

# Appendix 5.29: Supply to Griffith, Red Hill, Forrest, & Narrabundah 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.

## Project Justification Report

Project name	Supply to Griffith / Red Hill / Forrest / Narrabundah
Expenditure type	Capital Expenditure
Business Group	Asset Strategy
Regulatory Period	1 July 2019 to 30 June 2024
Total Project Cost Estimate	\$1,788,750 excluding corporate overheads, excluding contingency, and excluding GST
Five year total spend 2019-24	\$1,788,750 excluding corporate overheads, excluding contingency, and excluding GST
CAPEX category	ENAA Distribution
Primary driver	Load growth in Griffith / Red Hill / Forrest / Narrabundah area
Project Number	20001378

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## 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
Augmentation NPV Model Methodology	1.0	29.9.17

## 1. Executive Summary

The ACT Government's Suburban Land Agency (SLA) has prepared an Indicative Land Release Program for the 2017–21 period which includes developments that will increase maximum demand in the Griffith / Red Hill / Forrest / Narrabundah area by approximately 6.3 MVA. These developments are primarily residential redevelopments, eg demolition of old flats and replacement with multi-storey apartment buildings.

This area is approximately 2 km west of Telopea Park Zone Substation. Existing feeders in the area are heavily loaded. Telopea Park Zone Substation has a continuous summer rating of 100 MVA and is approaching this maximum demand level; however under a separate project load will be transferred from Telopea Park to East Lake Zone Substation.

This project proposes a new 11 kV cable feeder to be installed from Telopea Park Zone Substation to the Griffith area. Spare conduits will be installed along the feeder route to provide for future developments and load growth.

The proposed feeder will inter-tie with existing feeders emanating from Telopea Park, and thus enable load to be transferred off highly-loaded feeders.

Other options considered and evaluated were the installations of a feeder from the East Lake Zone Substation, non-network demand management, utilising a grid battery to defer a network upgrade and utilising a grid battery to avoid a network upgrade.

A preliminary cost estimate for the selected option of installing one new feeder from Telopea Park Zone Substation to Griffith is **\$1,788,750 excluding corporate overheads, excluding contingency, and excluding GST**. These works will be carried out during the 2019-24 Regulatory Control Period with completion proposed by June 2021.

## 2. Strategic Context and Expenditure Need

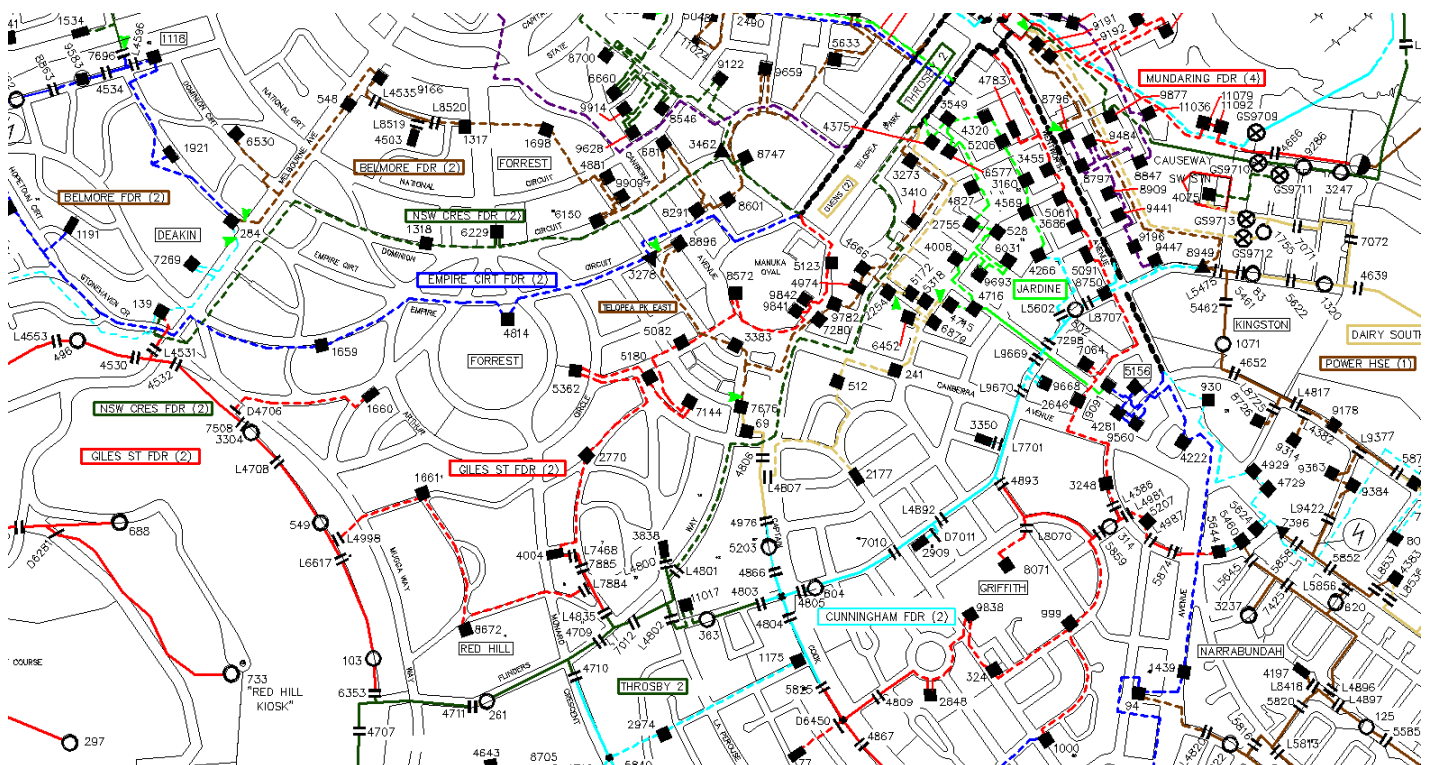
There is significant development planned for the Griffith / Red Hill / Forrest / Narrabundah area. Existing infrastructure has insufficient capacity to cater for the additional demand associated with these developments.

