Directlink Joint Venture

Managing IGBT failure risk across Directlink

RIT-T – Project Specification Consultation Report

8 April 2021

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Executive Summary

Energy Infrastructure Investments Pty Ltd on behalf of the Directlink Joint Venture is applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining Directlink's capacity to the end of its technical life, in light of the obsolescence of the existing insulated gate bi-polar transistors (IGBTs). Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

In October 2018, we were notified by the sole provider of Directlink's existing IGBTs ('Generation One' IGBTs) that due to the cessation of the manufacture and supply of crucial inputs it would no longer provide support for, or manufacture, the IGBTs that are currently used in Directlink.

The cost of replacing a proportion of the Generation One IGBTs was accepted by the Australian Energy Regulator (AER) in June 2020 as part of its determination of Directlink's regulated revenue for the current regulatory control period, based on our assessment of alternative options. The AER noted that the progression of the replacement investment would be subject to the successful completion of a RIT-T.[1]

We are therefore now commencing this RIT-T in order to assess and consult on the options for responding to the obsolescence of Generation One IGBTs.

The 'identified need' is to most efficiently maintain the full capacity of Directlink until end-of-life

Directlink comprises three parallel HVDC transmission lines, each of which are approximately 58 kilometres long, and delivers electricity between the New South Wales (NSW) and Queensland National Energy Market (NEM) regions. Specifically, Directlink connects the Terranora Interconnector[2] to the rest of the NSW network.

Converter stations for Directlink are located at Bungalora and Mullumbimby, both of which are located in NSW. Although geographically located in NSW,

[1] AER, *Directlink Transmission Determination 2020 to 2025*. Final Decision, Attachment 5 - Capital expenditure, June 2020, p. 11.

[2] The Terranora Interconnector is a high voltage alternating current (HVAC) 110kV double circuit between Mudgeeraba substation in Queensland and Terranora substation in NSW.

Directlink’s positioning in the transmission network is such that it effectively delivers electricity between NSW and Queensland and it has a capacity to delivery 180 MW into the alternating current (AC) network in either state.

Central to the operation of Directlink are IGBTs, which are semiconductor switching devices providing high efficiency and fast switching as part of the converter stations. IGBTs assist with switching power from AC to DC and, without them, the converter stations, and Directlink, would not be able to operate.

Action is required to replace the now obsolete Generation One IGBTs in order for Directlink to continue to operate and provide its full capacity, in line with its authorisation.

If no action is taken, continued failure would lead to the need to remove one of Directlink’s three lines from service, representing 60 MW of transmission capacity, since the line would not be able to be operated without sufficient spares. The mothballing of one line would then enable the IGBTs from the mothballed system to be used as spares to enable continued use of the other two lines. However, this will diminish the ability of Directlink to facilitate the efficient flow of electricity in the NEM and would be in breach of its authorisation as it would materially lower its available capacity.

We consider this a ‘reliability corrective action’ under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards (ie, continuing service under Directlink’s authorisation).

Three credible options have been identified

We consider there are three credible options that would meet the identified need from a technical, commercial and project delivery perspective. Each option facilitates retaining the existing capacity of Directlink (ie, 180 MW) until the end of its economic life in 2041.

Table E-1 –Summary of the credible options

Option	Description	Estimated capital cost	Estimated annual operating cost	Estimated completion date
1	Long term service contract with Hitachi ABB Power Grids to manage the ongoing	$3.417 million for years 1 to 10 $2.138 million for years 11 to 20		Ongoing from 2021

	replacement of the IGBTs			
2	Replace IGBTs one valve room at a time, with the timing dictated by failure rates	$15.4 million per valve room	2 per cent of capex	Timing to differ by scenario (see section 3.2)
3	Replace IGBTs one entire converter building at a time, with the timing dictated by failure rates	$29 million per converter building	2 per cent of capex	Timing to differ by scenario (see section 3.3)

Non-network options are not expected to be able to assist

We consider it unlikely to be commercially feasible for non-network solutions to assist with meeting the identified need for this RIT-T. This is due to the fact that IGBTs play a unique and specific role in the transmission of electricity for Directlink and that they have a relatively low replacement cost.

Notwithstanding, this PSCR sets out the required technical characteristics that a non-network option would need to provide, consistent with the requirements of the RIT-T and in order to ensure that we have fully canvassed all alternative options. We encourage any potential providers of non-network options to contact us if they consider that they could provide these characteristics in a cost-effective manner.

Wholesale market benefits will be modelled for this RIT-T

Each of the options is expected to have a significant impact on the wholesale market compared to the base case, since they are designed to avoid mothballing one Directlink line and, instead, maintain the full capacity of Direclink until the end of its technical life.

Based on preliminary market modelling undertaken, we propose to estimate the following categories of market benefit for each of the options as part of the assessment in the Project Assessment Draft Report (PADR):

- o changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- o changes in costs for parties, other than the RIT-T proponent (ie, changes in investment in generation and storage); and
- o differences in unrelated transmission investment (in particular, the cost of connecting Renewable Energy Zones).

While we view these market benefits as being relevant for this RIT-T, they are not expected to not affect the identification of the preferred option. This is because each of the three options maintain the existing capacity of Directlink going forward and so provide the same level of wholesale market benefits, compared to the base case. As such, these benefits will be quantified in the PADR to demonstrate the overall expected level of benefits from replacing the identified assets, though their inclusion is not expected to be material to the identification of the preferred option.

