Business Case
Burnett Heads 66kV Line Augmentation

Executive Summary

Feeder capacity and voltages to the Burnett Heads area are forecast to be increasingly constrained from FY 2019/20 onwards with committed block loads expected online by FY 2022/23. All three feeders supplying Burnett Heads are projected to be capacity constrained, as well as significantly exceeding the rating of the majority of high-voltage (HV) regulators. The heavy loading and large distance from East Bundaberg to Burnett Heads also imposes voltage constraints, making it impossible to connect the proposed future Burnett Heads State Development area customers.

Three network options were evaluated for this business case. Two other options were initially considered but rejected; a ‘Do nothing’ option, which failed to address customer demand, and an option to further upgrade the 11kV feeders, which is likely to be an order of magnitude more expensive than the options considered. The three network options evaluated were:

Option 1 - Build a 66kV wooden pole line, energised at 11kV, from East Bundaberg Zone Substation (ZS) to Burnett Heads ZS.

Option 2 - Build a 66kV concrete pole line, energised at 11kV, from East Bundaberg Zone Substation (ZS) to Burnett Heads ZS.

Option 3 - Rebuild one of the existing 11kV lines as a dual circuit 11kV line, with the construction of a new 66kV wooden pole line deferred to a later period.

Ergon Energy 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 case customer reliability is a strong driver, as without the upgrades the existing feeders will be unable to meet customer demand.

To this end the preferred option is Option 1, as it presents the most cost-effective option with its Net Present Value (NPV) of $3.84M the lowest of the highest of the three options considered. It has a direct cost of $5.4M within the 2020-25 regulatory period. Works for this option would be completed in 2022.

The new line could also later be energised at 66kV to supply future Burnett Heads (BUHA) zone substation and allows a staged approach for BUHA construction allowing deferral of substation construction. In addition, the project cost has least impact from the sensitivity of customer connections, compared to the other options.

The direct cost of the project 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
$5.4M	$0.5M	$5.4M

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1 Introduction

Feeder capacity and voltages to the Burnett Heads area are forecast to be increasingly constrained from FY 2019/20 onwards with committed block loads expected online by FY 2022/23. All three feeders supplying Burnett Heads are projected to be capacity constrained, as well as significantly exceeding the rating of the majority of High Voltage (HV) regulators. The heavy loading and large distance from East Bundaberg to Burnett Heads also imposes increasing voltage constraints, making it impossible to connect the proposed future Burnett Heads State Development Area customers in the current network configuration. Appendix H shows a geographic view of the supply network in the Bundaberg and Burnett Heads area.

1.1 Purpose of document

This document recommends the optimal capital investment necessary for maintaining Ergon Energy's supply to customers in the Burnett Heads district, under the forecasted load growth.

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 Ergon Energy 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 outlines the proposed works, other options considered, and the risk reductions achieved through the proposed works.

1.3 Identified Need

Ergon Energy 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 case customer reliability is a strong driver, as without the upgrades the existing feeders will be unable to meet customer demand.

By 2022/23 all three 11kV feeders supplying Burnett Heads Zone Substation (BUHA) are projected to exceed 75% of their exit cable ratings, hence if there is a failure on one feeder adjacent feeders have insufficient capacity to pick up the load. In addition to this the majority of HV regulators are projected to exceed their rating and will be thermally constrained. The heavy loading and large distance from East Bundaberg to Burnett Heads also imposes increasing voltage constraints, making it impossible to connect the proposed future Burnett Heads State Development area customers. It is also noted that there is not capacity to supply even the low demand forecast detailed in the Jacobs Electrical Demand and Timing Report, commissioned by the State Government. 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 below details how the Burnett Heads 66kV line augmentation contributes to Energy Queensland's corporate and asset management objectives. The linkages between these Asset Management Objectives and EQL's Corporate Objectives are shown in Appendix D.

Table 1: Asset Function and Strategic Alignment

Objectives	Relationship of Initiative to Objectives
Ensure network safety for staff contractors and the community	Ensuring that asset capacity is sufficient to safely meet demand without exceeding practical limitations will reduce risk to staff and the community by reducing the risk of electrical failures due to overloading of assets.
Meet customer and stakeholder expectations	As demand increases in the area, existing assets would reach their physical limitations, leading to a high risk of failure in service. Augmentation to increase the capacity will reduce such a risk.
Manage risk, performance standards and asset investments to deliver balanced commercial outcomes	Ergon Energy is required to supply customers within its jurisdiction. Augmenting the line will allow this requirement to be met and the proposed works will do so in a commercially balanced manner.
Develop Asset Management capability & align practices to the global standard (ISO55000)	The proposed works have been developed in accordance with established planning standards and systems to align with the asset management standards.
Modernise the network and facilitate access to innovative energy technologies	This project will be subject to consideration through the Regulatory Investment Test for Distribution (RIT-D) process to ensure that suitable non-network innovative solutions are considered.