### 2.1. Existing infrastructure in the Griffith / Red Hill / Forrest / Narrabundah Area

There are currently four 11 kV feeders supplying the Griffith / Red Hill / Forrest / Narrabundah Area. These are Belmore, Jardine, Sturt and Throsby feeders, all of which emanate from Telopea Park Zone Substation. The maximum demand at Telopea Park Zone Substation is forecast to exceed its continuous rating of 100 MVA by 2022. Under a separate project it is proposed to transfer some load from Telopea Park to East Lake Zone Substation.

The existing feeder network is illustrated in Figure 1.

**Figure 1: Telopea Park to Griffith / Red Hill / Forrest / Narrabundah area 11 kV Feeders**



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.

Table 1: Griffith / Red Hill / Forrest / Narrabundah Area Feeder Loadings

Feeder Name	Zone	Feeder Rating (MVA)				2015		2016		2017	Spare capacity MVA
		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	
Belmore	TP	3.6	4.9	4.1	5.4	77%	80%	93%	92%	83%	0.6
Jardine	TP	4.8	6.4	5.4	7.2	63%	72%	52%	63%	55%	1.9
Sturt	TP	4.1	5.4	4.6	6.1	78%	63%	68%	78%	74%	1.0
Throsby	TP	4.8	6.4	5.4	7.2	82%	81%	63%	84%	92%	0.3
<b>Total</b>											<b>3.8</b>

## 2.2. Driving need for infrastructure investment

Forecast additional maximum demand in the Griffith / Red Hill / Forrest / Narrabundah area is indicated in Table 2. This has been based on an assessment of known developments (either at application or Preliminary Network Advice stage) proposed for the area. Some of these developments are currently being designed. There is a high degree of certainty (> 80%) that these developments will proceed.

Table 2: Proposed Developments in the Griffith / Red Hill / Forrest / Narrabundah area.

Proposed Development and Net Additional Diversified Load in MVA	2018	2019	2020	2021	2022
B50 S19, Eyre St, Kingston			2.6		
Stuart Flats, Light St / Stuart St, Griffith				1.5	
B13 S13, Canberra Ave, Forrest.					0.5
Red Hill Village, Discovery St, Red Hill		1.2			
Gowrie Court Flats, B3 S62, McIntyre St, Narrabundah					0.5
<b>Additional Load (MVA)</b>	<b>0.0</b>	<b>1.2</b>	<b>2.6</b>	<b>1.5</b>	<b>1.0</b>
<b>Cumulative Additional Forecast Load (MVA)</b>	<b>0.0</b>	<b>1.2</b>	<b>3.8</b>	<b>5.3</b>	<b>6.3</b>
Spare capacity of existing feeders to Griffith / Red Hill / Forrest / Narrabundah area	<b>3.8</b>	<b>2.6</b>	<b>0.0</b>	<b>-1.5</b>	<b>-2.5</b>

The 11 kV feeders that currently supply the Griffith / Red Hill / Forrest / Narrabundah area are Belmore, Jardine, Sturt and Throsby feeders from Telopea Park. Between them these feeders have approximately 3.8 MVA spare firm capacity during summer. The proposed developments shown in Table 2 indicate there will be no spare capacity available from winter 2021 onwards so additional feeders will be required unless demand side management initiatives can avoid this.

**Major proposed developments are as follows:**

### Stuart Flats, Light St / Stuart St, Griffith.

This is currently a complex of 11 blocks of single level flats which are to be demolished and redeveloped as multi-storey apartment buildings of 550 dwellings. Estimated maximum demand 1.5 MVA. Nearest feeder is the Throsby feeder (from Telopea Park).