Three different scenarios are proposed to address uncertainty

The credible options will be assessed using three different scenarios, which differ in terms of the key drivers of the estimated net market benefits. It is this 'expected' (weighted) net benefit that will be used to rank credible options and identify the preferred option.

The three alternative scenarios can be characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits;
- a 'central' scenario which consists of assumptions that reflect our central set of variable estimates that provides the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions which have been selected to investigate an upper bound of net economic benefits.

The table below summarises the specific key expected variables that we expect to influence the net benefits of the options, and our current expectation around the parameters that will be included under each scenarios.

Table E-2 – Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
ISP scenario	2020 ISP central scenario	2020 ISP slow scenario	2020 ISP step-change scenario
Failure rate of IGBTs	56/year	63/year	48/year
Discount rate	5.90 per cent	7.90 per cent	2.23 per cent

At this stage, we are intending to consider three scenarios from the 2020 ISP that capture a range of possible wholesale market impacts. However, we intend to review the outcomes of the wholesale market modelling to determine whether the inclusion of alternative ISP scenarios is warranted, given the extent of work associated with modelling each scenario and its potential impact on the outcomes of the RIT-T assessment.

In addition to the scenario analysis, we will also consider the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity and ‘boundary’ testing.

Submissions and next steps

We welcome written submissions on material contained in this PSCR. Submissions are due on or before **Friday 2 July 2021**.

Submissions should be emailed to rittdirectlink@apa.com.au. In the subject field, please reference ‘IGBT RIT-T PSCR’.

Submissions will be published on the APA Group website. If you do not want your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

Subject to issues raised in submissions to this PSCR, a Project Assessment Draft Report (PADR), including full options analysis, is expected to be published in mid-2021.

1 Introduction

Energy Infrastructure Investments Pty Ltd on behalf of the Directlink Joint Venture is applying the Regulatory Investment Test for Transmission (RIT-T) to options for maintaining Directlink's capacity to the end of its technical life, in light of the announced obsolescence of the existing insulated gate bi-polar transistors (IGBTs) that form an integral part of Directlink's capability. Publication of this Project Specification Consultation Report (PSCR) represents the first step in the RIT-T process.

Directlink delivers electricity between the New South Wales (NSW) and Queensland National Energy Market (NEM) regions. Specifically, Directlink connects the Terranora Interconnector[3] to the rest of the NSW network.

Directlink comprises three parallel HVDC transmission lines, each of which are approximately 58 kilometres long. Converter stations for Directlink are located at Bungalora and Mullumbimby, both of which are located in NSW. Although geographically located in NSW, Directlink's positioning in the transmission network is such that it effectively delivers electricity between NSW and Queensland and it has a capacity to delivery 180 MW into the alternating current (AC) network in either state.

Central to the operation of Directlink are IGBTs, which are semiconductor switching devices providing high efficiency and fast switching as part of the converter stations. IGBTs assist with switching power from AC to DC and, without them, the converter stations, and Directlink, would not be able to operate.

In October 2018, we were notified by Hitachi ABB Power Grids[4] (the sole provider of Directlink's existing IGBTs) that due to the cessation of the manufacture and supply of crucial inputs it would no longer provide support for, or manufacture, the Generation One IGBTs that are currently used in Directlink. The cost of replacing a proportion of the Generation One IGBTs was accepted by the Australian Energy Regulator (AER) in June 2020 as part of its determination of Directlink's regulated revenue, based on our assessment of

3 The Terranora Interconnector is a high voltage alternating current (HVAC) 110kV double circuit between Mudgeeraba substation in Queensland and Terranora substation in NSW.

4 Specifically, we were notified by ABB, who have since merged with Hitachi to form Hitachi ABB Power Grids.

alternative options. The AER noted that the progression of the replacement investment would be subject to the successful completion of a RIT-T.[5]

We have therefore now commenced this RIT-T in order to assess and consult on the options for responding to the obsolescence of Generation One IGBTs.

1.1 Purpose

The purpose of this PSCR is to:

- set out the reasons why we propose that action be undertaken (that is, the 'identified need');
- present credible network options that can address the identified need;
- set out the technical characteristics that a network support option would be required to deliver to address this identified need; and
- discuss specific categories of market benefit that, in the case of this RIT-T assessment, are expected to be material (and those that are not).

The entire RIT-T process is detailed in Appendix B. The next steps for this particular RIT-T assessment are discussed further below.

1.2 How to make a submission and next steps

We welcome written submissions on material contained in this PSCR. Submissions are due on or before **Friday 2 July 2021**.

Submissions should be emailed to rittdirectlink@apa.com.au. In the subject field, please reference 'IGBT RIT-T PSCR'.

Submissions will be published on the APA Group website. If you do not want your submission to be made publicly available, please clearly specify this at the time of lodging your submission.

Subject to issues raised in submissions to this PSCR, a Project Assessment Draft Report (PADR), including full options analysis, is expected to be published in mid-2021.

5 AER, *Directlink Transmission Determination 2020 to 2025*. Final Decision, Attachment 5 - Capital expenditure, June 2020, p. 11.

2 The 'identified need'

This section outlines the identified need for this RIT-T, as well as the assumptions underpinning it. It first sets out useful background on the Directlink interconnector.

2.1 Background to the identified need

Directlink was commissioned in 1999 and comprises three parallel HVDC transmission lines, each of which are approximately 58 kilometres long. Converter stations for Directlink are located at Bungalora and Mullumbimby, both of which are in NSW. In addition, there is:

- a 132 kV line that runs from Dunoon to Mullumbimby; and
- a 110 kV line that runs from Bungalora to Terranora.

