Business Case
Establish Modular Substation at Petrie

Executive Summary

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 to Queensland Railways (QR) Petrie (SSQRPE). SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas. The following risks have been identified for the study area:

- Normal Cyclic Capacity (NCC) rating at SSKLG is exceeded in 2025
- There will be a breach of the Safety Net Distribution Authority criteria at SSKLG for the loss of a single transformer at SSKLG from 2025.

The counterfactual, 'do nothing' option was considered but rejected. If the identified limitations are not addressed, the risks outlined above will not be resolved which is an unacceptable approach to risk management. Similarly, an option to transfer load from SSKLG to other adjoining substations such as SSMHL, SSLTN and SSNRA was also considered but rejected, as load growth in this area far exceeds the ability to deal with additional demand through new 11kV feeders or through transfers on existing 11kV feeders. Two options to address NCC exceedance and Safety Net criteria risks have been evaluated in this business case:

Option 1 – Establish a single 25MVA modular substation at Petrie. This is the recommended option.

Option 2 – Replace the existing transformers (TR) TR2 and TR3 at SSKLG with two 25MVA transformers. This option also involves adding a new 11kV feeder at SSKLG every 2 years.

Energex aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case regulatory obligations are a strong driver, due to the identified risks of breaching the NCC rating of the SSKLG substation and failing to meet the Safety Net criteria as load growth continues in the study area.

To this end, Option 1 is the preferred option, as it provides the most cost-effective means of mitigating the identified risks in the study area. The Net Present Value of this Option is -$14.0M, compared to -$18.8M for Option 2.

The direct cost of the program for each submission made to the AER is summarised in the table below. Note that all figures are expressed in 2018/19 dollars and apply only to costs incurred within the 2020-25 regulatory period for the preferred option.

Regulatory Proposal	Draft Determination Allowance	Revised Regulatory Proposal
$5.5M	$3.5M	$5.5M

As the project costs are estimated at greater than $5 million, a Regulatory Investment Test for Distribution (RIT-D) is required, as required by the Australian Energy Regulator (AER). The RIT-D will compare potential for a non-network or hybrid solution against the projected costs of the new feeder to determine the lowest cost solution.

Contents

1 Introduction

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 to Queensland Railways (QR) Petrie (SSQRPE). SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas. This is a high demand growth area in the rapidly growing Moreton Bay regional council area just north of Brisbane.

Due to anticipated increases in load in coming years, SSKLG has been identified as having both NCC and N-1 Safety Net breaches in coming years. This business case outlines the need for a regulatory investment test for distribution (RIT-D) investigating a new 33kV/11kV zone substation to supply the increasing demand in the area.

1.1 Purpose of document

This document recommends the optimal capital investment necessary to address both NCC and Safety Net Target limitations for SSKLG.

This is a preliminary business case document and has been developed for the purposes of seeking funding for the required investment in coordination with the Energex Revised Regulatory Proposal to the Australian Energy Regulator (AER) for the 2020-25 regulatory control period. Prior to investment, further detail will be assessed in accordance with the established Energy Queensland (EQL) investment governance processes. The costs presented are in $2018/19 direct dollars.

1.2 Scope of document

This document is the business case to establish a new 33/11kV zone substation at Petrie. The document will outline the need for this investment, any associated risks and benefits, options analysed, and the financial modelling completed.

1.3 Identified Need

Energex aims to minimise expenditure in order to keep pressure off customer prices, however understands that this must be balanced against critical network performance objectives. These include network risk mitigation (e.g. safety, bushfire), regulatory obligations (e.g. safety), customer reliability and security and preparing the network for the ongoing adoption of new technology by customers (e.g. solar PV). In this business case regulatory obligations are a strong driver, due to the identified risks of breaching the NCC rating of the SSKLG substation and failing to meet the Safety Net criteria as load growth continues in the study area.

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 to QR Petrie (SSQRPE). SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas.

Geographic and schematic views of the network area under study are provided in Figure 1 and Figure 2.

Figure 1: Existing sub-transmission Network Arrangement (Geographic View)

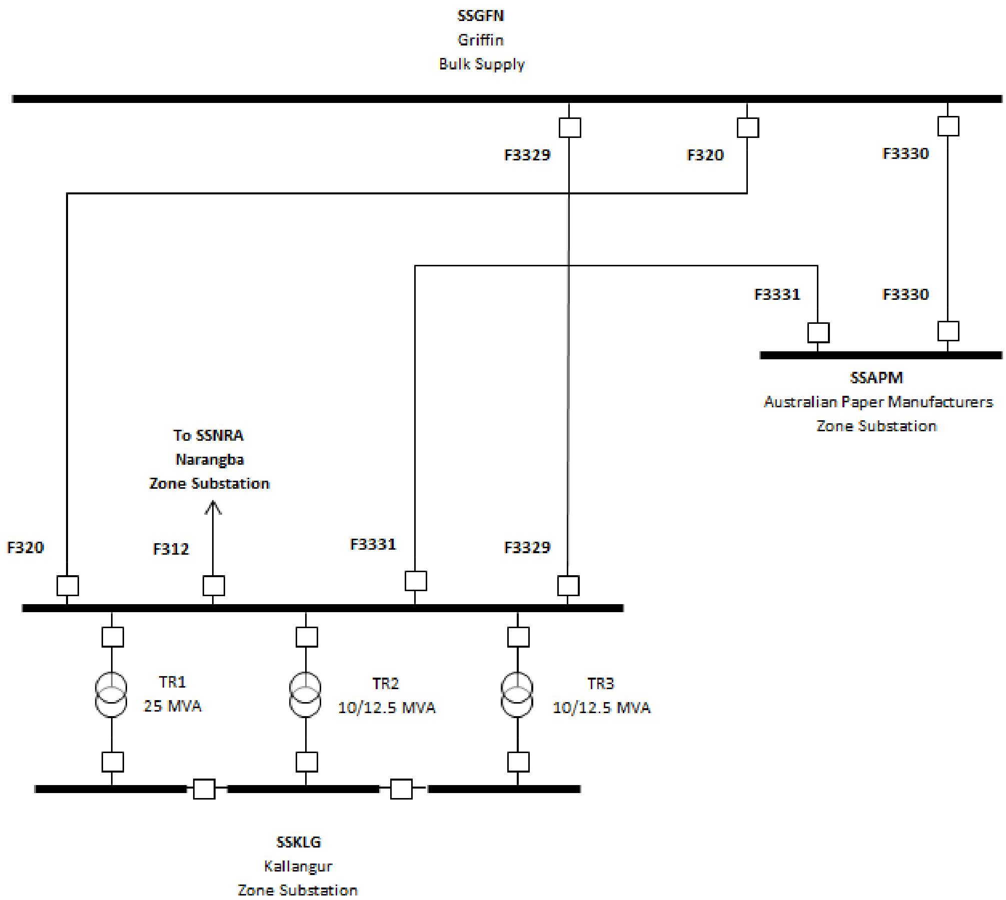

Figure 2: Existing Network Arrangement (Schematic View)

The Mill Moreton Bay Development

A future development site "The Mill at Moreton Bay" is a priority development area approximately 460 hectares in size and is located within the suburbs of Petrie, Kallangur, and Lawton. This site will consist of a number of different developments and load types including a new university, a new hospital, and mixed domestic and commercial precincts.

