Appendix 5.24: Supply to Strathnairn PJR

Regulatory proposal for the ACT electricity distribution network 2019-24
January 2018

Disclaimer: On 1 January 2018, the part of ActewAGL that looks after the electricity network changed its name to Evoenergy. This change has been brought about from a decision by the Australian Energy Regulator. Unless otherwise stated, ActewAGL Distribution branded documents provided with this regulatory proposal are Evoenergy documents.

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Project Justification Report

Project name	**Supply to Strathnairn**
Expenditure type	Capital Expenditure
Business Group	Asset Strategy
Regulatory Period	1 July 2019 to 30 June 2024
Total Project Cost Estimate	$3,398,540 excluding corporate overheads, excluding contingency, and excluding GST
Five year total spend 2019-24	$1,552,377 excluding corporate overheads, excluding contingency, and excluding GST
CAPEX category	ENAA Distribution
Primary driver	Load growth in new Strathnairn suburb
Project Number	20001761

Contents

Reference documents

Document	Version	Date
National Electricity Rules	102	
National Electricity Law		19.12.13
Utilities Act (ACT)		2000
Utilities (Management of Electricity Network Assets Code) Determination		2013
Evoenergy Maximum Demand Forecast		2017
ActewAGL Annual Planning Report		22.12.17
Distribution Network Augmentation Standard SM1197	1.1	12.5.15
Evoenergy Risk Assessment Tables PR4660.2	1.0	12.1.17
Evoenergy Quality of Supply Strategy SM11150	1.0	8.10.15
Evoenergy Asset Management Strategy SM1192	2.12	22.6.15
Evoenergy Peak Demand Reduction Strategy	2.0	22.8.17
Technical Study Lower Molonglo East and West Feeders	1.0	19.12.16
Augmentation NPV Model Methodology	1.0	29.9.17

1. Executive Summary

The development of the West Belconnen District is being carried out by a joint partnership between the ACT Government's Suburban Land Agency (SLA) and Riverview Developments Pty Ltd. 11 kV feeders along with low voltage reticulation will be installed throughout the new suburbs as they are developed. The maximum demand in the West Belconnen District is forecast to increase steadily to 45 MVA over the next 30 years as load grows in the new and developing suburbs of Strathnairn and Macnamara. The development of this area will include 11,500 residential dwellings, plus commercial and community facilities.

ActewAGL proposes to construct a new Strathnairn Zone Substation to supply this area with timing scheduled for approximately 2025-26. Until then, supply to the area will be from existing 11 kV feeders and an additional feeder as described in this Project Justification Report. Existing 11 kV feeders to the area have insufficient capacity to meet the forecast load beyond summer 2019.

Maximum demand is forecast to grow initially at approximately 0.8 MVA per annum.

There are two existing 11 kV feeders to this area, Macrossan and Latham feeders from Latham Zone Substation. Together they have approximately 1.4 MVA spare summer firm capacity only.

This project proposes one new 11 kV cable feeder to be installed to the Strathnairn area. The proposed new feeder will be an extension of the existing O'Loghlen feeder from Latham Zone Substation. Load transfers will be made from this feeder to other existing feeders to provide sufficient spare capacity to meet the forecast demand until the new Strathnairn Zone Substation is constructed in 2025-26.

The developers of Strathnairn have mandated the compulsory installation of rooftop PV generation on all dwellings. It is proposed to offer additional incentives to these customers to provide up to an additional 2.2 MVA in demand management. This will also require investment in a centralised demand management system.

A preliminary cost estimate for the selected option of extending the O'Loghlen 11 kV feeder to Strathnairn plus the demand management investment is **$3,398,540 excluding corporate overheads, excluding contingency, and excluding GST**.

These works for the new feeder will be carried out during the 2019-24 Regulatory Control Period with proposed completion by December 2019. Expenditure for the 2019-24 period is estimated at **$1,552,377 excluding corporate overheads, excluding contingency, and excluding GST**.

2. Strategic Context and Expenditure Need

There is significant development planned for the West Belconnen District. Existing infrastructure has insufficient capacity to cater for the additional demand associated with the development.

2.1. The West Belconnen development

The West Belconnen District is situated in Canberra's north-west, approximately 15 km from the Canberra Central Business District (CBD). It lies to the west of the urban areas of Macgregor and Holt. Land servicing has commenced for the initial developments and when fully developed over the next 30 years, the West Belconnen District including the new suburbs of Strathnairn and Macnamara and an as-yet unnamed suburb located over the border in New South Wales will comprise an estimated 11,500 dwellings plus shopping centres, schools and community facilities.

