09 SEPTEMBER 2020

ASSESSING THE BENEFITS OF INTERCONNECTORS

A REPORT FOR TRANSGRID

Table of contents

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.[1] Further investment in transmission infrastructure 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.[2]

1.2 To address these challenges, the Australian Energy Market Operator ("AEMO") aims to take a coordinated approach to planning a cost-efficient evolution of the transmission network. The Integrated System Plan ("ISP"), published every two years, seeks to identify and recommend investment choices that "*minimise costs and the risk of events that can adversely impact future power costs and consumer prices, while also maintaining the reliability and security of the power system*".[3] The ISP published in 2020 identifies three committed projects, six actionable projects (two of which have decision rules) and a further nine future projects as part of the "*optimal development path"* towards affordable, secure and reliable energy supply in the NEM.[4]

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

2 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).

3 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 8.

4 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 84.

1.3 Project EnergyConnect ("EnergyConnect"), a proposed interconnector between New South Wales ("NSW") and South Australia ("SA"), has been identified as one of the projects on the "*optimal development path*". EnergyConnect has been classified as an *"Actionable ISP project"*, which is a project *"critical to address cost, security and reliability issues"* in the NEM.[5,6] EnergyConnect is being jointly developed by ElectraNet and TransGrid, the Transmission Network Service Providers ("TNSPs") in SA and NSW respectively.

1.4 In January 2020, EnergyConnect satisfied the Australian Energy Regulator's ("AER") Regulatory Investment Test for Transmission ("RIT-T").[7] 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 amendments. In this context, FTI was 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. This analysis (referred to in this report as the "FTI June report") was included as part of TransGrid's Contingent Project Application ("CPA"), submitted in June 2020.

1.5 Compared to the FTI June report, this report presents an updated view on the impact of EnergyConnect on wholesale electricity prices, based on AEMO's Final ISP 2020 modelling assumptions.[8] It also explores in greater detail how interconnectors are assessed in other jurisdictions and lessons from international experience could be applied to EnergyConnect.

5 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 14 and 84.

6 Queensland-New South Wales Interconnector ("QNI") upgrade (a Committed ISP project) and Victoria-New South Wales Interconnector ("VNI") upgrade (an Actionable ISP project) have also been included in the optimal development path.

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

8 We have sought to reflect as many of AEMO's Final ISP 2020 input assumptions as possible in the time available. Given the limited time available to perform this analysis, we have not been able to fully reflect structural updates.

Purpose and objectives of this report

1.6 FTI Consulting ("FTI") has been engaged by TransGrid to provide a second report on the benefits of EnergyConnect, to help inform the CPA submission. This report presents an updated view on the impact of EnergyConnect on wholesale electricity prices using updated modelling assumptions released by AEMO as part of Final ISP 2020. In addition, this report evaluates (in greater detail than the FTI June report) the wider benefits of EnergyConnect not currently captured by the RIT-T framework, by considering:

- whether other jurisdictions account for the benefits of transmission assets that are difficult to monetise (for example, renewables integration and system security) and, if so, how these benefits may be assessed, and the extent to which these might be relevant to EnergyConnect;
- the different perspectives and frameworks used by other jurisdictions to assess potential transmission projects, particularly where these depart from the social cost-benefit assessment that the RIT-T applies, and how this would impact on an assessment of EnergyConnect; and
- how other jurisdictions assess potential investments in "groups" of interconnectors and how the incremental benefits of individual interconnectors may vary depending on the order in which the interconnectors are included in the analysis.

Restrictions

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

1.8 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

1.9 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.

1.10 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.

1.11 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

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

- **Section 2** presents our estimate of the impact of EnergyConnect on wholesale electricity prices;
- **Section 3** discusses how 'hard-to-monetise' benefits are accounted for in other jurisdictions, and describes the expected 'hard-to-monetise' benefits of EnergyConnect;
- **Section 4** summarises alternative perspectives used in other jurisdictions to assess interconnector investments, and considers their relevance to EnergyConnect; and
- **Section 5** describes how other jurisdictions assess the incremental benefit of individual interconnectors in the context of a proposed group of interconnector investments and considers how these approaches might be applied to EnergyConnect.

1.13 The report includes the following appendices:

- **Appendix 1** sets out the modelling methodology and key assumptions used for our calculations of EnergyConnect's impact on wholesale electricity prices, as well as additional detail on the impact of EnergyConnect on capacity and generation in the NEM; and
- **Appendix 2** provides further details on transmission investment assessments in other jurisdictions.

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

2. Impact of EnergyConnect on wholesale electricity prices

2.1 Electricity interconnectors are transmission assets that link two different price zones and allow for generation to be transferred from a low price zone, to a higher price zone. This benefits consumers in the high price zone, who now have access to cheaper sources of electricity, and it also benefits both connecting regions in the sense that consumers now have access to additional sources of electricity, which increases the security of supply at both ends.

2.2 To evaluate the merits of EnergyConnect to NEM consumers, we have considered how wholesale electricity prices are likely to evolve with and without EnergyConnect. This approach intentionally differs to how benefits are assessed under the RIT-T framework: the RIT-T framework considers the impact of EnergyConnect on system costs, while our analysis considers the impact of EnergyConnect on the prices faced by consumers.

2.3 In this section, we first briefly summarise our approach to estimating the impact of EnergyConnect on wholesale electricity prices (Section A), and then present the results of that analysis (Section B).[9]

9 Further details on our modelling methodology and key inputs can be found in Appendix 1.

A. Overview of our approach to estimating the impact of EnergyConnect on wholesale electricity prices

2.4 To estimate the impact of EnergyConnect on wholesale electricity prices, we use FTI's in-house power market model, which runs on the Plexos® Market Simulation Software.[10] To estimate the incremental impact of EnergyConnect, we model prices (on a regional basis) with EnergyConnect and then compare them to prices in the counterfactual scenario of the NEM without EnergyConnect, with the difference between the two scenarios being the impact of the project.[11]

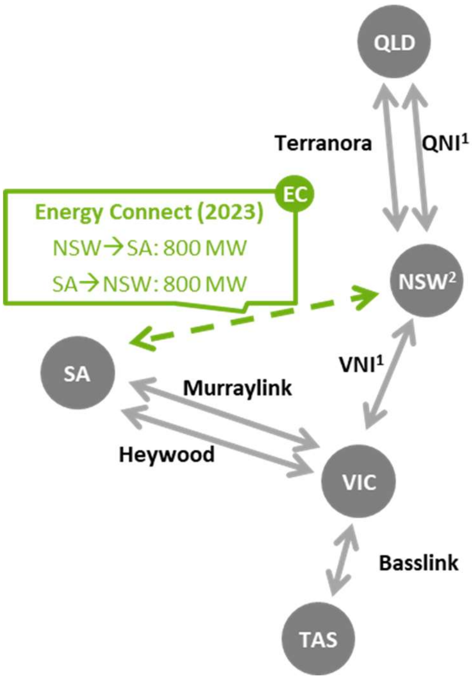
2.5 The modelled topology of the NEM is illustrated in Figure 2-1 below:

---

[10] For further details on the: (i) Plexos® software; (ii) inputs used in our analysis; and (iii) key outputs, see Appendix 1.

[11] Our analysis assesses the impact of EnergyConnect on wholesale prices relative to a baseline that includes all existing interconnectors and those interconnectors expected to come online before EnergyConnect (i.e.) QNI minor and VNI upgrades. HumeLink is also modelled implicitly, as it is an actionable ISP project that is not dependent on a decision rule. All three proposed transmission investments are included in ISP 2020's Optimal Development Path, with QNI (minor) upgrade considered a committed project and both VNI and Humelink considered Actionable projects.

Figure 2-1: Modelled NEM topology



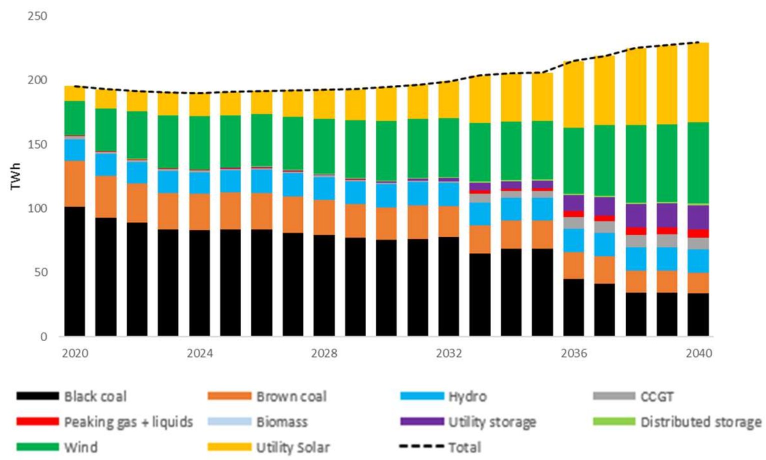
Source: FTI analysis.

Note: 1) Includes VNI and QNI minor 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.

2.6 The figure below presents the modelled baseline generation in the NEM, without EnergyConnect:

Figure 2-2: Baseline NEM generation profile (Model Run 3)



Source: FTI analysis.
Note: Generation is broadly similar across all Model Runs.

2.7 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 29% 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 71% of total TWh output over the same period.

2.8 To estimate wholesale prices, we use "Bertrand" pricing methodology.[12] This assumes that all generators learn, over time, 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). In so doing, the prices observed in the market tend to be higher than the short run marginal cost of production of the marginal generation unit. This approach enables us to estimate the benefit of EnergyConnect in terms of constraining generators' bidding behaviour, to the benefit of consumers.

12 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.

2.9 We consider the impact on wholesale electricity prices in each region separately, and we also calculate the impact on weighted-average NEM prices. EnergyConnect impacts prices in each region to a different extent, depending on the region's proximity to the interconnector. Our analysis focuses on the impact on wholesale electricity prices in NSW and SA, as these regions are directly impacted by EnergyConnect.

B. Impact of EnergyConnect on wholesale electricity prices

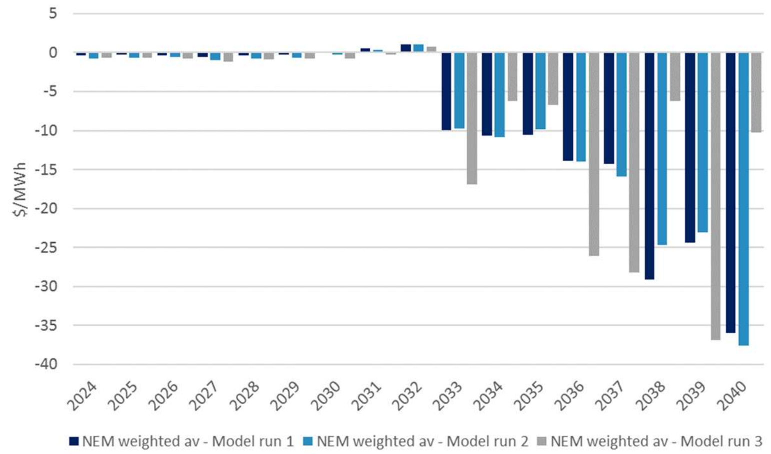
2.10 EnergyConnect results in a material reduction in the weighted-average wholesale price in all NEM regions. The average decrease in NEM wholesale electricity prices over the 2020 to 2040[13] modelling period is between \$7.0/MWh/year and \$7.4/MWh/year.[14] Wholesale prices expected to decrease as soon as EnergyConnect is commissioned (although the largest price impact occurs in the late 2030s), as illustrated in the figure below:

---

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

14 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 these results 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). For further detail on stability constraints, see Appendix 1.

Figure 2-3: Annual weighted average NEM wholesale price impact from EnergyConnect



Source: FTI analysis.
Note: The three model runs represent an envelope of the likely price impact outcomes depending on the system constraints included (see Appendix 1 for further details).

