforcements are required.[70] Currently, a minimum level of four units of synchronous generation must be online at all times for system security purposes, and this requirement is expected to be reduced to two units after the four synchronous condensers are installed. However, the combination of the four synchronous condensers and EnergyConnect is expected to completely remove the "two-unit constraint" (i.e. the requirement for synchronous generation to be online at all times).

2.38 Therefore, in order to capture this benefit of EnergyConnect to system security in SA, while taking into account the impact of the synchronous condensers, our model includes a series of constraints designed to reflect:

- current SA system conditions;
- conditions following the installation of four synchronous condensers; and
- conditions following the commissioning of EnergyConnect.

2.39 In our modelling, we consider the installation of four synchronous condensers as a committed investment. It is therefore included in the 'counterfactual' scenario without EnergyConnect.

2.40 The selection and implementation of SA constraints follows AEMO's guidance,[71] and is presented in Table 2-4 below:

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70 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, (link), page 10.

71 AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019 (link), Section 3.

Table 2-4: Modelled SA system security constraints

Scenario → ↓ System security constraint	**Before synchronous condensers**	**After synchronous condensers but before EnergyConnect**	**After synchronous condensers and after EnergyConnect**
Synchronous condensers modelled	0	4	4
ROCOF constraint	Limits ROCOF to 3 Hz/sec in SA immediately following loss of Heywood interconnector	Constraint relaxed by 500MW	Removed
Non-synchronous cap (MW)	2,000MW	2,000MW	Removed
Number of synchronous units online at all times[1]	4	2	0
Modelling approach	Modelled up to 1 January 2021 in both the counterfactual (i.e. scenario without EnergyConnect) and with EnergyConnect	Modelled in the counterfactual from 1 January 2021 to 2040	Modelled in the scenario with EnergyConnect (from commissioning)

Note: See Appendix 1 for further detail on constraints; 1) These must be a combination of Torrens Island B, Osborne GT or Pelican Point GT units.

2.41 We also impose other stability constraints across the NEM in some model runs to reflect factors that impact dispatch. These stability constraints and the different combinations used in the different model runs are discussed in Section 2C above.

E.4 Generator retirements and new build

<u>Overview of the AER position</u>

One of the main modelling assumptions underpinning the evaluation of the impact of new investments is the extent to which other generators are able to "react" to the new investment by adapting their new build or retirement decisions.

Plexos® offers the choice of modelling generator retirements exogenously (i.e. as an input) or endogenously (i.e. the model determines retirement decisions as an output of the overall cost-minimisation algorithm).

In the PACR, ElectraNet modelled all generator retirements exogenously. These retirement dates were taken from AEMO's ISP 2018 modelling. In its Determination, the AER comments that the model has the ability to endogenously model retirements and therefore this method is preferable.

2.42 New interconnection increases cross-border transmission capacity, and therefore can have an impact on the optimal generation mix in each region of the NEM. However, some new build or retirement decisions are pre-committed and therefore are unlikely to change as a result of a new interconnector. In this report, we differentiate between:

- **Exogenous assumptions**. For certain types of plant (notably committed new renewable capacity and coal retirements), we followed the Draft ISP 2020 assumptions regarding planned closures and new build dates.[72]
- **Endogenous assumptions**. For other types of plant, we used the Plexos® optimisation platform to determine the appropriate amount of new build to adapt to the different levels of interconnection in the NEM, for example, new renewable capacity in Renewable Energy Zones ("REZ"). This means we could assess the extent to which EnergyConnect acts as an 'enabler' of new generation (e.g. renewables and storage), or where it may help avoid new build of thermal generation (that might otherwise be needed). Furthermore, we also allow Plexos® to endogenously decide whether SA gas units should be closed before their expected retirement or remain open for longer.[73]

2.43 We use Plexos® to forecast the optimal capacity expansion first without EnergyConnect, and then with EnergyConnect to consider how the generation capacity changes. Figure 2-2 outlines the evolution of NEM capacity without EnergyConnect, and Figure 2-3 outlines how this changes with EnergyConnect:

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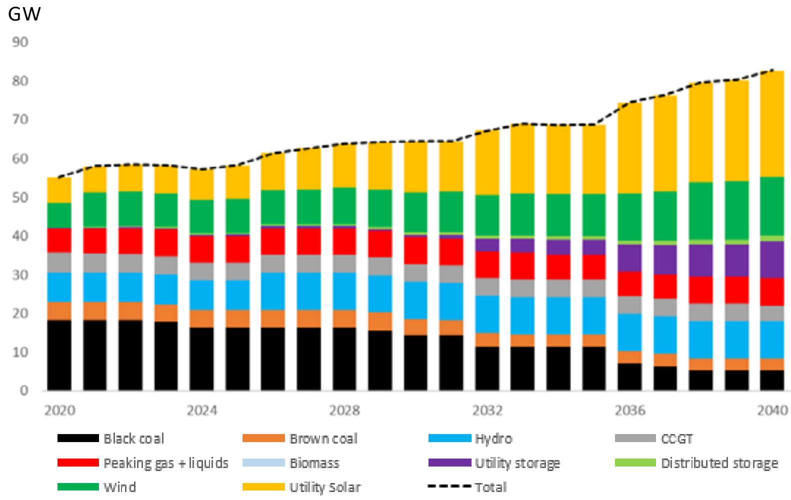
72 For further detail on the dates of thermal capacity planned closure and committed new renewable capacity, see Appendix 1, subsection A1.8.

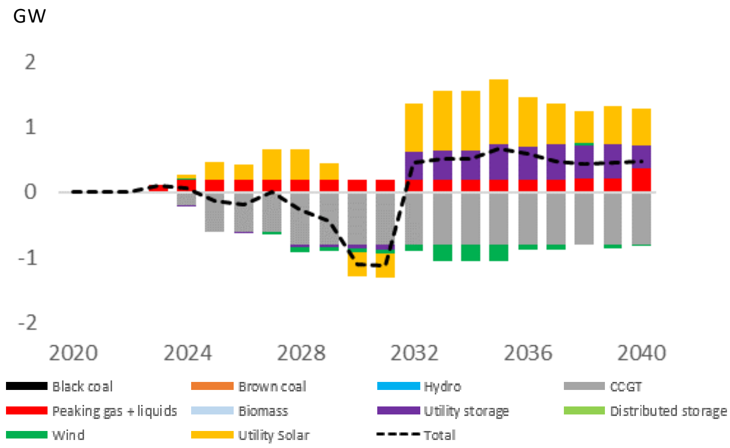
73 The exceptions to these assumptions are Torrens Island A and Osborne. The announced retirement dates for these units are treated as committed. For further detail, see Appendix 1, subsection A1.8.

Figure 2-2: NEM capacity, without EnergyConnect (GW)



Source: FTI Plexos® model.
Note: Capacity evolution is the same across all model runs.

Figure 2-3: Change in NEM capacity with EnergyConnect (GW)



Source: FTI Plexos® model.
Note: Change in capacity is the same across all model runs.

2.44 With EnergyConnect, the following changes in NEM capacity evolution are observed:

- Torrens Island B (an SA gas generator) retires early (one unit retires in 2023, two units retire in 2024 and the final unit retires in 2027). This leaves Pelican Point as the only remaining Combined-Cycle Gas Turbine ("CCGT") generator in SA from 2027.
- Initially, additional solar is built to replace the retired Torrens Island B. However, in 2030 and 2031, the rate of new solar installation slows relative to the scenario without EnergyConnect, before increasing again from 2032. New solar capacity is built in NSW, SA and Victoria ("Vic").
- Additional storage is built in NSW and Vic from 2032.
- A small amount of additional peaking capacity is built in NSW.
- There is an increase in Vic wind capacity and decrease in NSW and Queensland ("Qld") wind capacity. This has a net impact of marginally less wind capacity on a NEM-wide basis.

2.45 We consider that our 'mixed' approach of exogenous and endogenous capacity assumptions is reasonable. It reflects the short-term pre-committed investments and retirements, the long-term planned black coal closures, while also allowing for a degree of adjustment to the capacity mix in response to the commissioning of EnergyConnect (in particular endogenous closure dates of relevant SA gas plants). Furthermore, after taking modelling limitations into consideration, it is broadly consistent with the AER's guidance that *"no plant investments or retirements be imported from other modelling results."*[74,75]

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74 AER, Decision: South Australian Energy Transformation, January 2020 (link), page 68.

75 It was not feasible to model endogenous closures for all generators across the NEM in the time available. Therefore, we only modelled endogenous closures for a sub-set of NEM generators. See Appendix 1, subsection C for further detail.

3. Benefits of EnergyConnect

3.1 Using the methodology set out in Section 2, we have modelled the benefits of EnergyConnect in line with the methodology set out in the RIT-T. This section sets out the detailed analysis of each benefit category.

3.2 In the following subsections, we first set out the gross benefits of EnergyConnect and discuss each assessed benefit category in turn (Section A). We then compare our estimate of gross benefit to gross benefits calculated by ElectraNet in the PACR and the gross benefits calculated using the AER's preferred set of modelling assumptions (Section B).

3.3 We then consider, the maximum level of project costs that would support positive societal benefits – we refer to this as the 'break even' level of total project costs – as assessed under the RIT-T framework (Section C) and then the impact of the discount rate on the NPV value of benefit (Section D).

A. Gross benefits

3.4 Gross benefits are derived from changes in cost (actual or deferred) facilitated by EnergyConnect. The categories of gross benefit that we estimate in our analysis are:

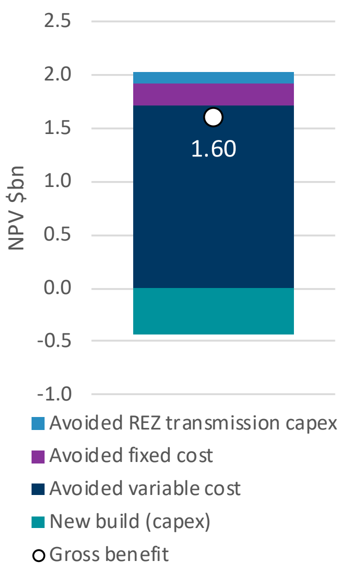
- **Avoided variable cost**: This category includes the reduction in the fuel cost, variable operating and maintenance cost, and start-up costs that would have been incurred by generators in the absence of EnergyConnect, but which are no longer incurred when EnergyConnect is operational. Our modelling indicates that the reduction in these costs is the biggest driver of benefit from EnergyConnect, accounting for $1.7 billion of the total estimated gross benefits accrued between 2021 and 2040. This is because EnergyConnect allows for NEM dispatch to be optimised over a larger geographical area, enabling relatively less expensive generation in one region (this can sometimes be SA and sometimes NSW[76]) to displace relatively more expensive generation in the connected region. In particular, the modelling shows that EnergyConnect enables a reduction in the reliance on SA gas generation, saving significant fuel costs.
- **Avoided fixed cost**: This category reflects the impact of EnergyConnect on the evolution of generator capacity across the NEM. Costs savings (i.e. benefits) are derived when fixed costs incurred by generators (e.g. fixed operating and maintenance costs) are avoided or deferred because generators retire early or commence operating later. For example, in our modelling, EnergyConnect allows certain SA gas units to retire earlier than they otherwise would in the absence of the interconnector, thus avoiding significant annual fixed costs. We estimate that this category accounts for $0.2 billion of the total gross benefits.
- **Avoided REZ transmission capex**: This category reflects the extent to which EnergyConnect changes the timings of, or need for, investment in other transmission designed to meet a different 'need'. We consider this benefit to be material and have therefore included it as a gross benefit of EnergyConnect. However, as this is not a key driver of the overall cost-benefit analysis (accounting for only a small percentage of the total gross benefits), we have not undertaken detailed analysis of this benefit and instead use the **$0.1 billion** value calculated in the PACR.

[76] We also observe that in some periods, Vic brown coal generation is exported into SA, and then transported onwards to NSW via EnergyConnect.

- **Capex from new build generation**: Considers the impact on NEM-wide generators' capex resulting from changes in the modelled NEM capacity mix as a result of EnergyConnect (this can be an increase or a reduction in generation capex, depending on whether more or less new generation is built). For EnergyConnect, we find that there is a **$0.4 billion** net decrease in this benefit category (i.e. it is an incremental cost) as commissioning of new plant is brought forward or new plant is built that would not have otherwise been constructed.

3.5 We estimate total gross benefit – the sum of each benefit category – to be around **$1.6 billion**,[77] on a Net Present Value ("NPV") basis for the 2020 to 2040 modelling period.[78] Avoided fuel cost (which is the majority of avoided variable cost) is the main driver of this gross benefit, as illustrated in Figure 3-1 below:

Figure 3-1: NEM gross benefit from EnergyConnect (NPV, 2020 to 2040)



Source: FTI Analysis
Note: Model Run 3 (NEM constraints), the full set of results are presented in Appendix 2.

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77 The value of gross benefit is dependent on the model constraints imposed. This estimate corresponds to model run 3 (NEM constraints) and the full $1.6 billion to $1.7 billion range of benefits is discussed in Appendix 2.

78 Discounted at 5.9%, which is the WACC outlined by AEMO for its Draft ISP 2020 central scenario.

3.6 Below, we elaborate on each category of gross benefits.

A.1 Avoided variable cost

3.7 The RIT-T guidance specifies that *"a credible option may lead to a decrease, increase, or no material net change in the variable operating costs of supplying electricity to load".*[79] We have captured the impact of EnergyConnect on the total NEM avoided variable cost (which includes the difference in the fuel cost, variable operating and maintenance costs, and start-up costs) by comparing the modelled estimate of total variable cost with and without EnergyConnect.

3.8 We find that with EnergyConnect, the NPV value (for the 2020 to 2040 modelling period) of **avoided variable cost is equal to $1.7 billion.**[80] This is because, when EnergyConnect is operational, it enables certain generators to reduce the number of hours they operate, thus saving on the fuel costs and on variable operating and maintenance costs. This is the case particularly for certain SA gas plants: for example, the load factor of Torrens Island B (unit 2) reduces from 17% to 1% in the 2020s after EnergyConnect comes online. In addition, the interconnector also enables plants to reduce their start-up costs, if they no longer need to start as frequently as they otherwise would have done.

3.9 In this section, we first explain the mechanisms behind the reduction in the variable costs (Section A.1.1), followed by a more detailed analysis of the fuel cost savings, which are the largest component of the variable cost savings (Section A.1.2).

A.1.1 Change in the generation profile

3.10 Following the commissioning of EnergyConnect, the cost-minimising dispatch (generation) profile re-adjusts across the NEM, as more lower cost generation can flow to regions with a higher cost of meeting demand. Total NEM variable costs fall, in aggregate, as a result of these changes in dispatch profile.

3.11 Figure 3-2 below illustrates the change in the modelled NEM generation output as a result of EnergyConnect:

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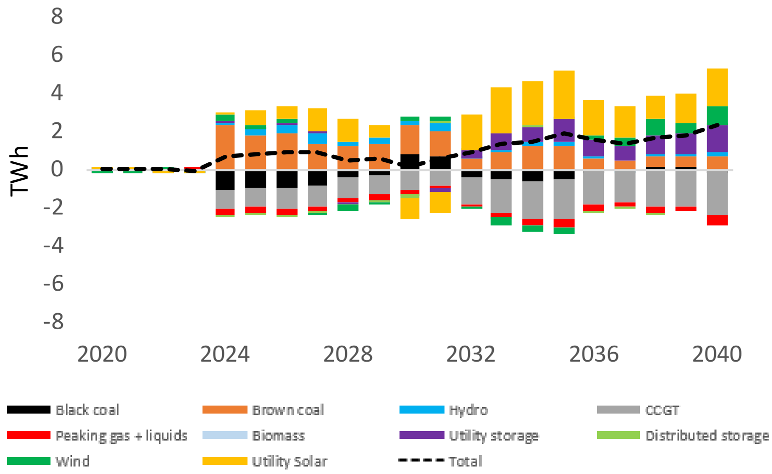
79 AER, Application guidelines: Regulatory investment test for transmission, December 2018 (link), page 80.

80 The value of avoided variable cost is dependent on the model constraints imposed and the full $1.7 billion to $1.8 billion range is outlined in Appendix 2.

Figure 3-2: Change in NEM generation with EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).
Further detail on NEM generation mix and interconnector flows in Appendix 2.

3.12 Figure 3-2 above illustrates the difference in total NEM generation with EnergyConnect (broken down by technology type) for each modelled year, relative to the counterfactual scenario without EnergyConnect. For example, when EnergyConnect is commissioned in financial year 2024 (i.e. 1 July 2023), there is 2.3TWh more brown coal, 1TWh less black coal and 1TWh less CCGT relative to the counterfactual scenario without EnergyConnect.

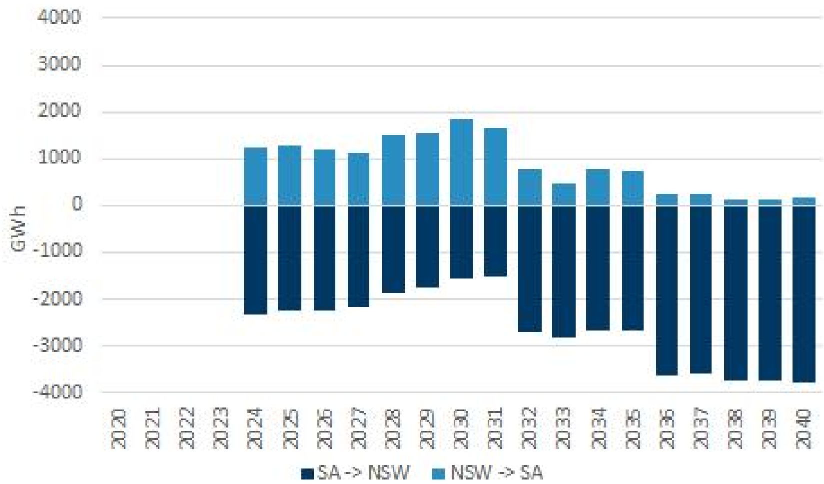
3.13 In the 2020s, EnergyConnect allows for SA gas generation and NSW black coal generation to be displaced predominantly by Vic brown coal, which is a relatively less expensive form of generation. This displacement is facilitated by increased exports of brown coal generation from Vic to SA on existing interconnectors: some of the brown coal exports from Vic directly reduce gas generation in SA, and some brown coal generation is transported onwards to NSW via EnergyConnect, displacing black coal generation.[81] Furthermore, renewable generation in SA increases with EnergyConnect and also displaces SA gas generation. On days when renewable generation in SA is high and beyond that needed to meet local demand, excess generation is able to be exported to NSW via EnergyConnect.

3.14 In terms of net export position, there are two broad phases as illustrated in Figure 3-3 below.

[81] For further detail on interconnector flows, see Appendix 2, subsection B.

- During the 2020s, SA exports around 1.5-2 TWh/year to NSW, but also imports between 1-2 TWh/year from NSW and is therefore overall a net exporter of electricity from SA to NSW over the period.
- In the 2030s, SA exports become more significant as a share of the overall flows, with annual flows from SA to NSW around 3 TWh/year, and imports from NSW below 1TWh/year. In terms of the generation mix, SA gas generation continues to be displaced, but is displaced by a combination of brown coal (Vic), new solar generation (SA and NSW) and storage (NSW). In the 2030s, SA net exports to NSW (via EnergyConnect) increase as SA renewables (and some gas) contribute to meeting the supply gap resulting from black coal retirements in NSW. SA also becomes a net exporter to Vic (via Heywood and Murraylink) as the amount of renewable generation being exported exceeds the amount of brown coal being imported in any given year.

Figure 3-3: Import and export flows on EnergyConnect



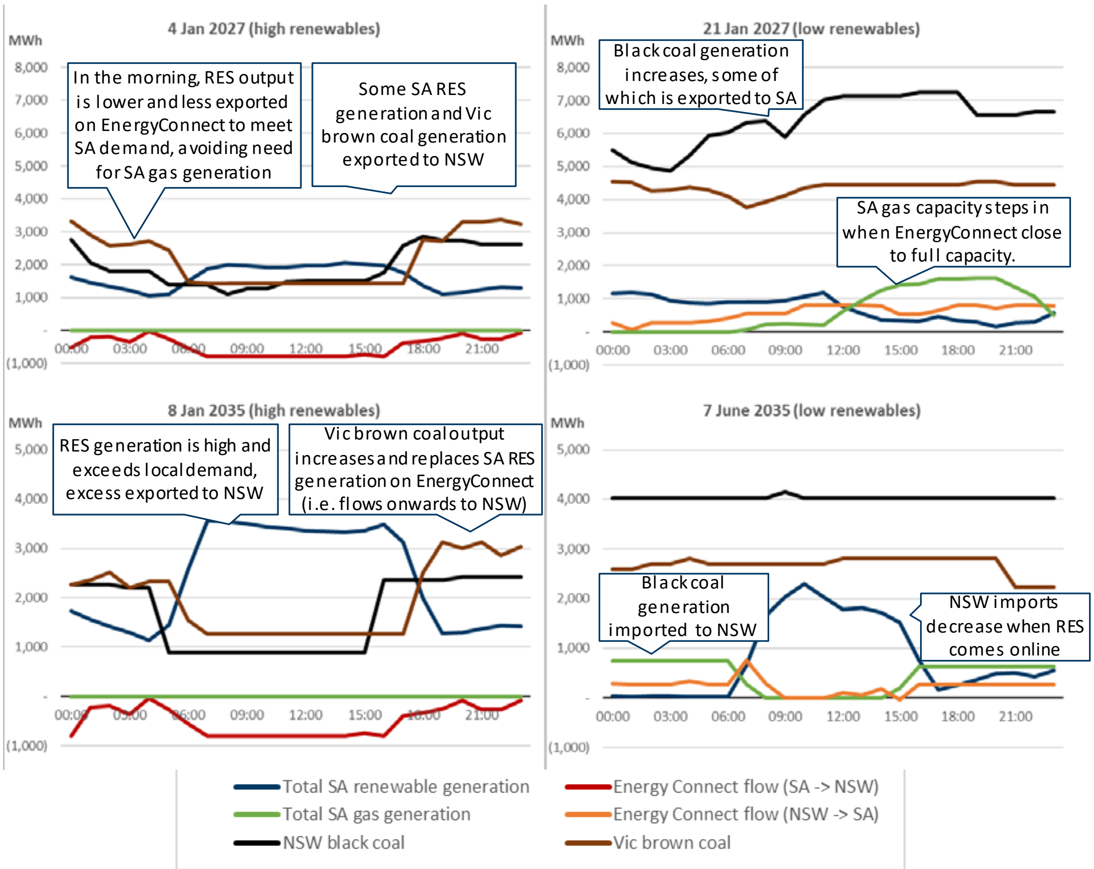
Source: FTI analysis.
Note: Model run 3 (NEM constraints).

3.15 The figures below illustrate generation by fuel type and flows through EnergyConnect during days of relatively high renewables generation and days of relatively low renewables generation, in 2027 and 2035. The figures present the following days:

- 4 January 2027 (high renewables generation);
- 21 January 2027 (low renewables generation);
- 8 January 2035 (high renewables generation); and

- 7 June 2035 (low renewables generation in early morning and evening).

Figure 3-4: Generation in SA by fuel type and flows on EnergyConnect



Source: FTI analysis.
Note: Negative energy flows on EnergyConnect indicate flows from SA to NSW. "RES" refers to renewable energy sources, and includes: (i) wind; (ii) solar; and (iii) hydro generation. Gas generation includes that of: (i) OCGTs; (ii) CCGTs; and (iii) peaking gas and liquids.

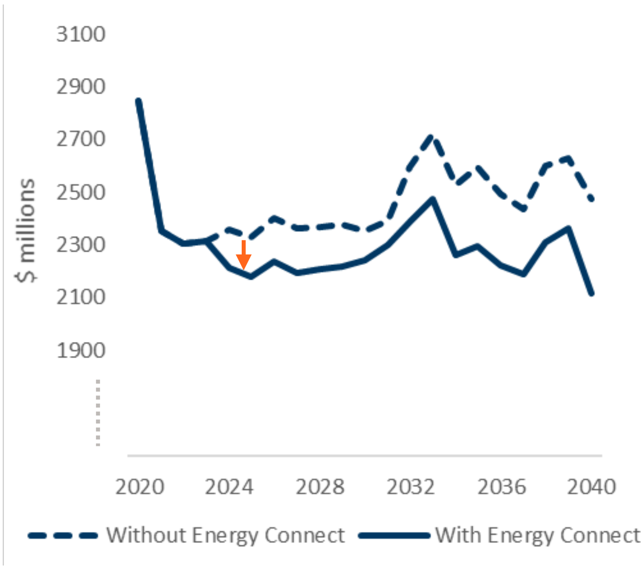
3.16 When SA renewable generation is relatively higher (and exceeds local demand), EnergyConnect is able to export this cheaper form of generation to NSW, helping to reduce overall energy costs in the NEM as a whole. During this period, SA gas generation is not needed, and therefore does not produce.

3.17 When SA renewable generation is relatively lower, EnergyConnect imports electricity from NSW in addition to using local gas generation (mostly in the form of peaking plants) to cover the shortfall.

A.1.2 Fuel cost analysis

3.18 Figure 3-5 below presents the evolution of the total NEM fuel cost[82] in the model runs with and without EnergyConnect:

Figure 3-5: Total annual NEM fuel cost, with and without EnergyConnect ($mn/year, undiscounted)



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).
The difference between forecast fuel cost with and without EnergyConnect represents the fuel cost saving.

3.19 There are two main mechanisms through which EnergyConnect leads to a decrease in the aggregate NEM fuel cost:

- EnergyConnect enables NEM dispatch to be optimised over a larger geographic footprint, and relatively cheaper generation to be sourced from neighbouring regions to meet local demand. Our modelling shows that with EnergyConnect, brown coal generation from Vic will displace gas generation in SA and black coal generation in NSW (see Figure 3-5 above).

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82 Avoided fuel cost is the main source of cost saving (96% of total avoided variable cost), with avoided variable operating and maintenance and start-up cost being comparatively much smaller (2% of total avoided variable cost respectively). Source: FTI analysis.