**B50 S19, Eyre St, Kingston.**

This is currently an open air carpark but is proposed to be redeveloped to include a supermarket, 1,000m<sup>2</sup> gross floor area (GFA) of retail shops, and a multi-storey apartment building of 100 dwellings. Estimated maximum demand 2.5 MVA. Nearest feeder is the Jardine feeder (from Telopea Park).

**B13 S13, Canberra Ave, Forrest.**

This is currently an open space and is proposed to be developed as a multi-storey apartment building of 168 dwellings. Estimated maximum demand 500 kVA. Nearest feeder is Belmore (from Telopea Park).

**Red Hill Village, Discovery St, Red Hill.**

This is currently a complex of 114 single level dwellings which are to be demolished and redeveloped as 240 town-houses. Estimated maximum demand 750 kVA. Nearest feeder is the Throsby feeder (from Telopea Park).

**Gowrie Court Flats, B3 S62, McIntyre St, Narrabundah.**

This is currently a complex of 6 blocks of single level flats which are to be demolished and redeveloped as a multi-storey apartment building of 160 dwellings. Estimated maximum demand 400 kVA. Nearest feeder is the Sturt feeder (from Telopea Park).



### 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 below. 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
<b>Responsible</b>	<ul style="list-style-type: none"> <li>Achieve zero deaths or injuries to employees or the public.</li> <li>Maintain a good reputation within the community.</li> <li>Minimise environmental impacts, for example bushfire mitigation.</li> <li>Meet all requirements of regulatory authorities, such as the AER as outlined in the NER, and the ACT Utilities (Technical Regulations) Act 2014.</li> </ul>	The selected option must ensure environment and safety standards will be met.
<b>Reliable</b>	<ul style="list-style-type: none"> <li>Tailor maintenance and renewal programs for each asset class based on real time modelling of asset health and risk.</li> <li>Meet network SAIDI and SAIFI KPIs.</li> <li>Record failure modes of the most common asset failures in the network.</li> <li>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.</li> </ul>	<p>Options evaluations to consider the value of customer reliability (VCR).</p> <p>In accordance with regulated requirements, the selected option must ensure access to an electricity supply.</p>
<b>Sustainable</b>	<ul style="list-style-type: none"> <li>Enhance asset condition and risk modelling to optimise and implement maintenance and renewal programs tailored to the assets' needs.</li> <li>Make prudent commercial investment decisions to manage assets at the lowest lifecycle cost.</li> <li>Integrate primary assets with protection and automation systems in accordance with current and future best practice industry standards</li> <li>Deliver the asset class PoW within budget.</li> </ul>	<p>Options evaluations to consider the cost effectiveness of the solution.</p> <p>In accordance with regulated requirements, the selected option must be the most prudent and efficient.</p> <p>Non-network options will be evaluated on equal merit with network solutions.</p>
<b>People</b>	<ul style="list-style-type: none"> <li>Proactively seek continual improvement in asset management capability and competencies of maintenance personnel.</li> </ul>	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 <sup>2</sup>
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).

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<sup>1</sup> "N" represents the number of feeders operating in parallel.

<sup>2</sup> 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 five options to provide additional capacity to the Griffith / Red Hill / Forrest / Narrabundah area as listed in Table 5.

**Table 5: Options considered for provision of additional capacity to the Griffith / Red Hill / Forrest / Narrabundah area**

Option	Option type	Description	Evaluation
0	Network	Do nothing	Not selected as does not meet minimum requirements
1	<b>Network</b>	<b>Construct one new 11 kV cable feeder from Telopea Park Zone Substation</b>	<b>Selected as higher NPC</b>
2	Network	Construct new 11 kV cable feeder from East Lake Substation	Not selected due to lower NPC
3	Non-network	Demand side management and embedded generation	Not selected as does not meet need
4	Mixed	Delayed preferred network option using grid battery	Not selected as cost of delay exceeded benefits
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 insufficient network capacity in the area to meet demand during a contingency event.

The value of energy at risk is estimated to be approximately \$20.8m over a five year period based on the probability of a contingency event at the same time as demand exceeding firm capacity.

The feeders supplying Griffith are highly interconnected so the firm rating is close to the thermal rating. The forecast level of demand growth will exceed the thermal rating by 2021, resulting in a high value of energy at risk.

The Do Nothing option would result in Evoenergy breaching its Distribution Network Augmentation Standards and thus its obligation to provide a reliable and secure power supply.

#### 4.1.2. Option 1: Construct new 11 kV cable feeder from Telopea Park Zone Substation

Option 1 proposes to install one new underground 11 kV cable feeder to the Griffith / Red Hill / Forrest / Narrabundah area from Telopea Park Zone Substation to meet the growing load demand. The new feeder would provide up to 5.5 MVA firm capacity (summer).

