

OPTIONS EVALUATION REPORT (OER)



FY24-28 LT1 Secondary Systems Renewal

OER- N2405 revision 0.0

Ellipse project no(s):

TRIM file: [TRIM No]

Project reason: Capability - Asset Replacement for end of life condition

Project category: Prescribed - Replacement

Approvals

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Change history

Revision	Date	Amendment
0	09/11/2021	First Issue

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Executive summary

Lower Tumut Switching Station connects Snowy Hydro's Tumut 3 power station to the 330kV transmission network with a generating capacity of 1,500MW. Lower Tumut Switching Station was previously the Control Centre for the entire Snowy Hydro Scheme and as such, a number of legacy systems have remained since it was transferred to TransGrid ownership. These include integrated and shared control systems, outdated pilot wire protection systems and a building that is significantly larger than required for TransGrid's purposes and in need of significant upgrades to bring it to modern standards.

There is a need to address the degrading condition and increasing risk of failure associated with the secondary systems at Lower Tumut Switching Station, by 2027/28. Addressing this need will ensure that TransGrid continues meeting its regulatory obligations set out in the NER.

The assessment of the options considered to address the need/opportunity appears in Table 1. A summary of all options considered are detailed below.

Under the Base Case TransGrid continues to operate and maintain (O&M) the existing site secondary systems as required. This approach will not address the obsolescence and health of the sites ageing secondary system assets.

Option A replaces all secondary system assets identified as end-of-life in a like for like approach for individual assets. This option does not leverage any technological advancements or lifecycle efficiencies within the latest design standards.

Option B renews all identified assets at the site including protection, control, metering and underlying infrastructure to leverage technological advancements in modern equipment.

Option C involves the complete upgrade and renewal of the secondary systems by using modular Secondary Systems Buildings (SSBs) and installing new cable throughout the site. This option will also leverage technological advancements in modern equipment and deliver lifecycle benefits to consumers.

Option D involves the complete upgrade and renewal of the secondary systems leveraging IEC 61850 technology standards and methodologies where available.

Table 1 - Evaluated options (\$ million)

Option	Description	Direct capital cost	Network and corporate overheads	Total capital cost ¹	Weighted NPV	Rank
Option A	Individual Asset Replacement	2.81	0.38	3.19	10.11	3
Option B	Complete In-Situ Replacement	Option is not technically feasible				
Option C	Complete SSB replacement	21.72	3.24	24.33	23.51	1
Option D	Upgrade to IEC-61850	21.28	3.67	24.95	21.67	2

It is recommended that Option D – Upgrade to IEC-61850 be scoped in detail.

This option will deliver a comparably high net economic benefit to that of Option C, but additionally affords an opportunity to deploy an advanced technology suite whilst still ensuring compliance with all regulatory and safety obligations.

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.

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1. Need/opportunity

Lower Tumut Switching Station comprises 8x 330kV feeders (including 3 generation lines), 6x 11kV feeders, and 3x 415V feeders (for auxiliary supply). The site was established in 1972 and the secondary systems assets have install dates between 1972 and 2019.

Lower Tumut Switching Station connects Snowy Hydro's Tumut 3 power station to the 330kV transmission network with a generating capacity of 1,500MW. Lower Tumut Switching Station was previously the Control Centre for the entire Snowy Hydro Scheme and as such, a number of legacy systems have remained since it was transferred to TransGrid ownership. These include integrated and shared control systems, outdated pilot wire protection systems and a building that is significantly larger than required for TransGrid's purposes and in need of significant upgrades to bring it to modern standards. These issues at Lower Tumut were highlighted as significant risks in the Technical Vendor Due Diligence report compiled by Advisian as part of the Transaction process. The site utilises 250V DC for powering all secondary systems and is only one of two sites within TransGrid's network to do so.

Network Performance Requirements, set out in Schedule 5.1 of the NER, place an obligation on TNSPs to provide redundant protection schemes to ensure the transmission system is adequately protected. Schedule 5.1.9(c) of the NER requires a TNSP to provide sufficient primary and back-up protection systems, including any communications facilities and breaker fail protection systems, to ensure that a fault of any type anywhere on its transmission system is automatically disconnected.

Additionally, TNSPs are required to disconnect the unprotected primary systems where a secondary systems fault lasts for more than eight hours (for planned maintenance) or 24 hours (for unplanned outages). TNSPs must also ensure that all protection systems for lines at a voltage 66kV or above are well-maintained so as to be available at all times other than for short periods (less than eight hours), while the maintenance of protection systems is being carried out². In the event of an unplanned outage, AEMO's Power System Security Guidelines require that the primary network assets must be taken out of service within 24 hours³.

