OPTIONS EVALUATION REPORT (OER)

FY24-28 Transformer Refurb Program

OER- N2404 Murray revision 1.0

Ellipse project no(s):
TRIM file: [TRIM No]

Project reason: Capability - Asset Replacement for end of life condition
Project category: Prescribed - Asset Renewal Strategies

Approvals

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Change history

Revision	Date	Amendment
00	31/10/2021	Initial
01	08/11/2021	Changes in refurbishment scope and cost

Executive summary

Power transformers are essential for a safe and reliable electricity transmission as they enable different voltage levels throughout the transmission and distribution networks. As part of the condition assessment and health index methodology, Murray No.1 and No.2 transformers have been identified as reaching end of life and with an increasing risk of failure. The need of this project is economic benefit, with risks to be considered for remediation within the 2023 – 2028 regulatory period.

Murray 330kV Substation is located in TransGrid's Southern NSW network. It is an integral connection point for Snowy Hydro into TransGrid's 330kV transmission network as well as interconnection between TransGrid's Southern NSW network and the Victorian transmission network.

The No.1 and No.2 TransGrid transformers at Murray Substation were commissioned in 1967 and 1963 and they have now reached end of their serviceable life. The health index considers natural age, dissolved gas analysis (DGA), oil quality (OQ), Bushing DDF, defects, load and corrosive oil.

The No.1 and No.2 transformers are showing signs of deterioration due to the following key factors:

> Natural Age: The transformer will be 56 (No.1) and 60 (No.2) years in 2022/23 which is well above the 45-year expected useful life of a power transformer.
> Aged Synthetic Resin Bonded (SRBP) Bushings: SRBP bushings are known to have a type fault which results in delamination of the bushing paper over time resulting in catastrophic failure of the transformer. The 132kV SRBP were originally installed in 1967 on the No.1 transformer and are well above the 30-year useful life of high voltage bushings.
> Oil Impregnated Paper (OIP) Bushings: The 330kV OIP bushings were originally installed in 1967 on the No.1 transformer and are well above the 30-year useful life of high voltage bushings. The 132kV and 330kV bushings on the No.2 transformer were replaced 1998 and are approaching the end of their 30-year useful life by 2022/23.
> Moisture: Oil sampling indicates poor oil quality and a history of moisture in oil.
> Oil leaks: There are leaks from the bushings, pumps, valves, main tank and tap changer, allowing moisture ingress and oxygen into the main insulation.
> Lack of Voltage Control: Both transformers have offload tap changers, voltage variations in the 330kV cannot be compensated using an Automatic voltage regulator (AVR), resulting in significant voltage fluctuations for customers connected to the 132kV, 11kV and 415V network.

These condition issues have been evaluated through the transformer health index methodology to give an effective age of 59 years for No.1 Transformer and 60 years for No.2 Transformer (2022/23. These condition issues, if not remediated, increase the probability of transformer failure. The replacement of the Murray transformers would alleviate the risk of prolonged and frequent unserved energy in the region, provide market benefits due to renewable generation and pump loads on the Snowy Hydro Scheme and help TransGrid manage its safety obligations.

The key economic benefits associated with addressing this need are summarised as:

> Reduction of risk as valued as a direct impact to TransGrid and consumers including:
  – Changes in involuntary load shedding
  – Safety and environmental hazards associated with a catastrophic failure.
> Avoided operating expenditure related to corrective maintenance;

Two options have been considered to address the increasing risk of failure of the Murray transformers, as shown in Table 1 below. These options are the complete replacement of the two transformers with new units (option A) and refurbishment of the existing transformers involving replacement of bushings attempting to address the identified condition issues (option B).

The preferred option is the replacement of the Murray No.1 and No.2 Transformers (option A). This option is technically feasible and has the highest Net Present Value. The option is optimally timed to be completed within the 2023-2028 regulatory period.

Table 1 - Evaluated options ($ million)

Option	Description	Direct capital cost	Network and corporate overheads	Total capital cost[1]	Weighted NPV	Rank
Option A	Replacement	9.68	0.55	10.23	368.87	1
Option B	Refurbishment	2.16	0.66	2.82	77.65	2

[1] Total capital cost is the sum of the direct capital cost and network and corporate overheads. Total capital cost is used in this OER for all analysis.

