Regulatory Investment Test for Distribution (RIT-D)

Kallangur Zone Substation Limitation

Final Project Assessment Report

7 September 2021

energex
Part of Energy Queensland

EXECUTIVE SUMMARY

About Energex

Energex Limited (Energex) is a subsidiary of Energy Queensland Limited and manages the electricity distribution network in the growing region of South East Queensland which includes the major urban areas of Brisbane, Gold Coast, Sunshine Coast, Logan, Ipswich, Redlands and Moreton Bay. Our electricity distribution area runs from the NSW border north to Gympie and west to the base of the Great Dividing Range.

Our electricity network consists of approximately 54,200 kilometres of powerlines and 680,000 power poles, along with associated infrastructure such as major substations and power transformers.

Today, we provide distribution services to more than 1.4 million domestic and business connections, delivering electricity to a population base of around 3.4 million people.

Identified Need

Kallangur zone substation (SSKLG) is supplied from Griffin bulk supply substation (SSGFN) via a 33kV mesh network, which also supplies Mango Hill zone substation (SSMHL) and a direct customer connection. SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas. With new developments in the Petrie area, loads are forecast to increase significantly causing network limitations in the area.

The identified need for this Final Project Assessment Report (FPAR) is that Energex will exceed its Substation system normal cyclic capacity (NCC) rating and will not meet its Safety Net obligation as outlined in its Distribution Authority at SSKLG in the summer of 2025/26 due to load growth in the area.

The requirements of a non-network option to solve the identified need are summarised in Table 1 and Table 2.

Customer Category	Total Limit	Year	Forecast 10 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
Urban	44.6 MVA	2020/21	40.8	0.0	-	-	-
		2021/22	41.2	0.0	-	-	-
		2022/23	41.6	0.0	-	-	-
		2023/24	43.2	0.0	-	-	-
		2024/25	44.7	0.0	-	-	-
		2025/26	46.1	1.5	3	0.04%	3.5
		2026/27	48.3	3.7	4	0.09%	7.5
		2027/28	50.2	5.6	5	0.13%	11.5
		2028/29	50.8	6.2	6	0.15%	13.5
		2029/30	51.7	7.1	8	0.20%	17.5

Table 1: Non-network Option Requirements for SSKLG under System Normal (N)

Customer Category	Total Limit	Year	Forecast 50 PoE Load (MVA)	Security Standard Load At Risk (MVA)	Days Above Limit	% Time Above Limit	Hrs Over Limit
Urban	39.3 MVA	2020/21	35.2	0.0	-	-	-
		2021/22	35.5	0.0	-	-	-
		2022/23	35.9	0.0	-	-	-
		2023/24	37.4	0.0	-	-	-
		2024/25	38.9	0.0	-	-	-
		2025/26	40.3	1.0	2	0.03%	3
		2026/27	42.7	3.4	4	0.09%	8
		2027/28	44.5	5.2	5	0.14%	12.5
		2028/29	45.1	5.8	7	0.17%	15
		2029/30	45.8	6.5	8	0.22%	19.5

Table 2: Non-network Option Requirements for SSKLG under System Contingency (N-1)

As part of its operational strategy following a contingency, Energex will deploy 4MVA of generation using its fleet of mobile generators.

Approach

The National Electricity Rules (NER) require that, subject to certain exclusion criteria, network business investments for meeting service standards for a distribution business are subject to a Regulatory Investment Test for Distribution (RIT-D). Energex has determined that network investment is essential in this case for it to continue to provide electricity to the consumers in the Kallangur supply area in a reliable, safe and cost-effective manner. Accordingly, this investment is subject to a RIT-D.

Energex published a Draft Project Assessment Report (DPAR) for the above described network constraint on 14 June 2021. No submissions were received by the closing date of 9 August 2021.

Three potentially feasible options have been investigated by the DPAR:

- **Option 1:** Establish a new 33/11kV zone substation at Petrie
- **Option 2:** Replace existing transformers TR2 and TR3 at SSKLG with two 25 MVA transformers
- **Option 3:** Contract a 10MW Battery Energy Storage Solution (BESS)

This Final Project Assessment Report (FPAR), where Energex provides both technical and economic information about possible solutions, has been prepared in accordance with the requirements of clause 5.17.4(o) of the NER.

Energex's preferred solution to address the identified need is Option 1 – Establish a new 33/11kV zone substation at Petrie.

CONTENTS

1. INTRODUCTION

This FPAR has been prepared by Energex in accordance with the requirements of clause 5.17.4(o) of the NER.

This report represents the final stage of the consultation process in relation to the application of the RIT-D on potential credible options to address the identified need for the Kallangur network area.

In preparing this RIT-D, Energex is required to consider reasonable future scenarios. With respect to major customer loads and generation, Energex has, in good faith, included as much detail as possible while maintaining necessary customer confidentiality. Potential large future connections that Energex is aware of are in different stages of progress and are subject to change (including outcomes where none or all proceed). These and other customer activity can occur over the consultation period and may change the timing and/or scope of any proposed solutions.

1.1. Response to the DPAR

Energex published a DPAR for the identified need in the Kallangur network area on the 14 June 2021. No submissions were received by the closing date of the 9 August 2021.

1.2. Structure of the Report

This report:

- Provides background information on the network capability limitations of the distribution network supplying the Kallangur area.
- Identifies the need which Energex is seeking to address, together with the assumptions used in identifying and quantifying that need.
- Describes the credible options that are considered in this RIT-D assessment.
- Describes the market benefit assessment methodology
- Provides the results of Net Present Value (NPV) analysis of each credible option and accompanying explanatory statements regarding the results.
- Identifies the proposed preferred option, including detailed characteristics, estimated commissioning date, indicative costs, and noting that it satisfies the RIT-D.
- Provides contact details for queries on this RIT-D.

1.3. Dispute Resolution Process

In accordance with the provisions set out in clause 5.17.5(a) of the NER, Registered Participants or Interested Parties may, within 30 days after the publication of this report, dispute the conclusions made by Energex in this report with the Australian Energy Regulator. Accordingly, Registered Participants and Interested Parties who wish to dispute the conclusions outlined in this report based on a manifest error in the calculations or application of the RIT-D must do so within 30 days of the publication date of this report. Any parties raising a dispute are also required to notify Energex. Dispute notifications should be sent to demandmanagement@energex.com.au

If no formal dispute is raised, Energex will proceed with the preferred option to establish a new 33/11kV zone substation at Petrie.

1.4. Contact Details

For further information and inquiries please contact:

E: demandmanagement@energex.com.au
P: 13 74 66

2. BACKGROUND

2.1. Geographic Region

SSKLG is supplied from Griffin bulk supply substation (SSGFN) via a 33kV mesh network, which also supplies Mango Hill zone substation (SSMHL) and a direct customer connection. SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas.

The geographical location of Energex's sub-transmission network and substations in the area is shown in Figure 1 and Figure 2.

Figure 1: Existing network arrangement (geographic view)

