Energy Infrastructure Investments

Directlink Joint Venture

Managing IGBT failure risk across Directlink

RIT-T – Project Assessment Draft Report

3 February 2022

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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 Draft Assessment Report (PADR) represents the second 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 progressing this RIT-T following the publication of the Project Specification Consultation Report (PSCR) in April 2021.

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 would 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).

No submissions were received in response to the PSCR

EII published a PSCR on 8 April 2021 that presented three credible options that would meet the identified need from a technical, commercial and project delivery perspective. The PSCR also set out the required characteristics of non-network options.

EII invited written submissions on the materials contained within the PSCR, particularly on the credible options presented and from potential proponents of non-network options that could meet the technical requirements set out in the PSCR.

On publication of the PSCR, EII opened a 12-week consultation period, during which time no submissions were received.

Three options have been assessed

We have assessed three options under the RIT-T. These options are summarised in the table below.

We consider that Option 2 and Option 3 meet the identified need from a technical, commercial and project delivery perspective, and are therefore credible options.[3] We no longer consider that Option 1 is a credible option, as the second contract period (for years 11 to 19) is currently indicative only and may not be agreed to by Hitachi ABB Power Grids. Notwithstanding, we have included this option in the RIT-T assessment to determine whether it would deliver materially higher net benefits relative to the credible options.

Table E-1 – Summary of options assessed

<table>
<tr><th>Option</th><th>Description</th><th>Estimated capital cost</th><th>Estimated annual operating cost</th><th>Investment timing</th></tr>
<tr><td>1</td><td>Long term service contract with Hitachi ABB Power Grids to manage the ongoing replacement of the IGBTs</td><td colspan="2">$3.759 million for years 1 to 10
$2.352 million for years 11 to 19[4]
(Note: contract costs are treated as opex)</td><td>Ongoing from 2022-23</td></tr>
<tr><td>2</td><td>Replace IGBTs in two valve rooms initially, followed by replacement in the other valve rooms one at a time, with timing dictated by failure rates</td><td>$24.4 million for first two valve rooms
$13.1 million per subsequent valve room</td><td>2 per cent of capex</td><td>2022-23 for initial simultaneous replacement of two valve rooms
Timing of subsequent single valve room replacements differs by scenario</td></tr>
</table>

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

[4] Contract costs for the second contract period are indicative only. Hitachi ABB Power Grids has only provided a firm commitment for the first ten years of the long term contract. As such, the specific terms of the contract would need to be renegotiated at the end of the first ten years, with scope for either no contract to be agreed or for the indicative contract price to rise.

3	Replace IGBTs one entire converter building at a time, with the timing dictated by failure rates	$31.9 million per converter building	2 per cent of capex	2022-23. Timing of subsequent replacements differs by scenario

Net benefits have been estimated across three different 'scenarios'

The options have been 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 is 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 the 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 the net economic benefits.

The table below summarises the specific key variables that influence the net benefits of the options, and the parameters included under each scenario.

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

Maintaining Directlink's capacity results in significant positive net benefits

The table below summarises the gross benefits estimated for the options relative to the base case in present value terms. Each option has the effect of maintaining Directlink's capacity to its end-of-life, and so each option yields the same gross market benefits over the assessment period.

Table E-3 – Present value of gross benefits relative to the base case (2021-22, $m)

Market benefit/scenario	Central	Low benefit scenario	High benefit scenario	Weighted
Scenario weighting	50%	25%	25%	
Gross benefits	185.1	77.0	93.7	135.2

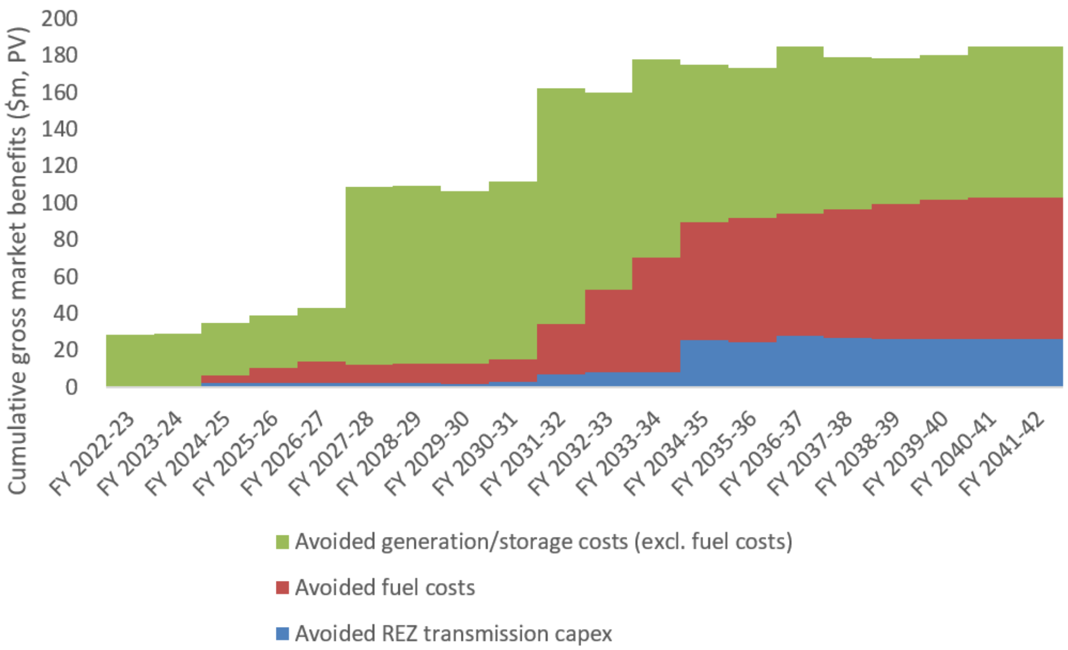
The table shows that benefits under the central scenario are materially higher than the low and high benefit scenarios. This outcome reflects the outcomes of the wholesale market modelling, ie:

- the highest level of demand occurs in the central scenario, which leads to a greater need for replacement investment (generation and storage) in response to the retirements of coal-fired generation plants;
- there is a higher gas price in the 2020 ISP central scenario relative to the 2020 ISP slow change scenario (corresponding to the central and low benefit scenarios in this RIT-T), which increases the benefits from fuel cost savings from avoiding dispatch of gas-generation; and
- there are higher net flows into NSW (from Queensland) in the central case.

We have confirmed that adjusting the three scenarios modelled in this RIT-T to yield outcomes consistent with the low, central and high scenarios having the lowest, middle and highest net benefits does not affect the outcome of the RIT-T.

The figure below presents the cumulative present value of gross benefits under the central scenario. It shows that costs for non-RIT-T proponent parties is the most material market benefit that arises from maintaining Directlink's capacity. This principally reflects avoided investment related to renewable generation capacity that is required to replace retiring coal plants.

Figure E-1 – Breakdown of cumulative gross market benefits over the assessment period under the central scenario (PV, $2021-22)



The table below summarises the net market benefit in net present value terms across the three scenarios, as well as on a weighted basis. The net market benefit is the gross benefits minus the option costs, all in present value terms.

The table below shows that each option has substantial net market benefits across each scenario investigated. On a weighted basis, Option 2 has the highest net market benefit, at approximately $97.4 million, and is therefore the top-ranked option under the RIT-T (the 'preferred option').

Table E-4 – Present value of net benefits relative to the base case (2021-22, $m)

Option/scenario	Central	Low benefit scenario	High benefit scenario	Weighted
Scenario weighting	50%	25%	25%	
Option 1	**148.2**	**44.8**	45.1	96.6
Option 2	147.4	38.0	**56.8**	**97.4**
Option 3	143.3	35.0	52.0	93.4

We note that there is a negligible difference in the weighted net benefits of Option 1 and Option 2. As noted above, Option 1 is not considered credible and is included in the analysis only to determine whether it would deliver materially higher net benefits relative to the credible options. Table E-4 demonstrates that there is a negligible difference in the net benefits of Option 1 and Option 2. This reaffirms our conclusion that Option 2 is the preferred option.

Option 3 is consistently ranked as the third option.

On the basis of the assessment in this PADR we consider Option 2 to be the preferred option under the RIT-T. This reflects the fact that:

- the cost of the initial replacement of two valve rooms under Option 2 would need to increase by approximately four per cent for Option 1 to become the preferred option on a weighted basis. Such a relative cost increase is unlikely given that the costs of Option 2 reflect firm contractual commitments for the replacement of the two valve rooms upfront (which total $24.3 million, and represent 64 per cent of the overall weighted cost); and
- the cost of Option 1 would need to decrease by approximately two per cent for Option 1 to become the preferred option. This is unlikely since the costs of the second contracting period for Option 1 are currently indicative only and are more likely to increase – reducing Option 1's ranking. For instance, a 20 per cent increase in costs in the second contracting period would result in Option 2 having three per cent higher net benefits than Option 1 on a weighted basis.

Further, we also consider that Option 1 is no longer a credible option from a:

- technical perspective, because it is unclear that this option will maintain Directlink's capacity to its end of life due to uncertainty regarding whether the second contract period will proceed; and
- commercial perspective, because further negotiations with Hitachi ABB Power Grids have now made clear that a high degree of operational risk (and therefore further cost uncertainty) would continue to be borne by EII.

Draft assessment

Option 2 is the preferred option at this draft assessment stage. It involves replacing all Generation One IGBTs with Generation Three IGBTs. There is a contractually agreed replacement of two valve rooms that will occur in 2022-23. Those Generation One IGBTs salvaged from the replacement will be used as spares for the remaining valve rooms. The timing of any subsequent single valve room replacements will be dictated by failure rates and how many of the salvaged IGBTs are able to be re-used.

The estimated capital cost of Option 2 is $24.3 million for the replacement of two valve rooms, and $13.1 million for the replacement of subsequent single valve rooms in 2021-22 dollars, plus the holding costs of Generation Three IGBTs. Operating expenditure is expected to be approximately two per cent of the capital cost. Based on the assumptions presented in this PADR, Option 2 has an estimated present value cost of $37.8 million (weighted scenarios). Since these costs reflect firm contractual costs for the first replacement of two valve rooms, it is not expected that they will change materially in the PACR.

The preferred option ensures Directlink can maintain its operational capacity to its end of life in line with its authorisation, with the resulting market benefits outweighing the cost of the investment.

Submissions and next steps

EII welcomes written submissions on the material contained in this PADR. Submissions are due on or before 17 March 2022.

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

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.

