OPTIONS EVALUATION REPORT (OER)

Maintain voltage in Alpine area

OER N2645 revision 2.0

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Approvals

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Change history

Revision	Date	**Amendment**
0	20/09/2021	Initial Issue
1	12/11/20221	Updated for minor errors
2	24/12/2021	Updated as per CutlerMerz's comments; Revised for minor editorial changes

Executive summary

There is a need to manage existing peak demand and to meet expected future demand growth in the Alpine area of New South Wales supplied from Munyang and Cooma, as the winter demand is forecast to substantially increase over the next 10 years. The identified need for this project is the requirement to ensure that the loads supplied from these supply points are reliably supplied whilst maintaining satisfactory voltage levels in the area as the loads grow.

The latest demand forecasts indicate that the winter peak demand at Munyang is expected to continue to increase in the near future due to a number of spot loads associated with snow making and ski-related commercial loads in the Thredbo and Perisher areas. With these additional spot loads the total peak demand at Munyang will increase by approximately 7 MW over the next 10 years.

It has been identified there will be potential future network constraints that are required to be remediated to ensure that these loads can be connected to the network at their full capacity. Under N-1 outage conditions there will be voltage limitations reached and/or breached at Cooma and Munyang. If the spot loads become operational as planned, there will be times when the voltages at Munyang and Cooma will be outside the acceptable levels for secure operation of the power system[1]. Under-voltage conditions (< 0.9pu) are expected to occur at Munyang 132 kV and 33 kV busbars, Cooma 132 kV and 66 kV busbars and Williamsdale 132 kV busbar under N-1 outage conditions. The step voltage changes following the critical contingency will exceed 10%.

As the transmission network services provider in New South Wales, Transgrid is obliged to comply with the relevant Clauses of the National Electricity Rules to facilitate connection of loads while operating the network in a secure and satisfactory state. Addressing the need will also assist in meeting connection point supply reliability requirements as required under Transgrid's NSW licence conditions.

The assessment of the options evaluated to address the need/opportunity appears in Table 1.

Table 1 - Evaluated options

Option	Description	Direct capital cost ($m)	Network and corporate overheads ($m)	Total capital cost[2] ($m)	Weighted NPV (PV, $m)	Rank
Option A	Install a Static VAr Compensator (+75/-40 MVAr) at Williamsdale	21.5	0.8	22.4	37.7	1
Option D	Install a 40 MW/80 MWh BESS system at Cooma	123.5	0.7	124.2	-31.0	2

Option A delivers the highest positive Net Present Value and requires lowest capital expenditure compared to the other technically feasible options considered. Based on the above reasons and meeting the requirement of the identified Need, Option A has been identified as the preferred Option.

It is therefore recommended that the project be approved to proceed to a RIT-T assessment, with a view to the preferred option being implemented and commissioned in 2029/30.

[1] The critical N-1 condition: Trip of Line 3F (Stockdill to Williamsdale)

[2] 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

The existing peak demand in the Alpine area of New South Wales, supplied from Transgrid's Munyang and Cooma substations, is currently resulting in limitations in the network that supplies it. Further, the winter load is forecast to substantially increase over the next 10 years, which will increase the demand on the network and increase the occurrence and extent of network supply limitations. A need has been identified to address these current and expected future network supply limitations to reliably supply the existing load and to meet expected future demand growth in the area. Addressing the identified need for this project will assist in meeting connection point supply reliability requirements as required under Transgrid's NSW licence conditions.

Transgrid's 330 kV network from the Yass - Canberra area to the Victorian border has a 132 kV parallel from Cooma, across the alpine region via Munyang 132/33 kV Substation and Snowy Hydro's Guthega Power Station to Murray 330/132/11 kV Substation (refer Figure 1).

Munyang substation supplies the alpine villages of Thredbo and Perisher, with the majority of the Snowy Mountains winter ski resorts being supplied from this location. Guthega Power Station has two 30 MW run-of-the-river generators, and the Jindabyne Pumping Station (also supplied from Guthega) has two 35 MW pumps used to transfer water from Lake Jindabyne to Geehi Dam as required. As shown in Figure 1, supply to the Jindabyne Pumping Station is normally at 132 kV from Murray via Line 97G and 97L, whilst the 132 kV interconnection from Cooma to Murray is operated normally open at Guthega (on Line 979). This is to manage power flows on this 132 kV network, as flows on the 330 kV network which it parallels can induce high flows on the underlying 132 kV network.