Telopea Park Zone Substation has three 132/11 kV 50 MVA power transformers providing a continuous firm summer/winter rating of 100 MVA. The substation has three 11 kV switchboards comprising a total of 36 feeder circuit breakers each rated at 800 Amps. The switchboards are GEC double bus type 1985 vintage.

There are no spare feeder circuit breakers available. There are existing feeders that are lightly loaded. None of these feeders runs towards to the Griffith / Red Hill / Forrest / Narrabundah area. Under this option a lightly-loaded feeder

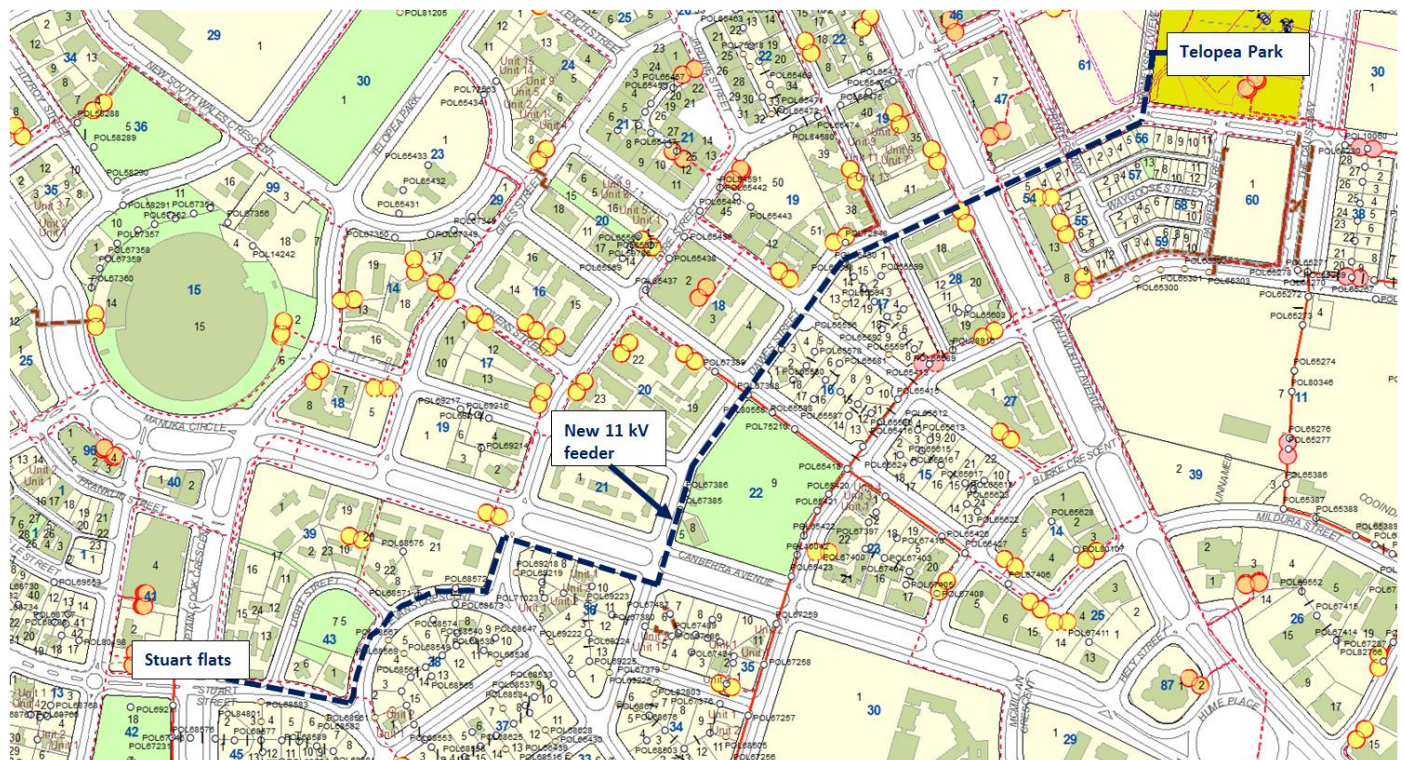


would be disconnected and doubled-up with another lightly loaded feeder (eg Sandalwood + York Park No 1) to the same circuit breaker, thus freeing-up a circuit breaker for connection of the proposed new feeder.

The cable route length would be approximately 2.0 km and due to the heavily built up nature of the area, this cable would need to be installed full length via directional drilling. Three 150mm conduits would be installed via directional drilling to accommodate the 11 kV 3c/400mm<sup>2</sup> AL XLPE feeder cable plus provide spare conduits for two future feeders.

Figure 2 illustrates the proposed cable route.

**Figure 2: Proposed 11 kV feeder cable route Telopea Park Zone Substation to Griffith / Red Hill / Forrest / Narrabundah**



A preliminary cost estimate for Option 1 is **\$1,788,750 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

Option 1 is selected due to its higher (ie least negative) net present cost (NPC).