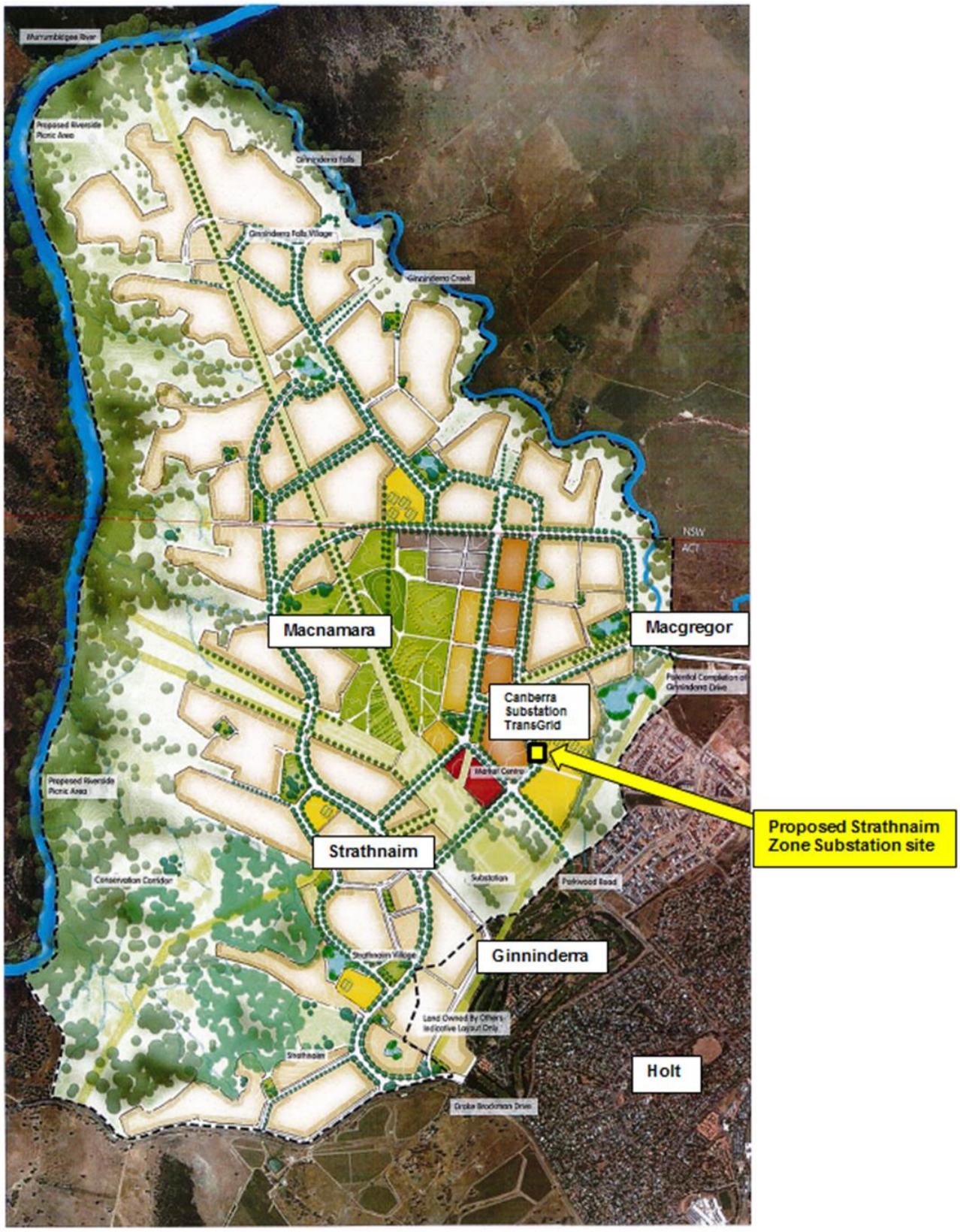
The first stage of development of West Belconnen is under construction, comprising Stage 1 of the suburb of Strathnairn. The proposed Macnamara suburb is at planning stage with construction scheduled to commence around 2026-27.

The West Belconnen District is being developed by a joint venture of the ACT Government's Suburban Land Agency and Riverview Developments Pty Ltd. The SLA has published an indicative land release programme that indicates development will proceed at approximately 380 dwellings per annum. A population of approximately 30,000 people is expected to ultimately live in the West Belconnen District. Maximum demand of the West Belconnen District is forecast to grow steadily to approximately 45 MVA over the next 30 years. This includes the proposed future transfer of the Lower Molonglo Water Quality Control Centre (LMWQCC) 10.6 MVA load from Latham to Strathnairn Zone Substation.

The developers of West Belconnen have mandated the installation of rooftop PV generation (ranging in size from 1.5 kW to 4.0 kW) on all detached dwellings and terraced townhouses. Battery storage systems are voluntary. It is anticipated that after diversity maximum demand (ADMD) levels for this area will be lower than elsewhere and have been assumed to be 2.0 kVA per dwelling. At a rate of 380 new dwellings per annum, this will add approximately 0.8 MVA load growth annually.

Figure 1 shows the proposed development of the West Belconnen District (source SLA).

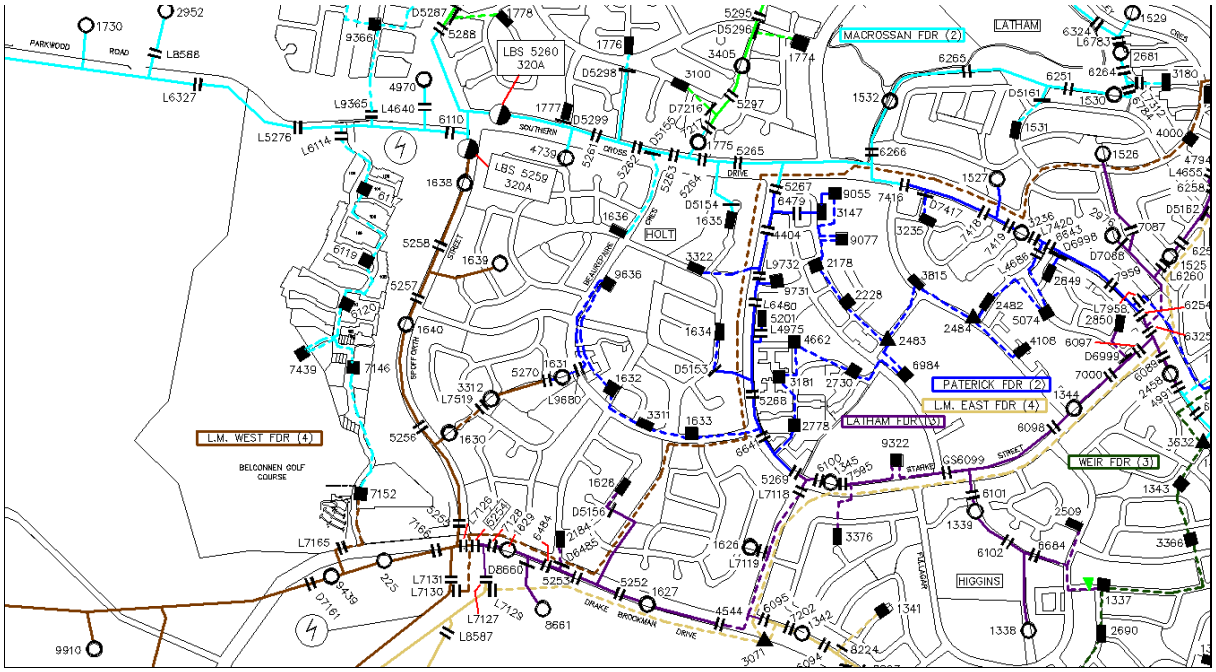
Figure 1: Proposed development of West Belconnen District



2.2. Existing infrastructure in the Strathnairn area

There are currently two 11 kV feeders supplying the Strathnairn area. These are Macrossan and Latham feeders from Latham Zone Substation. The existing feeder network is illustrated in Figure 2.