Furthermore, as per clause 4.11.1 of the NER, remote monitoring and control systems are required to be maintained in accordance with the standards and protocols determined and advised by AEMO.

A failure of secondary systems would involve replacement of failed components or taking affected primary assets, such as lines and transformers, out of service.

Though replacing of failed secondary systems components is a possible interim measure, the approach is not sustainable as spare components may not be available due to supplier constraints and technological obsolescence in the future. Once manufacturer support ceases and subsequently, spares are depleted, defect repairs can no longer be a viable approach to maintain compliance with performance obligations.

The likelihood of significant secondary systems failure, and therefore not maintaining compliance with NER obligations, is anticipated to increase beyond tolerable levels once manufacturer support ceases and subsequently, available spares critical to maintaining secondary systems diminish. Based on increasing technological obsolescence and reducing levels of manufacturer support, a feasible secondary systems replacement is recommended prior to 2027/28.

Table 2 - Identified condition of secondary systems

Asset components	Issues	% of services at site
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² As per S5.1.2.1(d) of the NER

³ Australian Energy Market Operator. "Power System Security Guidelines, 23 April 2019." Melbourne: Australian Energy Market Operator, 2019. Accessed 15 May 2019. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Power_System_Ops/Procedures/SO_OP_3715---Power-System-Security-Guidelines.pdf

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Asset components	Issues	% of services at site
Energy Meters	<ul style="list-style-type: none"> > Component technology obsolescence resulting in a lack of spares and no manufacturer support > End of serviceable life 	100% of all market meters on site
Protection Relays	<ul style="list-style-type: none"> > Component technology obsolescence resulting in a lack of spares and no manufacturer support > Increasing numbers of faults across a range of models > End of serviceable life 	82% of all protection relays on site
Remote Monitoring and Control Equipment	<ul style="list-style-type: none"> > End of serviceable life > Manufacturer support withdrawn 	100% of all remote monitoring and control on site

Under TransGrid's Renewal and Maintenance Strategy for Infrastructure Systems⁴, an opportunity exists to address these risks by performing a full secondary system replacement at the site (see risk summary in Appendix A). This opportunity arises due to the high concentration of the secondary system assets required to be addressed. It is expected that this would provide additional benefits for the consumers and the organisation including:

- > Moving to a combined protection and control methodology to minimise the number of installed components and reduction in complexity. Increasing the reliability of digital assets at the site.
- > Upgrading Auto Reclose facilities to allow better control, indication and fault analysis than what is currently available at the site.
- > Upgrading to modern design philosophies to reduce operational and maintenance requirements at the site with the delivery of increased remote interrogation capabilities.
- > Reduction in reliability consequence during failures due to consistent return to service times with standardised deployments.
- > Investment will offset operational costs in corrective maintenance for unsupported technologies.

2. Related needs/opportunities

The following related Needs contain works for the site that would be fulfilled by completing a Secondary Systems Replacement:

- > Need N2242 – Transmission Line Protection Renewal Program
- > Need N2244 – Reactor Protection Asset Renewal Program
- > Need N2245 – Capacitor Protection Asset Renewal Program
- > Need N2246 – Busbar Protection Asset Renewal Program

3. Options

3.1 Base case

The Base Case for this Need is to continue with TransGrid's business as usual operations and maintenance (O&M) for the site. This approach does not address the deteriorating condition of secondary systems at the site or the risk cost associated with maintaining aging assets. The risk will likely increase due to:

⁴ Refer Renewal and Maintenance Strategy – Infrastructure Systems

- > The probability of failure increasing as assets move further along their failure curves⁵.
- > TransGrid's inability to recover from asset failure in the future due to reducing levels of manufacturer support, and depletion of spares availability that would otherwise limit the overall consequence of asset failure.

Key drivers for this risk cost are:

- > The majority of assets at this site have reached their end of technical life or have limited spares and no manufacturer support as highlighted in previous sections. This therefore increases the likelihood of a hazardous event occurring and decreases TransGrid's ability to mitigate or repair failures.
- > Assets have increasing numbers of failure as they progress along their failure curves, degrading components or are prone to mechanical wear, increasing the likelihood of a hazardous event occurring.

Increasing maintenance on secondary systems equipment cannot reduce the probability of failure or reduce risk costs. This is because maintenance of secondary assets is focused on device inspection and functional performance checks only, the conduct of maintenance at an electronic component level is neither feasible nor practicable.