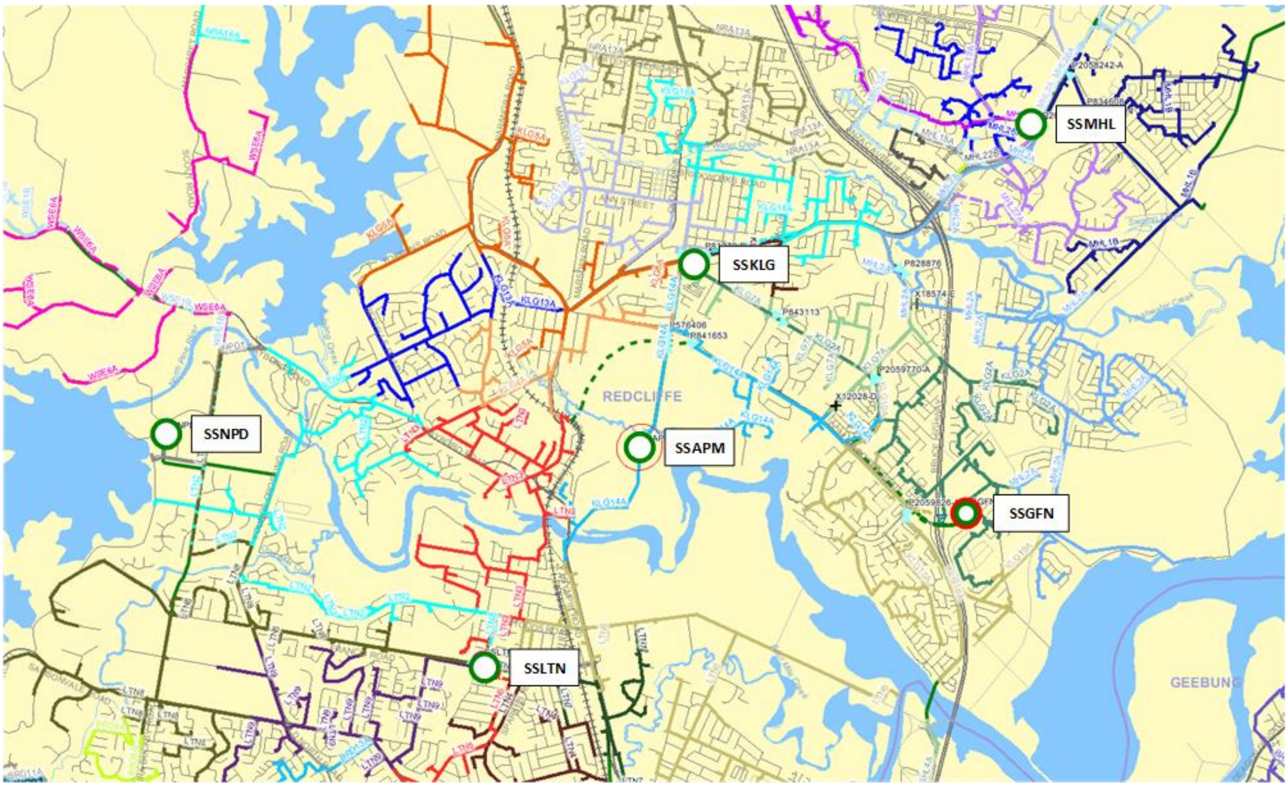


Figure 2: Existing 11kV network arrangement (Geographic view)

2.2. Existing Supply System

SSKLG is supplied via three incoming 33kV feeders from SSGFN under system normal. There is a normally opened 33kV feeder to supply Narangba (SSNRA) zone substation under feeder contingency in the Hays Inlet bulk supply network.

SSKLG has 2 x 12MVA and 1 x 25MVA 33/11kV transformers. The substation supplies ten 11kV distribution feeders and has limited 11kV ties to Lawnton (SSLTN), SSMHL and SSNRA substations.

A schematic view of the existing sub-transmission network arrangement is shown in Figure 3 and the geographic view of Kallangur Substation is illustrated in Figure 4.

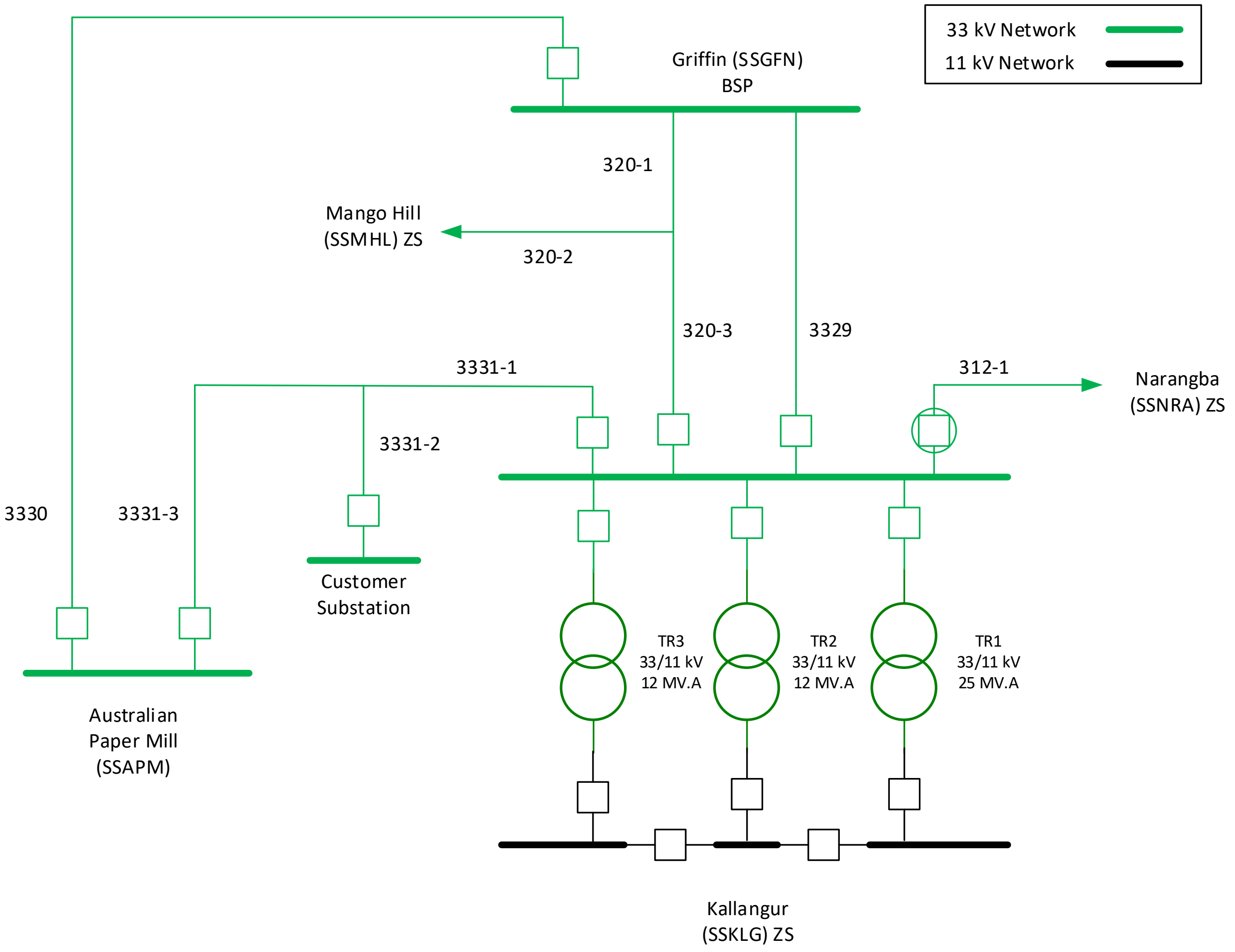


Figure 3: Existing network arrangement (schematic view)

Note: The SSAPM switching station will be recovered as part of the land development in the area. The recovery cost is not part of this RIT-D as it will be done as a separate project.