2.11 This decrease in wholesale prices is predominately driven by:

- improved access to cheaper sources of generation from neighbouring regions (which is particularly pronounced in the years where certain states face very tight supply-demand balance, such as NSW in the 2030s due to planned coal generation closures); 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.

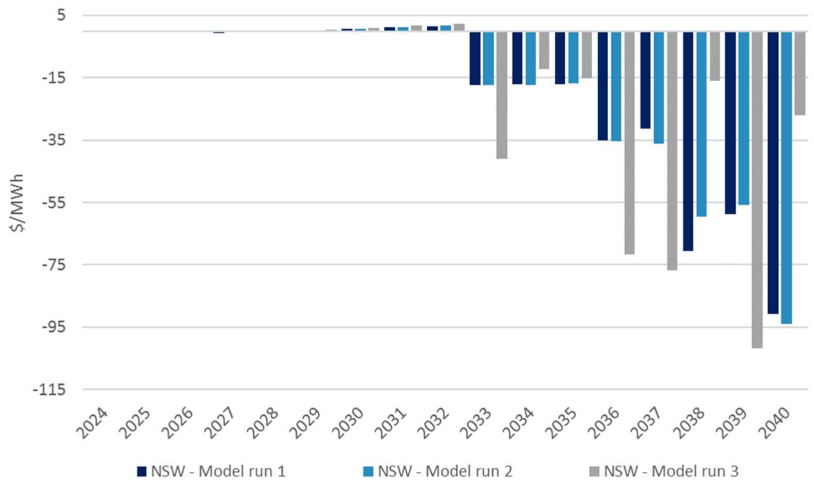
2.12 The following subsections provide additional detail on the regional impact of EnergyConnect, and on the mechanisms that drive the observed reduction in wholesale electricity prices.

Impact of EnergyConnect on a regional basis

2.13 We estimate that **NSW customers** stand to benefit significantly from EnergyConnect. NSW wholesale electricity prices are expected to decrease by between \$16.4/MWh/year and \$17.6/MWh/year on average over the 2020 to 2040 modelling horizon.

2.14 The impact of EnergyConnect on NSW wholesale prices is presented in Figure 2-5 below:

Figure 2-4: Annual weighted average NSW wholesale price impact from EnergyConnect



Source: FTI analysis.

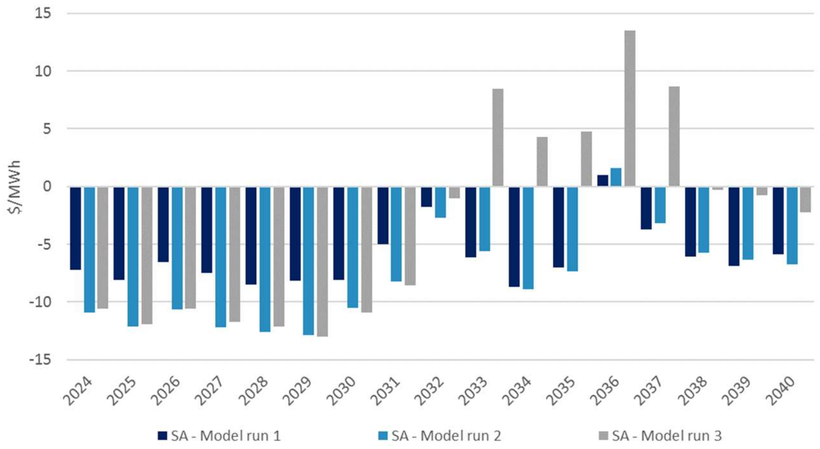
2.15 Taking into account the total cost of EnergyConnect that would be incurred by TransGrid and our estimate of the impact on interconnector residues arising from EnergyConnect, we estimate that overall cost saving to a household in NSW would on average be between $58.4 and $63.9 per year.[15]

2.16 For **SA customers**, we estimate that wholesale electricity prices will fall by between $2.5/MWh/year and $6.4/MWh/year on average over the same time period. The impact of EnergyConnect on SA wholesale prices is presented in Figure 2-5 below:

---

[15] This is calculated using an assumed cost for TransGrid's portion of EnergyConnect of $1.9 billion ($Real 2017-18). This is based on the average of TransGrid's Request for Tender ("RFT") Phase B capex forecasts of $1,902.6 million ($Real 2017-18), provided to us by TransGrid. For the purposes of our analysis (which uses $Real 2018-19 prices) we have adjusted the capex estimate to 2018-19 prices using an inflation rate of 1.6% (Source: Australian Bureau of Statistics, Consumer Price Index (All Groups), (link)).

Figure 2-5: Annual weighted average SA wholesale price impact from EnergyConnect



Source: FTI analysis.

Key drivers of wholesale price reduction

2.17 EnergyConnect enables NEM dispatch to be optimised over a larger geographic footprint, and allows relatively cheaper generation to be sourced from neighbouring regions to meet local demand. This reduces the number of hours that more expensive generators (in particular gas plants in SA) are needed.

2.18 The price impact is more significant in SA in the 2020s. In SA there is a decrease in SA prices as with EnergyConnect the need for gas generation (in particular during peak periods and times of low renewable generation) is reduced. Instead, SA is able to import generation from NSW (hydro generation and black coal generation) via EnergyConnect and from Vic (brown coal generation) via existing interconnectors.[16] This reduces the frequency of prices in excess of $100/MWh in SA. Without EnergyConnect, hourly SA prices over the 2024 to 2030 period are forecast to exceed $100/MWh for around 19% to 25% of hours. In comparison, with EnergyConnect, hourly SA prices during this same period are only expected to exceed $100/MWh for around 4% to 5% of hours.[17]

---

16 With EnergyConnect, the transfer limit on Heywood, an existing interconnector between SA and Vic, increases from 650MW to 750MW in both directions. This allows SA to rely on imports from Vic more during peak periods.

17 The range presented refers to the different Model Runs, under which different combinations of stability constraints are imposed.

2.19 In the 2030s, NSW consumers benefit from a significant reduction in wholesale electricity prices. EnergyConnect allows for cheap electricity to be imported by NSW 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 2-4 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 is mitigated by EnergyConnect.

2.20 On the other hand, SA exports become a more significant share of overall flows on 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 2-5 above. This is particularly the case in Model Run 3, when the system is more constrained.

2.21 Furthermore, given that all mainland regions are connected to NSW via existing interconnectors, the NSW price has at least some impact on prices in all these connected regions. The significant reduction in NSW prices in the 2030s has a secondary impact of relieving some of the upward pressure on prices in other mainland regions that existed in the counterfactual scenario without EnergyConnect. We observe that on average, prices fall across the NEM with EnergyConnect relative to the counterfactual scenario without EnergyConnect.

2.22 Overall, our modelling shows that, on average over the modelling period, both NSW and SA wholesale electricity prices are lower with EnergyConnect relative to the counterfactual scenario without EnergyConnect.

Impact of VNI West Interconnector

2.23 For completeness, we have also considered in separate analysis how EnergyConnect might impact on wholesale prices assuming the commissioning of proposed VNI West Interconnector. However, the status of VNI West differs from the other proposed interconnectors in our modelling as it is classed as an actionable ISP project that does depend on a decision rule and hence appears less certain to progress relative to those that do not depend on a decision rule.[18] This uncertainty is indicated in the Final ISP.[19]

2.24 We discuss further in Section 5 the methodology regarding the approach to the inclusion of VNI West and its impact on lowering market benefits assessed for EnergyConnect when EnergyConnect is assessed on an incremental basis (under the "Take One Out at a Time" approach). However, we note that when we considered the wholesale price impact of EnergyConnect in a scenario that assumes VNI West is operational we find a smaller (but still downwards) impact on prices.

---

18 We note that Marinus Link has the same status as VNI West, however is not modelled in our analysis.

19 As outlined in the Final ISP 2020 (link), there is still a degree of uncertainty regarding whether VNI West will proceed and will depend on the decision rules, which *"…will be confirmed by AEMO as part of the ISP feedback loop process with the TNSP once the decision rule eventuates*" (page 84). AEMO also consider potential situations that would result in the pausing or cancelling of VNI West (page 82).

3. Wider benefits for the electricity system

3.1 In the NEM, the merits of potential investments in interconnectors are assessed through the RIT-T framework. Indeed, EnergyConnect satisfied the RIT-T criteria in January 2020 and is progressing through the remaining regulatory steps.

3.2 However, interconnectors often bring wider benefits to the electricity system beyond the monetary cost savings of the type identified by the RIT-T, although sometimes these benefits may be difficult to associate with monetary figures. We recognise that these 'hard-to-monetise' benefits are not (and cannot be) considered in the RIT-T assessment, but, interconnector assessments in other jurisdictions often take hard-to-monetise benefits into account.

3.3 By excluding these wider benefits, the RIT-T assessment process may ascribe a lower value to any given interconnector project relative to the assessment of similar projects in other international jurisdictions.

3.4 In addition, EnergyConnect has an expected useful life of around 50 years and is unlikely to stop operating in 2040 (which is the end-point of the period of the RIT-T's benefits assessment). Instead it is likely to continue operating and delivering benefits to the NEM. Although the long-term benefits are much less certain, excluding them (as per the RIT-T) could undervalue the merits of the project.

3.5 In this section we illustrate how hard-to-monetise benefits are accounted for internationally and show that such benefits are considered to be highly relevant in specific jurisdictions across Great Britain ("GB"), Europe and the United States ("US"), in Section A. We then discuss the hard-to-monetise benefits we expect EnergyConnect to bring to the NEM, in Section B, which would be additional to monetary benefits identified under the RIT-T. Finally, we discuss the potential benefits of EnergyConnect in the post-2040 period, in Section C.

A. Approaches in other jurisdictions

3.6 Interconnectors often have additional effects on energy systems (which may be quantitative or qualitative), that cannot be expressed in monetary terms, or may be inherently difficult to quantify. As a strictly monetary assessment, the RIT-T, by design, does not necessarily fully account for these hard-to-monetise benefits.

3.7 We review interconnector policy in three separate jurisdictions to determine how other regulators and other relevant policy makers treat hard-to-monetise benefits of transmission investments. In particular, we examine interconnector policy in three jurisdictions, with specific examples for each of:

- GB: Ofgem's Cap and Floor regime;[20]
- Europe: the European Network of Transmission System Operators for Electricity's ("ENTSO-E") classification of Projects of Common Interest ("PCI"); and
- New York Independent System Operator ("NYISO"): the New York Power Authority's ("NYPA") assessment of the Hudson Transmission Project.

3.8 Our key finding is that in all three jurisdictions, hard-to-monetise benefits are considered as part of 'standard' regulatory assessments of interconnectors.[21] While the specific details differ, a common theme across all three jurisdictions is that failing to take hard-to-monetise benefits into account would not provide a complete picture of the transmission investment's merits.

Great Britain – Ofgem's Cap and Floor regime

3.9 Ofgem's Cap and Floor regime is the regulated route for interconnection investment within GB and all regulated interconnectors are therefore assessed under this framework. Since 2014, a total of eight different interconnectors have been evaluated through this regime.[22]

3.10 The Cap and Floor regime starts with an initial project assessment ("IPA") phase, during which Ofgem first performs a quantitative cost-benefit analysis ("CBA"). It then assesses additional hard-to-monetise benefits that were not reflected in the CBA. [23]

3.11 Ofgem uses a general framework to identify the hard-to-monetise benefits of any given interconnector investment. This is outlined in the figure below.