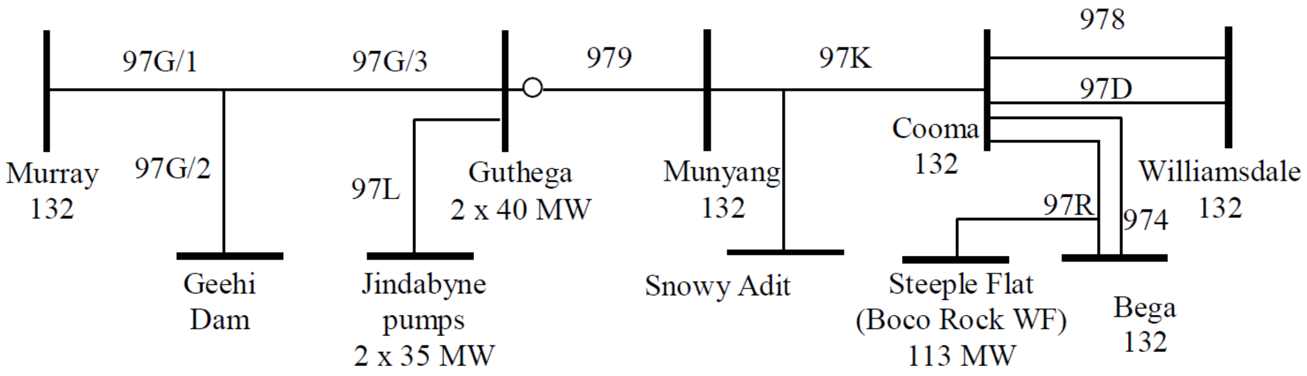

Figure 1: Single Line Diagram (SLD) of the 132 kV link between Williamsdale and Murray

The latest demand forecasts indicate that the winter peak demand at Munyang is expected to continue to increase in the near future. This is due to a number of spot loads associated with snow making and ski-related commercial loads in the Thredbo and Perisher areas that are planned to be connected to the network, but take supply only during winter times. With these additional spot loads the total peak demand at Munyang will increase by approximately 7 MW over the next 10 years. The winter peak demand at Cooma 132/66 kV BSP is also increasing at a steady growth rate of 0.3 MW/year but this is not related to any spot loads.

Figure 2 shows the demand forecast for Munyang and Cooma over the next 10 years.

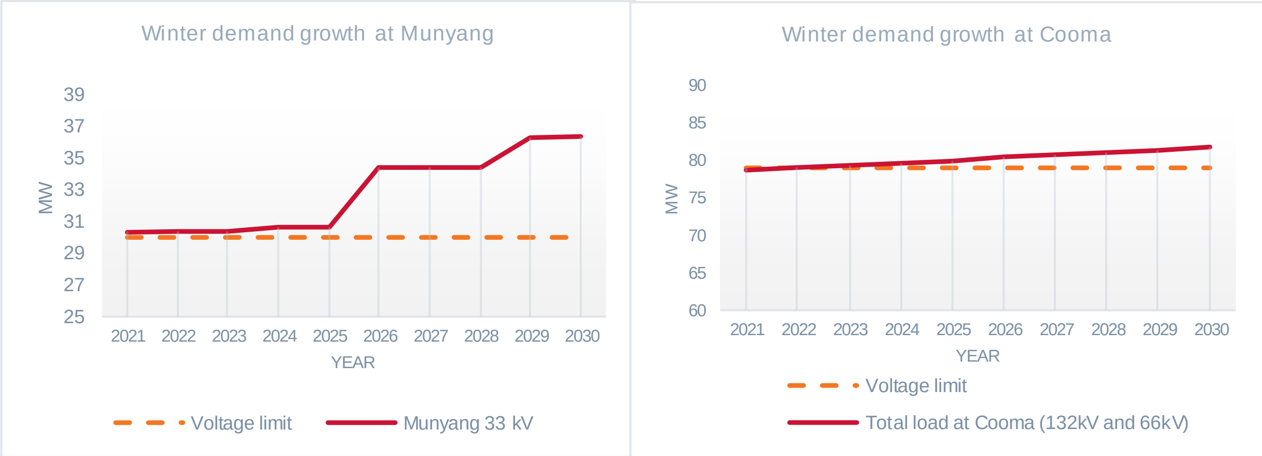

Figure 2: Demand growth at Munyang and Cooma

As the transmission network services provider in New South Wales, Transgrid is obliged to comply with the relevant Clauses of the National Electricity Rules to facilitate connection of loads while operating the network in a secure and satisfactory state. As per NER Clause 4.2.2 Transgrid must operate the network in a *satisfactory operating state* where:

> *"The power system is defined as being in a satisfactory operating state when:*
>
> *(b) the voltage magnitudes at all energised busbars at any switchyard or substation of the power system are within the relevant limits set by the relevant Network Service Providers in accordance with clause S5.1.4 of schedule 5.1;*
>
> *(c) the current flows on all transmission lines of the power system are within the ratings (accounting for time dependency in the case of emergency ratings) as defined by the relevant Network Service Providers in accordance with schedule 5.1;"*

Furthermore, in order to maintain system security, Transgrid's Operating Standards requires that the system must be operated such that, in the event of a single credible contingency, the voltage level will not exceed the maximum voltage rating for equipment, nor fall below 90% of nominal voltage.

Transgrid has assessed the existing peak demand and the impact of the additional spot loads during winter times in the Alpine region for the planning horizon. These proposed spot loads are in the "Advanced stage" of their project development process[3], with the progressive load growth over the next 10 years from these new connection shown in Table 2.

Table 2: Spot loads in the Thredbo/Perisher area (MW)

BSP	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31
Munyang 33 kV	5	5	5	5.2	5.2	9	9	9	11	11

[3] Reference: Spot load forecast (spreadsheet dated 21June 2021)

This assessment has identified existing and potential future network constraints as described below, and these are required to be remediated to ensure that these loads can be fully supplied from the network.

1. The present day loads and the forecast demand growth can be satisfactorily supplied under normal conditions without further network remediation, with the network voltage profile able to be maintained to within acceptable limits.
2. However, under N-1 outage conditions, there will be voltage limitations reached and/or breached at Cooma and Munyang. The critical contingency for the area under study is trip of 330 kV Line 3F (Stockdill to Williamsdale).
3. During 2021 winter peak demand times, voltages levels at Munyang and Cooma under N-1 outage conditions are expected to drop close to 0.9pu. The voltage step change at these locations for a contingent trip of 3F would exceed the acceptable limit of 10%. This observation has been noted by Transgrid System Operations via EMS on a high demand day. In order to manage the potential under voltages hence ensure the system security under N-1 conditions, all capacitors in the area need to be switched in pre-contingent. Other operational measures include increasing transformer AVR set points at Williamsdale and/or Canberra.
4. If the spot loads summarised in Table 2 become operational as planned, there will be times when the voltages at Munyang and Cooma will be outside the acceptable levels for secure operation of the power system[4]. This is demonstrated in Figure 4. Under-voltage conditions (< 0.9pu) are expected to occur at Munyang 132 kV and 33 kV busbars, Cooma 132 kV and 66 kV busbars and Williamsdale 132 kV busbar under N-1 outage conditions. The step voltage changes following the critical contingency will exceed 10%.

Figure 3 illustrates projected load duration curves Munyang for a selected years within the planning horizon. The energy at risk is the area between the LDC curves and the “voltage limit” line shown in the graphs. Although unserved energy at Munyang is expected to occur for less than 2% of the year, the risk of the unserved energy is substantial due to the nature of the load. On a typical peak winter day, the high demand times last for a prolonged period of time and with the proposed spot loads there could be substantially long periods of high demand in excess of the voltage limited supply capacity of the network, as illustrated in Figure 4.