- EnergyConnect is expected to improve system security in SA and remove the requirement for synchronous generation to be online at all times.[83] EnergyConnect, in combination with four synchronous condensers, reinforces SA system security and removes the current requirement for SA gas generators to be online at all times, hence enabling SA gas generation to be reduced in such a way that does not compromise system security.[84] The improvement to system security brought about by EnergyConnect changes the system conditions, meaning that relative to the counterfactual, less gas generation is required at any given time.

3.20 We estimate that even in the absence of EnergyConnect the level of SA gas usage will decrease significantly relative to current levels. This is because the installation of synchronous condensers[85] and new renewables coming online are expected to reduce the need for gas plants to generate electricity for much of the time. However, the magnitude of this reduction will depend on whether EnergyConnect is commissioned. For the reasons outlined in ¶3.13 to ¶3.14 above, our modelling results show that EnergyConnect is expected to further decrease total SA gas usage below the level estimated in the absence of EnergyConnect.

3.21 The modelled gas usage in SA (both in the counterfactual scenario without EnergyConnect, and with EnergyConnect) is compared to historical gas usage in SA in Figure 3-6 below:

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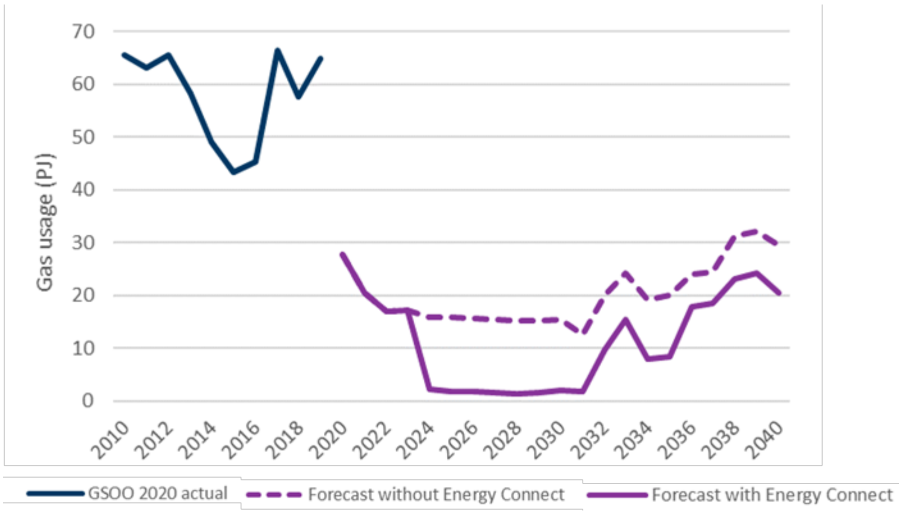
83 *"Detailed studies, to be undertaken in parallel with commissioning of synchronous condensers and the implementation of EnergyConnect, will determine the operating requirements for managing the power system during outages, protected events, or abnormal operating conditions"* but "*for the planning assumptions used in the modelling of the 2018 ISP, AEMO assumed the minimum requirements, including a reduction of synchronous generating units to zero"*. We have followed AEMO's ISP 2018 approach of assuming zero synchronous generating units are required after EnergyConnect is commissioned.
Source: AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, (link) page 15.

84 The 2018 ISP identified high-inertia synchronous condensers and a new interconnector to NSW as the most efficient pathways for meeting existing SA system security requirements.
Source: AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, (link) page 10.

85 The installation of four synchronous condensers in SA is expected to reduce the requirement for synchronous generation to be online at all times in SA from four to two units.
Source: AEMO, Assumptions for South Australian GPG in the 2018 Integrated System Plan, August 2019, (link) page 14.

Figure 3-6: SA historical and forecast gas usage (PJ/year)



Source: AEMO GSOO 2020 (historical gas usage), FTI analysis (modelled gas usage).

3.22 As indicated in Figure 3-6 above, during the 2020s, we estimate that gas usage will decline from around 65PJ/year to around 15PJ/year as a result of the recent (and ongoing) investments in synchronous condensers and renewable generation. However, following the commissioning of EnergyConnect gas usage is expected to fall even further to around 2PJ/year in the 2020s.

3.23 We forecast gas usage to increase from 2032, and for this increase to be relatively higher with EnergyConnect (albeit total usage will remain lower than what it would have been in the counterfactual scenario without EnergyConnect). This result is driven by SA gas generation increasing output in response to closures of black coal in NSW and brown coal in Vic:[86]

- Both with and without EnergyConnect, there is less Vic brown coal generation (due to retirements) available for export from Vic to SA via Heywood and Murraylink. Therefore, SA gas usage is expected to increase to cover the decrease in Vic brown coal imports to SA.

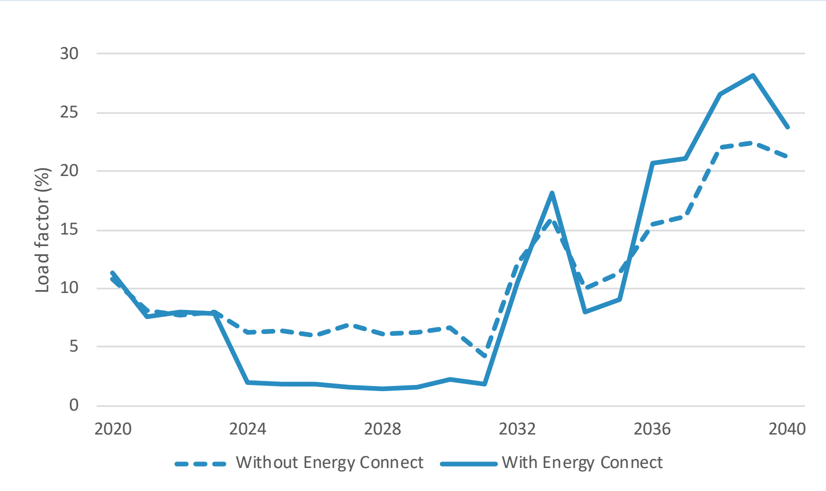
86 For example, Eraring (2,880MW) is expected to retire in 2031, Bayswater (2,640MW) is expected to retire in 2035 and Yallourn (1,320MW) is expected to close unit-by-unit between 2029 and 2032.

- With EnergyConnect, there is an increase in SA gas usage because SA starts exporting to NSW to help meet the supply gap following the black coal closures. This outcome demonstrates how EnergyConnect is beneficial to both SA and NSW over the modelling period.

Box 3-1: Pelican Point load factor

When EnergyConnect is built, our modelling indicates that it is optimal for Pelican Point to be the sole CCGT generator in SA from 2027.[87] To illustrate the point about how the increase in SA gas usage is larger with EnergyConnect, the Figure below presents forecast load factor for a single unit of Pelican Point across the modelling horizon:

Forecast load factor for a single unit of Pelican Point



Source: FTI analysis.
Note: Pelican Point Unit 1, Model Run 3 (NEM constraints).

The following changes in load factor are observed in the Figure above:

- Load factor decreases in 2021 as the installation of four synchronous condensers reduces the number of SA gas units required to be online at all times.[88]
- With EnergyConnect, load factor decreases from 2024 as SA gas generation is displaced by lower cost generation.

87 See ¶2.44 for further detail on changes in capacity with EnergyConnect.

88 Even with the requirement for a given number of SA gas units to be online for system security purposes at any given time, the load factor of Pelican Point remains relatively low because it is infrequently the lowest cost solution to satisfying this constraint.

- Load factor increases in 2032 as gas generation increases to cover retiring black and brown coal generators in NSW and Vic respectively (there is less generation from other states to import). The increase in load factor is larger with EnergyConnect, as Pelican Point (the only remaining SA CCGT generator) increases output and some gas is exported to NSW.
- Greater black coal availability in 2034 and 2035 (following refurbishments in 2032 and 2033 that lowered availability in these years) results in lower SA gas usage. This reverts in 2036 as black coal availability decreases again as 4GW of black coal retires.

A.2 Avoided fixed cost

3.24 Avoided fixed cost considers the extent to which EnergyConnect brings about *"reductions to other parties' costs"*[89] in the form of other generators' fixed operating and maintenance costs. We estimate **avoided fixed cost to equal $210 million**[90] on an NPV basis for the 2020 to 2040 modelling period.

3.25 Fixed operating and maintenance costs are incurred by each generator regardless of how much energy it generates (in contrast to variable costs). Changes to total fixed cost occur when the capacity profile changes:

- If new capacity is built or comes online earlier than anticipated, total fixed costs increase in a given time period.
- Conversely, if capacity is retired earlier, total fixed costs decrease as they are no longer being incurred.

3.26 As explained in ¶2.44 above, our model determines that it is optimal for Torrens Island B to retire between 2023 and 2027[91] with EnergyConnect. In the counterfactual scenario without EnergyConnect, all units of Torrens Island B stay open for the full modelled period. This result is presented graphically in Figure 3-7 below:

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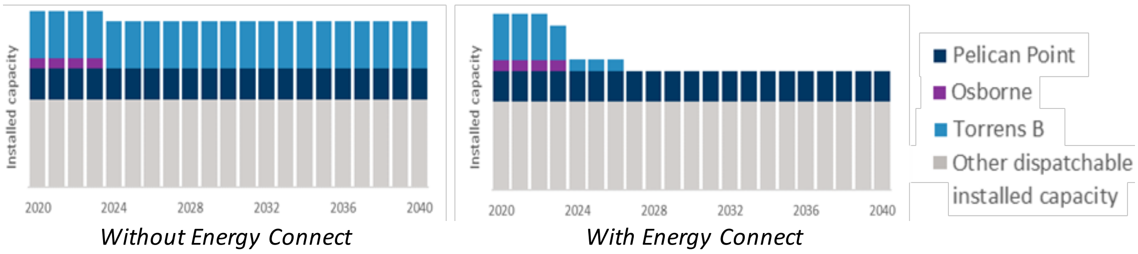
89 AER, Application guidelines: Regulatory investment test for transmission, December 2018, (link), page 88.

90 This cost saving is constant across all model runs.

91 One unit of Torrens Island B is retired in 2023, two units in 2024 and the final unit in 2027.

Figure 3-7: Illustration of the impact of EnergyConnect on SA installed capacity



Source: FTI analysis.

3.27 Torrens Island B incurs fixed cost of $9.6 million per year per unit in our model. With EnergyConnect, this cost is avoided for all four units for most of the modelling period.

3.28 The current need for synchronous generation to be online at all times in the absence of other alternatives is expected to be removed once EnergyConnect comes online. This means that Torrens Island B is able to retire (leaving Pelican Point as the only remaining CCGT generator in SA) without compromising system security.

3.29 The retirement of Torrens Island B is the main driver of avoided fixed costs. However, there is also a net increase in fixed costs relative to the counterfactual scenario without EnergyConnect from:[92]

- new capacity coming online and incurring fixed cost; and
- other new capacity no longer being built, or being delayed, and hence not incurring fixed costs.

A.3 Avoided Renewable Energy Zone Transmission Capex

3.30 The RIT-T includes a category of market benefit designed to capture the extent to which *"a credible option may change the timing (or configuration) of other investments to be made by (or for) the RIT-T proponent in the future"*.[93] These 'other investments' must be to address different 'needs' to those that the credible option is designed to meet.

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92 This category only considers fixed operation costs. Capex implications are discussed in 3.A.4 below.

93 AER, Application guidelines: Regulatory investment test for transmission, December 2018, (link), page 89.

3.31 In the PACR, ElectraNet estimated the extent to which EnergyConnect changes the timing and configuration of transmission upgrades to connect new REZ capacity to the network. This analysis found benefit equal to **$102 million** on an NPV basis for the 2020 to 2040 modelling period,[94] which was derived from the net impact of:

- removing the need for additional transmission capacity to support REZ capacity expansion;
- deferring the need for additional transmission capacity; and
- bringing forward a (small) upgrade to transmission capacity.

3.32 In its RIT-T Determination, the AER concluded that *"the approach ElectraNet has taken to estimating benefits of avoided transmission investment, and the input data and assumptions used, are appropriate. We* [the AER] *are satisfied that the preferred option* [EnergyConnect] *is likely to provide benefits from avoided transmission investment"*.[95]

3.33 Our view is that this benefit is material, but we have not undertaken any additional analysis. In this report we have included the PACR estimate of $102 million as the estimate of avoided REZ capex of EnergyConnect.

A.4 Capex from new build capacity

3.34 Capex from new build capacity *"captures the impact of a credible option on the plant expansion path of the market"*[96] by assessing the net impact on total NEM capex following the commissioning of EnergyConnect. In this case, it is a negative benefit (i.e. 'cost'), as EnergyConnect has the net impact of bringing forward the commissioning of new plant, or results in new plant being built when it otherwise would not. However, if the reverse was true (i.e. if EnergyConnect had the net impact of delaying other investment), this would be considered a positive market benefit.

3.35 Capex from new build capacity is estimated by calculating the change in the capex schedule due to new investment: either in terms of a reduced volume of investment (e.g. avoided new build of generation) or changes in the timing of investment (e.g. deferred new build). The incremental capex is annuitised over the relevant asset's life at 5.9% and then the portion corresponding to the 2020 to 2040 modelling period is isolated and discounted to find the total NPV cost.

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94 AER, Decision: South Australian Energy Transformation, January 2020 (link), page 76.

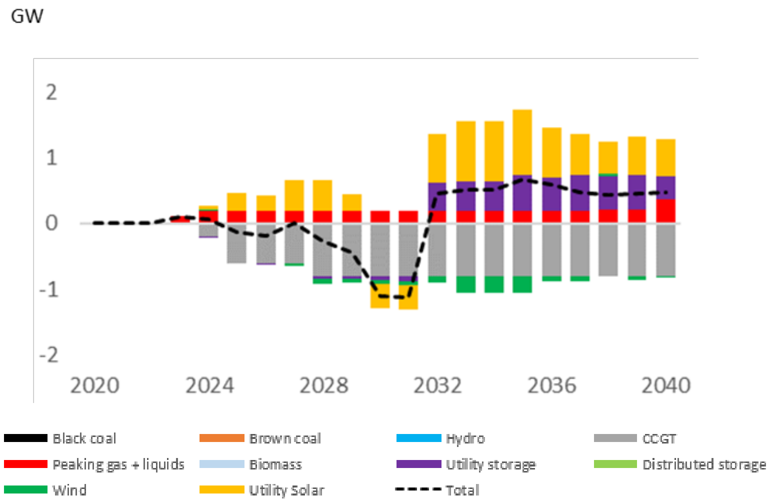
95 AER, Decision: South Australian Energy Transformation, January 2020 (link), page 78.

96 AER, Application guidelines: Regulatory investment test for transmission, December 2018, (link), page 88.

3.36 As discussed in Section 2.E.4 above, the evolution of NEM capacity is assumed to be adjusted with EnergyConnect. The assumption underlying this calculation is that market participants anticipate and/or observe the construction of EnergyConnect, and adjust their investment schedules in new generation assets accordingly.

3.37 The outcome of this adjustment is presented in Figure 3-8 below:

Figure 3-8: Change in NEM capacity with EnergyConnect



Source: FTI analysis.

3.38 Figure 3-8 above illustrates the difference in total NEM capacity with EnergyConnect (broken down by technology type) for each modelled year, relative to the counterfactual scenario without EnergyConnect. For example, in 2028, after EnergyConnect is commissioned, there is 800MW less CCGT (i.e. Torrens Island B retires), 470MW more solar and 190MW more peaking capacity relative to the counterfactual scenario without EnergyConnect.

3.39 The main mechanism behind the modelled changes in the generation capex across the NEM is that with EnergyConnect, Torrens Island B (CCGT) retires early. The cost impact of this retirement is captured in fixed cost savings in Section 3.A.2 above. There are no additional capex changes associated with the retirement of Torrens Island B, as the capex was incurred prior to the modelling period.

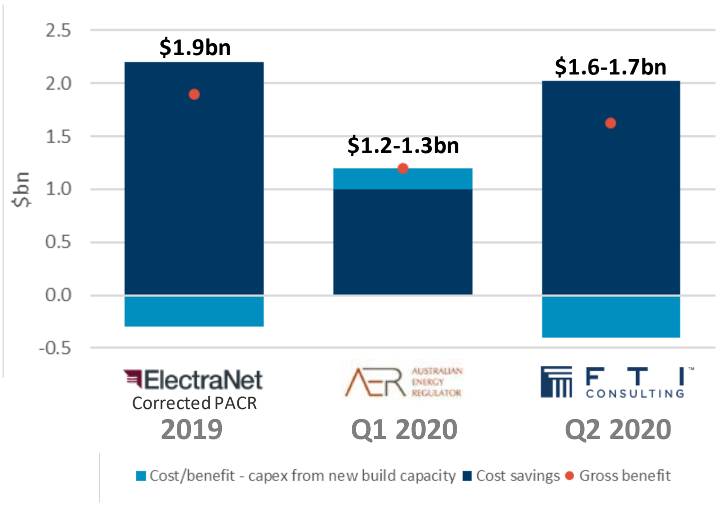
3.40 However, as part of the model's re-optimisation of NEM capacity in the presence of EnergyConnect, new capacity is constructed across the NEM. A large portion of this new capacity is built in SA in response to the retirement of Torrens Island B (for further detail on the changes in capacity, see ¶2.44 above). This new capacity incurs a capex charge, which is captured in this cost. The net impact of EnergyConnect on new capex is an increase of **$420 million** on an NPV basis over the 2020 to 2040 modelling period.[97] This cost is additional to the capex and operating expenditure ("opex") of EnergyConnect itself.

B. Comparison of gross benefits modelled by ElectraNet, AER and FTI

3.41 In this subsection, we compare FTI's estimate of $1.6 billion for the gross benefits of EnergyConnect to (i) ElectraNet's estimate of gross benefits outlined in the PACR; and (ii) the gross benefits estimated using the AER's preferred set of modelling assumptions (informed by their consultants, Frontier Economics).

3.42 Figure 3-9 below compares the gross benefit of EnergyConnect as estimated by ElectraNet, AER[98] and FTI:

Figure 3-9: Gross benefits of EnergyConnect



Source: AER, Decision: South Australian Energy Transformation, January 2020 (link), page 30. FTI analysis (see Section 3A for further detail).

97 This capex cost represents the annuitised value of incremental capex relating to the 2020 to 2040 modelling period.

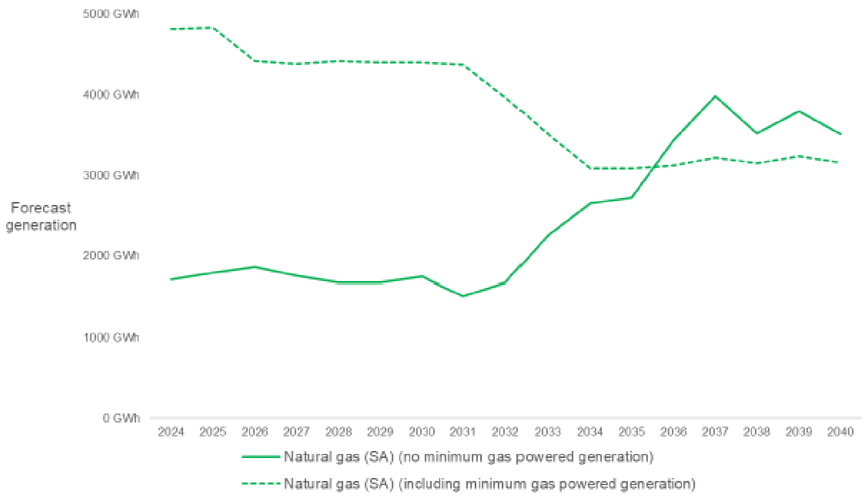
98 This modelling was performed by ElectraNet using the AER's preferred set of assumptions.

3.43 A key driver of cost savings from EnergyConnect is the extent to which it facilitates the displacement of gas generation in SA. Therefore, estimating the behaviour and cost of SA gas generators in the absence of EnergyConnect is critical, as the resulting reduction in requirements for gas generation in SA as a result of EnergyConnect is one of its main benefits. We understand that the assumptions used to estimate the likely operating patterns of SA gas plant in the absence of EnergyConnect has been an area of key contention between the AER and ElectraNet. Therefore, we discuss below how these assumptions differ between each set of results and present our own analysis to allow a comparison of differences in modelling inputs and assumptions.

3.44 As part of its determination, the AER critiqued a number of key modelling assumptions and requested that ElectraNet update its PACR modelling with these amended. Most of these key assumptions had a direct impact on the amount of SA gas generation in the counterfactual scenario without EnergyConnect. Notably, the original PACR modelling applied an MCF on three key SA gas units (50% Pelican Point, 25% Torrens Island B and 60% Osborne) in the counterfactual scenario without EnergyConnect. Imposing an MCF has the effect of forcing a given generator to run for a specific number of hours each year at least at minimum stable load. As discussed in Section 2.E.1, the AER's preferred set of assumptions removed all MCFs.

3.45 Figure 3-10 below, which is taken from the AER's determination, compares the amount of SA gas generation without EnergyConnect with MCF applied, against the amount of SA gas generation when the MCF is removed. It demonstrates how applying MCFs has a significant impact on the amount of SA gas generation in the counterfactual, and therefore the total amount of gas generation that can be displaced in the scenario with EnergyConnect, leading to higher fuel cost savings.

Figure 3-10: SA gas generation as modelled with and without MCF on SA gas units

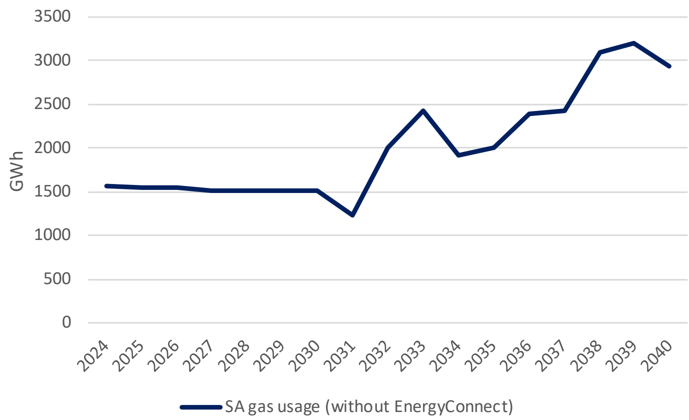


Source: AER, Decision: South Australian Energy Transformation, January 2020 (link), page 49.

3.46 In line with the AER's guidance, we have not applied MCFs and instead used other assumptions to reflect reasonable generator behaviour over the forecast period. To reflect generator behaviour, we have refined the specific inputs and assumptions in our Plexos® model such that we reflect the **costs, technical limitations and operating decisions** faced by the fleet of SA generators. In particular, we carefully defined appropriate assumptions on the gas generators' minimum on/off times, minimum stable load and start-up cost assumptions. The level of gas generation that we model is reasonably similar to that in Figure 3-10 above without MCF.

3.47 Figure 3-11 below presents our modelled SA gas generation in the counterfactual scenario without EnergyConnect:

Figure 3-11: FTI modelled SA gas usage (without EnergyConnect)



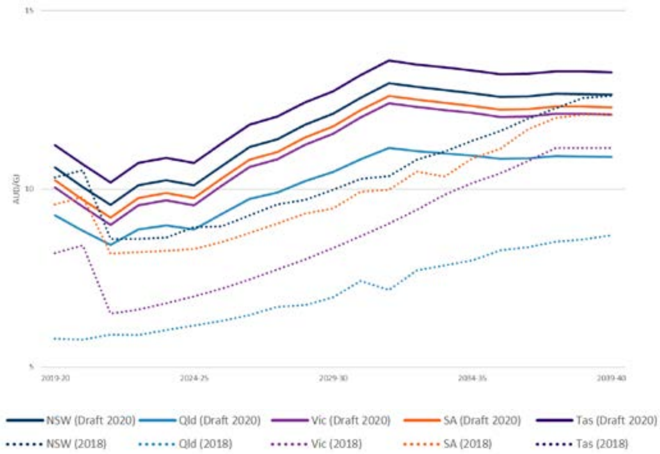
Source: FTI analysis.

3.48 As Figure 3-11 above indicates, our assessment of the volume of gas that would be used to generate electricity in SA in the absence of EnergyConnect is broadly similar to the data presented in Figure 3-10 for "no minimum gas powered generation".

3.49 Our modelling also takes into account changes in forecast commodity prices between ISP 2018 and Draft ISP 2020. In particular, gas prices forecast in AEMO's Draft ISP 2020 are up to 29% higher in some years compared to those assumed in ISP 2018. These updated commodity prices mean that the cost impact per unit of gas displaced by EnergyConnect is materially higher in our model as compared to previously modelling performed with ISP 2018 assumptions, which has a material impact on the quantum of gross benefit from EnergyConnect.

3.50 Figure 3-12 below outlines average regional gas prices from Draft ISP 2020 and ISP 2018:

Figure 3-12: Annual average gas prices by region – Comparison between Draft ISP 2020 and ISP 2018



Source: Draft ISP 2020 assumptions workbook (December 2019). ISP 2018 assumptions workbook.
Note: ISP 2018 gas prices adjusted to 2019 prices using CPI published by ABS.

3.51 The table below compares the input assumptions modelled by FTI in this report against the input assumptions used by ElectraNet in the PACR and the preferred set of assumptions outlined by the AER in its determination.

Table 3-1: Comparison of input assumptions

Assumption	ElectraNet (PACR)	AER	FTI
Minimum Capacity Factor (Pelican Point 50%, Osborne 60%, Torrens B 25%)	✓	✗	✗
ISP assumptions	ISP 2018	ISP 2018	AEMO Draft ISP 2020
SA gas closures	AEMO modelled retirements as **exogenous** input	**Endogenous**	**Endogenous** (SA gas, except Osborne and Torrens A committed)[1]
Cycling [min on/off time]	NSW black coal [120hrs/12hrs] Gas [24hrs/12hrs]	ACIL Allen: NSW black coal [8hrs/8hrs] Osb & PP [4hrs/4hrs] Torrens B [1hrs/1hrs]	ACIL Allen: NSW black coal [8hrs/8hrs] Osb & PP [4hrs/4hrs] Torrens B [1hrs/1hrs]
Minimum load	Redacted	Redacted	AEMO Draft ISP 2020
Start up cost	Not modelled	Consider them reasonable to include	ACIL Allen (average of cold, warm and hot start)
Two synchronous units online at all times[2]	✓	✓	✓
Inertia capability (i.e. ROCOF constraint)	1,300 MW	4,400 MW	4,400 MW
Non-synchronous cap	1,870 MW	2,000 MW	2,000 MW
Interconnector flow limits – Heywood and combined Heywood + Energy Connect	✓	✓	✓
ESOO stability constraints (additional to those mentioned above)	Some SA voltage constraints	Unknown	Different combinations of SA and NEM constraints[3]
Capital cost of SA pumped hydro	$1.4m/MW	$1.9m/MW	~$1.9m/MW (AEMO Draft ISP 2020 Central)

Source: FTI analysis, ElectraNet, SA Energy Transformation RIT-T - PACR, February 2019 (link), AER, Decision: South Australian Energy Transformation, January 2020 (link).