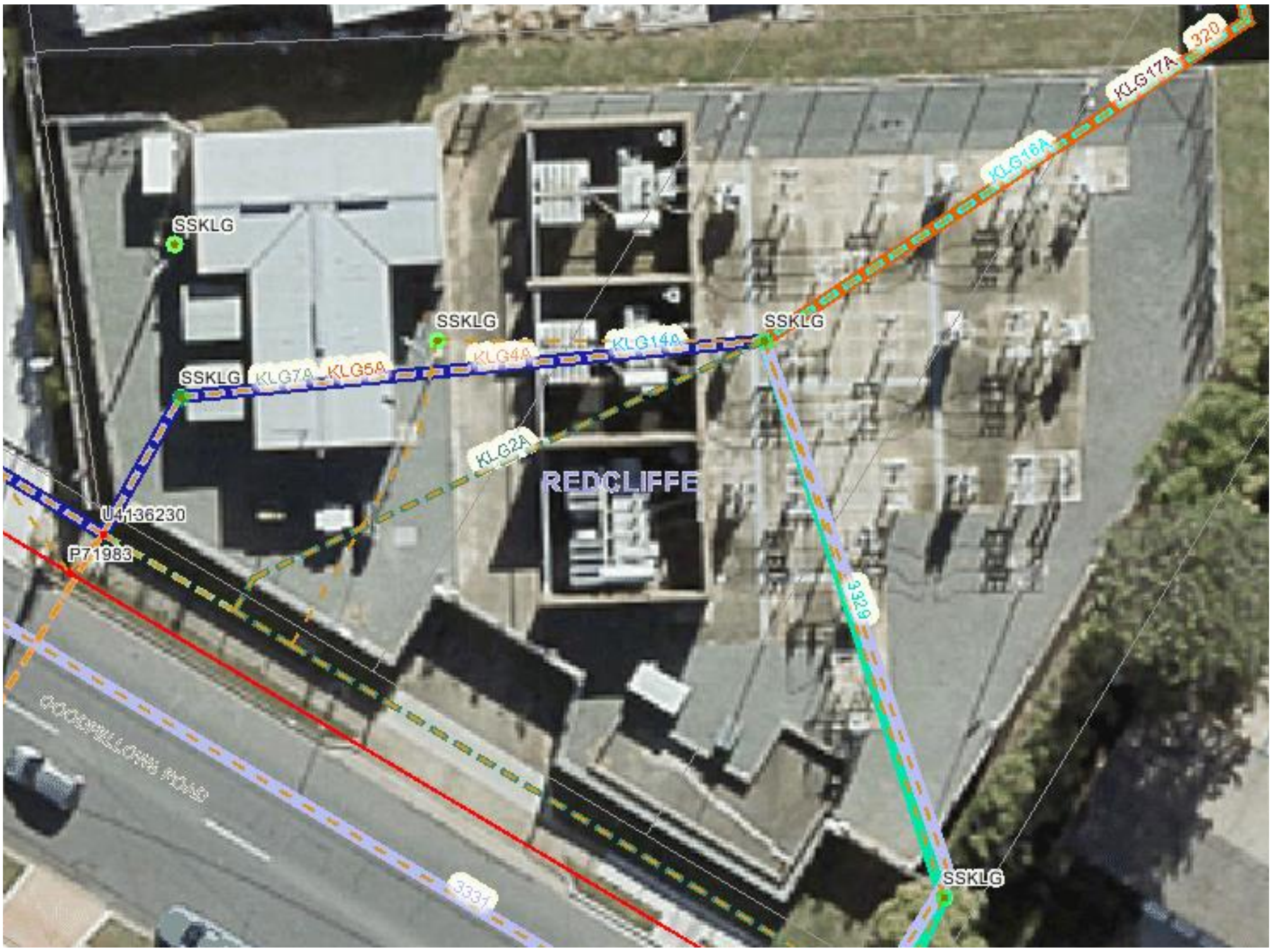


Figure 4: Kallangur Substation (geographic view)

2.3. Load Profiles / Forecasts

The load at Kallangur Substation comprises a mix of residential and commercial/industrial customers. The load is summer peaking, and the growth in annual peak loads are predominantly driven by new development in the supply area.

2.3.1. Full Annual Load Profile

The full annual load profile for Kallangur Substation over the 2019/20 financial year is shown in Figure 5. It can be noted that the peak load occurs during summer.

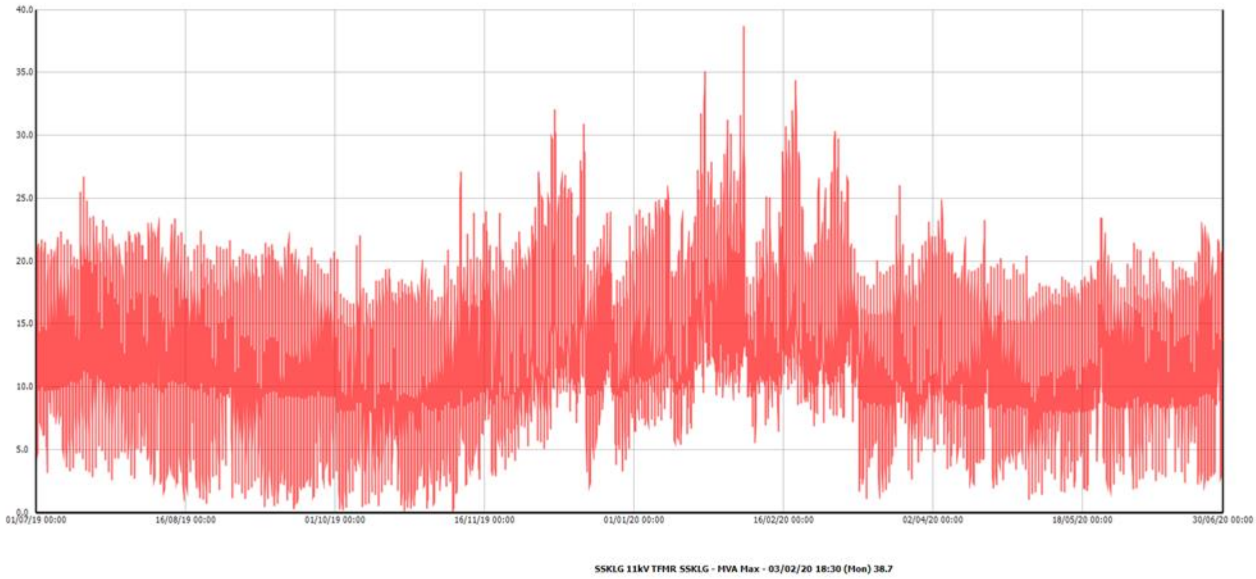
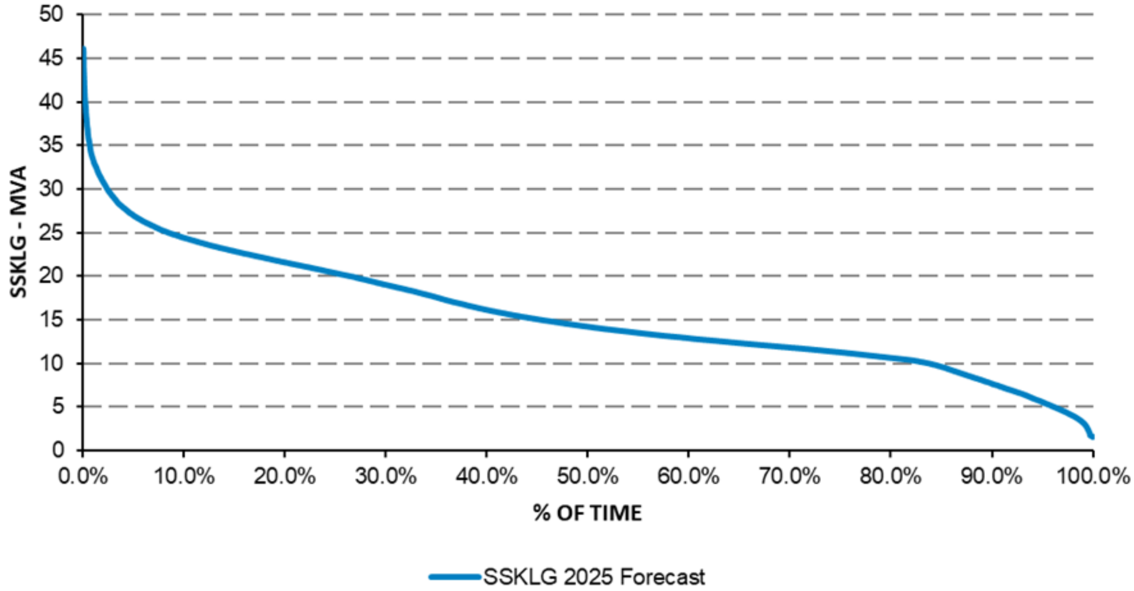


Figure 5: Substation actual annual load profile

2.3.2. Load Duration Curve

Figure 6 shows the load duration curves for SSKLG under System Normal (N) and System Abnormal (N-1). These are based on the previous 3 years of data and are scaled to their respective maximum 10% Probability of Exceedance (10PoE) and 50% Probability of Exceedance (50PoE) forecasts.



*The values for SSKLG have been scaled to the 2025 peak forecast load of 46.1MVA. 2025 is the year the identified need first appears at SSKLG.

Figure 6: Substation load duration curve

3. IDENTIFIED NEED

3.1. Applied Service Standard

Under its Distribution Authority, Energex must adhere to the Safety Net which identifies the principles that apply to the operation of network assets under network contingency conditions. System contingency related capability is assessed against a 50% probability of exceedance (PoE) forecast load, available load transfers, emergency cyclic capacity (ECC) ratings, non-network response, mobile plant, mobile generators, and short-term ratings of plant and equipment where available. This process allows LAR under contingency conditions to be identified and assessed. Energex's Distribution Authority can be accessed by the following link:

https://www.dnrme.qld.gov.au/__data/assets/pdf_file/0003/219486/distribution-authority-d0798-energex.pdf

As per the Energex Safety Net criteria, for substations supplying urban load, during a single contingency event, interruption of supply up to 40MVA is permissible for the first 30 minutes, followed by a maximum interruption of up to 12MVA, provided that all load except for up to 4MVA can be restored within 3 hours, and the remaining 4MVA is fully restored within 8 hours. Table 3 below outlines the Safety Net criteria.