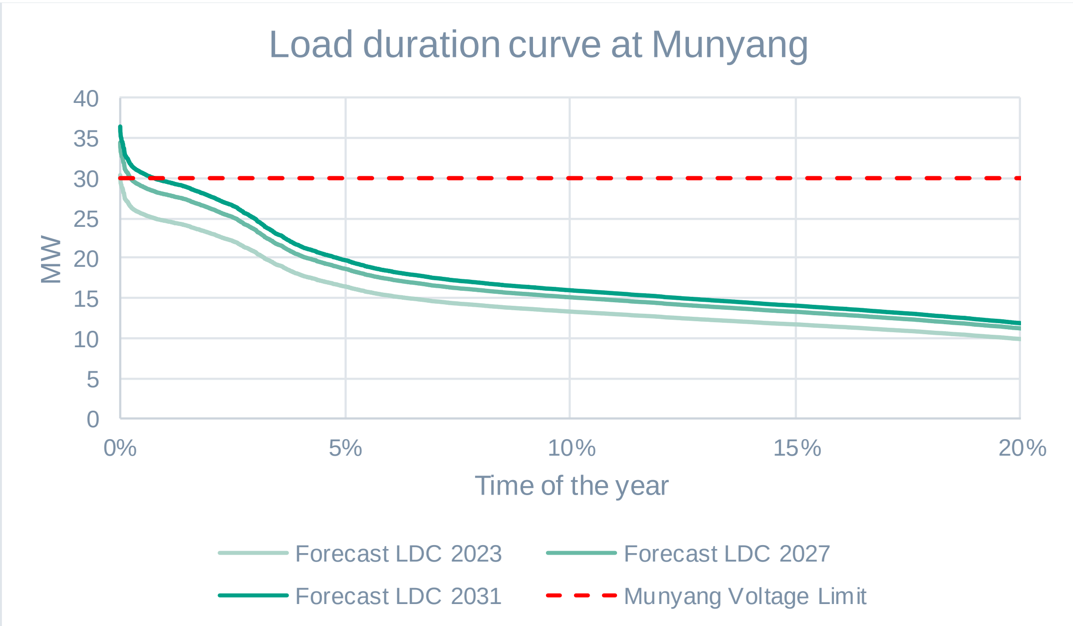

Figure 3: Load Duration Curves at Munyang

[4] The critical N-1 condition: Trip of Line 3F (Stockdill to Williamsdale)