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

Corporate Policies relating to establishing the desired level of service are detailed in Appendix D.

Under the Distribution Authorities, EQL is expected to operate with an ‘economic’ customer value-based approach to reliability, with “Safety Net measures” for extreme circumstances. Safety Net measures 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. A table of safety net obligations can be found in Appendix F. EQL is expected to employ all reasonable measures to ensure it does not exceed minimum service standards (MSS) for reliability, assessed by feeder types as

- 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.

1.6 Compliance obligations

Table 2 shows the relevant compliance obligations for this proposal.

Table 2: Compliance obligations related to this proposal

Legislation, Regulation, Code or Licence Condition	Obligations	Relevance to this investment
Distribution Authority for Ergon Energy 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 set out works required to provide capacity to supply existing and new customers in the Burnett Heads area over the 2020-2025 regulatory period.

1.7 Limitation of existing assets

Transformer Limitations

East Bundaberg ZS (EABU) is equipped with two 16MVA 66/11kV transformers manufactured in 1979. The Plant Rating report illustrates that the main limitations are the transformer 11kV cable box bushings which have a rating of 850A (16.2MVA), followed by the 11kV transformer cable at 16.4MVA. Table 3 shows the 2018 forecast for 50% Probability of Exceedance (POE) and 10 POE at East Bundaberg ZS which incorporates the committed block loads along with the forecast block loads as provided in the Jacobs report. Hence, for N-1 contingency conditions, the ratings are currently exceeded for both 50 and 10POE forecasts. Further, by 2026/27 the 10POE forecast is nearing the system normal ratings for these components.

Table 3: EABU ZS 50 POE and 10 POE Summer Day Forecast and Load at Risk

Year	50 POE with Block Loads (MVA)	10 POE with Block Loads (MVA)	50 POE Load At Risk (MVA)
2017/18 (Actual)	19.5		
2018/19	20.23	21.45	4.03
2019/20	22.62	23.84	6.42
2020/21	23.99	25.22	7.79
2021/22	24.74	25.98	8.54
2022/23	28.11	29.36	11.91
2023/24	28.30	29.56	12.10
2024/25	28.44	29.72	12.24
2025/26	28.96	30.27	12.76
2026/27	29.00	30.31	12.80

Feeder Limitations

Table 4 shows the modelled forecast for feeders supplying the Burnett Heads area. The forecast includes the block loads and their expected location. For the purposes of this report only the Summer Evening peak period has been considered and only the low forecast has been modelled.

Table 4: Burnett Heads 11kV Feeder Forecast for Summer Evening Season

Feeder and Growth Rate	Section	Rating (A)	N-1	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27	27/28	28/29	29/30
EABU Substation Peak Load																
Sugar Port (1.1%)	UG OH	440 673	330	105	145	221	291	292	424	428	433	438	443	448	453	457
Burnett Heads (1.2%)	UG OH	320 673	240	151	154	235	236	246	360	364	369	373	377	382	387	391
Windermere (1.0%)	UG OH	274 475	206	197	199	201	203	205	207	209	211	213	215	218	220	222

Peak load > 50% N-1   Peak load > N-1   Peak load > cable rating

The forecast shows that beginning in 2021/22 the three feeders supplying Burnett Heads will be increasingly constrained, with Burnett Heads feeder exceeding the exit cable rating by 2022/23 and Sugar Port feeder by 2026/27. Due to the distance from East Bundaberg ZS and the radial nature of the network supplying Burnett Heads, maintaining sufficient transfer capability between the three feeders is critical to ensuring continued reliability for the area.

Almost all backbone conductor on Burnett Heads and Sugar Port was replaced with Pluto 19/3.75AAC or Iodine 7/4.75AAC under previous projects and the Windermere feeder conductor was initially of reasonable capacity (Pluto or Mercury 7/4.50AAC). Load has also been balanced across feeders as much as possible. Four additional sets of HV regulators have also been installed, previously. To further upgrade these feeders is not feasible for the following reasons:

- There are 2 sets of pole mounted HV regulators on each feeder with a nameplate rating of 200A/3.8MVA. These are the largest size Ergon Energy has available. The rating can be boosted to 320A/6.1MVA by reducing the regulation range from 10% to 5%. The reduced regulation could be managed by installing an additional set of regulators on each feeder, however the first set of regulators would be expected to carry most of the feeder load so for practical purposes 320A/6.1MVA is the limiting factor for feeder capacity. It is also not practical to install additional voltage regulators to supply industrial loads given the time delays it takes for the regulators change tap and respond to loading changes. The pure nature of suppling industrial loads at the end of long 11kV feeders not only poses steady state but also more transient voltage challenges associated with motor starting and load rejection.
- An alternative option to have a larger rating than the pole mounted regulators could be a ground mounted regulating substation where size/rating is not limited by pole mounting considerations. In practical terms this would be similar to establishing a miniature zone substation. There would be a requirement for a significant land parcel/easement, earth grid, secure fencing and HV switches. This would be a significantly more expensive option than the standard pole mounted regulators. The site/easement acquisition process is also likely to take a number of years (2 years minimum based on prior experience).