This development site includes land currently occupied by the existing Energex Australian Paper Mill (APM) zone substation (SSAPM), which is soon to be decommissioned. In exchange for relinquishing this land, Energex will be given a free parcel of land to use for constructing the expected future Petrie substation.

It is anticipated that The Mill at Moreton Bay development will add block loads totalling 11 MVA to the Kallangur distribution area over the coming ten years. These loads have been incorporated into the forward forecasts for the area. This proposal aligns with the CAPEX objectives and criteria from the National Electricity Rules as detailed in Appendix C.

1.4 Energy Queensland Strategic Alignment

Table 1 details how this proposal contributes to Energy Queensland's corporate and asset management objectives.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	This initiative contributes to meeting the Energex Safety Net, which aims to prevent outages exceeding 8 hours for significant customer demand to 'avoid unexpected customer hardship and/or significant community or economic disruption.' Increases in outage duration present unacceptable safety risk to staff, contractors, and the community.
Meet customer and stakeholder expectations	The initiative aims to minimise risk of increased outage duration for the customers and stakeholders supplied by the existing SSKLG zone substation.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	The initiative outlines the need for a RIT-D to be conducted, which would allow for a detailed business case to be developed to manage risk, performance standards, and asset investments.
Develop Asset Management capability & align practices to the global standard (ISO55000)	This business case is consistent with ISO55000 objectives and drives asset management capability by promoting a continuous improvement environment.
Modernise the network and facilitate access to innovative energy technologies	This initiative proposes to use current standard equipment which modernises and upgrades the existing network.

1.5 Applicable service levels

Corporate performance outcomes for this asset are rolled up into Asset Safety & Performance group objectives, principally the following Key Result Areas (KRA):

- Customer Index, relating to Customer satisfaction with respect to delivery of expected services
- Optimise investments to deliver affordable & sustainable asset solutions for our customers and communities

Under its Distribution Authority, Energex is expected to operate with an 'economic' customer value-based approach to reliability, with "Service Safety Net Targets" for extreme circumstances. These are intended to mitigate against the risk of low probability vs high consequence network outages. Safety Net targets are described in terms of the number of times a benchmark volume of energy is undelivered for more than a specific time period. Energex's Service Safety Net Targets are as set out in Appendix F.

Further, Energex is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types for the following measure:

- System Average Interruption Duration Index (SAIDI), and;
- System Average Interruption Frequency Index (SAIFI).

Both Safety Net and MSS performance information are publicly reported annually in the Distribution Annual Planning Reports (DAPR). MSS performance is monitored and reported within EQL daily.

The applicable safety net standard is shown in Appendix F and the table below is derived from the Safety net standard for clarity.

Table 2: Safety Net Standard – Urban Interpretation

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

1.6 Compliance obligations

Table 3 shows the relevant compliance obligations for this proposal.

Table 3: Compliance obligations related to this proposal

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
Distribution Authority for Ergon Energy or Energex issued under section 195 of *Electricity Act 1994* (Queensland)	Under its Distribution Authority: • The distribution entity must plan and develop its supply network in accordance with good electricity industry practice, having regard to the value that end users of electricity place on the quality and reliability of electricity services. • The distribution entity will ensure, to the extent reasonably practicable, that it achieves its safety net targets as specified. • The distribution entity must use all reasonable endeavours to ensure that it does not exceed in a financial year the Minimum Service Standards (MSS)	This proposal reduces the risk of Energex not meeting its Safety Net targets

1.7 Limitation of existing assets

Substation Limitations

Kallangur zone substation

SSKLG is equipped with one 25MVA 33/11kV transformer and two 10/12.5MVA 33/11kV transformers. The substation capacity is limited by the 11kV transformers and provides capacity parameters as shown below:

- Normal Cyclic Capacity (NCC) – 58.80 MVA
- Emergency Cyclic Capacity (ECC) – 30.0 MVA
- 2 Hour Emergency Capacity (2HEC) – 32.4 MVA

Table 4: SSKLG Load Forecast and Ratings

Substation	Year	10% Probability of Exceedance (POE) Load (MVA)	NCC (MVA)	NCC Load At Risk (LAR) (MVA)	50% POE Load (MVA)	ECC (MVA)	Safety Net LAR
SSKLG	2019	40.72	58.80	0.00	33.59	30.0	0.00**
	2020	41.03	58.80	0.00	33.85	30.0	0.00**
	2021	41.24	58.80	0.00	34.02	30.0	0.00**
	2022	41.37	58.80	0.00	34.13	30.0	0.00**
	2023	41.09	58.80	0.00	33.90	30.0	0.00**
	2024	42.79	58.80	0.00	35.99	30.0	0.00**
	2025	45.12	58.80	0.12*	38.31	30.0	1.40**
	2026	46.57	58.80	1.05*	39.71	30.0	2.80**
	2027	48.81	58.80	2.48*	41.58	30.0	4.67**
	2028	50.34	58.80	3.46*	43.01	30.0	6.10**

*After load sharing

**Assuming 5.91 MVA of remote transfers available, plus 1MVA of emergency generation

From Table 1, there will be two limitations:

- In 2025 there will be a system normal limitation at SSKLG (based on 10POE forecast and NCC).
- In 2025 there will also be a breach of the Safety Net at SSKLG (based on 50POE load and ECC) as all load cannot be restored within 8 hours.

Lawnton zone substation (SSLTN)

SSLTN is equipped with 1x12.5MVA 33/11kV transformer, 1x15MVA 33/11kV transformer, and 1x25MVA 33/11kV transformer. Details of the substation capacity and forecasts are shown in Appendix H.

There are currently no limitations with the existing equipment at SSLTN. It is important to note that very little transfer capacity exists at this substation as it is approaching its ECC limitation.