The next step in this RIT-T, following consideration of submissions received via the six-week consultation period and any further analysis required, will be publication of a PACR. EII anticipates publication of a PACR in mid-2022.

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 Assessment Draft Report (PADR) represents the second 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[5] 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[6] (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

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

6 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.[7]

We are therefore progressing this RIT-T following the publication of the Project Specification Consultation Report (PSCR) in April 2021.

1.1 Purpose of this report

The purpose of the PADR is to:

- identify and confirm the market benefits expected from the various options that enables Directlink to continue to operate and provide its full capacity, in line with its authorisation;
- summarise points raised in submissions to the PSCR;
- describe the options being assessed under this RIT-T;
- present the results of the net present value (NPV) analysis for each of the credible options assessed;
- describe the key drivers of these results, and the assessment that has been undertaken to ensure the robustness of the conclusion; and
- identify the preferred option at this stage of the RIT-T, ie, the option that is expected to maximise net benefits.

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 Submissions and next steps

We welcome written submissions on material contained in this PADR. Submissions are due on or before 17 March 2022.

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

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 PADR, a Project Assessment Conclusions Report (PADR) is expected to be published in mid 2022.

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

2 Benefits from enabling Directlink to continue to operate at full capacity

This section outlines the identified need for this RIT-T, as well as the expected benefits from addressing the identified need. 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:

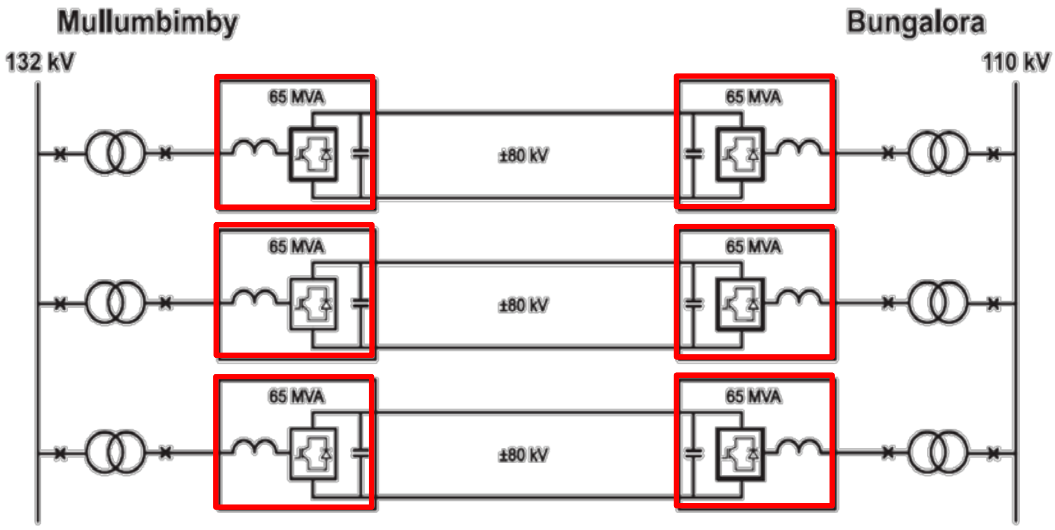
- a 132 kV line that runs from Dunoon to Mullumbimby; and
- a 110 kV line that runs from Bungalora to Terranora.

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

Directlink exhibits many features that make it unique amongst more conventional static transmission assets operated by other TNSPs in the NEM. By way of example, it is a point-to-point transmission line, as opposed to a network with multiple connections for directly connected customers. Further, its cables are exposed to direct voltages, which imposes different stresses and potential insulation breakdown mechanisms relative to alternating voltage cables.

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

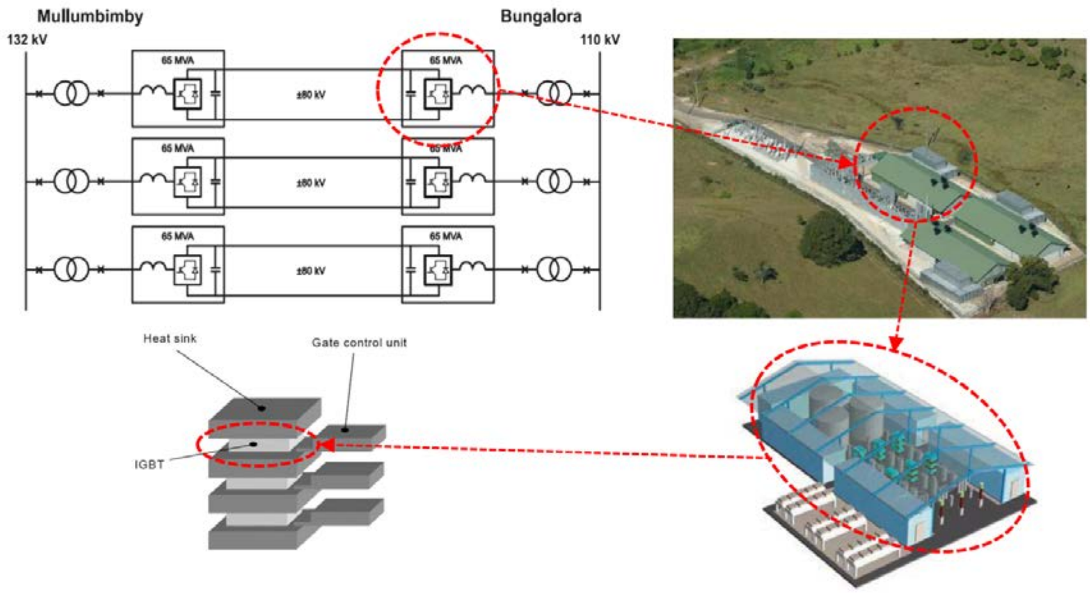


Directlink plays a key role in the transmission of electricity between the Queensland and NSW NEM regions. For example, in 2018 more than 300,000 MWh of electricity flowed across Directlink. The flow of electricity across Directlink facilitates significant benefits to the NEM and contributes to lower 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 the figure above perform this task for each of the three transmission lines that comprise Directlink, ie, one converter building sits at either end of each line.

