PSC
Specialist Consultants
to the Electricity Industry

Directlink

Operating Cost Risk and Cost-Benefit Assessment

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Executive Summary

Directlink is an HVDC facility that connects the power networks at Mullumbimby (NSW) and Bungalora (NSW) via High Voltage DC cables. The facility consists of the converter stations at Mullumbimby and Bungalora, the DC cables connecting them and the AC cables, switchgear and converter transformers connecting each converter station to the nearby AC substation.

On 14 August 2012 a fire at Mullumbimby System 1 converter building resulted in the complete destruction of the System 1 converter (“August 2012 Fire Event”).

In August 2013, PSC was engaged by the Directlink Joint Venture (DJV), to perform an independent review of the Directlink Operation and Maintenance (O&M) procedures and practices in accordance with Good Electricity Industry Practice (GEIP). This review recommended a total of 114 changes to the Directlink facilities O&M procedures and practices.

In February 2014, PSC was engaged to determine the expected change in risk profile in the operation and maintenance of the Directlink facility before and after the August 2012 Fire Event and to review, at a high level, the costs and benefits of each recommendation, determine the mitigation of risk associated with that recommendation and determine whether the incremental cost of implementing that recommendation can be justified in terms of a change in risk profile.

PSC initially organized the 114 GEIP recommendations into groups to allow a more focused estimation of costs and benefits. This grouping was deemed appropriate to reduce the number of individual assessments required and to account for the fact that the recommendations vary considerably in terms of effort, cost and anticipated benefits.

The recommendations were grouped by the affected process, procedure or equipment and could be summarized into two overall categories and 23 sub categories. The two overall categories were:

- Operational Procedures – for general improvements to O&M practices for the Directlink facility; and
- Equipment Maintenance Procedures – for specific improvement to the maintenance of equipment by type.

Change in Risk Profile

PSC was requested to review and consider whether there was a change in the risk profile for the operation of the Directlink facility following the August 2012 Fire Event. PSC concluded during the initial GEIP review that the August 2012 Fire Event itself and the unexpected outcome of such a fire would be expected to change the DJV’s view on what is considered Good Electricity Industry Practice.

PSC first selected a set of operational risks where the risk assumptions and/or risk levels are expected to change as a result of the August 2012 Fire Event. For each operational risk, PSC considered how the risk assumptions have changed between pre- and post-event.

The results showed that the post-event residual risk levels for the selected operational risks are considerably higher than the pre-event risk levels.

Each operational risk was then considered with a view to what GEIP recommendations could be used to mitigate the post-event residual risk levels, potentially to the same levels as the pre-event residual risk profile. As well as the GEIP recommendations, PSC also considered two key capital projects currently under consideration by the DJV, being:

1. The installation of improved fire detection and new fire suppression in the converter buildings and the valve enclosures; and
2. Proposed modifications to the existing phase reactor cooling system, including a proposed dust and contamination filtering method.

Collectively, the capital projects and a collection of the GEIP recommendations form a "suite" of recommendations to be applied as risk mitigations to lower the post-event residual risk levels.

The pre- and post-event residual risk levels and the target risk levels following the implementation of the suite of recommendations are shown below.

Operational Risk	Pre-Event Inherent Risk Level	Post-Event Residual Risk Level	Post-Event Target Risk Level
Failure of a phase reactor;	Low	High	Low
Failure of capacitors;	Low	High	Low
Failure of other primary equipment;	Low	High	Low
Plant failure caused by accelerated ageing of equipment;	Low	High	Moderate
Fire in the converter building;	Low	High	Low
Non-compliance to NER or AER agreements;	Low	High	Low
Trips/extended outage to converter station caused by converter station elements;	Low	High	Low
Equipment fire causing adjacent fire or bush fire;	Low	High	Low
Employee safety in the event of a converter building fire.	Negligible	Low	Negligible

This report details the reasons why the risk profile of the operator of the Directlink facility could be expected to be altered by the August 2012 Fire Event. PSC has presented the residual risk profiles pre- and post-event in the above table.

Of the recommendations determined by the GEIP review, the majority if not all of them will not mitigate the identified operational risks effectively on their own. Each individual recommendation represents in some cases a relatively small change to the operation and maintenance practices implemented by the DJV. PSC discovered during the activity of selecting risk mitigation methods from the GEIP recommendations, that a suite of mitigation measures are more appropriate, namely:

1. Capex changes, including the installation of improved fire detection and new fire suppression in the converter buildings and the valve enclosures and the proposed modifications to the existing phase reactor cooling system, including a dust and contamination filtering method; and
2. All GEIP recommendations as detailed in Appendix 2 of this report.

Applying this suite of recommendations, the result of PSC's review and analysis is that:

1. The risk levels for the selected operational risks post-event are significantly higher than the risk levels pre-event; and

2. Applying the suite of recommendations will reduce the target risk level (i.e. the risk profile after all mitigations in place) for all of the operational risks, and will reduce the risk level to pre-event levels for all but one of the operational risks.

PSC performed a high level cost-benefit analysis using Net Present Value (NPV) to compare the cost of implementation of the suite of recommendations against a quantification of cost exposure to a similar August 2012 Fire Event following the change in risk profile. PSC quantified at high level a cost exposure based on the unforeseen cost of loss of the converter station following the main circuit equipment failure and compared this cost exposure to a high level estimate of the costs for the implementation of the suite of recommendations. PSC estimated that the cost of implementing the suite of recommendations was significantly less than the quantified cost exposure. Therefore, PSC recommends the implementation of the suite of capital and GEIP recommendations.

Cost Benefit Analysis

The scope of this engagement required PSC to determine a high level cost for both the implementation and the ongoing performance of each group of recommendations in terms of High (H), Medium (M), Low (L) or Zero (Z) cost.

PSC was also required to determine the benefits for the implementation of GEIP recommendations in terms of High (H), Medium (M) and Low (L). The benefits, in almost all cases, could not be quantified in terms of cost and therefore the determination of the benefit was qualitative. PSC is of the view that, at a high level, there are two key benefits for the implementation of the GEIP recommendations as follows:

- Reduction in risk profile – As described in detail in this report, the reduction in the risk level for certain operational risks to pre-event levels.
- Market benefits - through cost saving or deferral of other transmission network assets in the NEM by ensuring and maintaining current levels of availability and reliability of the Directlink facility.

While the costs for the implementation of the GEIP recommendations will be accrued to the Directlink facility it is considered that the benefits will be distributed to all market participants through maintaining the current levels of availability and reliability of the Directlink facility.

PSC applied a high level multi criteria analysis to the high level costs and benefits. This was performed to determine whether the implementation of each group of recommendations would benefit the DJV and or other market participants. A cost-benefit acceptance criteria was developed by assessing the qualitative benefit in terms of risk reduction and market benefit against the high level estimate of both the implementation and ongoing costs. Where the benefit level (H, M or L) was the same or better than the highest cost the benefit (also in terms of H, M or L), the category is recommended to be implemented.

The results of the estimation of high level cost and benefits and the cost-benefit analysis are shown in the table below.

Groups	Cost		Benefit		Outcome
	Implement (H,M,L,Z)	Ongoing (H,M,L,Z)	Risk Δ (H,M,L)	Market (H,M,L)	(Y,N)
Operational Procedures					
Asset Management Plan	M	M	H	H	Y
Compliance Plan and Incident Investigation	H	H	H	H	Y
Documentation Improvement	M	Z	M	L	Y
Easement Management	M	L	M	M	Y
High Voltage Switching and Access Procedures	L	L	M	L	Y
Network Management Plan	L	L	M	L	Y
Operations, Access and Reporting	M	M	M	M	Y
Spare Parts and Special Tools	M	M	H	H	Y
Equipment Maintenance Procedures					
Auxiliary Power	L	L	L	L	Y
Capacitors	L	L	H	H	Y
Circuit Breakers	L	L	L	L	Y
Control, Protection and Telecommunication Equipment	M	L	H	H	Y
Current Transformers	L	Z	L	L	Y
Disconnectors & Earthing	L	L	M	M	Y
Filter Resistors	L	L	M	M	Y
Fire Systems	M	L	H	H	Y
High Voltage Cable	L	M	H	H	Y
HVAC, Valve and Reactor Cooling Systems	L	M	M	M	Y
IGBT Valves	L	L	H	H	Y
Power Transformers	L	L	M	M	Y
Reactors	M	L	H	H	Y
Surge Arresters	L	L	L	L	Y
Wall Bushings	L	L	L	L	Y

External Driver

In addition to the change in risk level, PSC has identified one external driver that would justify at least those GEIP recommendations associated with the development of the new Asset Management Plan along the principles of PAS55. PSC provides evidence in this report of an observed electricity industry trend towards the adoption of PAS 55 in Australia. From this, PSC is of the view that the perception of Good Electricity Industry Practice for asset management has changed since the Directlink facility revenue reset in 2006 and indeed since the commissioning of the Directlink facility in 2000.

PSC considers that the development of a new Asset Management Plan and new operation and maintenance principles in alignment with the principals of PAS 55/ISO 55000, demonstrates the DJV’s continual improvement in recognition of the industry’s changing perception of Good Electricity Industry Practice. It is PSC’s opinion that the recent adoption of the principals of PAS55/ISO 55000 in the electricity industry in Australia and in some cases, the securing of certification in the standard, represents an external driver to be considered in the justification of a number of the proposed GEIP recommendations including, but not limited to, the development of a new Asset Management Plan.

Conclusions

During the course of this engagement PSC has identified three key factors that justify the proposed changes to the operation and maintenance of the Directlink facility as identified in the GEIP recommendations. These are:

1. The change in risk profile resulting from the August 2012 Fire Event;
2. The benefit to other market participants of maintaining ongoing reliable operation and existing availability levels of the Directlink facility; and

3. The change in Good Electricity Industry Practice due to the adoption of PAS55/ISO 55000 by other market participants.

Following a cost-benefit assessment, and in consideration of the above three key factors, PSC has concluded that the benefit to the DJV and other market participants of the 114 GEIP recommendations exceeds the costs to implement them.

1. Introduction

Directlink is an HVDC facility that connects the power networks at Mullumbimby (NSW) and Bungalora (NSW) via High Voltage DC cables. The facility consists of the converter stations at Mullumbimby and Bungalora, the DC cables connecting them and the AC cables, switchgear and converter transformers connecting each converter station to the nearby AC substation. The Directlink facility utilizes Voltage Source Converter (VSC) technology, and comprises three independent VSC “links” operating in parallel. Each of the three links is labelled as System 1, System 2 and System 3.

The Directlink facility commenced commercial operation in December 2000 and the Directlink Joint Venture (DJV) was acquired by Energy Infrastructure Investments (EII) in 2006. APA Group (APA), a part owner of EII, operates and maintains the facility on EII’s behalf.

On 14 August 2012 a fire at Mullumbimby System 1 converter building resulted in the complete destruction of the System 1 converter. (“August 2012 Fire Event”).

In August 2013, PSC was engaged by the DJV, to perform an independent review of the Directlink facilities Operation and Maintenance (O&M) procedures and practices in accordance with Good Electricity Industry Practice (GEIP). This review recommended a total of 114 changes to the Directlink facility O&M procedures and practices. These changes varied in scope from small modifications to existing procedures through to the development of new procedures and processes.

In February 2014, PSC was engaged to determine the expected change in risk profile in the operation and maintenance of the Directlink facility before and after the August 2012 Fire Event and to review, at a high level, the costs and benefits of each recommendation, determine the mitigation of risk associated with that recommendation and determine whether the incremental cost of implementing that recommendation be justified in terms of a change in risk profile and overall benefits. This report summarizes the outcomes of this work.

2. Methodology

The methodology applied by PSC for this engagement is summarized below:

1. Review each of the 114 recommendations and group them into suitably sized groups by process or procedure and grouped these procedures into categories to facilitate the development of the cost estimates and benefits.
2. Determine a high level cost for the implementation and ongoing performance of each group of recommendations. The high level costs were determined for implementation (one off Opex) and ongoing performance (annual Opex) in terms of High, (H), Medium (M), Low (L) and Zero (Z).
3. Define the risk profile associated with the operation and maintenance of the converters both pre- and post-August 2012 Fire Event. Facilitation of a small workshop with APA personnel including asset management, regulatory and risk management to:
    a. Discuss and document how the August 2012 Fire Event affected the risk profile of the Directlink facility.
    b. Develop a set of O&M mitigation measures and obtain feedback from APA on the benefits associated with the implementation of these measures.

    c. Discuss and obtain feedback from APA on the relationship between the implementation for recommended mitigation measures and the associated change in risk profile and/or external driver.
4. Determine a high level estimate of the benefits of each group of recommendations and categorization of these benefits in terms of High, (H), Medium (M) or Low (L) for each group of recommendations.
5. Develop a cost-benefit analysis for each group of recommendations using the high level cost and benefit categories developed during steps 2 and 4 and feedback from APA during the workshop in step 3. Develop a cost-benefit multi-criteria analysis to evaluate the quantitative costs and qualitative benefits for the implementation of each group of GEIP recommendations.
6. Identify the change in risk and/or external drivers for the GEIP recommendations and develop the necessary connections between the anticipated increase in Opex for implementing the GEIP recommendations and the change in risk profile caused by the August 2012 Fire Event or external drivers associated with Good Electricity industry practice.