Mango Hill zone substation (SSMHL)

SSMHL is equipped with 2 x 25MVA transformers in a split bus arrangement and an auto-changeover scheme between the two transformers. Details of the substation capacity and forecasts are shown in Appendix H.

There is currently raw load at risk at SSMHL based on the failure of a transformer. No transfer capacity exists at this substation; hence no permanent transfers can be made from SSKLG to SSMHL.

Narangba zone substation (SSNRA)

SSNRA is equipped with 1 x 25 MVA 33/11kV transformer and 1 x 20 MVA 33/11kV transformer. Details of the substation capacity and forecasts are shown in Appendix H.

There are currently no limitations with the existing equipment at SSNRA. It is important to note that very little transfer capacity exists at this substation as it is approaching its ECC limitation.

Sub-Transmission Feeder Limitations

No 33kV feeder limitations have been identified in the area, other than the condition assessment and proposed replacement of a 2km section of F312.

Sub-Transmission Network Condition Limitations

Based on a Condition Based Risk Management (CBRM) analysis of the effect of current condition and ageing on the expected life of the 33/11kV transformers, isolators, relays and voltage transformers at SSKLG, the following limitations have been identified in the study area:

- 2km of 30/7/0.118 PANTHER on 33kV feeder between SSNRA and SSKLG will reach end of life in 2023.
- 33/11kV transformers (TR) TR2 and TR3 at SSKLG will reach their end of life in 2029.
- 33kV Circuit breakers (CB) CB3122, CB3202 and CB3392 at SSKLG will reach their end of life in 2025.
- 33kV Circuit breaker CB3T02 at SSAPM will reach end of life in 2025.

Further information on Energex's approach to condition assessment of plant can be found in Energex's suite of asset management plans for various asset classes.

11kV Load Shift Capability

SSKLG has 11kV tie feeders to SSNRA, SSMHL, and SSLTN. Currently there are significant constraints on permanently transferring load to these substations. There is around 3MVA of available load transfers from the existing SSKLG 11kV feeders that are in the area, however to transfer any more load without going over the target maximum utilisation, new 11kV feeders from SSKLG will be required. Further details of the transfer capacities are shown in Appendix H.

2 Counterfactual Analysis

2.1 Purpose of asset

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 to QR Petrie (SSQRPE). SSKLG provides electricity supply to approximately 14,025 predominantly domestic customers in the Kallangur, Kurwongbah, Petrie, Murrumba Downs, and Griffin areas. This area has significant demand growth and these assets are required for the ongoing secure and reliable supply to the area.

Based on the current assets at SSKLG and the demand forecast for the area, two limitations arise at SSKLG in the 2020-25 period. These are:

- In 2025 there will be a system normal limitation at SSKLG (based on 10POE forecast and NCC).
- In 2025 there will also be a breach of the Safety Net at SSKLG (based on 50POE load and ECC) as all load cannot be restored within 8 hours.

2.2 Business-as-usual service costs

The business as usual (BAU) service costs for these assets are the maintenance costs associated with ongoing operations. In addition to these costs, significant emergency response costs would be incurred for the counterfactual BAU case if failures occur.

2.3 Key assumptions

- The counterfactual is assumed as the BAU case where no augmentation works are completed.
- Demand is anticipated to increase in the SSKLG and surrounding areas due to growing local population, plus major developments in The Mill development.

2.4 Risk assessment

The following risks have been identified because of not addressing the identified limitations. These risks represent a Moderate and Low risk under the Energy Queensland Network Risk Framework, however Energex does not consider these risks to be as low as reasonably practicable (ALARP).

Table 5: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Forecast 10% PoE peak demand on SSKLG **exceeds substation NCC** by 2MV.A (1000 customers, < 3 hours) during Summer 2024/25.	Customer	3 *(5,000 customers for > 12 hours)*	3 *(Unlikely to occur)*	**9** ***(Low risk)***	2025
Without augmenting the network, Energex fails to meet the legislated Safety Net requirement as part of the Distribution Authority, resulting in the regulator being notified and a subsequent **improvement notice being issued**.	Legislative	4 *(Energex identified issue requiring regulator to be notified. Improvement notice issued.)*	3 *(Unlikely to occur)*	***12*** ***(Moderate risk)***	2024

Further Details of the risk ratings and descriptions can be found in Energy Queensland's Network Risk Framework.

2.5 Retirement or de-rating decision

Retirement or de-rating of any of these assets would result in the loss of supply to these customers, as no other substations feed into these locations with adequate capacity. Retirement or de-rating is therefore an unacceptable option.

3 Options Analysis

3.1 Options considered but rejected

Base Case (Counterfactual)

If the identified limitations are not addressed, the risks outlined above will not be resolved. Based on the current assets at SSKLG and the demand forecast for the area, two limitations arise at SSKLG in the 2020-25 period. These are:

- In 2025 there will be a breach of the Safety Net at SSKLG (based on 50POE load and ECC) as all load cannot be restored within 8 hours.
- In 2025 there will also be a system normal limitation at SSKLG (based on 10POE forecast and NCC).

As such, Energex considers that the counterfactual case is an unacceptable solution for the identified limitations.

11kV Solutions

The limitations identified in this planning report are at SSKLG for system normal demand and for N-1 transformer failure events. One potential solution for both limitations would be to transfer load from SSKLG to other adjoining substations such as SSMHL, SSLTN and SSNRA. While small load transfers are possible, this solution is not viable in the medium term due to the existing heavily loaded substations and heavily loaded 11kV feeders at all adjacent substations as shown above in Section 1.7. The other substations at SSMHL, SSLTN and SSNRA are currently at or near their system normal and N-1 safety net thresholds. Hence, the load growth in this area far exceeds the ability to deal with additional demand through new 11kV feeders or through transfers on existing 11kV feeders.

3.2 Identified options

3.2.1 Network options

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

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

- Establish a single 25 MVA modular substation.
- Decommission and recover existing site SSAPM.
- Establish 500m of temporary 33kV double circuit Overhead (OH) feeder from existing SSAPM to new Petrie substation site.
- Establish 250m of 33kV Double Circuit (DCT) Underground (UG) feeder tails into new Petrie modular substation.
- Establish five new 11kV feeder tails from new Petrie substation.

This has an estimated direct cost of $5.5M based on Energex's standard estimates which have been used for options analysis purposes and are accurate to +-50%. A schematic diagram of the proposed solution is shown in Figure 3 below.