#### 4.1.3. Option 2: Construct new 11 kV cable feeder from East Lake Zone Substation

Option 2 proposes to install one new underground 11 kV cable feeder to the Griffith / Red Hill / Forrest / Narrabundah area from East Lake Zone Substation to meet the growing load demand, a cable route length of approximately 3.4 km. The new feeder would provide up to 5.5 MVA firm capacity (summer).

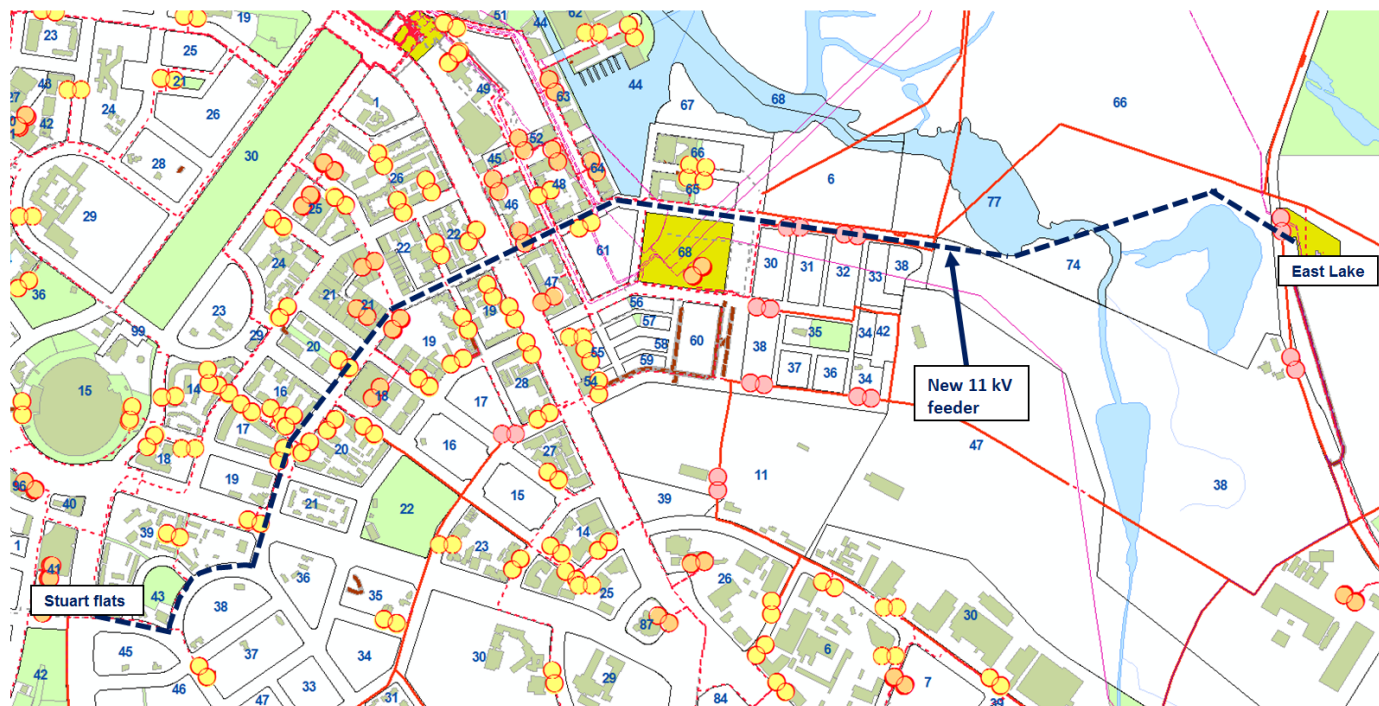
It is proposed that spare conduits would be installed from East Lake Zone Substation to Causeway Switching Station in association with the proposed East Lake – Causeway 132 kV underground cabling project (route length 1.4 km). This is a customer-driven project (SLA), currently scheduled for completion by June 2020. A spare 150mm conduit installed under this project would be used for this section of the East Lake to Griffith feeder.

The section from Causeway to Griffith cable route length would be approximately 2.0 km and due to the heavily built up nature of the area, this cable would need to be installed full length via directional drilling. Three 150mm conduits

would be installed via directional drilling to accommodate the 11 kV 3c/400mm<sup>2</sup> AL XLPE feeder cable plus provide spare conduits for two future feeders.

Figure 3 illustrates the proposed cable route.

**Figure 3: Proposed 11 kV feeder cable route East Lake Zone Substation to Griffith**



A preliminary cost estimate for Option 2 is **\$1,918,150 excluding corporate overheads, contingency and GST**. Refer to cost estimates, cash flows and NPC comparison in Appendices A and B.

This option is not preferred due to its lower NPC.

#### 4.1.4. Option 3: Demand Management

Option 3 considers 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.

To defer the Griffith feeder to the next regulatory control period (beyond 2024), it is estimated that non-network solutions would need to provide a maximum demand of approximately 3.7 MVA pa.