Category	Demand Range	Allowed Outage to be OK
Urban	> 40MVA	No outage OK
	12-40MVA	30 minutes OK
	4-12MVA	3 hours OK
	< 4MVA	8 hours OK

Table 3: Summary of Safety Net Criteria

Further to an assessment against its Safety Net obligations, Energex also undertake analysis of system capacity under normal conditions with all plant in service against the 10 PoE load. The total capacity of the substation or the system NCC limit with all assets in service, shall not be exceeded to avoid reducing its designed life.

3.2. Description of the Identified Need

3.2.1. Safety Net Non-Compliance

The existing supply to the Kallangur and Petrie areas do not meet the Safety Net for an unplanned outage of a transformer at SSKLG as well as under System Normal. The following section outlines the substation limitations of the existing network. The system normal condition is assessed against the 10%PoE load forecast for SSKLG. The 50%POE load forecast is used for N-1 contingency analysis.

3.3. Quantification of the Identified Need

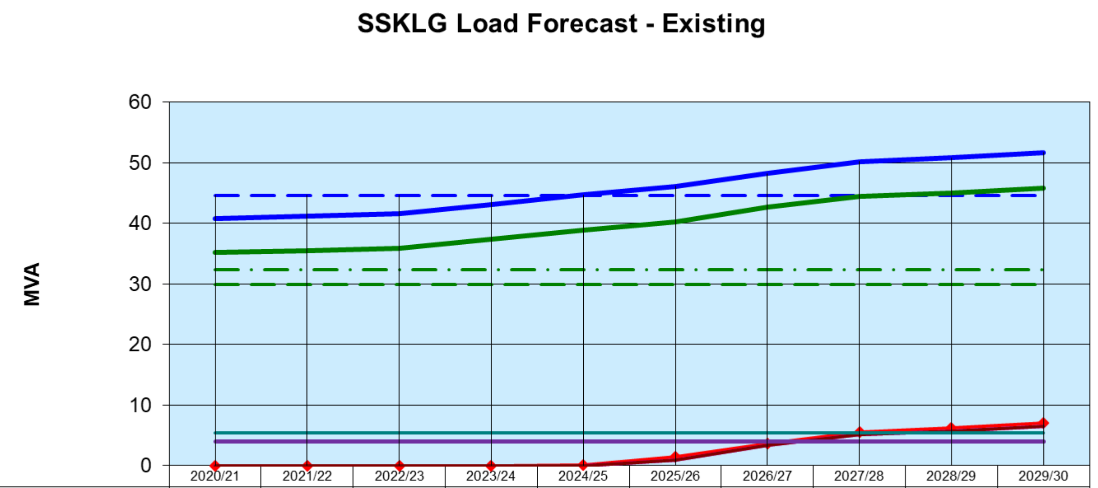
3.3.1. Safety Net Non-Compliance

SSKLG Limitations

SSKLG is equipped with one 25MVA 33/11kV transformer and two 10/12.5MVA 33/11kV transformers. The substation capacity is limited by the transformers and provides an NCC, ECC and 2 Hour Emergency Capacity as below:

- Normal Cyclic Capacity – 44.6MVA
- Emergency Cyclic Capacity – 29.9MVA
- 2 Hour Emergency Capacity – 32.3MVA

Figure 7 shows the limitations at SSKLG.

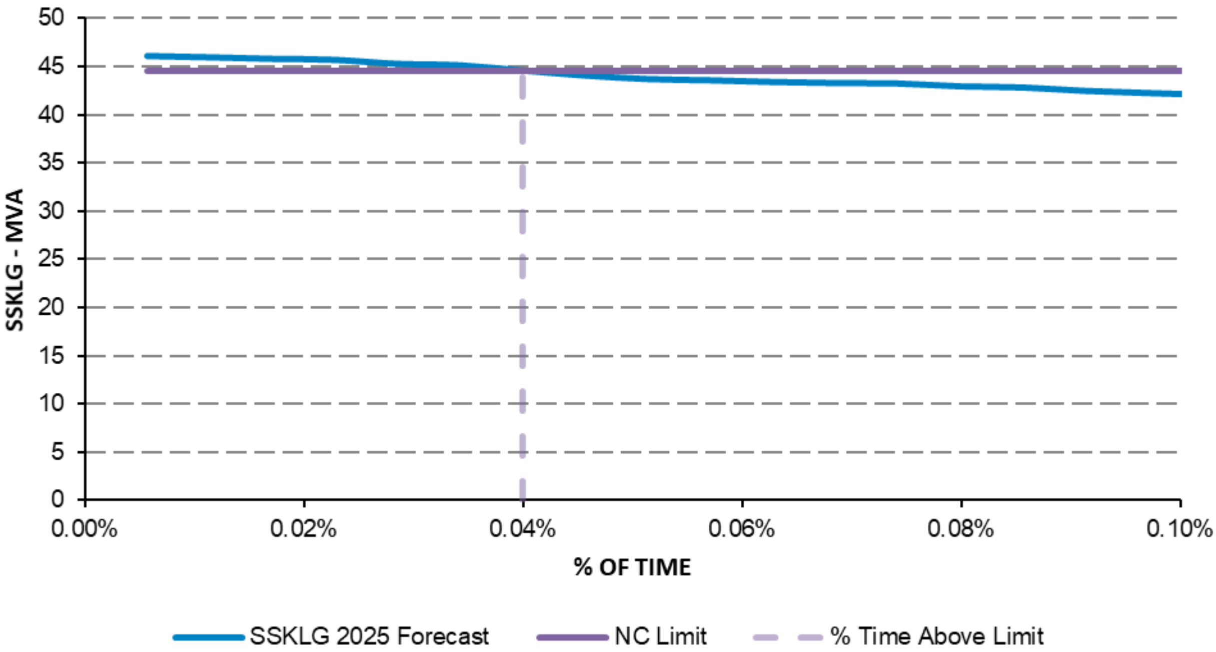


	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
10 PoE Load	40.79	41.16	41.61	43.16	44.67	46.13	48.26	50.18	50.84	51.70
Summer NCC	44.60	44.60	44.60	44.60	44.60	44.60	44.60	44.60	44.60	44.60
Load > NCC	0.00	0.00	0.00	0.00	0.07	1.53	3.66	5.58	6.24	7.10
50 PoE Load	35.18	35.50	35.88	37.40	38.87	40.27	42.67	44.48	45.06	45.80
Summer ECC	29.90	29.90	29.90	29.90	29.90	29.90	29.90	29.90	29.90	29.90
Summer 2HEC	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30	32.30
LAR	0.00	0.00	0.00	0.00	0.00	0.97	3.37	5.18	5.76	6.50
RLAR	0.00	0.00	0.00	0.00	0.00	0.97	3.37	5.18	5.76	6.50
Available Transfers	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40	5.40
Avail Mobile Eqpt	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00

Figure 7: SSKLG Load at Risk

Figure 7 illustrates that there is an NCC LAR limitation with the existing transformers at SSKLG from 2025/26. There is also Safety Net limitation for an outage of a transformer at SSKLG from 2025/26.