Notes: (1) Only SA gas units were modelled endogenously (see ¶A1.10 for further detail). (2) This refers to the existing requirement for four synchronous units to be online at all times before the installation of four synchronous condensers (end 2020). This requirement is expected to reduce to two units after the synchronous condensers are installed and zero units after EnergyConnect is commissioned. (3) As explained in ¶2.16, we have tested three combinations of stability constraints.

3.52 As discussed above, MCF and gas prices impact the amount of gas that runs in the baseline without EnergyConnect and the cost of that gas. This has a material impact on the benefit of EnergyConnect because it determines the quantity and cost of what can be displaced. With respect to the other assumptions outlined in Table 3-1 above:

- We calibrate our model with Draft ISP 2020 assumptions whereas ElectraNet and AER[99] use ISP 2018. Almost all Draft ISP 2020 assumptions were updated from those used in ISP 2018. Updates include an increase in commodity prices (in particular gas price, which is a key driver as discussed above), an increase in peak and annual demand and updated REZ. These updates reflect AEMO's current best forecast for the NEM. We consider that some changes are likely to increase EnergyConnect gross benefits while others are likely to decrease gross benefits.
- We model SA gas generator retirements endogenously, which is consistent with the AER's approach but differs to ElectraNet, who used the modelled retirement dates from AEMO's ISP 2018 modelling as exogenous inputs. The generator retirement profile has an impact on (i) avoided variable cost; (ii) avoided fixed cost; and (iii) capex from new build capacity. As the amount of available gas capacity changes, it has an impact on the fixed costs incurred, the amount of generation that can be displaced (saving variable cost) and the timing of new build capacity that comes in to take its place.
- There are differences in the generator specific input assumptions (cycling, minimum load and start-up costs), which will have an impact on the modelled behaviour of generators. It is difficult to definitely compare the three modelling approaches (FTI, AER and ElectraNet) as some critical information has been redacted.
- We model 4,400MW of inertia capability and a 2,000 non-synchronous generation cap. This approach is in-line with the approval of four synchronous condensers in SA (a decision that was made after the PACR was published but before the AER Determination) and the AER's approach. In comparison, ElectraNet modelled only two synchronous condensers and therefore lower inertia capability and non-synchronous cap. The synchronous condensers will improve system strength and inertia in SA and consequently reduce the need for this to be provided by synchronous generation.[100]

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99 All references to the 'AER's modelling' refer to the AER's preferred set of modelling assumptions. The modelling itself was performed by ElectraNet at the AER's request.

100 ElectraNet, Addressing the System Strength Gap in SA: Economic Evaluation Report, 18 February 2019 (link).

- Higher SA pumped storage capital cost is likely to have an impact on (i) the amount of pumped storage capacity that is optimal to build; and (ii) the capex profile of the capacity that is built. Both factors would have a direct impact on the quantum of capex from new build capacity and a secondary impact on avoided costs. We model the most recent data available from AEMO for capital cost, which is in-line with the AER's approach. ElectraNet on the other hand modelled lower capital cost for SA pumped storage, as the updated cost values were not available in time to be incorporated into their modelling.[101]

C. Total project cost supporting positive societal benefits

3.53 This report focuses on the gross benefits of EnergyConnect. Of course, in building EnergyConnect capex and ongoing opex are necessarily incurred. In this subsection, we consider the total project cost that could be supported such that there are still positive societal benefits given our estimate of gross benefits.

3.54 As described above, EnergyConnect is expected to bring $1.6 billion in gross benefits over the 2020 to 2040 modelling period. As this estimate of gross benefits covers only a portion of EnergyConnect's expected life, we analyse the potential cost of EnergyConnect that could be supported by this level of benefits over the equivalent period.

3.55 The RIT-T guidance outlines that interconnector costs included in the assessment of net benefits are *"costs incurred in constructing or providing the credible option; operating and maintenance costs over the credible option's operating life; and costs of complying with relevant laws, regulations and administrative requirements"*.[102] We therefore estimate interconnector cost to be comprised of both capex and opex.

[101] AER, Decision: South Australian Energy Transformation, January 2020 (link), page 68.

[102] AER, Application guidelines: Regulatory investment test for transmission, December 2018, (link), page 30.

3.56 To ensure expected capex is comparable to our estimate of gross benefits over the modelling period, we annuitise project capex, and consider the portion of total capex that will be incurred over that modelling period only. Specifically, we annuitise total capex over a 50 year period (the assumed asset life) at a rate of 5.9%, and only consider the portion incurred between 2023 (the date EnergyConnect becomes operational) and 2040. We also assume annual opex will be equal to $5 million per year.[103]

3.57 On the basis of our gross benefit estimate of $1.6 billion, we have considered the total projects costs that could be supported, such that there are still positive societal benefits. This value of total cost is the 'break-even' level that the expected gross benefits would support.

3.58 We estimate the break-even level of total lifetime capex for EnergyConnect to be around $3.0 billion. For this value of total lifetime capex, on an annuitised basis:[104]

- $186 million of capex is assumed to be incurred each year; and
- $5 million of opex is assumed to be incurred each year.

3.59 We assume that these annuitised annual costs are incurred from 1 July 2023 (i.e. start incurring cost in FY 2024 once EnergyConnect comes online) and are incurred for each year of the asset's expected life (i.e. from 1 July 2023 to 30 June 2073). On a present value basis over the modelling period (2020 to 2040) this equates to a total of $1.6 billion, i.e. cost is equal to gross benefit.

3.60 We have assumed that $5 million of opex will be incurred each year. However, if opex was higher, the break-even value of total capex would be lower. The sensitivity of break-even total capex to annual opex is presented in the table below:

[103] We have been instructed to assume that TransGrid will incur opex of $3.5 million per year and ElectraNet will incur opex of $1.5 million per year.

[104] De-commissioning costs are excluded.

Table 3-2: Impact of opex on 'break-even' level of total capex

Opex as a percentage of total capex *(%)*	Opex per annum *($ million)*	Break-even total project capex *($ billion)*
2.0%	46.2	2.3
1.5%	36.9	2.5
1.0%	26.3	2.6
0.5%	14.1	2.8
0.2%	5.0	3.0

Note: Shaded row highlights opex assumption used in the paragraphs above.
Source: FTI analysis.

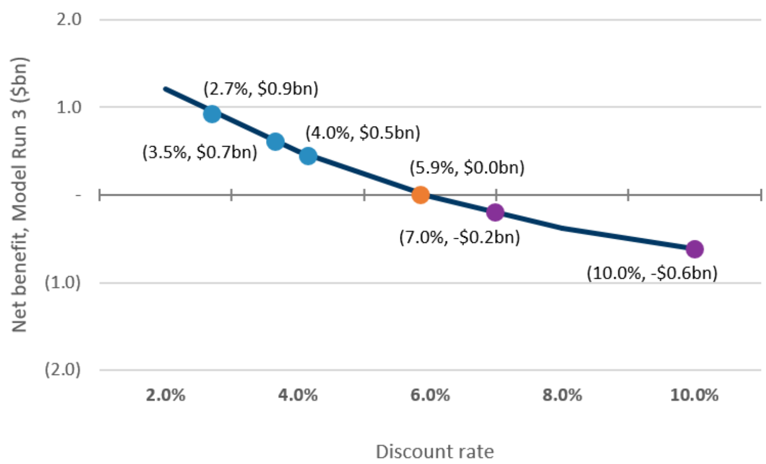
D. Discount rate sensitivity

3.61 The discount rate used to assess the present value of EnergyConnect should appropriately reflect the project's expected risks and a relative preference for short term versus long term benefit to consumers. For example, if greater weight was to be placed on a project providing longer term benefit, a lower discount rate should be used, and vice versa.

3.62 We have adopted AEMO's Draft ISP 2020 central scenario discount rate of 5.9%. This discount rate was updated from 6.0%, which was the value assumed for the equivalent scenario in ISP 2018.

3.63 Figure 3-13 below illustrates how the adopted discount rate has a significant impact on net benefit. For this analysis, we calculate net benefit as gross benefit (discounted at the specified discount rate) less interconnector cost (also discounted at the specified discount rate). The annual estimates for undiscounted gross benefit are unchanged and total project capital cost is assumed to be $3.0 billion (in-line with the break-even analysis at 5.9% presented in Section 3C).

Figure 3-13: Impact of discount rate of quantum of net benefit



Source: FTI analysis.
Note: Line represents trend between each estimate of net benefit. Net benefit is calculated under five different discount rates: 5.9% is AEMO's Draft ISP 2020 central scenario estimate, 3.5% is the societal discount rate commonly used in Great Britain ("GB") (see ¶3.66 below) and 7%, 3% and 10% are the central discount rate and lower and upper bound sensitivity estimates respectively as outlined by the Australian Office of Best Practice Regulation in its Cost-benefit analysis guidance (link).

3.64 As illustrated in the figure above, as the discount rate decreases below 5.9%, net benefit increases. This is because with a lower discount rate, benefits or costs accruing in later years become more significant.

3.65 Our calculations show that the annual benefits of EnergyConnect are generally greater in quantum after 2033, compared to the years before. A lower discount rate would suggest relatively greater weight is placed on benefits in later years, that is, the impact on future consumers are given relatively higher priority compared to today's consumers. By contrast, a higher discount rate would place relatively greater weight on the impact of EnergyConnect in earlier years, before it has had a chance to generate significant benefits.

3.66 The 5.9% discount was applied as this is the central scenario WACC used by AEMO for *“all generation and transmission options in a technologically agnostic manner*”.[105] In this context it is worth noting that, arguably the benefits and costs assessed under the RIT-T are not ultimately borne by a TNSP, but rather by Australian energy consumers. Therefore, there may be merit in considering whether a societal discount rate should be used that, in essence, provides a view on how policy makers should weigh up the interests of current consumers relative to those of future consumers.

3.67 Typically, a societal discount rate is lower than that of a regulated company. In GB for example, a discount rate of 3.5% is used to assess interconnectors,[106] which is the Social Time Preference Rate (or society discount rate) set out by the UK Treasury.[107] If this discount rate was adopted for EnergyConnect, gross benefits would be $2.1 billion for the 2020 to 2040 modelling period.

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105 AEMO, 2019 forecasting and planning scenarios, inputs, and assumptions, August 2019 (link), page 42.

106 National Grid, SO Submission to Cap and Floor, June 2017 (link), page 19 footnote 9.

107 HM Treasury, The Green Book: Central Government Guidance on Appraisal and Evaluation, 2018 (link), page 27 and 28.

4. Wider benefits of EnergyConnect

4.1 As shown in the previous section, our modelling indicates that there are significant positive benefits from EnergyConnect under the RIT-T framework. This analysis focused on specific categories of benefits, over a specified period (2020 to 2040), in line with the RIT-T methodology. However, we consider that there are likely to be additional expected benefits from EnergyConnect outside of the evaluation under the RIT-T framework, that should be considered. These are:

- Additional gross benefits, arising from the same categories of cost savings over the remaining useful life of the asset (i.e. outside of the modelled period 2020-2040), which may be up to 50 years (Section A); and
- Additional non-monetary benefits from EnergyConnect, reflecting the project's contribution to renewables integration, to the connection of complementary generation mixes and to security of supply (Section B).

4.2 We also present an alternative consumer-focused perspective on the net benefits of EnergyConnect (Section C). This approach, which some regulators in other international jurisdictions apply as part of formal regulatory evaluations, places greater weight on consumer welfare (as opposed to other stakeholders) in assessing the merits of potential interconnector projects.

A. Gross benefits arising beyond 2040

4.3 The gross benefits calculated in Section 3 have been modelled over the 2020 to 2040 period, thus capturing 17 years of the operational life of EnergyConnect. However, EnergyConnect is expected to have a useful life of 50 years. We expect that EnergyConnect continues operating beyond 2040,[108] such that some level of benefits would continue to accrue, albeit with a greater level of uncertainty. Furthermore, as annual gross benefit arising after 2040 is discounted to 2020, the materiality, while non-zero, is less.

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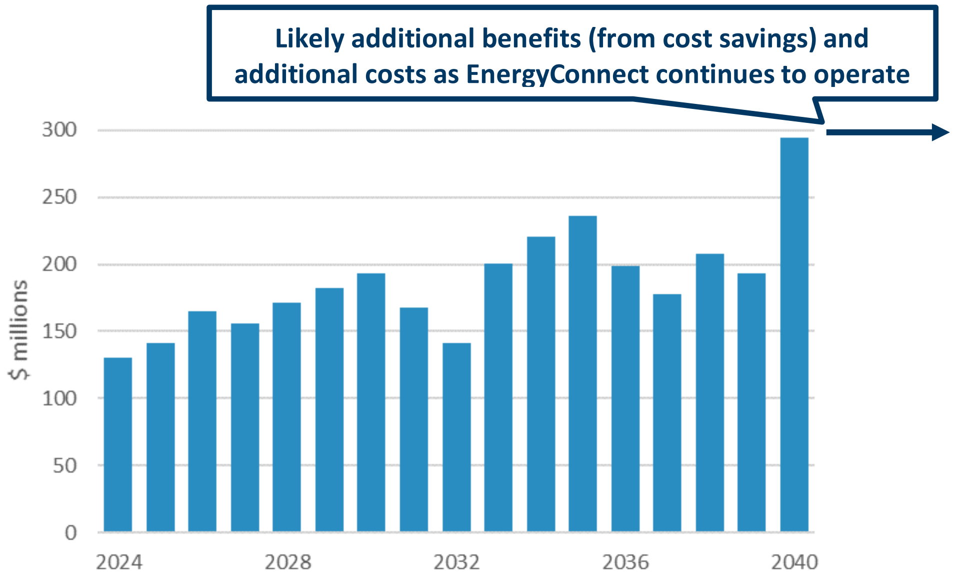
108 Interconnexion France-Angleterre, a 2,000MW interconnector between GB and France, has been operational for over 30 years and has provided benefit to GB consumers from lower wholesale prices over its operational life. The interconnector remains operational (with no plans for operation to cease) as of May 2020. Source: Ofgem, IFA Use of Revenue framework, 22 August 2016 (link), page 1.

Figure 4-1: Modelled annual NEM gross benefits from EnergyConnect (2024 to 2040)



Source: FTI analysis.

4.4 We have sought to estimate the same benefit categories as in the analysis performed under the RIT-T methodology in Section 3, for the 2041 to 2073 period. The magnitude of benefits accruing in this period is considerably less certain compared to the pre-2040 period. This is because, post-2040, they would be influenced by long-term changes in (i) the generation mix; (ii) the volume of additional interconnection across the NEM; (iii) commodity prices; and (iv) demand for electricity. Nevertheless, it seems unlikely that the benefits of EnergyConnect would fall to zero after 2040. Rather, we consider it likely that there will be some level of ongoing benefit beyond 2040 which could be included in the assessment of the wider benefits of EnergyConnect.

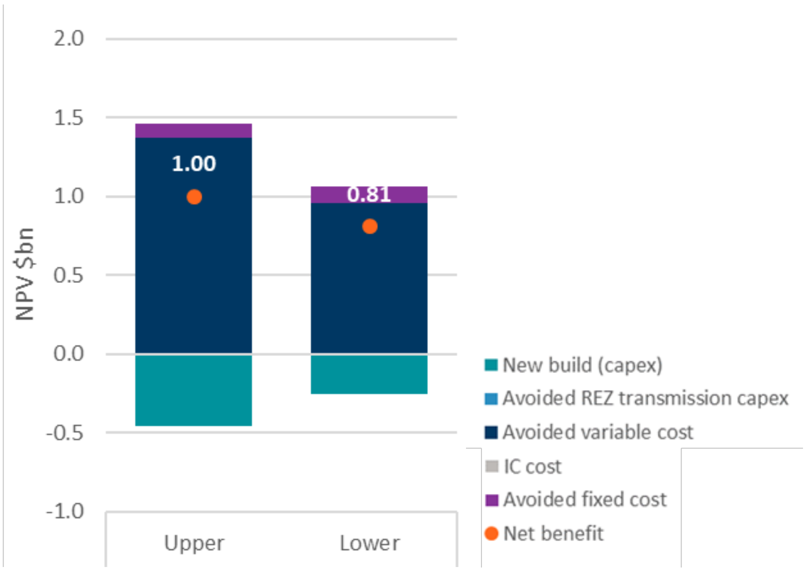
4.5 To illustrate the likely quantum of this long-term benefit, for each model run we estimated an upper bound and lower bound of gross benefit for the 2040 to 2073 period:

- The **upper bound** estimate assumes the incremental gross benefit of EnergyConnect after 2040 will be equal to the annual average of the final three modelled years (i.e. 2038 to 2040 inclusive). For Model Run 3, this is $232 million/year; and

- The **lower bound** estimate assumes the incremental gross benefit of EnergyConnect after 2040 will be equal to the annual average from the asset's modelled life (i.e. 2023 to 2040). For Model Run 3, this is $187 million/year.

4.6 Based on this methodology, the estimated range of gross benefits for the 2041 to 2073 period (i.e. the remaining asset life beyond 2040) is between **$0.8 billion and $1.0 billion** on an NPV basis,[109] as illustrated in the Figure below.

Figure 4-2: Estimated upper and lower bound gross benefits from EnergyConnect (post-2040)



Source: FTI analysis.

Note: Model Run 3 (NEM constraints).
We do not include a value for avoided REZ transmission capex as we have not estimated this market benefit category. It is likely that some gross benefit from avoided REZ transmission capex would accrue post-2040.

109 The estimate of annual benefit arising after 2040 is discounted to 2020 at a discount rate of 5.9%. This range corresponds to Model run 3 (NEM constraints). The estimates for the other model runs fall within this range and are presented in Appendix 3.

4.7 We recognise that the sources of benefits from EnergyConnect may evolve over time and are therefore inherently more uncertain. This is because, as with the pre-2040 analysis, the gross benefits of the project are driven by the difference between the scenario with EnergyConnect relative to the 'counterfactual', i.e. the would-be outcomes in the absence of the project. While in the pre-2040 period, the main benefits of the project relate to the avoided gas fuel cost, beyond 2040 the relevant counterfactual may be different (and it does not seem credible to us to attempt to estimate what that counterfactual might be). However, the qualitative conclusion remains that, in the absence of EnergyConnect, other generation sources would most likely need to step in to secure supply and these would have an associated cost (capex, fixed and/or variable cost). We therefore consider the order of magnitude of the estimated post-2040 benefits to be reasonable based on the information that is currently available.

4.8 Finally, the value of rolled-forward net benefit is dependent on the expected total cost of EnergyConnect, as total cost is annuitised over the full asset life.

B. Non-monetary benefits

4.9 Interconnectors often have additional, qualitative or quantitative effects on energy systems, that cannot be expressed in monetary terms and some of which may be inherently difficult to quantify. As a strictly monetary assessment, the RIT-T does not necessarily fully account for these non-monetary benefits.

4.10 These non-monetary benefits are however considered important to the NEM as a whole, in the context of the National Electricity Objective ("NEO"), which guides the Australian Energy Market Commission's policies and activities.

4.11 We reviewed interconnector policy in three separate jurisdictions to determine how other regulators and other relevant policy makers treat non-monetary benefits. In particular, we examined interconnector policy in: (i) Great Britain (Ofgem's Cap and Floor regime); (ii) Europe (Celtic Interconnector case study) and; (iii) the US (Hudson Transmission Project case study).

4.12 In all three of these jurisdictions, non-monetary benefits are considered as part of 'standard' regulatory assessments of interconnectors, albeit to different extents.[110]

[110] See Appendix 4 for further details on each jurisdiction.

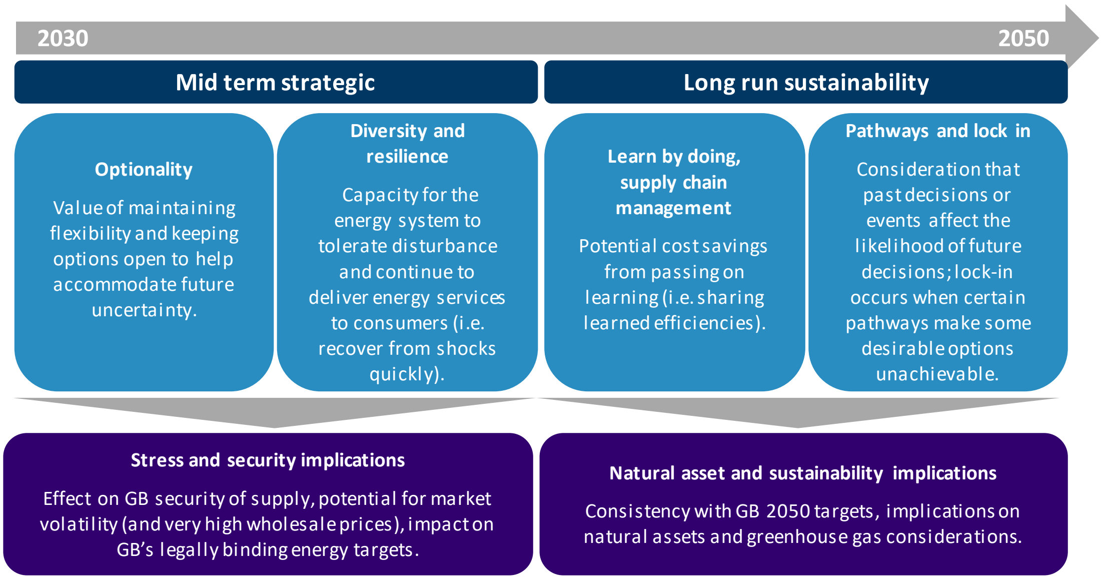
4.13 **In GB:** Ofgem includes 'hard-to-monetise' benefits in its assessments of proposed interconnector projects:

- Ofgem utilises a standard framework (described in Figure 4-3 below) to identify and evaluate 'hard-to-monetise' benefits, which considers mid-term strategic, and long-term sustainability factors.
- For the GridLink, NeuConnect and NorthConnect interconnectors specifically,[111] Ofgem's framework identified the following hard-to-monetise benefits: (i) connecting new providers of balancing services; (ii) increasing GB security of supply; and (iii) supporting the decarbonisation of the GB energy supplies.[112]
- In general, hard-to-monetise benefits have been used as supporting evidence for interconnector investment, in addition to traditional quantitative assessments.
- To date, all GB interconnectors assessed by Ofgem have passed Ofgem's quantitative assessments, so the criticality of 'hard-to-monetise' benefits has not been tested.

111 GridLink is a proposed 1.4GW interconnector between GB and France, NeuConnect is a proposed 1.4GW interconnector between GB and Germany and NorthConnect is a proposed 1.4GW interconnector between GB and Norway.

112 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), page 42.

Figure 4-3: Ofgem's framework for assessing hard-to-monetise benefits



Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

4.14 **In Europe:** As part of its Cost-Benefit Assessment ("CBA"), ENTSO-E assesses potential European transmission projects using both quantitative and qualitative criteria:

- ENTSO-E states that, in its assessment process: "*both qualitative assessments and quantified, monetised assessments are included. In such a way the full range of costs and benefits can be represented*".[113]
- Over time, ENTSO-E's CBA methodology has evolved towards including a wider range of qualitative benefits. This is likely to result in a broader range of benefits being captured within the formal ENTSO-E assessment (relative to the RIT-T, which includes only quantitative benefit categories).

113 ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Project, Draft Version, October 2019 (link), page 17.

- In some cases, these qualitative benefits have been used to justify CAPEX grants to support the development of interconnectors. For example, the Celtic Link interconnector was considered to reinforce "solidarity" [114] between Ireland and continental Europe following the United Kingdom's ("UK's") decision to leave the European Union ("EU"), which allowed it to obtain substantial funding from the EU.[115]

4.15 **In the US:** Non-monetary benefits are taken into account in all transmission project assessments:

- When the New York Power Authority ("NYPA") selected the Hudson Interconnector project over other alternative proposals, it cited both monetary and non-monetary reasons, such as contribution to system security, contribution to the diversification of the total number of electricity supply sources and contribution to policy objectives and land use policies.[116]
- Non-monetary benefits appear to have greater importance when selecting solutions to meeting "reliability" or "public policy" needs, as compared to projects that are selected on the basis of "economic" needs.[117]

4.16 Based on the review of the GB, US and EU precedents, non-monetary benefits appear to be part of the formal regulatory evaluation and are considered within the relevant decision-making frameworks. This is because authorities recognise that not all relevant benefits to consumers can necessarily be monetised. However, the weight given to non-monetary factors relative to monetary factors is uncertain (and likely to reflect regulatory discretion).

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114 EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link), page 38.

115 EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018, (link), page 38.

116 See Table A4- 7 for further detail of NYPA's assessment criteria.

117 'Reliability' projects are to improve the technical reliability of the network (e.g. voltage stability) and are identified by the relevant Independent System Operator ("ISO"). Each ISO applies their own process to identify the preferred investment, and some degree of subjectivity may be applied.
'Public policy' projects are undertaken in response to a particular public policy (e.g. transmission investment required to meet emissions targets). Discretion may be used in selecting which proposed investment best meets the public policy objective.

4.17 All the interconnector case studies examined as part of this report identified economic benefits from the projects based on monetised factors. Non-monetary factors were used as additional supporting evidence on top of an already-strong economic case.

4.18 Relative to other jurisdictions, the RIT-T may therefore undervalue total project benefits, as there are likely to be benefits that cannot be monetised or are project-specific and do not fall into one of the allowed benefit categories.