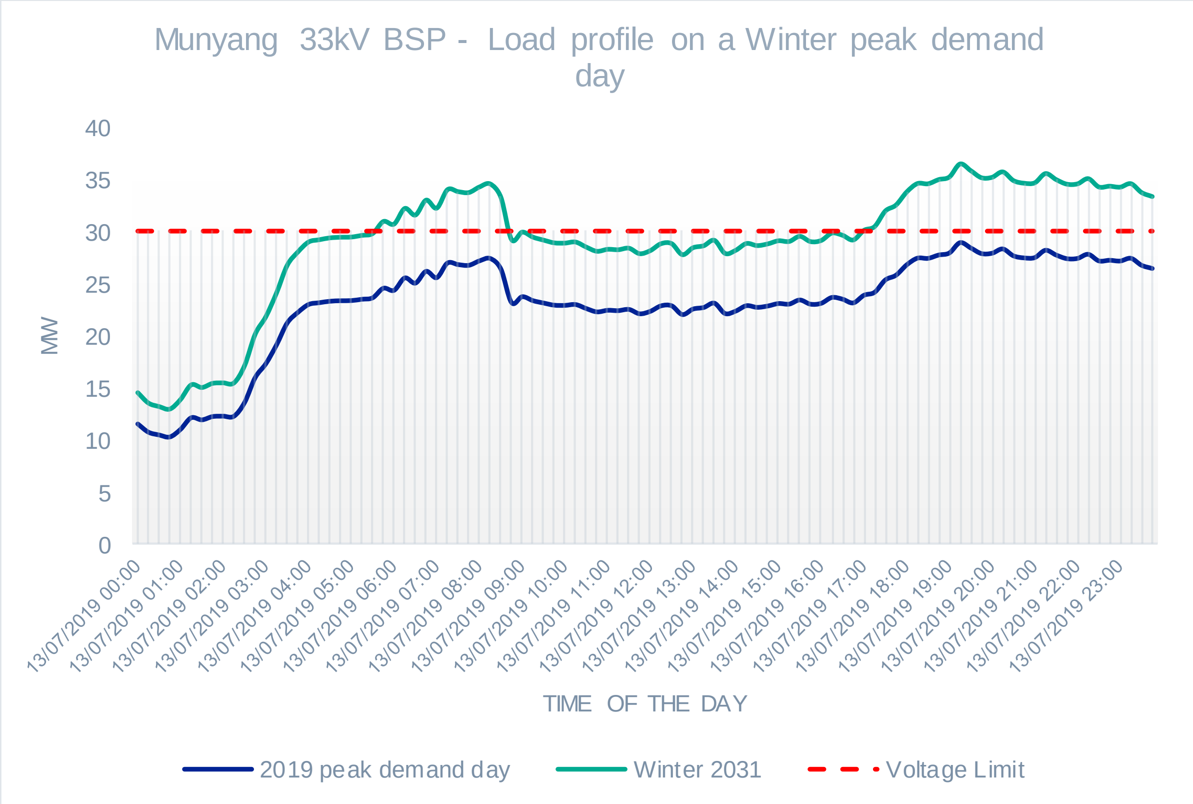

Figure 4: Load profile on a peak demand day (historical and projected)[5]

2. Related needs/opportunities

> N2215 Installation of QoS meters at Munyang:
  - This project is identified to install Quality of Supply (QoS) meters on the 33 kV side of No.1 and 2 Transformers at Munyang to monitor the harmonic levels at the BSP to be able to ensure that supply standards are being met.

> N2577 Supply to ACT Maintain Reliability of Supply to ACT:
  - This project investigates the network augmentation required to improve the supply reliability and supply resilience to the ACT network to avoid unplanned loss of load during planned or forced outage conditions.

3. Options

3.1 Base case

The Base Case for this Need is based on the “Do Nothing” option, with the present day network operating as it currently is. On this basis, with the existing demand levels and with the proposed spot load increases, supply to the Munyang and Cooma areas may need to be limited to obviate the risk of voltage limits being reached, thereby limiting supply to these seasonal loads to below their respective expected maximum demands.

Transgrid will not be compliant with NER requirements if there is insufficient network supply capacity to meet the expected demand levels in the area. Figure 5 and Figure 6 illustrates the expected unserved energy the estimated

[5] Historical data: TUOS 15min load data on 13/7/2019; Projected 2031 load profile is established by scaling the 2019 peak demand

total risk cost for Munyang and Cooma for the next 25 years. In order to manage the potential under voltages hence ensure the system security under N-1 condition, all capacitors in the area need to be switched in pre-contingent during high demand times. In addition, voltage support to the area can be further improved by the changing the transformer AVR settings at Williamsdale and/or Canberra until a viable network or non-network solution is implemented.