3. Grouping of Recommendations

PSC's initial task was to organize the 114 GEIP recommendations into groups to allow a more focused estimation of costs and benefits. This grouping was deemed appropriate to reduce the number of individual assessments required and to account for the fact that the recommendations vary considerably in terms of effort, cost and anticipated benefits.

The recommendations were grouped by the affected process, procedure or equipment and could be summarized into two overall categories and 23 sub categories. The two overall categories were:

- **Operational Procedures –** for general improvements to O&M practices for the Directlink facility; and
- **Equipment Maintenance Procedures** – for specific improvement to the maintenance of equipment by type.

The full list of overall categories and sub-categories is provided in Table 1. The number of recommendations for each category is summarized in the right hand column.

Table 1- GEIP Recommendations by Category

Groups	GEIP Reccomendations 114
Operational Procedures	**59**
Asset Management Plan	3
Compliance Plan and Incident Investigation	11
Documentation Improvement	11
Easement Management	8
High Voltage Switching and Access Procedures	8
Network Management Plan	4
Operations, Access and Reporting	11
Spare Parts and Special Tools	3
Equipment Maintenance Procedures	**55**
Auxiliary Power	4
Capacitors	3
Circuit Breakers	1
Control, Protection and Telecommunication Equipment	3
Current Transformers	2
Disconnectors & Earthing	2
Filter Resistors	1
Fire Systems	4
High Voltage Cable	2
HVAC, Valve and Reactor Cooling Systems	8
IGBT Valves	5
Power Transformers	3
Reactors	12
Surge Arresters	4
Wall Bushings	1

4. High Level Cost Estimates

Under this engagement, PSC were requested to determine a high level cost for both the implementation and the ongoing performance of each group of recommendations in terms of High (H), Medium (M), Low (L) or Zero (Z) cost.

PSC assessed that the majority of costs associated with the implementation and ongoing performance of the recommendations will be person-hours for engineering and operational staff, consultants and contractors. None of the recommendations required any additional tools and equipment or any capital expenditure.

The method used by PSC was to estimate, at a high level, the number of person-hours expected for both the implementation and the ongoing performance of each group of recommendations, for the categories listed in Table 1.

Whilst it is clear what constitutes Z (zero), the definition of H, M or L can be quite arbitrary. PSC has applied the following approximate threshold values for each level:

- High (H)
    - Implementation greater than or equal to 250 person-hours;
    - Ongoing performance cost greater than or equal to 250 person-hours per annum.

- Medium (M)
    - Implementation greater than or equal to 75 person-hours and less than 250 person-hours;
    - Ongoing performance cost greater than or equal to 75 person-hours per annum and less than 250 person-hours per annum.
- Low (L)
    - Implementation cost less than 75 person-hours;
    - Ongoing performance cost less than 75 person-hours per annum.

In developing the high level person-hour estimates and the grouping of costs into one of the four cost levels, PSC has applied the following principles and key assumptions:

1. PSC has determined the scope of each recommendation, both in terms of implementation and ongoing performance and used this scope to determine a high level estimate of person-hours.
2. Consideration was given to person-hour estimates of APA staff, contractors and consultants and included time to review and approve new documents and processes.
3. Where PSC has been requested to develop the new procedure or process (under a different engagement), including the Asset Management Plan, Compliance Plan and a few other new procedures, PSC's actual person-hours were applied as well as an estimate of the time for APA to engage with PSC, review and approve the deliverables.

The outcome of this high level estimate of costs is summarized for both implementation and ongoing costs in Table 6.

5. Change in Risk Profile

APA have adopted a risk management approach to the operation and maintenance of their assets and maintain a system of risk management based on the international risk standard AS/NZS ISO 31000:2009.

PSC was requested to review and to consider whether there was a change in the risk profile for the operation of the Directlink facility following the August 2012 Fire Event. In the initial review of the operations and maintenance process and procedures against GEIP for the Directlink facility, PSC had considered that a change in both the likelihood and consequence would drive a review and adjustment to their operating and maintenance practices[1]. PSC considered during the review that the August 2012 Fire Event itself and the unexpected outcome of such a fire would be expected to change the DJV's view on what is considered Good Electricity Industry Practice.

PSC is of the view that for certain operational risks, a step change in risk profile has occurred based on the experience of the August 2012 Fire Event. Certainly the consequence of a fire or failure of any individual item of main circuit equipment has changed because prior to the event a fire or failure in this equipment was not considered likely to cause the loss of an entire converter building.

PSC's approach in this review was to:

[1] PSC Report - JA4598-REPT-002 "Directlink HVDC Facility - Good Electricity Industry Practice (GEIP) Review of Operations and Maintenance".

1. Identify those operational risks which are expected to have the assessment of likelihood and/or consequence changed as a result of the August 2012 Fire Event.
2. Undertake an analysis of pre- and post-event risk assumptions, ignoring any benefits of hindsight caused by the August 2012 Fire Event when establishing the pre-event risk assumptions.
3. Evaluate the pre- and post-event likelihood and consequence for each identified operational risk (pre- and post-event risk profile).
4. Identify those GEIP recommendations which will mitigate either or both the likelihood and consequence of the post-event risk profile (residual risk) and include these as risk mitigations.
5. Re-evaluate the risk profile based on the implementation of the risk mitigations (target risk).
6. Present the outcomes of the initial assessment by PSC of items 1 to 5 in a risk workshop with key APA staff, discuss and obtain feedback. The risk workshop was held on 19th March 2014.
7. Fine tune and present a final risk assessment which identifies the pre- and post-August 2012 Fire Event residual risk and the target risk following implementation of the GEIP recommendations.

5.1 Affected Operational Risks

PSC identified the operational risks which are expected to have their likelihood and/or consequence affected as a result of the August 2012 Fire Event. These risks were discussed, fine-tuned and agreed with APA during the risk workshop held on 19th March 2014. These operational risks are:

1. Failure of a phase reactor;
2. Failure of capacitors;
3. Failure of other main circuit equipment;
4. Plant failure caused by accelerated ageing of equipment;
5. Fire in the converter building;
6. Non-compliance to NER, AER and Good Electricity Industry Practice;
7. Trips/extended outage to converter station caused by converter station elements;
8. Equipment fire causing adjacent fire or bush fire; and
9. Employee safety in the event of a converter building fire.

5.2 Risk Profile Assumptions

PSC developed and documented the key risk assumptions both pre-event and post-event that are likely to have been affected by the August 2012 Fire Event. These risk assumptions were discussed, fine-tuned and agreed with APA during the risk workshop held on 19th March 2014.

In determining the pre-event risk assumptions, PSC and APA needed to consider what was known or could reasonably have been assumed prior to the August 2012 Fire Event without any benefit of hindsight.

The identified topics within which the risk assumptions are considered to have changed between pre-event and post event are:

1. Operations and maintenance expectations;
2. VSC technology – lack of information and experience;
3. Reduced availability and revenue consequence;
4. Main circuit equipment failure mode and consequence;
5. Converter building design and fire protection; and
6. Regulatory risk - risk of non-compliance to NER, AER and Good Electricity Industry Practice.

Each of these topics are discussed, including the outcomes of the discussions during the risk workshop, in Table 2.

Table 2 - Pre- and Post-August 2012 Fire Event Risk Assumptions

Topic	Pre-Event Assumptions	Post-Event Assumptions
Operations and maintenance expectations	At the time that EII acquired the Directlink facility, EII's expectations of the O&M requirements for the converter stations, as detailed in the due diligence report, were that the converter stations were designed to be unmanned and "virtually maintenance free". The DJV relied heavily on the manufacturer, ABB, for ongoing operation and maintenance advice, even though ABB themselves had little operational experience with this design. The DJV had assumed that maintenance in accordance with manufacturer's recommendations constituted Good Electrical Industry Practice. This expectation was reinforced by the AER, which states in the revenue cap decision of 2006: • "no allowance for capital expenditure (Capex) and only an efficient operating expenditure has been allowed"[2]. Prior to EII acquiring the asset, the DJV revenue was set by the AER for a period of 10 years, without an allowance for capital expenditure. The exclusion of Capex demonstrates the expectation that ongoing "efficient" maintenance was considered sufficient.	Whilst HVDC links are often marketed by OEMs as requiring very little maintenance, operational experience with these assets have shown that a higher level of ongoing maintenance is required than for a typical AC substation. This is because of the unique nature of the technology (IGBTs, high harmonic frequencies etc.) and also because of the reliance on auxiliary systems with moving parts for operation (pumps, fans, air conditioning etc.). This event has highlighted the need for inspection and maintenance beyond the annual maintenance recommended by the manufacturer and to seek advice from experienced operators of similar assets. The lack of "stay in business" capital allowance is considered unusual to APA. Even highly reliable gas assets operated by APA include allowance for capital expenditure in regulated revenue streams. PSC considers that it is typical for HVDC converter stations to require some Capex expenditure throughout its lifetime, even within the first 10 years of operation. Additional event driven changes are to be expected due to the event. PSC anticipates that in addition to the GEIP recommendations, The DJV will be considering Capex expenditure as modifications and upgrades to the facilities are made as more operational experience is gained in the technology.
VSC technology – lack of information and experience	At the time of design and construction, the Directlink facility was the first commercial HVDC installation utilizing Voltage Source Converter (VSC) technology and limited operational experience was available. Although HVDC operational experience for LCC technology was reported by CIGRE, there were inherent differences in the Directlink facility VSC technology provided by ABB, hence the LCC industry experience was not directly applicable in many cases. Until 2010, ABB was the only manufacturer of VSC technology, hence, due to ABB's desire to protect its intellectual property there was very little reported information and therefore little, if any, good operational data available In the CIGRE documents. CIGRE is considered the best repository of such information for HVDC. The DJV relied heavily on the manufacturer, ABB, for ongoing operation and maintenance advice, even though ABB themselves had little operational experience with this design. The DJV had assumed that	The O&M procedures developed solely in accordance with the manufacturer's advice are now considered to potentially be inadequate for the current design. Some of the O&M procedures and practices employed prior to the August 2012 Fire Event can no longer be considered to be in accordance with Good Electricity Industry Practice. Investigation and interim procedural changes at minimum were required to reduce the risk of a similar failure occurring.

[2] AER Final Decision - Directlink JV Application for Conversion and Revenue Cap - 3 March 2006

Topic	Pre-Event Assumptions	Post-Event Assumptions
	maintenance in accordance with manufacturer's recommendations constituted Good Electrical Industry Practice.	
Reduced availability and revenue consequence	In the 2006 AER revenue cap decision the AER had determined to set a target supply availability of 99% for 120 MW out of the installed capacity of 180 MW (2 out of 3 systems). The decision to base revenue on 2 out of 3 systems was due to the ongoing reliability issues that the Directlink facility had experienced. The Directlink facilities unavailability was largely due to cable faults rather than converter station faults. In light of the known cable issues, the Directlink facility had demonstrated the ability to achieve close to the availability target set by the AER prior to EII acquisition and for the years leading up to the August 2012 Fire Event. The AER had put in place an availability based incentive system (reward/penalty) at ±1% of revenue, which was predominantly lost as a result of the DC cable faults and short term outages of the converter stations. The expectation at this time was the worst outage condition caused by the failure of main circuit equipment within the building would be for the installation of a replacement equipment (if a spare was available). Hence it was considered prudent to manage this issue using maintenance practices after consultation with the manufacturer.	A major consequence of the event is a significant impact on the availability of the Directlink facility, due to the loss of a complete system for close to 3 years after the event, which was not expected. The assumption of a relatively short outage to repair or simply to change-out failed main circuit equipment is no longer viable and the possibility of a fire of similar magnitude and consequence must now be considered as possible as a result of the failure of main circuit equipment. Given the AER's previous decision regarding the 120 MW availability, it may transpire that the capacity based revenue is reduced even further if further similar events occur on the remaining two systems.
Main circuit equipment failure mode and consequence	Prior to the August 2012 Fire Event the likelihood of main circuit equipment failure leading to a fire throughout the converter building was considered low based on the following assumptions: • Failure of main circuit equipment would result in damage to the item of main circuit equipment and potentially its associated auxiliary equipment only. • Electrical protection will operate to limit damage and prevent fire as has occurred during previous failures. • Tracking to earth of the phase reactor could be adequately managed through regular inspection and cleaning. • No fire suppression systems or fire segregation was included in the original design; indicating the manufacturer did not perceive a fire spreading throughout the converter building as a risk requiring additional engineering controls.	Following the event, the insurer (FM global) re-assessed the financial cost of the converter building fire to be in the order of $65m. The like for like replacement cost of the largest single item of main circuit equipment within the converter building, the phase reactor, is estimated to be in the order of $800k. Hence, the unanticipated consequence of the August 2012 Fire Event resulted in a significant change in the re-assessed risk cost and consequence from Low to High. Although limited statistics are available, statistics for the Directlink facility demonstrate: • 3 in 14 year likelihood of a major reactor failure (2007, 2012 and August 2012 Fire Event) • 1 in 14 year likelihood of a main circuit equipment failure resulting in fire and loss of converter building (August 2012 Fire Event)