3.2 Options evaluated

Option A — Replace Individual Assets [[NOSA N2405](#), [OFS N2405A](#)]

This option involves individual replacements of identified assets up to 2027/28. The option is based on a like-for-like approach whereby the asset is replaced by its modern equivalent. Additional system modifications or additional functionalities would not be deployed under this option. This option will lock TransGrid to a system architecture that cannot be expanded to match modern technology capabilities into the future.

This option would deliver the least benefits to consumers and the network by only affecting the probability of failure of targeted assets. This option will not provide any additional operational benefits such as improved capabilities for remote interrogation and predictive activities.

This option is planned for deployment across the 2023/24-2027/28 regulatory control period with remaining assets at the site to incur investment in future years. Targeted assets will be in service for approximately 15 years.

Option B — Complete In-Situ Replacement [[NOSA N2405](#), [OFS N2405B](#)]

This option involves replacement of all secondary systems assets at the site. This option will modernise the automation philosophy to current design standards and practices. This option also includes replacement of Direct Current (DC) supplies to account for an increase in secondary systems power requirements and remediation of the 415V Alternating Current (AC) distribution in the building and the switchyard.

The feasibility study for this option has determined that this option is not technically feasible due to the non-standard nature of the site, the non-standard panel arrangements and cabling congestion. Hence, this option has not been pursued further.

Option C — Complete SSB Replacement [[NOSA N2405](#), [OFS N2405C](#)]

This option involves the complete upgrade and renewal of the secondary systems by using modular Secondary Systems Buildings (SSBs) and installing new cable throughout the site. This option assumes that the new secondary systems will be designed to be accommodated within a similar panel arrangement as the existing installation. Redundant panels and tunnel boards in the ASB relay room will need to be progressively decommissioned and removed as the new secondary systems are cut-over and commissioned.

This option will also modernise the automation philosophy to current design standards and practices. A complete SSB replacement will also deliver benefits such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. However, there is a significant cost associated with the installation of new modular buildings and cabling.

⁵ Refer Network Asset Health Framework

Option D — Upgrade to IEC-61850 [\[NOSA N2405, OFS N2405D\]](#)

Option D involves the complete upgrade and renewal of the secondary systems leveraging IEC-61850 technology standards and methodologies where available. This option will utilise IEC-61850 protocol for unmanned substation site involving automation system, SCADA system, substation surveillance. Additional works unrelated to IEC-61850 are included such as renewal of building services and AC/DC supplies.

This option will modernise the automation philosophy and will provide additional operational benefit such as reduced preventative maintenance requirements, improved operational efficiencies, better utilisation of our high-speed communications network, improved visibility of assets using modern technologies and reduced reliance on routine maintenance and testing. However, a substantial amount of new cabling is required to implement this solution which comes at a significant cost.

3.3 Options considered and not progressed

Table 3 – Options not progressed

Option	Reason for not progressing
Asset Retirement	This can only be achieved by retiring the associated primary assets, which is not technically or economically feasible. This site will remain an essential connection point into the foreseeable future.
Non-network solutions	It is not technically feasible for non-network solutions to provide the functionality of secondary systems assets for protection, control, communications and metering

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 the table below.

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 costs benefit	100%	75%	125%
Benefits	100%	75%	125%
Scenario weighting	50%	25%	25%

Parameters used in this commercial evaluation:

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Table 5 - Commercial evaluation parameters

Parameter	Parameter Description	Value used for this evaluation
Discount year	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	Number of years included in economic analysis with remaining capital value included as terminal value at the end of the analysis period.	15 years
Safety disproportionality	Multiplier of the safety risk cost included in NPV analysis to demonstrate implementation of obligation to reduce safety 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.

Table 6 - Commercial evaluation (\$ million)

Option	Capital Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	8.84	8.66	0.43	22.70	10.11	3
Option B	Option is not technically feasible ⁶					
Option C	19.40	20.36	0.10	53.20	23.51	1
Option D	20.33	18.71	-1.33	50.57	21.67	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 obligation⁷.

In its Network Risk Assessment Methodology, under the ALARP test with the application of a gross disproportionate factor⁸, the weighted benefits are expected to exceed the cost. Where TransGrid's analysis

⁶ The feasibility study for Option B determined that the option is not technically feasible and hence could not be evaluated further.

⁷ TransGrid's ENSMS follows the International Organization for Standardization's ISO31000 risk management framework which requires following hierarchy of hazard mitigation approach

⁸ In accordance with the framework for applying the ALARP principle, a disproportionality factor of 6 has been applied to risk cost figures. 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.