4.19 Based on our understanding of the project, and the power market modelling performed, we expect EnergyConnect to bring the following non-monetary benefits to the NEM:

(1) Supporting the integration of renewable generation;

(2) Connecting complementary generation mixes in SA and NSW;

(3) Contributing to security of supply in SA;

(4) Providing optionality for potential future policy changes; and

(5) Supporting the National Electricity Objective.

4.20 Below, we discuss each of these non-monetary benefits in detail and explain why each is important and should therefore be considered as part of the assessment of EnergyConnect benefits.

B.1 Renewables integration

4.21 Our modelling shows that EnergyConnect is expected to facilitate greater integration of renewable generation in the NEM by enabling more renewables to be built within individual regions than would be the case without the interconnector. The increased volume of renewable generation can potentially be exported to the neighbouring regions if demand within the domestic region is low. This is particularly relevant to both SA and NSW, with both states aiming to achieve net zero emissions by 2050.[118,119]

4.22 The figure below illustrates the impact of building EnergyConnect on generation capacity in the NEM, classified by fuel type.

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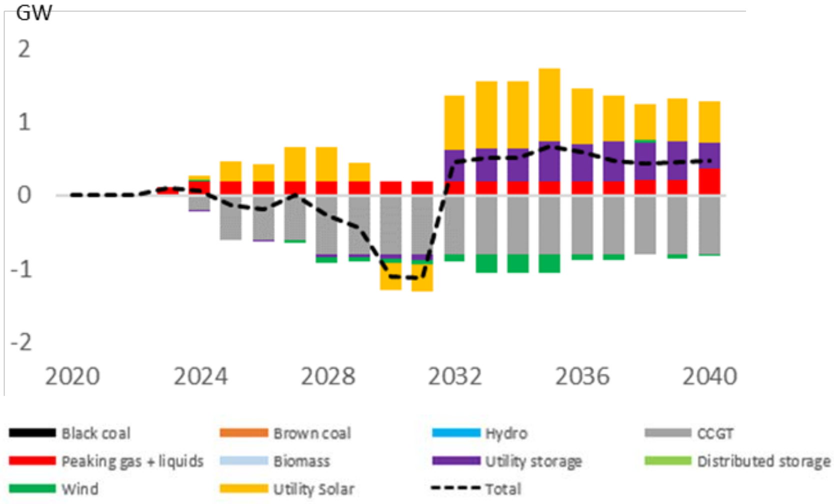
118 PV Magazine, NSW sets 2050 target for net-zero emissions, September 2019 (link).

119 Renew Economy, South Australia to accelerate transition, emissions cuts, after bushfires, January 2020 (link).

Figure 4-4: Change in NEM generation capacity with EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

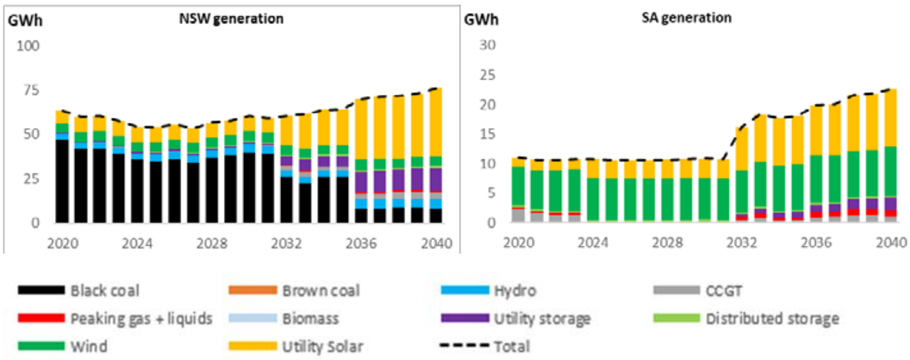
4.23 The figure above illustrates the difference in total NEM capacity with EnergyConnect (broken down by technology type) for each modelled year, relative to the counterfactual scenario without EnergyConnect. This Figure shows that EnergyConnect enables the development of a greater volume of renewable capacity, in the form of solar and utility storage (specifically, in NSW, SA and Victoria). It also facilitates the closure of gas generation (in particular, the early retirement of the Torrens Island B CCGT plant in SA). The net effect is a NEM-wide increase in the total renewable capacity relative to the counterfactual scenario without EnergyConnect.

4.24 Furthermore, EnergyConnect creates an option for excess renewables from one region to be exported to the connected region. This may reduce the risk of renewable generation being curtailed when there is excess local supply. Having this export option available (which essentially increases total demand that can be served) could encourage investment in renewables.

B.2 Connecting complementary generation mixes

4.25 EnergyConnect will connect the structurally different generation mixes of NSW and SA. As shown in the figures below, during the 2020s NSW generation is expected to continue to rely mostly on black coal generation, while SA generation is already dominated by wind and solar. Even in the 2030s the two generation profiles show a different, and complementary mix. Promoting a more diverse mix of generation will help the system balance supply and demand. It will also allow for the inherent intermittency of solar and wind to be better managed, as excess renewable generation from one region can be exported to an interconnected region when renewable generation in that region is low. This in turn allows both states to reduce reliance on fossil fuels (i.e. black coal and gas) as these sources of generation are likely to be needed less often to meet local demand, as renewable generation from neighbouring regions may be able to be imported instead.[120]

Figure 4-5: NSW and SA generation mix with EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

4.26 Some proportion of this benefit has arguably been monetised in our analysis via fuel cost savings, since our modelling has shown a reduction in the total fossil fuel costs as a result of optimising dispatch over a larger geographical footprint.

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120 The benefit of connecting complementary generation mixes is commonly assessed in Ofgem's Cap and Floor assessment in GB. For example, GridLink between GB and France would connect GB gas, biofuel and wind with French nuclear and hydro.

4.27 However, in other jurisdictions, such as under Ofgem's Cap and Floor regime, GB interconnectors are explicitly assessed on the extent to which they connect complementary generation mixes, in addition to any quantifiable monetary benefits. For example, Ofgem consider that there are non-monetary benefits to GB security of supply in having fuel source diversity.[121] We therefore consider it is reasonable to highlight this effect as a qualitative benefit of the interconnector.

B.3 Security of supply

4.28 EnergyConnect is also expected to provide security of supply benefits, particularly in SA. Reliability and security of supply in SA have been identified by AEMO as a growing challenge,[122] and AEMO is required from time-to-time to intervene in the market to ensure system security.[123,124]

4.29 We first discuss the impact of EnergyConnect on system security more generally. We then consider the potential impact of EnergyConnect on Frequency Control Ancillary Services ("FCAS") spending.

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121 Ofgem specifically highlighted that the GB system would be connected to: (i) France's nuclear dominated system via GridLink; (ii) and Norway's hydropower dominated system via NorthConnect, and that the high level of expected availability of these interconnectors will increase GB security of supply.
Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), pages 41-42.

122 On 13 October 2017, AEMO declared a Network Support and Control Ancillary Service gap for system strength in SA and on 24 December 2018 a shortfall in SA inertia was declared. Source: ElectraNet, Strengthening South Australia's Power System (link).

123 AEMO, South Australian Electricity Report, November 2019 (link), page 6.

124 Security of supply also used to be particularly relevant under the "Energy Security Target" of the previous Government, which was designed to ensure energy system stability in a competitive and cost-effective manner.
Source: Government of South Australia, Energy Security Target Stakeholder Consultation (link).

Impact of EnergyConnect on general system security

4.30 EnergyConnect is expected to improve security of supply, by reducing the need for synchronous generation to run at all times in SA (as is the current requirement). In SA, a significant proportion of synchronous generation comes from relatively expensive gas generation. EnergyConnect is expected to reduce the frequency at which gas generators in SA need to run (to maintain sufficient levels of synchronous generation). This benefit is monetised through avoided variable and fixed costs, as not only does less generation save variable costs, SA gas generators are also now able to retire earlier than they otherwise would.

4.31 However, the avoided cost analysis does not capture the benefits of improved system flexibility, which will help mitigate the effect of unexpected, **high impact, low probability system stress events**.

4.32 Such events have historically been labelled as very unlikely and not captured by the Reliability Standard (which mostly focuses on the robustness to a single contingency event). They are therefore not explicitly prepared for.[125] However, it appears that such 'non-credible' events have been happening with greater frequency in the recent years and are having a significant impact on security of supply.[126] Moreover, there has been a renewed focus on managing this new type of *"indistinct risks"*, including in the Review of South Australian Black System event, published in 2019,[127] which has explored new mechanisms to manage this new type of risk to the electricity system.

[125] AEMO, Reliability Standard Implementation Guidelines, August 2017 (link).

[126] SA was disconnected from the NEM twice in Q1 2020; (i) on 31 January 2020, when two transmission lines in western Victoria were damaged during a storm; and (ii) on 2 March 2020, due to an unexpected outage of the Heywood interconnector.
Source: AEMO, Quarterly Energy Dynamics Q1 2020, April 2020 (link), page 24.

[127] AEMC, Mechanisms to Enhance Resilience in the Power System – Review of the South Australian Black System Event, December 2019 (link).

Box 4-1: Case study – South Australia Disconnections

Between November 2019 and March 2020, SA was separated from the NEM three times following an unexpected outage of the Heywood interconnector.[128] These outages incur significant costs. The two separation events in Q1 2020 together incurred almost $90 million in FCAS costs, almost 30% of total NEM-wide system costs in the same period[129] and a further $8 million in FCAS costs were incurred for the November 2019 separation event (which lasted only five hours).[130]

Such events place additional stress on the SA system to:

- Supply sufficient energy to meet demand; and
- Ensure sufficient inertia to maintain a safe a stable system.

Separation events are not unique to Heywood interconnector: in January 2020 there was an unexpected outage of VNI and in August 2018 there was an unexpected outage of QNI.[131] EnergyConnect will diversify the interconnection of NSW with the rest of the NEM, and in doing so will mitigate the potential consequences on an outage of another interconnector.

4.33 EnergyConnect is likely to enhance the integration of SA with the rest of the NEM and help prevent SA from being 'islanded' during unexpected, low probability events (such as another unexpected outage of Heywood). The ability to use EnergyConnect as a mitigation tool against these events is an additional benefit, beyond avoided fuel costs, that should be recognised.

4.34 The increased interconnection provided by EnergyConnect is also likely to result in a reduction in unserved energy in the NEM, by allowing power to be redistributed from regions of high supply to regions of high demand. This is an additional benefit to NEM consumers, as it helps mitigate unnecessary situations of supply shortfalls.

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128 Renew Economy, South Australia's renewables grid separates from NEM, November 2019 (link), AEMO, UPDATED AEMO statement: heatwave conditions in Victoria, January 2020 (link), Renew Economy, South Australia separates from NEM, again, March 2020 (link).

129 AEMO, Quarterly Energy Dynamics Q1 2020, April 2020 (link), page 24 and 26.

130 AEMO, Quarterly Energy Dynamics Q4 2019, February 2020 (link).

131 AEMO, Quarterly Energy Dynamics Q1 2020, April 2020 (link). AEMO, Quarterly Energy Dynamics Q3 2018, November 2018 (link).

4.35 These views appear to be supported by AEMO. In a recent report on the risks of electricity supply disruption in SA, AEMO highlighted that *"the proposed EnergyConnect interconnector will substantially reduce the risk of South Australia separating from the rest of the NEM"* and that *"completion of the interconnector on the current proposed commissioning timelines should be considered crucial for the ongoing security of South Australia's power system"*.[132]

4.36 AEMO further concluded that these system security benefits are in addition to any cost savings delivered by EnergyConnect, that is, that they are *"additional to any benefits related to energy transfer"*.[133] The report further outlined the urgency of the interconnector, and argued that, in its absence, *"extreme measures such as an immediate moratorium on new distributed PV installations will likely be required"*.[134]

4.37 Furthermore, recent changes to the ISP may facilitate a greater emphasis on system security. These changes, and their potential relevance to EnergyConnect, are discussed in the box below.

Box 4-2: Rule changes to convert the ISP into action

In March 2020, the Energy Security Board published a Decision Paper with a final recommendation on rule changes to amend the transmission planning process and allow the ISP to be converted into action.

Under the updated rules, the ISP will identify the 'optimal development path', which *"efficiently meets a defined set of power system needs and public policy needs"*.[135] For transmission projects, the ISP will identify the need for the project as well as a preferred solution.

The optimal development path identified by AEMO in the ISP will include three categories of projects:[136]

132 AEMO, Minimum operational demand thresholds in South Australia, May 2020 (link), page 55.

133 AEMO, Minimum operational demand thresholds in South Australia, May 2020 (link), page 56.

134 AEMO, Minimum operational demand thresholds in South Australia, May 2020 (link), page 56.

135 COAG Energy Council, Energy Security Board: Converting the Integrated System Plan into Action Decision Paper, March 2020 (link), page 9.

136 COAG Energy Council, Energy Security Board: Converting the Integrated System Plan into Action Decision Paper, March 2020 (link), page 12.

- **Actionable ISP projects**: transmission projects for which a Project Assessment Draft Report ("PADR") is required within the next 2 years (i.e. before the next ISP is published).
- **Future ISP projects**: transmission projects that are not required until further in the future, and therefore the need for the project will be reassessed as part of the next ISP.
- **ISP development opportunities**: the ISP will also provide information on projects that do not relate to transmission to inform commercial decision making (examples include distribution, generation, storage and demand response projects).

Had these new rules been in place, the optimal development path would have been assessed by AEMO as part of the ISP. In determining the optimal development path (and the need for transmission investment), the new rules propose that AEMO should consider reliability standards and system security. Therefore, it is possible that additional focus may have been placed on system security benefits had EnergyConnect been assessed under the new rules.

Impact of EnergyConnect on expenditure on ancillary services

4.38 The system security benefits outlined above are likely to have an additional monetary effect in respect of reduced expenditure on ancillary services. During periods of system stress, a higher level of FCAS expenditure is necessary to maintain the frequency of the system within operational limits.

4.39 In general, interconnectors are likely to both:

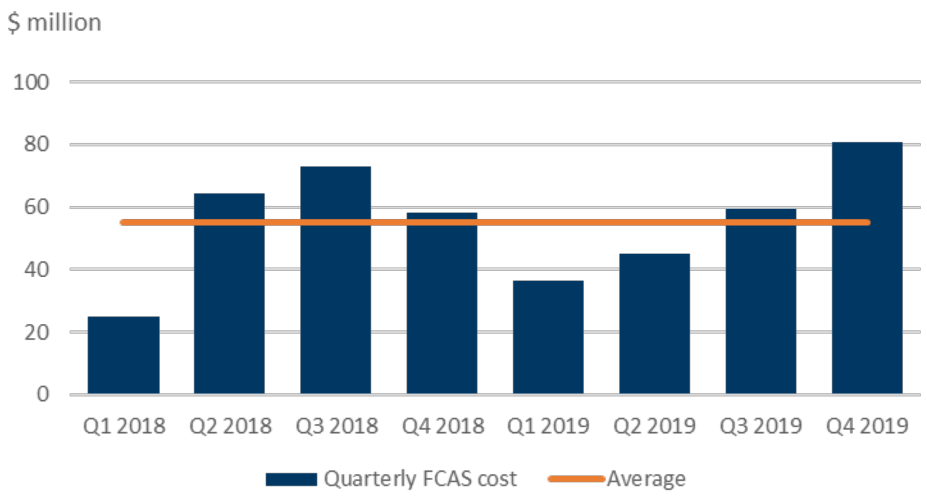
- reduce the frequency of system stress events, thereby reducing the frequency with which FCAS needs to be procured; and
- increase access to cheaper FCAS services in other regions, thereby reducing the price of FCAS.

4.40 For EnergyConnect specifically, AEMO highlighted that *"by reducing the likelihood of islanding, EnergyConnect would reduce the incidence of these* [FCAS] *costs"*. [137]

[137] AEMO, Minimum operational demand thresholds in South Australia, May 2020 (link), page 56.

4.41 Quantifying these effects is inherently challenging, since ancillary services are more granular and relatively bespoke products, compared to hourly MWh 'blocks' of wholesale market energy, which our modelling is based on. We are however able to provide an indicative estimate of the order of magnitude of FCAS cost savings that are possible, based on the historical FCAS costs shown in the figure below.

Figure 4-6: Total NEM FCAS per quarter (Q1 2018 – Q4 2019)



Source: AEMO, Quarterly Energy Dynamics Q1 2020 - databook, April 2020 (link).

4.42 Between Q1 2018 and Q4 2019,[138] average total FCAS cost per quarter was around $55 million on a NEM-wide basis.[139] If EnergyConnect allowed for say a 3% reduction in total expenditure on FCAS costs, this would have been equivalent to an average of $1.7 million per quarter, or around **$6.6 million per year**.[140] On a present value basis between 2020 and 2040, this is equal to around $56 million.[141]

138 We have excluded FCAS costs in Q1 2020 for the purposes of this calculation, as we understand this was an outlier period.

139 AEMO, Quarterly Energy Dynamics Q1 2020 - databook, April 2020 (link).

140 Source: FTI analysis.

141 Assuming FCAS cost savings only occur in 2024 onwards, after EnergyConnect comes online. Source: FTI analysis.

4.43 These potential savings may be important in the context of the ongoing review of ancillary services (otherwise known as Essential System Services) by the Energy Security Board. FCAS costs are likely to be a significant issue in the NEM going forward and facilitating their reduction could be a further benefit of EnergyConnect.

4.44 Ofgem has also considered the impact of interconnectors on ancillary services expenditure, in particular in its assessment of the Window 1 interconnectors.[142] In the table below, we present ancillary service cost savings estimated by National Grid.[143] Since each of these interconnectors is a different size to EnergyConnect, we scale down the estimates in proportion to their respective differences in capacities.

Table 4-1: Illustrative ancillary cost savings expected from GB Window 1 interconnectors

	FAB Link	IFA2	Viking Link
Cost savings on ancillary services and boundary capability *(£m p.a.)*	47.0	35.0	34.0
Cost savings on ancillary services[1] *(£m p.a.)*	23.5	17.5	17.0
Capacity of interconnector *(MW)*	1,400	1,000	1,400
Scaling factor[2]	0.6	0.8	0.6
Adjusted cost savings on ancillary services *(£m p.a.)*	**13.4**	**14.0**	**9.7**

Notes: (1) We assume cost savings on ancillary services represent half of the total cost savings on ancillary services and boundary capability; (2) The scaling factor is given by the capacity of EnergyConnect (800MW) divided by the capacity of the interconnector.
Source: Ofgem, Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink interconnectors, March 2015 (link) page 23, 25, 27 and 36.

142 These were FAB Link, IFA2, Viking Link and Greenlink.

143 We exclude Greenlink as it was not expected to have a material effect on ancillary services.

4.45 Our illustrative calculation for the Window 1 interconnectors suggests that National Grid estimated that a given interconnector of equal size to EnergyConnect would result in cost savings on ancillary services between £9.7 million and £14.0 million per year.

B.4 Optionality

4.46 The evolution of the NEM in the next 20 years (and beyond) is inherently uncertain. Therefore, there is value in having assets that are flexible to changing future circumstances.

4.47 In this report, we have only assessed EnergyConnect from the perspective of the ISP central scenario. The central scenario is the principal scenario considered by AEMO in Draft ISP 2020 and is based on a market-driven transition. It essentially represents one view of the future evolution of the NEM at a single point in time. Of course, many other possible future evolutions are possible. Indeed, in its Draft ISP, AEMO also considers a further four scenarios: Slow Change, High DER, Fast Change and Step Change. These each consider alternative trajectories and variations in the pace of transition.

4.48 While the central scenario – as described in the Draft ISP 2020 – is one very plausible future evolution of the NEM, it is possible to conceive of political or socioeconomic events in the future, which mean other scenarios become more likely. For example, it might be that (perhaps triggered by a climatic event) a policy of more aggressive roll out of renewables generation becomes a political objective and, in turn, means that the 'central' scenario becomes more akin to the current Step Change scenario.

4.49 In this way, the extent to which EnergyConnect provides "policy optionality" is a further benefit that should be considered.[144]

[144] We recognise that option value is a category of benefit under the RIT-T, however we have not quantitatively assessed option value as part of this analysis.

4.50 Under a Step Change scenario (which is characterised by aggressive global decarbonisation and strong consumer-led and technology-led transitions) retirements of black coal and brown coal capacity are expected to be accelerated, with variable renewable generation, distributed energy resources and storage expected to take their place.[145] In addition AEMO also notes that with such a rapid transformation *"there is a greater need for transmission development – both intra- and inter-regional – to improve access to REZs and share energy and capacity between regions".*[146] EnergyConnect would provide such value if a Step Change scenario were to eventuate.

4.51 The quantum of benefit estimated for EnergyConnect is dependent on the modelled input assumptions, many of which are scenario dependent. For example, commodity prices, demand and use of distributed resources (e.g. rooftop PV) varies by scenario. We have only estimated the benefits of EnergyConnect under the central scenario.

4.52 If, however, there were significant benefits under other scenarios – particularly those scenarios that supported more aggressive pursuit of current policy objectives – then the fact that EnergyConnect provides policy makers optionality may strengthen the case for the project even if a current central case is somewhat marginal.

B.5 The National Electricity Objective

4.53 The NEO is one of three key objectives that guide AEMC policy and legislation.[147] The NEO describes the overall objective of the National Electricity Law ("NEL"), which governs, among other matters, the manner in which economic regulation is applied to the electricity transmission networks in the NEM.[148] It is:[149]

> *"to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:*
>
> - *price, quality, safety and reliability and security of supply of electricity*
> - *the reliability, safety and security of the national electricity system."*

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145 AEMO, Draft 2020 Integrated System Plan Appendices, 12 December 2019 (link), page 37.

146 AEMO, Draft 2020 Integrated System Plan Appendices, 12 December 2019 (link), page 37.

147 The other two being the National Energy Retail Objective ("NERO"), which applies to the retail market, and the National Gas Objective ("NGO"), which applies to the gas market.

148 AEMC, Applying the Energy Market Objectives, July 2019, page 1 (link).

149 AEMC, National Electricity Objectives (link).

4.54 In particular, the *reliable supply* of electricity refers to the ability of the network to supply electricity to meet customer demand, while *security of supply* refers to the ability of the network to operate within defined technical limits, even during periods of system stress.[150] The NEO is relevant to Australia's wider climate change policy as well. Through the NEO, the AEMC aims to ensure climate change objectives are efficiently met, in such a manner that preserves the reliability and security of the electricity network.

4.55 The non-monetary benefits of EnergyConnect are directly relevant to the NEO. As discussed above, EnergyConnect is expected to have a direct impact on the reliability and security of the network, as it will help prevent SA from being 'islanded' during periods of system stress. EnergyConnect is also expected to facilitate a more effective integration of renewable generation into the NEM. By creating an option for excess renewables from one region to be exported to another, EnergyConnect will assist SA and NSW in meeting their emissions targets in a manner that preserves the reliability and security of the network.[151]

C. Net consumer benefit

4.56 The RIT-T framework focuses on the total socio-economic welfare impact of EnergyConnect, i.e. taking into account all stakeholders affected by the project. However, it is possible to take a more consumer-centric approach, which attributes a greater weight to the impacts of the project on consumers, and a lower weight to the impacts of the project on other categories of stakeholders.

4.57 In this subsection, we:

(1) describe in general the consumer-centric approach to estimating the benefits of an interconnector, with reference to a specific example of its use in assessing GB interconnectors;

(2) estimate the benefits of EnergyConnect from the perspective of all NEM consumers; and

(3) estimate the benefits to NSW and SA consumers specifically.

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150 AEMC, Applying the Energy Market Objectives, July 2019, pages 7 and 8 (link).

151 EnergyConnect may also support the NSW Government's Transmission Infrastructure Strategy to "*increase* [NSW's] *transmission capacity and access to low-cost generation"* and its 20-year Economic Vision for Regional NSW to support economic growth in rural NSW.
Sources: NSW Government, Transmission Infrastructure Strategy (link), NSW Government, A 20-Year Economic Vision for Regional NSW (link).

4.58 Independent of the impact on household electricity bills, we understand that EnergyConnect is expected to support job creation in NSW. Indeed TransGrid have estimated 1,500 jobs will be created in NSW as a direct result of EnergyConnect, while 2,780 jobs will be indirectly supported as a result of the wider effects of the interconnector.

C.1 Consumer-centric approach to calculating the benefits of new interconnectors

4.59 A consumer-centric approach may consider the impact of new interconnection on the electricity prices paid by consumers (approximated through the changes in the wholesale electricity prices). While some of this price change is already captured through the RIT-T analysis (e.g. the impact of lower fuel prices), there are other factors that are not, such as the extent to which the interconnector may help constrain the bidding behaviour of generators.

4.60 More generally, it is possible to deploy a consumer lens to evaluating the merits of an interconnector project by focusing on how consumer welfare changes (but not how producer welfare changes) as a result of the project. A similar consumer-focused approach is used by Ofgem in evaluating proposed GB interconnectors under the "Cap and Floor regime".

4.61 Ofgem's assessment of the expected benefits of interconnectors as part of the Cap and Floor regime (GB's default regulatory regime for interconnectors) primarily focuses on the expected benefits to GB consumers. This approach is *"in line with* [Ofgem's] *principal objective, which is to protect the interests of current and future GB energy consumers".*[152]

4.62 The table below presents the quantitative results from Ofgem's most recent Cap and Floor assessment:

Figure 4-7: Summary of the welfare impacts of Cap and Floor Window 2 interconnectors (base scenario)

	GridLink	NeuConnect	NorthConnect
Net GB consumer welfare (£m NPV)	2,984	2,197	2,739
GB total welfare (£m NPV)	62	-254	-410

Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017, Table 1, page 7 (link).

[152] Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017, page 6 (link).

4.63 For each interconnector assessed, Ofgem found significant benefit for GB consumers in excess of £2 billion on an NPV basis, but only marginal or negative net benefit from the perspective of all GB stakeholders (i.e. consumers, producers and interconnectors). In each case, the proposed interconnector was granted a 'cap and floor regime in principle', meaning that it satisfied this stage of the regulatory assessment and was permitted to proceed on the basis that it is *"likely to generate significant net benefits for GB consumers"*.[153] This outcome appears to illustrate that Ofgem places much lower priority on the full societal impact of interconnector investment and is willing to approve interconnector investment on the basis of significant benefit to GB consumers alone.