Topic	Pre-Event Assumptions	Post-Event Assumptions
	• The manufacturer's recommended maintenance practices were assumed adequate. In 2005, CIGRE published a document on VSC Transmission covering design and operation[3]. The CIGRE document is considered to represent the current understanding and practice with regard to VSC technology and the failure modes of main circuit equipment. The coverage of VSC phase reactors within the Cigre document makes no mention of the possibility of an event as serious as the August 2012 Fire Event. In particular, the indoor phase reactors at the Directlink facility are unique to VSC technology and are not included within LCC technology. DC smoothing reactors are common to LCC and VSC technology and failures of DC smoothing reactors are known. DC smoothing reactors are commonly located outdoors and segregated. The damage from reported failures has been localized with the outage in the order of weeks for replacement, with a complete converter station fire very unlikely. However this level of information is not available for indoor phase reactors. A phase reactor fire was experienced at the Murraylink facility, however it was determined to be caused by an external source and repair was also in the order of weeks, for localized repairs to the phase reactor.	There remain 15 similar phase reactors still in service across the remaining five converter stations. The assumption of likelihood and consequence has changed for each of these reactors. Electrical protection, designed to take the system off line in the event of a main circuit equipment failure, has proven not to work in all cases and to not be adequate for protection against a converter building fire. The manufacturer's recommended operation and maintenance procedures are now in question. Also, given the experiences and revised consequences of a main circuit equipment failure, the operation of the phase reactors can no longer be considered to be manageable by inspection and cleaning activities alone, requiring a change in design or other modifications. The various incidents of electrical tracking, and the effects of failures and flashovers within the phase reactors are likely to reduce their serviceable life to below the original 40 year design life. Design changes (i.e. changes to the cooling system) are unlikely to reverse aging that has occurred. The operation and maintenance procedures and processes must be adjusted, as well as the required design changes, to maximize the remaining service life. The design of the phase reactor cooling system is now in question. It has been revealed post-event that the original design was supposed to include intake air filters to reduce the level of dust and contamination in the building.
Converter building design and fire protection	Prior to the August 2012 Fire Event the design of the converter buildings was assumed to be adequate with regard to: • Fire protection; • Protection systems; and • Environmental conditions. Equipment within the converter buildings were, in the majority, outdoor type. In the event of equipment failure localized damage was assumed and that any resultant fire would self-extinguish. Adjacent equipment was not considered a risk of being a fuel source to propagate a fire.	The post-event consequences of a small failure or fire of the main circuit within the equipment must be considered to potentially result in a more wide spread fire within the converter building and potentially of the whole building. Post the August 2012 Fire Event the adequacy of the converter stations design is in question with regard to: • Fire protection • Protection systems; and • Adequacy for environmental conditions such as dust and humidity Further design, operation and maintenance controls must be investigated to mitigate the new concerns regarding the design.

[3] CIGRE – VSC Transmission (269) – Working Group B4 – April 2005 – (A proprietary document purchasable from CIGRE)

Topic	Pre-Event Assumptions	Post-Event Assumptions
	The greatest fire risk - converter transformers - were separate from the converter building and were segregated by blast proof walls, in accordance with good electrical industry practice. The original design of the converter building did not include a fire suppression system. Protection systems were assumed adequate to prevent significant damage The original design was assumed to be adequate for site conditions and that following manufacturer recommended O&M practices would be sufficient to achieve the plant design life.	
Regulatory risk - risk of non-compliance to NER, AER and Good Electricity Industry Practice.	Compliance was established during commissioning and was maintained in accordance with requirements of the NER, AER, Connection Agreements and Good Electricity Industry Practice. Operating in accordance with the manufacturer's recommendations was considered to be good electrical industry practice for this unique VSC technology. The consequence of non-compliance was considered significant in accordance with APA risk tables. I.e. a material non-compliance would be expected to be rectified on notification or at worse after an independent review.	The DJV consider that the risk of non-compliance may be higher due to the public nature of the event and that the consequence of non-compliance could be greater given what has happened. Any audit will likely be based on assertions of GEIP following the event and not on the assumptions and beliefs held by the DJV prior to the event. The DJV has a greater need for assurance with regards to compliance monitoring and activities to maintain compliance. The DJV needs to demonstrate that appropriate measures will be implemented following the event that demonstrate future operation of the Directlink facility accounts for the change in risk in accordance with good electricity industry practice.

5.3 Pre- and Post-Event Risk Profile

PSC has considered the pre- and post-event risk assumptions described in Section 5.2 and developed a pre- and post-event risk profile for each of the operational risks listed in Section 5.1.

In general terms, it is PSC's view that when discussing pre- and post-event risk levels following an unexpected event:

- It is usual for the risk profile to change as new knowledge and experience becomes available; that may not have otherwise been apparent or investigated prior to the event; and
- It is easier to criticize the operating, maintenance and management practices (or lack of) following such an event as the consequences are now evident (i.e. the benefits of hindsight).

PSC developed both a "Pre-Event Inherent Risk Level" and a "Post-Event Residual Risk Level" based on APA's approved risk matrix, repeated in Figure 1.

Figure 1 - APA Risk Matrix

Likelihood	Consequences					
	Insignificant 1	Minor 2	Medium 3	Significant 4	Major 5	Catastrophic 6
6. Frequent	Low	Moderate	High	Extreme	Extreme	Extreme
5 Likely	Low	Moderate	High	High	Extreme	Extreme
4 Occasional	Low	Low	Moderate	High	High	Extreme
3 Possible	Negligible	Low	Moderate	High	High	High
2 Unlikely	Negligible	Low	Moderate	Moderate	High	High
1 Rare	Negligible	Negligible	Low	Moderate	Moderate	High

For each operational risk, PSC has identified the relevant risk assumptions, likelihood and consequence both pre- and post-event. These risk assumptions were discussed, fine-tuned and agreed with APA during the risk workshop held on 19^{th} March 2014.

The assessment of "Pre-event Inherent Risk Level" was based on the risk assumptions and risk controls in place pre-event. The "Post-Event Residual Risk Level" is based on a new assessment of the risks without a change in risk controls.

The risk profile register is provided in Appendix 1. A summary of the outcomes of this activity is provided in Table 3.

Table 3 - Pre- and Post-Event Operational Risk Profile

Operational Risk	Pre-Event Inherent Risk Level	Post-Event Residual Risk Level
Failure of a phase reactor;	Low	High
Failure of capacitors;	Low	High
Failure of other primary equipment;	Low	High
Plant failure caused by accelerated ageing of equipment;	Low	High

Fire in the converter building;	Low	High
Non-compliance to NER or AER agreements;	Low	High
Trips/extended outage to converter station caused by converter station elements;	Low	High
Equipment fire causing adjacent fire or bush fire;	Low	High
Employee safety in the event of a converter building fire.	Negligible	Low

Table 3 demonstrates that the risk profile has changed post-event. The new Directlink facility risk levels are unacceptable and therefore the risk controls must be changed to bring the "Post-Event Residual Risks" down to an acceptable level as further discussed in Section 5.4.

5.4 Applying GEIP Recommendations as Mitigating Factors

Following the development and agreement on the pre- and post-event risk profiles, PSC identified which of the various GEIP recommendations would be mitigating factors to manage the post-event risk profile for each operational risk with a view to obtain at least the same risk profile as pre-event. In addition to the GEIP factors, PSC also considered two key capital projects currently under consideration for the Directlink facility, being:

1. The installation of improved fire detection and new fire suppression in the converter buildings and the valve enclosures; and
2. Proposed modifications to the existing phase reactor cooling system, including a proposed dust and contamination filtering method.

The outcomes of this activity and the assignment of risk mitigations is detailed in the risk profile register provided in Appendix 1.

The post-event "Target" risk level determined, based on all assigned mitigations being in place, is summarized in Table 4.

Table 4 - Pre- and Post-Event Operational Risk Profile with Target Risk Levels Following Mitigations

Operational Risk	Pre-Event Inherent Risk Level	Post-Event Residual Risk Level	Post-Event Target Risk Level
Failure of a phase reactor;	Low	High	Low
Failure of capacitors;	Low	High	Low
Failure of other primary equipment;	Low	High	Low
Plant failure caused by accelerated ageing of equipment;	Low	High	Moderate
Fire in the converter building;	Low	High	Low
Non-compliance to NER or AER agreements;	Low	High	Low
Trips/extended outage to converter station caused by converter station elements;	Low	High	Low
Equipment fire causing adjacent fire or bush fire;	Low	High	Low

Employee safety in the event of a converter building fire.	Negligible	Low	Negligible

As can be seen in all but one case, the level of risk has been reduced to the pre-event inherent risk level by the implementation of the GEIP recommendations and the recommended capital projects. In all cases, the target risk level is improved over the post-event residual risk level.

For one operational risk, plant failure caused by accelerated aging, the suite of recommendations did not reduce the target risk level back to the pre-event risk level. It is now considered that accelerated aging of the phase reactor elements may have occurred due to the humidity and dust exposure. The implementation of a new cooling system will not reverse the effects of accelerated aging.

5.5 Change in Risk Profile

Section 5.2 of this report provides the outcomes of PSC's analysis into the pre- and post-event risk assumptions that would reasonably have been expected to change due to the August 2012 Fire Event at Mullumbimby. It is important when doing so to not let the knowledge of the event cloud one's perception and understanding as to what those responsible for the operation and maintenance of the Directlink facility prior to the event would have considered to be reasonable assumptions and what would be considered Good Electricity Industry Practice.

The differences in risk assumptions and understanding of Good Electricity Industry Practice pre- and post-event can be summarized in Table 5.

Table 5 - Risk Assumptions and Understanding of Good Electricity Industry Practice Pre- and Post-Event

Pre-Event	Post-Event
• Maintenance in accordance with manufacturer's recommendations constituted Good Electrical Industry Practice. • The converter stations were designed to be unmanned and virtually maintenance free. • The worst outage condition for a failed item of main circuit equipment would be a replacement with the available spare. • It was prudent to manage the tracking on the reactor igloos using inspection and cleaning practices sanctioned by the manufacturer. • No experience of a catastrophic failure of the phase reactors for VSC projects. • Failure of an item of main circuit equipment, including the phase reactors, would result only in damage to the equipment and potentially its associated auxiliary equipment. • Electrical protection will operate to limit damage to the failed main circuit equipment and therefore prevent a major fire. • No fire suppression systems or fire segregation was included in the original design; indicating the manufacturer did not perceive a fire spreading throughout the converter building as a risk. • In the event of equipment failure localized damage was assumed and that any resultant fire would self-extinguish. Adjacent equipment was not	• The O&M procedures developed in accordance with the manufacturer's advice are now considered not adequate for the current design. • Some of the O&M procedures and practices employed prior to the August 2012 Fire Event can no longer be considered to be in accordance with Good Electricity Industry Practice. • Operational experience with VSC assets have shown that a higher level of ongoing maintenance is required than for a typical AC substation. • A need for inspection and maintenance beyond the annual maintenance recommended by the manufacturer. • A need to seek advice from experienced operators of similar assets. • It is typical for HVDC converter stations to require some Capex expenditure throughout its lifetime. • Failure of an item of main circuit equipment may be the cause of a fire and loss of the converter building. • The assumption of a relatively short outage to repair or simply change out failed main circuit equipment is no longer viable. • Electrical protection has proven not to work in all cases and to not be adequate for protection against a converter building fire.

considered a risk of being a fuel source to propagate a fire. • The original design was assumed to be adequate for site conditions and that following manufacturer recommended O&M practices would be sufficient to achieve the plant design life. • Compliance was established during commissioning and was maintained in accordance with requirements of the NER, AER, Connection Agreements and Good Electricity Industry Practice. • The consequence of non-compliance was considered significant.	• The various incidents of electrical tracking, and the effects of failures and flashovers within the phase reactors are likely to reduce their serviceable life. • It can no longer be assumed that an equipment failure/fire within the building will be limited to the failed equipment • Post-event consequences of a small failure or fire of the main circuit within the equipment must be considered to potentially result in a more wide spread fire within the converter building. • The DJV has a greater need for assurance with regards to compliance monitoring and activities to maintain compliance. • The DJV needs to demonstrate that appropriate measures have been implemented following the event that demonstrate future operation of the Directlink facility accounts for the change in risk in accordance with good electricity industry practice.

The summary provided in Table 5 shows many reasons why the risk profile of the operator of the Directlink facility could be expected to be altered by the August 2012 Fire Event. PSC has presented the residual risk profiles pre- and post-event as a result of the risk assumptions in Table 5. These are presented in Table 3.

Of the recommendations determined by the GEIP review (and as shown in Appendix 2), the majority if not all of them will not mitigate the risks effectively on their own. Each individual recommendation represents in some cases a relatively small change to the operation and maintenance practices implemented by the DJV. Even grouped as described in Table 1, a single group of recommendations is unlikely to have an effect on the residual risk profile for all of the identified operational risks post-event. PSC discovered during the activity of selecting risk mitigation methods from the GEIP recommendations, that a suite of mitigation measures are more appropriate, namely:

1. Capex changes, including the installation of improved fire detection and new fire suppression in the converter buildings and the valve enclosures and the proposed modifications to the existing phase reactor cooling system, including a proposed dust and contamination filtering method; and
2. All GEIP recommendations as detailed in Appendix 2.

Applying this suite of recommendations, the result of PSC's review and analysis is that:

1. The risk levels for the selected operational risks post-event are significantly higher than the risk levels pre-event; and
2. Applying the suite of recommendations will reduce the target risk level (i.e. the risk profile after all mitigations in place) for all but one of the operational risks, and will reduce the risk level to pre-event levels for all but two of the operational risks.

The effect of the application of this suite of recommendations can be seen in Table 4.