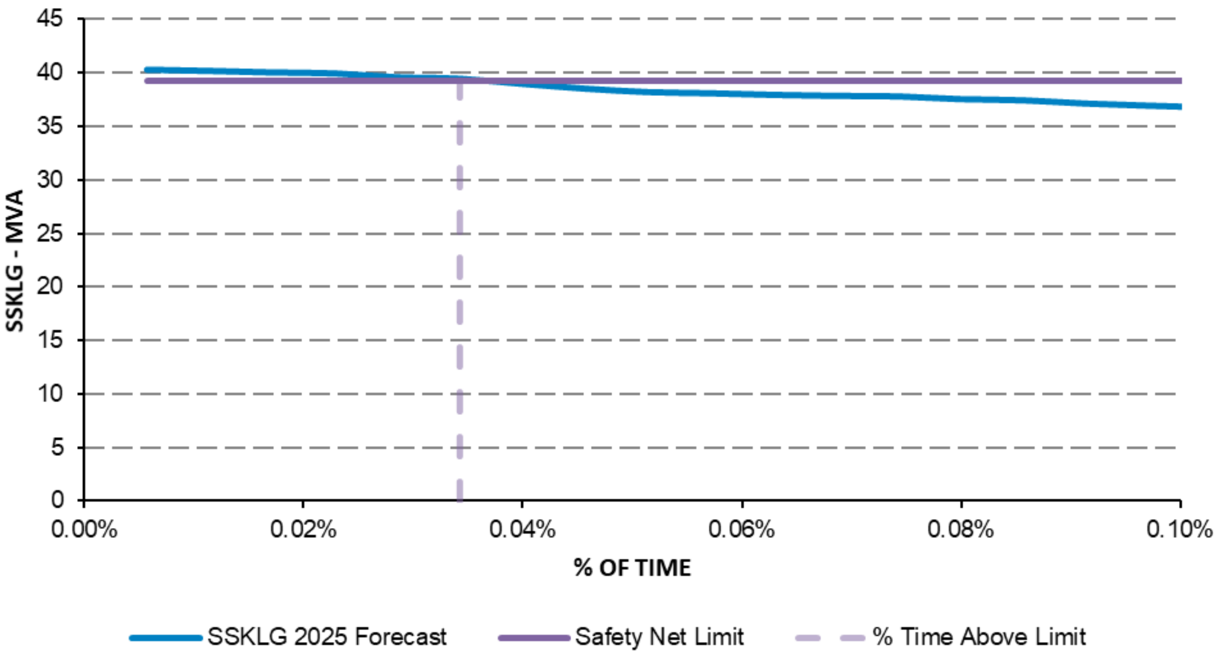
SSKLG can supply up to 44.6 MVA with all three transformers in service under system normal. Under system N-1 where one transformer has an outage, SSKLG can supply up to 39.9 MVA of load, incorporating 5.4 MVA of available load transfers and 4 MVA of mobile generation, to meet Energex's Safety Net obligation. Figure 8 and Figure 9 show the portion of the load duration curve for the 10% POE and 50% POE forecast 11kV load of SSKLG and the available capacity at SSKLG respectively.



*The values for SSKLG have been scaled to the 2025 peak forecast load of 46.1 MVA.

Figure 8: Load Duration Curve SSKLG in 2025 with NCC Limit

Figure 8 shows that approximately 0.04% of the time in 2025/26 the 10% PoE load is forecast to be above the 44.6MVA limit.



*The values for SSKLG have been scaled to the 2025 peak forecast load of 40.3 MVA.

Figure 9: Load Duration Curve SSKLG in 2025 with Safety Net Limit

Figure 9 shows that approximately 0.03% of the time in 2025/26 the 50% PoE load is forecast to be above the 39.3 MVA limit.

Figure 10 and Figure 11 show that as the load increases each year, the limit is surpassed for a longer duration per year for 10% POE against system normal capacity and 50% PoE load forecast against N-1 contingency capacity respectively. For ease of presentation, only every second year is shown.

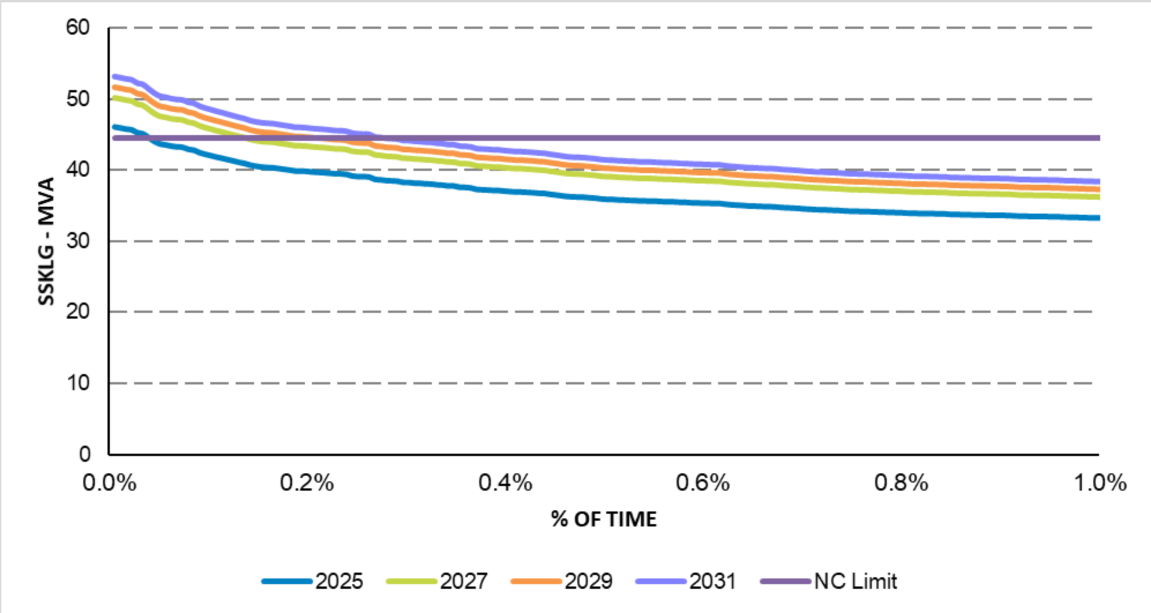


Figure 10: Load Duration Curve for 2025 – 2031 (10% POE load)

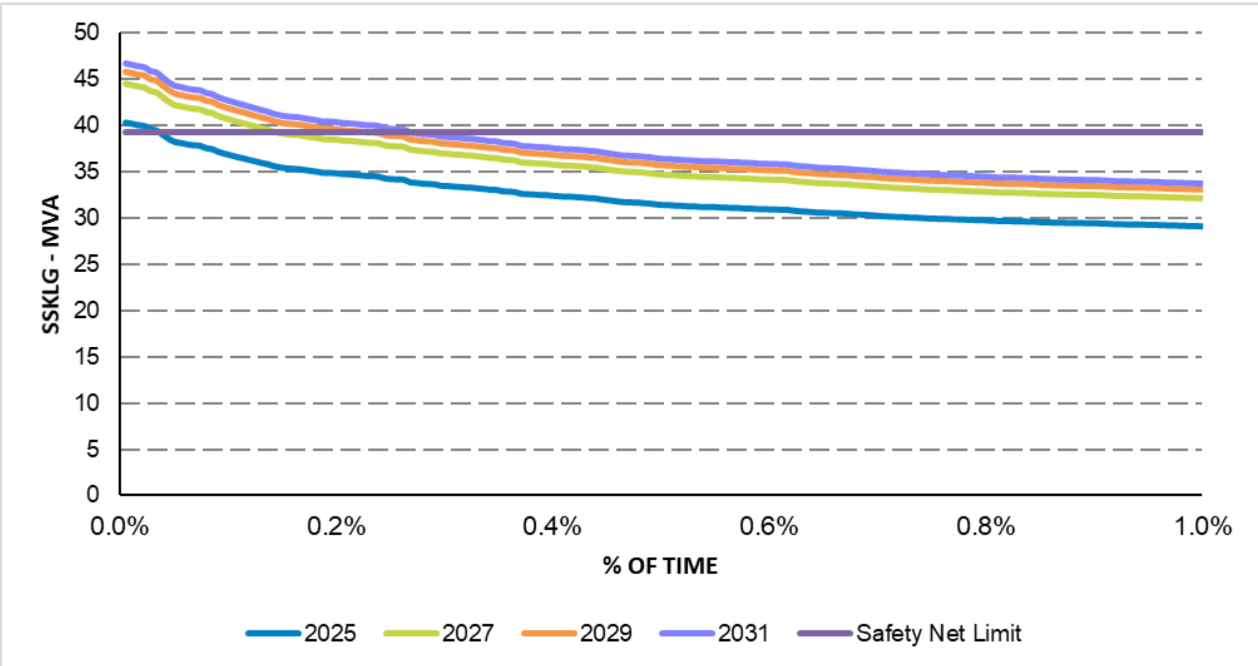


Figure 11: Load Duration Curve for 2025 – 2031 (50% POE load)

Figure 10 and Figure 11 above show that the duration in which the load is at risk rises from 0.04% to 0.3% from 2025 to 2031.

3.4. Assumptions in Relation to Identified Need

Below is a summary of key assumptions that have been made when the identified need has been analysed and quantified.

It is recognised that the below assumptions may prove to have various levels of correctness, and they merely represent a 'best endeavours' approach to predict the future identified need.

3.4.1. Forecast Maximum Demand

It has been assumed that forecast peak demand at SSKLG Substation will be consistent with the base case forecast outlined in Section 3.3.1.

Please refer to Section 5 (Network Forecasting) of the latest Energex DAPR publication for in-depth details regarding the methods and assumptions behind Energex's demand forecasts.