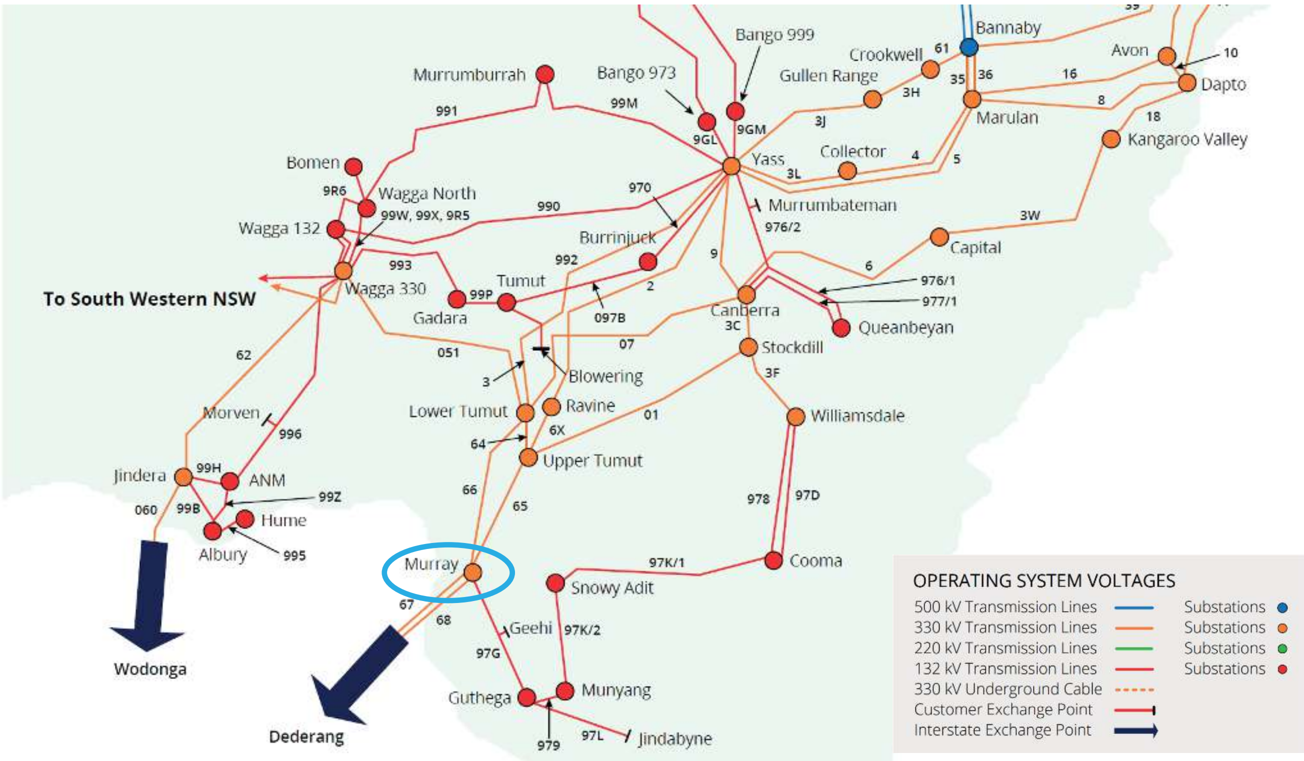
1. Need/opportunity

Murray 330 kV Substation is an ex-Snowy Mountains Hydro-electric Authority site which was commissioned in 1964. Murray Substation connects approximately 1500 MW of renewable hydro-electric energy generation, supports four 330kV transmission lines in the southern New South Wales network, and provides electricity flow paths between the Snowy Mountains and Victoria. The 132kV network connects Guthega Hydro (60MW), Jindabyne Pumping Station, Munyang and Cooma Substation

The location of Murray Substation and supply arrangements for the Southern NSW network is provided in

Figure 1 below.

Figure 1: Southern NSW transmission network



As a major generation and state interconnector connection point, Murray Substation supports transmission through the entire NEM.

The Murray No.1 and No.2 Transformers (330/132kV, 40MVA each) were commissioned in 1967 and 1963 during the initial construction of Murray Substation.

The transformers provide a connection for Guthega Hydro, Jindabyne Pumping Station, Munyang and Cooma Substation to the transmission network through the Murray 330kV busbar and also provide supply to customers on the Essential Energy 11kV network in the nearby Khancoban township.