5.6 Main Circuit Equipment Failure Risk Quantification

PSC performed a high level cost-benefit analysis using Net Present Value (NPV) to compare the cost of implementation of the suite of recommendations against a quantification of cost exposure to a similar August 2012 Fire Event following the change in risk profile. PSC quantified at high level a cost exposure based on the unforeseen cost of loss of the converter station following main circuit equipment failure and compared this cost exposure to a high level estimate of the costs for the implementation of the suite of recommendations. PSC estimated that the cost of implementing the suite of recommendations was significantly less than the quantified cost exposure. Therefore, PSC recommends the implementation of the suite of capital and GEIP recommendations.

5.6.1 Pre Event

Prior to the August 2012 Fire Event the risk of main circuit equipment failure was quantified using information available in the Reliability and Availability Prediction technical report provided by ABB[4]. This technical report was developed during the design and construction of the Directlink facility. The technical report only provides a likelihood and consequence of phase (converter) reactor faults, which are described as follows:

- **Likelihood:** "*The probability that one of the single HVDC Light systems is unavailable due to a major failure in the converter reactor is one outage per 126 years.*"
- **Consequence:** "*Major failures require that the reactor is repaired and tested in a factory. The time for such a procedure is estimated to be 2.5 months or 1800 hours. If a spare is available it is favourable to switch to that one, which will be done within 20 hours in average for the common spare*."

The likelihood of a phase reactor major failure is based on one system, hence for the three parallel systems of the Directlink facility, PSC consider the likelihood would be three times, hence, a one in 42 year probability of a major failure to the Directlink facility.

Based on quotations for the supply of a complete replacement phase reactor ($800k), which is the largest cost item of main circuit equipment, PSC has assessed the order of magnitude cost for a phase reactor replacement following a major failure to be less than (<)$1M.

5.6.2 Post Event

Following the August 2012 Fire Event the following assumptions have changed. PSC considers that the following would represent updated assumptions using the phase reactor as an example.

- **Consequence:** The cost of repair is estimated at $65M (FM Global) for the unforeseen failure of main circuit equipment resulting in the loss of the converter station. The time for replacement of the converter station is three years.
- **Likelihood**: Three major failures of main circuit equipment have occurred in the 14 years of the Directlink facility operation with one unforeseen failure resulting in loss of the converter station.

[4] 1JNL100030-030 – Reliability and Availability Prediction Technical Report – ABB (Proprietary Document) – 1999 – Page 7 – Note: Likelihood of converter reactor failure provided by ABB only. PSC has conservatively used this likelihood for the calculations for main circuit equipment failure.

5.6.3 Quantified Risk

Given the information available, PSC considers it is reasonable that following the August 2012 Fire Event, the risk-cost (consequence) has changed from <$1M to $65M in the event of the unforeseen loss of the converter station. Hence the differential risk-cost of failure following the event can be assessed as approximately $64M (i.e. $65M-$1M)

PSC considers that the likelihood of failure has also changed, however, this cannot be clearly quantified for the following reasons:

- ABB had not considered in the Reliability and Availability Prediction technical report the possibility of a failure of main circuit equipment causing loss of the entire converter station. Hence, ABB had not provided a likelihood for this event.
- The likelihood of a major failure is probability based. Due to the small sample size, a major failure at year 14 does not necessarily mean that the likelihood of failure has increased to 1 in 14 years.

For the purpose of the cost-benefit assessment, PSC has assumed that the new likelihood of a catastrophic failure could be between 1 in 42 years as per the ABB technical report and 1 in 14 years.

Therefore, based on the August 2012 Fire Event PSC has determined a new annualized cost exposure to the operation of the Directlink facility to be between:

- $64M/14 = $4.5m per year; and
- $64M/42 = $1.5M per year.

Without additional risk mitigation measures the Directlink facility could be exposed to this new quantified cost-risk for the remaining operational life. The economic life of the Directlink facilities converter stations is 40 years[5]. Therefore the remaining life following the event is 26 years.

PSC has performed a high level Net Present Value of the above cost exposure for the remaining service life based on a discount rate of 8.06%[6]. This results in a NPV range of:

- NPV - $48.4M (for a 1 in 14 year event); and
- NPV - $16.1M (for a 1 in 42 year event).

For the purpose of a cost-benefit evaluation, PSC considers that should the suite of recommendations (including capital upgrades and O&M) be equal to or less than the quantified cost exposure following the August 2012 Fire Event then the benefits for implementation could be considered greater than the costs.

For the purpose of this cost-benefit assessment PSC have estimated at a high level the cost of implementation of the suite of recommendations. The high level cost estimates are as follows:

- Capital upgrades at approximately $5M (including changes to reactor cooling system and installing fire suppression systems); and

[5] Converter station “tax standard life” sourced from AER – Final Decision – Directlink 2006-15 – post tax revenue model.xls - http://www.aer.gov.au/node/860
[6] Nominal Vanilla WACC – AER transitional decision – TransGrid post tax revenue model.xls (PTRM) http://www.aer.gov.au/node/23137

- GEIP O&M recommendations:
    - Initial implementation has been estimated in the order of 1 to 1.5 person years of additional engineer and operator effort. PSC has estimated approximately $600k for the purpose of this exercise;
    - Ongoing implementation has been estimated at up to 1 full time equivalent per year for additional operations and maintenance effort. PSC has estimated approximately $400k for the purpose of this exercise.

Assuming that the capital and initial implementation O&M costs are accrued in the first year, PSC has estimated the NPV for the implementation of the recommendations over the remaining 26 year lifetime to be of the order of $9.1M.

Following a high level cost-benefit assessment PSC considers that the NPV cost of implementing the suite of capital and O&M recommendations ($9.1M) is significantly less than the assessed NPV cost of a suspected phase reactor failure (between $16.1M and $48.4M). Therefore, PSC recommends the implementation of the suite of capital and O&M recommendations.

6. High Level Benefits

PSC were requested to determine the benefits for the implementation of GEIP recommendations in terms of High (H), Medium (M) and Low (L). The benefits, in almost all cases, could not be quantified in terms of cost and therefore the determination of the benefit was qualitative. PSC is of the view that, at a high level, there are two key benefits for the implementation of the GEIP recommendations as follows:

- Reduction in risk profile – As described in section 5.4, the reduction in the risk level for certain operational risks to pre-event levels.
- Market benefits - through cost saving or deferral of other transmission network assets in the NEM by ensuring and maintaining current levels of availability and reliability of the Directlink facility. This is described in more detail in Section 6.2.

While the costs for the implementation of the GEIP recommendations will be accrued to the Directlink facility it is considered that the benefits will be distributed to all market participants through maintaining the current levels of availability of the Directlink facility.

It is anticipated that each and every recommendation from the GEIP review provides benefits to the operation and maintenance of the Directlink facility. For this exercise, PSC has focused on the two key benefits described above and therefore has applied the following principles when determining the high level estimate of the benefits of the GEIP recommendations:

1. The expected effectiveness of that recommendation is considered with regard to:
    a. Assurance of compliance to AER requirements, the NER, standards and Good Electricity Industry Practice;
    b. Prevention of a major event requiring equipment replacement; and/or
    c. Prevention of a major fire of similar consequence to the August 2012 Fire Event.

The difference between the post-event residual risk profile and the target risk profile as described in Chapter 5 was used in the qualitative assessment of the reduction in risk.

2. The effect of each recommendation on the maintenance of the current levels of availability and reliability, for example the prevention of any event similar to the 2012 August Fire Event, is considered in a qualitative manner and this will determine its effect on market benefits.

For the consideration of overall benefits and reduction in risk, PSC has considered the two capital project mitigations listed in Section 5.4 and these are considered to be part of a suite of recommendations covering both Capex and Opex, the latter being the GEIP recommendations.

6.1 Reduction in Risk Profile

Many of the GEIP recommendations have been assessed to result in a reduction in the risk profile of certain operational risks to pre-event levels. This is described in detail in Chapter 5.

For the purpose of assessing the benefits, PSC has considered the effect of each group of recommendations on the reduction in risk profile.

6.2 Market Benefit - Capital Deferral through Maintenance of Directlink Reliability

A benefit to all market participants of a reliable Directlink facility is the potential to defer the proposed TransGrid Northern NSW (Dumaresq to Lismore) 330kV transmission line.

In the 2013 Transmission Annual Planning Report[7] TransGrid has identified that the proposed Lismore to Dumaresq 330kV transmission line, at an estimated capital cost of $227M, will be deferred until 2020 and may be further deferred beyond 2030 if the Directlink facility can be relied on. The planning report states:

> *"Based on the most recent load forecast the limitations are expected to arise in the early 2020s if no support from Directlink is available…"*

Furthermore a public notice by TransGrid regarding deferral of the Lismore to Dumaresq 330kV transmission Line states[8]:

> *"The Transmission Annual Planning Report 2013 indicates that the proposed Far North NSW Project is not expected to be required until the 2020s. This date may be further deferred to the 2030s or later if Directlink, part of a high voltage connection from Queensland, can be relied upon and load growth remains subdued."*

The TransGrid-Country Energy proposal for the Development of Supply to the NSW Far North Coast[9] states the assumption on the reliability of the Directlink facility as:

[7] New South Wales Transmission Annual Planning Report 2013 - TransGrid

[8] Far North NSW Project – Dumaresq to Lismore transmission line cancellation – Build Cancellation Information fact sheet - http://yoursaytransgrid.com.au/far-north-nsw-project-dumaresq-to-lismore-transmission-line-cancellation

[9] TransGrid-Country Energy – Final Report – Proposed New Large Transmission Asset – Development of Electricity Supply to the NSW Far North Coast – page 27 - http://yoursaytransgrid.com.au/far-north-nsw-project-dumaresq-to-lismore-transmission-line-cancellation

"TransGrid considers that a maximum of one link could be relied upon to be available".

The TransGrid assumption is approximately half of the AER target reliability for Directlink of 99% for 120MW[10] and is equivalent to two systems in service.

PSC is of the understanding that, based on current available planning data and assumptions, TransGrid will begin to rely on one system of the Directlink facility by 2020 to achieve the planning criteria of N-1 security at 50% PoE (Probability of Exceedance). Based on the same constant load growth trend TransGrid would rely on a second system by approximately 2030 until the end of the Directlink facilities 40 year service life.

Based on current planning information provided by TransGrid, the Directlink facility AER target reliability of 99% at 120MW provides a market benefit by assisting in deferring the proposed Lismore to Dumaresq 330kV transmission line ($227M) until 2040, coinciding with the estimated end of the Directlink facilities planned service life for the converter stations. PSC considers that the implementation of the suite of recommendations will return the risk profile back to pre-event levels and in doing so will assist in maintaining the reliability and availability levels of the converter stations to those originally predicted by ABB in the Reliability and Availability Prediction technical report[11].

To provide a relative comparison of the market benefit of the Directlink facility for the deferral of the Lismore to Dumaresq line, PSC performed a high level NPV calculation using a nominal discount rate of 8.06%[12] from 2020 until the end of the Directlink facility converter stations service life at 2040, as follows:

- NPV for 2020 installation - $134M;
- NPV for 2030 installation - $63M; and
- NPV for 2040 installation - $29M.

PSC considers that activities to ensure the maintenance of the reliability and availability levels of the Directlink facilities would assist in ensuring the planned deferral of this project and would provide a market benefit. PSC has estimated the implementation NPV cost of the suite of recommendations to be in the order of $9.1M (see Section 5.6.3) which is relatively small compared to the potential market benefit.

7. Cost-Benefit Analysis

Within the scope of this engagement, PSC were requested to undertake a cost-benefit analysis of the GEIP recommendations.

A cost-benefit analysis of the GEIP recommendations is challenging in this case because:

1. The high level estimated costs and benefits are not numbers, eliminating the prospect of undertaking traditional quantitative cost-benefit analysis;
2. The costs have been quantified to an extent but the benefits have been developed qualitatively; and

[10] AER – Directlink Joint Venturers' Application for Conversion and Revenue Cap – Decision – 3 March 2006 – Page 24
[11] ABB – Reliability and Availability Prediction technical report – 1JNL100030-030 – 1999-10-12 – ABB predicted and availability of 99.6% for the whole transmission system.
[12] Nominal Vanilla WACC – AER transitional decision – TransGrid post tax revenue model.xls (PTRM) http://www.aer.gov.au/node/23137

3. The high level nature of these estimates.

For this reason, PSC applied a high level multi-criteria analysis to the high level costs and benefits discussed in Sections 4 and 6 respectively and based on the categories listed in Table 1.

In the following section a summary of the cost benefit analysis is provided. The detail of the comparison of cost and benefits for each category is provided in Appendix 3.

7.1 Multi-Criteria Analysis

A multi-criteria analysis of the cost and benefit was performed to determine whether each group of recommendations would benefit the Directlink facility for implementation.

A cost-benefit acceptance criteria was developed by assessing the qualitative benefit against the high level estimate of both the implementation and ongoing costs. Where the benefit level (H, M or L) was the same or better than the highest cost (also in terms of H, M or L), the category is recommended to be implemented.

For a further description of the implementation and ongoing cost ranking refer to Section 4. For a further description of the benefits considered, refer to Section 6. Only the two key benefits, the reduction in risk profile and market benefits, were considered.

The detail of the cost-benefit analysis is provided in Appendix 3.

7.2 Summary of High Level Costs and Benefits

The final outcomes of this high level estimation of the costs and the benefits for the grouped recommendations are provided in Table 6.