C.2 Impact of EnergyConnect from the perspective of all NEM consumers

4.64 To consider the impact of EnergyConnect from a consumer perspective (in-line with the approach taken by Ofgem in GB), we estimate net consumer benefit by calculating the:[154]

- change in consumer surplus as a result of lower wholesale prices;[155,156]
- interconnector residues earned by EnergyConnect, and its effect on the residues earned by other interconnectors;[157] and

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153 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017, page 7 (link).

154 This analysis does not take into account the loss of producer surplus as the result of lower revenues.

155 To estimate wholesale prices, we use Bertrand pricing methodology. We have undertaken analysis that indicates that this pricing methodology better reflects the bidding behaviour of generators in the NEM and therefore is likely to produce a more accurate forecast of wholesale prices. Bertrand pricing assumes that all generators understand their position in the merit order and increase their bid to just below that of the next generator in the merit order (i.e. bids increase but the merit order remains unchanged).

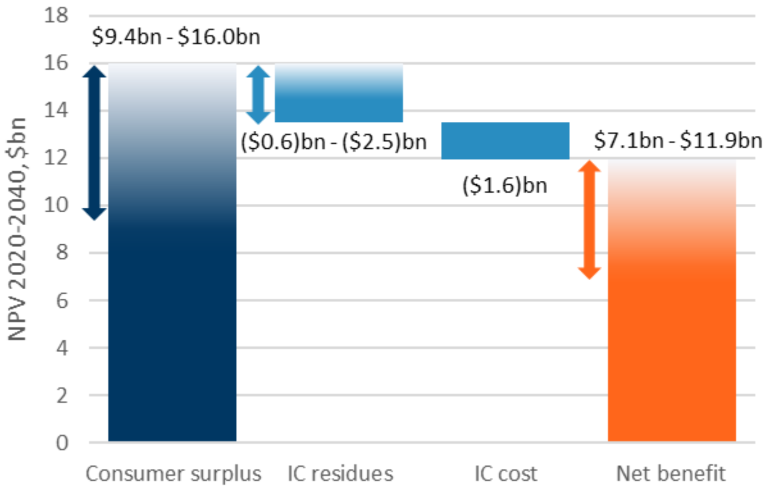
156 We do not consider the relationship between retail and wholesale electricity prices. The simplifying assumption is that any changes in the wholesale electricity prices are ultimately reflected in retail prices.

157 This assumes that all existing and future interconnectors are developed under a regulated regime, whereby the costs of those interconnectors (net of congestion revenues earned) are recouped from consumers. This would not be the case for "merchant" interconnectors.

- cost of constructing and operating EnergyConnect.[158]

4.65 The results of this analysis are presented in the figure below.

Figure 4-8: Net consumer surplus from EnergyConnect (all model runs)

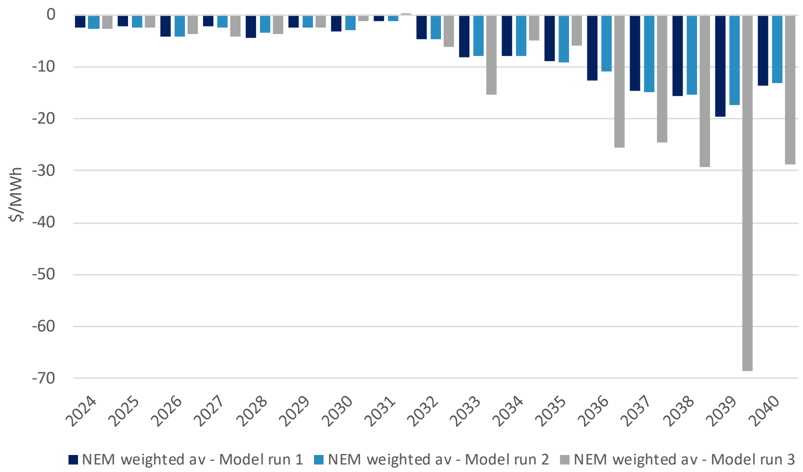


Source: FTI analysis.
Note: The range of consumer surplus, IC residues and net benefit is determined by imposing different sets of stability constraints (i.e. the different model runs). For further detail, see Appendix 3B. This analysis assumes total project capex of $3.0 billion and annual opex of $5 million.

4.66 EnergyConnect results in a significant increase in consumer surplus equal to between $9.4 and $16.0 billion on a NPV basis, as it causes a material reduction in the average wholesale price in all NEM regions. The average decrease in NEM wholesale electricity prices over the 2020 to 2040 modelling period is between $6.0/MWh/year and $11.2/MWh/year, with wholesale prices expected to decrease as soon as EnergyConnect is commissioned (although the largest price impact occurs in the late 2030s), as illustrated in Figure 4-9 below:

158 Interconnector cost includes the portion of annuitised capex (annuitised at 5.9% over a 50-year asset life) that corresponds to the 2020 to 2040 period plus annual opex equal to $5 million. We use a total capex of $3.0 billion, which is equivalent to the 'break-even' level estimated in Section 3C. For further detail on the calculation of interconnector cost, see Section 3C above.

Figure 4-9: Annual weighted average NEM wholesale price impact from EnergyConnect



Source: FTI analysis.

4.67 This decrease in wholesale prices is predominately driven by:

- improved access to cheaper sources of generation from neighbouring regions; and
- the bidding behaviour of local generators being constrained due to increased competition in the wholesale market, with the new interconnector enabling demand to be met through cheaper sources of generation from neighbouring regions.[159]

4.68 The quantum of benefit is dependent on wholesale prices with and without EnergyConnect, and wholesale prices are in turn dependent on how we have modelled system conditions. We therefore present consumer benefit as a range, as this considers that the impact of EnergyConnect on wholesale prices is likely to be higher when the system is tighter (i.e. with all NEM stability constraints).

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[159] We recognise that the RIT-T methodology allows for 'competition benefits' to be included in the calculation of gross benefits, to reflect the impact that the credible option is likely to have on the bidding behaviour of generators. The AER outlines two possible methodologies that could be used to isolate the benefit of competition on the cost of dispatch. Our consumer-focused approach considers the impact of increased competition on the wholesale electricity price, by estimating prices using the "Bertrand" methodology as explained in footnote 155. This approach enables us to estimate the benefit of EnergyConnect in terms of constraining generators' bidding behaviour, to the benefit of consumers. Source: AER, Application guidelines: Regulatory investment test for transmission, December 2018 (link) pages 91 to 95.

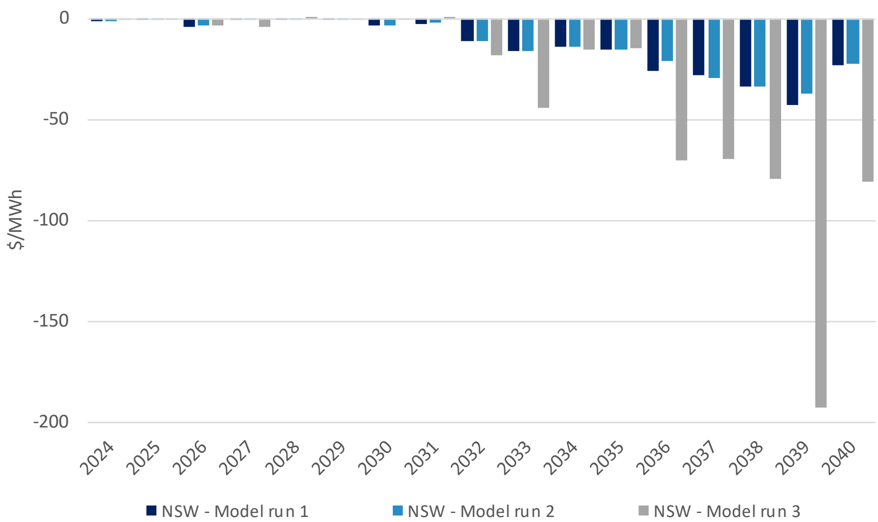
4.69 For completeness we should note that an additional interconnector, in the form of EnergyConnect, has an offsetting cost as it reduces congestion rent and encourages convergence in inter-regional wholesale prices, 'cannibalising' the congestion rent earned by existing interconnectors. We consider this a 'disbenefit' to consumers as we assume that the interregional settlement residues (or congestion rent) is earned by TNSPs and then transferred back to consumers through network charges.

4.70 Using this alternative consumer-focused approach, we estimate EnergyConnect brings a net benefit to NEM consumers of between $7.1 billion and $11.9 billion on an NPV basis over the 2020 to 2040 modelling period.

C.3 Impact of EnergyConnect on NSW and SA consumers

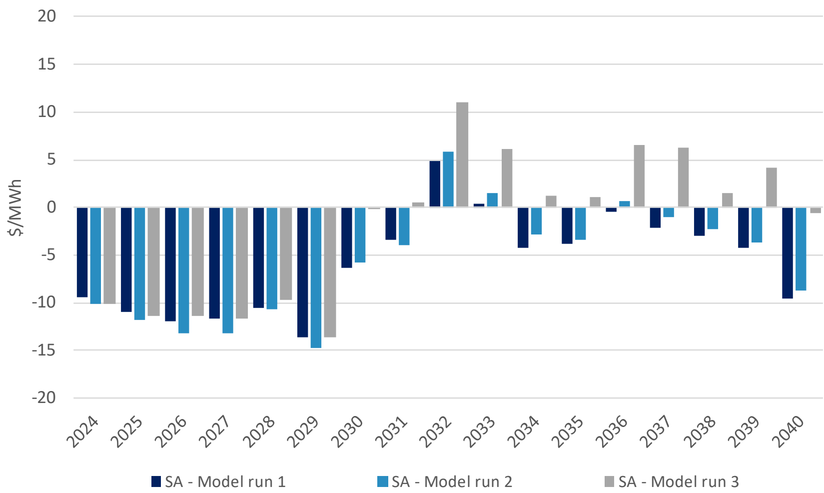
4.71 We have estimated that NSW customers stand to benefit significantly from EnergyConnect. Between $5.5 billion and $14.4 billion of gross consumer benefit (equivalent to an average decrease in NSW wholesale electricity prices of between $10.5/MWh/year and $29.6/MWh/year) is expected to accrue to NSW consumers over the forecast horizon. [redacted] The impact of EnergyConnect on NSW and SA wholesale prices is presented in Figure 4-10 and Figure 4-11 respectively below:

Figure 4-10: Annual NSW wholesale price impact from EnergyConnect



Source: FTI analysis.

Figure 4-11: Annual SA wholesale price impact from EnergyConnect



Source: FTI analysis.

4.72 NSW consumers in particular benefit from EnergyConnect in the 2030s, when the interconnector allows for cheap electricity to be imported from SA, helping to significantly mitigate the impact of planned black coal closures that would otherwise lead to a very material increase in the NSW wholesale electricity price. This is illustrated in Figure 4-10 above, where the greatest decrease in NSW wholesale prices occurs in the 2030s. This is particularly the case in model run 3 (where NEM-wide system stability constraints are imposed on the model) as in the counterfactual scenario without EnergyConnect there is significant amounts of unserved energy in the late 2030s, which does not occur with EnergyConnect. On the other hand, SA becomes a net exporter via EnergyConnect in the late 2030s (as SA wholesale price is on average lower than NSW wholesale price), placing upward pressure on SA wholesale prices, as illustrated in Figure 4-11 above.

4.73 [redacted]

Table 4-2: Impact of EnergyConnect on NSW and SA household bills (average impact, $/MWh/year, 2020 to 2040)

	Impact on NSW household bills			[redacted]		
	Model 1	Model 2	Model 3	[redacted]	[redacted]	[redacted]
Average decrease in wholesale electricity price ($/MWh/year)	**11.0**	**10.5**	**29.6**	[redacted]	[redacted]	[redacted]
Average cost of EnergyConnect ($/MWh/year)	*(2.3)*	*(2.3)*	*(2.3)*	[redacted]	[redacted]	[redacted]
Average change in IC rent ($/MWh/year)	*(0.2)*	*(0.2)*	*(1.2)*	[redacted]	[redacted]	[redacted]
Total average change in transmission charges ($/MWh/year)	**(2.5)**	**(2.4)**	**(3.4)**	[redacted]	[redacted]	[redacted]
Net average impact on consumers ($/MWh/year)	**8.6**	**8.1**	**26.1**	[redacted]	[redacted]	[redacted]
Annual household consumption (MWh)	**4.2**	**4.2**	**4.2**	[redacted]	[redacted]	[redacted]
Annual household savings ($/yr)	**36.2**	**34.1**	**110.1**	[redacted]	[redacted]	[redacted]

Source: FTI analysis. Annual household consumption taken from AEMC, Residential Electricity Price Trends 2019, 9 December 2019 (link) page 20.

Notes: (1) Transmission charges: We have assumed that the cost of EnergyConnect is allocated between NSW and SA consumers based on the average expected wholesale price decrease for each respective region. We have also assumed that all changes in existing interconnector rent are split 50:50 between each connected region, and fully passed onto consumers in each relevant region through transmission charges; (2) Wholesale prices: We assume that changes in wholesale electricity prices are passed onto consumer one-for-one by electricity retailers; (3) Averages: We have taken averages over the period 2020 to 2040.

4.74 As shown in the table above, EnergyConnect may bring net savings of:

- between $34 to $110 per year for NSW households; and
- [redacted]

Appendix 1 Further detail on modelling approach and inputs

A1.1 This appendix contains additional information on the modelling methodology, inputs, assumptions and scenarios discussed in Section 2.

A. Plexos modelling

A1.2 In this report we relied on our in-house power market model that runs on the Plexos® Integrated Energy Model platform.

A1.3 This platform is a dispatch optimisation software based on a detailed representation of the market supply and demand fundamentals at an hourly granularity. Plexos® takes into account power plant characteristics, minimum generation levels, variable opex, an approximation of realistic bidding patterns by generators, and market-driven basis for endogenous building of new capacity.

A1.4 The Plexos® model optimises dispatch in two phases, interlinked by the necessary minimum capacity margin[160] of each region to be maintained throughout the modelling horizon:

- First, the long-term (“LT”) model is used to determine the optimal capacity evolution, based on what combination of generating units meets the minimum capacity margin for each region at minimum cost. The LT model uses three-years of perfect foresight and a simplified chronological load modelling approach (28 blocks for each week) to perform this least-cost optimisation exercise. The LT model is a cost-based model and therefore does not consider the financial viability of generating units (i.e. based on wholesale electricity prices).
- Second, the short-term (“ST”) model takes the capacity from the LT model as given and determines the least-cost generation dispatch on an hourly basis. The ST model also estimates interconnector flows, costs and demand participation.

[160] The capacity margins are defined as the difference between the peak load and the sum of the firm capacity contribution provided by each generating unit and interconnection.

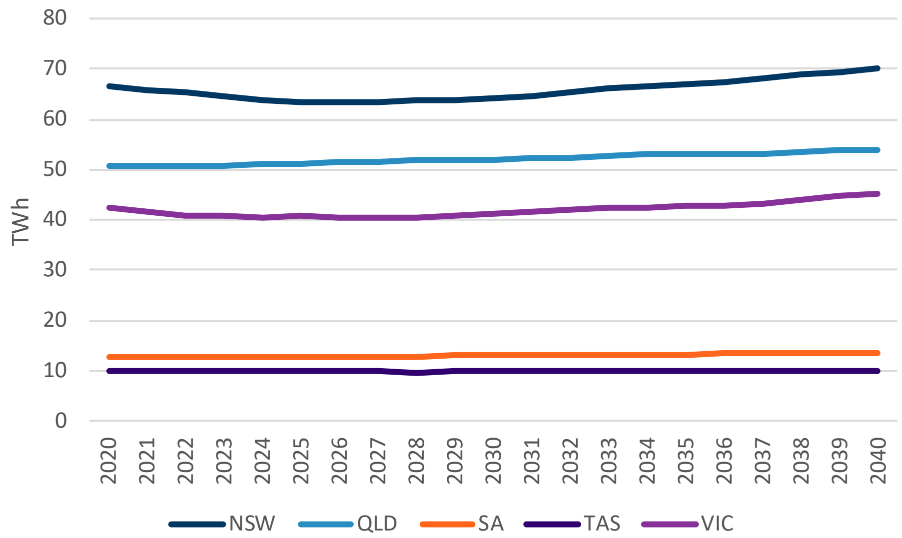
A1.5 The ST uses a SRMC pricing algorithm. Under this methodology, generators bid at their SRMC and will be dispatched if price is greater or equal to their SRMC (or bid).

B. Key modelling inputs

A1.6 The figures and tables in this subsection graphically illustrate the Draft ISP 2020 input assumptions used by our model.

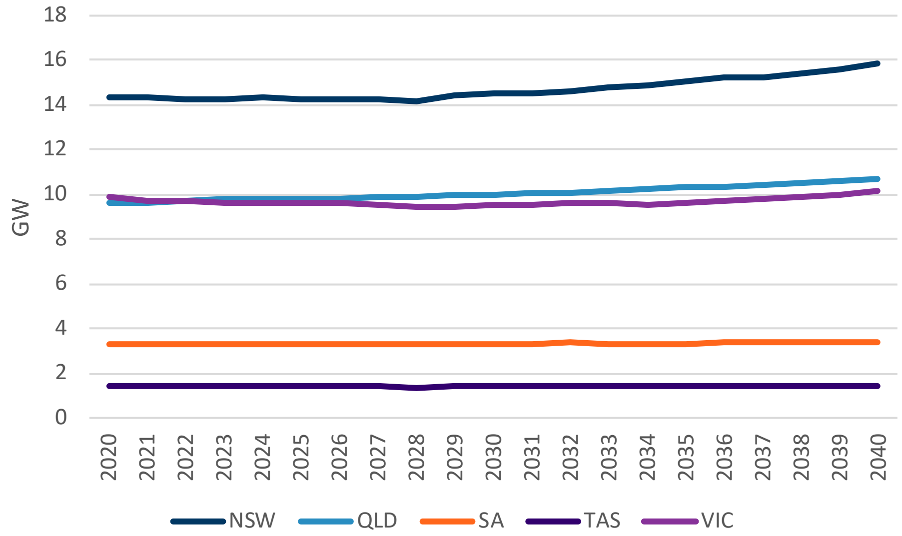
A1.7 All monetary inputs are in real 2019 values and not adjusted for inflation.

Figure A1- 1: Total demand (central scenario)



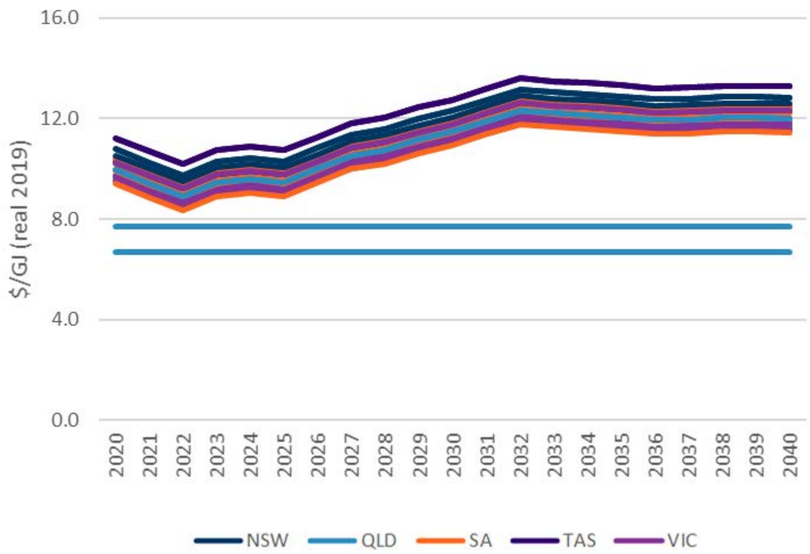
Source: Draft ISP 2020 (published December 2019)
Note: Demand is net of rooftop PV.

Figure A1- 2: Peak demand (10% POE, central scenario)



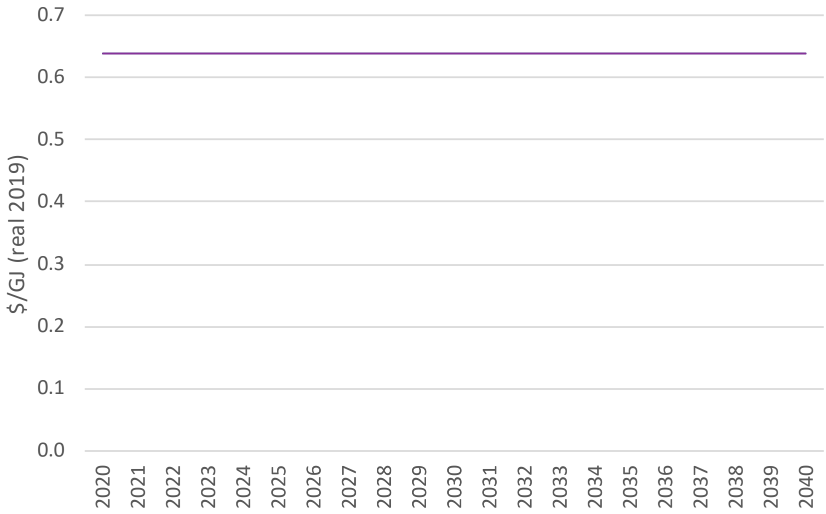
Source: Draft ISP 2020 (published December 2019)
Note: Demand is net of rooftop PV.

Figure A1- 3: Gas prices



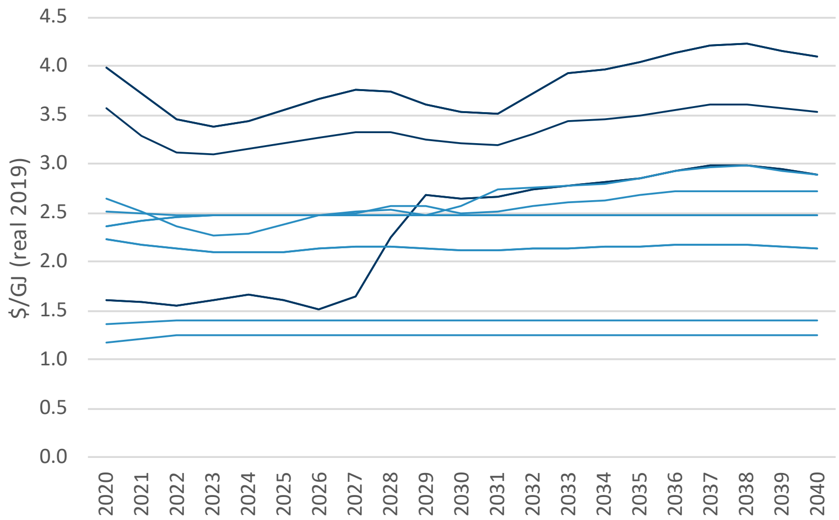
Source: Draft ISP 2020 (published December 2019).
Note: Draft ISP 2020 gas prices are generator specific. Colour of lines indicate the state in which the plant is located.

Figure A1- 4: Brown coal prices



Source: Draft ISP 2020 (published December 2019).
Note: Draft ISP 2020 brown coal commodity prices is the same for all generators and remains constant overtime.

Figure A1- 5: Black coal prices



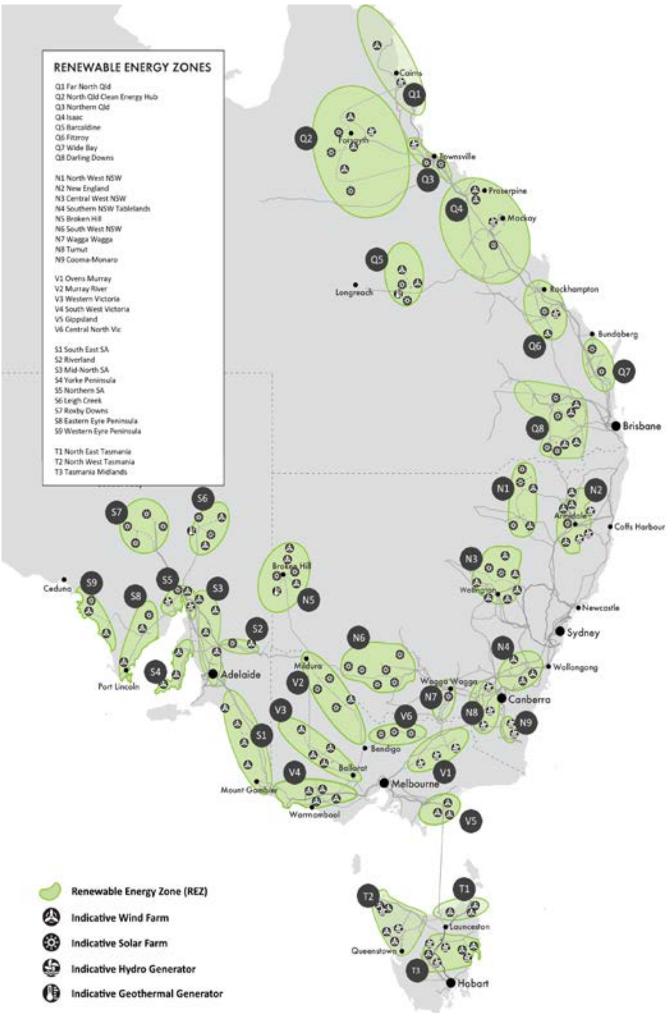
Source: Draft ISP 2020 (published December 2019).
Note: Draft ISP 2020 black coal commodity prices are generator specific. Dark blue line indicates NSW black coal plant, light blue line indicates Qld black coal plant.