3.4.2. Load Profile

Characteristic peak day load profiles are unlikely to change significantly from year to year and the shape of the load profile is assumed to remain virtually the same with increasing maximum demand.

4. CREDIBLE OPTIONS ASSESSED

4.1. Assessment of Network Solutions

Energex has identified two credible network options that will address the identified need.

4.1.1. Option 1: Establish a new 33/11kV zone substation at Petrie

This option involves establishing a new zone substation at Petrie in October 2025, including:

- Establish a single 25 MVA modular substation or equivalent
- Establish 500m of 33kV double circuit OH from existing SSAPM to the new Petrie substation site
- Establish 250m of 33kV DCCT UG feeder tails into the new Petrie substation
- Establish new 11kV feeder tails from new Petrie substation
- Estimated capital cost: $17.6 million ± 40%
- Estimated operating cost per annum: $40,418

A schematic diagram of the proposed network arrangement for Option 1 is shown in Figure 12.

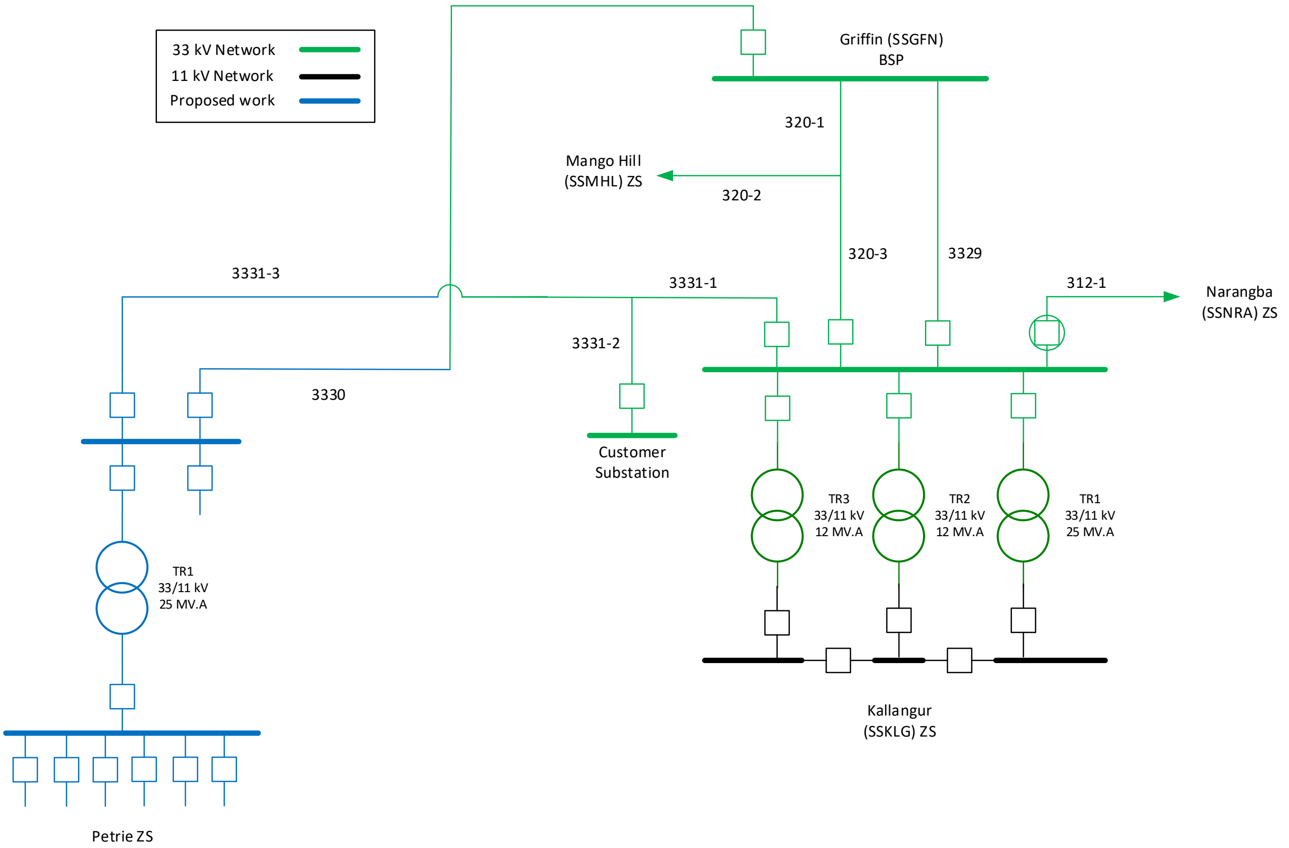


Figure 12: Option 1 proposed network arrangement (schematic view)

4.1.2. Option 2: Replace existing transformers TR2 and TR3 at SSKLG with two 25MVA transformers.

This option replaces the existing 2x33/11kV transformers TR2 and TR3 with two 25MVA transformers. This includes:

- Recover and scrap the existing 33/11kV transformers TR2 and TR3
- Establish foundation for new 33/11kV transformers and NEXs and install two new 25MVA 33/11kV transformers
- Establish a new 11kV feeder at SSKLG in 2026
- Estimated cost: $7.5 million ± 40%
- Estimated operating cost per annum: $4,032

A schematic diagram with the proposed network arrangement for Option 2 is shown in Figure 13.

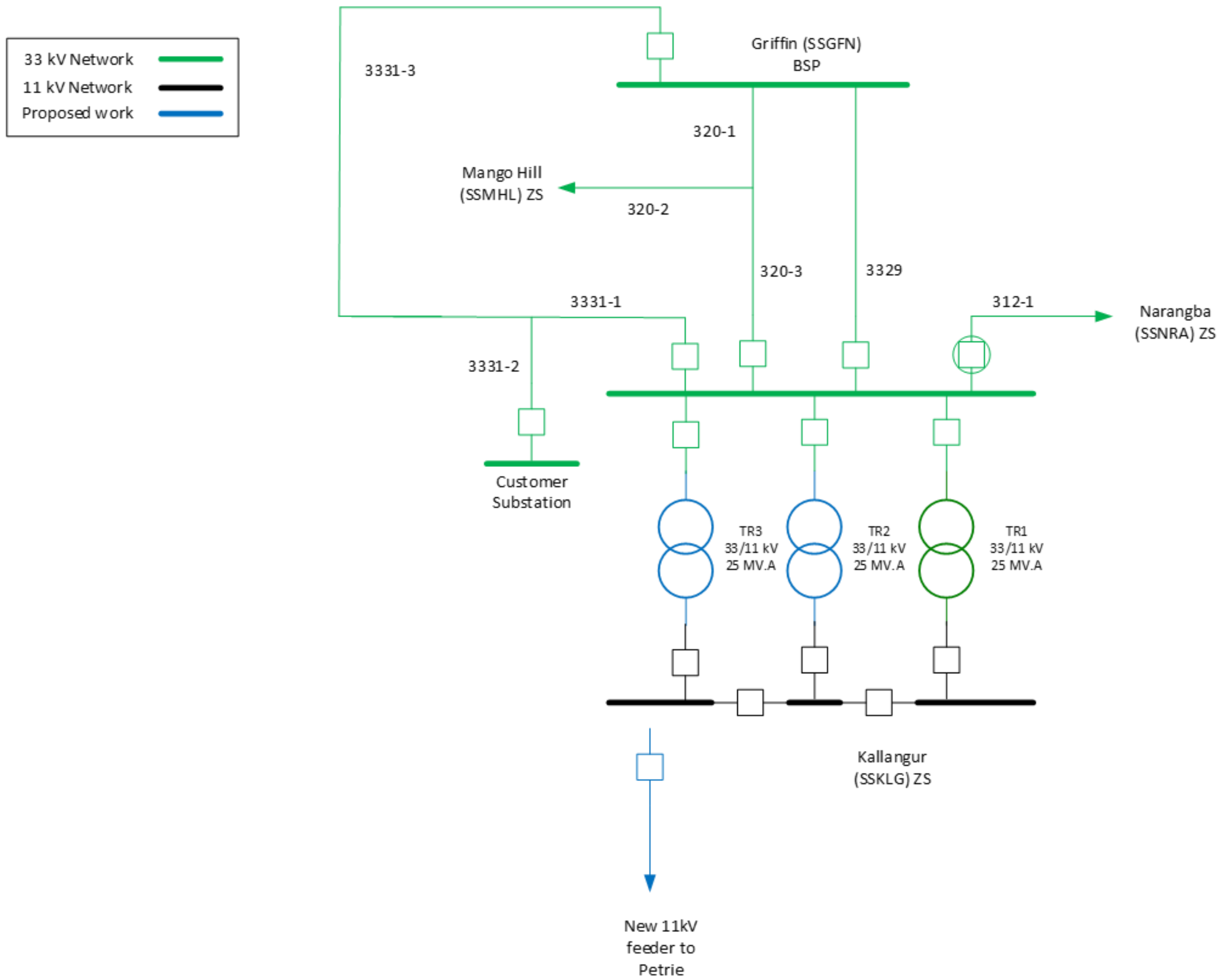


Figure 13: Option 2 proposed network arrangement (schematic view)

4.2. Preferred Network Option

Energex's preferred internal network option is Option 1. The scope of the preferred network option includes:

- Establish new single transformer 33/11kV 25MVA modular substation or equivalent
- Establish 2 x 33kV feeders to supply the new substation

The preferred network option has an estimated initial capital project cost of $17.6M, and an annual operating cost of approximately $40,418. The project is currently forecast for completion by October 2025.