Directlink has a capacity to delivery 180 MW into the AC network in NSW and Queensland.

Figure 2-1 provides a network diagram for the Directlink system, showing the six converter stations in red, ie, three at Mullumbimby and three at Bungalora.

Figure 2-1 – Overview of the Directlink system

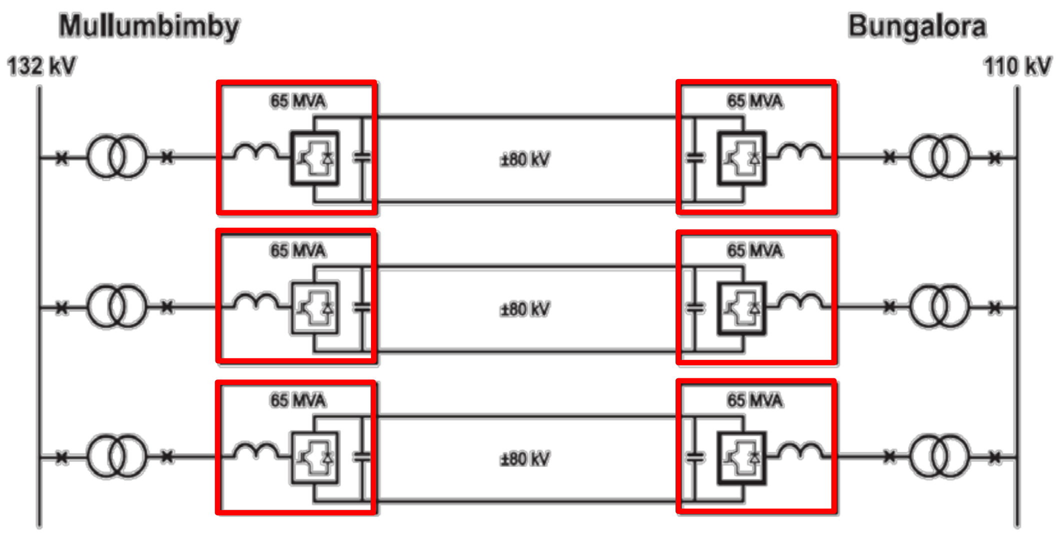


Figure 2-2 illustrates the Directlink transmission route in northern NSW (the blue line), running from Bungalora in the north to Mullumbimby in the south.

Figure 2-2—Map of the Directlink transmission route

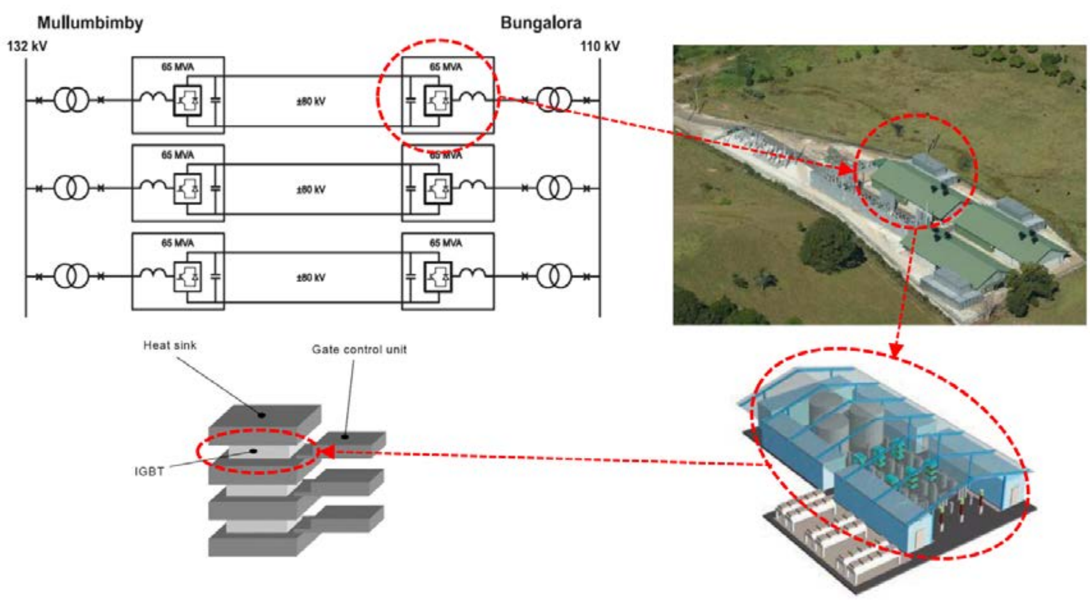
Directlink plays a key role in the transmission of electricity between the Queensland and NSW NEM regions. For example, in 2018 more than 300,000 MW of electricity flowed across Directlink. The flow of electricity across Directlink facilitates significant benefits to the NEM and contributes to lower electricity prices for consumers.

Directlink is a DC interconnector meaning that electricity must be converted from AC to DC when it enters Directlink from the NEM (since the NEM is an AC network) and back from DC to AC again when it re-enters in NEM. The six converter stations highlighted in section 2.1above perform this task for each of the three transmission lines that comprise Directlink, ie, one converter building sits at either end of each line.

IGBTs are an essential component of the converter stations and are semiconductor switching devices providing high efficiency and fast switching as part of converter stations. Without IGBTs the converter stations would not operate and Directlink would be unable to transmit electricity.

An overview of the positioning of IGBTs in the Directlink system is provided in figure 2-3. Generally speaking, IGBTs are housed in valve rooms, which in turn are housed in the converter buildings.