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

Figure 2-2 – Overview of the 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[8] 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.

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.

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

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 would 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). [9]

2.3 Benefits from addressing the identified need

2.3.1 Three material market benefits are captured in the analysis

As we describe in section 4.1 below, if action is not taken, the increasing failure of the IGBTs will lead to one of Directlink's HVDC transmission lines (60 MW) needing to be mothballed in 2022-23.

Each of the options assessed (described in section 4) are 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 on the wholesale market compared to the base case.

In particular, we have estimated the following categories of market benefit for each of options as part of the assessment in this 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 (REZ)).

Section 5 sets out the modelling approach adopted in this PADR in detail.

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[9] 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.

While we view these market benefits as being relevant for this RIT-T, they do not affect the identification of the preferred option. This is because each of the options assessed maintain the existing capacity of Directlink going forward and so provide the same level of wholesale market benefits, compared to the base case. These benefits therefore demonstrate the overall benefits from replacing the identified assets, though are not material to the identification of the preferred option.

2.3.2 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.

AEMO's modelling for the Electricity Statement of Opportunities assumes 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 (such as upon the retirement of Liddell). 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 therefore not undertaken in this RIT-T. However, we note that this benefit would be in addition to the benefits we have quantified.

3 Consultation on the PSCR

EII published a PSCR on 8 April 2021 that presented three credible options that would meet the identified need from a technical, commercial and project delivery perspective. The PSCR also set out the required characteristics of non-network options.

EII invited written submissions on the materials contained within the PSCR, particularly on the credible options presented and from potential proponents of non-network options that could meet the technical requirements set out in the PSCR.

On publication of the PSCR, EII opened a 12-week consultation period. No submissions were received.

4 Three options have been assessed against the base case

We have assessed three options under the RIT-T. These options are summarised in table 4-1.

We consider that Option 2 and Option 3 meet the identified need from a technical, commercial and project delivery perspective, and are therefore credible options.[10] We no longer consider that Option 1 is a credible option, as the second contract period (for years 11 to 19) is currently indicative only and may not be agreed to by Hitachi ABB Power Grids. Notwithstanding, we have included this option in the RIT-T assessment to determine whether it would deliver materially higher net benefits relative to the credible options..

Table 4-1 – Summary of the options assessed

Option	Description	Estimated capital cost	Estimated annual operating cost	Investment timing
1	Long term service contract with Hitachi ABB Power Grids to manage the ongoing replacement of the IGBTs	$3.759 million for years 1 to 10 $2.352 million for years 11 to 19[11] (Note: contract costs are treated as opex)		Ongoing from 2022-23
2	Replace IGBTs in two valve rooms initially, followed by replacement in the other valve rooms one at a time, with timing dictated by failure rates	$24.4 million for first two valve rooms $13.1 million per subsequent valve room	2 per cent of capex	2022-23 for initial simultaneous replacement of two valve rooms Timing of subsequent single valve room replacements differs by scenario (see section 4.3 below)

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

[11] As discussed in section 4.2, the contract costs for the second contract period are indicative only. There is the potential for either the second contract period to not proceed, or to proceed at a higher cost.

3	Replace IGBTs one entire converter building at a time, with the timing dictated by failure rates	$31.9 million per converter building	2 per cent of capex	2022-23. Timing of subsequent replacements differs by scenario (see section 4.4 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.

4.1 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.

The base case is the (hypothetical) projected case if no action is taken, ie:[12]

> *"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 IGBT 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 2022-23. 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 $302,500.

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. This has not been modelled 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.

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

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. These costs are therefore not included in the base case.

4.2 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 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.

Under this option, it is intended 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 the 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 19-year contract is split into two costs, namely:

- years one to ten having an annual cost of $3.759 million; and
- years 11 to 19 having an annual cost of $2.352 million.

These costs have been reflected in the NPV analysis as annual operating costs.

Importantly, Hitachi ABB Power Grids has only provided a firm commitment for the first ten years of the long term contract. As such, the specific terms of the contract would need to be renegotiated at the end of the first ten years, meaning there is the potential for:

- the costs of the second contract period to increase significantly (ie, the current costs for the second period are only indicative and subject to change) – an outcome we examine in section 6.4; or
- the contract not to be renewed for the second contract period, leading to the mothballing of one of the HVDC links. If this were to eventuate this would mean that Option 1 does not in fact meet the identified need for this RIT-T.

Further, negotiations with Hitachi ABB Power Grids subsequent to the PSCR have not resulted in the anticipated transfer of operational risk acceptable to both parties. In particular, Hitachi ABB Power Grids has only committed to two valve room upgrades as part of the contract (in effect resulting in the works under Option 1 being similar to those under Option 2 described below).