5. SUMMARY OF SUBMISSIONS RECEIVED

On 8 February 2021, Energex published the Non-Network Options Report (NNOR) providing details on the identified need at Kallangur Substation.

In response to the NNOR, Energex received three submissions. In assessing these submissions, Energex has identified one credible option as detailed in 5.1.1.

On 14 June 2021, Energex published the DPAR providing details on the identified need at Kallangur Substation. This report provided both technical and economic information about possible solutions and sought information from interested parties about possible alternate solutions to address the need for investment.

In response to the DPAR, Energex received no submissions by 9 August 2021, which was the closing date for submissions to the DPAR.

5.1.1. Option 3: Contract a 10MW/40MWh Battery Energy Storage Solution (BESS)

This option involves contracting a proponent to provide a 10MW/40MWh BESS for a 10 years period to eliminate the load at risk in the vicinity of SSKLG in 2025. The BESS will be fully charged and ready to provide peak load relief and provide backup supply to the substation for a transformer outage.

6. MARKET BENEFIT ASSESSMENT METHODOLOGY

The identified need outlined in the FPAR is a regulatory obligation to address the substation limitation as outlined in the Distribution Authority. Because of this, the assessment methodology is a lowest cost process, rather than a cost/benefit analysis based on market benefits. There is no material difference in specific market benefits, such as Value of Customer Reliability between identified Network and Non-Network Options. As such, no Market Benefits have been calculated for use in the economic analysis to identify the preferred option.

7. DETAILED ECONOMIC ASSESSMENT

7.1. Methodology

The Regulatory Investment Test for Distribution requires Energex to identify the credible option that maximises the present value of net economic benefit to all who produce, consume and transport electricity in the National Electricity Market.

For the identified need presented in this FPAR, a Weighted Average NPV, based on a sensitivity analysis, was conducted to establish the option that remained the lowest cost option in the scenarios considered. In effect, this means that Energex create a separate NPV for each scenario and assign a weighting to each, with the outcome a Weighted Average NPV to inform the lowest cost option in a range of scenarios to proceed with.

7.2. Key Variables and Assumptions

7.2.1. Discount Rate

Calculations for annual deferral values of projects are based on Energex's regulated pre-tax real Weighted Average Cost of Capital (WACC). This value is prescribed by the AER for a specific regulatory control period. The identified need described in this FPAR occurs in the 2020-2025 regulatory control period, where the WACC is 2.62%.

7.2.2. Cost Estimates

Project costs are calculated using standard estimate components which are developed and evaluated by estimation teams in Energex. The costs are split into 2 components: direct cost, which is the costs which are directly costed to the project; and indirect costs which cover overheads associated with the business. All costs provided in this report are estimated to fall within ± 40% accuracy of the stated cost.

7.2.3. Evaluation Test Period

Consideration of network options is assessed over an evaluation period of 60 years.

7.3. Scenarios Adopted for Sensitivity Testing

A sensitivity analysis was conducted on the base case to establish the option that remained the lowest cost option in the scenarios considered. In this instance, the scenarios that have been considered are:

1. **Medium demand** – under this scenario the existing load remains around the same as it currently is. This is consistent with the base case load forecast provided in Substation Investment Forecast Tool (SIFT). This scenario has been assigned a likelihood of 70% in the weighted average NPV.
2. **High demand** – under this scenario the only change from the Medium Growth scenario is that the high growth load forecast provided from SIFT has been used. This scenario has been assigned a likelihood of 30% in the weighted average NPV.

Low demand was not considered because the staging of projects and VCR benefit would be very similar to that of the Medium demand scenario.

7.4. Net Present Value (NPV) Results

Table 4 shows the Weighted Average NPV results for the identified options. The NPV cost results have been withheld for Option 3 as it is based on the submission to the NNOR that was received, which Energex and the proponent considers to be Commercial-in-Confidence. This option has been included for completeness, even though it was not re-submitted as part of the DPAR consultation.

Option	Option Name	Rank	Initial Capital Cost	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Establish a new 33/11kV zone substation Petrie	1	$17,599,089	-$23,586,000	-$22,359,000	-$1,228,000
2	Replace existing transformers TR2 and TR3 at SSKLG with two 25MVA transformers	2	$7,500,884	-$23,797,000	-$22,677,000	-$1,120,000
3	Install 10MW Battery	3	Withheld	Withheld	Withheld	Withheld

Table 4: Weighted Average NPV Results

Option 1 is the lowest cost option in the weighted average NPV results. Based on the detailed economic assessment, Option 1 is considered to provide the optimum solution to address the forecast limitations and is therefore the recommended development option.

8. CONCLUSION

The FPAR represents the final stage of the consultation process in relation to the application of the RIT-D.

Energex intends to take steps to progress the proposed preferred option to ensure any statutory non-compliance is addressed and undertake appropriately justified network reliability improvements, as necessary.

8.1. Preferred Option

Energex's preferred option is Option 1, to establish a single 25MVA 33/11kV Petrie modular substation in October 2025. The scope of work and estimated capital cost and operating cost of this option are as below:

- Establish a single 25MVA modular substation or equivalent
- Establish 500m of 33kV double circuit OH from existing SSAPM to the new Petrie substation site
- Establish 250m of 33kV DCCT UG feeder tails into the new Petrie substation
- Establish new 11kV feeder tails from new Petrie substation
- Estimated capital cost: $17.6 million ± 40%
- Estimated operating cost per annum: $40,418

8.2. Satisfaction of RIT-D

The proposed preferred option satisfies the RIT-D.