The cost-benefit recommendation for implementation following the multi-criteria assessment is also outlined in Table 6 in the column marked “Outcome”. All groups of recommendations were assessed to benefit the Directlink facility and therefore are recommended for implementation.

Table 6 - Cost-Benefit Analysis of Grouped Recommendations

Groups	Cost		Benefit		Outcome
	Implement (H,M,L,Z)	Ongoing (H,M,L,Z)	Risk Δ (H,M,L)	Market (H,M,L)	(Y,N)
Operational Procedures					
Asset Management Plan	M	M	H	H	Y
Compliance Plan and Incident Investigation	H	H	H	H	Y
Documentation Improvement	M	Z	M	L	Y
Easement Management	M	L	M	M	Y
High Voltage Switching and Access Procedures	L	L	M	L	Y
Network Management Plan	L	L	M	L	Y
Operations, Access and Reporting	M	M	M	M	Y
Spare Parts and Special Tools	M	M	H	H	Y
Equipment Maintenance Procedures					
Auxiliary Power	L	L	L	L	Y
Capacitors	L	L	H	H	Y
Circuit Breakers	L	L	L	L	Y
Control, Protection and Telecommunication Equipment	M	L	H	H	Y
Current Transformers	L	Z	L	L	Y
Disconnectors & Earthing	L	L	M	M	Y
Filter Resistors	L	L	M	M	Y
Fire Systems	M	L	H	H	Y
High Voltage Cable	L	M	H	H	Y
HVAC, Valve and Reactor Cooling Systems	L	M	M	M	Y
IGBT Valves	L	L	H	H	Y
Power Transformers	L	L	M	M	Y
Reactors	M	L	H	H	Y
Surge Arresters	L	L	L	L	Y
Wall Bushings	L	L	L	L	Y

8. Change in External Drivers

8.1 External Driver - PAS 55

PAS 55 was first issued in 2004 by the British Standards Institute as a Publically Available Standard (PAS). NGET in the UK was the first utility organization to gain certification in 2005. It was published as an international standard (ISO 55000) in January 2014.

The UK regulator “Ofgem” encouraged electricity distributors in the UK to implement PAS 55 by 2008[13]:

“Ofgem advised Network Companies that they believed that BSI-PAS 55 certification would help provide assurance as regards long term asset stewardship and establish greater clarity of the asset management policy and process that underpins the investment decisions of Network Companies.”

In Australia, PAS 55 was recognized amongst utilities as a standard for good electricity practice in asset management as early as 2008:

- SP AusNet (transmission and distribution utility in Victoria) was the first electricity and gas utility to achieve PAS 55 certification in 2008 and subsequently achieved re-certification in 2011. SP AusNet to date is the only energy network business to be accredited to PAS 55 in Australia[14].

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[13] UMS group presentation – Asset Management: BSI – PAS-55 Overview – 1 May 2008
[14] SPI PowerNet – Electricity Transmission Revenue Proposal 2014/15-2016/17 – 28th February 2013.

- SA Power Networks' (distribution utility in South Australia) has publically stated to the AER that their overall Asset Management framework is currently being reviewed to ensure that asset management practices are aligned with PAS 55, and with ISO 55000[15].
- Jemena Electricity Networks (distribution utility in Victoria) has announced that their asset management system now "leverages off the principles contained within" the PAS55 specification and that their system will be fully compliant by March 2014[16].
- The AER[17] has also made reference to PAS 55 in the Draft Capital Expenditure Guidelines (2013), which demonstrates AER's own recognition of PAS 55 as an industry standard for asset management.

With an observed electricity industry trend towards the adoption of PAS 55 in Australia, PSC is of the view that the perception of Good Electricity Industry Practice for asset management has changed since the DJV revenue reset in 2006 and indeed since the commissioning of the Directlink facility in 2000.

The DJV have initiated the implementation of an asset management plan for the Directlink facility in alignment with the principals of PAS 55/ISO 55000 as a measure to demonstrate the DJV's continual improvement in recognition of the industry's changing perception of Good Electricity Industry Practice. It is PSC's opinion that the adoption of the principals of PAS55/ISO 55000 and in some cases, the securing of certification in the standard, represents an external driver to be considered in the justification of a number of the proposed GEIP recommendations including, but not limited to, the development of a new Asset Management Plan.

[15] SA Power Networks – Expenditure Forecasting Methodology – 2015 Reset Project – 29 November 2013.
[16] Jemena Electricity Networks (Vic) Ltd, Distribution Annual Planning Report 2013
[17] AER – Better Regulation – Draft Capital Expenditure Incentive Guidelines – August 2013 Page 17

9. Conclusions

During the course of this engagement PSC has identified three key factors that justify the proposed changes to the operation and maintenance of the Directlink facility as identified in the GEIP recommendations. These are:

1. The change in risk profile resulting from the August 2012 Fire Event;
2. The benefit to other market participants of maintaining ongoing reliable operation and existing availability level of the Directlink facility; and
3. The change in Good Electricity Industry Practice due to the adoption of PAS55/ISO 55000 by other market participants.

Following a cost-benefit assessment, and in consideration of the above three key factors, PSC has concluded that the benefit to the DJV and other market participants of the 114 GEIP recommendations exceeds the costs to implement them.

Appendix 1 – Risk Profile Register

Directlink Asset

Risk Register - O&M Cost Benefit Analysis - Rev 0

ID	Risk Category	Description of Risk	Pre-Event Assumptions	Inherent likelihood	Inherent consequence	inherent risk level	Post Event Assumptions	Residual likelihood	Residual consequence	Residual risk level	Risk Mitigation	Target likelihood	Target consequence	Target risk level
1	Equipment Failure	Phase Reactor Failure	- Failure of the phase reactor could result in damage to phase reactor and potentially auxiliary equipment. - Electrical protection will operate to limit damage to reactor and prevent fire in reactor. - Tracking to reactor can be adequately managed through regular inspection and cleaning. - Reliance on manufacturer's recommended maintenance practices. - No fire suppression systems or fire segregation was included in the original design; indicating the manufacturers perceived level of fire risk.	Occasional	Minor	**Low**	Statistics for Directlink demonstrate: - 3 in 14 year likelihood of reactor failure - 1 in 14 year likelihood of fire and loss of converter building - 15 similar phase reactors still in service. - FM global assessment of the cost was $65m. - tracking perceived as a design flaw requiring rectification.	Occasional	Major	**High**	Capital - fire suppression in reactor area - Modifications to reactor cooling Operation - Create new maintenance procedure for phase reactors - Change start-up and operating procedures -Assurance -> improve quality control of works undertaken on reactor - increased and improved condition monitoring	Unlikely	Minor	**Low**
2	Equipment Failure	Failure of Capacitors	- Failure does occur (1 in 4 years) - consequence insignificant with damage localised, some cleaning of adjacent equipment required and replacement of capacitor can - failures can be adequately managed through regular inspection and cleaning. - Reliance on manufacturer's recommended maintenance practices. - No fire suppression systems or fire segregation was included in the original design; indicating the manufacturers perceived level of fire risk.	Occasional	Insignificant	**Low**	- potentially fire and loss of converter building as per phase reactor - Following investigation after the fire it was found that the sealed building had trapped significant heat, which means that it can no longer be assumed that a capacitor failure/fire will be limited to the capacitor cans.	Occasional	Major	**High**	Capital - Install fire suppression in AC and DC Yard Operation - Improve maintenance procedures - improve quality control - increased and improved condition monitoring	Possible	Insignificant	**Low**
3	Equipment Failure	Failure of other primary equipment	- Failure of primary equipment assumed to cause localised damage only. - Failures can be adequately managed through regular inspection and cleaning - Reliance on manufacturers recommended maintenance - No fire suppression systems or fire segregation was included in the original design; indicating the manufacturers perceived level of fire risk.	Possible	Insignificant	**Low**	- potentially fire and loss of converter building as per phase reactor - Following investigation after the fire it was found that the sealed building had trapped significant heat, which means that it can no longer be assumed that a equipment failure/fire will be limited to the primary equipment.	Possible	Major	**High**	Capital - Install fire suppression in AC and DC Yard Operation - Improve maintenance procedures - improve quality control - increased and improved condition monitoring	Possible	Insignificant	**Low**
4	Equipment Failure	Plant failure caused by accelerated ageing of equipment	- Asset "designed to be unmanned and virtually maintenance free" based on the Due Diligence documentation provided at the time APA acquired the asset. - Maintenance assumed adequate for design life of 40 years - Design assumed adequate for environmental conditions - Replacement of individual assets on an adhoc basis, considered to be low cost	Unlikely	Minor	**Low**	- Dust and moisture have caused tracking hence it is not likely that the reactors will achieve the 40 year design life. - The reactors have been subjected to accelerated aging for the first 14 years of their design life, hence design change (i.e. changes to the cooling system) is unlikely to reverse aging that has occurred. - Design of the cooling system is now in question, original design was supposed to include intake air filters - Manufacturer's recommended operation and maintenance procedures are now in question. - Consequence early replacement of the 15 remaining phase reactors is probable.	Likely	Significant	**High**	- condition assessment of reactors (the outcome of the condition assessment will further clarify the risk and course of actions) - modification to reactor cooling system - additional conditioning monitoring - improve maintenance procedures to consider environment (e.g. dust, humidity and general cleanliness) - additional training in maintenance procedures - improved quality control of works - improved record keeping	Occasional	Medium	**Moderate**

Directlink Asset

Risk Register - O&M Cost Benefit Analysis - Rev 0

ID	Risk Category	Description of Risk	Pre-Event Assumptions	Inherent likelihood	Inherent consequence	inherent risk level	Post Event Assumptions	Residual likelihood	Residual consequence	Residual risk level	Risk Mitigation	Target likelihood	Target consequence	Target risk level
5	Fire	Fire in the Converter Building	- Fire in converter building perceived to be localised and self extinguishing, - Outdoor equipment in building not perceived to be a fuel source for fire propagation. - No fire suppression systems or fire segregation was included in the original design; indicating the manufacturers perceived level of fire risk.	Occasional	Insignificant	**Low**	- Following investigation after the fire it was found that the sealed building had trapped significant heat, which means that it can no longer be assumed that equipment failure/fire will be limited to the capacitor cans. - No longer considered same fire risk as outdoor equipment - The building was enclosed and acoustically insulated to manage noise issues that appeared during the original construction, It appears that the fire risk may not have been adequately re-assessed in the original construction.	Possible	Major	**High**	Capital - Install fire suppression Operation - Improve maintenance procedures - improve quality control - increased and improved condition monitoring	Occasional	Insignificant	**Low**
6	Regulatory	Risk of non compliance to NER, AER and good electricity industry practice	- Compliance established during commissioning - Operating in accordance with manufacturers recommendations that are considered to be good electrical industry practice for this unique VSC technology - Consequence assumed as an inmaterial non-compliance, easily rectified	Possible	Minor	**Low**	- APA consider that the risk of non-compliance may be higher due to the public nature of the event and that the consequence of non-compliance could be greater given what has happened. Any audit will likely be based on assertions of GEIP following the event and not on the assumptions and beliefs held by APA prior to the event. APA has a greater need for assurance with regards to compliance monitoring and activities to maintain compliance. - APA needs to demonstrate that appropriate measures will be implemented following the event that demonstrate future operation of Directlink accounts for the change in risk in accordance with good electricity industry practice.	Likely	Major	**High**	Implementing a suite of recommendations including capital works and O&M measures will demonstrate that Directlink has changed it's operation in line with good electricity industry practice following the event. APA recognise a greater need for assurance that the controls are in place to demonstrate compliance, O&M measures shall assist, such as: - reporting & record keeping - compliance plan - improve maintenance procedures - asset management plan - quality control - training and certification Capital works to be implemented will include fire supression, changes to the reactor design and air filtering.	Unlikely	Minor	**Low**
7	Maintenance	Risk of trips/extended outage to converter station caused by converter station elements	- Only cable failures, and not converter station elements, cause extended outages of a system. - Based on the current rate of failures of cables, Directlink can meet AER requirements for supply quality and reliability as a 120MW system averaged over a year. - Recommended asset maintenance practices deemed adequate to limit equipment failure causing extended outage. - Directlink can achieve the 120MW availability and associated reliability even though cable faults are common. - availability penalties were quite low, in the order of $100k per year, also considering that the consequence of failure in the converter building was perceived as low there was not sufficient incentive to drive major design changes and capital works in the converter station.	Possible	Minor	**Low**	- failure of converter station elements could create extended outage resulting in a greater consequence where the supply reliability of 120MW cannot be achieved. - repairs/maintenance did not prevent failure of reactor - protection system did not prevent fire - adequacy of maintenance procedures in question?	Possible	Major	**High**	Capital - fire suppression in reactor area - fire suppression in AC and DC Yard - Modifications to reactor cooling Operation - Modify and create new maintenance procedures for converter station equipment - Change start-up and operating procedures -Assurance -> improve quality control of works undertaken on equipment - increased and improved condition monitoring	Unlikely	Minor	**Low**

Directlink Asset

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Risk Register - O&M Cost Benefit Analysis - Rev 0