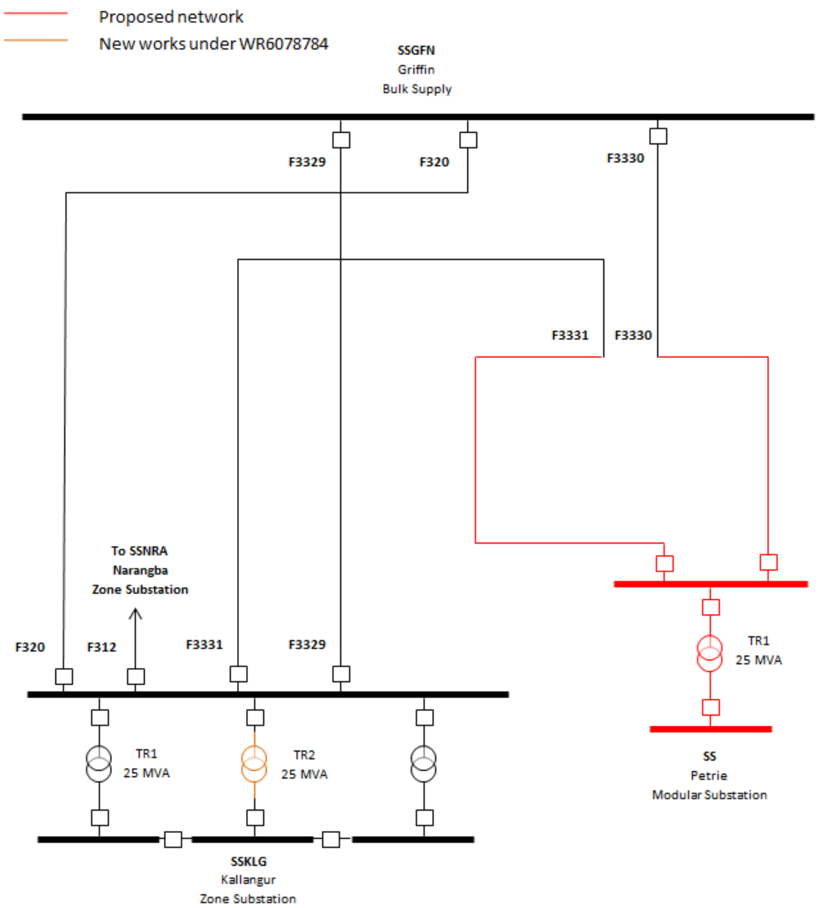

Figure 3: Proposed Network Arrangement under Option 1 (Schematic View)

Future Stages

2029 – Replace two 33/11kV 12.5 MVA transformers at SSKLG in 2029 with one 33/11kV 25MVA transformer due to age and condition. Under this option, only a single transformer upgrade is required due to the additional capacity provided through the establishment of Petrie zone substation. This work will be completed under a separate project.

2035 – Expand the capacity of Petrie Zone substation in 2035 by installing a second 33/11kV 25MVA transformer. This will be dependent on the load growth in the area. This work will be completed under a separate project.

Option 2: Replace existing transformers 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 Neutral Earthing Reactors (NEXs) and install two new 25MVA 33/11kV transformers. In this option two transformer upgrades are required due to the additional capacity required to supply the new developments, absent a new zone substation at Petrie.
- Add a new 11kV feeder at SSKLG every 2 to 3 years.
- Decommission and recover existing site SSAPM under a separate project.

This option would reduce the scope of works of planned project WR6078784 (see section 3 for details). Schematic diagrams are shown in Figure 4 below.

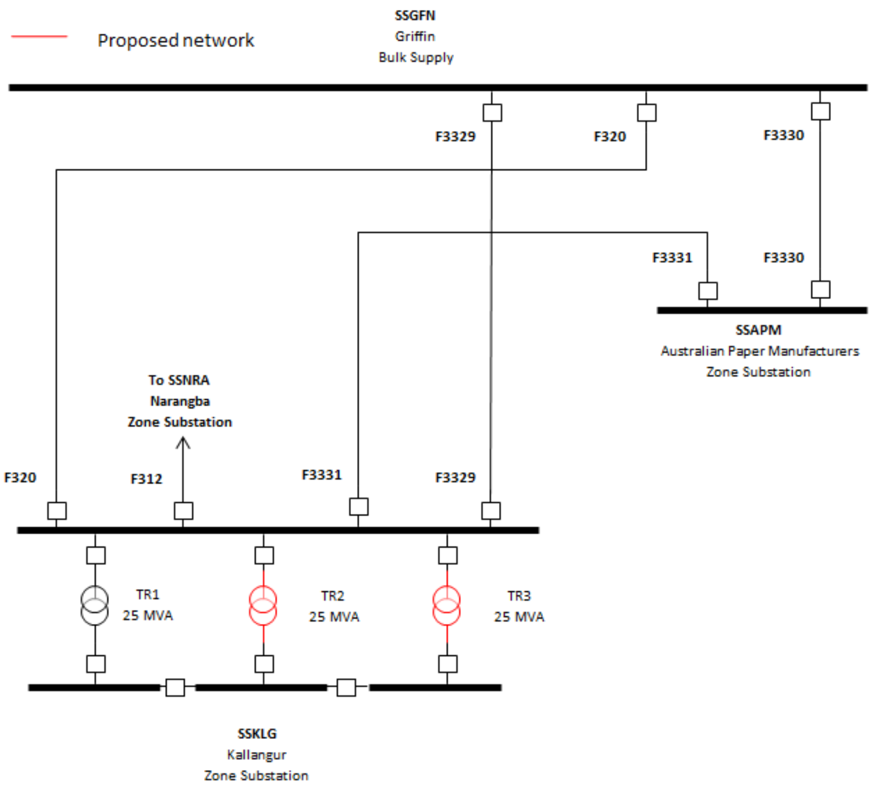

Figure 4: Proposed Network Arrangement under Option 2 (Schematic View)

Future Stages

2035 - Build Petrie Zone substation in 2035 with one 33/11kV 25MVA transformer. This work will be completed under a separate project.

2045 - Expand the capacity of Petrie Zone substation in 2045 by installing a second 33/11kV 25MVA transformer. This work will be completed under a separate project.

3.2.2 Non-network options

Energex is committed to the implementation of Non-Network Solutions to reduce the scope or need for traditional network investments. Our approach to Demand Management is listed in Chapter 7 of our Distribution Annual Planning Report but involves early market engagement around emerging constraints as well as effective use of existing mechanisms such as the Demand Side Engagement Strategy and Regulatory Investment Test for Distribution (RIT-D). We see that the increasing penetration and improving functionality of customer energy technology, such as embedded generation, Battery Storage Systems and Energy Management Systems, have the potential to present a range of new non-network options into the future.