Figure 2: Existing 11 kV Feeders supplying Strathnairn



The maximum load supplied by each feeder as a percentage of its firm rating, is shown in Table 1 for summer and winter. Yellow denotes load above 80% of the firm rating, red denotes load above firm rating. Firm rating of an 11 kV feeder is dictated by the number of inter-connections it has to other 11 kV feeders in order to provide full back-up capacity in the event of a contingency. Thus a feeder that is inter-connected to one other feeder may be loaded to 50% of its thermal capacity, and a feeder that is inter-connected to two other feeders may be loaded to 75% of its thermal capacity. 100% firm rating should not be exceeded as this places load at risk in the event of a contingency.

Table 1: West Belconnen Locality Feeder Loadings

Feeder Name	Zone	Feeder Rating (MVA)				2015		2016		2017	
		Firm Summer Rating	Thermal Summer Rating	Firm Winter Rating	Thermal Winter Rating	Percent Loaded Summer	Percent Loaded Winter	Percent Loaded Summer	Percent Loaded Winter	Percent Loaded Summer	Spare capacity MVA
Macrossan	LA	4.5	5.9	5.0	6.7	87%	101%	87%	109%	85%	0.1
Latham	LA	4.5	5.9	5.0	6.7	46%	47%	40%	47%	51%	2.2
Florey	LA	4.5	5.9	5.0	6.7	55%	55%	49%	56%	48%	2.3
Paterick	LA	4.5	5.9	5.0	6.6	86%	87%	79%	84%	73%	1.2
O'Loghlen	LA	4.5	5.9	5.0	6.7	70%	62%	48%	62%	43%	2.6
Powers	LA	4.5	5.9	5.0	6.7	66%	68%	52%	92%	50%	2.2
Markell	LA	4.7	6.3	5.4	7.2	65%	67%	52%	69%	50%	2.3
Total											**12.9**

2.3. Driving need for infrastructure investment

Table 2 shows a summary of the load forecast in the Strathnairn suburb for the next 10 years. These forecast loads make allowance for predicted penetration of rooftop solar PV and customer-owned battery storage systems. This shows that available firm summer capacity will be exceeded by December 2019.

Table 2: Load forecast of existing feeders supplying Strathnairn

Load Forecast for Strathnairn suburb												
Year	**Feeder rating MVA**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Macrossan Feeder load forecast	4.5	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Macrossan Feeder spare capacity		0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Latham Feeder load forecast	4.5	2.3	3.0	3.8	4.6	5.4	6.2	7.0	7.8	8.6	9.4	10.2
Latham Feeder spare capacity		2.2	1.4	0.6	-0.2	-1.0	-1.8	-2.6	-3.4	-4.2	-5.0	-5.8
Total combined load forecast		6.7	7.5	8.3	9.1	9.9	10.7	11.5	12.3	13.1	13.9	14.7
Total spare capacity available		**2.3**	**1.4**	**0.6**	**-0.2**	**-1.0**	**-1.8**	**-2.6**	**-3.4**	**-4.2**	**-5.0**	**-5.8**

The Strathnairn load centre is approximately 7 km from Latham Zone Substation and 10 km from Belconnen Zone Substation. Latham has three 132/11 kV transformers and Belconnen has two. Latham has a firm capacity of 100 MVA and Belconnen has a firm capacity of 55 MVA. The maximum demand at Latham is forecast to rise to approximately 83 MVA over the next 10 years, with expansion of the Lower Molonglo Water Quality Control Centre and residential developments in the area (eg Ginninderra Estate – adjacent to Strathnairn). The maximum demand at Belconnen is forecast to rise to approximately 63 MVA over the next 10 years, with proposed new multi-unit developments in the Belconnen town centre, University of Canberra Hospital, and residential developments in the area (eg Lawson Estate).

At an expected fill rate of approximately 380 dwellings pa, the West Belconnen load is forecast to grow steadily at approximately 0.8 MVA pa on average (based on 2 kVA ADMD per dwelling). The majority of demand will be residential dwellings.

3. Objectives

3.1. Corporate, asset management and key project objectives

The corporate, asset management and related key project objectives are shown in Table 3. These objectives are used to assess the relative risk of options.

Table 3: Corporate, asset management and key project objectives

Corporate objectives	Asset management objectives	Key project objectives
Responsible	• Achieve zero deaths or injuries to employees or the public. • Maintain a good reputation within the community. • Minimise environmental impacts, for example bushfire mitigation. • Meet all requirements of regulatory authorities, such as the AER as outlined in the NER, and the ACT Utilities (Technical Regulations) Act 2014.	The selected option must ensure environment and safety standards will be met.
Reliable	• Tailor maintenance and renewal programs for each asset class based on real time modelling of asset health and risk. • Meet network SAIDI and SAIFI KPIs. • Record failure modes of the most common asset failures in the network. • Successfully deliver the asset class Program of Work (PoW) to ensure that the protection operates correctly to disconnect faulty sections in accordance with the NER.	Options evaluations to consider the value of customer reliability (VCR). In accordance with regulated requirements, the selected option must ensure access to an electricity supply.
Sustainable	• Enhance asset condition and risk modelling to optimise and implement maintenance and renewal programs tailored to the assets' needs. • Make prudent commercial investment decisions to manage assets at the lowest lifecycle cost. • Integrate primary assets with protection and automation systems in accordance with current and future best practice industry standards • Deliver the asset class PoW within budget.	Options evaluations to consider the cost effectiveness of the solution. In accordance with regulated requirements, the selected option must be the most prudent and efficient. Non-network options will be evaluated on equal merit with network solutions.
People	• Proactively seek continual improvement in asset management capability and competencies of maintenance personnel.	A post implementation review to incorporate learnings through the asset management system.

The project objectives are consistent with Evoenergy's regulatory requirements described below.

3.2. Regulatory Compliance

3.2.1. National Electricity Law and National Electricity Rules

Evoenergy is subject to the National Electricity Law (NEL) and the National Electricity Regulations (NER) which regulate the National Electricity Market (NEM). Evoenergy operates in the NEM as both a Transmission Network Service Provider (TNSP) and a Distribution Network Service Provider (DNSP).

The National Electricity Objective (NEO), as stated in the NEL is to:

"…promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:

a) price, quality, safety, reliability and security of supply of electricity; and
b) the reliability, safety and security of the national electricity system."