---

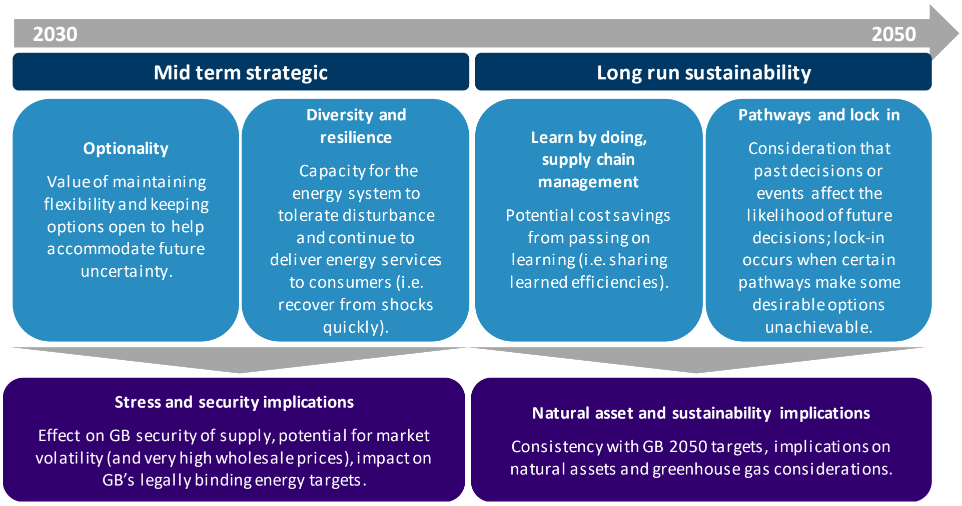
20 Ofgem is the independent energy regulator for GB.

21 See Appendix 2 for further details on each jurisdiction.

22 These are: NSL, FAB Link, IFA2, Viking Link, Greenlink, GridLink, NeuConnect and NorthConnect.

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

Figure 3-1: 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).

3.12 To date, Ofgem has run two separate 'Windows'. These are fixed periods of time in which prospective interconnectors can apply for the Cap and Floor Regime. In the most recent Window, run during 2016-2017, Ofgem assessed three projects connecting GB to France, Germany and Norway: GridLink, NeuConnect and NorthConnect.

3.13 When assessing these three interconnectors, Ofgem used the framework above to identify the following hard-to-monetise benefits: [24, 25]

(1) connecting new providers of balancing services;

(2) increasing GB security of supply; and

(3) supporting the decarbonisation of the GB energy supplies.

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

25 Ofgem identified similar hard-to-monetise benefits for Window 1 interconnectors. Source: Ofgem, Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink Interconnectors (link), page 39.

3.14 Ofgem noted that GridLink, NeuConnect and NorthConnect were expected to have a positive impact on GB balancing services in particular, by providing the GB system with greater access to ancillary services. When Ofgem performed a similar assessment of interconnectors in an earlier application Window, it noted that the interconnectors were expected to contribute significant cost savings in the provision of certain ancillary services:[26]

- FAB Link: between £32 million and £63 million in savings,
- IFA2: between £22 million and £48 million in savings; and
- Viking Link: between £23 million and £46 million in savings.

3.15 All three interconnectors have been found to contribute positively to the hard-to-monetise benefits listed above, ranging from a 'slightly positive impact' to 'strongly positive impact' (see Appendix 1 for more detail on each of the interconnectors). Ofgem has also approved all three projects 'in principle', meaning that the projects have progressed to the next phase of the regulatory assessment.

3.16 Ofgem does not explicitly 'weight' the importance of monetary factors relative to hard-to-monetise benefits. These three interconnectors also passed the quantitative benefit assessment performed by Ofgem.[27] This suggests **hard-to-monetise benefits have been used as supporting positive evidence for interconnector investments**, in addition to monetary considerations, rather than as a deciding factor on whether to approve the project.

3.17 To date, the importance of hard-to-monetise benefits in Ofgem's interconnector regime has not been tested in cases where the investment may be more marginal.

Europe – ENTSO-E's Cost-Benefit Assessment

3.18 ENTSO-E is responsible for coordinating the development of the transmission grid across Europe. In performing this role, it seeks to identify interconnector projects that are in the interests of the European network as a whole.

---

[26] Ofgem, Cap and floor regime: Initial Project Assessment of the FAB Link, IFA2, Viking Link and Greenlink Interconnectors (link), page 35.

[27] Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), Table 4, Table 5, Table 6.

3.19 To inform and help coordinate the development of the transmission network, ENTSO-E publishes a biennial Ten-Year Network Development Plan ("TYNDP")[28] which sets out plans to develop the electricity grid over the next 10 to 20 years.[29]

3.20 In particular, ENTSO-E identifies specific energy infrastructure projects that are in the interest of Europe, which are known as PCIs. These are projects within the TYNDP that *"link the energy systems of EU countries"* and *"are intended to help the EU achieve its energy policy and climate objectives".*[30] PCIs generally benefit from:[31]

- an accelerated planning and consenting process;
- more favourable regulatory environments; and
- the ability to apply for and obtain funds from the Connecting Europe Facility ("CEF").

3.21 To inform the TYNDP and the selection of PCIs, ENTSO-E uses a multi-criteria cost-benefit methodology to evaluate the merits of potential new electricity interconnectors.

3.22 ENTSO-E's view is 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." (emphasis added)*[32]

---

28 ENTSO-E is an authority made up of European transmission system operators ("TSOs") whose key responsibilities include (amongst others), assisting in transmission planning. Source: ENTSO-E, The Third Energy Package (link).

29 ENTSO-E, About the TYNDP (link).

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

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

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

3.23 Each potential TYNDP project is therefore assessed using a common CBA methodology, which includes both quantitative and qualitative criteria, under a common set of scenarios.[33]

3.24 This CBA is the *"main input"* in determining whether or not a project can be considered a PCI.[34] The full list of criteria of the CBA is presented in the table below. The highlighted criteria are those that are hard-to-monetise, including: (i) renewable energy integration; (ii) societal renewable energy benefits; (iii) security of system – flexibility; and (iv) security of system – system stability.

---

33 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.

34 ENTSO-E, 2nd ENTSO-E Guideline For Cost Benefit Analysis of Grid Development Projects, 27 September 2018 (link), page 1.

Table 3-1: 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	Reduction of curtailment and reduced fuel costs fully monetised through B1. 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).

3.25 Although not all criteria in the table above are (or are only partially) monetised, they form an integral part of the cost-benefit assessment methodology and are therefore used to systematically assess proposed interconnector projects and their eligibility for the 'preferred status' of a PCI.

3.26 ENTSO-E is currently in the process of updating this CBA methodology, which will consider the benefits identified above,[35] and include the following additional non-monetised categories of benefits: (i) non-CO2 emissions; (ii) avoidance of the infrastructure renewal or replacement costs; (iii) synchronisation with Continental Europe; and (iv) the cost of redispatch services.[36]

USA – New York Power Authority's Hudson Transmission Project

3.27 The NYPA is the public power utility for the NYISO area and is responsible for providing power to New York State customers.

3.28 In 2005, NYPA identified the need for additional generation and/or transmission capacity in the New York City area,[37] and issued a request for proposals to meet that demand.[38] In response to this request, NYPA received several submissions, including proposals to build new generation and to build a new 660 MW interconnector that runs under the Hudson river between New York City (part of the NYISO area) and New Jersey (part of PJM's area).[39]

3.29 To select the preferred project, the NYPA established several evaluation criteria, which were designed to meet numerous long-term objectives,[40, 41] a number of which are hard-to-monetise. These are summarised in the table below.

35 Excluding societal renewable energy benefits.

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

37 The Hudson Project website (link).

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

39 The Hudson Project website (link).

40 To: (i) reduce energy costs; (ii) provide energy price stability; (iii) improve system reliability; (iv) diversify electricity supply both in terms of physical locations and fuel supply; and (v) contribute to environmental and health quality enhancements.

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

Table 3-2: NYPA assessment criteria to determine a preferred solution

Indicator	Monetary/ hard-to-monetise
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	Hard-to-monetise
Contribution to the overall reduction of electricity costs city-wide	Monetary
Contribution to the diversification of the total number of electricity supply sources	Hard-to-monetise
Contribution to the diversification of physical locations of electricity supply	Hard-to-monetise
Contribution to policy objectives, including environmental and health quality enhancements	Hard-to-monetise
Consistency with the City of New York's land-use policies and re-zoning plans	Hard-to-monetise

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

3.30 While the relative importance of each criteria is not clear, the table above shows that, in common with other jurisdictions, the NYPA's assessment takes into account both monetary and hard-to-monetise benefits of transmission assets.

3.31 Based on its assessment, using the criteria presented in Table 3-2 above the NYPA selected the Hudson Transmission Project ("Hudson") project over alternative proposals.

Conclusions from review of other jurisdictions

3.32 Based on our review of the GB, US and EU precedents, **hard-to-monetise benefits appear to be an integral part of regulatory evaluation of interconnectors in other jurisdictions** and are considered within the relevant decision-making frameworks. Our review suggests that **hard-to-monetise benefits tend to be used as additional supporting evidence** over and above quantitative monetary benefits.

3.33 These **authorities recognise** that **not all relevant benefits to consumers can necessarily be monetised**. However, the weight given to hard-to-monetise factors relative to monetary factors is uncertain (and likely to reflect regulatory discretion).

B. Hard-to-monetise benefits of EnergyConnect

3.34 Based on our understanding of the project, and the power market modelling we have performed for TransGrid both in this report and as part of the FTI June report, we expect EnergyConnect to bring the following hard-to-monetise benefits to the NEM:

- Supporting the integration of renewable generation;
- Connecting complementary generation mixes in SA and NSW; and
- Contributing to security of supply in SA.

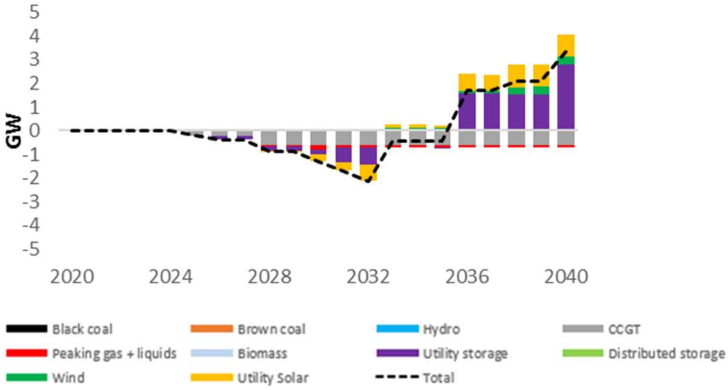
3.35 These hard-to-monetise benefits may not be fully accounted for in the RIT-T's strictly monetary approach. We discuss each benefit further detail below.

B.1 Renewables integration

3.36 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 neighbouring regions if demand within the domestic region is low.

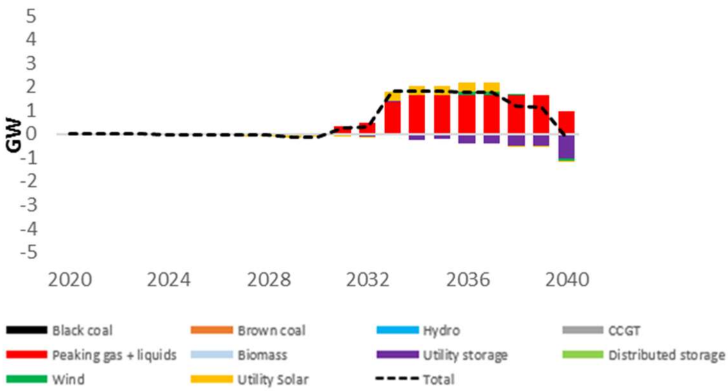
3.37 The figures below illustrate the impact of building EnergyConnect on generation capacity in SA and Vic respectively, classified by fuel type.