EII therefore no longer considers Option 1 to be a credible option from a:

- technical perspective, because it is unclear that this option will maintain Directlink's capacity to its end of life due to the uncertainty regarding whether the second contract period will proceed; and
- commercial perspective, because further negotiations with Hitachi ABB Power Grids have now made clear that a high degree of operational risk (and therefore cost uncertainty) would continue to be borne by EII.

However, we have included this option in the economic analysis to ensure a robust assessment of the options available to maintain Directlink's capacity.

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

Option 2 involves replacing all Generation One IGBTs with Generation Three IGBTs, with an initial replacement of two valve rooms followed by the replacement of one valve room at a time as needed. 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.

Under this option, two valve rooms will be replaced in 2022-23. The timing of this replacement is fixed as part of the proposed contractual arrangements 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).

The need for and timing of subsequent replacement of single valve rooms (following the initial replacement of two valve rooms) will depend on IGBT failure rates and is determined in the NPV assessment by IGBT 'stock and flow modelling'[13]. The timing of further replacements (ie, those not contractually agreed) differs across the scenarios modelled – namely:

- the central scenario assumes further valve room IGBTs are replaced in 2029-30, 2032-2033, 2036-37 and 2039-40:

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[13] Stock and flow modelling refers to the modelling of the number of spare Generation One IGBTs 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.

    - 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 failure rate);
  - the low benefits scenario assumes further valve room IGBTs are replaced in 2028-29, 2031-32, 2034-35, 2037-38 and 2040-41:
    - 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 further valve room IGBTs are replaced in 2030-31, 2034-35 and 2038-39:
    - these assumes dates are based on IBGT 'stock and flow modelling' assuming that 48 Generation One IGBTs fail per year (based on the lowest observed failure rate in a year).

The replacement timings above illustrate that applying the stock and flow modelling leads to replacements occurring in the final two years of Directlink's economic life. However, it is unlikely any significant expenditure would occur in those years due to the impending end-of-life. We explain in section 6.4.2 that assuming no capital expenditure occurs in either the penultimate or final year of Directlink's economic life does not affect the outcome of the RIT-T (ie, identification of the preferred option).

The cost of replacing two valve rooms simultaneously with Generation Three IGBTs is estimated to be $24.4 million ($2021-22). Subsequent replacements of single valve rooms is estimated to cost $13.1 per valve room ($2021-22).

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 it would be captured within the overall Hitachi ABB Power Grids' contract cost).[14]The cost of these spares is assumed to be $12,100 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).

4.4 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.

[14] Directlink would be required to hold Generation Three IGBT spares if the cap in the contract was exceeded. However, it is unlikely that this cap would be substantially exceeded and lead to costs that would be material in the context of the RIT-T.

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.

Under this option, one converter building will be replaced in 2022-23. As is the case for option one, the timing of this replacement is determined through contractual arrangements 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).

Analogous to Option 2, the timing of further replacements (ie, those not contractually agreed) differs across the scenarios modelled – namely:

- the central scenario assumes a further converter building is replaced in 2032-33, based on IGBT 'stock and flow modelling' assuming that 56 Generation One IGBTs fail per year (based on the historical average failure rate);
- the low benefits scenario assumes a further converter building is replaced in 2031-32 and 2040-41, 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); and
- the high benefits scenario assumes a further converter building is replaced in 2034-35, based on IBGT 'stock and flow modelling' assuming that 48 Generation One IGBTs fail per year (based on the lowest observed failure rate in a year).

Analogous to Option 2, the stock and flow modelling leads to replacements occurring in the final two years of Directlink's economic life. However, it is unlikely any significant expenditure would occur in those years due to the impending end-of-life. We explain in section 6.4.2 that assuming no capital expenditure occurs in either the penultimate or final year of Directlink's economic life does not affect the outcome of the RIT-T (ie, identification of the preferred option).

The cost of replacing an entire converter building with Generation Three IGBTs is estimated to be $31.9 million ($2021-22).

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).

4.5 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 further are summarised in table 4-2.

Table 4-2 – 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 $159 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.

5 Overview of the assessment approach

This section outlines the approach that EII has applied in assessing the net benefits associated with maintaining the operational capacity of Directlink.

5.1 General modelling parameters adopted

As outlined in section 4, all costs and benefits considered have been measured against a base case where the nearly depleted stock of spare Generation One IGBTs would continue to be used to maintain Directlink's capacity until it is fully exhausted. Further failure of IGBTs would then lead to one of Directlink's HVDC transmission lines being mothballed in 2022-23.

The RIT-T analysis adopts a 19-year assessment period from 2022-23 to 2040-41 (which is the projected end of economic life for Directlink).[15]

Where the capital components of the credible options have asset lives extending beyond the end of the assessment period, the NPV modelling includes 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 adopt a real, pre-tax discount rate of 5.90 per cent as the central assumption for the NPV analysis, consistent with the assumptions adopted in the 2020 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,[16] and an upper bound discount rate of 7.90 per cent (i.e., consistent with the 2020 AEMO Input Assumptions and Scenarios report (IASR).

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15 A 20-year assessment period was initially proposed in the PSCR. However, the year delay in option timing (ie, commencing in 2022-23 as opposed to 2021-22) has resulted in a shortening of the assessment period.