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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 + 6 x Safety Risk Reduction + 3 x other Environmental Risk Reduction + 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? ⁹
A	1.51	0.30	Yes
C	1.49	2.31	No
D	1.45	2.37	No

The result of the ALARP evaluation is that only option A meets ALARP.

4.4 Preferred option

The preferred option to meet the identified need by 2027/28 is Option D. Whilst not having the highest NPV Option D remains a prudent and economically efficient solution to enable TransGrid to continue meeting its regulatory obligations set out in clauses 4.11.1, 4.6.1(b),¹⁰ and Schedule 5.1 of the NER. This option provides comparable net economic benefits to Option C, and therefore also to all those who produce, consume and transport electricity in the market. Option D also equally ensures performance standards applicable to the site’s secondary systems continue to remain met.

Option D involves the complete upgrade and renewal of the secondary systems leveraging IEC-61850 technology standards and methodologies where available. This option will utilise IEC-61850 protocol for unmanned substation site involving automation system, SCADA system, substation surveillance.

Capital and Operating Expenditure

There is negligible difference in predicted ongoing planned routine operational expenditure between the option and the Base Case. The removal of Nickel Cadmium systems and their associated infrastructure will deliver savings regarding battery and room maintenance activities.

Resultant corrective maintenance under the base case strategy will result in higher medium to long term expenditure. Delivery of proposed works under Option D will reduce the risk of increasing direct defect response costs.

It has been modelled that those components with no manufacturer support and limited spares carry the potential for incurring aspects of the proposed capital expenditure as operational expenditure. In such a scenario, these higher costs are attributable to significant design and preparation costs, and likely augmentation of linking systems required to move a system from one design solution to a differing solution. Such costs would not be present in cases where a like-for-like replacement is feasible.

These operating expenditure benefits have been captured in the economic evaluation.

Regulatory Investment Test

⁹ Reasonably practicable is defined as whether the annualised CAPEX is less than the Network Safety Risk Reduction.

¹⁰ As per clause 4.6.1(b) of the NER, AEMO must ensure that there are processes in place, which will allow the determination of fault levels for normal operation of the power system and in anticipation of all credible contingency events and protected events that AEMO considers may affect the configuration of the power system, so that AEMO can identify any busbar which could potentially be exposed to a fault level which exceeds the fault current ratings of the circuit breakers associated with that busbar.

The program and estimate allows for the appropriate Regulatory approvals as required.

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:

- > Optimal commissioning year: 2027/28
- > Commissioning year annual benefit: \$1.02 million
- > Annualised cost: \$2.37 million

The project is expected to commence in the 2023/24-2027/28 Regulatory Period based on the optimal timing.

6. Recommendation

It is the recommendation that Option D – Upgrade to IEC-61850 be scoped in detail.

The total project cost is \$24.95 million including \$2.5 million to progress the project from DG1 to DG2.

Appendix A – Option Summaries

Table 8 - Option A Summary Analysis

Project Description		FY24-28 LT1 SSR	
Option Description		Option A - Individual Asset Replacement	
Project Summary			
Option Rank	3	Investment Assessment Period	15
Asset Life	15	NPV Year	2020/21
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, \$m)	8.66	Annualised CAPEX @ Central Benefit Scenario (\$m)	Annualised Capex - Standard (Business Case) 0.30
NPV @ Lower Bound Scenario (PV, \$m)	0.43	Network Safety Risk Reduction (\$m)	Network Safety Risk Reduction 1.51
NPV @ Higher Bound Scenario (PV, \$m)	22.70	ALARP	ALARP Compliant? Yes
NPV Weighted (PV, \$m)	10.11	Optimal Timing	Optimal timing (Business Case) 2023/24
Cost (Central Scenario)			
Total Capex (\$m)	3.19	Cost Capex (PV,\$m)	8.84
Terminal Value (\$m)	0.00	Terminal Value (PV,\$m)	0.00
Risk (Central Scenario)	Pre	Post	Benefit
Reliability (PV,\$m)	Reliability Risk (Pre) 5.54	Reliability Risk (Post) 3.05	Pre – Post 2.49
Financial (PV,\$m)	Financial Risk (Pre) 8.19	Financial Risk (Post) 5.24	Pre – Post 2.95
Operational/Compliance (PV,\$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,\$m)	Safety Risk (Pre) 0.01	Safety Risk (Post) 0.00	Pre – Post 0.01
Environmental (PV,\$m)	Environmental Risk (Pre) 21.38	Environmental Risk (Post) 10.59	Pre – Post 10.79
Reputational (\$m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk (PV,\$m)	Total Risk (Pre) 35.12	Total Risk (Post) 18.89	Pre – Post 16.24
OPEX Benefit (PV,\$m)			OPEX Benefit 0.00
Other benefit (PV,\$m)			Incremental Net Benefit 1.26
Total Benefit (PV,\$m)			Business Case Total Benefit 17.50