Figure 2-3 – Overview of IGBTs in the Directlink system



There are approximately 4,440 existing IGBTs ('Generation One IGBTs') that were installed as part of the initial design of Directlink (commissioned in 1999). The equipment that houses and operates them is the intellectual property of Hitachi ABB Power Grids. There are no alternative economic providers for these IGBTs since the use of alternative suppliers would involve a complete redesign of the entire converter stations.

In October 2018, we were notified by Hitachi ABB Power Grids that, due to the cessation of the manufacture and supply of crucial inputs, it would no longer provide support for (or manufacture) Generation One IGBTs. Generation One IGBTs are used at five of Directlink's six converter buildings[6] and the cessation of supply means that the current stock of spares represents the total amount of spares available to Directlink into the future. The failure rate of IGBTs is such that the available number of spares has now almost been exhausted.

6 The Mullumbimby System 1 converter station was upgraded to Generation Three IGBT technology after a fire in 2012 required the station to be rebuilt.

2.2 Description of the identified need

Action is required to replace the IGBTs in order for Directlink to continue to operate and provide its full capacity, in line with its authorisation.

If no action is taken, continued failure would lead to the need to remove one of Directlink's three lines from service, representing 60 MW of transmission capacity, since the line would not be able to be operated without sufficient spares. The mothballing of one line would then enable the IGBTs from the mothballed system to be used as spares to enable continued use of the other two lines. However, this will diminish the ability of Directlink to facilitate the efficient flow of electricity in the NEM and would be in breach of its authorisation as it would materially lower its available capacity.

We consider this a 'reliability corrective action' under the RIT-T as the proposed investment is for the purpose of meeting externally-imposed regulatory obligations and service standards (ie, continuing service under Directlink's authorisation). [7]

[7] A 'reliability corrective action' refers to investment for the purpose of meeting the service standards linked to the technical requirements, or other requirements, under either the NER or in other applicable regulatory instruments (eg, laws, regulations, orders, licences, codes, determinations and other regulatory instruments). See clause 5.10.2 of the NER and the definition of 'applicable regulatory instruments' in chapter 10 of the NER.

3 Options that meet the identified need

We consider there are three credible options that would meet the identified need from a technical, commercial and project delivery perspective.[8] These options are summarised in table 3-1.

Table 3-1 – Summary of the credible options

Option	Description	Estimated capital cost	Estimated annual operating cost	Estimated completion date
1	Long term service contract with Hitachi ABB Power Grids to manage the ongoing replacement of the IGBTs	$3.417 million for years 1 to 10 $2.138 million for years 11 to 20		Ongoing from 2021
2	Replace IGBTs one valve room at a time, with the timing dictated by failure rates	$10 million per valve room	2 per cent of capex	Timing to differ by scenario (see section 3.2 below)
3	Replace IGBTs one entire converter building at a time, with the timing dictated by failure rates	$28 million per converter building	2 per cent of capex	Timing to differ by scenario (see section 3.3 below)

The remainder of this section describes these options in greater detail. Each option facilitates retaining the existing capacity of Directlink (ie, 180 MW) until the end of its economic life in 2041.

3.1 Description of the 'base case'

Consistent with the RIT-T requirements, the RIT-T assessment will compare the costs and benefits of each option to a base case 'do nothing' option.

[8] Consistent with the requirements of the NER clause 5.15.2(a).

The base case is the (hypothetical) projected case if no action is taken, ie:[9]

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

Under this base case, the nearly depleted stock of spares would continue to be used to maintain Directlink's capacity until it is fully exhausted. The further failure of IGBTs would then lead to one of Directlink's HVDC transmission lines (60 MW) being mothballed in 2022. The converter buildings associated with this system would be cannibalised to recover Generation One IGBTs as spares for the other two HVDC lines, at a cost of $275,000.

A second link may need to be mothballed later depending on the failure rates for the remaining IGBTs, further reducing Directlink's capacity. The condition of the 'scavenged' IGBTs from the mothballed transmission line will determine how many are suitable to be used as spares, and their remaining life, and would not be known until the line was mothballed. At this stage we do not propose to model the mothballing of a second line as part of the RIT-T, since it will affect all options equally and is therefore not material to the outcome of the RIT-T. However, avoiding the mothballing of a second link would be expected to result in additional market benefits for the investment options considered in this RIT-T.

There are also expected to be escalating reactive maintenance costs in the base case, if the Generation One IGBTs are not replaced. However, the magnitude of these costs is expected to be relatively low and they are again expected to be required under all of the options considered, and so will not be material to the choice of option. We are therefore not currently intending to include these costs as part of the base case.

3.2 Option 1 – long term service contract to manage the ongoing operation and replacement of the IGBTs

Option 1 involves entering into a long term replacement contract (LTCRC) with Hitachi ABB Power Grids to manage the ongoing operation of the Generation One IGBTs and, where no longer possible, upgrade to Generation Three IGBTs.

9 AER, *Regulatory Investment Test for Transmission Application Guidelines,* August 2020, p. 21.

Under this option, it is anticipated that responsibility for the technical risk of Generation One IGBTs would be transferred to Hitachi ABB Power Grids, who would then receive a set amount per year regardless of then number of assets that need replacing. The contract would also cover spares management, 24/7 support and security updates for each of the assets.

The twenty-year contract is split into two costs, namely:
- years one to ten having an annual cost of $3.417 million; and
- years 11 to 20 having an annual cost of $2.138 million.