- The exit cables on Sugar Port and Burnett Heads are 400mm Cu 3 x 1 core (1 core per phase). The nominal rating is approximately 480A installed underground in conduit. In practice ratings are limited by soil conditions and layout, resulting in a rating closer to 420A/8MVA. It is also noted that all 11kV feeders exit the substation through a single exit point/trench section in very difficult rocky conditions. Increasing the capacity and current on one cable will impact ratings on remaining cables.
- The exit cable on Windermere is 240mm Cu Triplex. The nominal rating is approximately 400A installed underground in conduit. In practice ratings are limited by soil conditions and layout, resulting in a rating closer to 350A/6.7MVA.
- The feeders are limited by voltage with little capacity to supply new point loads as forecast to occur at Burnett Heads. Even with further works to improve feeder capacity ratings, the voltage limitations present a practical limit under both system normal and contingency conditions.
- The construction of further 11kV feeders has been considered, but routes are extremely limited, plus the transformer cable limitations limit the possibility of supplying further demand at 11kV.

Regulator and Voltage Limitations

It is also important to note that voltage constraints and HV regulator capacity also impose a major limit on feeder loads. A voltage drop of more than 7.5% will prevent Ergon Energy from maintaining voltage within statutory limits. All three feeders have two sets of line regulators installed with a nominal rating of 200A. While this can be boosted beyond nominal rating it comes at the cost of a restricted tapping range and therefore reduced regulation range. Due to the distances between regulation zones and the resulting voltage constraints as load increases it is not viable to boost regulator ratings to more than 120% (i.e., 4.8MVA).

The forecast shows that by 2022/23 most of the regulators will significantly exceed even the boosted rating with voltage constraints becoming significant from 2020/21 onwards. By 2022/23 the degree and duration of the overloading is likely to lead to accelerated loss of life and premature failure.

On top of these feeder regulator capacity limits, two feeders are forecast to be significantly impacted by voltage constraints for system normal in future years as shown below in Table 5. Under contingency conditions with an extended outage, it is unlikely that all load could be supplied from the remaining existing feeders due to voltage limitations. The addition of further voltage regulators will not assist this situation, as all feeders already have two sets of regulators which will be capacity constrained. Placing significant numbers of voltage regulators in series also generates power quality issues due to the sequential time delays required to respond to load induced voltage changes. The forecast block load increases also cannot realistically be supplied due to the long length of feeders and the resulting voltage limitations.

Table 5: 11kV Voltage Drop Forecast

Feeder	Regulation Zone	17/18	18/19	19/20	20/21	21/22	22/23
Burnett Heads Feeders - Regulation Zone Voltage Drop							
Sugar Port	1	2%	2%	4%	5%	5%	8%
	2	2%	3%	4%	5%	5%	8%
	3	2%	3%	4%	6%	6%	8%
Burnett Heads	1	2%	2%	4%	4%	4%	6%
	2	2%	2%	4%	4%	4%	6%
	3	3%	3%	6%	6%	6%	9%
Windermere	1	3%	3%	3%	3%	3%	3%
	2	4%	4%	4%	4%	4%	4%
	3	1%	1%	1%	1%	1%	1%

(red)	=	Voltage drop > 5%
(black)	=	Voltage drop > 7.5% (restricted range)

End of Life Limitations

East Bundaberg ZS has a number of assets identified for replacement due to age and condition. A separate project has been created (WR 1339689 – CBRM WB EABU 1TR 2CB 9CT 5VT 2ES 9IS) to address these issues. The scope for WR1339689 will require replacement of at least one power transformer and all of the 66kV equipment. Provision will be made for additional 66kV bays to supply future Burnett Heads and Bargara 66kV lines. As a separate report has been prepared for this replacement work it will not be replicated here.

Summary of Key Limitations

- The 66/11kV cables limit the amount of available 11kV feeder capacity from the substation in future years. An outage would result in a breach of the safety net provision with more than 5 MVA (1,200 customers) unable to be supplied for 12 hours or more;
- The 11kV feeders to Burnett heads cannot supply all demand under contingency conditions due to a combination of feeder cable tail capacity, voltage regulator capacity and voltage limitations. This results in a breach of the safety net provisions with more than 5MVA unable to be supplied for 12 hours or more.
- For N-1 contingency conditions, the ratings of the EABU transformer 11kV cable box bushings are currently exceeded for both 50 and 10POE forecasts. Further, by 2026/27 the 10POE forecast is nearing the system normal ratings for these components.