Figure 3-2: Change in SA generation capacity with EnergyConnect



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

Figure 3-3: Change in Vic generation capacity with EnergyConnect



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

3.38 The figures above illustrate the difference in total capacity with EnergyConnect (broken down by technology type) for each modelled year, relative to the counterfactual scenario without EnergyConnect. It shows that EnergyConnect enables the development of a greater volume of renewable capacity, in the form of solar, wind and utility storage in SA, and brings forward the develop of solar capacity and peaking generation in Victoria. It also facilitates the closure of gas generation (in particular, the early retirement of the Torrens Island B CCGT plant in SA).

3.39 Furthermore, EnergyConnect creates the option for excess renewables from one region to be exported to the other connected region, increasing the total demand that can be served. This may be particularly beneficial if there are specific geographic areas that are well suited to the deployment of renewables (i.e. experience high levels of sunshine or high wind speeds) but are distant from the significant load needed to consume electricity at times of peak production. The additional transmission provides greater market access for renewables generation and, in so doing, encourages additional production and deployment of renewables generation in the localities best suited for it.

3.40 This view is supported by AEMO. In its Final ISP 2020, AEMO explains that EnergyConnect is expected to support the development of solar generation in the Murray River REZ and in the Riverland REZ.[42] More generally, AEMO expects EnergyConnect will *"unlock already stranded renewable investments"*.[43]

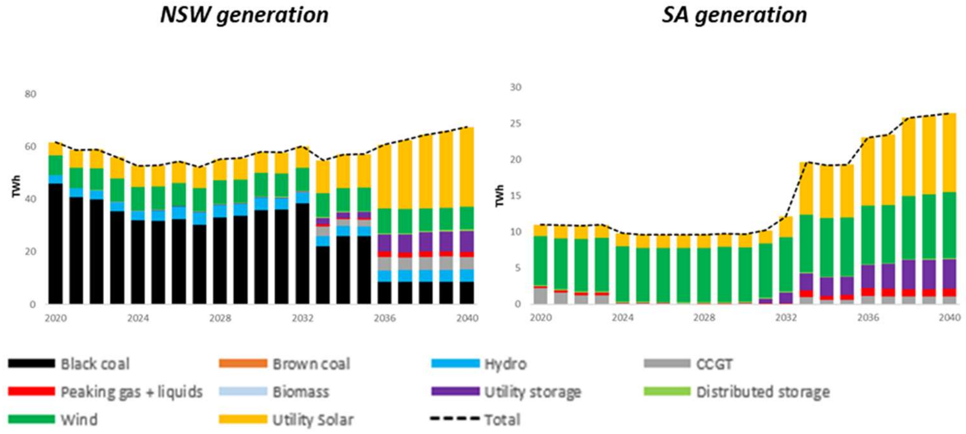
B.2 Connecting complementary generation mixes

3.41 EnergyConnect will connect the structurally different generation mixes of NSW and SA. As shown in the figure 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 generation. 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 generation 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.

42 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 49.

43 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 61.

Figure 3-4: NSW and SA generation mix with EnergyConnect



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

3.42 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 hard-to-monetise benefits to GB security of supply in having fuel source diversity.[44] We therefore consider it reasonable to highlight this effect as a hard-to-monetise benefit of the interconnector.

44 As discussed in Section 3A above, the benefit of connecting complementary generation mixes is assessed in Ofgem's Cap and Floor regime in GB. For example, Ofgem highlighted that the GB system would benefit from being 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. See Appendix 2 for further details.

B.3 Security of supply

3.43 EnergyConnect is also expected to provide security of supply benefits to the NEM, and particularly in SA. Reliability and security of supply in SA have been identified by AEMO as a growing challenge,[45] and AEMO is required from time-to-time to intervene in the market to ensure system security.[46,47]

3.44 In this section, we first discuss the impact of EnergyConnect on system security in general. We then consider whether EnergyConnect could help reduce the costs of services that help the system operator ("SO") maintain a stable and reliable power supply (known as "ancillary services" or "essential system services"). We focus in particular on the potential impact of EnergyConnect on Frequency Control Ancillary Services ("FCAS") spending.

Impact of EnergyConnect on overall system security

3.45 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).

3.46 In addition, EnergyConnect is likely to improve overall system flexibility, which will help mitigate the effect of unexpected, **high impact, low probability system stress events**.

---

45 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).

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

47 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).

3.47 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.[48] 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.[49] 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,[50] which has explored new mechanisms to manage this new type of risk to the electricity system. We discuss a number of these events, specifically disconnections in SA, in Box 3-1 below.

Box 3-1: 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.[51] 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[52] and a further $8 million in FCAS costs were incurred for the November 2019 separation event (which lasted only five hours).[53]

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.

---

48 AEMO, Reliability Standard Implementation Guidelines, August 2017 (link).

49 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.

50 AEMC, Mechanisms to Enhance Resilience in the Power System – Review of the South Australian Black System Event, December 2019 (link), page 13.

51 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).

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

53 AEMO, Quarterly Energy Dynamics Q4 2019, February 2020 (link), page 21.

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.[54] 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.

3.48 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 that should be recognised.

3.49 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.

3.50 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"*.[55]

3.51 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"*.[56] 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"*.[57]

---

54 AEMO, Quarterly Energy Dynamics Q1 2020, April 2020 (link),page 10. AEMO, Quarterly Energy Dynamics Q3 2018, November 2018 (link), page 3.

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

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

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

3.52 In its Final ISP 2020, AEMO reiterated this need, citing *"enhancing security of electricity supply in South Australia"* as a distinct identified need for EnergyConnect.[58]

Impact of EnergyConnect on expenditure on ancillary services

3.53 The system security benefits outlined above are likely to have an additional monetary effect in respect of reduced expenditure on ancillary services. Although there is a wide range of ancillary services that AEMO procures, the FCAS is a category of services that is particularly relevant for EnergyConnect.

3.54 During periods of system stress, a higher level of FCAS expenditure is necessary to maintain the frequency of the system within operational limits.

3.55 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.

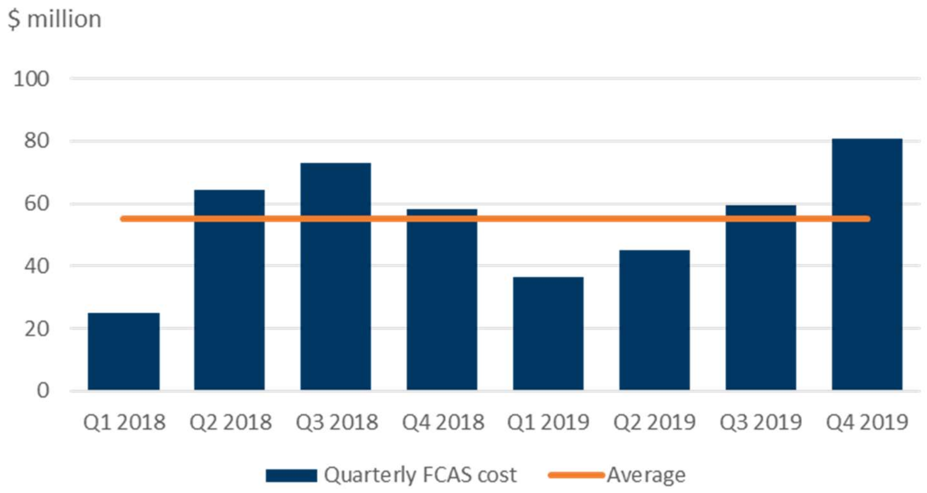
3.56 For EnergyConnect specifically, AEMO highlighted that *"by reducing the likelihood of islanding, EnergyConnect would reduce the incidence of these* [FCAS] *costs"*.[59]

3.57 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. 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.

58 AEMO, Final 2020 Integrated System Plan, July 2020 (link), page 86.

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

Figure 3-5: Total NEM FCAS per quarter (Q1 2018 – Q4 2019)



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

3.58 Between Q1 2018 and Q4 2019,[60] average total FCAS expenditure per quarter was around $55 million on a NEM-wide basis.[61] 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**.[62] On a present value basis between 2020 and 2040, this is equal to around $56 million.[63]

3.59 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.

---

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

61 AEMO, Quarterly Energy Dynamics Q1 2020 - Databook, April 2020 (link).

62 Source: FTI analysis.

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

3.60 Ofgem has also considered the impact of interconnectors on ancillary services expenditure, in particular in its assessment of the Window 1 interconnectors.[64] In the table below, we present ancillary service cost savings estimated by National Grid.[65] 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 3-3: 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.

3.61 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. This is equivalent to around $17.6 million and $25.4 million per year,[66] and suggests the $6.6 million per year estimate above may be a conservative one.

64 These were FAB Link (between GB and France), IFA2 (between GB and France), Viking Link (between GB and Denmark) and Greenlink (between GB and Ireland).

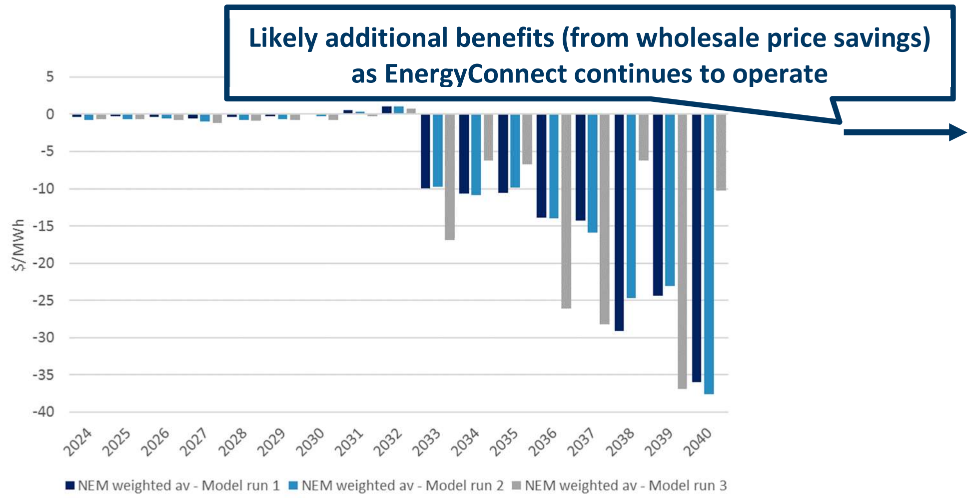
65 We exclude Greenlink as it was not expected to have a material effect on ancillary services.

66 Using a conversion rate of £1 to $1.81.

C. Wholesale price benefits arising beyond 2040

3.62 The wholesale price reductions calculated in Section 2 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,[67] such that some level of consumer price benefits would continue to accrue, albeit with a greater level of uncertainty. Furthermore, as annual benefits arising after 2040 are discounted to 2020, their materiality, while non-zero, is lower.

Figure 3-6: Modelled annual NEM wholesale price reductions from EnergyConnect (2024 to 2040)



Source: FTI analysis.

[67] 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.

3.63 As indicated in Figure 3-6 above we have sought to estimate the potential value of wholesale price savings to consumers for the 2041 to 2073 period. The magnitude of the 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) the demand for electricity. Nevertheless, it seems unlikely that the wholesale price 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.

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

- The **upper bound** estimate assumes the wholesale price reductions 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 $17.8/MWh in each year; and
- The **lower bound** estimate assumes the wholesale price reductions 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 $8.4/MWh in each year.

3.65 Based on this methodology, the estimated range for gross savings for the 2041 to 2073 period (i.e. the remaining asset life beyond 2040) is between **$6.8 billion and $14.7 billion** on an NPV basis.[68] Assuming that wholesale price savings are fully passed onto consumers, this value represents the gross savings to consumers.[69]

---

68 The estimate of annual wholesale price reductions arising after 2040 is discounted to 2020 at a discount rate of 5.9%. This range corresponds to Model Run 3 (NEM constraints).