The primary investment driver for this project is Augmentation Expenditure (Augex), supporting customer growth and network security. A successful Non-Network Solution may be able to assist in reducing the scope or timing for this project. As the cost of options considered as part of this report is greater than $5M this investment will be subject to RIT-D as a mechanism for customer and market engagement on solutions to explore further opportunities.

The customer base in the study area is predominantly established residential and commercial and has a medium opportunity to reduce demand or provide economic non-network solutions.

Expenditure for the proposed project has been modelled as CAPEX and included in the forecast for the current regulatory control period. Funding of any successfully identified Non-Network solutions will be treated as an efficient OPEX/CAPEX trade-off, consistent with existing regulatory arrangements. This will be determined as a result of the RIT-D process.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of the proposed options have been determined by considering costs and benefits across 2019/20 to 2069/70, at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%, using EQL's standard NPV analysis tool.

Costs

The Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) costs attached to each of the options considered in this business case are summarised in Table 6, in undiscounted real $2018/19 dollars. The OPEX costs are incurred annually across the useful life of the assets.

Table 6: CAPEX and OPEX costs for different works under each option

Option	Work Description	Useful Life	CAPEX ($ 000s)	OPEX ($ 000s/yr)
1	Build Petrie zone substation – single Tx	50	8,781	97
	SSKLG – Replace two 33/11kV TRs with one 25 MVA 33/11kV TRs	50	2,500	26
	Petrie 2nd transformer	50	2,138	26
2	11 kV feeders at SSKLG	45	990	10
	Upgrade SSKLG – Replace two 33/11kV TRs with two 25 MVA 33/11kV TRs	50	4,500	52
	Build Petrie zone substation – single Tx	50	8,781	97
	Petrie 2nd transformer	50	2,138	26

Results

Table 7 outlines the NPV and Present Value (PV) of CAPEX and OPEX associated with each option using the above cost assumptions and the forecast demand (medium demand scenario).

Table 7: NPV estimate ($ 000s)

Option	Option Name	Rank	NPV	CAPEX PV	OPEX PV
1	Establish Petrie Zone Substation	1	**-14,005**	-10,862	-3,143
2	Upgrade Kallangur Zone Substation	2	**-18,772**	-14,740	-4,032

3.4 Scenario Analysis

3.4.1 Sensitivities

Sensitivity analysis was performed, and the net present value comparison is shown below in Table 8. Because of the critical nature of the demand forecast, this analysis included a sensitivity to changes in demand. The scenarios that have been considered are:

- **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. It should be noted that a case of negative growth has not been modelled because the current and future stages of the options remain the same. This scenario has been assigned a likelihood of 80% in the weighted average NPV.
- **Low demand** – under this scenario the only change from the Medium Growth scenario is that the system normal network limitation at SSKLG occurs one year later, in 2026. Project staging has been altered to reflect this change. This scenario has been assigned a likelihood of 20% in the weighted average NPV.

The High demand scenario was not considered because the staging of projects is identical to the Medium demand scenario.

It can be seen from Table 8 that Option 1 represents the lowest cost network option over the tested scenarios. Both demand scenarios (and the weighted outcome) result in Option 1 having the lowest NPV cost, hence it is the preferred option.

Table 8: NPV estimate – weighted scenarios

Option	Option Name	Rank	NPV	CAPEX PV	OPEX PV
1	Establish Petrie Zone Substation	1	**-13,939**	-10,816	-3,123
2	Upgrade Kallangur Zone Substation	2	**-18,664**	-14,665	-3,999

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', the key uncertainty is the demand growth rate. The recommended option has been selected by using a risked NPV which applies a deterministic proportional weighting to the low and moderate growth rates to compare and evaluate the options. The option also allows for an economically efficient balanced approach to investment by targeting works based on asset criticality and assessed condition and reducing risk to the greatest extent without bringing forward unnecessary expenditure.

A quantitative value of regret analysis has been conducted to test whether the investment decision is robust in the outcome of each of the uncertain growth scenarios. The following table provides a summary of the analysis to determine which option minimises the maximum NPV regret across the weighted growth demand scenarios (moderate and low). The methodology used in the value of regret analysis is an "expected regret" calculation which is also known as "minimisation of opportunity loss."

Table 9: Value of Regret Analysis

Growth scenarios	Value of Regret Analysis						
							NPV max for scenario
	NPV	Weighted NPV	Regret	NPV	Weighted NPV	Regret	
Mid (80%)	-14,005	-11,204	0	-18,772	-15,018	3,814	-11,204
Low (20%)	-13,677	-2,735	0	-18,232	-3,646	911	2,735
Expected regret ($ NPV)						4,725	

This analysis supports that Option 1 has the "least amount of regret" or "opportunity loss" across the demand growth scenarios.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

A comparison of the advantages and disadvantages of the alternative development options is given in the table below.

Table 10: Comparison of options

Option	Advantages	Disadvantages
Option 1: Establish Petrie Zone Substation	• Highest reliability option, due to substation being located closer to the load centre • Enables more responsiveness to higher load growth, with a zone substation located close to the load centre.	• No obvious disadvantages.
Option 2: Upgrade Kallangur	• No obvious technical advantages.	• Significantly increases feeder lengths from SSKLG, reducing reliability and increasing unserved energy. • Less responsive to high load growth, as tie capacity to surrounding substations remains limited. • Higher safety risk compared to Option 1 as SSKLG is located in an urban, high traffic density area.

3.5.2 Alignment with network development plan

The proposed works would ensure that Energex meets its Service Safety Net Targets obligations. It looks to proactively provide contingency capacity just in time for load growth, maximising utilisation of assets while also considering the long-term growth of the local network and customer base. The proposal aligns with the Asset Management Objectives in the Distribution Annual Planning Report. In particular it manages risks, performance standards and asset investment to deliver balanced commercial outcomes while modernising the network to facilitate access to innovative technologies.

3.5.3 Alignment with future technology strategy

This program of work does not contribute directly to Energy Queensland's transition to an Intelligent Grid, in line with the Future Grid Roadmap and Intelligent Grid Technology Plan. However, it does support Energy Queensland in maintaining affordability of the distribution network while also maintaining safety, security and reliability of the energy system, a key goal of the Roadmap, and represents prudent asset management and investment decision-making to support optimal customer outcomes and value across short, medium and long-term horizons.