This objective requires Registered NEM participants to balance the costs and risks associated with electricity supply.

The planning and development process for distribution and transmission networks is carried out in accordance with the National Electricity Rules (NER) Chapter 5 Part B Network Planning and Expansion.

The primary objective of planning is to ensure that customers are able to receive a sufficient and reliable supply of electricity now and into the future.

3.2.2. Capital Expenditure Objectives and Criteria

The NER provides further guidance in terms of allowable capital expenditure via the capital expenditure objectives and criteria for standard control services. These capital expenditure objectives, specified in clause 6.5.6(a) and 6.5.7(a) of the NER describe the outcomes or outputs to be achieved by the expenditure. The objectives include:

1) *Meet or manage the expected demand for standard control services*
2) *Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services*
3) *To the extent that there is no applicable regulatory obligation or requirement in relation to the quality, reliability or security of supply of standard control services; or the reliability or security of the distribution system through the supply of standard control services, to the relevant extent:*
    a) *Maintain the quality, reliability and security of supply of standard control services*
    b) *Maintain the reliability and security of the distribution system through the supply of standard control services*
4) *Maintain the safety of the distribution system through the supply of standard control services.*

The expenditure criteria, set out in Section 6.5.6(c) and Section 6.5.7(c) of the NER, further outline requirements for the way in which expenditure must be set to achieve the objectives above. These include:

1) *The efficient costs of achieving the expenditure objectives*
2) *The costs that a prudent operator would require to achieve the expenditure objectives; and*
3) *A realistic expectation of the demand forecast and cost inputs required to achieve the expenditure objectives.*

The above criteria therefore imply that the capital expenditure, determined in line with the expenditure objectives, must be met via prudent and efficient expenditure, is to be achieved at least cost.

3.2.3. Regulatory Investment Test

Section 5.16 of the NER describes the Regulatory Investment Test for Transmission (RIT-T) and Section 5.17 describes the Regulatory Investment Test for Distribution (RIT-D). These tests must be carried out for any proposed investment where the augmentation or replacement cost of the most expensive credible option exceeds $5 million.

The regulatory investment tests provide the opportunity for external parties to submit alternative proposals to the Network Service Provider, who is obliged to consider any credible proposal objectively.

Since the required investment is greater than $5million the project is subject to the RIT-D. Evoenergy commenced RIT-D process in 2014 with publication of a Project Specification Consultation Report, but has yet to complete the RIT-D process (ie publication of Draft Project Assessment Report and Final Project Assessment Report). These reports will need to be prepared as part of the development of this project. The initial RIT-D consultation paper published in 2014 recommended establishing a new zone substation at the Arboretum site (comprising two transformers and two switchboards) by 2017-18, but lower load growth rate has enabled this to be deferred to 2021-22.

3.2.4. Utilities Act 2000 (ACT)

Evoenergy has an obligation to comply with the Utilities Act 2000 (ACT) which imposes specific technical, safety and reliability obligations via the Management of Electricity Network Assets Code and the Electricity Distribution Supply Standards Code.

The Electricity Distribution Supply Standards Code (August 2013) sets out performance standards for Evoenergy's distribution network. Evoenergy is required to take all reasonable steps to ensure that its Electricity Network will have sufficient capacity to make an agreed level of supply available.

This local jurisdictional code specifies reliability standards that Evoenergy must endeavour to meet when planning, operating and maintaining the distribution network. It also specifies power quality parameters that must be met including limits on voltage flicker, voltage dips, switching transients, earth potential rise voltage unbalance, harmonics and direct current content.

The Management of Electricity Network Assets Code requires electricity distributors to protect integrity and reliability of the electricity network and to ensure the safe management of the electricity network without injury to any person or damage to property and the environment.

3.2.5. Evoenergy's Distribution Network Augmentation Standards

Evoenergy's distribution network augmentation standards are set to ensure compliance with the relevant regulatory instruments as described above.

Evoenergy's planning standards are determined on an economic basis but expressed deterministically so that peak demand can be met with an appropriate level of backup should a credible contingency event occur. A credible contingency event is the loss of a single network element, which occurs sufficiently frequently, and has such consequences, as to justify Evoenergy to take prudent precautions to mitigate. This is commonly referred to as an N-1 event.

Zone substation capacity must be augmented if the forecast zone substation maximum demand based on 50% PoE under N-1 conditions exceeds the two-hour emergency rating.

Major zone substation augmentation such as the installation of an additional transformer will not be considered until all other options such as load transfer to adjacent zone substations and non-network options have been fully explored and implemented.

For high voltage (11kV) distribution feeders in urban areas Evoenergy specifies that there should be a minimum of two effective feeder ties to meet two-for-three arrangement where it is economically viable, i.e. two feeders able to supply the load normally supplied by three feeders. A firm rating is assigned to each feeder based on its thermal rating and the number of feeder ties available.

Distribution high voltage feeder capacity must be augmented or demand management solutions provided if the forecast 50% PoE feeder maximum demand exceeds the firm ratings as given in Table 4.

Table 4: Feeder Firm Rating standard

Feeder configuration	Firm rating as percentage of thermal capacity
Two or more feeder ties	75%
One feeder tie	50%
Feeders operating in parallel	{(N-1)/N}%[1]
Partial feeder tie	100% or less[2]
No feeder tie	100%

3.2.6. Cost compliance

Cost compliance is achieved by proactively pursuing the philosophy of compliance with the national electricity objective by fully exploring and evaluating all options technically and commercially so as to seek approval for a solution that provides sound grounds for an efficient investment while meeting the long term interests of the consumers.

The investment value has been determined using 2016-17 market prices. The methodology and estimated costs used for this project are developed through the application of industry knowledge and Good Engineering Operating Practices based on historical similar projects. This approach complies with paragraphs 6 & 7 of the National Electricity Law (NEL).

[1] "N" represents the number of feeders operating in parallel.

[2] A partial feeder tie refers to a tie with limited back feeding capacity. The firm capacity of a feeder with a partial feeder tie may be set below 100% its thermal capacity.

4. Options Assessment

Evoenergy has considered four options to provide 11 kV supply to Strathnairn as listed in Table 5.