Table A1- 1 : Interconnector capacity and commissioning dates

IC	Forward direction capacity	Reverse direction capacity	Modelled from	Included in the counterfactual scenario	Included in the scenario with EnergyConnect
MurrayLink	VIC→SA: 220MW	SA→VIC: 200MW	Start of modelling	✓	✓
Heywood	VIC→SA: 650MW[1]	SA→VIC: 650MW[1]	Start of modelling	✓	✓
Basslink	TAS→VIC: 478MW	VIC→TAS: 478MW	Start of modelling	✓	✓
VNI (Existing)	VIC→NSW: 700MW	NSW→VIC: 400MW	Start of modelling	✓	✓
VNI (Upgrade)	VIC→NSW: 170MW	NSW→VIC: -	1 November 2021	✓	✓
Terranora	QLD→NSW: 150MW	NSW→QLD: 50MW	Start of modelling	✓	✓
QNI (Existing)	QLD→NSW: 1,040MW	NSW→QLD: 415MW	Start of modelling	✓	✓
QNI (Upgrade)	QLD→NSW: 145MW	NSW→QLD: 200MW	1 September 2021	✓	✓
EnergyConnect	NSW→SA: 800MW	SA→NSW: 800MW	1 July 2023	✗	✓

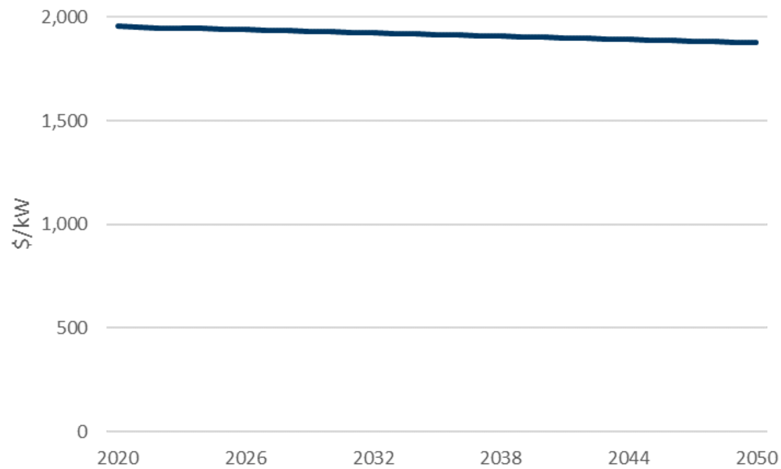
Source: Draft ISP 2020 (published December 2019).
Note: Humelink is implicitly modelled by assuming that there is no congestion once Snowy 2.0 comes online. (1) Heywood flow capacity increases to 750MW in both directions with EnergyConnect.

Figure A1- 6: Renewable Energy Zones



Source: Draft ISP 2020 (published December 2019).

Figure A1- 7: SA Pumped hydro capital cost



Source: Draft ISP 2020 (published December 2019).

A1.8 The table below compares the input assumptions modelled by FTI in this report against the input assumptions used by ElectraNet in the PACR and the preferred set of assumptions outlined by the AER in its determination:

Figure A1- 8: Comparison of input assumptions

Assumption	ElectraNet (PACR)	AER	FTI
Minimum Capacity Factor (Pelican Point 50%, Osborne 60%, Torrens B 25%)	✓	✗	✗
ISP assumptions	ISP 2018	ISP 2018	AEMO Draft ISP 2020
SA gas closures	AEMO modelled retirements as **exogenous** input	**Endogenous**	**Endogenous** (SA gas, except Osborne and Torrens A committed)[1]
Cycling [min on/off time]	NSW black coal [120hrs/12hrs] Gas [24hrs/12hrs]	ACIL Allen (but Torrens B allowed to be [4hrs/4hrs])	ACIL Allen: NSW black coal [8hrs/8hrs] Osb & PP [4hrs/4hrs] Torrens B [1hrs/1hrs]
Minimum load	Redacted	Redacted	AEMO Draft ISP 2020
Start up cost	Not modelled	Consider them reasonable to include	ACIL Allen (average of cold, warm and hot start)
Two synchronous units online at all times[2]	✓	✓	✓
Inertia capability (i.e. ROCOF constraint)	1,300 MW	4,400 MW	4,400 MW
Non-synchronous cap	1,870 MW	2,000 MW	2,000 MW
Interconnector flow limits – Heywood and combined Heywood + Energy Connect	✓	✓	✓
ESOO stability constraints (additional to those mentioned above)	Some SA voltage constraints	Unknown	Different combinations of SA and NEM constraints[3]
Capital cost of SA pumped hydro	$1.4m/MW	$1.9m/MW	~$1.9m/MW (AEMO Draft ISP 2020 Central)

Source: FTI analysis, ElectraNet, SA Energy Transformation RIT-T - PACR, February 2019 (link), AER, Decision: South Australian Energy Transformation, January 2020 (link).

Notes: (1) only SA gas units were modelled endogenous due to modelling limitations (see ¶A1.10 below for further detail). (2) This refers to the existing requirement for four synchronous units to be online at all times before the installation of four synchronous condensers (end 2020). This requirement is expected to reduce to two units after the synchronous condensers are installed and zero units after EnergyConnect is commissioned. (3) As explained in ¶2.16, we have tested three combinations of stability constraints.

C. Generator retirements and new build capacity

A1.9 With respect to generator retirements, we have assumed that generators across the NEM (with the exception of SA gas plants)[161] will retire as per the announced (or expected) retirement dates outlined by AEMO in Draft ISP 2020. These retirement dates are outlined in Table A1- 2 below:

Table A1- 2: Existing generator retirement dates (up to and including 2040)

Generator	Expected closure year
Bayswater	2035
Eraring	2031
Liddell	2022 (1 unit); 2023 (3 units)
Vales Point B	2029
Callide B	2028
Gladstone	2035
Tarong	2036 (2 units); 2037 (2 units)
Tarong North	2037
Yallourn W	2029
Kareeya	2037
Barcaldine Power Station	2034
Condamine A	2039
Roma	2034
Swanbank E GT	2028
Somerton	2033
Jeeralang A	2039
Jeeralang B	2039
Newport	2039
Hallett GT	2032
Dry Creek GT	2030
Ladbroke Grove	2034
Mintaro GT	2030
Osborne	**2023**
Torrens Island A	**2020 (2 units); 2021 (1 unit); 2022 (1 unit)**
Bell Bay Three	2040
Hunter Valley GT	2035
Mackay GT	2021
Mt Stuart	2033
Port Lincoln GT	2030

161 The retirement dates of Torrens Island A and Osborne are treated as committed. See ¶A1.11 below for further detail.

Generator	Expected closure year
Snuggery	2030
Boco Rock Wind Farm	2040
Capital Wind Farm	2040
Taralga Wind Farm	2040
Cullerin Range Wind Farm	2038
White Rock Wind Farm - Stage 1	2037
Gunning Wind Farm	2036
Sapphire Wind Farm	2037
Bald Hills Wind Farm	2040
Challicum Hills Wind Farm	2033
MacArthur Wind Farm	2038
Waubra Wind Farm	2039
Yambuk Wind Farm	2040
Oaklands Hill Wind Farm	2037
Hallett 5 The Bluff WF	2036
Cathedral Rocks Wind Farm	2037
Clements Gap Wind Farm	2039
Canunda Wind Farm	2030
Hallett Stage 1 Brown Hill	2033
Hallett Stage 2 Hallett Hill	2035
Lake Bonney 1 Wind Farm	2035
Lake Bonney 2 Wind Farm	2038
Lake Bonney 3 Wind Farm	2040
Mount Millar Wind Farm	2036
Hallett 4 North Brown Hill	2036
Snowtown S2 Wind Farm - North	2034
Snowtown S2 Wind Farm - South	2034
Snowtown Wind Farm	2028
Starfish Hill Wind Farm	2033
Wattle Point Wind Farm	2029
Coleambally Solar Farm	2038
White Rock Solar Farm	2037
Darling Downs Solar Farm	2035
Kidston Solar Project Phase One 50MW	2037
Dalrymple BESS	2030
Ballarat Energy Storage System	2033
Bulgana Green Power Hub - BESS	2034
Gannawarra Energy Storage System	2033

Source: Draft ISP 2020 (published December 2019).

A1.10 However, Plexos® has the ability to endogenously consider whether a generator is required to meet system capacity requirements at least cost, or whether it is not required and should retire. Allowing Plexos® to endogenously consider the retirement decisions of all generators across the NEM is not feasible due to the computational requirements, therefore we have only endogenised the retirement decisions for SA gas units. We allow Plexos® to decide whether to close these units early or keep them open for longer.[162]

A1.11 The exceptions to this are Torrens Island A and Osborne. The announced retirement dates for these units are treated as committed. Three years of notice must be given for any planned generator retirement.[163] The owners of Torrens Island A have already announced their intentions to retire this generator unit-by-unit between 2020 and 2022[164] and the owners of Osborne are expected imminently to announce formally their intentions to retire all Osborne units in 2023.[165]

A1.12 Table A1- 3 outlines the retirement decisions for specific SA gas units:

162 This is performed using the Plexos® Long Term ("LT") model. In stage one, the model makes decisions on a linear basis (i.e. it can decide to partially close a unit). In stage two, the results from stage one are used to decide whether to retire a full unit, or keep the full unit open: if remaining unit capacity is less than 50%, the unit is fully retired. However, in applying this decision criteria, the aggregate remaining plant capacity is considered (i.e. partially open units are aggregated where possible).

163 AEMC, National Electricity Amendment (Generator Three Year Notice of Closure) Rule 2019, November 2018 (link).

164 AGL, Schedule for the closure of AGL plants in NSW and SA, August 2019 (link).

165 Australian Energy Council, South Australia's surprise RRO, January 2020 (link).

Table A1- 3: Modelled retirement decisions for SA gas units

Generator unit	Retirement year without EnergyConnect	Retirement year with EnergyConnect	Modelling approach (exogenous or endogenous)
Osborne GT	2023	2023	Exogenous
Osborne ST	2023	2023	Exogenous
Torrens A 1	2021	2021	Exogenous
Torrens A 2	2020	2020	Exogenous
Torrens A 3	2022	2022	Exogenous
Torrens A 4	2021	2021	Exogenous
Pelican Pt GT 1	Does not close	Does not close	Endogenous
Pelican Pt GT 2	Does not close	Does not close	Endogenous
Pelican Pt ST	Does not close	Does not close	Endogenous
Torrens B 1	Does not close	2023	Endogenous
Torrens B 2	Does not close	2027	Endogenous
Torrens B 3	Does not close	2024	Endogenous
Torrens B 4	Does not close	2024	Endogenous

Source: Draft ISP 2020 (exogenous) and FTI Plexos® model (endogenous).

A1.13 In Draft ISP 2020, AEMO outlines the expected commissioning dates for committed new capacity. Our Plexos® model takes the commissioning of this capacity, outlined in Table A1- 4 below, as an exogenous input:

Table A1- 4: Capacity and commissioning date for committed new generation

Generator unit	Region	Installed capacity (MW)	Commissioning date
Barker Inlet Power Station	SA	210	November 2019
Coopers Gap Wind Farm	QLD	453	April 2020
Kennedy Energy Park Wind Farm	QLD	43	August 2019
Crowlands Wind Farm	VIC	80	July 2019

Generator unit	Region	Installed capacity (MW)	Commissioning date
Cattle Hill Wind Farm	TAS	154	January 2020
Granville Harbour Wind Farm	TAS	112	April 2020
Bulgana Green Power Hub - Wind Farm	VIC	204	August 2019
Cherry Tree Wind Farm	VIC	58	June 2020
Dundonnell Wind Farm	VIC	336	July 2020
Lal Lal Elaine Wind Farm	VIC	84	July 2019
Lal Lal Yendon Wind Farm	VIC	144	July 2019
Lincoln Gap Wind Farm - stage 2	SA	86	May 2020
Moorabool Wind Farm	VIC	320	June 2020
Murra Warra Wind Farm - stage 1	VIC	226	January 2020
Stockyard Hill Wind Farm	VIC	532	May 2020
Bomen Solar Farm	NSW	121	April 2020
Darlington Point Solar Farm	NSW	275	December 2019
Molong Solar Farm	NSW	30	June 2020
Nevertire Solar Farm	NSW	105	July 2019
Sunraysia Solar Farm	NSW	229	October 2019
Bungala Two Solar Farm	SA	135	March 2020
Maryrorough Solar Farm	QLD	35	March 2020
Haughton Solar Farm	QLD	133	September 2019
Kennedy Energy Park Solar Farm	QLD	15	August 2019
Lilyvale Solar Farm	QLD	100	September 2019
Finley Solar Farm	NSW	162	October 2019
Limondale Solar Farm 1	NSW	220	May 2020
Limondale Solar Farm 2	NSW	29	December 2019

Generator unit	Region	Installed capacity (MW)	Commissioning date
Oakey Solar Farm	QLD	25	August 2019
Oakey 2 Solar Farm	QLD	56	October 2019
Rugby Run Solar Farm	QLD	65	November 2019
Yarranlea Solar Farm	QLD	103	November 2019
Warwick Solar Farm	QLD	64	June 2020
Kiamal Solar Farm stage 1	VIC	200	October 2019
Numurkah Solar Farm	VIC	112	September 2019
Yatpool Solar Farm	VIC	94	November 2019
Cohuna Solar Farm	VIC	31	November 2019
Snowy 2.0	NSW	2040	March 2025

Source: Draft ISP 2020.

A1.14 With respect to additional new build capacity, Plexos® endogenously determines the optimal amount of capacity that should be built to ensure minimum capacity margin is met at minimum cost while respecting the following constraints detailed below:

- **Minimum capacity margin by region**: Each region has a specific capacity margin – defined as the difference between the peak load and the sum of the firm capacity contribution provided by each generating unit and interconnection – that must be maintained. Different technology types contribute different amounts of 'firm' capacity to meet the minimum capacity margin, which is considered by the model in deciding the technology of new build capacity.
- **Cost of new build capacity**: The model considers capex and opex of each technology type, annuitised over the asset's life at an appropriate discount rate.[166]

[166] Our model uses 5.9%, which is AEMO's central scenario WACC estimate. Source: AEMO, Draft 2020 Integrated System Plan, December 2019 (link).

- **Renewable energy targets**: The model ensures that state and federal renewable energy targets are met.[167]
- **REZ capacity and expansion cost**: New build renewable capacity is built in REZ. Each REZ has a transmission limited build limit (i.e. new capacity that can be built without transmission reinforcements), transmission expansion cost (i.e. cost of transmission reinforcements, which allow additional new capacity to be built in a given REZ) and total build limit (i.e. maximum new capacity in a given REZ that cannot be surpassed).

D. Further detail on stability constraints imposed in each scenario

A1.15 Table A1- 5 below outlines the constraints imposed in each model run:

[167] This includes the Large-scale Renewable Energy Target ("LRET"), Victorian Renewable Energy Target ("VRET") and Queensland Renewable Energy Target ("QRET").

Table A1- 5: Modelling constraints

Tighter system →

Constraint name	Constraint description	Model run 1: SA subset		Model run 2: All SA		Model run 3: NEM	
		Baseline	PEC	Baseline	PEC	Baseline	PEC
Draft ISP 2020 constraints							
Combined Heywood + Energy Connect flow limit	*Combined flow limited to 1,300 MW from NSW to SA and 1,450 MW from SA to NSW. This constraint is taken from the Draft ISP 2020 assumptions.*	✗ n/a	✓	✗ n/a	✓	✗ n/a	✓
Heywood flow limit	*Flow limit in both directions on Heywood. Limited to 650MW without Energy Connect, limit increased to 750MW with Energy Connect.*	✓ 650MW	✓ 750MW	✓ 650MW	✓ 750MW	✓ 650MW	✓ 750MW
ESOO stability constraints (based on ESOO 2019 ISP sensitivity)							
ROCOF constraint	*Ensures there is sufficient inertia to prevent RoCoF exceeding 3Hz/sec if there's an unexpected loss of Heywood. Constraint improves by 500MW after 4 synchronous condensers installed (end 2020).*	✓	✗ Removed after PEC	✓	✗ Removed after PEC	✓	✗ Removed after PEC
Non-synchronous generation cap	*Limits non-synchronous generation to 2,000MW (cap increased by flow on Heywood).*	✓	✗ Removed after PEC	✓	✗ Removed after PEC	✓	✗ Removed after PEC
Synchronous generation in SA	*Requirement for 4 units to run before 4 synchronous condensers installed (end 2020), 2 units afterwards.*	✓	✗ Removed after PEC	✓	✗ Removed after PEC	✓	✗ Removed after PEC
Contingency in case of loss of large SA generation block	*Protect voltage and transient stability in case of the loss of a large generation block in SA.*	Not applied	Not applied	✓	✗ Removed after PEC	✓	✗ Removed after PEC
Other transient stability constraints	*AEMO outline various constraints for transient stability. AEMO do not specify how these would change with Energy Connect, so we have assumed they remain constant.*	Not applied	Not applied	✓ SA only	✓ SA only	✓	✓
Other voltage stability constraints	*AEMO outline various constraints for voltage stability. AEMO do not specify how these would change with Energy Connect, so we have assumed they remain constant.*	Not applied	Not applied	✓ SA only	✓ SA only	✓	✓
Transmission outage constraints	*These constraints are outlined by AEMO and model the impact of transmission outages, which are very low probability events.*	Not applied	Not applied	Not applied	Not applied	Not applied	Not applied
Thermal constraints	*Manage the power flow on a transmission element so it does not exceed a rating (either continuous or short term) under normal conditions or following a credible contingency.*	Not applied	Not applied	Not applied	Not applied	Not applied	Not applied

A1.16 In order to make AEMO's ESOO ISP sensitivity constraint workbook functional with our model, we made a number of updates to generators names. These changes were 'presentational' as they reflected that our model has slightly different names for the same generator. The substance of the constraint did not change.

A1.17 In addition, we also made the following changes to the definition of the constraints themselves:

- All REZ were added to the workbook.
- New build SA REZ were included in the cap on SA non-synchronous generation.
- The value of the SA non-synchronous cap was increased from 1,870MW to 2,000MW.

A1.18 All other amendments (i.e. those made following the introduction of four synchronous condensers in SA and EnergyConnect) are outlined in Table A1- 5 above.

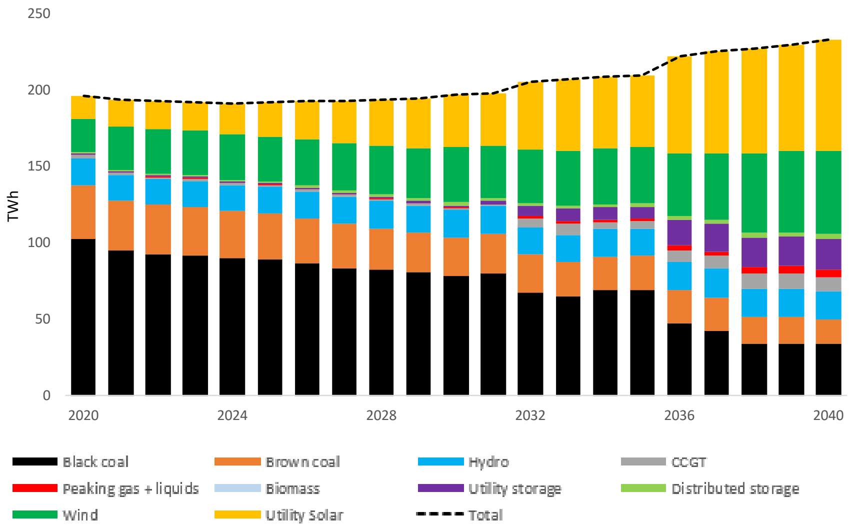
Appendix 2 Further detail on modelling outputs

A2.1 This appendix presents the modelling results for all three model runs. Each model run uses a different combination of stability constraints (see Table A1- 5 for further detail on the different model runs).

A. Generation

A2.2 Figure A2- 1 below presents the modelled counterfactual NEM generation, without EnergyConnect:

Figure A2- 1: NEM generation profile, without EnergyConnect (Model Run 3)

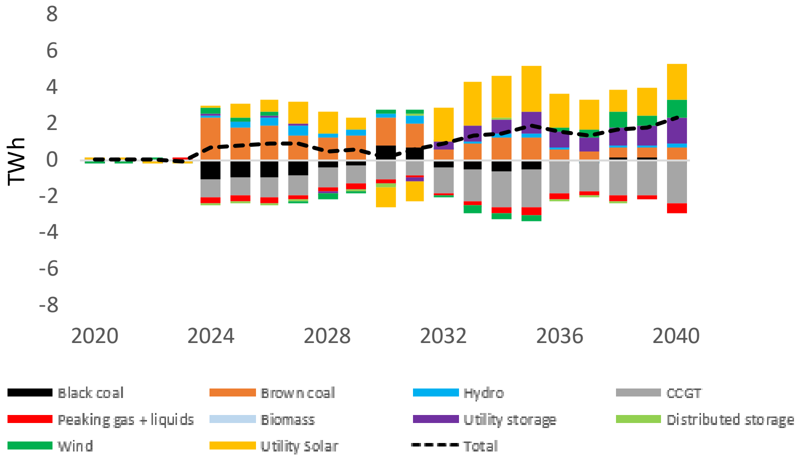


Source: FTI analysis.

A2.3 The share of conventional thermal generation (black coal, brown coal, CCGT and peaking gas + liquids) is forecast to decline from 72% of total TWh output in 2020 to 27% of total TWh output in 2040. Renewables and storage (this includes solar, wind, hydro and storage – both utility and distributed) are forecast to grow from 28% to 73% (as percentage of total output) over the same period.

A2.4 Figure A2- 2 below shows how the forecast NEM generation profile changes with EnergyConnect:

Figure A2- 2: Change in NEM generation with EnergyConnect (Model Run 3)

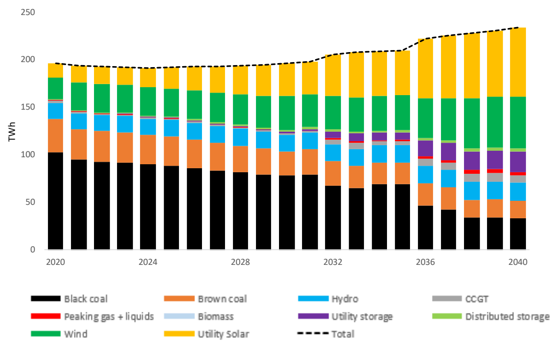


Source: FTI analysis.

A2.5 In the 2020s, SA gas generation and NSW black coal generation are displaced predominately by Vic brown coal, which is a relatively less expensive form of generation. This displacement is facilitated by exports of brown coal generation from Vic to SA, with some of this brown coal generation being transported onwards to NSW via EnergyConnect. In the 2030s, SA gas generation continues to be displaced, but is displaced by a combination of brown coal (Vic), new solar generation (SA and NSW) and storage (NSW).

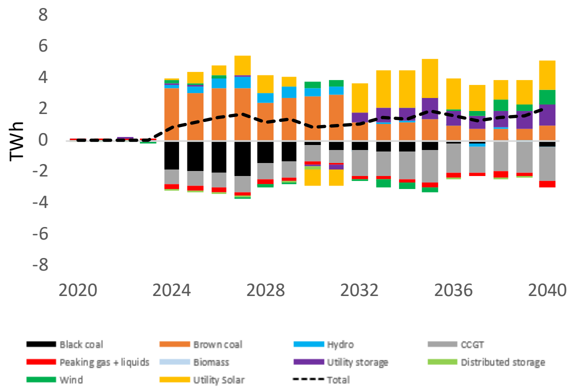
A2.6 The optimal generation profile across the NEM differs across the model runs as it is impacted by the stability constraints. Figure A2- 3 to Figure A2- 4 below present NEM generation without EnergyConnect and the change in NEM generation with EnergyConnect for Model Run 1 (subset of SA constraints) and Model Run 2 (all SA constraints).

Figure A2- 3: NEM generation profile, without EnergyConnect (Model Run 1)



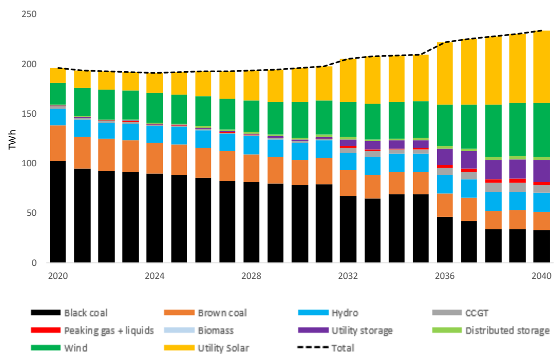
Source: FTI analysis.

Figure A2- 4: Change in NEM generation with EnergyConnect (Model Run 1)



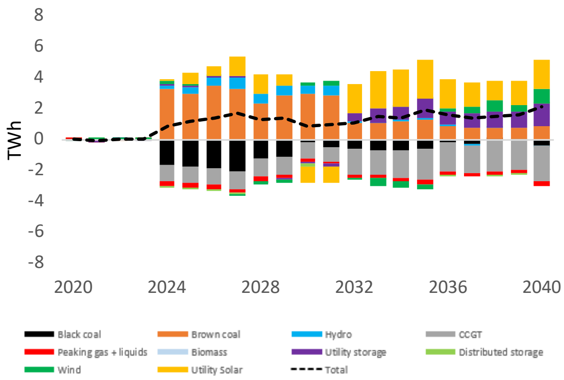
Source: FTI analysis.

Figure A2- 5: NEM generation profile, without EnergyConnect (Model Run 2)



Source: FTI analysis.

Figure A2- 6: Change in NEM generation with EnergyConnect (Model Run 2)



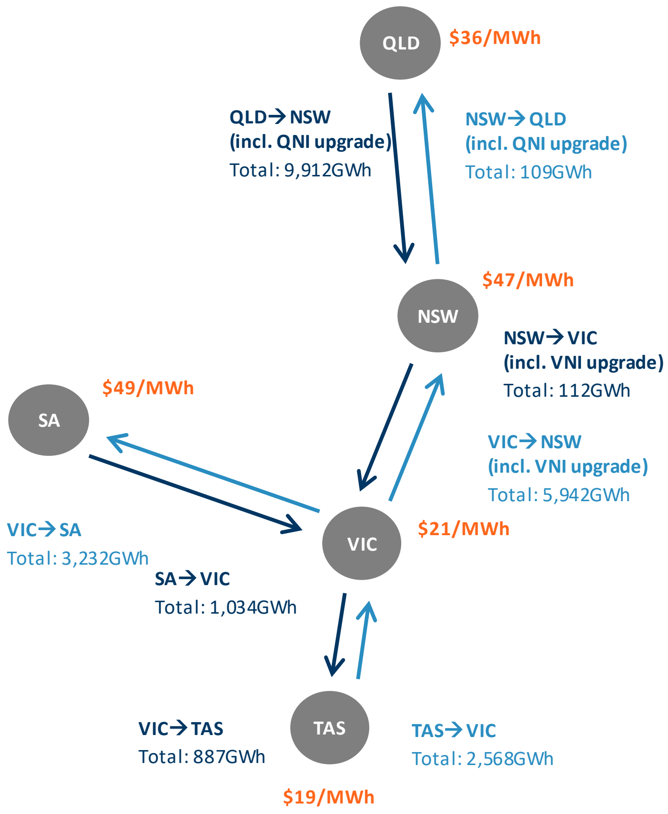
Source: FTI analysis.