Directlink is currently in discussions with Hitachi ABB Power Grids as to the precise details of this service contract option, and in particular the extent to which Hitachi ABB Power Grids will assume the operational risks associated with the on-going operation of the IGBTs rather than simply undertaking replacements where determined by Directlink. and who is the ultimate owner of the IGBT assets. Transferring the operational risk to Hitachi ABB Power Grids would provide advantages for customers in in terms of future certainty of costs associated with the IGBT replacements.

The outcome of these discussions will determine the precise nature of the services provided under this contract and consequently whether the associated expenditure is appropriately treated as opex or capex.[10]

3.3 Option 2 – replacing IGBTs one valve room at a time

Option 2 involves replacing all Generation One IGBTs with Generation Three IGBTs one valve room at a time. There are three valve rooms in each of the five converter buildings currently using Generation One IGBTs (ie, 15 valve rooms in total). Each of these valve rooms houses 296 Generation One IGBTs that are in principle able to be salvaged and used as spares for the other valve rooms.

The timing of each valve room IBGT replacement under this option is assumed to be determined by the contract with Hitachi ABB Power Grids and does not change depending on the outturn failure rate of the existing Generation One IGBTs (since Hitachi ABB Power Grids are assumed to bear this risk).

While contracts are not yet final with Hitachi ABB Power Grids, we propose to assume three different sets of agreed timings across the scenarios – namely:

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10 At the time of Directlink's regulatory proposal the expenditure was presumed to be capex. However, discussions with Hitachi ABB Power Grids since that time has raised the prospect of greater transfer of operational risk under the service agreement.

- o the central scenario assumes valve room IGBTs are replaced in 2022, 2025, 2029, 2032, 2036 and 2039:
  - these assumed dates are based on IGBT 'stock and flow modelling'[11] assuming that 56 Generation One IGBTs fail per year (based on the historical average failure rate);
- o the low benefits scenario assumes valve room IGBTs are replaced in 2022, 2025, 2028, 2031, 2034, 2037 and 2040:
  - these assumed dates are based on IGBT 'stock and flow modelling' assuming that 63 Generation One IGBTs fail per year (based on the highest observed failure rate in a year);
- o the high benefits scenario assumes valve room IGBTs are replaced in 2022, 2026, 2030, 2034 and 2038:
  - these assumed dates are based on IGBT 'stock and flow modelling' assuming that 48 Generation One IGBTs fail per year (based on the lowest observed failure rate in a year).

The cost of replacing a valve room with Generation Three IGBTs is estimated to be $10.0 million ($2021).

Option 2 will also require holding spare Generation Three IGBTs, to use as replacements in the event of failure of the new Generation Three IGBTs. This is not a cost incurred under Option 1 (since under that option is would be captured within the overall Hitachi ABB Power Grids' contract cost). The cost of these spares is assumed to be $11,000 per IGBT (based on recent purchases) and the average failure rate for Generation Three IGBTs is assumed to be 0.18 per cent/per year (based on the current stock at the Mullumbimby System 1 converter station).

3.4 Option 3 – replacing IGBTs one converter building at a time

Option 3 is similar to Option 2 except that it involves replacing all Generation One IGBTs with Generation Three IGBTs one entire converter building at a time. There are currently five converter buildings using Generation One IGBTs, each housing 888 IGBTs that are in principle able to be salvaged and used as spares for the other converter buildings.

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11 'Stock and flow modelling' refers to the modelling of the number of spare Generation One IGBTs undertaken to determine when certain actions are required, in order to ensure there are sufficient spares on-hand to service the remaining Generation One IGBTs. This action is replacing all Generation One IGBTs in a valve room (under Option 2) or converter building (under Option 3) with Generation Three IGBTs in order to top-up the spares when spares get too low to service the remaining Generation One IGBTs.

Analogous to Option 2, we propose to assume three different sets of agreed timings for convertor building IGBT replacement with Hitachi ABB Power Grids across the scenarios – namely:

- the central scenario assumes converter building IGBTs are replaced in 2022 and 2032:
  - these assumed dates are based on IGBT 'stock and flow modelling' assuming that 56 Generation One IGBTs fail per year (based on the historical average);
- the low benefits scenario converter building IGBTs are replaced in 2022, 2031 and 2040:
  - these assumed dates are based on IGBT 'stock and flow modelling' assuming that 63 Generation One IGBTs fail per year (based on the highest observed failure rate in a year);
- the high benefits scenario assumes converter building IGBTs are replaced in 2022 and 2034:
  - these assumed dates are based on IGBT 'stock and flow modelling' assuming that 48 Generation One IGBTs fail per year (based on the lowest observed failure rate in a year).

The difference in the assumed dates for Option 3 compared to Option 2 is that 888 Generation IGBTs are potentially able to be salvaged from a converter building, compared to 296 IGBTs from a valve room.

The cost of replacing an entire converter building with Generation Three IGBTs is estimated to be $28 million ($2021).

Like Option 2, Option 3 will require holding spare Generation Three IGBTs, which is a cost not incurred under Option 1 (since under that option it is captured within the Hitachi ABB Power Grids' cost).

3.5 Options considered but not progressed

We have also considered whether four other network options would meet the identified need. The reasons these options have not been progressed any further are summarised in table 3-2.