2 Counterfactual Analysis

2.1 Purpose of asset

The purpose of the augmentation to the Burnett Heads 66kV line is to supply anticipated load growth in the area which cannot currently be supplied with the existing network configuration.

2.2 Business-as-usual service costs

The business as usual (BAU) service costs for these assets are the operational costs associated with ongoing operations. In addition to these costs, significant emergency response and replacement costs would be incurred for the counterfactual BAU case in the event that failures occur. These have not been explicitly costed in this case due to the significant safety, reliability and compliance risks associated with asset failures.

2.3 Key assumptions

Business as usual assumes no expenditure on the augmentation. This would result in physical constraints occurring in 2020/21 and increasing over time. By 2022/23 the degree and duration of the overloading is likely to lead to accelerated loss of life and premature failure of regulators.

The three feeders would start to be significantly constrained from 2021/22. In the event of a single feeder fault there is a large risk of an extended outage as load cannot be readily restored by transferring to adjacent feeders. This would impact a significant number of large commercial and industrial customers in an economically important area for the Bundaberg region.

2.4 Risk assessment

This risk assessment is in accordance with the EQL Network Risk Framework and the Risk Tolerability table from the framework is shown in Appendix E.

Table 6: Counterfactual risk assessment

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure to increase feeder capacity and voltage results in **inability to meet agreed target for increased supply to multiple large-scale businesses**.	Customer	4 *(Inability to meet agreed target dates and disruption to multiple large-scale businesses)*	4 *(Likely)*	**16** ***(Moderate)***	2020
Failure to increase feeder capacity and voltage results in adverse national media attention around electricity infrastructure **limiting industry and job growth** in State Development Area.	Customer	4 *(Adverse national media attention. Loss of public trust)*	4 *(Likely)*	**16** ***(Moderate)***	2022
Significant overloading of regulators increases risk of failure, which could lead to **multiple injuries** to members of the public.	Safety	4 *(multiple serious injuries/illnesses)*	2 *(Very Unlikely)*	**8** ***(Low)***	2021
Failure to increase feeder capacity and voltage leaves the feeder utilisation rate at > 75% with limited spare capacity	Customer	3 (5,000 customers for >12 hours)	4 *(Likely)*	**12** ***(Moderate)***	2020

available for load transfers. This results in an inability to restore load in a feeder outage resulting in **extended outage durations of >12 hours**.					
Outage of 11kV feeder results in a breach of the safety net provision with more than 1**,200 customers (5 MVA) unable to be supplied for >12 hours**.	Business	3 *(Compliance breach with external standards)*	3 *(Unlikely)*	**9** ***(Low)***	2020

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 derating of existing assets would bring forward the constraints on the regulators, feeders and transformers, increasing the frequency and duration of outages in the area. Over time, this would result in customers not being able to be connected due to the physical limitations of the current network configurations and would breach Ergon Energy's requirement to supply all customers.

3 Options Analysis

3.1 Options considered but rejected

Do Nothing

The 'Do Nothing' option does not address the customer impact risk around being unable to provide increased supply to multiple large customers that are wanting to connect to the Burnett Heads distribution area. With the focus on this area due to the "much-anticipated" Bundaberg State Development Area (SDA), (NewsMail, 2017), there is an unmitigated risk of adverse political and media attention. The do-nothing option is therefore rejected and is not considered a suitable option. It also noted that there has already been some adverse media and political attention given existing limited capacity into the SDA.

Upgrading Existing 11kV Feeders

In addition, an option to upgrade existing 11kV feeders, or otherwise defer the construction of the 66kV to Burnett Heads, is not deemed to be suitable based on the reasons described in Section 1.7, with extensive works already carried out to maximise the capacity of the feeders in the area. An expenditure exceeding $10M has been incurred creating feeder ties, installing new line regulators and reconductoring feeder backbones.

The key consideration is that the ratings of the existing overhead conductors and underground cables are not a limitation on feeder capacity to the Burnett Heads area, rather it is the voltage limitations, and therefore there would be no benefit in upgrading these further. Option 3 below instead considers the option of creating an express feeder to Burnett Heads.

3.2 Identified options

3.2.1 Network options

Option 1 – Wood Pole Line

Construct 66kV Wood Pole Line from East Bundaberg ZS to Burnett Heads ZS site and Energise at 11kV in 2022, capital cost $7.34M.