16 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

EII notes the recent publication of the draft 2022 Integrated System Plan (ISP), which is underpinned by AEMO's 2021 IASR. However, we have used the assumptions available at the time the market modelling was undertaken. This modelling was undertaken prior to the publication of the 2021 IASR, and the lead time to the publication of this PADR reflects the fact that Hitachi ABB Power Grids is the sole provider of IGBTs, meaning earlier publication of the PADR would have undermined commercial negotiations. EII intends to investigate at the PACR stage whether adopting the latest AEMO assumptions would make any material difference to the outcome of the RIT-T.

5.2 Summary of the wholesale market modelling

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).

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 adopts scenarios and assumptions consistent with the 2020 ISP, which was the most recent, final consistent set of assumptions available at the time the modelling was undertaken (see above for why the 2021 IASR has not been used). 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 are 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.

HoustonKemp has incorporated different limits on the Terranora interconnector for different aspects of the modelling. In particular, the modelling adopts:

- conservative limits on flows for the purpose of long-term investment planning; and
- the nominal flow limits that reflect the actual operating capacity of the link 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 the limits on flows over Terranora, the loss factors applied to flows over Terranora are adjusted to reflect the expected change in losses from a change in the capacity of Directlink.

Table 5-1 below provides a summary of the flow limits applied in the modelling.

Table 5-1 – 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

5.3 Three different 'scenarios' have been modelled 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.[17] It is this 'expected' net benefit that is used to rank credible options and identify the preferred option.

[17] 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.

The credible options are assessed under three scenarios, 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 the net present value of net economic benefits;
- a 'central' scenario which consists of assumptions that reflect a 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 the net economic benefits.

Table 5-2 below summarises the specific key variables that influence the net benefits of the options, and the parameters under each of the three scenarios. We have incorporated three scenarios from the 2020 ISP, to capture a range of possible wholesale market impacts.

Table 5-2 – 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 consider the robustness of the outcome of the cost benefit analysis through undertaking a range of sensitivity and 'boundary' testing.

6 Assessment of options

This section outlines the assessment we have undertaken of the network options.

6.1 Estimated benefits

The table below summarises the gross benefits estimated for the options relative to the base case in present value terms. As we describe in section 4, each option has the effect of maintaining Directlink's capacity to its end of economic life. Each option therefore yields the same gross market benefits over the assessment period.

Table 6-1 – Present value of gross benefits relative to the base case (2021-22, $m)

Market benefit/scenario	Central	Low benefit scenario	High benefit scenario	Weighted
Scenario weighting	50%	25%	25%	
Gross benefits	185.1	77.0	93.7	135.2

Table 6-1 shows that benefits under the central scenario are materially higher than the low and high benefit scenarios. This outcome reflects the outcomes of the wholesale market modelling, ie:

- the highest level of demand occurs in the central scenario, which leads to a greater need for replacement investment (generation and storage) in response to the retirements of coal-fired generation plants;
- there is a higher gas price in the 2020 ISP central scenario relative to the 2020 ISP slow change scenario (corresponding to the central and low benefit scenarios in this RIT-T), which increases the benefits from fuel cost savings from avoiding dispatch of gas-generation; and
- there are higher net flows into NSW (from Queensland) in the central case.

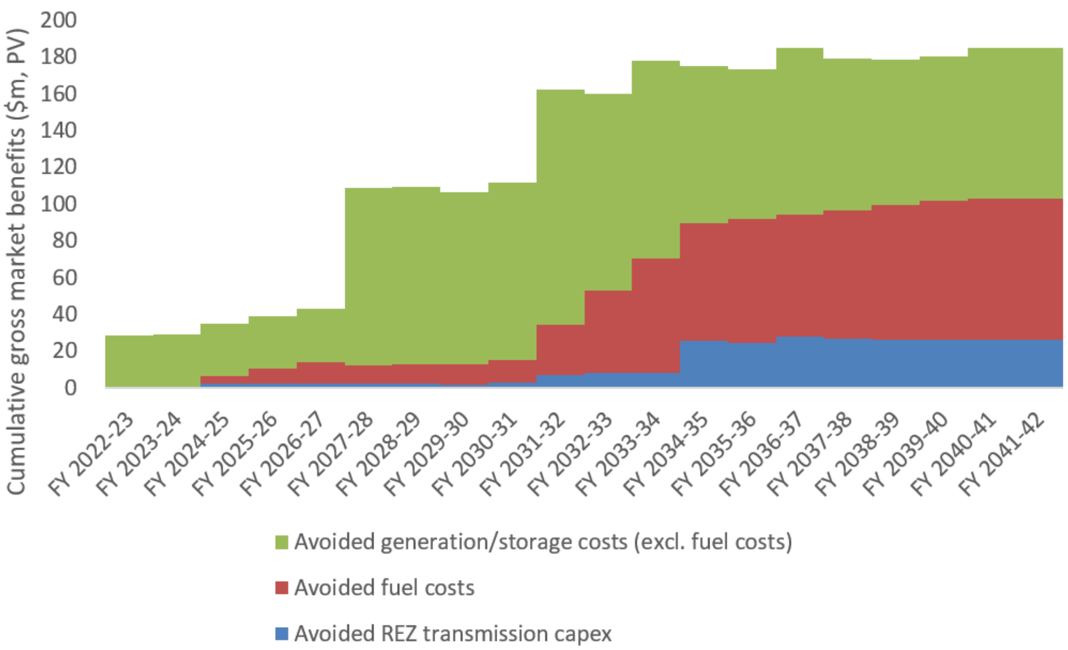
These features reflect adopting the common practice with regard to applying the ISP scenarios in the RIT-T, ie:

- the low economic benefit scenario corresponds to the slow change ISP scenario;
- the central economic benefit scenario corresponds to the central ISP scenario; and
- the high net economic benefit scenario corresponds to the step-change ISP scenario.