Condition Assessment of the Murray Transformers using TransGrid's Network Asset Risk Assessment Methodology (RAM) has noted signs of deterioration, primarily due to condition issues set out in Table 2 below.

Table 2 - Condition Issues

Issue	Potential impact

Issue	Potential impact
Synthetic Resin Bonded Paper (SRBP) Bushings	The No.1 transformer has 132kV SRBP bushings which were originally installed with the transformer. SRBP bushings are wound using resin impregnated paper and cured before being encapsulated in a porcelain housing. The paper layers in the bushing tend to delaminate over time resulting in voids and high levels of partial discharge (PD). Over time treeing can occur in the bushing, damaging the insulation system and ultimately bushing or transformer failure.
Oil Impregnated Paper (OIP) Bushings	The No.1 (330kV) and No.2 (132kV and 330kV) transformer OIP bushings were installed in 1967 and 1998, and are equipped with porcelain insulators and a condenser based core. Their advanced age makes them susceptible to failures from high over voltages and thermal stresses and humidity ingress.
Paper insulation moisture	The transformer insulation system is based on special papers impregnated with insulating oil. Moisture acts to increase the rate of degradation of the paper insulating system. At high levels, it may compromise the insulation. The papers provided insulation and also support the structure of the transformer winding. Over time and with load and the presence of moisture, the paper becomes brittle. This may progress to the point where a mechanical shock caused by a through fault can result in electrical failure.
Loss of oil due to leaks	Flange and gasket leaks can cause loss of oil within the Transformer resulting in a catastrophic failure. Moisture and oxygen can also enter the transformer resulting in accelerated aging of the insulation resulting in failure.
Lack of voltage control	The tapchangers on the Murray transformers are off-load units which require an outage to change taps. The transformers cannot compensate for voltage fluctuations that occur in the 330kV network. These voltage fluctuations are frequent as AEMO switches the 330kV shunt reactors at Murray to manage the 330kV bus bar voltages for the NSW-Victoria interchange. This leads to voltage issues being reported by: > Snowy Hydro - 132kV voltage levels affecting pump start operation > Essential Energy - 11kV voltage issues affecting customer equipment and solar inverters.

If the deteriorating asset condition is not addressed by a technically and commercially feasible option, the likelihood of prolonged and involuntary load shedding in the Southern region will increase. Remediation under the need will also provide market benefits due to renewable generation and pump loads on the Snowy Hydro Scheme.

In addition, the increased risk of failure presents a safety risk which TransGrid is obligated to manage. Rectifying the worsening condition of the transformer will reduce safety risks, as well as lower planned and unplanned corrective maintenance costs.

The key economic benefits associated with addressing this need are summarised as:

- Reduction of risk as valued as a direct impact to TransGrid and consumers including:
  - Changes in involuntary load shedding
  - Safety and environmental hazards associated with a catastrophic failure.
- Avoided operating expenditure related to corrective maintenance;

2. Related needs/opportunities

- N2534 - Increase fault levels in Southern NSW. Increases in renewable generation in the South and South Western NSW will increase the fault levels in the Snowy region. The project scope increases the fault rating of high voltage equipment across Lower Tumut, Upper Tumut, Wagga and Murray substations. N2534 has been reduced by $0.65 million as the uprating of the No.1 and No.2 Transformer bushings will now be covered by the Murray transformers need (N2404).
- N2261 - Maintain public safety and QoS at Khancoban. Under certain outage conditions the Khancoban township is supplied from Murray power station at 11kV via TransGrid's Murray substation 11kV switchboard without an appropriate 11kV earthed neutral. This results in an inability to detect earth fault conditions resulting in safety hazards. Replacement of one of the existing Murray 11kV auxiliary transformers will effectively mitigate this risk and this scope has been evaluated under the Murray transformers need (N2404).

3. Options

3.1 Base case

Under the 'Base Case' scenario, there is no consideration for planned replacement of the transformer. This is a 'run to fail' scenario and will lead to an increase in the identified risks, the transformer's eventual failure, and the materialisation of the expected consequences. This case shall only be considered as a last resort should no option be deemed viable through the economic evaluation process.