- At EABU Transfer load from South Kalkie feeder to Kepnock and Hinkler Place feeders to free up 11kV CB
- Connect South Kalkie feeder CB to new 66kV line and energise line at 11kV to create express 11kV feeder to Burnett Heads (rename to Boat Harbour feeder)
- Install 200A closed delta regulators at Burnett Heads end to provide voltage regulation

Option 2 – Concrete Pole Line

Construct 66kV Concrete Pole Line from East Bundaberg ZS to Burnett Heads ZS site and Energise at 11kV in 2022, capital cost $10.42M.

- At EABU Transfer load from South Kalkie feeder to Kepnock and Hinkler Place feeders to free up 11kV CB
- Connect South Kalkie feeder CB to new 66kV line and energise line at 11kV to create express 11kV feeder to Burnett Heads (rename to Boat Harbour feeder)
- Install 200A closed delta regulators at Burnett Heads end to provide voltage regulation

Option 3 – New Dual circuit 11kV feeder

Rebuild portions of Windermere and Burnett Heads feeders as dual circuit 11kV in 2022 defer 66kV Wood Pole Line to 2031, capital cost $9.8M.

2022

- Rebuild portions of Windermere and Burnett Heads feeders as dual circuit 11kV to create express feeder to Burnett Heads
- At EABU Transfer load from South Kalkie feeder to Kepnock and Hinkler Place feeders to free up 11kV CB
- Connect new express feeder to South Kalkie feeder CB (rename to Boat Harbour feeder)

2031

- Construct 66kV wood pole line from East Bundaberg ZS to Burnett Heads ZS site
- Construct Burnett Heads ZS

3.2.2 Non-network options

Energy Queensland 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 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 $6M 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 a mix of residential and established commercial and industrial. 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 alternative solutions will be treated as an efficient OPEX/CAPEX trade-off, consistent with existing regulatory arrangements.

3.3 Economic analysis of identified options

3.3.1 Cost versus benefit assessment of each option

The Net Present Value (NPV) of each option has been determined by considering costs and benefits over the program lifetime from FY2020/21 to FY2030/31, discounted at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%, using EQL's standard NPV analysis tool.

Capital Costs

Each of the three options include costs for distribution works, subtransmission works, a 66kV bay and a SKID. The 66kV bay and SKID costs are common across the options and were estimated at $1,026,013 and $2,521,005 respectively (in real 2018/19 dollars). Note that under all three options the 66kV bay and SKID costs are only expected to be incurred in 2031 and are included here for completeness.

The costs for distribution works and subtransmission works vary across the options and are summarised in Table 7 and Table 8 respectively (all figures in real 2018/19 dollars).

Table 7: Cost of distribution works in 2020-25 regulatory period

Option	2020-21	2021-22	2022-23	2023-24	2024-25	Total
1	$7,098	$369,879	$520,140	$160,818	$1,805	$1,059,740
2	$7,098	$369,879	$520,140	$160,818	$1,805	$1,059,740
3	$13,003	$337,617	$3,214,789	$984,068	$3,610	$4,553,087

Table 8: Cost of subtransmission works in 2020-25 regulatory period

Option	2020-21	2021-22	2022-23	2023-24	2024-25	Total
1	$7,098	$69,056	$3,232,082	$1028,363	$1,805	$4,338,404
2	$7,098	$69,056	$5,870,196	$1,790,636	$1,805	$7,738,791
3	-	-	-	-	-	$0

The subtransmission works for Option 3 are planned to occur in 2031, with a total direct cost of $4,688,404 in real 2018/19 dollars.

Results

The Net Present Value (NPV) of each option has been determined by considering costs and benefits over the program lifetime from FY2020/21 to FY2030/31, discounted at the Regulated Real Pre-Tax Weighted Average Cost of Capital (WACC) rate of 2.62%, using EQL's standard NPV analysis tool.

Table 9 outlines the results of the analysis, showing the Present Value (PV) of costs and benefits, and the total NPV of each option. These results demonstrate that Option 1 represents the lowest NPV cost network option. Further information can be found in Appendix D.

Table 9: Net present value of options

Option Name	Rank	NPV	CAPEX PV	Benefits PV
Option 1	1	**-6,486**	-7,566	1,081
Option 2	3	**-9,606**	-10,687	1,081
Option 3	2	**-9,145**	-10,226	1,081

3.4 Scenario Analysis

3.4.1 Sensitivities

Limitation Delay

The initial forecast which this case was based on was carried out by Jacobs in 2018. Since that time, a number of the loads expected to come online in 2019 have been delayed and are now due to come online in 2020. As such, we have included an assessment reflecting the current scenario where these developments are delayed by a year, causing all loads to be pushed back a year. The NPV values of the options in this scenario are shown in Table 10.

Table 10: NPV of Options under limitation delay scenario

Option Name	Rank	NPV	PV Benefit
Option 1	1	**-6,282**	**+204**
Option 2	3	**-9,330**	**+276**
Option 3	2	**-8,959**	**+186**

Limitation Acceleration

Should something cause the limitations to occur before the feeder is built, the first year's lost Value of Customer Reliability (VCR) is as shown in Table 11.