3.5.4 Risk Assessment Following Implementation of Proposed Option

Table 11: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Forecast 10% PoE peak demand on SSKLG **exceeds substation NCC** by 2MV.A (1000 customers, < 3 hours) during Summer 2024/25.	Customer	(Original) 3 *(5,000 customers for > 12 hours)*	3 *(Unlikely to occur)*	**9** ***(Low risk)***	2019
		(Mitigated) 3 *(As above)*	1 *(Almost no likelihood to occur)*	**3** ***(Very low risk)***	2025
Without augmenting the network, the Safety Net legislated requirement as part of the Distribution Authority is not met, resulting in the regulator being notified and a subsequent **improvement notice being issued.**	Legislative	(Original) 4 *(Energex/ Ergon identified issue requiring regulator to be notified. Improvement notice issued)*	3 *(Unlikely to occur)*	**12** ***(Moderate risk)***	2019
		(Mitigated) 4 *(As above)*	1 *(Almost no likelihood to occur)*	**4** ***(Very low risk)***	2023

Risk Assessment Outcome:

The network (business) risk the organisation would be exposed to if the project was not undertaken is not deemed to be as low as reasonably practicable (ALARP). Addressing the risks as detailed above through implementation of the preferred option will reduce Energex's risk exposure.

4 Recommendation

4.1 Preferred option

To address the emerging NCC and N-1 limits for SSKLG, it is recommended that Energex undertake a RIT-D to establish the lowest cost non-network or hybrid solution for comparison with the installation of a new zone substation at Petrie.

4.2 Scope of preferred option

The preferred option requires completion of a RIT-D to establish the lowest cost non-network or hybrid solution for comparison with the installation of a new 33/11kV zone substation at Petrie. Direct costs are estimated at $5.5M. The detailed scope includes:

- Establish a single 25 MVA modular substation.
- Decommission and recover existing site SSAPM.
- Establish 500m of temporary 33kV double circuit OH from existing SSAPM to new Petrie substation site.
- Establish 250m of 33kV DCT UG feeder tails into new Petrie modular substation.
- Establish five new 11kV feeder tails from new Petrie substation.

Appendix A. References

Note: Documents which were included in Energy Queensland's original regulatory submission to the AER in January 2019 have their submission reference number shown in square brackets, e.g. Energy Queensland, *Corporate Strategy [1.001], (31 January 2019).*

Energex, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.050]*, (21 December 2018).

Energy Queensland, *Asset Management Overview, Risk and Optimisation Strategy [7.025]*, (31 January 2019).

Energy Queensland, *Corporate Strategy [1.001],* (31 January 2019).

Energy Queensland, *Future Grid Roadmap [7.054],* (31 January 2019).

Energy Queensland, *Intelligent Grid Technology Plan [7.056],* (31 January 2019).

Energy Queensland, *Network Risk Framework*, (October 2018).

Appendix B. Acronyms and Abbreviations

The following abbreviations and acronyms appear in this business case.

Abbreviation or acronym	Definition
$M	Millions of dollars
$ nominal	These are nominal dollars of the day
$ real 2019-20	These are dollar terms as at 30 June 2020
2020-25 regulatory control period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
2HEC	Hour emergency capacity
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low as Reasonably Practicable
APM	Australian Paper Manufacturers
Augex	Augmentation capital expenditure
BAU	Business as Usual
BLB	Bulimba
CAPEX	Capital expenditure
CB	Circuit Breaker
CBRM	Condition Based Risk Management
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
DAPR	Distribution Annual Planning Report
DCT	Double Circuit
DER	Distributed energy resources
DNSP	Distribution Network Service Provider
ECC	Emergency Cyclic Capacity
EQL	Energy Queensland Ltd
GFN	Griffin
IT	Information Technology
KLG	Kallangur
KRA	Key Result Areas
kV	Kilovolts
LTN	Lawnton (Zone Substation)
MHL	Mango Hill (Zone Substation)
MVA	Megavolt Amperes
MSS	Minimum Service Standard

Abbreviation or acronym	Definition
NCC	Normal cyclic capacity
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)
NEX	Neutral Earthing Reactor
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NPV	Net Present Value
NRA	Narangba (Zone Substation)
OH	Overhead
OOS	Out of Service
OPEX	Operating Expenditure
PCBU	Person in Control of a Business or Undertaking
POE	Probability of Exceedance
QRPE	Queensland Railways Petrie
Regulatory Proposal	Energex or Ergon Energy's proposal for the next regulatory control period submitted under clause 6.8 of the NER
Repex	Replacement capital expenditure
RIT-D	Regulatory Investment Test - Distribution
SCCT	Single circuit
SSAPM	Australian Paper Manufacturers Zone Substation
SSGFN	Griffin bulk supply substation
SSKLG	Kallangur zone substation
SSLAR	Security standard load at risk
SSMHL	Mango Hill zone substation
SSNRA	Narangba Zone Substation
SSQRPE	Queensland Railways Petrie Substation
TR	Transformer
UG	Underground
VCR	Value of customer reliability
WACC	Weighted average cost of capital

Appendix C. Alignment with the National Electricity Rules (NER)

Table 12 details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

Table 12: Alignment with NER

Capital Expenditure Requirements	Rationale
6.5.7 (a) (1) **The forecast capital expenditure is required in order to meet or manage the expected demand for standard control services.**	This project is required to meet the forecast demand growth in the Kallangur, Petrie, Mango Hill area.
6.5.7 (a) (2) **The forecast capital expenditure is required in order to comply with all applicable regulatory obligations or requirements associated with the provision of standard control services**	Our alignment to regulatory obligations or requirements is demonstrated in this proposal, whereby CAPEX is required in order to maintain compliance and electrical safety through alignment with the QLD Electrical Safety Act 2002 and the QLD Electrical Safety Regulation 2006. In particular, this proposal refers to the Energex Safety Net targets, which are set to meet threshold criteria following an N-1 event on the sub-transmission network. This proposal maintains operations within the Safety Net targets so that Energex remains in compliance and alignment with the NER.
6.5.7 (a) (3) **The forecast capital expenditure is required in order to:** **(iii) maintain the quality, reliability and security of supply of standard control services** **(iv) maintain the reliability and security of the distribution system through the supply of standard control services**	This proposal seeks to ensure we adhere to our Safety Net targets. These targets are set such that any disruption to supply is minimised in terms of the outage time and number of customers affected. This proposal will utilise CAPEX to maintain reliability and security of supply for those customers in the above-mentioned regions.
6.5.7 (c) (1) (i) **The forecast capital expenditure reasonably reflects the efficient costs of achieving the capital expenditure objectives**	The Unit Cost Methodology and Estimation Approach sets out how the estimation system is used to develop project and program estimates based on specific material, labour and contract resources required to deliver a scope of work. The consistent use of the estimation system is essential in producing an efficient CAPEX forecast by enabling: • Option analysis to determine preferred solutions to network constraints • Strategic forecasting of material, labour and contract resources to ensure deliverability • Effective management of project costs throughout the program and project lifecycle, and • Effective performance monitoring to ensure the program of work is being delivered effectively. The unit costs that underpin our forecast have also been independently reviewed to ensure that they are efficient (Attachments 7.004 and 7.005 of our initial Regulatory Proposal).
6.5.7 (c) (1) (ii) **The forecast capital expenditure reasonably reflects the costs that a prudent operator would require to achieve the capital expenditure objectives**	The prudency of this proposal is demonstrated through the options analysis conducted and the quantification of risk and benefits of each option. The prudency of our CAPEX forecast is demonstrated through the application of our common frameworks put in place to effectively manage investment, risk, optimisation and governance of the Network Program of Work. An overview of these frameworks is set out in our Asset Management Overview, Risk and Optimisation Strategy (Attachment 7.026 of our initial Regulatory Proposal).