Replacement of a failed transformer is expensive and requires significant time to restore capacity. Key considerations against the base case are:

- TransGrid does not hold a like-for-like spare for the Murray No.1 and No.2 transformer. A potential spare is a 150MVA unit that is significantly larger than the capacity of the existing 40MVA units.
- Civil works would be required at Murray Substation to support the increased size and weight of the spare transformer.
- Primary and secondary asset modifications will also be required at Murray Substation to adapt the 150MA unit.
- If the failure is catastrophic, there is substantial clean up and disposal costs and likely to take 1-2 weeks.
- As there are no spares on site, a spare transformer will need to be dismantled and transported from another depot/substation and assembled at Murray.
- Transportation permits will likely be required due to the physical size and weight of the spare transformer.
- The spare transformer will need to undergo high voltage testing and commissioning works.

3.2 Options evaluated

Option A — Replacement of No.1 and No.2 Transformers [NOSA 2404, OFS 2404A]

This option replaces both transformers with new 330/132 kV 40 MVA transformers. The option will address the identified need by installing a new transformer with a very low probability of failure, associated risks and lower operating costs.

This option involves:

> Installation of two new 40MVA power transformers;
> Installation of the No.3 auxiliary transformer (star-delta-star);
> Construction of new firewalls for each transformer;
> Minor modifications to associated HV and LV assets.

The transformers will be installed in-situ, during shoulder periods to maintain reliability during construction.

The estimated Capex for this option is $10.23 million, comprising of $5.03 million for No.1 Transformer replacement and $4.68 million for No.2 Transformer replacement, and $0.52 million associated with the No.3 Auxiliary transformer (to address need N2261 based on the estimate provided under N2590 minus expected efficiencies from bundled delivery). The new transformers have an expected asset life of 45 years and an expected project timeframe from Decision Gate 1 (DG1) is 35 months.

Option B — Refurbishment of No.1 and No.2 Transformers [NOSA 2404, OFS 2404B]

This option consists of an in-situ refurbishment of the Murray No.1 and No.2 Transformers according to the recommended scope in Network Asset Condition Assessment (NACA):

> Replacement of high voltage (No.1), low voltage (No.1) and tertiary voltage bushings (No.1 and No.2);
> Oil treatment and/or replacement;
> Moisture removal;
> Corrosion repair, leak repair and repainting;
> Major overhaul of the off-load tap changer;
> Conservator modifications and/or repairs.

The refurbishment is expected to result in a reduction in the effective age of five years, limited by the natural age of the transformer. While refurbishment will remediate some of the condition issues, it will not improve the quality of the paper insulation and ageing in the core of the transformer.

The majority of reliability, safety and environmental risk will remain even after the refurbishment and will only be addressed by replacement. The refurbishment option will essentially delay the transformer replacement into 2028 – 2033 regulatory period.

The estimated Capex with for option is $2.82 million, comprising of $1.76 million for No.1 Transformer refurbishment and $1.06 million for No.2 Transformer refurbishment, with an expected improvement of asset life of 5 years. The expected project timeframe from DG1 is 21 months.

3.3 Options considered and not progressed

The following options were considered but not progressed:

Table 3 - Options not progressed

Option	Reason for not progressing
Increased maintenance or inspections	The condition issues have already been identified and cannot be rectified through increased maintenance or inspections, and therefore is not technically feasible to address the need.
Elimination of all associated risk	This can only be achieved by retiring the assets, which is not technically feasible due to the requirement to maintain the existing network reliability.
Non-network solutions	Transgrid does not consider non-network options to be commercially feasible to assist with meeting the identified need.

4. Evaluation

4.1 Commercial evaluation methodology

The economic assessment undertaken for this project includes three scenarios that reflect a central set of assumptions based on current information that is most likely to eventuate (central scenario), a set of assumptions that give rise to a lower bound for net benefits (lower bound scenario), and a set of assumptions that give rise to an upper bound on benefits (higher bound scenario).

Assumptions for each scenario are set out in Table 4.