Table 11: Value of Customer Reliability

Number of Feeders	Average Load at Risk (MVA)	Outage Rate /Feeder/Year	Customer Group $/MWh	Time to Repair (Avg.)	Annual VCR in Year 1
3	1.5	0.725	$41,000	4	$401,288
4	1.125	0.544	$41,000	3	$300,966
Incremental Annual Benefit from 4th Feeder					$100,322

Since the limitations on the feeders would increase over time, if the 4th feeder is not built, the outage rate would likely increase and with it the lost value of customer reliability. Therefore, since the NPV benefit from deferring the works a year is of the same magnitude as the VCR lost in the first year of unaddressed limitations, the proposed timing for the works is considered to be least regret.

Demand Growth

Since the proposed works are designed to provide capacity for the expected load increases, the utilisation of the works is sensitive to demand growth in the area. There are a number of existing block loads connected to Burnett Heads, which are not yet operating at full capacity so demand there will increase over time although the 2018 actual demand has been used for forecasting. Table 12 summarises block loads that have applied for connection as well as their expected date of connection.

Table 12: Pending Burnett Heads Block Loads

Customer	Size	Expected Date	Likelihood	Work request
Oceanside RV Village	Not disclosed	End 2019	Committed	1355737
Marina Redevelopment	Not disclosed	Start 2020	Committed	1442203
Customer E	3.5MVA	2020+	50%	

The feeders supplying Burnett Heads are historically Summer Evening peaking and some of the existing and pending block loads will contribute to these peaks. Oceanside and the Marina are largely residential/tourist developments, while one existing block load closely follows the residential peak loads.

In 2018 the Department of State Development commissioned an investigation into Electricity Demands and Timing for the Bundaberg SDA. The subsequent report provided to Ergon Energy in October 2018 summarised load requirements for known developments, as well as provides a forecast for proposed developments and future land uses. This report is considered commercial in confidence and not to be released to the public. The low and high scenario forecasts are reproduced, including a correction for a withdrawn connection application, in Table 13. The low forecast shown below has been used in determining the limitations in this proposal.

Table 13: Forecast Year-on-Year Electrical Demand Increases

Scenario	Additional Electrical Demand over Previous Year (MVA)					
	2018	**2019**	**2020**	**2021**	**2022+**	**Total**
Low Future Demand	0.64	2.61	1.0	0.2	3.21	7.7
High Future Demand	1.05	3.65	2.0	0.26	6.4	13.4

3.4.2 Value of regret analysis

In terms of selecting a decision pathway of 'least regret', Option 1 presents an economically efficient and staged approach to investment. The option also allows for a less upfront capital-intensive material selection, choosing suitable wood over concrete poles. In addition, the project cost has the least impact from the sensitivity of customer connections.

The key regret scenario in this case is the inability to supply future block loads. This would be likely to result in adverse media attention and significant disruption to the new entrant loads and the local community. Since the feeder constraints in section 1.7 have been calculated using the low forecast, the chance of building stranded assets is negligible, however, the timing of the limitations could advance. Even in the low forecast scenario the current network configuration is not sufficient to supply the customers through the 2020-2025 regulatory period, therefore the proposed works are considered the least regret option. Construction of the 66kV line and utilisation at 11kV supports the scenario where the load increases are above forecast. This option opens the way for advancement of the 66/11kV substation as required to meet the load increases and hence is a low regret option.

3.5 Qualitative comparison of identified options

3.5.1 Advantages and disadvantages of each option

Table 14 details the advantages and disadvantages of each option considered.

Table 14: Assessment of options

Options	Advantages	Disadvantages
Option 1	• Least cost option • Line can be energised at 66kV to supply future BUHA substation • Staged approach for BUHA construction allowing deferral of substation construction • Lower initial capital cost than concrete pole line • Project costs has least impact from the sensitivity of customer connections	• Availability of suitable wood pole sizes may be problematic
Option 2	• Line can be energised at 66kV to supply future BUHA substation • Staged approach for BUHA construction allowing deferral of substation construction	• Higher initial capital cost over wood pole line • Highest NPV of the three options

Options	Advantages	Disadvantages
Option 3	• Defer construction of 66kV line • Lowest initial capital cost in 2020-2025 period	• Will require significant re-work to utilise line once BUHA is constructed • Does not provide a staged approach for BUHA construction • Project more sensitive to customer connections and therefore is exposed to significantly more financial risk. • Is likely to significantly increase costs of 66kV line construction costs when the 66kV line is needed due to limited line routes to the port and needing to rebuild the 11kV under the new 66kV line whilst maintaining supply. • Greater operational and maintenance costs due to accessibility and outage management requirements.