Capital Expenditure Requirements	Rationale
6.5.7 (c) (1) (iii) **The forecast capital expenditure reasonably reflects a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objective**	Our peak demand forecasting methodology employs a bottom-up approach reconciled to a top-down evaluation, to develop the ten-year zone substation peak demand forecasts. Our forecasts use validated historical peak demands and expected load growth based on demographic and appliance information in small area grids. Demand reductions, delivered via load control tariffs, are included in these forecasts. This provides us with accurate forecasts on which to plan.

Appendix D. Mapping of Asset Management Objectives to Corporate Plan

This proposal has been developed in accordance with our Strategic Asset Management Plan. Our Strategic Asset Management Plan (SAMP) sets out how we apply the principles of Asset Management stated in our Asset Management Policy to achieve our Strategic Objectives.

Table 1: “Asset Function and Strategic Alignment” in Section 1.4 details how this proposal contributes to the Asset Management Objectives.

Table 13 provides the linkage of the Asset Management Objectives to the Strategic Objectives as set out in our Corporate Plan (Supporting document 1.001 to our Regulatory Proposal as submitted in January 2019).

Table 13: Alignment of Corporate and Asset Management objectives

Asset Management Objectives	Mapping to Corporate Plan Strategic Objectives
Ensure network safety for staff contractors and the community	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Meet customer and stakeholder expectations	COMMUNITY AND CUSTOMERS ***Be Community and customer focused*** Maintain and deepen our communities' trust by delivering on our promises, keeping the lights on and delivering an exceptional customer experience every time
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	GROWTH ***Strengthen and grow from our core*** Leverage our portfolio business, strive for continuous improvement and work together to shape energy use and improve the utilisation of our assets.
Develop Asset Management capability & align practices to the global standard (ISO55000)	EFFICIENCY ***Operate safely as an efficient and effective organisation*** Continue to build a strong safety culture across the business and empower and develop our people while delivering safe, reliable and efficient operations.
Modernise the network and facilitate access to innovative energy technologies	INNOVATION ***Create value through innovation*** Be bold and creative, willing to try new ways of working and deliver new energy services that fulfil the unique needs of our communities and customers.

Appendix E. Risk Tolerability Table

Network Risks - ***Risk Tolerability Criteria and Action Requirements***

Risk Score	Risk Descriptor	Risk Tolerability Criteria and Action Requirements			
30 – 36	***Intolerable*** *(stop exposure immediately)*				
24 – 29	***Very High Risk***	***ALARP** Risk in this range managed to As Low As Reasonably Practicable	**Executive Approval** (required for continued risk exposure at this level)	May require a full Quantitative Risk Assessment (QRA) Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	**SFAIRP** Risks in this area to be mitigated So Far as is Reasonably Practicable
18 – 23	***High Risk***		**Divisional Manager Approval** (required for continued risk exposure at this level)	Introduce new or changed risk treatments to reduce level of risk Periodic review of the risk and effectiveness of the existing risk treatments	
11 – 17	***Moderate Risk***		**Group Manager / Process Owner Approval** (required for continued risk exposure at this level)	Introduce new or changed risk controls or risk treatments as justified to further reduce risk Periodic review of the risk and effectiveness of the existing risk treatments	
6 – 10	**Low Risk**				
1 to 5	***Very Low Risk***		No direct approval required but evidence of ongoing monitoring and management is required	*Periodic review of the risk and effectiveness of the existing risk treatments*	

Figure 5: A Risk Tolerability Scale for evaluating Semi-Quantitative risk score

Appendix F. Safety Net Obligations

Safety Net Criteria

Network planning criteria is a set of rules that guide how future network risk is to be managed for and under what conditions network augmentation or other related expenditure should be undertaken.

Energex

The Safety Net is effectively a deterministic security standard, requiring Energex to meet a set of threshold criteria following an N-1 event on the sub-transmission network. Energex has a legislated requirement to “design, plan and operate its supply network” to meet the Safety Net “to the extent reasonably practicable”.

The Safety Net Targets are outlined in the Distribution Annual Planning Report, and aim for the following:

Table 14: Safety Net targets – load not supplied and maximum restoration times following a credible contingency

Feeder Type	Targets
CBD	• Any interruption in customer supply resulting from an N-1 event at the sub-transmission level is restored within 1 minute
Urban – following an N-1 event	• No greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • No greater than 12 MVA (5,000 customers) is without supply for more than 3 hours; and • No greater than 4 MVA (1,600 customers) is without supply for more than 8 hours.
Short rural – following an N-1 Event	• No greater than 40 MVA (16,000 customers) is without supply for more than 30 minutes; • No greater than 15 MVA (6,000 customers) is without supply for more than 4 hours; and • No greater than 10 MVA (4,000 customers) is without supply for more than 12 hours.