ID	Risk Category	Description of Risk	Pre-Event Assumptions	Inherent likelihood	Inherent consequence	inherent risk level	Post Event Assumptions	Residual likelihood	Residual consequence	Residual risk level	Risk Mitigation	Target likelihood	Target consequence	Target risk level
8	Public and Employee Safety	Directlink equipment fire could cause adjacent fire or bush fire	- the converter station was not considered bush fire prone in the network management plan. - converter station would not catch fire enough to threaten the adjacent electrical substation	Unlikely	Minor	**Low**	- Now the idea that a fire can rage to affect neighbouring facilities and/or flora has higher likelihood - Essential Energy expressed concern based on switchyard proximity -Experience shows long times for fire brigade to arrive and then feel safe to extinguish fire - higher chance of high/large flames.	Possible	Major	**High**	Capital - fire suppression in reactor area - fire suppression in AC and DC Yard and valve containers - Modifications to reactor cooling Operation - develop a documented isolation plan share with fire brigade (APA Recommendation during meeting) - site walkthroughs with fire brigade (annual) (APA Recommendation during meeting) - Improve maintenance procedures (bush fire plan) - man both sites for future energisation activities (APA Recommendation during meeting)	Unlikely	Minor	**Low**
9	Employee Safety	Employee safety in the event of a converter building fire	- converter station unlikely to catch fire enough to threaten safety of personnel - the converter building is locked closed during operation preventing operator access when fire is likely. - fire would be contained within the building allowing time to evacuate - it is possible that an operator could be in the control room at the back of the building at the time of a fire	Unlikely	Insignificant	**Negligible**	- the converter building is locked closed during isolation preventing operator access. - it is possible that an operator could be in the control room at the back of the building at the time of a fire. - radiant heat from building was high potentially making it difficult to get past the building to evacuation point, hence evacuation of the building should be re-evaluated	Possible	Minor	**Low**	- reassess egress route from control building - locate alternative exit points on the perimeter of the sites	Possible	Insignificant	**Negligible**

Appendix 2 – Summary of GEIP Recommendations

Ref	Priority (1-3)	Recommendation	Affected Process or Equipment	DL Doc Ref
1	1	Include signature boxes for all checklists including someone from APA to inspect and verify satisfactory completion of the work.	Operating Procedures and Work Instructions	
2	1	Include a process that drives obtaining photographic evidence of issues of concern, and how to store and recall these images easily	Operating Procedures and Work Instructions	
3	1	Develop a procedure for documentation control including the control of site documentation to ensure on site staff are operating from the latest versions of each document and to encourage the use of the manufacturer's documentation through easy access	Control of O&M Documentation	DL-DO-02
4	1	Fix DL-WI-02 diagrams and instructions to identify that there is no earth switch in the WT yard.	Site Access and Control of Authorised Personnel	DL-WI-02
5	1	Modify DL-WI-03 to include checks that water valve positions are checked and confirmed opened and that corona rings are checked for tools and debris before closing up a valve enclosure	Site Access and Control of Authorised Personnel	DL-WI-03
6	1	Check section 3.2 of the DL-WI-09 as to why there is a need to lock OPEN the earth switches and that there is no reference to locking the earth switch CLOSED.	High Voltage Switching and Access Procedures	DL-WI-09
7	1	If no record of authorisation levels exist, then ensure that these are maintained and available to system control	Authorisation Levels Register	
8	1	Recommend redoing the Asset Management Plan to address the key comments The plan should include: a. Missing elements normally associated with an AMP - key roles and responsibilities, operations and maintenance team structure, call out philosophy, contractors under contract, which staff/contractors are used for which work, location of staff, plant and equipment, storage location of spare parts and consumables, overall maintenance philosophy (preventative, reliability centred etc), interface with the MMIS etc b. Missing elements normally associated with a Lifecycle Plan for the asset suc as breaking the equipment into classes, identifying risks associated with the equipment, redundancy vs. non-redundancy, spares availability, strategy for managing the asset class and maintenance strategy. c. More detailed identification of asset management risks and associated mitigations.	Asset Management Plan	ML & DL EII Asset Management Plan
9	1	Consider developing separate asset management and maintenance strategies for each asset class (e.g. transformers, filter equipment, IGBTs, cables, cooling system etc)	Asset Management Plan	ML & DL EII Asset Management Plan
10	1	The recommendations for the maintenance plan will depend on which recommendations are adopted by APA for the Asset Management Plan above. Breaking the various items of equipment into asset classes and developing individual asset management and maintenance strategies for each class is recommended. These documents may be able to be used across both Directlink and Murraylink (i.e. the strategy for the converter transformers may be applied to all converter transformers including those at both Directlink and Murraylink).	Maintenance Plan	Extract from MMIS
11	1	Update DL-SP-01 to provide guidance as to how to conduct an investigation (e.g. evidence, interviews with staff shortly after the event) etc and which form shall be completed for record purposes	Electrical Incident Investigation	DL-SP-01
12	1	Update DL-SP-02 to provide instruction on how to document and record instructions from the NSP and actions taken by APA in the case of future investigations.	Electrical Incident Investigation	DL-SP-02
13	1	Update Chapter 12 of DL-OP-06 to refer to which form shall be completed in the event of an electrical accident	Electrical Incident Investigation	DL-OP-06
14	1	Develop procedures for the investigation and reporting of Directlink response to AC network events to demonstrate compliance to NER requirements.	Investigation and Reporting of Directlink Response to External AC N	DL-OP-20
15	1	Develop procedures for the investigation and reporting of Directlink protection trip events to demonstrate compliance to NER requirements	Investigation and Reporting of Directlink Protection Operations	DL-OP-20
16	1	Develop a more detailed public electrical safety plan, perhaps using the Essenti Energy plan as a guide and/or comparing back to the requirements of this plan. It may be possible to combine a plan for all APA's transmission assets (e.g. Directlink and Murraylink	Public Electrical Safety Awareness Plan	NMP 23/5/2013
17	1	Compare the Bush Fire Risk Management Plan against the requirements.	Bush Fire Risk Management Plan	NMP 23/5/2013
18	1	Develop documented procedures for undertaking cable repairs including an inspection by APA personnel and sign off that the repairs have been completed and tested in accordance with the procedure	Fault Detection and Cable Repair	
19	1	Develop and issue a checklist for the preparation of the valve enclosures for re-energisation follow working in the valve enclosures	Pre-Energisation Inspection - Valve Containers	
20	1	Expand the inspection in DL-WI-44 to cover inspection of the rest of the building prior to energisation.	Pre-Energisation Inspection - Converter Building	DL-WI-44
21	1	Increase the instructions in DL-WI-44 beyond simply dealing with the moisture issue. Include inspections for tools and debris for example	Pre-Energisation Inspection - Phase Reactors	DL-WI-44
22	1	Create work instructions for the maintenance of the zero sequence reactors and remove references to these items from DL-WI-29	Zero Sequence Reactor	DL-WI-29
23	1	The table in DL-WI-38 needs a column for capacitance measurement.	Capacitors	DL-WI-38
24	1	Specify which manufacturer document applies to each reactor and be specific about which reactors are covered by DL-WI-29	Trench type reactors	DL-WI-29
25	1	Establish a pre-energisation checklist to ensure no water valves are left closed after IGBT replacements.	Valve IGBT Bank	DL-WI-13
26	1	Create a work instruction for the maintenance of the phase reactors and remove reference to these items from DL-WI-29	Phase reactor	DL-WI-29
27	1	Establish an annual work instruction for the maintenance of the SF6 Wall Bushings	SF6 Wall Bushing	
28	1	Establish a work instruction for yearly transformer maintenance in accordance with Section 8.4 of ABB document 000169568 Rev. 00	Power Transformer (3 ph). Including 2 x Current Transformers	
29	1	Confirm how/if Directlink IT assets are managed and maintained?	Control and Protection Systems	
30	1	Locate any additional manuals delivered with PCs and review for maintenance instructions.	Control and Protection Systems	
31	1	If IT maintenance procedures do not exist, put in place maintenance work instructions and IT/Control system procedures that follow good electricity industry practices	Control and Protection Systems	
32	1	Check all maintenance instructions for out of date document numbering (Some references to TEA documents can be found)	Operating Procedures and Work Instructions	
33	1	Check the procedures of the existing contractor meet all requirements outlined in the manufacturer documentation and create a work instruction for circuit breaker maintenance. This work instruction should be broken down into sections for the 3, 6 15 and 30 year circuit breaker maintenance.	Circuit Breaker	
34	1	Archive and maintain on hand the original test and commissioning documents that demonstrate compliance with the requirements of the NER.	Chapter 5 NER Review	
35	1	Develop a documented process for controlling and monitoring any changes implemented in the protection and control systems and confirmation of the NER compliance following such changes	Chapter 5 NER Review	

Ref	Priority (1-3)	Recommendation	Affected Process or Equipment	DL Doc Ref
36	1	Develop a documented and defined process for undertaking the analysis of the response of the HVDC Assets to external (AC network) faults in close proximity and internal protection trips, using the information available from the SER and TFR and other systems, concluding whether or not the HVDC Assets protection and controls have operated/responded correctly and as per design. Each investigation report shall: i. State whether the response of the HVDC Asset control and protection systems was the correct designed action or not; ii. State whether or not the HVDC Asset has met the performance obligations and is compliant with the NER, and iii. If discrepancies or a non-compliance is detected then NER rule 5.7.4(a3)-(a4) apply.	Chapter 5 NER Review	
37	1	Locate any commissioning documents that state specifically the results comply with the specification, CA or NER, for example fault clearing times or power quality.	Chapter 5 NER Review	
38	1	Clarify Section 4.3.1 of the Directlink Network Management Plan, which states that supply quality standard are monitored 24/7 at the control centre, and whether harmonics (CA Schedule 11, item 4) are covered by this monitoring.	Chapter 5 NER Review	
39	1	Check the Essential Energy CA to determine if testing intervals for protection systems (if any) and the agreed protocols for maintenance coordination are defined within it and if not that these be defined during the next review of the CA.	Chapter 5 NER Review	
40	1	Update the Directlink Network Management Plan and/or Asset Management Pla to document that APA will cooperate with any testing required by the respective NSP's for the connection asset protection and control systems and the ECSs.	Chapter 5 NER Review	
41	1	Develop a documented compliance program document specific for the Directlink protection and control systems covering how APA will demonstrate ongoing compliance with the NER, the periodic testing regime and the rationale behind the testing regime.	Chapter 5 NER Review	
42	1	The control system drawings embedded in the 'Plant Docs" system be updated to reflect the current "as built" status. It is noted that some changes made in 200 to the protection and control system have not been implemented in these drawings.	Chapter 5 NER Review	
43	1	Establish work instructions for the 1, 3 and 5 year maintenance of the various disconnectors and earth switches	Disconnectors and Earth Switches	
44	1	Create a four monthly maintenance work instruction to cover items in Section 8.3 of ABB document 000169568 Rev. 00	Power Transformer (3 ph). Including 2 x Current Transformers	
45	1	Review the fire system maintenance contractor procedures to ensure all manufacturer requirements are being me	Fire Detection Controller	
46	1	Add the four year replacement of lead acid batteries to fire system maintenance if this is not already covered in the existing schedule	Fire Detection Controller	
47	1	Consider a form included with the IGBT Replacement Form to ensure the Switching and Communication tests are performed on all IGBTs in a stack where an IGBT has been replaced	Maintenance Documentation	
48	1	Consider including a place in the IGBT Replacement form for the leakage current tests being performed on the faulty and adjacent positions.	Maintenance Documentation	
49	1	Modify the forms to allow more room for legible comments	Maintenance Documentation	
50	1	Discuss with staff regarding filling out forms correctly - clear and legible writing, dating the forms, identifying the sites, completing forms as required	Maintenance Documentation	
51	2	Include a section in all Work Instructions on which items of plant the WI applies to.	Operating Procedures and Work Instructions	
52	2	Where two procedures or work instructions cover the same ground, ensure one refers to the other rather than repeating and risking contradictions.	Site Access and Control of Authorised Personnel	
53	2	Ensure that instructions in DL-OP-06 and DL-OP-01 (tagging procedure) align. Some differences have been found that should be addressed	Site Access and Control of Authorised Personnel	DL-OP-06
54	2	Refer to where personnel can find the Safe Approach Distances referred to in DL-WI-02.	Site Access and Control of Authorised Personnel	DL-WI-02
55	2	Modify DL-OP-18 to include approvals and revision log. Be clear in this procedure on which application form to be used, how to obtain a "permit" and whether a risk assessment is mandatory or no	Site Access and Control of Authorised Personnel	DL-OP-18
56	2	Update Section 11 of DL-OP-05 to refer to DL-WI-02 and remove potential contradictions.	High Voltage Switching and Access Procedures	DL-OP-05
57	2	Update DL-OP-06 to address the various comments made.	High Voltage Switching and Access Procedures	DL-OP-06
58	2	Check consistency and ensure no double up between DL-OP-06 and other WIs.	High Voltage Switching and Access Procedures	DL-OP-06
59	2	Update DL-OP-05 to comply with how Directlink is currently being operated and dispatched.	Control Room Operations and Dispatch	DL-OP-06
60	2	Remove any contradictions or doubling up with other Wis in DL-OP-05.	Control Room Operations and Dispatch	DL-OP-05
61	2	Include a section in DL-OP-05 on how to respond to ambient temperatures belo zero degrees.	Control Room Operations and Dispatch	DL-OP-05
62	2	Update DL-DO-04 to provide clear instruction as to who is responsible for recording the outage and how	Recording and Reporting Outages	DL-DO-04
63	2	The use of the Operations Logs (DL-OF-16) may not be appropriate as the outage may get lost in other events. Suggest using DL-OF-17 the Outage Register and referring to it	Recording and Reporting Outages	DL-OF-16
64	2	Establish a contract for the periodical inspection of the cable route as stated in the NMP.	Bush Fire Risk Management Plan	NMP 23/5/2013
65	2	Develop a procedure for the periodical inspection of vegetation along the cable route and in the vicinity of the converter stations	Bush Fire Risk Management Plan	NMP 23/5/2013
66	2	Develop procedures for contractor management, if not covered by APA's overal systems. Include a process for receiving, reviewing and managing procedures used by specialist contractors	Contractor Management	
67	2	Modify DL-OP-18 according to comments in Directlink GEIP checklists	Easement Management	DL-OP-18
68	2	Include an explanation as to how to obtain a Permit in DL-OP-18	Easement Management	DL-OP-18
69	2	Develop an application pro-forma for the procedure in DL-OP-18	Easement Management	
70	2	Develop a procedure for the management of vegetation along the cable route/easement as identified in the NMP	Vegetation Control Surrounding the GST	
71	2	Develop a procedure or work instruction for the Maintenance and Testing of Earthing Systems	Maintenance and Testing of Earthing Systems	
72	2	Fix DL-WI-44 of errors and unclear instruction	Pre-Energisation Inspection - Converter Building	DL-WI-44
73	2	Modify DL-WI-34 so that they are clear as to which surge arresters are covered and which manufacturer document applies to each arreste	Surge Arresters	DL-WI-34
74	2	Check all capacitors covered by DL-WI-38 for unbalance protection. Establish annual capacitance measurement for those without unbalance protection	Capacitors	DL-WI-38
75	2	Correct errors under document references in DL-WI-29.	Trench type reactors	DL-WI-29
76	2	Change DC filter reactor document reference in DL-WI-29 from MI-99.01.0050 Rev. 00 to MI-201.01.0050 Rev. 00	Trench type reactors	DL-WI-29
77	2	Confirm correct manufacturer documentation for AC reactor WA-Z1-L1	Trench type reactors	DL-WI-29
78	2	Correct reference to PLC noise filter reactor documentation in DL-WI-29	Trench type reactors	DL-WI-29