Latent demand management within the existing customer base was investigated, with a maximum estimated capacity of 0.667 MVA. This does not meet the minimum capacity required to enable the new feeder to be deferred.

These non-network options are summarised in Table 6.



Table 6: Summary of latent demand management

Non-network Option	Total
Customer – owned embedded generation	0.6 MVA
Customer – owned energy storage	0.06 MVA
Load curtailment	0.007 MVA
<b>Totals</b>	<b>0.667 MVA</b>

Third party non-network proposals has been requested in ActewAGL's 2017 Annual Planning Report and via Evoenergy's website demand management portal and may identify additional opportunities.

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). For the purposes of the evaluation, it is assumed that no more than 30% of demand growth can be offset using additional demand management.

For the Griffith area it was determined that 40% of demand growth would need to be offset by demand management to enable the project to be deferred, implying that new demand management is unlikely to defer investment.

#### 4.1.5. Option 4: Grid battery to defer Option 1

This option utilises a grid battery to enable Option 1 to be deferred. 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 1 with a preliminary cost estimate of **\$2,650,979 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 utilises 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 grid battery is modular and is 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 Griffith however, the grid battery is not economic due to the relative certainty of demand with a preliminary cost estimate of **\$16,203,879 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 7: 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	<b>Construct new 11 kV cable feeder from Telopea Park to Griffith</b>	<b>\$1,788,750</b>	<b>\$1,788,750</b>	<b>-\$1,812,156</b>	<b>Selected due to higher NPC</b>
2	Construct new 11 kV cable feeder from East Lake to Griffith	\$1,918,150	\$1,918,150	-\$1,943,249	Not selected due to lower NPC
3	Demand side management	N/A	N/A	N/A	Not selected as does not meet need
4	Grid battery to defer option 1	\$2,650,979	\$2,650,979	-\$2,462,494	Not selected as deferral not economic
5	Grid battery only	\$16,203,879	\$4,092,050	-\$8,492,080	Not selected due to lower NPC

#### 4.2. Recommendation

The selected option is Option 1, the construction of a new 11 kV underground feeder from Telopea Park Zone Substation to the Griffith area. Cable to be 11 kV 3c/400mm<sup>2</sup> AL XLPE.

Financial analysis shows Option 1 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 Evoenergy's regulated asset base. The major assets will have an economic life of 50 years.

The new feeder will provide capacity and security of supply to the new developments proposed for the Griffith / Red Hill / Forrest / Narrabundah area. Additional spare conduits will be installed for future feeders to meet future load growth.

Timing is scheduled for completion by June 2021. Future additional feeder cables will be installed as the load growth and demand increases with further development of the Griffith / Red Hill / Forrest / Narrabundah area.

The preliminary cost estimate for the selected option is **\$1,788,750 excluding overheads, contingency and GST**.

The proposed 11 kV feeder will provide ties to existing feeders from Telopea Park and Woden zone substations, and thus provide some backup supply capability and load transfer capability in the future.

## Appendix A – Preliminary Cost Estimates

### A.1 Cost Estimate – Option 1: 11 kV Feeder from Telopea Park Zone Substation to Griffith

Griffith supply from Telopea Park Zone Substation via new 11 kV feeder @ 2km long. Assume directional drilling full length.					
Preliminary Estimate ± 30% Accuracy					
Description	Notes	Unit	\$/Unit	Quantity	Cost
<b>Trenching and drilling</b>					<b>\$1,235,000</b>
Clearing of route where required	Allowance	m2	\$10	200	\$2,000
Directional drilling	Assume drilling with no rock. Assume three 150mm conduits per drill.	m	\$600	2000	\$1,200,000
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume two or three cables per trench.	m	\$300	0	\$0
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	5	\$15,000
Traffic management		m	\$5	2000	\$10,000
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Site is mostly flat .	m3	\$40	200	\$8,000
<b>Cabling works</b>					<b>\$221,000</b>
11 kV 3c/400mm2 XLPE cable		m	\$56	2000	\$112,000
Throughjoints	Assume every 500m	ea	\$1,000	3	\$3,000
Terminations		ea	\$1,500	2	\$3,000
Conduit and marker tape	Assume all cables installed in conduit	m	\$10	6000	\$60,000
Cable installation labour and plant		m	\$20	2000	\$40,000
HV Cables and connections Test & Commissioning	Allowance	ea	\$3,000	1	\$3,000
<b>11 kV Switchgear</b>					<b>\$27,000</b>
11 kV feeder CB double-ups	Assume CBs able to accommodate two cables	ea	\$25,000	1	\$25,000
11kV Test & Commissioning	per CB	lot	\$2,000	1	\$2,000
<b>Electrical (Secondary System)</b>					<b>\$11,750</b>
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
<b>SCADA</b>					<b>\$4,000</b>
SCADA connections for new feeder panels		ea	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
<b>Indirect Costs</b>					<b>\$290,000</b>
Development Application	Allowance	ea	\$40,000	1	\$40,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	\$50,000	1	\$50,000
Project management and administration	Allowance	ea	\$200,000	1	\$200,000
<b>Project Sub Total without overheads</b>					<b>\$1,788,750</b>
<b>Overheads</b>					
Overall average overhead rate	Allowance	27%	\$482,963	1	\$482,963
<b>Project Sub Total with overheads</b>					<b>\$2,271,713</b>
<b>Contingency</b>					
All project works	Preliminary allowance	15%	\$340,757	1	\$340,757
<b>Project budget total</b>					<b>\$2,612,469</b>