69 In our June 2020 report, we briefly discuss the potential gross benefits to consumers under a lower societal discount rate (see FTI June report on the "Benefits of Project EnergyConnect" dated 29 June 2020). In GB, the Social Time Preference Rate (or society discount rate) set by the UK Treasury, and used to assess interconnectors, is 3.5% (National Grid, SO Submission to Cap and Floor, June 2017 (link), page 19 footnote 9). If this discount rate was adopted for EnergyConnect, gross benefits would be between $14.9 billion and $32.0 billion for the modelling period beyond 2040, on an NPV basis (this range corresponds to Model Run 3).

3.66 The total capex costs of EnergyConnect have most recently been estimated to be between $2.2 billion to $2.4 billion.[70] Taking this capex cost into account, in addition to opex[71] and the potential impact on interconnector residues arising as a result of EnergyConnect, would imply a total net benefit to consumers between 2041 and 2073 of **$5.5 billion to $13.9 billion** on an NPV basis.[72]

3.67 We recognise that the price impact of EnergyConnect may evolve over time and are therefore inherently more uncertain. This is because, as with the pre-2040 analysis, the price impacts 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. However, we consider the order of magnitude of the estimated post-2040 price savings to be reasonable based on the information that is currently available.

---

70 See shaded area of chart "*Project Connect Update: Stakeholder Webinar, 20 August 2020*", slide 26.

71 We assume that total opex is equal to $5 million per year.

72 This range corresponds to Model Run 3.

4. Other perspectives in assessing interconnector investments

4.1 The AER's RIT-T framework assesses proposed interconnector investments with reference to their **economic impact** on **all market participants**. The AER is prescriptive in the categories that are included in the RIT-T assessment, and the selection of reasonable inputs, discount rate and scenarios.[73] It is also a purely monetary assessment.

4.2 Regulators in other jurisdictions may assess specific projects from **different perspectives**. In some cases, regulators may **limit their focus to the economic impacts on consumers** alone. In others, **wider motivations** such as political or public policy objectives (rather than pure economic considerations) are used to assess interconnectors.

4.3 This section describes the alternative perspectives that are used by regulators in other jurisdictions (Section A) and illustrates how they might be considered in respect of EnergyConnect (Section B). We discuss the:

- consumer-focused approach used by Ofgem in GB;
- political factors recently considered by ENTSO-E in Europe; and
- public policy aims considered by US ISOs for certain categories of transmission assets.

A. Approaches in other jurisdictions

4.4 This subsection describes three alternative perspectives used to assess interconnector projects in the following jurisdictions:

(1) **In GB**, Ofgem consistently uses a **consumer-focused approach** to calculate the **monetary benefits of an interconnector.** Consumer benefits take precedence over any disbenefits to other categories of stakeholders**.**

(2) **In Europe**, ENTSO-E considers the wider impacts of interconnectors and has recently awarded a "priority" **PCI status** to an interconnector on the basis of **political motivations,** despite the project not being economically viable.

---

[73] For the full RIT-T guidelines see AER, Application guidelines: Regulatory investment test for transmission, December 2018 (link).

(3) **In the US**, some Independent System Operators ("ISOs") consider **public policy aims** when assessing certain categories of interconnectors.

4.5 The following subsections discuss each of these jurisdictions in detail.

Great Britain – Consumer-focused monetary assessment

4.6 Ofgem's assesses prospective interconnectors in discrete 'Windows'. As explained in Section 3 above, these are fixed periods of time in which interconnectors can apply for the Cap and Floor Regime.

4.7 Ofgem's assessment of the monetary benefits of interconnectors (as part of the Cap and Floor regime) 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"*.[74]

4.8 This was demonstrated in the most recent IPA of interconnectors in Window 2. For each interconnector assessed, Ofgem found significant positive net benefits for GB consumers, but only marginal or negative net benefits from the perspective of all GB stakeholders (i.e. consumers, producers and interconnectors). This is presented in the table below.[75]

Table 4-1: Summary of the welfare impacts of Cap and Floor Window 2 interconnectors (base scenario)

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

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

4.9 Each of the proposed interconnectors were, however, progressed to the next stage of the regulatory assessment, on the basis that they are *"likely to generate significant net benefits for GB consumers"*.[76]

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

75 GridLink will connect GB and France, NeuConnect will connect GB and Germany, NorthConnect will connect GB and Norway.

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

4.10 This suggests that Ofgem places much lower priority on the full societal impact of interconnector investment and is willing to award regulatory approval on the basis of significant benefits to GB consumers, despite the disbenefits to the society as a whole.

ENTSO-E – Consideration of political factors

4.11 As explained in Section 3 above, ENTSO-E considers both monetary and hard-to-monetise benefits when assessing interconnectors. Recently, political motivations, in conjunction with other hard-to-monetise benefits, have been used to accelerate the development of an interconnector project (the Celtic Interconnector) by providing a capex grant to the project developers.

4.12 The Celtic Interconnector is a proposed 700MW interconnector between Ireland and France.[77] Following the United Kingdom's ("UK") decision to leave the EU, there has been a renewed focus on the Celtic project as a means to reinforce "*solidarity*"[78] between Ireland and continental Europe, as it would be the only link between Ireland and the rest of the EU.

4.13 The project developers, EirGrid and RTE,[79] have previously explained that, in the absence of EU support, the interconnector was not commercially viable. They stated that *"the business plans for the Celtic Interconnector…provide clear evidence of the non-commercial viability of the project"*.[80]

4.14 The developers further highlighted that the Celtic Interconnector would help Ireland access 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*".[81]

---

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

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

79 Réseau de Transport d'Electricité ("RTE") is the electricity TSO in France.

80 EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link), page 41.

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

4.15 It appears that these two categories of hard-to-monetise benefits were a key factor in the project developers receiving a €530 million grant from the EU (equivalent to around 53% of the interconnector's capital cost).[82] On this basis, the project is now progressing and is expected to be commissioned in 2026.[83]

New York State – NYISO assessment of public policy assets

4.16 NYISO uses different approaches to assess transmission assets depending on the need the asset in question is intended to satisfy:

- Reliability assets – required to resolve certain potential technical standards violations (e.g. thermal, voltage, frequency, etc.).
- Economic assets – which reduce congestion costs and/or generate market benefits (e.g. by improving dispatch and reducing wholesales costs).
- Public policy assets – which are used to satisfy particular policies set by specific state governments (e.g. emissions targets).

4.17 While some transmission investments are developed as economic assets (and therefore are required to meet specific benefit-to-cost thresholds), there are other classes of transmission investments that follow different rules. In particular, the need for a public policy asset is typically identified by the New York Public Service Commission ("NYPSC"), the public utilities regulator for the New York State. NYISO evaluates each proposed solution on:

(1) the extent to which it independently satisfies the public policy need identified by the NYPSC;[84]

(2) any additional evaluation criteria specified by the NYPSC;[85] and

(3) its cost efficiency.[86]

---

82 EirGrid, EirGrid Welcomes Celtic Interconnector Funding Decision (link).

83 EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link), page 18.

84 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.4.6.4 (link).

85 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.4.6.4 (link).

86 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.4.8.1 (link).

4.18 NYISO's cost efficiency evaluation is based on several criteria, including:[87]

- proposed capital costs (in total and in per MW terms);
- the future expandability of the proposed solution;
- the impact of the solution on the operating flexibility of the NYISO system (e.g. impact on dispatch of generation, access to operating reserves or ancillary services); and
- other metrics NYISO deems appropriate.

4.19 Therefore, for public policy assets, the key consideration is the extent to which the transmission asset satisfies the public policy need in question. The regulator (the NYPSC) and NYISO are able to exercise a level of judgement in selecting a preferred solution. Monetary considerations remain relevant but are largely limited to a cost minimisation exercise. Moreover, there is no explicit need for NYISO to select the lowest cost solution.

4.20 By contrast, economic assets are assessed purely on a monetary basis (and the process is somewhat closer to the RIT-T assessment, compared to the public policy assets). A given economic transmission asset will only be allowed to earn a regulated return[88] if its benefits exceeds its costs.[89] Benefits are measured as *"production cost savings"*, and costs are measured as *"revenue requirements for the project"*.[90] NYISO will additionally consider other benefits, including the effect on ancillary services, transmission losses, and others.[91]

4.21 Overall, in the NYISO jurisdiction, the approach to assessing transmission solutions depends on the purpose of the asset. This differs from the one-size-fits-all approach of the RIT-T in the NEM. For assets intended to meet public policy objectives, NYISO and the NYPSC consider a wide range of factors and are able to exercise a degree of regulatory judgement. For economic assets, the range of factors is much narrower, and the assessment process is more prescriptive.

87 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.4.8.1 (link).

88 In NYISO's terminology, 'qualify for cost allocation'.

89 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.5.4.3 (link).

90 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.5.4.3.2 and ¶31.5.4.3.3 (link).

91 NYISO Open Access Transmission Tariff – Attachment Y, ¶31.5.4.3.6 (link).

B. Implications for EnergyConnect

4.22 In light of the different approaches to interconnector assessments described above, we consider that the wider, hard-to-monetise effects of EnergyConnect are likely to help the NSW and SA governments advance a number of stated public policy aims. In this way, the benefits of EnergyConnect can be seen through the lens of a 'public policy' objectives, similar to how certain European and US projects are evaluated when they are perceived to be in the wider interest of society.

4.23 First, both the NSW and SA governments are aiming to achieve net zero emissions by 2050.[92, 93] By facilitating greater integration of renewable generation in the NEM (as explained in Section 3 above), EnergyConnect will help advance this objective.

4.24 Second, the positive effect of EnergyConnect on security of supply in SA may also be in line with the "Energy Security Target" of the previous Government, which was designed to ensure energy system stability in a competitive and cost-effective manner.[94]

4.25 Third, EnergyConnect may also support the NSW government's wider economic objectives. This includes the NSW Government's Transmission Infrastructure Strategy to increase the state's "*transmission capacity and access to low-cost generation*"[95] and its 20-year Economic Vision for Regional NSW to support economic growth in rural NSW.[96]

4.26 Based on the above, we consider that wider public policy aims might warrant a consideration of factors beyond monetary cost savings (as is the case with ENTSO-E and NYISO) and lead the AER to exercise a greater degree of regulatory judgement in the assessment of the merits of EnergyConnect.

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

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

94 Government of South Australia, Energy Security Target Stakeholder Consultation (link).

95 NSW Government, Transmission Infrastructure Strategy (link).

96 NSW Government, A 20-Year Economic Vision for Regional NSW (link).

5. Assessing the incremental benefits of multiple interconnectors

5.1 Within a given electricity system, it is often the case that multiple prospective interconnectors are assessed simultaneously by the relevant authorities. This may be because they are developed in parallel, or because regulators deliberately seek to use the information provided by different developers to 'benchmark' the merits of the links, as part of the overall decision process.[97] If the interconnectors are close to each other both in temporal and geographical terms (for example, connecting to the same region(s) at around the same time), then the estimated welfare impact of any given interconnector will typically be closely interrelated with the other interconnectors being assessed at that time. This is because the inclusion of each additional interconnector impacts on the overall market dynamics and therefore may impact the other interconnectors being assessed.

5.2 As a simplified example, consider two proposed interconnectors, Interconnector A and Interconnector B, both of which are planning to connect the same two price zones. Suppose both interconnectors have yet to reach a Final Investment Decision ("FID"), as this is dependent on regulatory approval, which is in turn dependent on the expected benefits of the interconnectors. The individual contribution of each interconnector to market integration (and associated price convergence) is higher if the interconnector is assessed in isolation, but lower if the interconnector is assessed assuming that the other one will be built.