Ref	Priority (1-3)	Recommendation	Affected Process or Equipment	DL Doc Ref
79	2	No maintenance instructions were included in the manufacturer documentation for the tuning units WT-Z(1,2). Locate maintenance requirements and include in a work instruction.	AC PLC Filter Tuning Unit	
80	2	Confirm that UPS system SCE is included in the six monthly inspection of UPS supply A and B	UPS System SCE (Exide Prestige 1500VA)	
81	2	Confirm that UPS system for DC disconnector is included in the six monthly inspection of UPS supply A and B	UPS for DC Disconnector (Powerware 2000VA)	
82	2	Check if the AC switchyard lighting maintenance is included in the emergency lighting maintenance	AC switchyard lighting	
83	2	Review the fire system maintenance contractor procedures to ensure all manufacturer requirements are being me	NT Fire Panel	
84	2	Review daily and weekly operator procedures to ensure the checks detailed in WFS-NTF-GB2202 Section 5 are being performed	NT Fire Panel	
85	2	Include a maintenance instruction for the eye wash station in DL-WI-17.	Eye wash station	DL-WI-17
86	2	Include a maintenance instruction for the spill kit in DL-WI-17.	Spill kit	DL-WI-17
87	2	Develop a work instruction for weekly cooling system inspection.	Valve cooling system	
88	2	Add a check of running hours for the valve cooling system pump since last oil change to DL-WI-17 Section 1.4.2. Alternatively, establish a three month work inspection that covers the requirements of the manufacturer document 8-1000-150/E.	Valve cooling system	DL-WI-17
89	2	Establish work instructions for the 1, 2 and 5 year valve cooling system maintenance	Valve cooling system	
90	2	Check existing 2 and 5 year maintenance for replacement of Ion-exchange resin and cleaning of strainers	Valve cooling system	
91	2	Check if the valve cooling system oxygen testing can be performed while the converters are deblocked and include a monthly oxygen test in DL-WI-17.	Valve cooling system	DL-WI-17
92	2	Correct header of DL-WI-33. It currently states that the work instruction is for an outdoor post type CT.	DC Cable Screen Current Transformer	DL-WI-33
93	2	Confirm the correct manufacturer documentation for the DC cable screen current transformer and update document reference in DL-WI-33	DC Cable Screen Current Transformer	DL-WI-33
94	2	Establish a work instruction for the six month check of the emergency lighting	Emergency Lighting	
95	2	DL-WI-28 - Three Year Capacitor Maintenance - the Forms are clearly not sufficient for all readings. It is recommended to redo these forms to align with the readings taken in the field	Maintenance Documentation	DL-WI-28
96	2	Fix header of document DL-WI-25. It currently states the work instruction is for a capacitive voltage transformer.	Valve Dehumidifier	DL-WI-25
97	2	Establish a work instruction for the 3 month clean of the dehumidifier filter.	Valve Dehumidifier	
98	2	Alter DL-WI-25 to include annual maintenance of the dehumidifier.	Valve Dehumidifier	DL-WI-25
99	3	Standardise on the name/title of the control centre (e.g. DLSC, Directlink System Control?)	Operating Procedures and Work Instructions	
100	3	Check definitions. For access and site control related procedures and work instructions, refer to definitions of DL-OP-06.	Site Access and Control of Authorised Personnel	DL-OP-06
101	3	Update DL-OP-05 to remove references to NorthPower, NEMMCO etc	High Voltage Switching and Access Procedures	DL-OP-05
102	3	Ensure that an accurate and up to date inventory of spare parts is maintained.	Spare Parts Inventory	
103	3	Ensure that a procedure exists and is followed that logs spare parts in and out and triggers the procurement of new spares where required. It should also identify who is responsible for the procurement decisions related to new spare parts.	Procedure for Managing Spare Parts Inventory	
104	3	Ensure that a procedure exists for managing special tools, including recording calibration dates, keeping certificates and ensuring the need for new calibration is triggered.	Procedure for Managing Special Tools	
105	3	Create an annual work instruction for cable ends. This will likely be limited to a clean and inspection	Cable Ends	
106	3	Include a reference to document XL 300 021-243 Rev. 01 in DL-WI-34 for arrester WA-Z1-F1	Surge Arresters	DL-WI-34
107	3	Include a check and record of the surge arrester operation counters in DL-WI-34	Surge Arresters	DL-WI-34
108	3	Establish a work instruction for periodic checking of the spark gap and procedure if flashover of spark gap should occur	Spark Gap	
109	3	Check on the maintenance requirements of the two CTs shown with P1-WT2-T1 No maintenance information was found for these items	Power Transformer (3 ph). Including 2 x Current Transformers	
110	3	Implement a permit log system to track permits issued and ensure unique numbering of permits	Site Access and Control of Authorised Personnel	
111	3	APA should have a copy of the training materials provided for HV Switching Course, even though this is provided by an external provider. The training content may be audited or otherwise may need to be referred to in the event of an incident	High Voltage Switching and Access Procedures	
112	3	Introduce a register of training undertaken to flag and record the performance of annual competency assessment and any re-training	High Voltage Switching and Access Procedures	
113	3	Maintain a record of authorisation levels exist, then ensure that these are maintained and available to system contro	Authorisation Levels Register	
114	3	Implement the annual assessment of competency into MARCUS.	Authorisation Levels Register	

Appendix 3 – Cost-Benefit Analysis

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
Asset Management Plan	3	New Procedure (3)	Medium	Medium	High	High	By adopting recognised global leading practices in asset management the benefit is assessed to be High for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • A more transparent and demonstrable ability to critically assess and manage asset risks; • A more structured approach to the management of assets by managing repair and replacement times and avoiding unplanned failures; • A more transparent management of life cycle costs and investment needs; and • A clearer and more concise governance of asset management by improving the understanding between business owners and operations managers. • A recent electricity industry trend towards the adoption of PAS 55	The cost of implementation and ongoing performance of the group of recommendations is estimated to each be medium. The benefits for implementation and ongoing performance are qualitatively assessed to be high. In addition the adoption of PAS 55 by other electricity industry is publically recognised as Good Electricity Industry Practice by the AER. PSC is of the view that the benefits are greater than the cost and hence recommends the implementation of the group of recommendations associated with the development of the Asset Management Plan.