We have confirmed that adjusting the three scenarios modelled in this RIT-T to yield outcomes consistent with the low, central and high scenarios having the lowest, middle and highest net benefits does not affect the outcome of the RIT-T.[18]

The figure below presents the cumulative present value of gross benefits under the central scenario. It shows that costs for non-RIT-T proponent parties is the most material market benefit that arises from maintaining Directlink's capacity. This principally reflects avoided investment related to renewable generation capacity that is required to replace retiring coal plants.

Figure 6-1—Breakdown of cumulative gross market benefits over the assessment period under the central scenario (PV, $2021-22)



6.2 Estimated costs

The table below summarises the costs of each option relative to the base case in present value terms. The costs of each option have been calculated for each of the reasonable scenarios outlined in table 5-2. The key driver in the

18 Specifically, we have re-run the NPV analysis adopting the ISP step-change scenario for the low benefits scenario, the ISP slow change scenario for the central benefits scenario and the central ISP scenario for the high benefits scenario. This analysis leads to identification of the same preferred option as in the above scenarios.

difference in costs for Options 2 and 3 across each scenario is the failure rate assumption, which dictates the number of replacements required (either by valve room or converter station, respectively), following those contractually agreed.

Table 6-2 – Present value of costs of options relative to the base case (2021-22, $m)

Option/scenario	Central	Low economic benefit	High economic benefit	Weighted
Scenario weighting	50%	25%	25%	
Option 1	36.9	32.2	48.6	38.6
Option 2	37.7	39.0	37.0	37.8
Option 3	41.8	41.9	41.8	41.8

6.3 Net market benefits

The table below summarises the net market benefit in net present value terms across the three scenarios, as well as on a weighted basis. The net market benefit is the gross benefits minus the option costs, all in present value terms.

The table below shows that each option has substantial net market benefits across each scenario investigated. On a weighted basis, Option 2 has the highest net market benefit, at approximately $97.4 million, and is therefore the top-ranked option under the RIT-T (the 'preferred option').

Table 6-3 – Present value of net benefits relative to the base case (2021-22, $m)

Option/scenario	Central	Low benefit scenario	High benefit scenario	Weighted
Scenario weighting	50%	25%	25%	
Option 1	**148.2**	**44.8**	45.1	96.6
Option 2	147.4	38.0	**56.8**	**97.4**
Option 3	143.3	35.0	52.0	93.4

We note that there is a negligible difference in the weighted net benefits of Option 1 and Option 2. As noted earlier, Option 1 is not considered credible and is included in the analysis to determine whether it would deliver materially higher net benefits relative to the credible options. Table 6-3 demonstrates that there is a negligible difference in the net benefits of Option 1 and Option 2. This reaffirms our conclusion that Option 2 is the preferred option.

Option 3 is consistently ranked as the third option.

Due to the small difference in benefits between Options 1 and 2, we explain through sensitivity analysis below our opinion that Option 2 is the preferred option. We do not consider Option 3 in this sensitivity analysis, reflecting the greater percentage difference in the estimated net benefits.

We also consider that Option 1 is no longer credible from a:

- technical perspective, because it is unclear that this option will maintain Directlink's capacity to its end of life due to uncertainty regarding whether the second contract period will proceed; and
- commercial perspective, because further negotiations with Hitachi ABB Power Grids have made clear that a high degree of operational risk (and therefore further cost uncertainty) would continue to be borne by EII.

Overall, our analysis shows that the investment to replace IGBTs one valve room at a time is highly positive in NPV terms. Even under the scenario where the lowest net market benefits are generated, $38.0 million in net benefits is still estimated.

6.4 Sensitivity testing

6.4.1 Examining the ranking of options 1 and 2

Section 6.1 explains that the estimated gross benefits are identical across each option. It follows that the small difference in the estimated net market benefits between Option 1 and Option 2 in some scenarios reflects the difference in project cost.

As such, the relative ranking of Options 1 and 2 may change due to:

- an increase in the costs of Option 2 (holding all else constant), leading to a decrease in the net market benefits of Option 2 to the point that it is no longer the preferred option; or
- a decrease in the costs of Option 1 (holding all else constant), leading to an increase in the net market benefits of Option 1 to the point that it is the preferred option.

We have investigated these 'boundary points' at which the ranking of Options 1 and 2 change. Our analysis indicates that:

- o the cost of the initial replacement of two valve rooms under Option 2 would need to increase by approximately four per cent for Option 1 to be the preferred option; and
- o the cost of Option 1 would need to decrease by approximately two per cent for Option 1 to be the preferred option.

These sensitivities further reinforce the small difference in net benefits between Option 1 and Option 2. However, were either of these changes to occur the difference in net benefits between Option 1 and Option 2 would continue to be negligible. Coupled with the fact that Option 1 is not considered credible, we continue to consider Option 2 is the preferred option.