Urban Interpretation

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

Appendix G. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$5.50
Business Case Value	
(M$2020)	$5.74

Appendix H. Additional information

Other Zone Substation Forecasts and Limitations

Lawnton zone substation

SSLTN is equipped with 1x12.5MVA 33/11kV transformer, 1x15MVA 33/11kV transformer, and 1x25MVA 33/11kV transformer. The substation capacity is limited by these transformers and provides a NCC, ECC and 2HEC as below:

- Normal Cyclic Capacity (NCC) – 63.0 MVA
- Emergency Cyclic Capacity (ECC) – 34.38 MVA
- 2 Hour Emergency Capacity (2HEC) – 37.13 MVA

The table below shows the limitations at SSLTN:

Table 15: SSLTN Load Forecast and Ratings

Substation	Year	10% POE Load (MVA)	NCC (MVA)	NCC LAR (MVA)	50% POE Load (MVA)	ECC (MVA)	Safety Net LAR
SSLTN	2019	37.77	63.0	0.00	31.58	34.3	0.00
	2020	37.81	63.0	0.00	31.61	34.3	0.00
	2021	38.14	63.0	0.00	31.43	34.3	0.00
	2022	38.31	63.0	0.00	31.57	34.3	0.00
	2023	37.93	63.0	0.00	31.72	34.3	0.00
	2024	37.79	63.0	0.00	31.60	34.3	0.00
	2025	37.99	63.0	0.00	31.77	34.3	0.00
	2026	38.30	63.0	0.00	31.56	34.3	0.00
	2027	38.41	63.0	0.00	31.65	34.3	0.00
	2028	38.85	63.0	0.00	32.01	34.3	0.00

As shown in Table 15, there are currently no limitations with the existing equipment at SSLTN. It is important to note that very little transfer capacity exists at this substation as it is approaching its ECC limitation.

Mango Hill zone substation

SSMHL is equipped with 2 x 25 MVA 33/11kV transformers in a split bus arrangement with an auto-changeover arrangement between the transformers. The substation capacity is limited by this transformer cables whilst the substation ECC capacity is limited by the 11kV bus tie cable. The substation NCC, ECC and 2HEC rating is shown below:

- Normal Cyclic Capacity (NCC) – 28.5 MVA
- Emergency Cyclic Capacity (ECC) – 14.0MVA
- 2 Hour Emergency Capacity (2HEC) – 23.40MVA

Table 16 shows the limitations at SSMHL Bus 1:

Table 16: SSMHL Bus 1 Load Forecast and Ratings

Substation	Year	10% POE Load (MVA)	NCC (MVA)	NCC LAR (MVA)	50% POE Load (MVA)	ECC (MVA)	Safety Net LAR
SSMHL Bus 1	2019	28.23	28.58	0.00	23.30	14.00	0.00*
	2020	28.58	28.58	0.00	23.59	14.00	0.00*
	2021	28.83	28.58	0.2	23.80	14.00	0.00*
	2022	30.37	28.58	1.8*	25.36	14.00	0.00*
	2023	30.04	28.58	1.4*	25.08	14.00	0.00*
	2024	29.82	28.58	1.2*	24.90	14.00	0.00*
	2025	29.81	28.58	1.2*	24.89	14.00	0.00*
	2026	29.86	28.58	1.3*	24.93	14.00	0.00*
	2027	29.77	28.58	1.2*	24.86	14.00	0.00*
	2028	29.89	28.58	1.3*	24.96	14.00	0.22*

* This NCC limitation will be solved through load transfers on the 11kV network from Bus 1 to Bus 2.

As shown in Table 16 there is currently raw load at risk at SSMHL. No transfer capacity exists at this substation.

Narangba zone substation

SSNRA is equipped with 1 x 25 MVA 33/11kV transformer and 1 x 20 MVA 33/11kV transformer. The substation NCC, ECC and 2HEC rating is shown below:

- Normal Cyclic Capacity (NCC) – 54.0 MVA
- Emergency Cyclic Capacity (ECC) – 25.0 MVA
- 2 Hour Emergency Capacity (2HEC) – 27.0 MVA

Table 17 shows the limitations at SSNRA:

Table 17: SSNRA Load Forecast and Ratings

Substation	Year	10% POE Load (MVA)	NCC (MVA)	NCC LAR (MVA)	50% POE Load (MVA)	ECC (MVA)	Safety Net LAR
SSNRA	2019	24.10	54.00	0.00	21.38	25.00	0.00
	2020	24.15	54.00	0.00	21.43	25.00	0.00
	2021	24.24	54.00	0.00	21.50	25.00	0.00
	2022	24.37	54.00	0.00	21.62	25.00	0.00
	2023	24.23	54.00	0.00	21.50	25.00	0.00
	2024	24.19	54.00	0.00	21.46	25.00	0.00
	2025	24.33	54.00	0.00	21.58	25.00	0.00
	2026	24.54	54.00	0.00	21.77	25.00	0.00
	2027	24.63	54.00	0.00	21.85	25.00	0.00
	2028	24.84	54.00	0.00	22.04	25.00	0.00

As shown in Table 17, there are currently no limitations with the existing equipment at SSNRA. It is important to note that very little transfer capacity exists at this substation as it is approaching its ECC limitation.

Sub-Transmission Network Limitations

No 33kV feeder limitations have been identified in the area, other than the condition assessment and proposed replacement of a 2km section of F312.

Sub-transmission Network Condition Limitations

Based on a Condition Based Risk Management (CBRM) analysis of the effect of current condition and ageing on the expected life of the 33/11kV transformers, isolators, relays and voltage transformers at SSKLG, the following limitations have been identified in the study area:

- 2km of 30/7/0.118 PANTHER on 33kV feeder between NRA and Kallangur will reach end of life in 2023.
- 33/11kV transformers TR2 and TR3 at SSKLG will reach their end of life in 2029.
- 33kV Circuit breakers CB3122, CB3202 and CB3392 at SSKLG will reach their end of life in 2025.
- Nine 11kV feeders at SSKLG do not currently have adequate back-up protection.
- 33kV Circuit breaker CB3T02 at SSAPM will reach end of life in 2025.

Further information on Energex's approach to condition assessment of plant can be found in Energex's suite of asset management plans for various asset classes.

11kV Load Shift Capability

SSKLG has 11kV tie feeders to SSNRA, SSMHL, and SSLTN. Currently there are significant constraints on permanently transferring load to these substations. The utilisation of available SSKLG tie feeders is shown in the table below.

Table 18: SSLTN tie feeder rating and utilisation

Tie Feeder	Rating (A)	2024 Forecast (A)	2024 Utilisation
LTN2	414	334	81%
LTN3	414	261	63%
LTN6	407	282	69%
MHL2	432	375	87%
NRA13A	406	455	112%

There is around 3MVA of available load transfers from the existing SSKLG 11kV feeders that are in the area, however to transfer any more load without going over the target maximum utilisation, new 11kV feeders from SSKLG will be required.