5.3 Under these circumstances, the expected incremental benefits of Interconnector A are dependent on whether or not Interconnector B is likely to be operational. The incremental benefits of Interconnector A are higher if Interconnector B is not approved, and lower if it is approved. More importantly, the regulatory assessment itself can have material impact on prospective developers. If a regulator assesses the merits of Interconnector A under the assumption that Interconnector B will be developed, then the estimated incremental benefits of Interconnector A will most likely be reduced.

---

97 For example, Ofgem typically invites groups of interconnector developers to submit applications for the Cap and Floor regime within pre-specified windows. In the past, Ofgem has thus assessed two groups of interconnectors through so-called Window 1 and Window 2.

5.4 This process can make it challenging to make a favourable decision on approving either interconnector, as, at the time of the assessment, it is uncertain whether either project will progress to FID. A situation may arise such that neither Interconnector A nor B bring net positive benefits *when the other link is taken as given*, yet individually, each of the interconnectors could be beneficial. In this case, the regulatory process could erroneously reject both applications, to the detriment of consumers. This problem is further compounded when more than two prospective interconnectors are being assessed.

5.5 In this section we first describe how other jurisdictions address the challenge of simultaneous assessment of multiple interconnector investments. We then consider how, in theory, the interaction of EnergyConnect's benefits with another interconnector being considered in the NEM, VNI West, might be taken into account.

Approaches in other jurisdictions

5.6 The various jurisdictions discussed in this report take different approaches to addressing the challenge of simultaneous interconnector assessment. We examine the approach taken in:[98]

- GB, through Ofgem's Cap and Floor regime; and
- Europe, through ENTSO-E's Cost Benefit Assessment.

Great Britain – Ofgem's Cap and Floor regime

5.7 Within each window, Ofgem assesses several interconnectors. For example, in its assessment of Window 2 interconnectors in 2017, the benefits of the GridLink, NeuConnect and NorthConnect Interconnectors were evaluated together.[99]

5.8 When assessing each individual interconnector within a given 'Window', Ofgem recognises that its welfare impact will depend on the other interconnectors in that window. Ofgem recognises, as discussed above, that this presents a challenge in terms of assessing the impact of each individual interconnector.

---

98 NYISO does not address this issue.

99 GridLink will connect GB and France, NeuConnect will connect GB and Germany, NorthConnect will connect GB and Norway.

5.9 Ofgem addresses this challenge by estimating, for each individual interconnector, two welfare impacts:[100]

- **The *"first additional"* ("FA") approach.** The welfare impact of the interconnector is estimated assuming no other interconnector projects within that 'Window' become operational. For Window 2, for example, the welfare impact of GridLink would be estimated assuming NeuConnect and NorthConnect do not become operational.
- **The "marginal additional" ("MA") approach.** The welfare impact of the interconnector is estimated assuming all other interconnector projects within that 'Window' become operational. For Window 2, for example, the welfare impact of GridLink would be estimated assuming both NeuConnect and NorthConnect are also commissioned.

5.10 This allows Ofgem to estimate a range of welfare impacts for each individual interconnector, with the FA approach giving the best case for the interconnector, and the MA approach giving the worst case.

Europe – ENTSO-E's Cost-Benefit Assessment

5.11 To address the challenge of simultaneous assessment, ENTSO-E's CBA models a reference network. The assessment method applied to each prospective interconnector then depends on whether it is included in the reference network, which is made up of:

- the existing network and projects that are already under construction; and
- projects in *"the 'permitting' or 'planned, but not yet permitting' phase where their timely realisation is most likely"*.[101]

5.12 Some of the interconnectors under assessment will therefore fall within the reference network if, for example, *"country specific legal requirements have stated the need of the projects"*.[102] Other prospective interconnectors will fall outside the reference network.

---

[100] Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017, page 23 (link).

[101] ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019 (link), page 13.

[102] ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019 (link), page 13.

5.13 Prospective interconnectors that fall within the reference network will be assessed using the Take Out One at the Time ("TOOT") method. This approach assumes all prospective interconnectors within the network reference are operational, then removes the interconnector being assessed, and calculates the change in load flow and other benefits indicators.[103]

5.14 Prospective interconnectors that fall outside the reference network, are then assessed using the Put In one at the Time ("PINT") method. This approach assumes all TOOT-assessed prospective interconnectors are operational, but that no other PINT projects are, then adds the interconnector being assessed.[104]

5.15 It is generally recognised that the TOOT method underestimates the benefits of prospective interconnectors, while the PINT method overestimates them.

5.16 ENTSO-E's approach differs slightly from Ofgem, in that the two different methods are not both applied to each interconnector being assessed. Instead, each interconnector is evaluated using one of the two methods, depending on its maturity. A significant amount of judgment is required therefore, when deciding whether a prospective interconnector should be included in the reference network.

103 ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019 (link), page 13.

104 ENTSO-E, 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects: Draft version, 15 October 2019 (link), page 13.

Interaction of the benefits of EnergyConnect with VNI West

5.17 VNI West is a proposed high voltage alternating current ("HVAC") interconnector between Victoria and NSW, which is being developed in parallel with EnergyConnect. It is expected to have a capacity of 1,930MW from Vic to NSW, and 1,800MW from NSW to Vic.[105] VNI West has been included in the ISP 2020 and is expected to be completed by 2027-28 under the accelerated timeline.[106,107]

5.18 We understand that the AER, in assessing the benefits of EnergyConnect for the NEM, requires that the developers take into account the potential development of VNI West. The key challenges with this approach are that:

- There is no certainty that VNI West will be developed. If EnergyConnect were to be rejected on the grounds that VNI West is going to be developed, and the VNI West investment did not materialise, then this could lead to an undesirable outcome for NEM consumers where neither project is built.
- The argument appears circular. If the regulatory decision on EnergyConnect assumes that VNI West is developed, and the regulatory decision on VNI West also assumes that EnergyConnect is developed, then both projects could end up being rejected, potentially to the detriment of NEM consumers.

---

105 Final ISP 2020, Appendix 3 (link), page 14.

106 Final ISP 2020 (link), page 15.

107 VNI West was originally expected to be complete by 2035-36. Final ISP 2020 (link), page 66.

5.19 In developing the Final ISP 2020, and selecting projects to be included in the *"optimal development path"*, AEMO (in line with AER guidelines) have ensured that the *"optimal development path must have a positive net benefit in the most likely scenario"*.[108] In doing so, AEMO has effectively assessed the benefits of the proposed transmission projects in aggregate.

5.20 Under the AER cost benefit analysis guidelines, a RIT-T proponent of an actionable ISP project is then required to assess the benefits of its proposed project using the "take out one at a time" approach. In calculating market benefits, the RIT-T proponent must:[109]

- include all actionable ISP projects, including the project being assessed, in its base case; then
- compare this to a scenario in which the project being assessed is removed.

5.21 This is similar to ENTSO-E's TOOT approach but does not include a corresponding PINT assessment. Applying this approach to the assessment of EnergyConnect requires one to assume that VNI West is developed, despite the fact that its approval is not yet certain.[110]

5.22 As previously discussed, ENTSO-E's TOOT approach inherently underestimates the benefits of prospective interconnectors. There is a risk therefore, that if the regulatory decision on EnergyConnect assumes VNI West is approved, and vice versa, that both projects are not approved, to the detriment of NEM consumers.

5.23 Alternatively, Ofgem's FA and MA methodology could be considered. In this approach, two separate calculations would be performed to estimate the envelope of potential benefits of Energy Connect:[111]

- The first would calculate the benefits of EnergyConnect while excluding VNI West from the actual and counterfactual scenarios, and give a 'best case' estimate of EnergyConnect's benefits; and

---

108 AER, Draft cost benefit analysis guidelines, 15 May 2020 (link), page 31. This requirement is retained in the finalised AER guidelines. See AER, Cost benefit analysis guidelines, 25 August 2020 (link), page 32.

109 AER, Draft cost benefit analysis guidelines, 15 May 2020 (link), page 61. This requirement is retained in the finalised AER guidelines. See AER, Cost benefit analysis guidelines, 25 August 2020 (link), page 63.

110 And vice versa for the assessment of VNI West.

111 In both calculations, one would model the NEM with EnergyConnect and compare it to the counterfactual of the NEM without EnergyConnect. The difference between the two scenarios would give the impact of the project.

- The second would include VNI West in both the actual and counterfactual scenarios and give a ‘worst case’ estimate of EnergyConnect’s benefits.

5.24 Ofgem’s approach may provide a more balanced assessment of EnergyConnect’s benefits, as it estimates a range of likely benefits of EnergyConnect, and does not depend on judgment over which of the two interconnectors is more likely to be constructed.

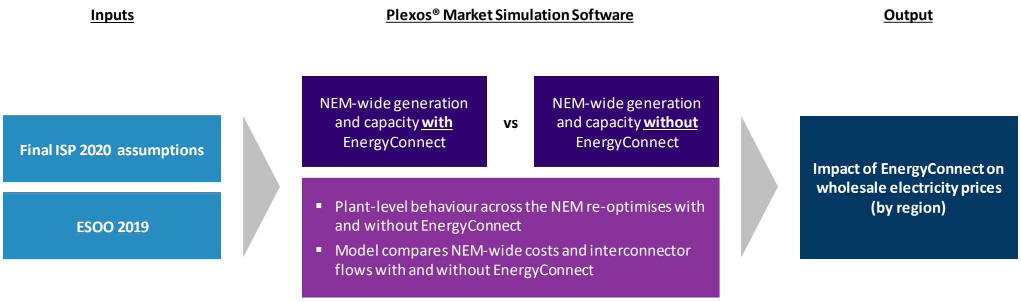
Appendix 1 Further detail on our modelling approach

A1.1 This appendix sets out the methodology used to calculate the impact of EnergyConnect on wholesale electricity prices (presented in Section 2). It describes:

- the modelling software used;
- our key inputs and assumptions; and
- the impact of EnergyConnect on NEM capacity and generation.

A1.2 Our overall approach is summarised in the figure below.

Figure A1- 1: Overview of our modelling approach



Modelling software used

A1.3 We use FTI's in-house power market model (that runs on the Plexos® Market Simulation Software), calibrated with a detailed representation of the NEM, to model the period 2020 to 2040.[112] The Plexos® platform is a plant-level dispatch optimisation software based on a detailed representation of the market supply and demand fundamentals at an hourly granularity. It considers individual power plant characteristics, including minimum generation levels and variable opex.[113]

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

113 For further technical details on FTI's in-house power market model, see FTI's June report (dated 29 June 2020).

A1.4 In our modelling of wholesale electricity prices, we have used a bidding methodology that approximates realistic generator bidding behaviour. The methodology – called Bertrand competition – 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).

A1.5 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.[114] The model assumes that EnergyConnect will be online from 1 July 2023.

A1.6 We calculate the incremental impact of EnergyConnect on each of the RIT-T benefit categories in the figure above, to give the total gross benefits of the proposed interconnector in each year over the modelling period 2020 to 2040. We then discount the annual incremental benefit to the start of 2020 at 5.9%.[115]

Main inputs and assumptions

A1.7 Our models use 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 ISP 2020, published in July 2020.[116] In particular, our inputs are sourced from the Central Scenario of ISP 2020. These were the most recent assumptions available at the time of modelling.[117]

---

114 The counterfactual model considers all existing NEM interconnectors, and treats the VNI and QNI minor upgrades as committed investments. We have applied the same interconnector assumptions as our June 2020 report (see FTI June report on the "Benefits of Project EnergyConnect" dated 29 June 2020).

115 ISP 2020 Central scenario WACC estimate. Source: AEMO ISP 2020 Inputs and Assumptions workbook, July 2020 (link).

116 AEMO, 2020 Integrated System Plan, July 2020 (link) and AEMO ISP 2020 Inputs and Assumptions workbook, July 2020 (link).