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Table 9 - Option C Summary Analysis

Project Description		FY24-28 LT1 SSR	
Option Description		Option C - Complete SSB Replacement	
Project Summary			
Option Rank	1	Investment Assessment Period	15
Asset Life	15	NPV Year	2020/21
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, \$m)	20.36	Annualised CAPEX @ Central Benefit Scenario (\$m)	Annualised Capex - Standard (Business Case) 2.31
NPV @ Lower Bound Scenario (PV, \$m)	0.10	Network Safety Risk Reduction (\$m)	Network Safety Risk Reduction 1.49
NPV @ Higher Bound Scenario (PV, \$m)	53.20	ALARP	ALARP Compliant? No
NPV Weighted (PV, \$m)	23.51	Optimal Timing	Optimal timing (Business Case) 2023/24
Cost (Central Scenario)			
Total Capex (\$m)	24.33	Cost Capex (PV,\$m)	19.40
Terminal Value (\$m)	0.00	Terminal Value (PV,\$m)	0.00
Risk (Central Scenario)	Pre	Post	Benefit
Reliability (PV,\$m)	Reliability Risk (Pre) 5.54	Reliability Risk (Post) 2.83	Pre – Post 2.71
Financial (PV,\$m)	Financial Risk (Pre) 8.19	Financial Risk (Post) 4.78	Pre – Post 3.41
Operational/Compliance (PV,\$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,\$m)	Safety Risk (Pre) 0.01	Safety Risk (Post) 0.00	Pre – Post 0.01
Environmental (PV,\$m)	Environmental Risk (Pre) 21.38	Environmental Risk (Post) 9.60	Pre – Post 11.78
Reputational (\$m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk (PV,\$m)	Total Risk (Pre) 35.12	Total Risk (Post) 17.21	Pre – Post 17.91
OPEX Benefit (PV,\$m)			OPEX Benefit 0.09
Other benefit (PV,\$m)			Incremental Net Benefit 21.76
Total Benefit (PV,\$m)			Business Case Total Benefit 39.76

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Table 10 - Option D Summary Analysis

Project Description		FY24-28 LT1 SSR	
Option Description		Option D - Complete IEC-61850 Replacement	
Project Summary			
Option Rank	2	Investment Assessment Period	15
Asset Life	15	NPV Year	2020/21
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, \$m)	18.71	Annualised CAPEX @ Central Benefit Scenario (\$m)	Annualised Capex - Standard (Business Case) 2.37
NPV @ Lower Bound Scenario (PV, \$m)	-1.33	Network Safety Risk Reduction (\$m)	Network Safety Risk Reduction 1.45
NPV @ Higher Bound Scenario (PV, \$m)	50.57	ALARP	ALARP Compliant? No
NPV Weighted (PV, \$m)	21.67	Optimal Timing	Optimal timing (Business Case) 2023/24
Cost (Central Scenario)			
Total Capex (\$m)	24.95	Cost Capex (PV,\$m)	20.33
Terminal Value (\$m)	0.00	Terminal Value (PV,\$m)	0.00
Risk (Central Scenario)	Pre	Post	Benefit
Reliability (PV,\$m)	Reliability Risk (Pre) 5.54	Reliability Risk (Post) 3.41	Pre – Post 2.13
Financial (PV,\$m)	Financial Risk (Pre) 8.19	Financial Risk (Post) 6.32	Pre – Post 1.87
Operational/Compliance (PV,\$m)	Operational Risk (Pre) 0.00	Operational Risk (Post) 0.00	Pre – Post 0.00
Safety (PV,\$m)	Safety Risk (Pre) 0.01	Safety Risk (Post) 0.00	Pre – Post 0.01
Environmental (PV,\$m)	Environmental Risk (Pre) 21.38	Environmental Risk (Post) 10.33	Pre – Post 11.05
Reputational (\$m)	Reputational Risk (Pre) 0.00	Reputational Risk (Post) 0.00	Pre – Post 0.00
Total Risk (PV,\$m)	Total Risk (Pre) 35.12	Total Risk (Post) 20.06	Pre – Post 15.06
OPEX Benefit (PV,\$m)			OPEX Benefit 0.10
Other benefit (PV,\$m)			Incremental Net Benefit 23.88
Total Benefit (PV,\$m)			Business Case Total Benefit 39.04

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