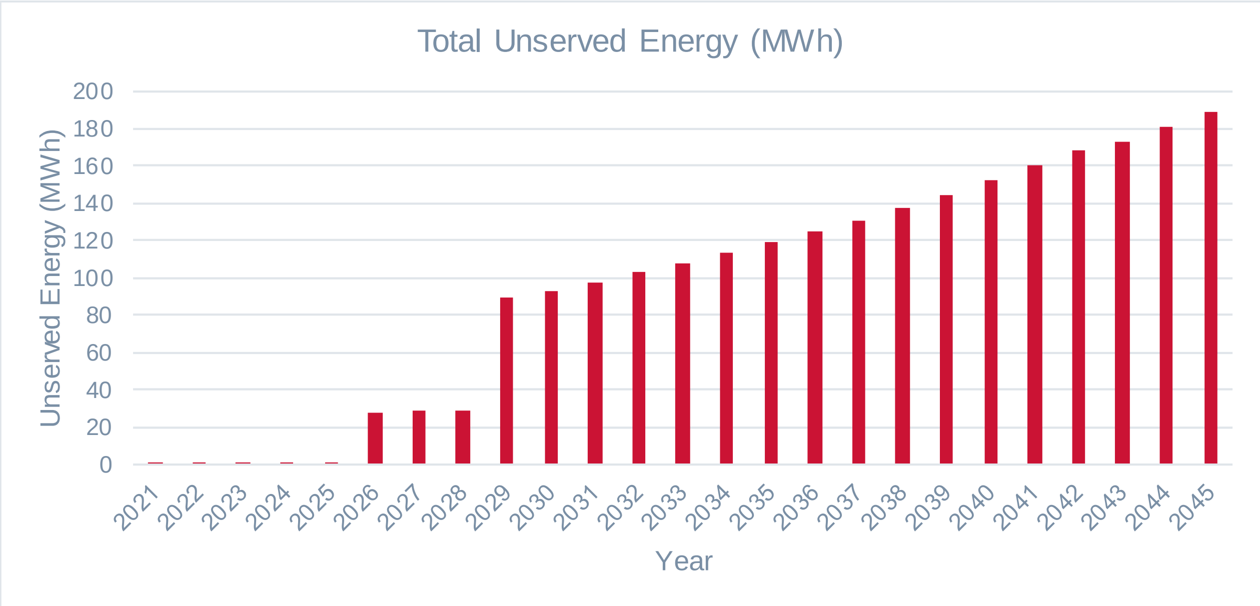

Figure 5: Estimated Unserved Energy

Figure 6: Estimated Risk Cost Total risk cost of the unserved energy

3.2 Options evaluated

Option A — Install a Static VAr Compensator (+75/-40 MVAr) at Williamsdale

Under this option it is proposed to install an SVC connected to the 132 kV busbar at Transgrid's Williamsdale 330/132 kV substation, with a reactive power range of 75 MVA capacitive and -40 MVAr inductive. It is proposed to use the new SVC to control the 330 kV voltage at Williamsdale hence maintain a healthy supply voltage to the far south transmission network and Southern ACT during contingencies.

The benefits of this option include the rapid response of the SVC to the voltage variations in the 132 kV subsystem due to the disturbances in the main 330 kV grid and ability to maintain the standard operating levels of the pre-contingent voltages in the 132 kV network between Williamsdale and Munyang during times of peak demand, thereby managing and containing the post contingent voltage step size to within acceptable limits. Implementation of this option will ensure the both the steady-state voltage levels and the transient step voltage changes on occurrence of the critical contingency are maintained to within acceptable limits at Cooma and Munyang.

The works associated with this Option includes:

> extending the existing switchyard within the existing property boundaries;
> installation of a new 100 MVA 132/33 kV transformer;
> installation of a new +75/-40 MVAr SVC; and
> associated other primary equipment installation, civil works and secondary systems works.

The expected commissioning date for this option is 2029/30.

The expected expenditure profile for this option has been obtained from the Transgrid's Standard Cost Estimating System. The estimates in Table 3 below includes an uncertainty of ± 25%.

Table 3 - Projected expenditure profile for Option A

	Total Project Base Cost ($M)	2026/27	2027/28	2028/29	2029/30
Estimated Cost – non-escalated ($m 2020-21)	22.4	0.3	1.8	14.8	5.5

It is estimated that an amount up to $2 million is required to progress the project from DG1 to DG2 and this cost has been included in the expenditure provided in the Table 3. This is to cover activities such as site assessments, development of concept design, the commencement of project approvals and the early procurement of long lead-time items if required.

This project is expected to be completed in an estimated 41 months following the approval of DG1.

Option D — Install a 40 MW/80 MWh BESS system at Cooma

Option D would utilise the ability of a battery storage system to charge and to store renewable generation, and discharge active or reactive power when required, thereby providing additional dynamic active or reactive power support as needed. Under this option a 40 MW/80 MWh Battery Energy Storage System (BESS) would be installed at Cooma.

The benefits of this option includes the ability to provide dynamic active or reactive power support as required during the disturbances, capability to storing the excess generation of nearby Boco Rock Wind Farm and potential future renewable generators in the Cooma area. During a contingency or planned outage of a main grid Line 3F, the BESS should be able to provide additional reactive power support required to maintain voltage profile in the 132 kV link between Williamsdale and Munyang above 0.9pu.

The scope of the works under this option include but not limited to:

> extension of the existing switchyard and 132 kV busbar;
> installation of a new 60 MVA 132/33 kV transformer; and

- other minor primary equipment installation and modifications the existing secondary systems.

The expected commissioning date for this option is 2029/2030.

The expected expenditure profile for this option is obtained from the Transgrid's Standard Cost Estimating System. The estimates in the table below have an uncertainty of ± 25%.

Table 4: Project Expenditure Profile - Option D

	Total Project Base Cost ($M)	2026/27	2027/28	2028/29	2029/30
Estimated Cost – non-escalated ($m 2020-21)	124.2	1.5	8.7	67.5	46.5

It is estimated that an amount up to $5 million is required to progress the project from DG1 to DG2 and this costs has been included in the expenditure listed in Table 4. This is to cover activities such as site assessments, development of concept designs, the commencement of project approvals and the early procurement of long lead-time items if required.

This project is expected to be completed in an estimated 41 months following the approval of DG1.