Further, it is also unlikely that the above changes in relative costs between the options will occur. With respect to Option 2, the $24.3 million to replace two valve rooms simultaneously represents a firm contractual cost with Hitachi ABB Power Grids(this 64 per cent of the overall weighted cost). It is therefore unlikely that this cost will increase by the amount that would result in Option 2 no longer being preferred.

Turning to Option 1, our opinion is that a cost increase is more likely than a cost decrease. Section 4.2 explains that the annual costs in the second contract period are indicative and subject to change. However, any change is more likely to upward due increasing operational risk over time, reflecting the ageing nature of the fleet of Generation One IGBTs. We expect that there is scope for the annual cost of the second ten years of the contract to increase by up to 20 per cent. Applying this cost increase in the NPV analysis, Option 1 results in net market benefits of $94.6 million on a weighted basis (present value terms). Under this sensitivity, Option 2 would now yield net benefits three per cent higher than Option 1.

Finally, we note that under both Option 1 and Option 2 the IGBT replacements would involve the same firm (Hitachi ABB Power Grids) providing the same service (replacement of IGBTs) – suggesting there should be no material change in relative costs between these two options.

6.4.2 *Forgoing replacement in the final two years of Directlink's economic life does not affect the results of the RIT-T*

Sections 4.3 and 4.4 note that the stock and flow modelling used to determine replacement timing for options 2 and 3 leads to replacements occurring in the final two years of Directlink's economic life. However, it is unlikely any significant capital expenditure would occur in those years due to the impending end-of-life.

Table 6-4 reproduces the NPV results assuming that no capital expenditure occurs in either the penultimate or final year of Directlink's economic life.[19] It shows that Option 2 continues to be the preferred option, illustrating that the outcome of the RIT-T is not sensitive to late-life capital expenditure.

Table 6-4 – Present value of net benefits relative to the base case assuming no capital expenditure in final two years of assessment period (2021-22, $m)

Option/scenario	Central	Low benefit scenario	High benefit scenario	Weighted
Scenario weighting	50%	25%	25%	
Option 1	**148.2**	**44.8**	45.1	96.6
Option 2	**148.2**	38.3	**56.8**	**97.9**
Option 3	143.3	35.6	52.0	93.5

[19] In effect we assume that Directlink is able to find sufficient IGBTs from existing spares at that time to facilitate all required IGBT replacements in these final years, without the need for further mass replacements of IGBTs either a valve room or a convertor station.

7 Draft assessment

Option 2 is the preferred option at this draft assessment stage. It involves replacing all Generation One IGBTs with Generation Three IGBTs. There is a contractually agreed replacement of two valve rooms that will occur in 2022-23. Those Generation One IGBTs salvaged from the replacement will be used as spares for the remaining valve rooms. The timing of any subsequent single valve room replacements will be dictated by failure rates and how many of the salvaged IGBTs are able to be re-used.

The estimated capital cost of Option 2 is $24.4 million for the replacement of two valve rooms, and $13.3 million for the replacement of subsequent single valve rooms in 2021-22 dollars, plus the holding costs of Generation Three IGBTs. Operating expenditure is expected to be approximately two per cent of the capital cost. Based on the assumptions presented in this PADR, Option 2 has an estimated present value cost of $37.8 million (weighted scenarios). Since these costs reflect firm contractual costs for the first replacement of two valve rooms, it is not expected that they will change materially in the PACR.

The preferred option ensures Directlink can maintain its operational capacity to its end of life in line with its authorisation, with the resulting market benefits outweighing the cost of the investment.

EII welcomes written submissions on the material contained in this PADR. Submissions are due on or before 17 March 2022.

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

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.

The next step in this RIT-T, following consideration of submissions received via the six-week consultation period and any further analysis required, will be publication of a PACR. EII anticipates publication of a PACR in mid-2022.

Appendix A – Compliance checklist

This section sets out a compliance checklist which demonstrates compliance of this PADR with the requirements of clause 5.16.4(k) of the National Electricity Rules version 170.

Rules clause	Summary of requirements	Relevant section(s) in the PADR
5.16.4(k)	A RIT-T proponent must prepare a report (the assessment draft report) which must include:	-
	(1) a description of each credible option assessed;	Section 4
	(2) a summary of, and commentary on, the submissions on the project specification report;	Section 3 (No submissions were received)
	(3)a quantification of the costs, including a breakdown of operating and capital expenditure, and the classes of material market benefit for each credible option;	Sections 2 and 4
	(4) a detailed description of the methodologies used in quantifying each class of material market benefit and cost;	Section 5
	(5) reasons why the RIT-T proponent has determined that a class or classes of market benefit are not material;	Section 5
	(6) the identification of any class of market benefit estimated to arise outside the region of the Transmission Network Service Provider affected by the RIT-T project, and quantification of the value of such market benefits (in aggregate across all regions);	Sections 2 and 5
	(7) the results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results;	Section 6
	(8) the identification of the proposed preferred option	Section 7
	(9) for the proposed preferred option identified under subparagraph (8), the RIT-T proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date; (iii) if the proposed preferred option is likely to have a material inter-network impact and if the Transmission Network Service Provider affected by the RIT-T project has received an augmentation technical report, that report; and (iv) a statement and the accompanying detailed	Sections 4 and 7

	analysis that the preferred option satisfied the regulatory investment test for transmission.	

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 B 1 – The RIT-T assessment and consultation process