117 We have sought to reflect as many of AEMO's ISP 2020 input assumptions as possible in the time available. Given the limited time available to perform this analysis, we have not been able to fully reflect some of the structural updates to modelling. This includes: (i) complex heat rates; and (ii) modelling batteries and pumped hydro assets of multiple durations. Furthermore, this analysis pre-dates the release of AEMO's ISP 2020 Plexos® model and therefore AEMO's ISP 2020 model input files were unavailable at the time this analysis was undertaken.

A1.8 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[118] and stability constraints.[119]

A1.9 The figure below summarises the main input assumptions we used and compares this to assumptions used in previous assessments of EnergyConnect.

Figure A1- 2: Summary of main input assumptions

Assumption	ElectraNet PACR (Feb 2019)	AER Determination (Jan 2020)	FTI (Jun 2020 report)	FTI (Aug 2020)
Minimum Capacity Factor (Pelican Point 50%, Osborne 60%, Torrens B 25%)	✓	✗	✗	✗
ISP assumptions	ISP 2018	ISP 2018	Draft ISP 2020	ISP 2020
SA gas closures	AEMO modelled retirements as **exogenous** input	**Endogenous**	**Endogenous** (SA gas, except Osborne and Torrens A committed)[1]	**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]	ISP 2020: NSW black coal [8hrs/8hrs] SA gas [4hrs/4hrs]
Minimum load	Redacted	Redacted	Draft ISP 2020	Final ISP 2020
Start up cost	Not modelled	Consider them reasonable to include	ACIL Allen (average of cold, warm and hot start)	ISP 2020 and ACIL Allen[4]
Two synchronous units online at all times[2]	✓	✓	✓	✓
Inertia capability (i.e. ROCOF constraint)	1,300 MW	4,400 MW	4,400 MW	4,400 MW
Non-synchronous cap	1,870 MW	2,000 MW	2,000 MW	2,000 MW
Interconnector flow limits – Heywood and combined Heywood + Energy Connect	✓	✓	✓	✓
Fast Frequency Response (FFR)	Not applicable at the time	Not applicable at the time	Not applicable at the time	400MW of SA battery without EnergyConnect
ESOO stability constraints (additional to those mentioned above)	Some SA voltage constraints	Unknown	Different combinations of SA and NEM constraints[3]	Different combinations of SA and NEM constraints[3]
Capital cost of SA pumped hydro	$1.4m/MW	$1.9m/MW	~$1.9m/MW (Draft ISP 2020 Central)	~$2.9m/MW (ISP 2020 Central)

Sources: AEMO, 2020 Integrated System Plan, July 2020 (link), AEMO, Electricity Statement of Opportunities, August 2019 (link), ElectraNet, SA Energy Transformation RIT-T - PACR, February 2019 (link), AER, Decision: South Australian Energy Transformation, January 2020 (link).

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

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

Notes: (1) only SA gas units were modelled endogenous due to modelling limitations. (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 Energy Connect is commissioned. (3) As explained below, we have tested three combinations of stability constraints. (4) We model only one type of generator start (i.e. we do not differentiate between hot, warm and cold starts). The ISP 2020 inputs and assumptions workbook (July 2020) outlines warm and cold start costs for some GPG units, and we use an average of these costs. For generators not included in the ISP 2020 workbook, start-up costs are calculated as an average of hot, warm and cold start costs, published by ACIL Allen.

Stability constraints

A1.10 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:[120]

A1.11 **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.
- A cap equal to 2,000 MW plus the flow on Heywood Interconnector on SA non-synchronous generation, which is removed once EnergyConnect is commissioned.
- A 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.

A1.12 **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.

A1.13 **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.

120 The stability constraints are taken from ESOO 2019 and were the most recent available constraint set at the time of modelling.

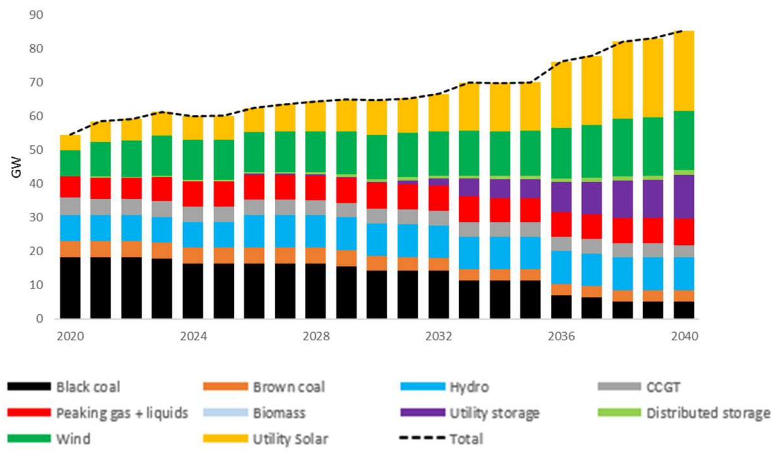
Effect of EnergyConnect on NEM capacity mix

A1.14 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 ISP 2020 assumptions regarding planned closures and new build dates.
- **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.[121]

A1.15 The figures below illustrate to outcomes of these capacity assumptions. The figure below presents the counterfactual NEM capacity without EnergyConnect.

Figure A1- 3: Baseline NEM capacity without EnergyConnect



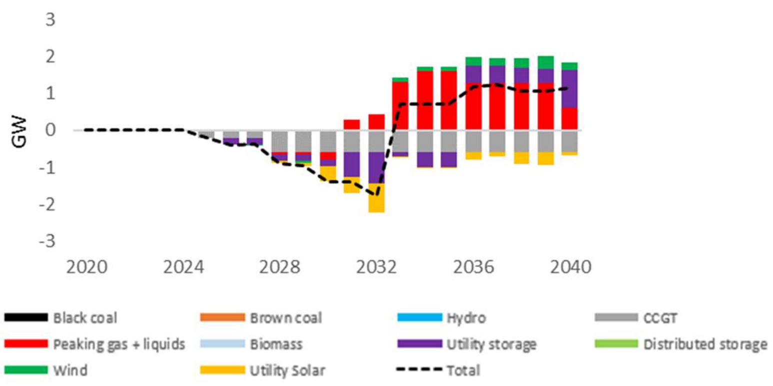
Source: FTI analysis.

[121] The exceptions to these assumptions are Torrens Island A and Osborne. The announced retirement dates for these units are treated as committed.

Note: Capacity evolution is the same across all Model Runs.

A1.16 As shown in the figure above, without EnergyConnect, the volume of gas generation capacity is expected to remain relatively constant, while that of solar, wind and utility storage generation capacity is likely to rise. The figure below then illustrates how this is expected to change with EnergyConnect.

Figure A1- 4: Change in NEM capacity with EnergyConnect



Source: FTI analysis.
Note: Change in capacity is the same across all Model Runs.

A1.17 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. For example, in 2028, after EnergyConnect is commissioned, there is 600MW less CCGT[122] (i.e. Torrens Island B retires) and marginally less peaking gas, utility storage and solar, relative to the counterfactual scenario without EnergyConnect.

A1.18 EnergyConnect is expected to reduce the probability of SA needing to be operated as an electrical island, and hence mitigate the need for 400MW of Fast Frequency Response ("FFR") in SA.[123] This contributes to a reduction in utility storage capacity with EnergyConnect in the 2020s, relative to the counterfactual without EnergyConnect.

---

122 In our baseline scenario (without EnergyConnect) one unit of Torrens Island B is retired by the model in 2027. In the scenario with EnergyConnect, the model retires one unit of Torrens Island B in 2024 and the remaining three units in 2027. These additional closures mean that, relative to the baseline, there is 600MW less CCGT capacity in SA from 2027.

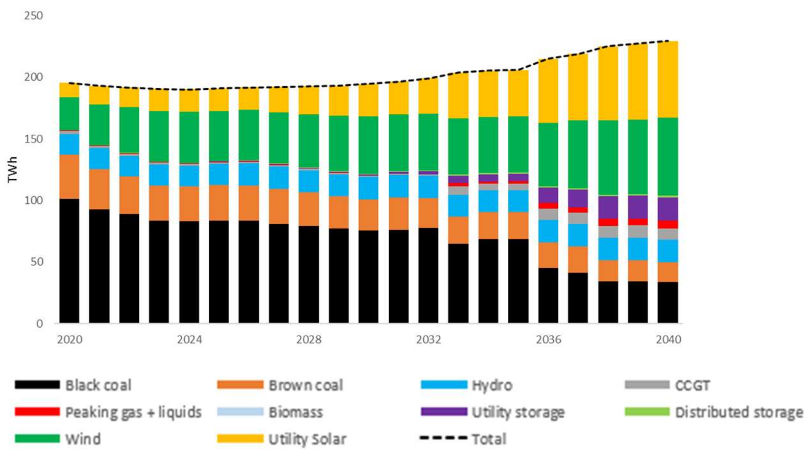
123 AEMO, ISP 2020 Appendix 7 (link), page 57.

A1.19 As part of the model's re-optimisation of NEM capacity in the presence of EnergyConnect, new capacity is constructed across the NEM (in particular additional peaking gas and storage capacity). This additional capacity is predominately built in SA and Vic.

Effect of EnergyConnect on NEM generation mix

A1.20 The figure below presents the modelled counterfactual NEM generation, without EnergyConnect:

Figure A1- 5: Baseline NEM generation profile without EnergyConnect (Model Run 3)

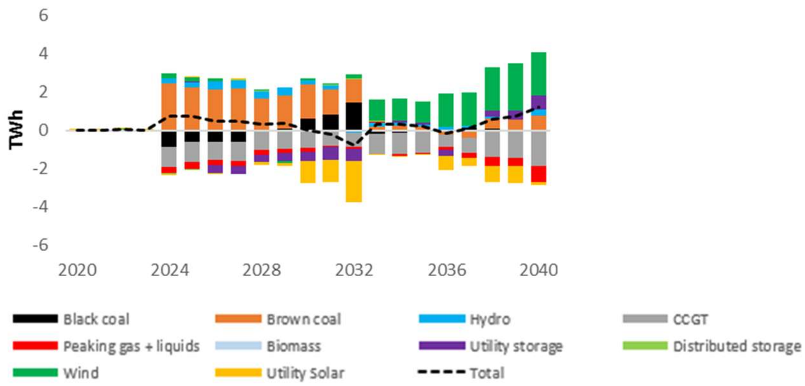


Source: FTI analysis.
Note: This chart presents the generation mix for Model Run 3. Generation is broadly similar in Model Runs 1 and 2.

A1.21 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 29% 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 71% of total TWh output over the same period.

A1.22 The figure below shows how the forecast NEM generation profile changes with EnergyConnect:

Figure A1- 6: Change in NEM generation with EnergyConnect (Model Run 3)



Source: FTI analysis.
Note: This chart presents the change in generation for Model Run 3. The absolute quantity of the change in generation is larger in Model Runs 1 and 2, but the sources of generation are broadly similar.

A1.23 In the 2020s, SA gas generation and NSW black coal generation are displaced predominately by Vic brown coal, which is a less expensive form of generation. This displacement is facilitated by exports of brown coal generation from Vic to SA, with some of this 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 wind generation (SA and a small amount from Vic) and storage (SA).

Appendix 2 Interconnector assessments in other jurisdictions

A2.1 In this appendix, we provide further information on the assessment of interconnectors in other jurisdictions. We focus on Ofgem's Cap and Floor assessment (Section A), ENTSO-E's CBA methodology (Section B) and the NYPA's assessment of the Hudson Interconnector (Section C).

A. Ofgem's Cap and Floor assessment

A2.2 The Cap and Floor regime is the *"regulated route for interconnection investment within GB"*.[124] 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.[125] This exposes developers to some of the variability in the congestion revenues earned by the interconnector.