Table 4 - Scenario assumptions

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	4.8%	7.37%	2.23%
Capital cost	100%	125%	75%
Operating expenditure benefit	100%	75%	125%
Risk cost benefits	100%	75%	125%
Other Benefits	Not applicable in this assessment		
Scenario weighting	**50%**	**25%**	**25%**

Parameters used in this commercial evaluation are in Table 5

Table 5 - Commercial evaluation parameters

Parameter	Parameter Description	Value used for this evaluation
Discount year	The year that dollar values are discounted to	2020/21
Base year	The year that dollar value outputs are expressed in real terms	2020/21 dollars
Period of analysis	The number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	25 years
ALARP disproportionality	Multiplier of the environmental and safety related risk cost included in NPV analysis to demonstrate implementation of the obligation to reduce to ALARP.	Refer to section 4.3 for details.

The capex figures in this OER do not include any real cost escalation.

4.2 Commercial evaluation results

The commercial evaluation of the technically feasible options is set out in Table 6. Details appear in Appendix A and Appendix B

Table 6 - Commercial evaluation (PV, $ million)

Option	Capital Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	8.48	343.29	187.62	601.28	368.87	1
Option B	2.41	72.46	39.67	126.04	77.65	2

4.3 ALARP evaluation

TransGrid manages and mitigates bushfire and safety risk to ensure they are below risk tolerance levels or ‘As Low As Reasonably Practicable’ (‘ALARP’), in accordance with the regulation obligations and TransGrid’s business risk appetite. Under the Electricity Supply (Safety and Network Management) Regulation 2014 Section 5 ‘A network operator must take all reasonable steps to ensure that the design, construction, commissioning, operation and decommissioning of its network (or any part of its network) is safe.’ TransGrid maintains an Electricity Network Safety Management System (ENSMS) to meet this obligation.[2]

[2] TransGrid’s ENSMS follows the International Organization for Standardization’s ISO31000 risk management framework which requires following hierarchy of hazard mitigation approach

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor[3], the weighted benefits are expected to exceed the cost. TransGrid's analysis concludes that the costs are less than the weighted benefits from mitigating bushfire and safety risks. The proposed investment will enable TransGrid to continue to manage and operate this part of the network to a safety and risk mitigation level of ALARP.

Evaluation of the above options has been completed in accordance with As Low As Reasonably Practicable (ALARP) obligations. The Network Safety Risk Reduction is calculated as 6 x Bushfire Risk Reduction + 3 x Safety Risk Reduction + 3 x Other Environmental Risks + 0.1 x Reliability Risk Reduction.

Results of the ALARP evaluation are set out in Table 7.

Table 7 - Reasonably practicable test ($ million)

Option	Network Safety Risk Reduction	Annualised Capex	Reasonably Practicable?[4]
A	1.82	0.56	No
B	0.44	0.27	No

The disproportionality test does not apply to this need, as the reliability risk is greater than 50% of the total pre-investment network safety risk reduction. Therefore, all options are below the ALARP threshold and the preferred option will be the one that has the highest NPV.

4.4 Preferred option

The preferred option is the replacement (Option A) of the Murray No.1 and No.2 Transformers, as this is technically feasible and has the highest positive NPV. This option addresses the need by achieving the largest risk reduction. A new transformer has a relatively low probability of failure (PoF) and corresponding post-investment risk.

Capital and Operating Expenditure

Opex benefits associated with avoided corrective and reduced routine expenditure have been included in the business case NPV and optimal timing evaluation.

There are no capex to opex trade-offs considered in this evaluation.

Regulatory Investment Test

A Regulatory Investment Test for Transmission (RIT-T) is expected to be required as the preferred option is above $6 million.

5. Optimal Timing

The test for optimal timing of the preferred option has been undertaken. The approach taken is to identify the optimal commissioning year for the preferred option where net benefits (including avoided costs and safety disproportionality tests) of the preferred option exceeds the annualised costs of the option. The commencement year is determined based on the required project disbursement to meet the commissioning year based on the OFS.

The results of optimal timing analysis are:

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3 The values of the disproportionality factors were determined through a review of practises and legal interpretations across multiple industries, with particular reference to the works of the UK Health and Safety Executive. The methodology used to determine the disproportionality factors in this document is in line with the principles and examples presented in the AER Replacement Planning Guidelines and is consistent with TransGrid's Revised Revenue Proposal 2023/24-2027/28.

4 Reasonably practicable is defined as whether the annualised CAPEX is less than the Network Safety Risk Reduction.

- Optimal commissioning year: 2023/24. This is the earliest feasible commissioning year due to the significant lead time required to design, procure and commission a transformer replacement.
- Commissioning year annual benefit: $18.22 million
- Annualised cost: $0.56 million

Based on the optimal timing, the project is expected to be completed within the 2023-2028 Regulatory Period

6. Recommendation

It is recommended that Option A for the replacement of the transformer be scoped in detail.