Table 3-2 – Options considered but not progressed

Option	Reason(s) for not progressing
Using alternative suppliers and redesigning the converter stations	Not commercially feasible. We believe that this option would be prohibitively expense due to the additional work required to redesign the converter stations and it is not expected to generate greater benefits than

	any of the credible options to offset the much higher cost.
Requesting Hitachi ABB Power Grids to find an alternative manufacturer for Generation One IGBTs	Not technically feasible. We have investigated this option, but Hitachi ABB Power Grids has indicated that it can no longer source components for the Generation One IGBTs and so an alternative manufacturer is not feasible.
Replace all Generation One IGBTs with Generation Three IGBTs as a single project	Not commercially feasible. We expect the full replacement of all Generation One IGBTs to cost approximately $33 million. This cost is significantly greater than the costs of the credible options considered in this RIT-T and would not generate higher benefits to offset this additional cost. This option would also result in additional costs associated with needing to hold additional spares for the Generation Three IGBTs.
Replace Generation One IGBTs with Generation Two IGBTs	Not technically feasible. We have investigated this option but Generation Two IGBTs suffer from the same situation as Generation One IGBTs where they are in very short global supply and are no longer being manufactured.

4 Non-network options

We consider it unlikely to be commercially feasible for non-network solutions to assist with meeting the identified need for this RIT-T.

IGBTs play a unique and specific role in the transmission of electricity for Directlink. They also have a relatively low replacement cost.

Notwithstanding, this section sets out the required technical characteristics that a non-network option would need to provide, consistent with the requirements of the RIT-T and in order to ensure that we have fully canvassed all alternative options. This information is intended to enable interested parties to formulate and propose genuine and practicable non-network solutions such as, but not limited to, local generation and demand side management initiatives. We encourage any potential providers of non-network options to contact us if they consider that they could provide these characteristics in a cost-effective manner.

4.1 Required technical characteristics and costs of non-network options

As described in section 3.1, absent network investment, in 2022 one of Directlink's three HVDC lines would need to be mothballed, reducing Directlink's capacity by 60 MW. It follows that non-network options must be able to provide 60 MW of capacity to be considered technically feasible.

For a non-network option to be commercially feasible, it must be able to provide the 60 MW of capacity at a cost similar to the preferred network option and/or provide greater expected market benefits. Based on preliminary analysis, Option 1 is anticipated to be the preferred network option at this stage and has an average annual cost of $1.62 million ($27.24 million, in present value terms, in total over the assessment period).

We also note that the HVDC nature of Directlink means that it has the capability to provide both voltage and frequency stability to the northern NSW network and southern Queensland network. While this capability is not currently drawn on, Directlink may offer a low cost source of these stability services in the future. The ability for non-network solutions to also contribute additional market services in the future would therefore also be a relevant consideration in comparing network and non-network solutions.

5 Materiality of market benefits

This section outlines the categories of market benefits prescribed in the NER and whether they are expected to be material for this RIT-T.

5.1 Context for the estimates of market benefits

Directlink previously engaged Energy Edge to model the market benefits provided by Directlink in terms of wholesale prices in Queensland and New South Wales. This analysis estimated that Directlink provided benefits in the order of $1.2 billion over the period from 1 January 2016 to 30 December 2018. This historical analysis demonstrated the value of Directlink in reducing prices, and particularly the frequency of periods of very high prices. The analysis also referenced the unique manner in which Directlink was operated over the first quarter of 2017, during which time planned outages meant that Directlink was required to support system security in northern NSW.

The modelling required under the RIT-T has a different focus in estimating benefits compared with that in the earlier Energy Edge analysis. Specifically, the RIT-T assessment focuses on the future development of the market with and without the investment and on the impact of the proposed investment on the costs incurred across the market in supplying electricity. In such an analysis, effects on wholesale prices have less of an influence. It follows that some of the benefits incorporated in the previous estimate from Energy Edge, particularly from the avoidance of high price periods, will not be fully captured in the assessment of future market benefits under the RIT-T.

Further, the RIT-T modelling of market benefits, by virtue of being a forward-looking assessment, will take account of anticipated future changes in the market that will influence the benefits provided by Directlink. These future changes in the market include:

- potential future expansions of the Queensland to New South Wales interconnector (QNI);
- new developments of renewable energy generation in New South Wales and Queensland; and
- retirements of coal fired generation assets.

5.2 Material market benefits that will be captured in the RIT-T modelling

As outlined in sections 2.2 and 3, if action is not taken, the increasing failure of IGBT's will lead to one of Directlink's HVDC transmission lines (60 MW) needing to be mothballed in 2022.

Each of the credible options have been designed to avoid this situation and maintain the full capacity of Directlink (180 MW) until the end of its technical life. Each of the options is therefore expected to have a significant impact the wholesale market compared to the base case.

Based on preliminary market modelling, we propose to estimate the following categories of market benefit for each of the options as part of the assessment in the PADR:

- changes in fuel consumption in the NEM arising through different patterns of generation dispatch;
- changes in costs for parties, other than the RIT-T proponent (ie, changes in investment in generation and storage); and
- differences in unrelated transmission investment (in particular, the cost of connecting Renewable Energy Zones).

Section 6.1 outlines how we propose to model these benefits in the RIT-T assessment.

While we view these market benefits as being relevant for this RIT-T, they will not affect the identification of the preferred option. This is because each of the three options maintain the existing capacity of Directlink going forward and so provide the same level of wholesale market benefits, compared to the base case. As such, these benefits will be quantified in the PADR to demonstrate the overall expected level of benefits from replacing the identified assets, though their inclusion is not expected to be material to the identification of the preferred option.

5.3 All other categories of market benefits are not considered material

We do not consider that any of the other classes of market benefits under the RIT-T are material for this RIT-T assessment for the reasons set out below. We are therefore not intending to estimate these as part of this RIT-T.