Option F — Non-network Options

Potential non-network options may include but are not limited to the following, or may include a combination of:

- procurement of demand management services within the area supplied by Munyang BSP (Perisher and Thredbo areas) during the times of peak demand and/or outage conditions to alleviate the network constraints;
- Voluntary under voltage load shedding schemes associated with the commercial loads in the Perisher/Thredbo area and in Cooma area.

It is expected that investigation of potential non-network options will be undertaken during the RIT-T process.

3.3 Options considered and not progressed

The options that were not progressed as they were considered not technically or economically feasible are outlined in the table below.

Table 5: Options considered and not progressed

Option	Reason for not progressing
Option B - Install 2 x 30 MVAr 132 kV capacitors at Williamsdale and 1 x 8 MVAr 132 kV capacitor at Munyang	Installation of a new 132 kV capacitor bank at Munyang and relocating the Line 94K feeder bay would require extension of the existing switchyard. As the switchyard at Munyang is located next to the Snowy River further extension is not feasible. Due to this physical constraint identified at Munyang, this option is not technically feasible and has not been considered for further development.
Option C- Install 1 x 16 MVAr 132 kV capacitor at Cooma and 2 x 8 MVAr 132 kV capacitors at Munyang	Studies confirmed that despite the acceptable post-contingency voltage levels, by installation of the capacitors at Cooma and Munyang, the step voltage change can still be outside the acceptable limit of 10% as required under the NER. This is due to the relatively high pre-contingent voltages in the 132 kV that could lead to large step voltages after the critical contingency. This option is not technically feasible.
Option E - Operational arrangement to move the normally open point at Guthega.	This option investigated the technical feasibility of implementing a trip scheme for Guthega, and a changeover scheme to transfer the generation of Guthega to flow to Cooma when required under the appropriate operational and network conditions. A feasibility assessment has confirmed that this option would have the following limitations: Although a trip scheme on Guthega would resolve potential islanding during N-1 outage conditions, if the Jindabyne Pumps are to be supplied from Cooma side there will be voltage and thermal constraints whenever reactive power support is not available from Guthega, i.e. when Guthega is not generating. Therefore, Jindabyne pumps may have to be constrained off most of the time until Guthega is generating. As such this option is deemed to impose a lower Standard on Jindabyne Pumps hence identified as technically not feasible.

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 6: Assumptions made in the scenarios

Parameter	Central scenario	Lower bound scenario	Higher bound scenario
Discount rate	4.8%	7.37%	2.23%
Demand Growth	Medium (POE50)	Low (POE90)	High (POE10)
Capital cost	100%	125%	75%
Operating expenditure	100%	125%	75%
VCR	AER Latest VCR[6] (escalated) 100%	70%	130%
Scenario weighting	**50%**	**25%**	**25%**

Since the central scenario represents the most likely scenario to occur, it has been weighted at 50%. The other two scenarios reflect extreme combinations of assumptions designed to stress test the results. Accordingly, these scenarios are weighted at 25% each.

Parameters used in this commercial evaluation:

Table 7 – Key parameters used in the comercial evaluation

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.	25 years

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 2. Details appear in Appendix A.

[6] AER 2019 December VCR value escalated by CPI to 2020/21 dollars.

Table 8 - Commercial evaluation (PV, $ million)

Option	Capital Cost PV	OPEX Cost PV	Central scenario NPV	Lower bound scenario NPV	Higher bound scenario NPV	Weighted NPV	Ranking
Option A	11.8	3.7	32.5	6.2	79.7	37.7	1
Option D	65.1	20.5	-37.6	-71.1	22.2	-31.0	2

4.3 Preferred option

Amongst the 5 options considered, Options A and D have been assessed through the commercial evaluation with the Base Case as a reference. Option B, C and E have been excluded from the commercial evaluation due to the limitations in their respective technical feasibility.

As per Table 8, only Option A delivers positive Net Present Values for all three scenario considered whereas Option D delivers positive NPV only for the High scenario. Option A has a higher weighted NPV than that of Option D. Furthermore, the capital expenditure of Option D is approximately five times higher than Option A.

As Option A provides the highest NPV with the lowest capital expenditure while meeting the requirement of the identified Need, it has been selected as the preferred option.