3.5.2 Alignment with network development plan

The proposed works would ensure that Ergon Energy meets its requirements to supply all customers under the scenario of growing demand in the Burnett Heads district. It looks to proactively provide capacity just in time for load coming online, maximising utilisation of assets while also considering the long-term growth of the local network and customer base.

The proposed works enable the deferral of the Burnett Heads Zone Substation (BUHA), and thereby avoids the premature construction of major assets. This ensures that when the substation is eventually required, the most up-to-date technology can be implemented in order to provide the best level of service going forward.

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 15: Risk assessment showing risks mitigated following Implementation

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure to increase feeder capacity and voltage results in **inability to meet agreed target for increased supply to multiple large-scale businesses**.	Customer	*(Original)* *4* *(Inability to meet agreed target dates and disruption to multiple large-scale businesses)*	*4* *(Likely)*	***16*** ***(Moderate)***	2020
		(Mitigated) 4 *(As above)*	2 *(Very Unlikely)*	**8** ***(Low)***	

Risk Scenario	Risk Type	Consequence (C)	Likelihood (L)	Risk Score	Risk Year
Failure to increase feeder capacity and voltage results in adverse national media attention around electricity infrastructure **limiting industry and job growth** in State Development Area.	Customer	*(Original)* *4* *(interruption to 15,000 customers, >1 day, every day in 1 week)* (Mitigated) 4 *(As above)*	 *4* *(Likely)* 1 *(Almost No Likelihood)*	 ***16*** ***(Moderate)*** **4** ***(Very Low)***	2022
Significant overloading of regulators increases risk of failure, which could lead to **multiple injuries** to members of the public.	Safety	*(Original)* *4* *(multiple serious injuries/illnesses)* (Mitigated) 4 *(As above)*	 *2* *(Very Unlikely)* 1 *(Almost No Likelihood)*	 ***8*** ***(Low)*** **4** ***(Very Low)***	2021
Failure to increase feeder capacity and voltage leaves the feeder utilisation rate at > 75% with limited spare capacity available for load transfers. This results in an inability to restore load in a feeder outage resulting in **extended outage durations of >12 hours**.	Customer	*(Original)* *3* *(5,000 customers for > 12 hours)* (Mitigated) 3 *(As above)*	 *4* *(Likely)* 1 *(Almost No Likelihood)*	 ***12*** ***(Moderate)*** **4** ***(Very Low)***	2020
Outage of 11kV feeder results in a breach of the safety net provision with more than 1**,200 customers (5 MVA) unable to be supplied for >12 hours**.	Business Impact	*(Original)* *3* *(Compliance breach with external standards)* (Mitigated) 3 *(As above)*	 *3* *(Unlikely)* 1 *(Almost No Likelihood)*	 *9* *(Low)* **3** ***(Very Low)***	2020

4 Recommendation

4.1 Preferred option

The report recommends the construction of a 66kV wood pole line from East Bundaberg Zone Substation (ZS) (EABU) to the future Burnett Heads ZS (BUHA) and initially energised at 11kV as an express feeder for the Burnett Heads area (Option 1). The financial analysis supports Option 1 as the preferred option with an estimated NPV 15% more favourable to Option 3 and 40% more favourable to Option 2.

4.2 Scope of preferred option

- Construct 66kV wood pole line from East Bundaberg ZS to Burnett Heads ZS site
- At EABU Transfer load from South Kalkie feeder to Kepnock and Hinkler Place feeders to free up 11kV Circuit Breaker (CB)
- Connect South Kalkie feeder CB to new 66kV line and energise line at 11kV to create express 11kV feeder to Burnett Heads (rename to Boat Harbour feeder)
- Install 200A closed delta regulators at Burnett Heads end to provide voltage regulation

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).*

AEMO, *Value of Customer Reliability Review, Final Report,* (September 2014).

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).

Ergon Energy, *Distribution Annual Planning Report (2018-19 to 2022-23) [7.049]*, (21 December 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
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ALARP	As Low As Reasonably Practicable
AMP	Asset Management Plan
Augex	Augmentation Capital Expenditure
BAU	Business As Usual
BUHA	Burnett Heads Zone Substation
CAPEX	Capital expenditure
CB	Circuit Breaker
Current regulatory control period or current period	Regulatory control period 1 July 2015 to 30 June 2020
DAPR	Distribution Annual Planning Report
DC	Direct Current
DNSP	Distribution Network Service Provider
EABU	East Bundaberg Zone Substation
EQL	Energy Queensland Ltd
HV	High Voltage
IT	Information Technology
KRA	Key Result Areas
kV	Kilovolt
LV	Low Voltage
MSS	Minimum Service Standard
MVA	Megavolt Ampere
NEL	National Electricity Law
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules (or Rules)