The total project cost is $10.23 million, including $1 million to progress the project from DG1 to DG2.

Appendix A - Option A Summary

Project Description	Murray Transformer Renewals		
Option Description	Option A - Transformer Replacement		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*25*
Asset Life	*45*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *343.29*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) *0.56*
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] *187.62*	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction *1.82*
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] *601.28*	ALARP	ALARP Compliant? *No*
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *368.87*	Optimal Timing	Optimal timing (Business Case) *2022*
Cost			
Direct Capex ($m)	*9.68*	Network and Corporate Overheads ($m)	*0.55*
Total Capex ($m)	*10.23*	Cost Capex (PV,$m)	*8.48*
Terminal Value ($m)	*4.32*	Terminal Value (PV,$m)	*1.11*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *385.61*	Reliability Risk (Post) *37.36*	Pre – Post *348.25*
Financial (PV,$m)	Financial Risk (Pre) *1.11*	Financial Risk (Post) *0.14*	Pre – Post *0.97*
Operational/Compliance (PV,$m)	Operational Risk (Pre) *0.00*	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *1.30*	Safety Risk (Post) *0.16*	Pre – Post *1.14*
Environmental (PV,$m)	Environmental Risk (Pre) *0.22*	Environmental Risk (Post) *0.03*	Pre – Post *0.19*
Reputational ($m)	Reputational Risk (Pre) *0.09*	Reputational Risk (Post) *0.01*	Pre – Post *0.08*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *388.34*	Total Risk (Post) *37.69*	Pre – Post *350.65*
OPEX Benefit (PV,$m)			OPEX Benefit *0.01*
Other benefit (PV,$m)			Incremental Net Benefit *0.00*
Total Benefit (PV,$m)			Business Case Total Benefit *350.66*

Appendix B - Option B Summary

Project Description	Murray Transformer Renewal		
Option Description	Option B - Transformer Refurbishment		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*25*
Asset Life	*15*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	[Net Present Value (Standard - OER)] *72.46*	Annualised CAPEX ($m)	Annualised Capex - Standard (Business Case) 0.27
NPV @ Lower Bound Scenario (PV, $m)	[Net Present Value (Upper Bound)] 39.67	Network Safety Risk Reduction ($m)	Network Safety Risk Reduction 0.44
NPV @ Higher Bound Scenario (PV, $m)	[Net Present Value (Lower Bound)] 126.04	ALARP	ALARP Compliant? Yes
NPV Weighted (PV, $m)	[Net Present Value (Weighted)] *77.65*	Optimal Timing	Optimal timing (Business Case) 2022
Cost			
Direct Capex ($m)	*2.16*	Network and Corporate Overheads ($m)	*0.66*
Total Capex ($m)	*2.82*	Cost Capex (PV,$m)	*2.41*
Terminal Value ($m)	*0.00*	Terminal Value (PV,$m)	*0.00*
Risk (central scenario)	Pre	Post	Benefit
Reliability (PV,$m)	Reliability Risk (Pre) *385.61*	Reliability Risk (Post) *311.25*	Pre – Post *74.36*
Financial (PV,$m)	Financial Risk (Pre) *1.11*	Financial Risk (Post) *0.91*	Pre – Post *0.20*
Operational/Compliance (PV,$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) *0.00*	Pre – Post *0.00*
Safety (PV,$m)	Safety Risk (Pre) *1.30*	Safety Risk (Post) *1.07*	Pre – Post *0.23*
Environmental (PV,$m)	Environmental Risk (Pre) *0.22*	Environmental Risk (Post) *0.18*	Pre – Post *0.04*
Reputational ($m)	Reputational Risk (Pre) 0.09	Reputational Risk (Post) *0.08*	Pre – Post *0.01*
Total Risk Benefit (PV,$m)	Total Risk (Pre) *388.34*	Total Risk (Post) *313.49*	Pre – Post *74.85*
OPEX Benefit (PV,$m)			OPEX Benefit *0.01*
Other benefit (PV,$m)			Incremental Net Benefit *0.00*
Total Benefit (PV,$m)			Business Case Total Benefit *74.87*