Table 5-1 – Market benefit categories not considered material

Market benefit	Reason(s) it is not considered material for this assessment
Changes in involuntary load curtailment	In general, there is expected to be sufficient redundancy in the NEM to avoid involuntary load shedding if Directlink's capacity is reduced.

	We have identified two cases of high impact, low probability (HILP) system conditions that may give rise to changes in involuntary loads shedding. However, given that the probability of these events occurring is low, we do not propose producing a quantitative estimate of these benefits as it is unlikely to materially impact the preferred option – see section 5.4 for further discussion of these potential benefits.
Changes in voluntary load curtailment	There is not expected to be a significant impact on pool prices in the NEM from the options and so there is not expected to be material changes to the levels of voluntary load curtailment in the NEM.
Changes in network losses	Any difference in losses between the base case and the option cases is expected to be negligible.
Option value	Option value is likely to arise in a RIT-T assessment where there is uncertainty regarding future outcomes, the information that is available is likely to change in the future, and the credible options considered by the TNSP are sufficiently flexible to respond to that change.[12] While Option 2 and Option 3 exhibit flexibility in terms of when investment is undertaken (ie, depending on the outturn failure rate of IGBTs), the value of this flexibility has been captured through the three different scenarios having different timed investment profiles. The inclusion of option value in the assessment has therefore been implicitly captured through the scenario analysis. The estimation of any additional option value benefit would require a significant modelling

12 This is consistent with the AER's view, see: AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, pp. 53-54.

	assessment, which would be disproportionate to any additional option value benefit that may be identified for this specific RIT-T assessment.
Competition benefits	While each of the credible options are expected to generate a level of wholesale market benefits, it is not considered sufficient to affect the competitiveness of generator bidding behaviour in any region of the NEM.

5.4 Additional qualitative benefits

Continued operation of Directlink at its full capacity is expected to continue to provide additional market benefits through supporting system security and reducing the risk of unserved energy under certain system conditions. These benefits of Directlink will tend to arise under high-impact, low probability events and so will likely make a minor contribution to benefits when applying a probability that reflects the expected likelihood of the specific system conditions occurring. They are therefore not given substantive weight under the RIT-T framework.

Under certain circumstances Directlink's capacity may be required to support system security, particularly in northern New South Wales. By way of example, Directlink provided support for system security in northern NSW during an outage of a transmission line between Coffs Harbour and Koolkhan between January and April 2017. During this period, flow over Directlink was frequently constrained to be southward during periods of very high prices in Queensland to ensure that an additional transmission outage in northern NSW did not give rise to load shedding. Given the specific conditions that are required for this benefit to arise, the benefit has a low probability of being realised but a high impact if it does occur.

Additionally, an increased risk of involuntary load curtailment may also arise in the context of the retirement of Liddell Power Station, expected to occur in 2023. The reduction in capacity of Directlink that would occur under the 'base case' scenario would occur prior to the retirement of Liddell.

Modelling conducted by AEMO for its 2020 Electricity Statement of Opportunities suggests that while the reliability standard will not be breached with the retirement of Liddell, unserved energy is expected to increase, and cites the committed expansion of QNI in 2022-23 as a key factor in reducing the risk of unserved energy. AEMO's modelling was conducted assuming that the current capacity of Directlink would be available to provide energy into New South Wales. It follows that, if the capacity of Directlink were to be reduced, then there would be an increased risk of unserved energy. A full quantitative analysis of the potential impact on unserved energy of a change in the capacity of Directlink would be a substantive exercise and is not proposed for this RIT-T. However, we note that this benefit would be in addition to the benefits that we do intend to quantify in the RIT-T assessment.

6 Overview of the assessment approach

This section outlines the approach that we propose to apply in assessing the net benefits associated with replacing the obsolete Generation One IGBTs.

6.1 General modelling parameters adopted

We propose to adopt a 20-year assessment period from 2021-22 to 2040-41 (which is the projected end of economic life for Directlink).

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling will include a terminal value to capture the remaining asset life. This ensures that all options have their costs and benefits assessed over a consistent period, irrespective of option type, technology or asset life. In the case of the options being considered in this RIT-T, this terminal value can be interpreted as an estimate for the resale value for the IGBTs (and any other capex components) at the end of Directlink's economic life.

We propose to adopt a real, pre-tax discount rate of 5.90 per cent as the central assumption for the NPV analysis presented in the PADR, consistent with the assumptions adopted in the ISP. The RIT-T requires that sensitivity testing be conducted on the discount rate and that the regulated weighted average cost of capital (WACC) be used as the lower bound. We therefore also propose to test the sensitivity of the results to a lower bound discount rate of 2.23 per cent,[13] and an upper bound discount rate of 7.90 per cent (i.e., consistent with the latest AEMO Input Assumptions and Scenarios report).

6.2 Summary of the wholesale market modelling proposed

The RIT-T requires categories of market benefits to be calculated by comparing the 'state of the world' in the base case where no action is undertaken, with the 'state of the world' with each of the credible options in place, separately. The 'state of the world' is essentially a description of the NEM outcomes expected in each case, and includes the type, quantity and timing of future generation investment as well as unrelated future transmission investment (e.g., that is required to connect REZ across the NEM).