A2.3 Ofgem's primary consideration in its Cap and Floor assessment is the social welfare impact on British consumers, although the change in total GB welfare (i.e. change in consumer, producer and interconnector welfare) is also considered.[126]

A2.4 During the IPA (which is the first stage of the assessment process), Ofgem evaluates proposed interconnectors using the following elements:

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

---

124 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), page 2.

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

126 Ofgem, Cap and floor regime: Initial Project Assessment of the GridLink, NeuConnect and NorthConnect Interconnectors, June 2017 (link), page 8.

A2.5 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).

Case study: GridLink

A2.6 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.[127]

A2.7 In its IPA, Ofgem explained that GridLink is likely to bring *"net positive strategic and sustainable impacts…*[by] *increasing the level of connection to a market with a significantly different and low-carbon electricity mix"*.[128] It further highlighted the positive impact on GB security of supply and carbon emissions targets.[129]

A2.8 A summary of Ofgem's assessment of the hard-to-monetise benefits of GridLink is outlined in Table A2- 1: below:

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

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

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

Table A2- 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 SO	*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
Providing alternative solutions to increase GB security of supply	○ *Access to high levels of nuclear generation in France leads to increase in fuel diversity;* ○ *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* ○ *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), page 42.

A2.9 There is no official methodology published that explains how Ofgem determines the ratings outlined in the table above.

Case study: NeuConnect

A2.10 NeuConnect is a planned 1.4GW interconnector, of around 720 km, and would be the first direct undersea power link between Germany and GB.[130] 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.

130 NeuConnect, Project overview (link).

A2.11 Ofgem expects NeuConnect to facilitate a more efficient dispatch of renewable generation across the GB and German markets, driven by negatively correlated weather patterns as well as time and daylight differences.[131] This is despite the generation mix in Germany being similar to that of GB.[132]

A2.12 A summary of Ofgem's assessment of the hard-to-monetise benefits of NeuConnect is outlined in Table A2- 2 below:

Table A2- 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	*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	○ *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;* ○ *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* ○ *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), page 42.

---

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

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

Case study: NorthConnect

A2.13 The NorthConnect Interconnector is a proposed 1.4GW link between GB and Norway.[133] The interconnector will connect a wind-reliant area of the Scottish grid to a region of Norway that produces surplus, readily available hydropower.

A2.14 In its IPA, Ofgem stated that NorthConnect is likely to facilitate increased connection to Norway's *"significantly different and low-carbon electricity mix"* and improve the dispatch of renewable generation across both markets.[134]

A2.15 A summary of Ofgem's assessment of the hard-to-monetise benefits of NorthConnect is outlined in Table A2- 3 below:

Table A2- 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	○ *Access to high levels of hydro generation in Norway leads to increase in fuel diversity* ○ *Interconnector mostly expected to import to GB leads to increase in capacity of supply; and* ○ *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

133 NorthConnect, Information brochure (link).

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

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

B. ENTSO-E's Cost-Benefit Analysis methodology

A2.16 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 CBA and European interconnection targets are discussed in this subsection.

ENTSO-E Cost Benefit Analysis

A2.17 Every two years, ENTSO-E assesses potential transmission projects in Europe and publishes its recommendation in its 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.[135]

A2.18 Each project included in the TYNDP is assessed using the pan-European CBA methodology. This methodology sets out the range of criteria considered in the assessment of the costs and benefits of transmission and storage projects, all of which stem from European policies on market integration, security of supply and sustainability. The CBA also helps to determine if a proposed interconnector can be considered a PCI. PCIs are entitled to a number of benefits (discussed in Section 3 above), including the right to apply for funding from the CEF.[136]

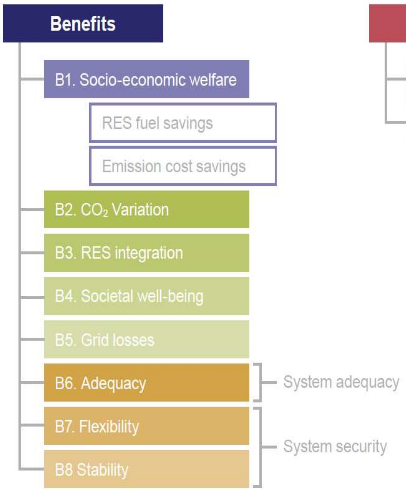
A2.19 The current CBA framework is version two ("CBA 2.0"), but ENTSO-E is also in the process of consulting on draft rules for CBA version three ("Draft CBA 3.0").

A2.20 **CBA 2.0:** 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 the figure below:

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

[136] European Commission, Key cross border infrastructure projects (link).

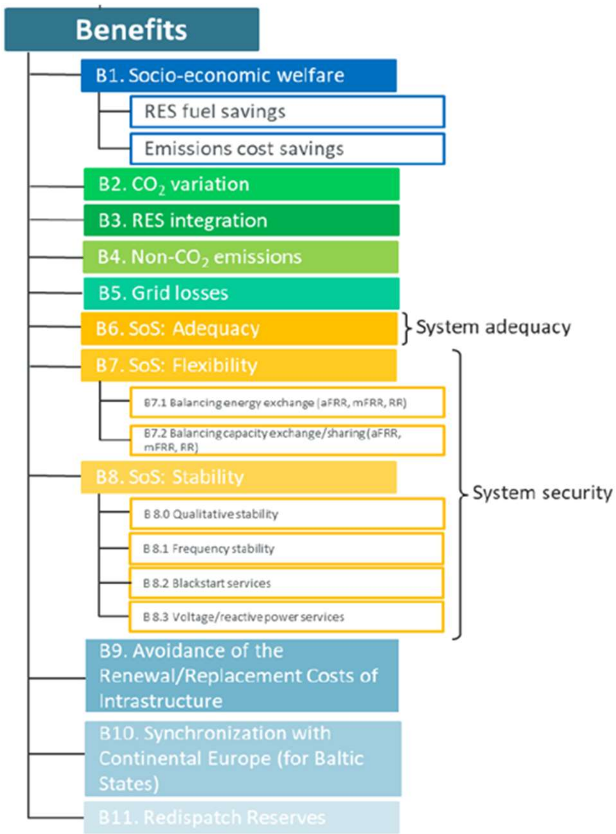
Figure A2- 1: CBA 2.0



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

A2.21 **Draft CBA 3.0**: The latest CBA methodology is in the process of being developed and is illustrated in the figure below. The Draft CBA 3.0 methodology has added new and modified existing benefit categories. Notably, it has added or amended criteria, including System Adequacy (B6), Stability (B8) and Synchronisation with Continental Europe for the Baltic States (B10).

Figure A2- 2: 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).

European interconnection targets and policy

A2.22 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.

A2.23 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.[137]

---

[137] EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link), page 3.

A2.24 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.[138] Specific benefits of interconnectors that have been identified by the group include: [139]

- Market integration;
- Climate and environmental benefits;
- Security of supply;
- **Political relevance and European integration**; and
- Industrial competitiveness and innovation

A2.25 On political relevance, the European Commission makes the following argument:[140]

> *"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."*

A2.26 We observe that these 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.

---

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

139 EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link), pages 10 to 14.

140 EC, Report of the Commission Expert Group on electricity interconnection targets, Nov 2017 (link), page 14.

Case study: Celtic Interconnector

A2.27 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, RTE. It has been designated as a PCI for the North Seas Countries Offshore Grid Initiative priority corridor in 2013.[141]

A2.28 Following the UK's decision to leave the EU, the Celtic project became a renewed area of focus to reinforce "*solidarity*"[142] between Ireland and continental Europe, as it would be the only link between Ireland and the rest of the EU.

A2.29 **Cost benefit assessment:** As part of their investment case, EirGrid and RTE proposed the following benefits would be created by the Interconnector, only one of which is monetary:[143]

- 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;
- 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 energy connection to other EU Member States once the UK leaves the EU; and
- Help to improve telecommunications between Ireland and continental Europe, as the project will also lay a fibre optic link between the two nations.

A2.30 As per the CBA framework, eight categories of project benefits were assessed as part of the project's assessment. In the table below, the best and worst case across all four scenarios assessed is presented:

---

141 EirGrid & RTE, Celtic Interconnector Project Investment Request File, September 2018 (link), page 6.

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

143 Celtic Interconnector, Project PCI Information Brochure (link).

Table A2- 4: Celtic Interconnector 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).

A2.31 As part of the CBA, the project developers also noted that they expect Celtic to contribute towards the following EU-level objectives:[144]

- 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.

144 Celtic Interconnector, Project PCI Information Brochure (link).

A2.32 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*".[145] 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.

A2.33 It appears that political motivations, in conjunction with other hard-to-monetise benefits 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.

---

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

C. NYPA's assessment of the Hudson Interconnector

A2.34 In this subsection, we discuss the assessment of hard-to-monetise benefits in the US in the context of a specific interconnector recently developed between New York and New Jersey: the Hudson project.

Case study: Hudson Transmission Project

A2.35 In 2005, NYPA identified the need for additional capacity in the New York City area,[146] 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.

A2.36 NYPA issued a request for proposals to meet that demand.[147] In response to this request, NYPA received several submissions, including proposals to build new generation and to build the 660 MW Hudson Interconnector between NYISO and PJM. Hudson is one of the few examples of an electricity interconnector between different ISOs within the US and was completed in June 2013.

A2.37 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).[148] This was considered in addition to the assessment criteria and long term objectives discussed in Section 3 above.

A2.38 In 2010, NYPA set out both the monetary and hard-to-monetise benefits of the Hudson Interconnector project, which led it to select Hudson over other alternatives.[149] It is unclear what relative weighting was placed on each criterion.

A2.39 **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.

A2.40 Among all projects submitted to NYPA, Hudson was estimated to provide the greatest benefit at the lowest cost.

---

[146] The Hudson Project website (link).

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

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

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

A2.41 **<u>Hard-to-monetise</u>**: As required by the evaluation framework, NYPA considered a number of hard-to-monetise factors when assessing the project. The following were cited as factors in support of the project:[150]

- 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.

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

Glossary

Term	Definition
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CBA	Cost benefit analysis
CBA 2.0	Current CBA Framework
CEF	Connecting Europe Facility
CPA	Contingent Project Application
Draft CBA 3.0	CBA version three
EnergyConnect	Project Energy Connect
ENTSO-E	European Network of Transmission System Operators for Electricity
ESOO 2019	Electricity Statement of Opportunities 2019
EU	European Union
FA	First Additional
FCAS	Frequency Control Ancillary Service
FFR	Fast Frequency Response
FID	Final Investment Decision
FTI	FTI Consulting
GB	Great Britain
Hudson	Hudson Transmission Project
HVAC	High Voltage Alternating Current
IPA	Initial Project Assessment
ISO	Independent System Operator
ISP	Integrated System Plan
MA	Marginal Additional
NEM	National Electricity Market
NPV	Net Present Value
NSW	New South Wales
NYISO	New York Independent System Operator

Term	Definition
NYPA	New York Power Authority
NYPSC	New York Public Service Commission
PACR	Project Assessment Conclusions Report
PCI	Projects of Common Interest
PINT	Put In one at the Time
QNI	Queensland-New South Wales Interconnector
REZ	Renewable Energy Zones
RFT	Request for Tender
RIT-T	Regulatory Investment Test for Transmission
ROCOF	Rate of Change of Frequency
RTE	Réseau de Transport d'Electricité
SA	South Australia
SO	System Operator
TNSP	Transmission Network Service Providers
TOOT	Take Out One at the Time
TSO	Transmission System Operators
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom
US	United States
VNI	Victoria-New South Wales Interconnector
WACC	Weighted Average Cost of Capital
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