## A.2 Cost Estimate – Option 2: 11 kV Feeder from East Lake Zone Substation to Griffith

Griffith supply from East Lake Zone Substation via new 11 kV feeder @ 3.4 km long. Assume directional drilling for 2.0 km and spare conduit available for 1.4 km (installed under separate project).					
Preliminary Estimate ± 30% Accuracy					
Description	Notes	Unit	\$/Unit	Quantity	Cost
<b>Trenching and drilling</b>					<b>\$1,266,000</b>
Clearing of route where required	Allowance	m2	\$10	500	\$5,000
Directional drilling	Assume drilling with no rock. Assume three 150mm conduits per drill.	m	\$600	2000	\$1,200,000
Open trenching and backfilling	Assume excavation with no rock. Backfill with bedding sand and native soil. Assume two or three cables per trench.	m	\$300	0	\$0
Cable jointing and haulage pits	Assume every 500m	ea	\$3,000	8	\$24,000
Traffic management		m	\$5	3400	\$17,000
Reinstatement incl revegetation as required	Excavation, no rock (minor boulders only). Site is mostly flat .	m3	\$40	500	\$20,000
<b>Cabling works</b>					<b>\$344,400</b>
11 kV 3c/400mm2 XLPE cable		m	\$56	3400	\$190,400
Throughjoints	Assume every 500m	ea	\$1,000	6	\$6,000
Terminations		ea	\$1,500	2	\$3,000
Conduit and marker tape	Assume all cables installed in conduit	m	\$10	7400	\$74,000
Cable installation labour and plant		m	\$20	3400	\$68,000
HV Cables and connections Test & Commissioning	Allowance	ea	\$3,000	1	\$3,000
<b>11 kV Switchgear</b>					<b>\$2,000</b>
11 kV feeder CB double-ups	Assume CBs able to accommodate two cables	ea	\$25,000	0	\$0
11kV Test & Commissioning	per CB	lot	\$2,000	1	\$2,000
<b>Electrical (Secondary System)</b>					<b>\$11,750</b>
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
<b>DC Supply System</b>					<b>\$7,000</b>
DC Cabling	per switchgear panel/bay	ea	\$5,000	1	\$5,000
DC Test & Commission	Allowance	ea	\$2,000	1	\$2,000
<b>SCADA</b>					<b>\$4,000</b>
SCADA connections for new feeder panels		ea	\$2,000	1	\$2,000
Test & Commissioning	Allowance	ea	\$2,000	1	\$2,000
<b>Indirect Costs</b>					<b>\$290,000</b>
Development Application	Allowance	ea	\$40,000	1	\$40,000
Contractor's Preliminaries, site establishment and disestablishment	Allowance	ea	\$50,000	1	\$50,000
Project management and administration	Allowance	ea	\$200,000	1	\$200,000
<b>Project Sub Total without overheads</b>					<b>\$1,918,150</b>
<b>Overheads</b>					
Overall average overhead rate	Allowance	27%	\$517,901	1	\$517,901
<b>Project Sub Total with overheads</b>					<b>\$2,436,051</b>
<b>Contingency</b>					
All project works	Preliminary allowance	15%	\$365,408	1	\$365,408
<b>Project budget total</b>					<b>\$2,801,458</b>

## 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	\$1,788,750	\$1,918,150		\$862,229	\$862,229
2020/21				\$1,788,750	\$807,455
2021/22					\$807,455
2022/23					\$807,455
2023/24					\$807,455
2024/25					\$807,455
2025/26					\$807,455
2026/27					\$807,455
2027/28					\$807,455
2028/29					\$807,455
2029/30					\$807,455
2030/31					\$807,455
2031/32					\$807,455
2032/33					\$807,455
2033/34					\$807,455
2034/35					\$807,455
2035/36					\$807,455
2036/37					\$807,455
2037/38					\$807,455
2038/39					\$807,455
<b>Total Cost (20 yr)</b>	<b>\$1,788,750</b>	<b>\$1,918,150</b>	<b>N/A</b>	<b>\$2,650,979</b>	<b>\$4,092,050</b>
<b>2019-24 Regulatory Control Period Cost</b>	<b>\$1,788,750</b>	<b>\$1,918,150</b>	<b>N/A</b>	<b>\$2,650,979</b>	<b>\$16,203,879</b>