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13 This is equal to WACC (pre-tax, real) in the latest final decision for a transmission business in the NEM, see: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/directlink-determination-2020-25

We have retained HoustonKemp to undertake the wholesale market modelling exercise for this RIT-T assessment. The HoustonKemp wholesale market modelling suite comprises a set of optimisation models that simulates investment in the NEM across generation, storage and transmission and period-by-period wholesale price and dispatch outcomes. The model utilises input assumptions as specified by AEMO and is structured to produce estimates of RIT-T market benefit categories. The HoustonKemp modelling approach is consistent with the approach adopted by AEMO in the modelling undertaken to produce the ISP.

The market modelling will adopt scenarios and assumptions consistent with the 2020 ISP, which is the most recent, final consistent set of assumptions available. The differences in assumptions between the base case and each of the option cases will relate to the assumed transfer capacity of Directlink. These differences in transfer capacity will be modelled as changes in the limits on flows across the Terranora interconnector. Directlink's transfer capacity is a major determinant of the limits of flows over Terranora. Differences between transfer capacity of Directlink and the Terranora interconnector are a result of loads in the area north of Directlink, between Directlink and measurement points for Terranora.

We intend to incorporate different limits on the Terranora interconnector for different aspects of the modelling. In particular, the modelling will adopt:

- o conservative limits on flows for the purpose of long-term investment planning; and
- o the nominal flow limits that reflect the actual operating capacity of the links in the medium and short term models.

This approach is consistent with the approach adopted by AEMO in its modelling for the ISP. In addition to changes to the limits on flows over Terranora, the loss factors applied to flows over Terranora will be adjusted to reflect the expected change in losses resulting from a change in the capacity of Directlink.

Table 6-1 below provides a summary of the flow limits proposed to be applied in the modelling.

Table 6-1 – Summary of Terranora interconnector limit assumptions in the market modelling

From	To	Long-term investment modelling		Dispatch modelling	
		With	**Without**	**With**	**Without**
NSW	QLD	50MW	0MW	107MW	47MW
QLD	NSW	150MW	90MW	210MW	150MW

6.3 Three different 'scenarios' to address uncertainty

The RIT-T is focused on identifying the top ranked credible option in terms of expected net benefits. However, uncertainty exists in terms of estimating future inputs and variables (termed future 'states of the world').

To deal with this uncertainty, the NER requires that costs and market benefits for each credible option are estimated under reasonable scenarios and then weighted based on the likelihood of each scenario to determine a weighted ('expected') net benefit.[14] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

The credible options will be assessed under three scenarios as part of the PADR assessment, which differ in terms of the key drivers of the estimated net market benefits.

The three alternative scenarios can be characterised as follows:

- a 'low net economic benefits' scenario, involving a number of assumptions that gives a lower bound and conservative estimate of net present value of net economic benefits;
- a 'central' scenario which consists of assumptions that reflect our central set of variable estimates that provides the most likely scenario; and
- a 'high net economic benefits' scenario that reflects a set of assumptions which have been selected to investigate an upper bound of net economic benefits.

The table below summarises the specific key expected variables that we expect to influence the net benefits of the options, and the proposed parameters under each of the three scenarios. At this stage we are intending to incorporate three scenarios from the 2020 ISP, to capture a range of possible wholesale market impacts. However we intend to review the outcomes of the wholesale market modelling to determine whether the inclusion of alternative ISP scenarios is warranted, given that the extent of work associated with modelling each scenario and its potential impact on the outcomes of the RIT-T assessment.

14 The AER RIT-T Application Guidelines explicitly refer to the role of scenarios as the primary means of taking uncertainty into account. See: AER, *Regulatory Investment Test for Transmission Application Guidelines*, August 2020, p. 49.

Table 6-2 – Summary of scenarios

Variable	Central	Low net economic benefits	High net economic benefits
ISP scenario	2020 ISP central scenario	2020 ISP slow scenario	2020 ISP step-change scenario
Failure rate of IGBTs	56/year	63/year	48/year
Discount rate	5.90 per cent	7.90 per cent	2.23 per cent

In addition to the scenario analysis, we will also consider the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity and 'boundary' testing.

7 Appendix A – Compliance checklist

Rules clause	Summary of requirements	Relevant section(s) in PSCR
5.16.4 (b)	A RIT-T proponent must prepare a report (the project specification consultation report), which must include:	–
	(1) a description of the identified need;	2
	(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-T proponent considers reliability corrective action is necessary);	2
	(3) the technical characteristics of the identified need that a non- network option would be required to deliver, such as: (i) the size of load reduction of additional supply; (ii) location; and (iii) operating profile;	4
	(4) if applicable, reference to any discussion on the description of the identified need or the credible options in respect of that identified need in the most recent National Transmission Network Development Plan;	NA
	(5) a description of all credible options of which the RIT-T proponent is aware that address the identified need, which may include, without limitation, alterative transmission options, interconnectors, generation, demand side management, market network services or other network options;	3
	(6) for each credible option identified in accordance with subparagraph (5), information about: (i) the technical characteristics of the credible option; (ii) whether the credible option is reasonably likely to have a material inter-network impact; (iii) the classes of market benefits that the RIT-T proponent considers are likely not to be material in accordance with clause 5.16.1(c)(6), together with reasons of why the RIT-T proponent considers that	3 & 5

	these classes of market benefit are not likely to be material; (iv) the estimated construction timetable and commissioning date; and (v) to the extent practicable, the total indicative capital and operating and maintenance costs.	

8 Appendix B – RIT-T process

For the purposes of applying the RIT-T, the NER establishes a typically three stage process, ie: (1) the PSCR; (2) the PADR; and (3) the PACR. This process is summarised in the figure below (in red).

Figure 8-1 – The RIT-T assessment and consultation process