Abbreviation or acronym	Definition
Next regulatory control period or forecast period	The regulatory control period commencing 1 July 2020 and ending 30 Jun 2025
NPV	Net Present Value
OPEX	Operational Expenditure
PCBU	Person in Control of a Business or Undertaking
POE	Probability of Exceedance
Previous regulatory control period or previous period	Regulatory control period 1 July 2010 to 30 June 2015
PV	Present Value
Repex	Replacement Capital Expenditure
RIN	Regulatory Information Notice
RIT-D	Regulatory Investment Test – Distribution
RTS	Return to Service
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
SDA	State Development Area
SFAIRP	So Far As Is Reasonably Practicable
WACC	Weighted average cost of capital
ZS	Zone Substation

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

The table below details the alignment of this proposal with the NER capital expenditure requirements as set out in Clause 6.5.7 of the NER.

Table 16: 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 Burnett Heads area due to the State Development 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**	Under the Distribution Authorities, Ergon Energy is expected to operate with an 'economic' customer value-based approach to reliability, with "Safety Net measures" for extreme circumstances. Under a credible contingency the current network would breach safety net targets under future demand growth. The proposed works address this limitation to ensure safety net targets continue to be met.
6.5.7 (a) (3) **The forecast capital expenditure is required in order to:** **(iii) maintain the quality, reliability and security of supply of supply of standard control services** **(iv) maintain the reliability and security of the distribution system through the supply of standard control services**	This project ensures the continued reliability of quality, reliability and security of supply in the Burnett Heads area in the scenario of demand growth established by the State Development Area.
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 a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objective**	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.

The Table below 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 17: 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

<table>
<tr><th colspan="5">Network Risks - Risk Tolerability Criteria and Action Requirements</th><th></th></tr>
<tr><th>Risk Score</th><th>Risk Descriptor</th><th colspan="3">Risk Tolerability Criteria and Action Requirements</th><th></th></tr>
<tr><td>30 – 36</td><td colspan="4">Intolerable
(stop exposure immediately)</td><td></td></tr>
<tr><td>24 – 29</td><td>Very High Risk</td><td rowspan="5">*ALARP
Risk in this range managed to As Low As Reasonably Practicable</td><td>Executive Approval
(required for continued risk exposure at this level)</td><td>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</td><td rowspan="5">SFAIRP
Risks in this area to be mitigated So Far as is Reasonably Practicable</td></tr>
<tr><td>18 – 23</td><td>High Risk</td><td>Divisional Manager Approval
(required for continued risk exposure at this level)</td><td>Introduce new or changed risk treatments to reduce level of risk
Periodic review of the risk and effectiveness of the existing risk treatments</td></tr>
<tr><td>11 – 17</td><td>Moderate Risk</td><td rowspan="2">Group Manager / Process Owner Approval
(required for continued risk exposure at this level)</td><td rowspan="2">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</td></tr>
<tr><td>6 – 10</td><td>Low Risk</td></tr>
<tr><td>1 to 5</td><td>Very Low Risk</td><td>No direct approval required but evidence of ongoing monitoring and management is required</td><td>Periodic review of the risk and effectiveness of the existing risk treatments</td></tr>
</table>

Figure 1: 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.

Ergon Energy

Ergon Energy is required under Distribution Authority No. D01/99 to adhere to the probabilistic planning approach where full consideration is given to the network risk at each location, including operational capability, plant condition and network meshing with load transfers.

The Safety Net requirements provide a backstop set of ‘security criteria’ that set an upper limit to the customer consequence (in terms of unsupplied load) for a credible contingency event on our network. Ergon Energy is required to meet the restoration targets defined in Schedule 4 of Ergon Energy’s Distribution Authority “…*to the extent reasonably practicable.”*

The safety net criteria are classified into Regional Centre and Rural Area, each with a different timeline as follows:

Area	Targets
Regional Centre	Following an N-1 Event, load not supplied must be: • Less than 20 MVA (5,000 customers) after 1 hour; • Less than 15 MVA (3,600 customers) after 6 hours; • Less than 5 MVA (1,200 customers) after 12 hours and • Fully restored within 24 hours.
Rural Areas	Following an N-1 Event, load not supplied must be: • Less than 20 MVA (7,700 customers) after 1 hour; • Less than 15 MVA (5,800 customers) after 8 hours; • Less than 5 MVA (2,000 customers) after 18 hours and • Fully restored within 48 hours.

Table D1: Safety Net – Load not supplied and maximum restoration times following a credible contingency

Appendix G. Reconciliation Table

Reconciliation Table Conversion from $18/19 to $2020	
Business Case Value	
(M$18/19)	$5.40
Business Case Value	
(M$2020)	$5.59

Appendix H. Geographic Diagram of Area of Supply

Figure 2: Geographic Diagram of Supply Area