\* 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  $\pm 10\%$  of the forecasted spot loads expected in Griffith, Red Hill, Forrest and Narrabundah. 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 Supply to Griffith / Red Hill / Forrest / Narrabundah

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

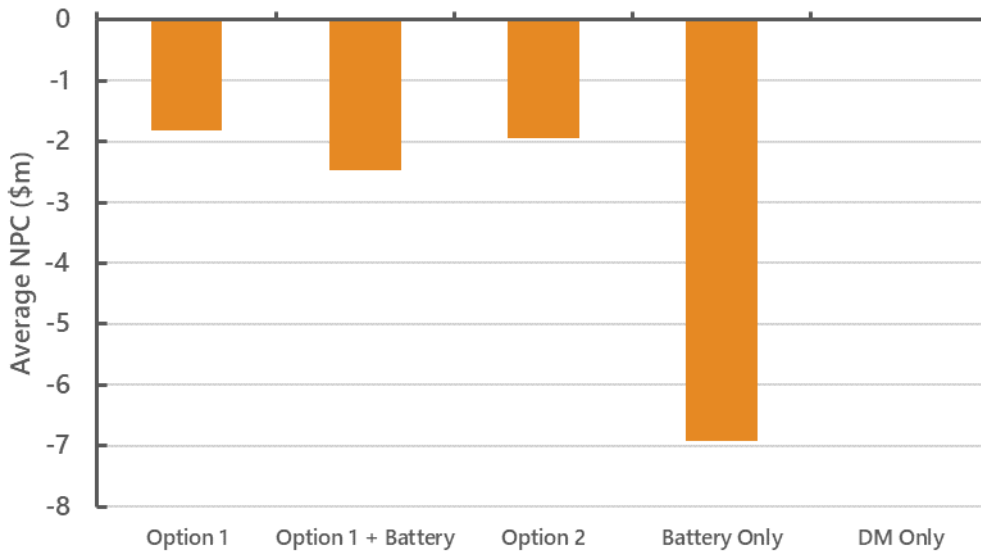
#### Options:

- One – One new 11 kV feeder from Telopea Park Zone Substation
- Two – One new 11 kV feeder from East Lake Zone Substation
- Three – Demand management
- Four – Grid battery to defer option 1
- Five – Grid battery only

#### RESULTS (Average over 50 simulations):

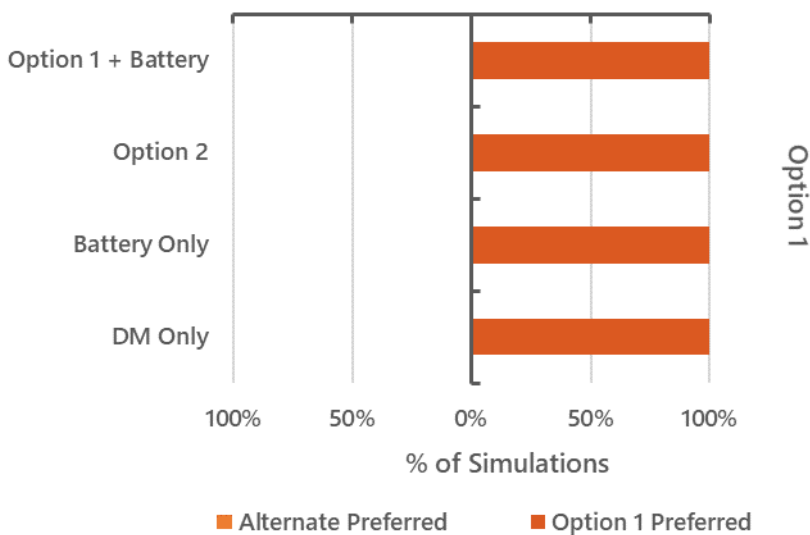
Option:	One	Two	Three	Four	Five
NPC (2019-2024)	-\$1,657,869	-\$1,777,801	N/A	-\$2,308,207	-\$2,708,154
NPC (2019-2039)	-\$1,812,156	-\$1,943,249	N/A	-\$2,462,494	-\$6,909,931
Network Option total Capital Cost	\$1,788,750	\$1,918,150	N/A	\$1,788,750	-
Option Capital Cost (2019-2024)	\$1,788,750	\$1,918,150	N/A	\$2,650,979	\$3,427,410
Option Capital Cost (2019-2039)	\$1,788,750	\$1,918,150	N/A	\$2,650,979	\$13,067,437

**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 1 was the preferred option in 100% of simulations.

**Value of Risk:**

Year	Volume of Energy at Risk (kWh)	Value of Energy at Risk (\$)
2020	5,312	17
2021	60,764	1,265,987
2022	150,658	6,399,133
2023	150,658	6,399,133
2024	150,658	6,399,133

**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:  $6\% \times 8 / 24 / 365$

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.