Table 5: Options considered for 11 kV supply to Strathnairn

Option	Option type	Description	Evaluation
0	Network	Do nothing	Not selected as does not meet minimum requirements
1	Network	Construct new 11 kV cable feeder from Latham Zone Substation to Strathnairn	Not selected due to lower NPC
2	**Network and non-network**	**Extend existing 11 kV O'Loghlen feeder to Strathnairn and employ non-network demand management within Strathnairn**	**Selected as higher NPC**
3	Non-network	Demand side management	Not selected as does not meet need
4	Network and non-network	Extend existing 11 kV O'Loghlen feeder to Strathnairn and grid battery	Not selected due to lower NPC
5	Non-network	Grid battery only	Not selected due to lower NPC

4.1. Options analysis

4.1.1. Do Nothing Option

The 'Do Nothing' option would result in demand exceeding firm capacity in 2019 and exceeding the emergency capacity by 2023, such that the existing infrastructure would be unable to supply peak demand within the suburb of Strathnairn from

The value of energy at risk is estimated to be approximately $10.3m over a five year period.

The Do Nothing option would result in ActewAGL breaching its obligations under the National Electricity Law, and the Utilities Act as well as not meeting the capital expenditure objectives under the National Electricity Rules.

4.1.2. Option 1: Construct one new 11 kV feeder from Latham Zone Substation

Option 1 considers the installation of one new underground 11 kV cable feeder to Strathnairn from Latham Zone Substation to meet the growing load demand until the Strathnairn Zone Substation is constructed. Route length is approximately 7.0 km. It is assumed that this route would require directional drilling. Throughjoints would be required approximately every 500 m.

There are no spare feeder circuit breakers at Latham Zone Substation, so one of the 11 kV switchboards would be extended and a feeder circuit breaker added.

A preliminary cost estimate for Option 1 is **$3,431,750 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Option 1 is not selected due to its lower net present cost (NPC), constructability issues, the distance from Latham Zone Substation to Strathnairn, future reliability concerns, potential voltage drop and network loss issues.

4.1.3. Option 2: Extend existing O'Loghlen 11 kV Feeder from O'Loghlen St to Strathnairn and reconfigure other feeders

Feeder Extension:

Option 2 proposes to extend the existing 11 kV O'Loghlen cable feeder from the intersection of O'Loghlen St and Southern Cross Drive to supply the first stage of Strathnairn. The O'Loghlen feeder cable at this location is 3c/194mm^2 AL PILC. The proposed feeder extension to Strathnairn would utilise 3c/400mm^2 AL XLPE cable. The existing load on the O'Loghlen feeder (approximately 1.9 MVA) would be transferred to adjacent Powers and/or Markell feeders by rearranging open points. This would free up almost the full firm capacity of the O'Loghlen feeder (4.5 MVA) to supply Strathnairn Stage 1.

The proposed cable route would be from O'Loghlen St via Southern Cross Drive, Starke St, MacNaughton St, Drake Brockman Drive and Stockdill Drive. Cable route length is approximately 4.2 km. It is assumed that 50% (2.1 km) of this route would be suitable for open trenching and 50% (2.1 km) would require directional drilling. Throughjoints would be required approximately every 500 m.

The O'Loghlen feeder extension, coupled with extensions of Macrossan and Latham feeders, will be capable of meeting the Strathnairn demand until the new Strathnairn Zone Substation is constructed in 2025-26.

The preliminary estimated cost of this option is **$1,514,700 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Demand management:

Under a high demand scenario, 4.5 MVA of capacity would not be sufficient to meet demand of Strathnairn Stage 1 which is forecast to reach 6.7 MVA by 2025-26. Therefore an additional 2.2 MVA capacity would need to be identified in the form of non-network initiatives including:

- Incentives to realise the potential of latent demand management within the customer base.
- Incentives to encourage the uptake of additional demand management within the customer base.

These options are further discussed within the Demand Management Paper.

Latent demand management within the existing customer base was investigated, with a maximum estimated capacity of 0.141 MVA. This does not meet the capacity required of 2.2 MVA.

These non-network options are summarised in Table 6.

Table 6: Summary of non-network options

Non-network Option		Latham Feeder	Macrossan Feeder	Total
Controllable load	**Capacity**	0.02 MVA	0.04 MVA	**0.06 MVA**
Battery storage	**Capacity**	0.02 MVA	0.04 MVA	**0.06 MVA**
Load curtailment	**Capacity**	0.007 MVA	0.014 MVA	**0.021 MVA**
Totals	**Capacity**	**0.047 MVA**	**0.094 MVA**	**0.141 MVA**

Where there is insufficient latent demand management within the customer base, there is further opportunity to incentivise customers to adopt additional technologies to reduce demand. This includes opportunities to permanently reduce demand (such as energy efficiency technology or power factor correction) as well as opportunities to adopt technology to enable participation in demand response markets (such as embedded generation, battery storage, building management systems).

Under Option 2, Evoenergy would procure this additional demand management from the market during the Regulatory Control Period via request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme.

The cost of this demand management is assumed to include the following:

1) Subsidy required to incentivise customers who have already deployed demand management technology (as shown in Table 7) to provide prescribed demand management at relevant times.

2) Subsidy required to incentivise customers to deploy new demand management technology to provide prescribed demand management services at relevant times.

3) Cost to establish a centralised demand management platform.

For the purposes of this Project Justification Report, 1) and 2) above are estimated to be equal to the subsidy that must be provided to promote an NPV positive business case for deployment of behind the meter battery storage systems at residential premises (assuming a time of use tariff)., while in practice it may be that existing demand management may be procured at a reduced cost.

The costs for the demand management platform are less certain due to the relative immature market and lack of existing available products. However, it is understood that several smart grid equipment providers are seeking to launch applicable products in early 2018. The costs of these services include a centralised communications receiver and distributed controls for each distributed unit providing demand management services. The estimated costs associated with the demand management solution are shown in 7 below.

Table 7 – Demand management costs for Option 2

Item	Cost per unit	Estimated number of units required	Total cost (over regulatory control period)
Incentive payment	$3,180	463	$1,472,340
DM platform distributed equipment	$500	463	$231,500
DM platform centralised equipment[3]	$180,000	1	$180,000
Total			$1,883,840

The total cost of Option 2, including the feeder extension and demand management is therefore **$3,398,540** excluding corporate overheads, contingency and GST plus an additional opex component assumed to be equal to 1% of capital expenditure.