Under this option, the following investments are proposed to be undertaken:

> Extend the existing switchyard including earth grid, earthworks and drainage
> Installation of a new +75/-40 MVAr 132 kV Static VAr Compensator (SVC)
> Installation of a new 132/33 kV 100 MVA SVC Transformer including associated civil, and secondary systems
> Installation of a new 132 kV and 33 kV SVC Transformer switchbay and associated secondary systems
> Install a new firewall on the eastern side of the existing No.3 Transformer and new gantries to string overhead conductor from 33 kV switchbay to the new SVC
> Update the existing Substation Automation System (SAS) to include the new 132 kV switchbay and SVC
> Update the existing HMI to reflect the new 132 kV switchbay, SVC and Reactive Plant Control (RPC)

Capital and Operating Expenditure

The preferred option requires capital expenditure of $22.4 million. For the commercial evaluation an operating expenditure of 2% (of the Capital expenditure) has been assumed.

Regulatory Investment Test

As the estimated cost of the project is above the Regulatory Investment Test (RIT-T) threshold of $6 million, a RIT-T will be 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 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 the meet the commissioning year based on the OFS.

The results of optimal timing analysis is:

Optimal commissioning year: 2029/30

> Commissioning year annual benefit: $3.85 million
> Annualised cost: $1.27 million

Based on the optimal timing, the project is expected to commence in the 2023-2028 Regulatory Period.

6. Recommendation

Given there may be non-network options that will be required to be assessed, the final preferred option will be determined through the RIT-T process. This will be based on detailed network analysis, market modelling, technical and economic feasibility. However, based on the option evaluations in this report, the preferred network option is:

Option A – Install a Static VAr Compensator (+75/-40 MVAr) at Williamsdale.

It is therefore recommended that the project be approved to proceed to a RIT-T assessment, with a view to the preferred option being implemented as soon as practicable from 2026/27.

Based on the options listed in Section 3.1, it is expected that this Project would incur a capital cost of approximately $22.4 million in non-escalated 2020/21 dollars. Further, the preferred option requires $2 million of capital cost to progress the project to Decision Gate 2 (DG2).

Appendix A – Option Summaries

Table 9: Summary of the Option A - Install a Static VAr Compensator (+75/-40 MVAr) at Williamsdale.

Project Description	**Maintain voltage levels in the Alpine area**		
Option Description	Option A — Install a Static VAr Compensator (+75/-40 MVAr) at Williamsdale		
Project Summary			
Option Rank	*1*	Investment Assessment Period	*40*
Asset Life	*40*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	*32.5*	Annualised CAPEX ($m)	*1.3 million*
NPV @ Lower Bound Scenario (PV, $m)	*6.2*	Network Safety Risk Reduction ($m)	*N/A*
NPV @ Higher Bound Scenario (PV, $m)	*79.7*	ALARP	N/A
NPV Weighted (PV, $m)	*37.7*	Optimal Timing	*2029/30*
Cost			
Direct Capex ($m)	21.5	Network and Corporate Overheads ($m)	0.8
Total Capex ($m)	22.4	Cost Capex (PV,$m)	11.8
Terminal Value ($m)	12.9	Terminal Value (PV,$m)	4.2

Table 10 - Summary of the Option D - Install a 40 MW/80 MWh Battery Energy Storage System (BESS) at Cooma

Project Description	**Maintain voltage levels in the Alpine area**		
Option Description	**Option D — Install a 40 MW/80 MWh Battery Energy Storage System (BESS) at Cooma**		
Project Summary			
Option Rank	*2*	Investment Assessment Period	*40*
Asset Life	*40*	NPV Year	*2021*
Economic Evaluation			
NPV @ Central Benefit Scenario (PV, $m)	-37.6	Annualised CAPEX ($m)	*7.0 million*
NPV @ Lower Bound Scenario (PV, $m)	-71.1	Network Safety Risk Reduction ($m)	*N/A*
NPV @ Higher Bound Scenario (PV, $m)	*22.2*	ALARP	N/A
NPV Weighted (PV, $m)	*-31.0*	Optimal Timing	*2029/30*
Cost			
Direct Capex ($m)	123.5	Network and Corporate Overheads ($m)	0.7
Total Capex ($m)	124.2	Cost Capex (PV,$m)	65.1
Terminal Value ($m)	71.4	Terminal Value (PV,$m)	23.2