B. Interconnector flows

A2.7 Interconnector flows help to explain the changes in modelled generation profile observed across the NEM with EnergyConnect. We examine modelled interconnector flows in snapshot years 2027 and 2035 to provide additional detail on the key dynamics brought about by EnergyConnect in the 2020s and 2030s respectively.

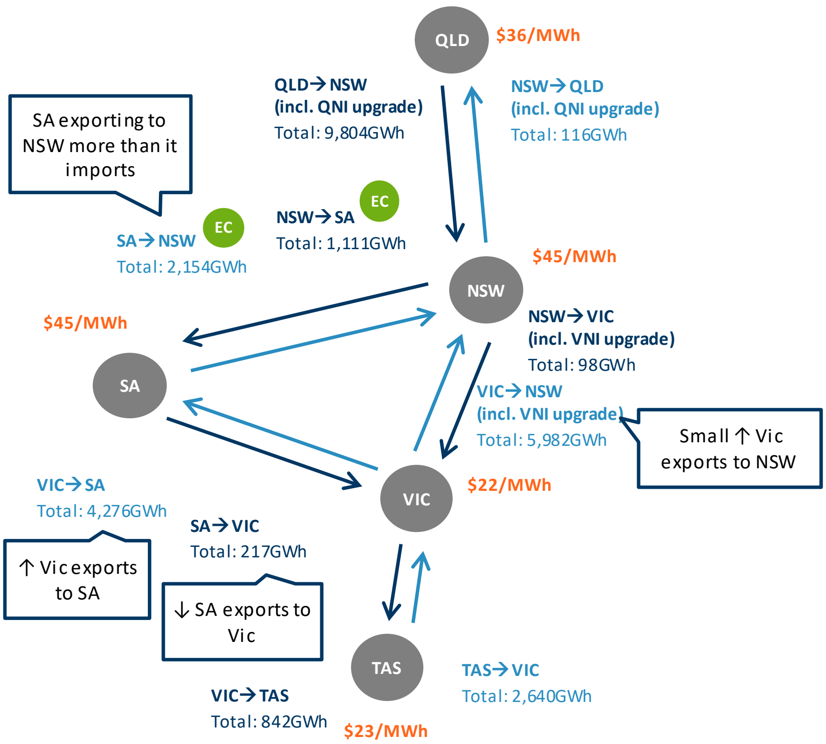
A2.8 EnergyConnect most commonly flows from SA to NSW in the 2020s as brown coal flows through from Vic and excess SA renewables are exported. In the 2030s, flows from SA to NSW increase as SA generation helps cover for retired NSW black coal.

Figure A2- 7: NEM interconnector flows in 2027 without EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

Figure A2- 8: NEM interconnector flows in 2027 with EnergyConnect

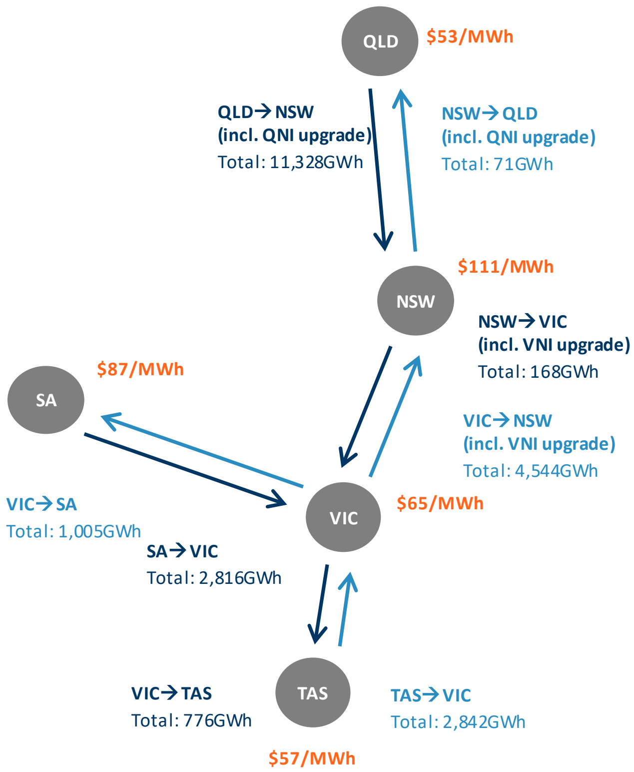


Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

A2.9 EnergyConnect is expected to flow in the direction of SA to NSW most often in 2027. Furthermore, the following changes to flows on existing interconnectors are also observed with EnergyConnect in 2027:

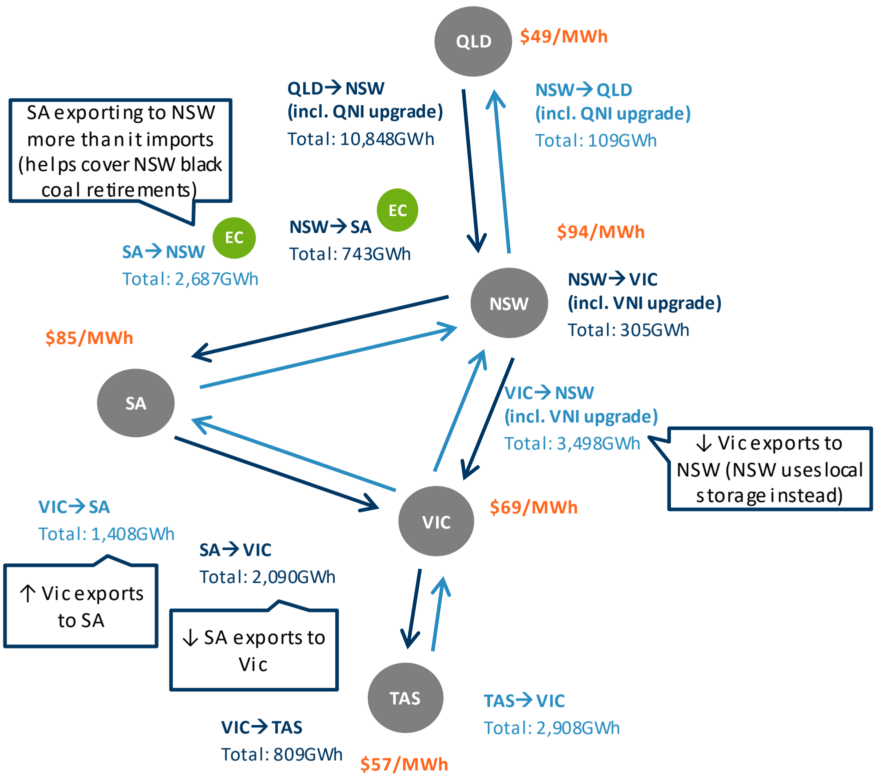
- SA exports to Vic via Heywood and MurrayLink significantly decrease (from 1,034GWh to 217GWh).
- Vic exports to SA significantly increase (from 3,232GWh to 4,276GWh) such that Heywood and Murraylink are almost always flowing towards SA.
- Exports from Vic to NSW increase marginally (from 5,942GWh to 5,982GWh), resulting in a small incremental displacement of NSW black coal by Vic brown coal via this route. However, further displacement of NSW black coal by Vic brown coal occurs through flows via SA on EnergyConnect.

Figure A2- 9: NEM interconnector flows in 2035 without EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

Figure A2- 10: NEM interconnector flows in 2035 with EnergyConnect



Source: FTI analysis.
Note: Model Run 3 (NEM constraints).

A2.10 In 2035, the following changes to interconnector flows are observed:

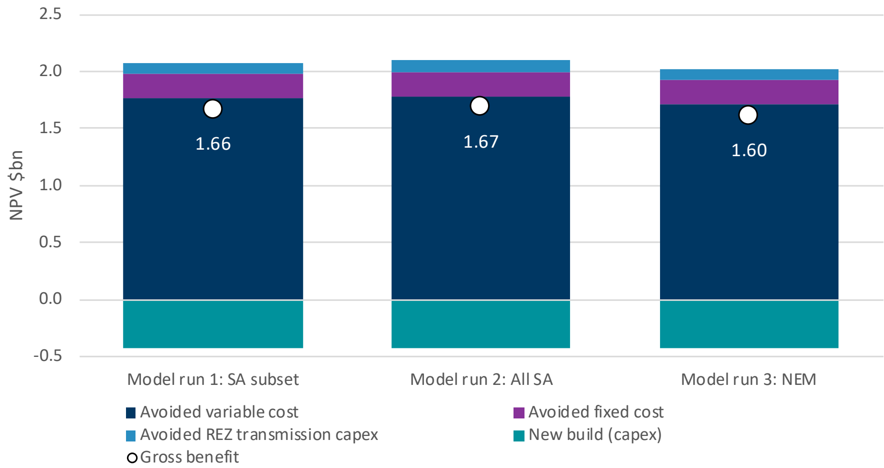
- SA exports to Vic decrease (from 2,816GWh to 2,090GWh, but are higher than in 2027) as excess SA generation flows to NSW instead.
- Vic exports to SA increase (from 1,005GWh to 1,408GWh, although are lower than in 2027) reflecting that there is still an increase in Vic brown coal exports with EnergyConnect, but this is lower in the 2030s because there is less brown coal available following the retirement of Yallourn.
- Vic exports to NSW decrease (from 4,544GWh to 3,498GWh), as NSW imports renewable energy from SA and uses local storage instead.
- SA exports to NSW (2,687GWh) via EnergyConnect much more often than it imports (743GWh). SA exports of renewable energy and gas generation increase as black coal retires in NSW.

C. Gross benefit

A2.11 The quantum of avoided variable cost is dependent on the modelling constraints imposed. However, the different sets of constraints do not impact the overall trends or the qualitative findings discussed in Section 3A.

A2.12 In each model run, avoided variable cost is the main driver of gross benefit, as illustrated in Figure A2- 11 below:

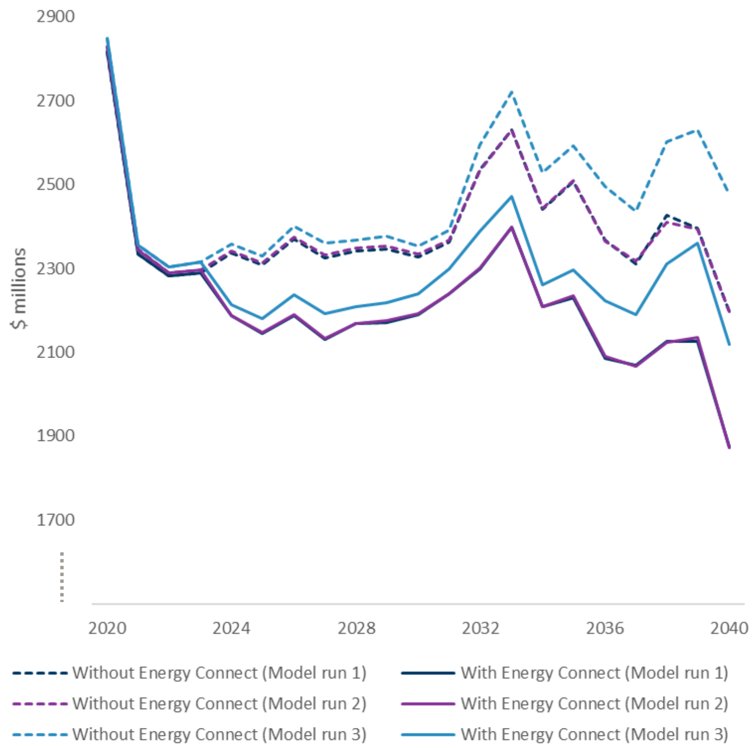
Figure A2- 11: NEM gross benefit (2020 to 2040)



Source: FTI analysis.

A2.13 Furthermore, in each model run, avoided fuel cost remains the most significant component of avoided variable cost, and therefore the single biggest benefit of EnergyConnect. The impact of EnergyConnect on total NEM fuel cost is presented in Figure A2- 12 below:

Figure A2- 12: NEM fuel cost, with and without EnergyConnect (2020 to 2040)



Source: FTI analysis.
Note: Model Run 1 (dark blue) is almost identical to model run 2 (purple).

A2.14 Avoided fixed cost and capex from new build capacity are both constant across all model runs (because they are dependent on capacity expansion, which is unaffected by the stability constraints).[168] Avoided REZ transmission capex is also constant across all model runs.

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[168] Stability constraints are only applied in the ST model, therefore capacity expansion (determined by the LT) is unaffected by the stability constraints.

Appendix 3 Wider quantitative benefits of EnergyConnect

A3.1 This appendix contains additional information on:

- benefits of EnergyConnect under the RIT-T framework for the 2040 – 2073 modelling period (Part A); and
- net consumer benefit (Part B).

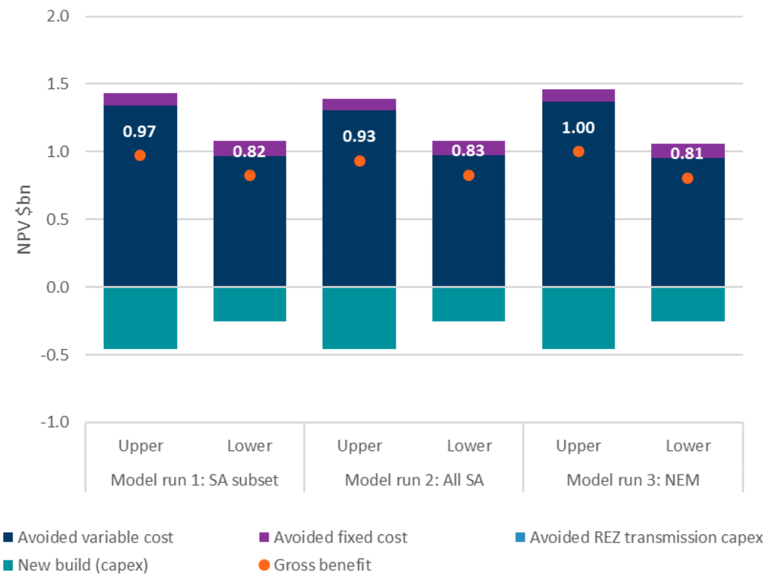
A. Benefits of EnergyConnect post 2040

A3.2 As explained in Section 4 above, for gross benefits for the 2040 to 2073 period we estimated:

- an upper bound assuming the incremental benefit of EnergyConnect after 2040 will be equal to the annual average of the final three modelled years (i.e. 2038 to 2040 inclusive); and
- a lower bound assuming the incremental benefit of EnergyConnect after 2040 will be equal to the annual average from the asset's modelled life.

A3.3 The results for all model runs are presented in the figure below.

Figure A3- 1: Estimated post-2040 benefits (discounted to 2020)

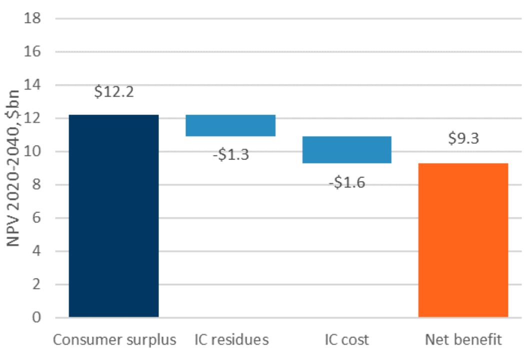


Source: FTI analysis.

B. Net consumer benefit

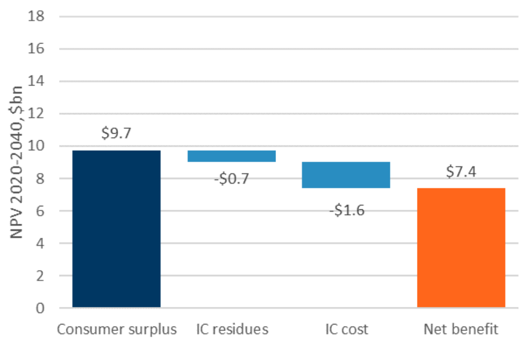
A3.4 This subsection breaks down net consumer benefit (discussed in Section 4) by model run. The following Figures outline the results for each model run in turn.

Figure A3- 2: Net consumer surplus from EnergyConnect (Model Run 1)



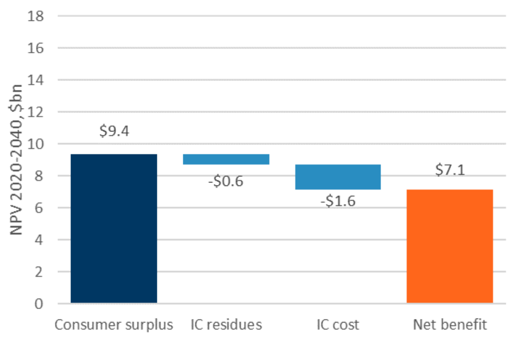
Source: FTI analysis. Assumes total capex of $3.0 billion and annual opex of $5 million.

Figure A3- 3: Net consumer surplus from EnergyConnect (Model Run 2)



Source: FTI analysis. Assumes total capex of $3.0 billion and annual opex of $5 million.

Figure A3- 4: Net consumer surplus from EnergyConnect (Model Run 3)



Source: FTI analysis. Assumes total capex of $3.0 billion and annual opex of $5 million.

Appendix 4 Non-monetary benefits from other jurisdictions

A4.1 In this appendix, we provide further information on the assessment of additional, qualitative or quantitative effects on energy systems, that cannot be expressed in monetary terms, referred to as non-monetary benefits.

A4.2 We describe the policy that regulators and other relevant policy makers apply in considering non-monetary benefits, focusing on GB (Section A), Europe (Section B) and the US (Section C).

A. Great Britain

A4.3 The Cap and Floor regime is the regulated route for interconnection investment within GB.[169] The regime sets a regulated maximum (cap) and minimum (floor) amount of congestion revenue that an interconnector can retain from operating the asset, but maintains a band of "merchant" exposure in between the cap and the floor levels[170] which exposes developers to some of the variability in the congestion revenues earned by the interconnector.

A4.4 Ofgem's primary consideration in its Cap and Floor assessment is the social welfare impacts for British consumers, although the change in total GB welfare (i.e. change in consumer, producer and interconnector welfare) is also considered.[171] This differs from the approach the RIT-T takes, which focuses on the total social welfare impact of prospective investments.

A4.5 Applications for a Cap and Floor are made within 'windows'. During Window 2, which was open from March 2016 to October 2016, three applications were submitted and approved to progress by Ofgem: GridLink, NeuConnect and NorthConnect (each of which is described in more detail further below).

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169 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

170 Ofgem, Cap and floor regime summary for the second window, May 2016 (link).

171 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

A4.6 **Assessment process:** During the initial project assessment ("IPA"), Ofgem assesses projects on the basis of developers' submissions, its own modelling of the impacts, and the information provided by the system operator.[172] This assessment is made in line with Ofgem's Impact Assessment Guidance.

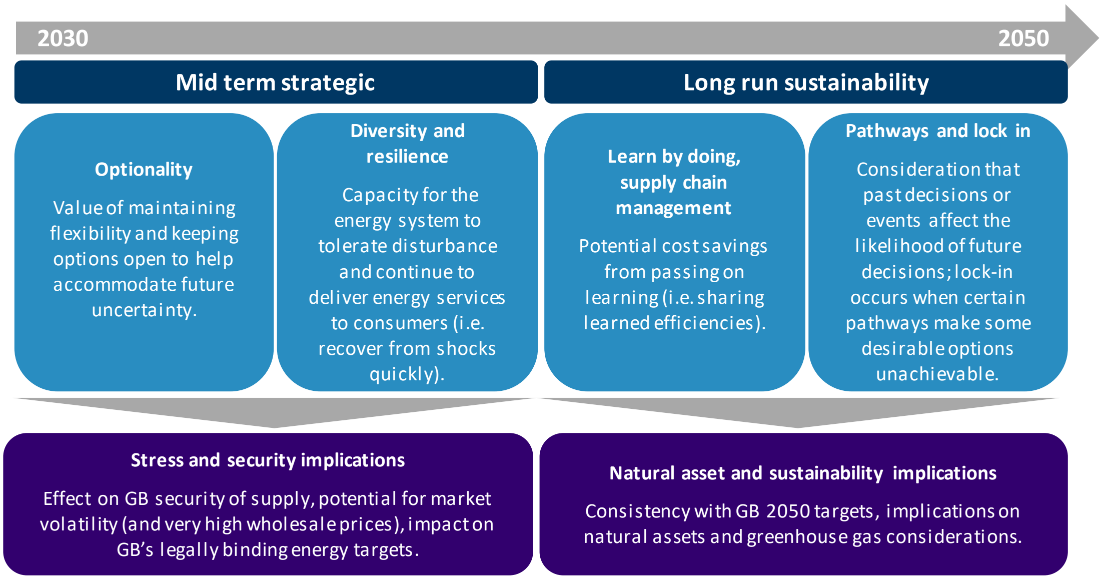
A4.7 Specific elements included in the assessment are:

- a quantified cost-benefit analysis against a range of scenarios;
- the associated societal welfare, interconnector and generator effects for GB;
- a qualitative evaluation on any non-monetary benefits (referred to as "hard-to-monetise" benefits), costs and risks that are not reflected in the modelling study; and
- location, technical design and feasibility.

A4.8 The hard-to-monetise assessment considers information received from the developers as well as Ofgem's own qualitative analysis. The assessment is concerned with longer-term sustainability and strategic issues. Figure A4- 1 below outlines the general framework used by Ofgem for identifying hard-to-monetise benefits.

[172] Ofgem, Decision to open a second cap and floor application window for electricity interconnectors in 2016, November 2015 (link), page 7.

Figure A4- 1: Ofgem's framework for assessing hard-to-monetise benefits



Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

A4.9 Ofgem does not explicitly 'weight' the importance of monetary factors relative to hard-to-monetise benefits; and the three interconnectors that were assessed within the second Cap and Floor Window (GridLink, NeuConnect and NorthConnect) passed the quantitative benefit assessment. This was also the case with interconnectors assessed in Window 1.

A4.10 Therefore, to date, it appears that hard-to-monetise benefits have been used as supporting evidence for interconnector investment, in addition to monetary considerations, rather than as a deciding factor on whether to approve the project. This is because all interconnectors assessed so far under the Cap and Floor regime have passed Ofgem's quantitative assessment and hard-to-monetise benefits have been used as additional support for these interconnectors. The importance of hard-to-monetise benefits has not been tested in cases where the investment might be more marginal.

A4.11 In the subsections below, we outline Ofgem's assessment of hard-to-monetise benefits for the three interconnectors assessed in the second Cap and Floor Window.

Case study: GridLink

A4.12 GridLink is a proposed 1.4GW electricity interconnector between GB and France. If built, it will connect two countries with complementary generation mixes:

- **<u>In GB:</u>** Gas plants form the most significant part of GB's electricity mix, alongside contributions from coal (prior to the planned phase-out), nuclear and renewable generation.

- **<u>In France:</u>** The majority of France's electricity generation is provided by nuclear plants, with hydro generation being the second most significant contributor.[173]

A4.13 In its IPA, Ofgem stated that:[174]

- "*GridLink is expected to provide net positive strategic and sustainable impacts. These are brought about by increasing the level of connection to a market with a **significantly different and low-carbon electricity mix** (e.g. 78% of France's electricity generated from nuclear) and a growing proportion of renewable energy. This would contribute to GB security of supply and the achievement of long-term carbon targets.*" (emphasis added)

- The scenarios of the ENTSO-E network development plan to 2030, which was the most recent plan available at the time, "*expect lower but significant levels of nuclear and an increase in generation from RES in France's electricity mix, showing consistent long-term benefits.*".

A4.14 A summary of Ofgem's assessment of the hard-to-monetise benefits of GridLink is outlined in Table A4- 1 below:

Table A4- 1: Summary of Ofgem's hard-to-monetise assessment of GridLink

Type of benefit	Ofgem's description	Ofgem's rating
Connecting new providers of balancing services to the GB System Operator ("SO")	A National Grid Electricity Transmission ("NGET") report shows that *"GridLink can provide benefits through provision of ancillary services. Good balancing arrangements are currently in place between the GB and French TSOs, but existing connections with France may limit benefits"*	Slight positive impact

173 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), page 41.

174 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), page 41.

Type of benefit	Ofgem's description	Ofgem's rating
Providing alternative solutions to increase GB security of supply	o *Access to high levels of nuclear generation in France leads to increase in fuel diversity;* o *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* o *The high level of availability of the interconnector provides additional system security to the GB system.*	Strongly positive impact
Supporting the decarbonisation of energy supplies	*High mix of imported low-carbon generation will displace GB thermal.*	Strongly positive impact

Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

A4.15 There is no official methodology published that explains how Ofgem determines the ratings outlined in the table above.

Case study: NeuConnect

A4.16 NeuConnect is a planned 1.4GW interconnector, of around 720 km, and would be a first direct undersea power link between Germany and GB.[175] The interconnector would join two areas with high amounts of wind generation: the south east coast of GB and the North Sea coast of Germany.

A4.17 In its IPA, Ofgem stated that:[176]

- *"By connecting to a new market, NeuConnect is likely to provide net positive strategic and sustainable impacts. While the electricity generation mix in Germany is similar to GB, they have higher shares of generation from renewables which are expected to continue to increase in all TYNDP 2030 scenarios."*

- *"NeuConnect is expected to maximise the value of GB and German renewables through efficient dispatch across the two markets, particularly wind. The flow of weather patterns, as well as time and daylight differentials, contributes to this."*

175 NeuConnect, Project overview (link).

176 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017, page 41 (link).