It is expected that embedded generation and demand management initiatives proposed for the Strathnairn suburb will assist with minimising the growth of maximum demand until the new zone substation is available.

Option 2 is selected due to its higher (ie least negative) net present cost (NPC).

4.1.4. Option 3: Demand management only

Option 3 proposes to utilise demand management to reduce demand within Strathnairn such that no supply side solution is required until 2025-26. It is estimated that a total of 6.7 MVA demand reduction is required.

As per Option 2, Evoenergy would procure the demand management from the market during the Regulatory Control Period via a request for demand management solutions in accordance with the minimum project evaluation requirements as prescribed by Clause 2.2.1 of the Demand Management Incentive Scheme.

[3] The platform may either be established by Evoenergy or a licensing fee could be paid to a supplier. For the purpose of the business case it is assumed that the platform is established by Evoenergy. Where the alternative licensing arrangement was adopted approximately $30,000 would be required in capital expenditure for the communications receiver and $150,000 available for licensing fees. This is considered sufficient due to the relatively small scale of the demand management, but further investment may be required in the future (next regulatory control period) where centrally controlled demand management is deployed more widely.

For the purposes of the regulatory proposal, the estimated cost of the demand management solution is shown in Table 1 below.

Table 1 – Demand management costs for Option 3

Item	Cost per unit	Number of units required	Total cost (over regulatory control period)
Incentive payment	$3,180	1,410	$4,483,800
DM Platform distributed equipment	$500	1,410	$705,000
DM platform centralised equipment	$180,000	1	$180,000
Total			$5,368,800

This indicates that of the 380 dwellings constructed per year and provisioned with rooftop solar PV generation, approximately 70% would require battery storage with a total incentive cost of **$5,368,800 excluding corporate overheads, contingency and GST.**

Option 3 has not been selected due to a higher NPC compared to Option 2 as well as the high level of penetration of battery storage required.

4.1.5. Option 4: Extend existing O'Loghlen 11 kV feeder and grid battery

A further option to adopt a grid battery in addition to the extension of the existing O'Loghlen 11 kV feeder was explored.

This option has the advantage of deferring the investment until greater certainty in future demand is known. However, given the relatively high certainty of future demand for this project and the relatively high cost of the grid battery, this option was assessed as higher cost than the network Option 2 or 3 with a preliminary cost estimate of **$5,881,264 excluding corporate overheads, contingency and GST .**

Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

4.1.6. Option 5: Grid battery only

This option explored the use of a grid battery only. A grid battery, although more expensive than a traditional network solution on a per MVA basis, has advantages over a traditional network solution. A network battery is modular and also able to be redeployed, meaning it can represent a more economic option in an environment of demand uncertainty or where demand is expected to increase for a short period and then decline.

In the case of Strathnairn however, the grid battery was not economic due to the relative certainty of demand with a preliminary cost estimate of **$19,740,533 excluding corporate overheads, contingency and GST.**

Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

4.1.7. Summary of Options Analysis

Table 8: Summary of Options

Option	Description	Total Capital Cost 2019-2039	Capital Cost 2019-24	20 year Net Present Cost	Outcome
0	Do nothing	$0	$0	$0	Not selected as does not meet need
1	Construct one new 11 kV cable feeder from Latham Zone Substation	$3,431,750	$3,431,750	-$3,476,655	Not selected due to lower NPC
2	**Extend O'Loghlen 11 kV feeder and demand management**	**$3,398,540**	**$1,552,377**	**-$2,920,734**	**Selected due to higher NPC**
3	Demand side management only	$5,368,800	$5,368,800	-$5,439,051	Not selected as does not meet need
4	Extend O'Loghlen 11 kV feeder and grid battery	$5,881,264	$1,526,562	-$3,312,264	Not selected due to lower NPC
5	Grid battery only	$19,740,533	$3,591,427	-$9,875,787	Not selected due to lower NPC

4.2. Recommendation

The selected option is Option 2, the extension of the 11 kV underground O'Loghlen feeder from the intersection of O'Loghlen St and Southern Cross Drive to Strathnairn plus demand management. This will provide capacity to Strathnairn until 2025-26 when the proposed 132/11 kV Strathnairn Zone Substation is constructed and new 11 kV feeders are installed from it.

Financial analysis shows Option 2 to be the best option due to its higher (ie least negative) NPC. It also has the lowest capital cost. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B. It can be implemented in time to meet the project needs as identified and will add to ActewAGL's regulated asset base. The major assets will have an economic life of 50 years.

The extended O'Loghlen feeder will provide capacity and security of supply to the new Strathnairn suburb, and will be inter-tied with future feeders from the proposed Strathnairn Zone Substation.

Timing is scheduled for completion by December 2019. Future 11 kV feeders will be installed as the load growth and demand increases with further development of the Strathnairn and Macnamara suburbs.

A preliminary cost estimate for the selected option of extending the O'Loghlen 11 kV feeder to Strathnairn plus the demand management investment is **$3,398,540 excluding corporate overheads, excluding contingency, and excluding GST**.

These works for the new feeder will be carried out during the 2019-24 Regulatory Control Period with proposed completion by December 2019. Expenditure for the 2019-24 period is estimated at **$1,552,377 excluding corporate overheads, excluding contingency, and excluding GST**.

Appendix A – Preliminary Cost Estimates

A.1 Cost Estimate – Option 1: New 11 kV Feeder to Strathnairn from Latham Zone Substation