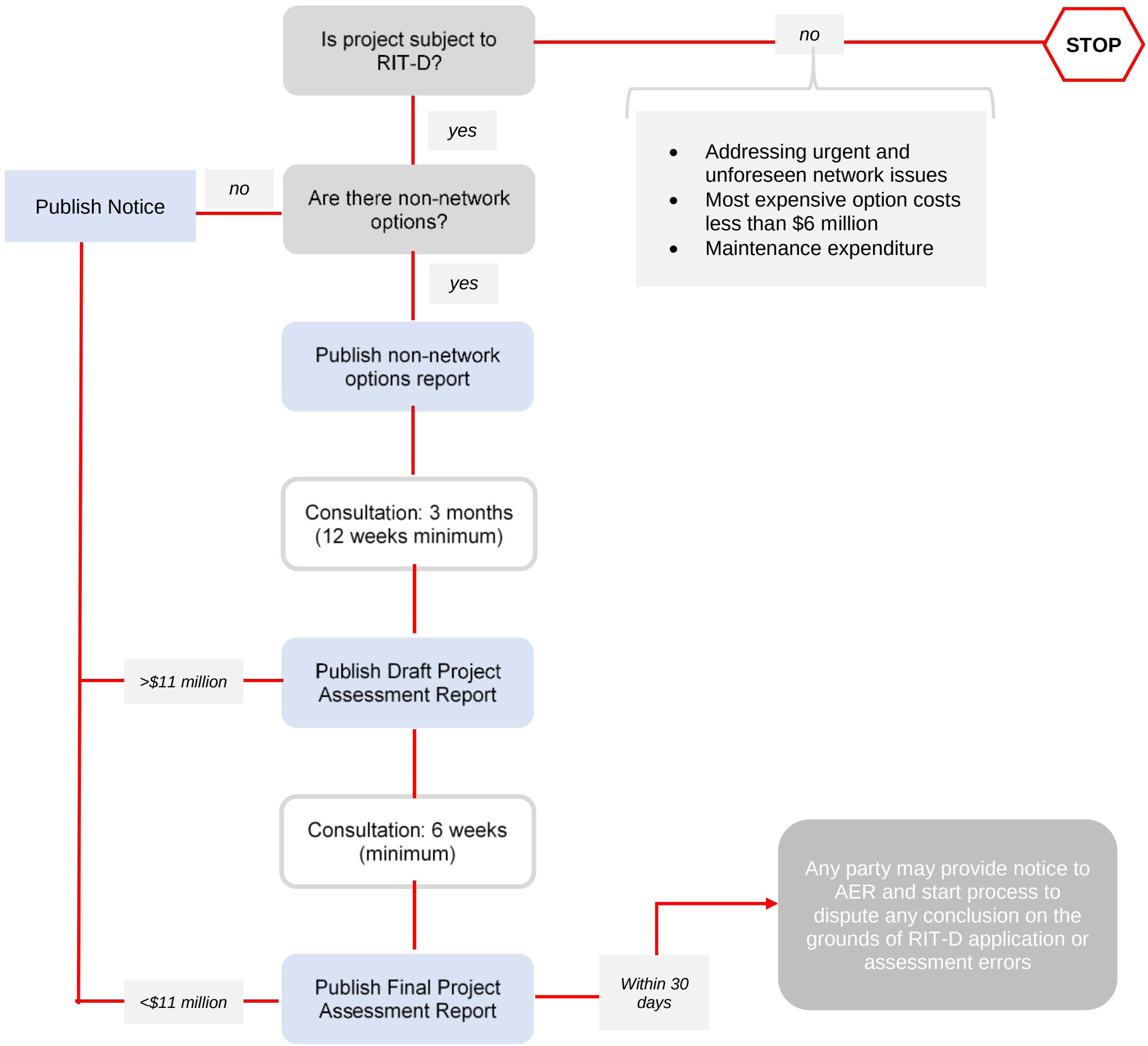
This statement is made on the basis of the detailed analysis set out in this report. The proposed preferred option is the credible option that has the highest net economic benefit under the most likely reasonable scenarios.

9. COMPLIANCE STATEMENT

This FPAR complies with the requirements of NER section 5.17.4(j) as demonstrated below:

Requirement	Report Section
(1) a description of the identified need for investment;	3
(2) the assumptions used in identifying the identified need (including, in the case of proposed reliability corrective action, why the RIT-D proponent considers reliability corrective action is necessary;	3.4
(3) if applicable, a summary of, and commentary on, the submissions received on the DPAR;	5
(4) a description of each credible option assessed	4
(5) where a *Distribution Network Service Provider* has quantified market benefits in accordance with clause 5.17.1(d), a quantification of each applicable market benefit of each credible option	6
(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	4
(7) a detailed description of the methodologies used in quantifying each class of costs or market benefit	6
(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	6
(9) the results of a NPV analysis of each credible option and accompanying explanatory statements regarding the results	7.4
(10) the identification of the proposed preferred option	8.1
(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of the technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (ii) the indicative capital and operating costs (where relevant); (iv) a statement and accompanying analysis that the proposed preferred option satisfied the RIT-D; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	8.1 & 8.2
(12) contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the final report may be directed.	1.4

APPENDIX A – THE RIT-D PROCESS



Source: AEMC, *Rule determination: National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, July 2017, p. 64.

APPENDIX B – GLOSSARY OF TERMS

Term	Definition
Peak Risk Period	The time period over which the load is highest (Day/Night).
NCC Rating (MVA)	Normal Cyclic Capacity – the total capacity with all network components and equipment in service. The maximum permissible peak daily loading for a given load cycle that plant can supply each day of its life. Taking impedance mismatch into consideration, it is considered the maximum rating for a transformer to be loaded under normal load conditions.
10 PoE Load (MVA)	Peak load forecast with 10% probability of being exceeded (one in every 10 years will be exceeded). Based on normal expected growth rates & weather corrected starting loads.
LARn (MVA)	Security standard load at risk under system normal condition, expressed in MVA.
LARn (MW)	Security standard load at risk under system normal condition, expressed in MW.
Power Factor at Peak Load	Compensated power factor at 50 PoE Load. Capacitive compensation is switched according to the size of the capacitor banks installed at the substation, compensation is generally limited to prevent a substation from going into leading power factor.
ECC Rating (MVA)	Emergency Cyclic Capacity – the long term firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply for an extended period of time without unacceptable damage. For substations with multiple transformers, the ECC is the minimum emergency cyclic capacity of all transformer combinations taking impedance mismatches into consideration, with one transformer off-line.
50 PoE Load (MVA)	Peak load forecast with 50% probability of being exceeded (one in every two years will be exceeded). Based on normal expected growth rates and weather corrected starting loads.
Raw LAR (MVA)	The amount of load exceeding ECC rating. (50 PoE Load – ECC Rating)
2-Hour Rating (MVA)	Two-Hour Emergency Capacity (2HEC) – the short term or firm delivery capacity under a single contingent condition. The maximum permissible peak emergency loading for a given load cycle that an item of plant can supply up to two hours without causing unacceptable damage. For substations with multiple transformers, the 2HEC is the minimum two hour emergency rating of all transformer combinations taking impedance mismatches into consideration, with one transformer off line.

Term	Definition
Auto Trans Avail (MVA)	SCADA or automatically controlled load transfers that can be implemented within one minute.
Remote Trans Avail (MVA)	Load transfers that can be implemented through SCADA switching procedures by the network control officer. It is assumed that this can generally be achieved within 30 minutes excluding complex or time –consuming restoration procedures.
Manual Trans Avail (MVA)	Load transfers can also be deployed via manually controlled switchgear locally by field staff. It is assumed that the implementation of manual switching procedures to isolate the faulted portion of the network to restore supply to healthy parts of the network can be fully implemented within three hours (urban) or four hours (rural). Manual transfers are obtained from load flow studies performed on each 11kV distribution feeder based on the forecast 2016/17 load, the sum of all available 11kV transfers at a substation is multiplied by a 0.75 factor to account for diversity and to provide a margin of error to avoid voltage collapse. The same approach applies throughout the forward planning period.
LARc (MVA)	Security standard load at risk for single contingent conditions.
LARc (MW)	Estimated generation / load reduction required to defer the forecast system limitation. This is the security standard load at risk for a single contingency, expressed in MW.
Customer Category	For security standard application, the general type of customer a substation or feeder supplying the area.

APPENDIX C – NPV DETAILS

Component Title Selection	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3
Establish Petrie 382 sub	2025	2044	2035
KLG Replace 1 x Transformers and 3 x 33kV CBs	2029		2029
KLG Replace 2 x Transformers		2025	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load		2039	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load		2033	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load		2026	
Establish 1 x Transformer at Petrie	2036		2036
KLG Replace 3 x 33kV CBs		2031	
10MW Battery			2025

Table 5: Project Staging for the Medium Demand Scenario

Option	Option Name	Rank	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Establish a new 33/11kV zone substation Petrie	2	-$23,069,751	-$21,868,794	-$1,200,957
2	Replace existing transformers TR2 and TR3 at SSKLG with two 25MVA transformers	1	-$22,339,298	-$21,312,699	-$1,026,600
3	Install 10MW Battery	3	Withheld	Withheld	Withheld

Table 6: NPV Results for Medium Demand Scenario

Component Title Selection	Recovery Date	Recovery Value $ Real	Stage Timing Option 1	Stage Timing Option 2	Stage Timing Option 3
Establish Petrie 382 sub			2023	2034	2030
KLG Replace 1 x Transformers and 3 x 33kV CBs			2027		2027
KLG Replace 2 x Transformers				2023	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load				2032	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load				2028	
KLG Establish new 11kV feeder (100% UG cable) to supply Petrie load				2026	
Establish 1 x Transformer at Petrie			2030		2030
KLG Replace 3 x 33kV CBs				2031	
10MW Battery					2023

Table 7: Project Staging for the High Demand Scenario

Option	Option Name	Rank	Net Economic Benefit ($ real)	PV of Capex ($ real)	PV of Opex ($ real)
1	Establish a new 33/11kV zone substation Petrie	1	-$24,792,230	-$23,502,013	-$1,290,217
2	Replace existing transformers TR2 and TR3 at SSKLG with two 25MVA transformers	2	-$27,197,738	-$25,860,128	-$1,337,609
3	Install 10MW Battery	3	Withheld	Withheld	Withheld

Table 8: NPV Results for High Demand Scenario