Compliance Plan & Incident Investigations	11	New procedures (6), Procedural Change (3), Documentation Check/Update (2)	High	High	High	High	By proactively demonstrating compliance and thoroughly investigating incidents the implementation of these recommendations will distinguish the DJV as a leader in terms of good electricity industry practice. PSC consider the benefits to be high for both Risk Reduction and Market Benefit.
							Benefits that will reduce risk and maintain reliability and availability have been identified as follows:
							• Provides greater assurance that Directlink is operating in compliance with:
							  ○ Connection Agreements;
							  ○ The requirements of the NER; and
							  ○ Good Electricity Industry Practice.
							• Improving reporting and investigations will assist in maintaining reliability and availability
							• Provide a clear and transparent process for ongoing training of staff and for auditing.
							• Adds clarity of reporting guidelines and information gathering requirements for incident investigations.
							• Ensure the best level of information can be obtained to make assessments and draw conclusions.
								The individual cost for the implementation and ongoing performance for each recommendation is estimated to be low to medium, whereas, the benefit for implementation of each recommendation is assumed to be high due to the change in risk profile.
								PSC is of the view that the benefits are greater than the cost of implementation and recommend implementation of the group of recommendations associated with the Compliance Plan and Incident Investigation.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							• Ensure that due process is followed if external parties were to be involved.	
Documentation Improvement	11	Procedural change (1), Documentation Check/Update (10)	Medium	Zero	Medium	Low	The implementation of this group of recommendations will most prominently improve quality. PSC have assessed a Medium benefit for Risk Reduction and a Low Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved quality assurance through better documentation for O&M activities. • Reduces overhead/administration time, and may assist in preventing errors on site by maintenance contractors. • Improved documentation for compliance and asset management purposes. • Better information for post fault analysis. • Adds clarity of reporting guidelines and information gathering requirements for incident investigations. • Ensure the best level of information can be obtained to make assessments and draw conclusions. • Ensure that due process is followed if external parties were to be involved.	For the group of recommendations the overall implementation cost is assessed to be medium and the ongoing performance cost to be zero. The overall benefit is considered to be medium on average. PSC is of the view that the benefits are greater than the cost of implementation and recommends implementation of the group of recommendations associated with the Documentation Improvement.
Easement Management	8	New procedures (4), Documentation Check/Update (4)	Medium	Low	Medium	Medium	This group of recommendations will improve the management of the cable and easement. PSC consider the benefit will be Medium for Risk Reduction. There is a potential to also influence the reliability of the cable through the implementation of these recommendations, hence, PSC has assessed the Market Benefit to also be Medium. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Greater understanding of how to evaluate the vegetation fire risk. • Minimise potential forced outages and loss of plant availability due to vegetation encroachment or bushfires. • Greater assurance on the process for working within easements and prevent cable damage from work activities, vegetation growth or fire	The cost for implementation of the eight recommendations is low, whereas the benefit for implementation of each is considered to be medium. PSC recommends the implementation of these low recommendations.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							hazard. • Greater assurance of the scope and quality of work performed by Contractors. • Clarification of documentation will reduce administration time. • Encourage correct document completion by Contractors for greater quality assurance.	
High Voltage Switching and Access Procedures	8	Procedural change (2), Documentation Check/Update (6)	Low	Low	Medium	Low	The benefits of this group of recommendations are assessed to be Medium for Risk Reduction based on safety improvement. The Market Benefit is assessed to be Low. Benefits that will reduce risk as follows: • A high focus on safety applied to HV switching and access procedures. • Improved management of personnel training records, ensuring that persons have been adequately trained and have the correct competencies for the tasks/work required. • Improved safety in workplace. • Greater assurance of the training and competency of personnel and training providers. • Clarity of documentation will reduce overhead/administration time, and may assist in preventing errors on site by maintenance contractors.	The implementation and ongoing performance costs for the eight recommendations is considered to be low. The benefit of these minor recommendations is considered to be at least medium due to the importance placed on safe operation and maintenance by trained and authorised personnel. PSC recommends the implementation of this group of recommendations associated with High Voltage Switching and Access Procedures.
Network Management Plan	4	Procedural Change (2), Documentation Check/Update (2)	Low	Low	Medium	Low	The group of recommendations associated with the Network Management Plan was assessed to provide a Medium Benefit for Risk Reduction. The Market Benefit is assessed to be Low. Benefits that will reduce risk have been identified as follows: • In comparison to the plans developed by Essential Energy, Directlink's plan has much less information. However, there are significant differences in the types of public safety and bush fire risks between both organisations, for which it would be expected that Essential Energy's plan would be more complex. • The detail included in the network management plan could be improved to provide more clarity of the risks and interfaces between APA and the	The four recommendations are low cost in implementation and ongoing performance, whereas the benefits are considered to be medium. PSC recommends the implementation of the group of recommendations associated with the Network Management Plan.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							public. • The implementation of the recommendation will further define the risks. • The benefits are considered to be improved public perception and risk management.	
Operations Access and Reporting	11	New procedure (4), Procedural change (2), Documentation Check/Update (1)	Medium	Medium	Medium	Medium	This group of recommendations is considered to focus on the improvement of activities at site, PSC assessed this group to provide a Medium benefit for Risk Reduction. PSC consider the recommendations will also improve the reliability of site works that may also result in an improvement in reliability of the Directlink facility, as such, the Market Benefit is assessed to also be Medium. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Photographic evidence will assist in record keeping/tracking as well as reliable external diagnosis of issues if required. • Better documentation control will assist future auditing. • More complete documentation will result in successful audits of maintenance activities. • Clarity of documentation will reduce overhead/administration time, and may assist in preventing errors by operations staff. • Greater transparency to management of authorisations for faster approvals, improved security and improved safety. • Clarification of operating procedures for below zero temperatures will prevent operator error and potential availability reduction. • Improved documentation for compliance and asset management purposes. • Better information for post fault analysis to identify risks	The overall cost for the eleven recommendations was considered to be medium. The overall benefits were considered to be medium and individually the benefits were qualitatively assessed to be higher than the cost of implementation. PSC recommends the implementation of the group of recommendations associated with the Operations, Access and Reporting.
Spare Parts and Special Tools	3	New procedure (2), Procedural change (1)	Medium	Medium	High	High	Improvements to the management of spare parts and special tools above current practice has been assessed by PSC to have a High benefit for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows:	The overall cost for the three recommendations is medium, whereas the benefits are considered to be high. PSC recommends the implementation of the group of recommendations associated with Spare Parts and Special Tools.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							• Reduced outage times during emergency/unplanned outages requiring replacement with spare parts which will improve availability • Manage outages more effectively through monitoring of minimum spares holdings based on prior failures. • A more efficent spares holding and associated cost saving. • Provision of a register for the management of spare parts and special tools saves time in spare parts management. • Reduced time auditing existing spares and special tools holdings. • Safety - Improved management of special tools and management of calibrations.	
Auxiliary Power	4	New Procedure (4)	Low	Low	Low	Low	The group of recommendations has been assessed to provide a Low benefit in Risk Reduction and Market Benefit, due to the incremental improvement to current practices. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved reliability by ensuring the maintenance activities are performed and results recorded. • High confidence of correct operation of UPS during a forced outage event or loss of auxiliary supply. • High confidence that lighting is operating adequately for emergency situation.	The costs and benefits have both been assessed as low. PSC is of the view that a prudent operator should document these maintenance instructions to ensure that they are being performed, hence PSC recommends the implementation of the group of recommendations associated with Auxiliary Power.
Capacitors	3	Procedural Change (1), Documentation Update/Check (2)	Low	Low	High	High	The benefit is assessed to be high for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Overall improved reliability and diagnosis of failure and potentially reduce the likelihood of a forced outage caused by a capacitor can failure. • Improved tracking and monitoring of capacitor condition to ensure reliable operation. • Improved documented asset management procedures and ensure reliable maintenance.	The costs of implementation and ongoing performance has been assessed as low, whereas the benefit of improved reliability through more frequent testing and recording has been considered as high. PSC recommends the implementation of the group of recommendations associated with capacitors.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							• Improved records for easier auditing. • Less reliance on staff knowledge. • Reduced training time for new staff.	
Circuit Breakers	1	Procedural Change (1)	Low	Low	Low	Low	The incremental benefit of this group has been assessed as low with regard to Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved condition monitoring. • Improved documented asset management procedures and ensure reliable maintenance.	PSC is of the view that the identified maintenance activities should be performed in accordance with recommended maintenance procedures, hence PSC recommends the implementation of the recommendation.
Control, Protection and Telecommunication Equipment	3	New Procedure (3)	Medium	Low	High	High	The incremental benefit above current practice for the implementation of these recommendations is considered to be High for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Enable better understanding of the asset and also planning future capital replacement works. • Improved asset reliability and lower risk of systems failure due to complete and regular maintenance. • Improved condition monitoring by regular inspection. • Improved documented asset management procedures and ensure reliable maintenance. • Improved records and easier auditing of past maintenance. • Less reliance on individual staff knowledge. • Reduced training time for new staff.	The qualitative assessment of benefits is higher than the quantified cost of implementation and ongoing performance. PSC recommends the implementation of the group of recommendations associated with control, protection and telecommunication.
Current Transformers	2	Documentation Check/Update (2)	Low	Zero	Low	Zero	The incremental benefit is considered to be Low for Risk Reduction, the Market Benefit is negligible. Benefits that will reduce risk have been identified as follows: • An improvement to the procedure so that maintenance staff reference correct information and avoid maintenance error or confusion.	The qualitative assessment of benefits is low as is the quantitative cost of implementation. PSC recommends the correction to the current transformer procedure.
Disconnectors and Earthing	2	New Procedure (2)	Low	Low	Medium	Medium	The incremental benefit has been assessed to be Medium for both Risk Reduction and Market Benefit.	The qualitative benefit has been assessed to exceed the quantified cost for implementation.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • The recommended improvement of procedures are required to comply with manufacturer's recommendations for reliable maintenance. • Improved compliance with the NER.	PSC recommends implementation of this group of recommendations.
Filter Resistors	1	Procedural Change (1)	Low	Low	Medium	Medium	This recommendation group identified a gap in maintenance activities for this item. The implementation is considered to provide a Medium benefit for both Risk Reduction and Market Benefit, by clarifying the procedure and avoiding potential outages or extension of outage due to uncertainty regarding procedures. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • An improvement to reliability through maintenance procedures and condition monitoring by regular inspection. • Lower the risk of forced outage caused by an unexpected failure of equipment.	The benefit has been qualitatively assessed to be medium, where-as the cost of implementation and ongoing performance is low. PSC recommends the implementation of these recommendations.
Fire Systems	4	Procedural Change (3), Documentation Check/Update (1)	Medium	Low			This recommendation group is considered to potentially assist in event early detection and suppression, the benefit of implementation has been assessed to be High for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Reduced consequence of any item of equipment catching fire. • Improved documented asset management procedures and ensure reliable maintenance. • Improved records and easier auditing of prior maintenance. • Less reliance on individual staff knowledge • Reduced training time for new staff. • Improved operator procedures. • Compliance with manufacturer recommendations for reliable system operation.	The fire system has been identified as a critical asset that could benefit from improvement in asset maintenance practices following the fire event. As such, the benefit of implementation of the recommendations has been qualitatively assessed to be high. The implementation cost has been quantified to be medium and the ongoing performance cost low. PSC is of the view that the assessment of benefits exceed the cost of implementation and recommend the implementation of the group of recommendations associated with the fire systems.
High Voltage Cable	2	New Procedure	Low	Medium	High	High	Improvements to cable procedures are considered to	The high voltage cable has been identified as

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
		(2)					have a High benefit for both Risk Reduction and Market Benefit via reliability. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • May help prevent unintentional damage and assist in further diagnosis of existing faults possibly leading to improvements in reliability. • Improved integrity assurance of all cable repairs. • Control and consistency regarding the quality and reliability of the workmanship of the Contractor. • Better documentation and record keeping regarding cable faults. • Risk mitigation by inspecting elements not currently included. • Improved training and certification and less reliance on individual knowledge. • Good Electricity Industry Practice.	a critical asset that could benefit from maintenance procedure improvement. As such, the benefit of implementation of the recommendations has been qualitatively assessed to be high. The implementation cost has been quantified to be low and the ongoing performance cost medium. PSC is of the view that the assessment of benefits exceed the cost of implementation and recommend the implementation of the group of recommendations associated with the high voltage cable.
HVAC Valve and Reactor Cooling Systems	8	New Procedure (3), Procedural Change (3), Documentation Check/Update (2)	Low	Medium	Medium	Medium	The incremental benefits for this recommendation group has been assessed to be Medium for both Risk Reduction and Market Benefit as it will achieve improvement to the operation and maintenance procedures of a critical item of plant. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Ensure essential knowledge is communicated to staff to lower the risk of avoidable damage to high cost elements. • Improved documented asset management procedures and ensure reliable maintenance. • Documented evidence that all required checks have been performed so as to better identify risk • Less reliance on individual staff knowledge. • Reduced training time for new staff.	The implementation cost of the group of recommendations has estimated to be low and the ongoing performance cost as medium. The benefit for the implementation of the group of recommendations has been qualitatively assessed to be medium. PSC is of the view that the assessment of benefits exceeds the cost of implementation and recommend the implementation of the group of recommendations associated with the HVAC valve and reactor cooling systems.
IGBT Valves	5	New Procedure (1), Procedural Change (4)	Low	Low	High	High	The incremental benefits for this recommendation group has been assessed to be High for both Risk Reduction and Market Benefit as it will achieve improvement to the operation and maintenance procedures of a critical and high cost plant group. Benefits that will reduce risk and maintain reliability	The implementation and ongoing cost for the group of recommendations has estimated to be low. The benefit for the implementation of the group of recommendations has been qualitatively assessed to be high as it will

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							and availability have been identified as follows: • Reduce failures (and potential outages) by obtaining a better understanding of the ongoing condition of the IGBT valves. • Improved documented asset management procedures and ensure reliable maintenance. • Improved records and easier auditing of past maintenance. • Improved condition monitoring through additional tests and inspections. • Less reliance on individual staff knowledge. • Reduced training time for new staff. • Documented evidence that all required checks have been performed so as to better identify risk • Reduced risk of an incident resulting from maintenance by pre-energisation checks. • Safety/ Reliability - Good housekeeping practices.	achieve improvement to the operation and maintenance procedures of a critical plant group. PSC is of the view that the assessment of benefits exceed the cost of implementation and recommend the implementation of the group of recommendations associated with the IGBT valves.
Power Transformers	3	New Procedure (2), Documentation Check/Update (1)	Low	Low	Medium	Medium	The incremental benefits for this recommendation group has been assessed to be Medium for both Risk Reduction and Market Benefit by improving current maintenance to match relevant manufacturer recommendations. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved reliability and avoidance of unplanned outages through application of the manufacturer's recommended inspections. • Full compliance with manufacturer's recommendations. • Improved documented asset management procedures and ensure reliable maintenance. • Improved condition monitoring and equipment reliability through additional tests and inspections.	The implementation and ongoing cost for the group of recommendations has estimated to be low. The benefit for the implementation of the group of recommendations has been qualitatively assessed to be medium as it will achieve improvement to the operation and maintenance procedures by complying with manufacturer's recommendations. PSC is of the view that the assessment of benefits exceed the cost of implementation and recommend the implementation of the group of recommendations associated with the power transformers.
Reactors	12	Procedural Change (6), Documentation Check/Update (6)	Medium	Low	High	High	The incremental benefits for this recommendation group has been assessed to be High for both Risk Reduction and Market Benefit by improving current maintenance processes and procedures. Benefits that will reduce risk and maintain reliability	The implementation cost of the group of recommendations has estimated to be medium and the incremental ongoing performance cost low. The benefit for the implementation of the

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							and availability have been identified as follows: • Improved documented asset management procedures and ensure reliable maintenance. • Ensure that maintenance and inspection recommendations for the various specific types of reactors are applied where they are needed. • Addresses environmental issues associated with the phase reactors. • Reduced risk of an incident resulting from tools and debris left over from maintenance. • Improved records and easier auditing of past maintenance. • Less reliance on individual staff knowledge. • Reduced training time for new staff. • Documented evidence that all required checks have been performed so as to better identify risk	group of recommendations has been qualitatively assessed to be high as it will achieve improvement to the operation and maintenance procedures for critical items of plant suspected to be associated with the reactor fire. PSC is of the view that the assessment of benefits exceed the cost of implementation and recommend the implementation of the group of recommendations associated with the reactors.
Surge Arresters	4	Procedural Change (2), New Procedure (1), Documentation Check/Update (1)	Low	Low	Low	Low	The incremental benefits for this recommendation group has been assessed to be Low for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved documented asset management procedures and ensure reliable maintenance. • Improved records and easier auditing of past maintenance. • Documented evidence that all required checks have been performed so as to better identify risk	The implementation cost of the group of recommendations has estimated to be low and the incremental ongoing performance cost low. The benefit for the implementation of the group of recommendations has been qualitatively assessed to be low and will provide a minor improvement in documentation of required maintenance activities. PSC is of the view that the assessment of benefits match the cost of implementation and recommend the implementation of the group of recommendations associated with the surge arresters.
Wall Bushings	1	Procedural Change (1)	Low	Low	Low	Low	The incremental benefits for this recommendation group has been assessed to be Low for both Risk Reduction and Market Benefit. Benefits that will reduce risk and maintain reliability and availability have been identified as follows: • Improved documented asset management procedures and ensure reliable maintenance. • Improved records and easier auditing of past maintenance. • Documented evidence that all required checks	The implementation and ongoing performance cost has been estimated to be low. The benefit for the implementation of the recommendation has been qualitatively assessed to be low and will provide a minor improvement in documentation of required maintenance activities. PSC is of the view that the assessment of benefits match the cost of implementation and recommend the implementation of the group of recommendations associated with the wall

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.

Category	No. Of GEIP Recom.	Type(s)	Implement. Cost	Ongoing Cost	Risk Reduction Benefit	Market Benefit	Benefits	Cost-Benefit Commentary and Analysis
							have been performed so as to better identify risk	bushings.

Legend:
Costs – High >250hrs, Medium > 75hrs, Low <75hrs
Benefits are qualitatively assessed based on an incremental improvement over current O&M practice.