Strathnairn supply from Latham Zone Substation via one new 11 kV feeder @ 7 km.					
Preliminary Estimate ± 30% Accuracy					
Description	**Notes**	**Unit**	**$/Unit**	**Quantity**	**Cost**
Trenching and drilling					$2,554,000
Clearing of route where required	Allowance	m2	$10	1000	$10,000
Directional drilling	Assume drilling with no rock. Assume 50% of 7 km total route length to be drilled, ie 3.5 km.	m	$350	7000	$2,450,000
Open trenching and backfilling	Assume excavation with no rock. Assume 50% of 7 km total route length can be trenched, ie 3.5 km.	m	$150		$0
Cable jointing and haulage pits	Assume every 500m	ea	$3,000	13	$39,000
Traffic management		m	$5	7000	$35,000
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Site is mostly flat. Extracted volume stockpile for use within West Belconnen Development.	m3	$40	500	$20,000
Cabling works					$688,000
11 kV 3c/400mm2 XLPE cable		m	$56	7000	$392,000
Throughjoints	Assume every 500m	ea	$1,000	13	$13,000
Terminations	Assume distribution substations at Strathnairn established under estate reticulation works.	ea	$1,500	2	$3,000
Conduit and marker tape		m	$10	14000	$140,000
Cable installation labour and plant		m	$20	7000	$140,000
11 kV Switchgear					$102,000
11 kV feeder CB panels	Add feeder panel to switchboard at Latham	ea	$100,000	1	$100,000
11kV Test & Commissioning	per CB	lot	$2,000	1	$2,000
HV Connections					$2,000
11 kV Cable Termination		ea	$1,000		$0
11 kV Cables and connections Test &	Allowance	ea	$2,000	1	$2,000
Electrical (Secondary System)					$11,750
Protection & Control					$4,750
P&C Secondary Cabling	per feeder panel	ea	$2,250	1	$2,250
P&C Test & Commission	Allowance	ea	$2,500	1	$2,500
DC Supply System					$7,000
DC Cabling	per switchgear panel/bay	ea	$5,000	1	$5,000
DC Test & Commission	Allowance	ea	$2,000	1	$2,000
SCADA					$4,000
SCADA connections for new feeder panels		ea	$2,000	1	$2,000
Test & Commissioning	Allowance	ea	$2,000	1	$2,000
Indirect Costs					$70,000
Development Application	Allowance	ea	$10,000	1	$10,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	$10,000	1	$10,000
Project management and administration	Allowance	ea	$50,000	1	$50,000
Project Sub Total without overheads					**$3,431,750**
Overheads					
Overall average overhead rate	Allowance	27%	$926,573	1	$926,573
Project Sub Total with overheads					**$4,358,323**
Contingency					
All project works	Preliminary allowance	15%	$653,748	1	$653,748
Project budget total					**$5,012,071**

A.2 Cost Estimate – Option 2: Extend O'Loghlen 11 kV Feeder to Strathnairn

Strathnairn supply from Latham Zone Substation via extended O'Loghlen 11 kV feeder @ 4.2 km.					
Preliminary Estimate ± 30% Accuracy					
Description	**Notes**	**Unit**	**$/Unit**	**Quantity**	**Cost**
Trenching and drilling					$1,114,000
Clearing of route where required	Allowance	m2	$10	500	$5,000
Directional drilling	Assume drilling with no rock. Assume 50% of 4.2 km total route length to be drilled, ie 2.1 km.	m	$350	2100	$735,000
Open trenching and backfilling	Assume excavation with no rock. Assume 50% of 4.2 km total route length can be trenched, ie 2.1 km.	m	$150	2100	$315,000
Cable jointing and haulage pits	Assume every 500m	ea	$3,000	8	$24,000
Traffic management		m	$5	5000	$25,000
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Site is mostly flat. Extracted volume stockpile for use within West Belconnen Development.	m3	$40	250	$10,000
Cabling works					$328,700
11 kV 3c/400mm2 XLPE cable		m	$56	4200	$235,200
Throughjoints	Assume every 500m	ea	$1,000	8	$8,000
Terminations	Assume distribution substations at Strathnairn established under estate reticulation works.	ea	$1,500	1	$1,500
Conduit and marker tape		m	$10		$0
Cable installation labour and plant		m	$20	4200	$84,000
11 kV Switchgear					$0
11 kV feeder CB panels	Assume able to double up two feeders at Latham to provide spare CB	ea	$10,000		$0
11kV Test & Commissioning	per CB	lot	$2,000		$0
HV Connections					$2,000
11 kV Cable Termination		ea	$1,000		$0
11 kV Cables and connections Test &	Allowance	ea	$2,000	1	$2,000
Electrical (Secondary System)					$0
Protection & Control					$0
P&C Secondary Cabling	per feeder panel	ea	$2,250		$0
P&C Test & Commission	Allowance	ea	$2,500		$0
DC Supply System					$0
DC Cabling	per switchgear panel/bay	ea	$5,000		$0
DC Test & Commission	Allowance	ea	$2,000		$0
SCADA					$0
SCADA connections for new feeder panels		ea	$2,000		$0
Test & Commissioning	Allowance	ea	$2,000		$0
Indirect Costs					$70,000
Development Application	Allowance	ea	$10,000	1	$10,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	$10,000	1	$10,000
Project management and administration	Allowance	ea	$50,000	1	$50,000
Project Sub Total without overheads					**$1,514,700**
Overheads					
Overall average overhead rate	Allowance	27%	$408,969	1	$408,969
Project Sub Total with overheads					**$1,923,669**
Contingency					
All project works	Preliminary allowance	15%	$288,550	1	$288,550
Project budget total					**$2,212,219**

Appendix B – Financial Analysis

B.1 Capital Expenditure Cash Flow for Each Option

Financial Year	Option 1	Option 2	Option 3	Option 4 *	Option 5 *
2019/20	$3,431,750	$1,514,700	$5,368,800	$1,514,700	$269,152
2020/21					$538,304
2021/22					$538,304
2022/23					$807,455
2023/24					$807,455
2024/25		$1,883,840		$593,077	$1,076,607
2025/26				$269,152	$1,076,607
2026/27				$269,152	$1,076,607
2027/28				$269,152	$1,076,607
2028/29				$269,152	$1,076,607
2029/30				$269,152	$1,076,607
2030/31				$269,152	$1,076,607
2031/32				$269,152	$1,076,607
2032/33				$269,152	$1,076,607
2033/34				$269,152	$1,076,607
2034/35				$269,152	$1,076,607
2035/36				$269,152	$1,076,607
2036/37				$269,152	$1,076,607
2037/38				$269,152	$1,076,607
2038/39				$269,152	$1,076,607
Total Cost (20 yr)	**$3,431,750**	**$1,514,700**	**$5,368,800**	**$1,514,700**	**$2,960,669**
2019-24 Regulatory Control Period Cost	**$3,431,750**	**$3,398,540**	**$5,368,800**	**$5,875,901**	**$19,109,775**

* Options 4 and 5 utilise a network owned battery which is modular and redeployable and has a 10 year lifetime. The battery is costed on a lease-like basis.