A4.18 A summary of Ofgem's assessment of the hard-to-monetise benefits of NeuConnect is outlined in Table A4- 2 below:

Table A4- 2: Summary of Ofgem's hard-to-monetise assessment of NeuConnect

Type of benefit	Ofgem's description	Ofgem's rating
Connecting new providers of balancing services to the GB SO	*NGET report shows NeuConnect can provide benefits through provision of ancillary services. Connection to a new market, currently no existing balancing arrangements between GB-German TSOs. However, both NG and TenneT DE actively involved in early implementation of the European Balancing Network Code.*	Slight positive impact
Providing alternative solutions to increase GB security of supply	o *Access to a new and highly interconnected market leads to increase in diversity of supply. However, benefits are slightly limited given similar electricity generation mixes;* o *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* o *The high level of availability of the interconnector provides additional system security to the GB system.*	Slight positive impact
Supporting the decarbonisation of energy supplies	*Lower carbon intensity of German power will displace GB thermal.*	Strongly positive impact

Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

Case study: NorthConnect

A4.19 The NorthConnect Interconnector will be a 1.4GW link between GB and Norway.[177] The interconnector will connect a wind-reliant area of the Scottish grid to a region of Norway that produces surplus, readily available hydropower.

177 NorthConnect, Information brochure (link).

A4.20 Within its IPA, Ofgem stated that:[178]

- *"NorthConnect is likely to provide similar levels of positive strategic and sustainable impacts as GridLink, given the connection to a significantly different and low-carbon electricity mix (e.g. 96% of Norway's electricity is generated from hydropower"*.
- *"NorthConnect's connection to Scotland is also likely to increase the integration of renewable energy sources and facilitate efficient dispatch of renewables across the two markets"*

A4.21 A summary of Ofgem's assessment of the hard-to-monetise benefits of NorthConnect is outlined in Table A4- 3 below:

Table A4- 3: Summary of Ofgem's hard-to-monetise assessment of NorthConnect

Type of benefit	Ofgem's description	Ofgem's rating
Connecting new providers of balancing services to the GB SO	*NGET report shows NorthConnect can provide benefits through provision of ancillary services (Frequency Response and Black Start). Currently no balancing arrangements between GBNorway TSOs. However, both NG and Statnett actively involved in early implementation of the European Balancing Network Code.*	Strongly positive impact
Providing alternative solutions to increase GB security of supply	o *Access to high levels of hydro generation in Norway leads to increase in fuel diversity* o *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* o *The high level of availability of the interconnector provides additional system security to the GB system.*	Strongly positive impact
Supporting the decarbonisation of energy supplies	*High level of imports of renewable hydro generation will displace GB thermal.*	Strongly positive impact

Source: Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

178 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link).

B. Europe

A4.22 European authorities use a multi-criteria cost-benefit methodology to evaluate the merits of potential new electricity interconnectors. In addition, the EU has a number of interconnector-specific policies and targets which may influence whether a proposed interconnector will be supported. Both the ENTSO-E cost-benefit assessment and European interconnection targets are discussed in this subsection.

ENTSO-E Cost Benefit Analysis

A4.23 Every two years, ENTSO-E assesses potential transmission projects in Europe and publishes its recommendation in its Ten-Year Network Development Plan ("TYNDP"). Each potential TYNDP project is assessed using a common CBA methodology, which includes both quantitative and qualitative criteria, under a common set of scenarios.[179]

A4.24 Projects may also be assessed to determine whether they meet the criteria to be a Project of Common Interest ("PCI"). PCI are *"infrastructure projects that link the energy systems of EU countries. They are intended to help the EU achieve its energy policy and climate objectives: affordable, secure and sustainable energy for all citizens, and the long-term decarbonisation of the economy in accordance with the Paris Agreement".*[180]

A4.25 In order to be included on the list of PCIs, the projects should meet a series of monetary and non-monetary criteria:[181]

- The project is necessary for at least one of the energy infrastructure priority corridors and areas.
- The overall benefits of the project outweigh its costs.
- The project meets at least one of the following: (i) involves at least two Member States by directly crossing the border of two or more Member States; (ii) is located on the territory of one Member State and has a significant cross-border impact; and (iii) crosses the border of at least one Member State and a European Economic Area country.

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179 Cost-Benefit methodology 3.0 ("3rd CBA Guideline for cost benefit analysis of grid development projects") was consulted on in Q4 2019 and is expected to be finalised in 2020.

180 European Commission, Key cross border infrastructure projects (link).

181 EU Regulation No. 347/2013 (link), Article 4. This is set to be renewed in 2020.

- For electricity transmission and storage specifically, the project must contribute significantly to at least one of: (i) market integration;[182] (ii) competition and system flexibility; (iii) sustainability;[183] or (iv) security of supply.[184]

A4.26 Projects that become a PCI may have various benefits conferred on them (including being eligible for EU funding of some of the project's costs).

A4.27 Each project included in the TYNDP is assessed using the pan-European CBA methodology. This multi-criteria methodology sets out the criteria for the assessment of costs and benefits of transmission and storage projects, all of which stem from European policies on market integration, security of supply and sustainability. Non-monetary criteria may still be assessed quantitively (e.g. CO2 emissions measured in tonnes per year), but they are not monetised.

A4.28 ENTSO-E is explicit in its view that relying on monetary factors alone does not fully recognise the benefits of a project:

> *"The assessment of costs and benefits are undertaken using combined cost-benefit and multi-criteria approach within which both qualitative assessments and quantified, monetised assessments are included. In such a way the full range of costs and benefits can be represented, highlighting the characteristics of a project and providing sufficient information to decision makers."*[185]

A4.29 Compared to the RIT-T, the ENTSO-E approach is a broader, more comprehensive approach to assessing potential benefits of projects, which may help capture wider project specific benefits.

A4.30 The current CBA framework is version two ("CBA 2.0"), but ENTSO-E is also in the process of consulting on draft rules for CBA version three ("Draft CBA 3.0").

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182 For example, through lifting the isolation of at least one Member State and reducing energy infrastructure bottlenecks.

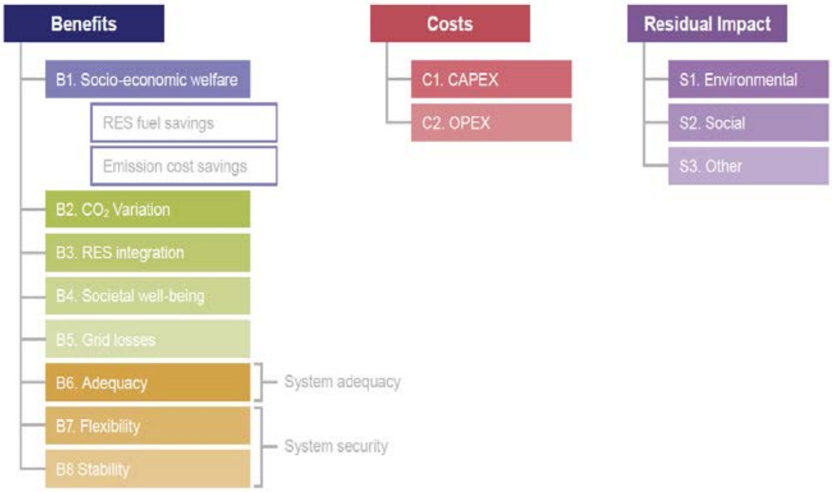
183 For example, through the integration of renewable energy into the grid and the transmission of renewable generation to major consumption centres and storage sites.

184 For example, through interoperability, appropriate connections and secure and reliable system operation.

185 ENTSO-E, 2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects, September 2018, page 18 (link).

A4.31 **<u>CBA 2.0</u>:** Under this methodology, each project is assessed against eight benefit indicators, two cost indicators and three indicators for residual impact. These indicators are outlined in Figure A4- 2 below:

Figure A4- 2: CBA 2.0



Source: ENTSO-E, 2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects, 27 September 2018, page 25 ([link]).

A4.32 ENTSO-E provides guidance on how benefit indicators in CBA 2.0 should be assessed and which indicators should be monetised. Table A4- 4 below outlines ENTSO-E's guidance on the monetisation of benefit indicators:

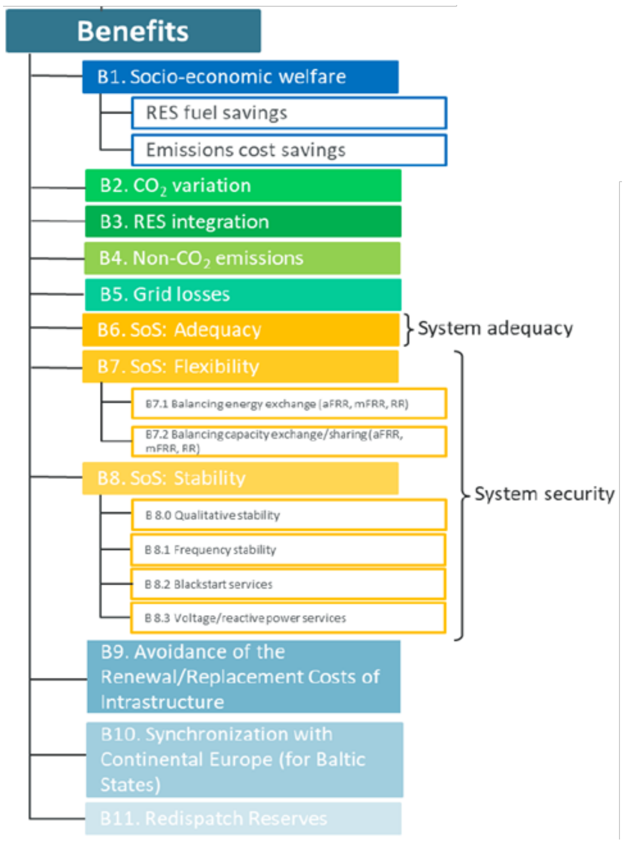
Table A4- 4: CBA 2.0 benefit indicators

Indicator	Original unit	Monetisation status
B1: Social economic welfare	€/yr	Already monetised
B2: CO2 emission	tonnes/yr	Renewable energy system fuel savings are fully monetised through B1. Other effects, such as contribution to meeting political CO2 reduction targets are not monetised.
B3: Renewable energy integration	MW or MWh/yr	Partly captured and monetised through B1 through reduction of curtailment and reduced fuel costs. Other effects, such as contribution to political renewables targets, are not monetised.
B4: Societal renewable energy benefits	Not specified	Specific indicator contents vary by project. Monetisation is recommended if suitable data available (in which case unit is €/yr).
B5: Losses	MWh/yr	Monetised using yearly average electricity price for each price zone.
B6: Security of system - adequacy	MWh/yr	Monetised, provided that VOLL-values are available. The additional adequacy margin may be conservatively monetised on the basis of investment costs in peaking units, provided that figures are available.
B7: Security of system – flexibility	% (of a MW value)	Quantified, but not monetised. Seeks to capture capability of system to accommodate fast and deep changes in the net demand. Percentage indicates contribution of project to ramping requirements.
B8: Security of system – system stability	Ordinal scale	Not monetised (qualitative criteria). Considers potential impact on system stability based on qualitative assessment scale.

Source: ENTSO-E, 2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects, 27 September 2018 (link).

A4.33 **<u>Draft CBA 3.0</u>**: The latest CBA methodology is in the process of being developed. The draft 3.0 methodology has added new and modified existing benefit categories. Notably, it has added or amended qualitative criteria, including System Adequacy (B6), Stability (B8) and Synchronisation with Continental Europe for the Baltic States (B10).

Figure A4- 3: Draft CBA 3.0 benefits



Source: ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019, page 36 (link).

A4.34 ENTSO-E provides guidance on how benefit indicators in Draft CBA 3.0 should be assessed and which indicators should be monetised. Table A4- 5 below outlines ENTSO-E's guidance on the monetisation of benefit indicators:

Table A4- 5: Draft CBA 3.0 benefit indicators

Indicator	Original unit	Monetisation status
B1: Social economic welfare	€/yr	Already monetised.
B2: CO_2 emission	tonnes/yr	Part 1: fully monetised under B1. Part 2: the additional societal value which is not monetised under B1. Political goals are formulated in percentages to values expressed in tonnes per year. The magnitude of the additional monetary effect is topic of an ongoing and controversial political debate. Therefore, the CBA guideline requires that CO_2 emissions are reported separately (in tonnes).
B3: Renewable energy integration	MW or MWh/yr	Fully monetised under B1, where the effects of RES integration on SEW due to the reduction of curtailment and lower generation costs are monetised. Political RES integration goals are formulated and expressed in MW. The magnitude of the additional monetary effect (on top of B1 and B2) cannot be monetised in an objective way. Therefore, the CBA guideline requires that RES integration is reported separately (MW or MWh/yr).
B4: Non-CO_2 emissions	Not specified	Not monetised.
B5: Grid losses	MWh/yr	Monetised using hourly marginal costs from the Market simulations per price zone.
B6: Security of system - adequacy	MWh/yr	Monetised, provided that VOLL-values are available. The additional adequacy margin may be conservatively monetised on the basis of investment costs in peaking units, provided that figures are available.
B7: Security of system – flexibility	Ordinal scale	Not monetised due to unavailability of quantitative models.
B8: Security of system – system stability	Ordinal scale	Not monetised due to unavailability of quantitative models.
B9. Avoidance of the Renewal/ Replacement Costs of Infrastructure	€	Already monetised.
B10. Synchronisation with Continental Europe	€	Monetisation is recommended under indicators B6, B7 and B8. This indicator is related to the additional societal value due to Synchronisation with Continental Europe.
B11. Redispatch Reserves	€/yr	Monetised using actual costs for allocation of Redispatch reserves. This indicator is optional and can only be achieved when Socioeconomic Welfare ("SEW") has been calculated using Redispatch simulations.

Source: ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019, page 41 (link).

European interconnection targets and policy

A4.35 In addition to the general electricity transmission policies and the CBA methodology described in the previous section, the EU has a number of interconnector-specific policies and targets which may influence whether a proposed interconnector may be supported. These targets tend to reflect political intentions rather than economically or technically justified objectives.

A4.36 Some of these targets are quantitative: in 2014, the EU agreed to extend an existing 10% electricity interconnection target (defined as import capacity over installed generation capacity in a Member State) to 15% by 2030.[186]

A4.37 Other targets are more qualitative in nature: for example, an expert group on electricity interconnection targets was established by the European Commission in 2016 to provide guidance on EU interconnector policy.[187] Specific benefits of interconnectors that have been identified by the group include: [188]

- **Market integration**: *"Interconnectors integrate European electricity markets in a number of ways, resulting in more competition and better prices for consumers and businesses."*
- **Climate and environmental benefits**: *"Much of Europe's electricity grid network has been designed in consideration of the location of conventional generation plants. However, a large share of today's renewable production…does not correspond to this grid architecture. Interconnectors…are key to creating new electricity routes to connect areas of abundance to areas of scarcity."*
- **Security of supply**: *"Additional interconnection capacity makes it possible to share generation capacities in parts where scarcity occurs at different times in differently connected systems."*

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186 EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link).

187 EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link).

188 EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link).

- **Political relevance and European integration**: "*The development of* [electricity] *networks is itself an important obligation for the EU… to strengthen economic, social and territorial cohesion*." *"Interconnectors, particularly as developed by the implementation of* [PCIs]*, are truly European projects that stimulate and strengthen regional cooperation between Member States and increase socio-economic welfare."*
- **Industrial competitiveness and innovation**: *"The European transmission and distribution industry has developed a strong technological leadership since the beginning of electrification. The energy transition is an opportunity to maintain and even strengthen this leading position."*

A4.38 We observe that interconnection targets and policies have been used by interconnector developers to help support their investment case with decision-making bodies. We discuss the Celtic Interconnector (an example of this) below.

Case study: Celtic interconnector

A4.39 The Celtic Interconnector is a proposed 700MW interconnector between Ireland and France. It is being developed by EirGrid, Ireland's TSO, and its counterpart in France, Réseau de Transport d'Electricité (RTE). It has been designated as a PCI for the North Seas Countries Offshore Grid Initiative priority corridor in 2013.[189]

A4.40 Following the UK's decision to leave the EU, the Celtic project became a renewed area of focus to reinforce "*solidarity*"[190] between Ireland and continental Europe, as it would be the only link between Ireland and the rest of the EU.

A4.41 While the CBA demonstrated that the project is economically beneficial and "*will deliver significant benefit to Europe*"[191] both the Irish (EirGrid) and French (RTE) project developers claimed the project was commercially unviable without additional support from the EU.

A4.42 In order to ensure the project would proceed, the EU provided the developers with substantial funding (grants equal to approximately 57% of total investment cost). This appears to indicate that EU policy-makers are willing to provide substantial financial support to proposed interconnector investments based (at least partially) on qualitative benefits.

A4.43 **Cost benefit assessment:** As part of their investment case, EirGrid and RTE proposed that a number quantitative and qualitative benefits would be created by the interconnector:[192]

- Electricity trading between Ireland, France and continental Europe, increasing competition in the electricity market and applying downward pressure on costs (to the benefit of consumers);
- Enhanced security of supply for both Irish and French electricity consumers;

[189] EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link).

[190] EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link).

[191] Assuming a 50/50 split in costs, the NPV of net benefits expected to accrue to Ireland was positive in all scenarios but only positive in two out of four scenarios for France. The 'Investment Request File' submitted by EirGrid and RTE therefore noted that the project entails some risks for French consumers, but that there are *"well-established EU mechanisms designed to facilitate projects with asymmetric benefits."*
Source: EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link).

[192] Celtic Interconnector, Project PCI Information Brochure.

- Consistency with Europe's transition to a low carbon energy future, by increasing the market available for renewable electricity and supporting the development of the renewable energy sector;
- Provide Ireland's only EnergyConnection to other EU Member States once the United Kingdom leaves the EU; and
- Help to improve telecommunications between Ireland and continental Europe, as the Celtic Interconnect project will also lay a fibre optic link between the two nations.

A4.44 As per the CBA framework, eight categories of project benefits were assessed as part of the project's assessment. In Table A4- 6 below, the best and worst case across all four scenarios assessed is presented:

Table A4- 6: Celtic CBA

Indicator	Worst case	Best case
B1. Increase in socio-economic welfare – MEUR/ yr	42	91
B2. Change in CO2 emissions, tonnes/yr	56,300 increase	868,700 decrease
B3. Increase in RES integration - GWh/yr	600	925
B4. Change in societal wellbeing	Effect captured through other benefits, e.g. change in CO2	
B5.a Increase in grid losses - GWh/yr	471	351
B5.b Increase in grid losses - MEuro/yr	22	17
B6.a Adequacy to meet demand – Reduction in energy not served - MWh/yr.	0	1,210
B6.b Adequacy to meet demand – Increase in adequacy margin - GWh	9.7	204
B7. System flexibility (i.e. contribution of project to maximum ramp)	6%	76%
B8. Security of supply - system stability	Significant improvement for transient and voltage stability. Small to moderate improvement for frequency stability.	

Source: ENTSO-E TYNDP assessment of Celtic Interconnector (link).

A4.45 As part of the CBA, the project developers also noted that they expect Celtic to meet the following monetary and non-monetary EU-level objectives:

- Meet the 2030 15% interconnection target;

- Develop infrastructure to mitigate renewable energy curtailment;
- Develop infrastructure to address system adequacy deficiencies; and
- Reduce price differentials across the EU.

A4.46 Furthermore, the developers argued that other project benefits would include:

- **Political relevance and European integration**: after Brexit, Celtic would be the only means of direct trading between Ireland and the Integrated European Market (continental Europe). A benefit of Celtic is that it would provide Ireland access to a diverse supply of energy, which would help meet the EU's objective of ensuring *"all EU Member States have secure, affordable and climate friendly energy*".[193] It appears that this benefit was a key factor in the project receiving a significant grant from the EU (equal to 57% of investment cost).
- **Industrial competitiveness and innovation**: including improved telecoms between Ireland and France through the provision of a fibre optic link at the same time.

A4.47 It appears that non-monetary benefits (in particularly those with political support) were used by the developers of the Celtic interconnector to support their investment case with decision-making bodies. Without the financial support that was ultimately received from the EU, it is unlikely that the project would have proceeded.

[193] EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018, page 39 (link).

C. US

A4.48 In this subsection, we discuss the assessment of non-monetary benefits in the US in the context of a specific interconnector recently developed between New York and New Jersey: the Hudson Transmission Project ("Hudson").

Case study: Hudson Transmission Project

A4.49 Hudson, which was completed in June 2013, is a 660 MW electric transmission link that runs under the Hudson river between New York City (part of the New York Independent System Operator's ("NYISO") area) and New Jersey (part of PJM's area).[194]

A4.50 The interconnector was built to provide a new source of electric power for NYPA customers.

A4.51 Hudson is one of the few examples of an electricity interconnector between different ISOs within the US.

A4.52 The need for additional capacity within Zone J in NYISO was originally identified by NYPA in order to meet the future electricity requirements of its New York City Governmental Customers and, in particular, to replace NYPA's 885 MW natural gas/oil-fired Poletti generator in Queens, which was scheduled for retirement in 2010.

A4.53 In response to this identified need, NYPA issued a Request for Proposal for solutions (both generation and transmission) that would provide at least 500MW of additional capacity to New York City.

A4.54 The key long-term objectives of the Request for Proposal were to:[195]

- reduce energy costs;
- provide energy price stability;
- improve system reliability;
- diversify electricity supply both in terms of physical locations and fuel supply; and
- contribute to environmental and health quality enhancements including the New York City's land use policies.

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194 The Hudson Project website (link).

195 FERC, Case 08-T-0034, Initial Brief of the Power Authority of the State of New York, June 2010, page 3 (link).

A4.55 An additional consideration was that New York City is required to source over 80% of its capacity from internal resources and controllable transmission (the Hudson interconnector met the criteria of controllable transmission).

A4.56 **Assessment process:** In 2005, NYPA, on behalf of its NYC Governmental Customers, established the evaluation criteria, which was designed to meet numerous long-term objectives.[196] A number of these evaluation criteria are non-monetary. However, the relative importance of each criteria is not clear. A list of relevant criteria is set out in Table A4- 7 below:

Table A4- 7: NYPA assessment criteria to determine a preferred solution

Indicator	Monetary/ non-monetary
Evaluated price of bidder's proposal	Monetary
Extent to which offered pricing is economical, stable and predictable over the offered term	Monetary
Overall portfolio cost and risk, including project and financing risk	Monetary
Contribution to system reliability	Non-Monetary
Contribution to the overall reduction of electricity costs city-wide	Monetary
Contribution to the diversification of the total number of electricity supply sources	Non-Monetary
Contribution to the diversification of physical locations of electricity supply	Non-Monetary
Contribution to policy objectives, including environmental and health quality enhancements	Non-Monetary
Consistency with the City of New York's land-use policies and re-zoning plans	Non-Monetary

Source: NYPA, Case 08-T-0034, Pre-trial brief in support of Hudson Transmission Partners, page 8.

196 NYPA, Case 08-T-0034, Pre-trial brief in support of Hudson Transmission Partners (link).

A4.57 In 2010, NYPA set out both monetary and non-monetary reasons for supporting the Hudson interconnector project over alternatives submitted, including generation options, as described in the following paragraphs.[197] However, it is unclear what relative weighting was placed on each criteria (i.e. benefit).

A4.58 **Monetary**: NYPA's economic analysis, which utilised GE-MAPS, a detailed economic dispatch and production costing model for electricity networks, found that the project would result in substantial economic savings.

A4.59 Among all projects submitted to NYPA, Hudson was estimated to provide the greatest benefit at the lowest cost.

A4.60 **Non-monetary**: As required by the evaluation framework, NYPA considered a number of non-monetary factors when assessing the project. The following were cited as reasons supporting the project:[198]

- Lower emissions compared to other options considered to meet New York's power demands, such as a CCGT.
- Provides the capacity required to meet NYPA's 80% locational capacity requirements. Without the interconnector, this target would be missed due to a local power plant ceasing operation in 2010.
- Provides access to a greater array of renewable energy resources. It was the cheapest near-term potential conduit of large amounts of renewable energy to the City. This is consistent with City and State policy promoting the increased use of renewable energy.
- Improves energy security by enhancing the city's transmission infrastructure and diversifying its generation resources outside of the city. The current geographic diversity of New York's power generation in particular was cited as an issue the interconnector could mitigate.

197 NYPA, Case 08-T-0034, Pre-trial brief in support of Hudson Transmission Partners, page 8 (link).

198 NYPA, Case 08-T-0034, Pre-trial brief in support of Hudson Transmission Partners, page 8 (link).

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CBA 2.0	Cost-benefit analysis, version 2
CCGT	Combined Cycle Gas Turbines
CPA	Contingent Project Application
Draft CBA 3.0	Draft cost-benefit analysis, version 3
Draft ISP 2020	Draft Integrated System Plan 2020
EnergyConnect	Project EnergyConnect
ENTSO-E	European Network of Transmission System Operators for Electricity
ESOO 2019	Electricity Statement of Opportunities 2019
EU	European Union
FCAS	Frequency Control Ancillary Services
FTI	FTI Consulting
GB	Great Britain
Hudson	Hudson Transmission Project
IC	Interconnector
IPA	Initial Project Assessment
ISO	Independent System Operator
ISP	Integrated System Plan
LRET	Large-scale Renewable Energy Target
LT	Long-term model (Plexos®)
MCF	Minimum capacity factors
NEL	National Electricity Law
NEM	National Electricity Market (Australia)
NEO	National Electricity Objective

Term	Definition
NGET	National Grid Electricity Transmission
NPV	Net Present Value
NSW	New South Wales
NYISO	New York Independent System Operator
NYPA	New York Power Authority
Opex	Operating expenditure
PACR	Project Assessment Conclusions Report
PADR	Project Assessment Draft Report
PCI	Projects of Common Interest
POE	Probability of Exceedance
Qld	Queensland
QNI	Queensland-New South Wales Interconnector
QRET	Queensland Renewable Energy Target
REZ	Renewable Energy Zone
RIT-T	Regulatory Investment Test for Transmission
ROCOF	Rate of Change of Frequency
RTE	Réseau de Transport d’Electricité (French electricity transmission system operator)
SA	South Australia
SEW	Socioeconomic Welfare
SO	System Operator
SRMC	Short-Run Marginal Cost
ST	Short-term model (Plexos®)
TNSP	Transmission Network Service Provider
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
US	United States
Vic	Victoria
VNI	Victoria-New South Wales Interconnector
VRET	Victorian Renewable Energy Target
WACC	Weighted Average Cost of Capital