B.2 NPC Analysis

The Net Present Cost (NPC) was calculated using a Monte-Carlo simulation model. The simulation randomly selects a peak demand growth rate for each year that is within ± 10% of the forecasted spot loads expected in Kingston. The use of a Monte-Carlo simulation results in selection of the best option that is robust to uncertain peak demand growth forecasts.

Investment within the simulation is dynamic – investment decisions change based on the randomly selected growth rates from previous years. Investment occurs automatically when the firm rating is breached so the value of energy at risk is always zero. In options where multiple investments are available the cheapest is selected.

Summary Financial Analysis Results for Strathnairn 11 kV Feeders

The summary below shows the average values for the selected characteristics after 50 simulations.

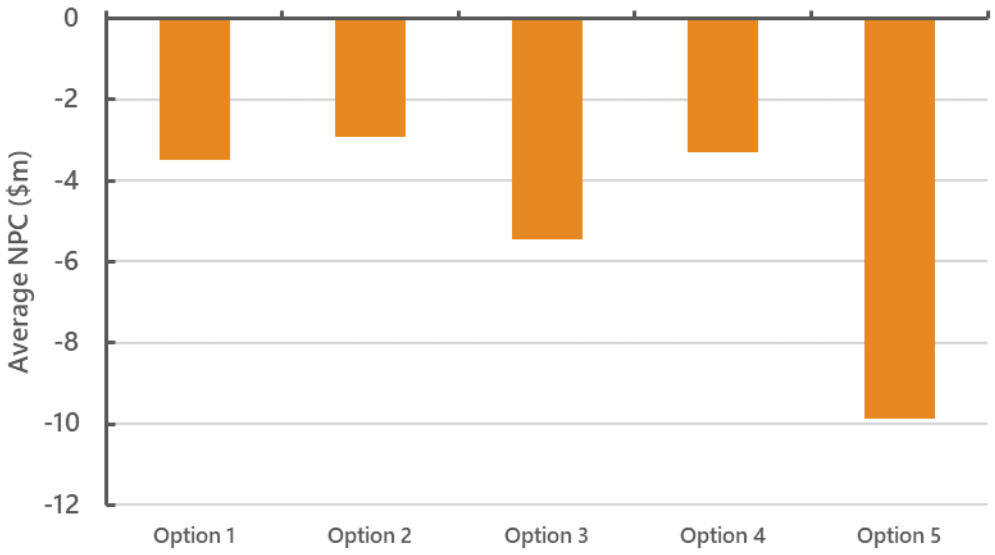
Options:

One – one new 11 kV feeders from Latham Zone Substation to Strathnairn
Two – extend O'Loghlen feeder to Strathnairn and demand management
Three – non-network option (demand management)
Four – extend O'Loghlen feeder to Strathnairn plus network battery
Five – non-network option (network battery)

RESULTS (Average over 50 simulations):

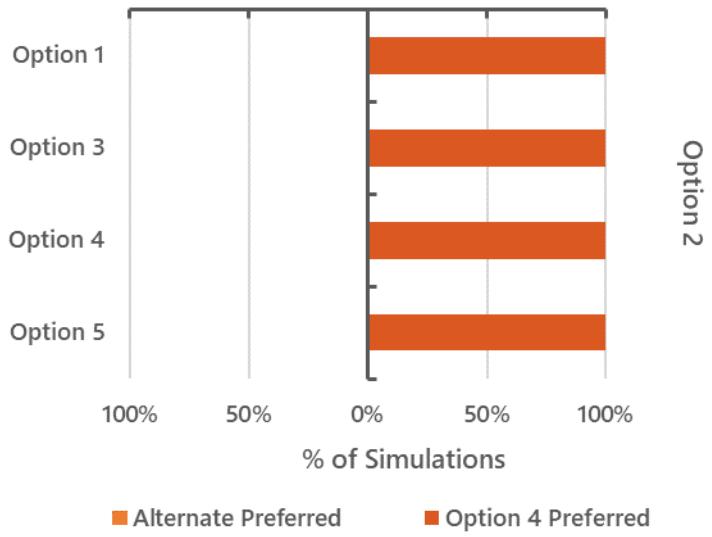
Option:	One	Two	Three	Four	Five
NPC (2019-2024)	-$3,180,652	-$1,430,166	-$4,975,971	-$1,346,648	-$2,836,913
NPC (2019-2039)	-$3,476,655	-$2,920,734	-$5,439,051	-$3,312,264	-$9,875,787
Network Option total Capital Cost	$3,431,750	$3,398,540	$5,368,800	$1,514,700	-
Option Capital Cost (2019-2024)	$3,431,750	$1,552,377	$5,368,800	$1,526,562	$3,591,427
Option Capital Cost (2019-2039)	$3,431,750	$3,398,540	$5,368,800	$5,881,284	$19,740,533

Average Net Present Cost for Each Network / Non-Network Combination:



Multiple combinations of network options, demand management and network batteries were tested using the Monte-Carlo model. The preferred option was selected on the basis of minimising the Net Present Cost.

Percentage of Simulations where the Selected Option had a Lower Cost than Other Options:



The random variation in peak demand growth in the Monte-Carlo model means that different options may be preferred in some simulations. The above chart shows that Option 2 was the preferred option in 100% of simulations.

Value of Risk:

Year	Volume of Energy at Risk (kWh)	Value of Energy at Risk ($)
2020	6,450	28
2021	44,762	151
2022	163,140	423
2023	366,966	1,409,339
2024	686,174	10,343,649

Notes:

Energy at risk is the volume of energy served above the firm rating each year. An indicative load duration curve has been used to determine the relationship between peak demand, firm rating and volume of energy in kWh.

Value at risk assumes:
Value of Customer Reliability = $26.93/kWh
Probability of Failure = 6% (3% annual probability of transformer failure + 3% probability of feeder failure)
Outage duration = 8 hours
Probability of failure in any given hour: 6% * 8 / 24 / 365
Value above firm rating = VCR * probability * volume of energy
All energy above the emergency rating is not served. This is equivalent to assuming a 100% outage probability for energy above this level.

In addition to the VCR cost, there are litigation, reputational and other financial risks that are included in the total:

Litigation costs = $100,000 / event
Reputational risk cost = external consultations and communications costs = $10,000 / event.
Financial risk cost = internal investigation costs = $10,000 / event.

Total risk cost = Reliability risk cost + Litigation + Reputational risk cost + Financial risk cost
= VCR / kWh + $120,000 / event.