Distribution Augmentation - Capacity and Voltage

Business Case

17 January 2024

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DOCUMENT VERSION

Version Number	Change Detail	Date	Updated by
1	Initial Version	19/3/2023	Manager Distribution Planning
2	Updated with Latest Figures based on updated model results	4/5/2023	Manager Distribution Planning
3	Updated based on latest forecast and removal of minimum demand constraints.	10/11/2023	Manager Distribution Planning
4	Approved	20/12/2023	General Manager Grid Planning

RELATED DOCUMENTS

Document Date	Document Name	Document Type
03/10/2019	Distribution Authority No. D01/99, Ergon Energy Corporation Limited	PDF
04/05/2023	Reactive Distribution Augmentation AER Business Case	PDF
04/05/2023	Distribution Augmentation Unplanned Reliability - AER Business Case	
04/05/2023	Distribution Augmentation Unplanned Reliability Model	XLS

1 SUMMARY

Title	Distribution Feeder Augmentation Capacity and Voltage
DNSP	Ergon Energy
Expenditure category	☐ Replacement ☒ Augmentation ☐ Connections ☐ Tools and Equipment ☐ ICT ☐ Property ☐ Fleet
Identified need *(select all applicable)*	☒ Legislation ☒ Regulatory compliance ☒ Reliability ☐ CECV ☒ Safety ☐ Environment ☐ Financial ☐ Other Augment the Distribution Network (11kV, 22kV, 33kV, LV and SWER) as required meet regulatory and legislative obligations associated with network capacity, voltage, and reliability.
Summary of preferred option	The Preferred Option is to provide funding as detailed below such that regulatory and legislative obligations are met.
Expenditure	(see table below)
Benefits	Compliance with Regulatory and Legislative obligations regarding network capacity and network voltage performance.

Year	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30
$m, direct 2022-23	15.32	16.19	17.51	18.84	20.23	**88.09**

2 PURPOSE AND SCOPE

Ergon Energy operates medium voltage distribution networks at 11kV, 22kV and 33kV as well as a range of 12.7kV and 19.1kV SWER systems. Ergon Energy operates a very different network to most Australian Distribution Network Service Providers (DNSPs) in the National Electricity Market (NEM), typified by small customer numbers, long network distances, large geographical spread of network and subsequent low network densities. The distribution network is made up of approximately 120,000km of overhead powerline and 9,000km of underground cable, with about 1,000,000 power poles and close to 100,000 distribution transformers. With approximately 8% of the total NEM customer base, Ergon Energy's network area is approximately 44% of the total area covered by the networks that form part of the NEM. Ergon Energy operates one of the lowest density networks in Australia which has a large impact on how the network is designed, managed, and operated. It is a largely overhead and radial network which includes one of the largest SWER networks in Australia and the world. The SWER Network is 64,000km in length, supplying around 26,000 customers predominately in regional Queensland.

The Planned Distribution Augmentation expenditure that Ergon Energy proposes is required to maintain the safety of the distribution system through the supply of standard control services. Ergon Energy has obligations under the Electrical Safety Act 2002 (Qld) to inspect, test and maintain works, and a duty to ensure that its works are electrically safe and are operated in a way that is electrically safe. Under the Work Health and Safety Act 2011 (Qld), Ergon Energy must ensure, so far as is reasonably practicable, that the fixtures, fittings, and plant are without risks to the health and safety of any person. Ensuring the safety of our staff, customers and communities is our foremost priority. To discharge these obligations, Ergon Energy must ensure that network assets do not exceed plant capacity ratings, fault ratings, voltage limits or other technical limits that may compromise the safety of the distribution system.

Ergon Energy's Planned Distribution Augmentation expenditure is driven by forecast maximum demand, which, if left uncontrolled, can constrain network assets. Planned Distribution Augmentation expenditure is necessary as it enables Ergon Energy to take action to prevent these constraints from impacting customers. Growth in peak demand is a critical aspect that drives any expansion of the distribution network. Peak demand occurs at different times in different locations and is also dependent on the underline customer base. Ergon Energy must maintain sufficient capacity to supply every home and business on the day of the year when electricity demand is at its maximum or minimum demand without exceeding plant ratings whilst also maintaining voltages within statutory limits. The average demand growth during the 2020-2025 period in some parts of Ergon Energy's networks has moderate, however in other areas strong growth has occurred particularly where new property development is occurring, which requires the network to be upgraded, expanded, or modified. Ergon Energy not only expect this to continue in the 2025 period but also expect to see more growth from within the existing customer base. Without Ergon Energy's proposed Distribution Augmentation expenditure, Ergon Energy would not be able to meet the expected demand for standard control services over the regulatory control period 2025-30.

The Planned Distribution Augmentation program is characterised by higher cost projects where work is being done to ensure legislative obligations are met and to avoid customer complaints due to network capacity exceedance, and under or over voltages. The program is made up of individual projects of relatively short duration, with the work typically expected to be constructed within approximately 2 years of projects being issued. Operating on a relatively short duration ensures projects can proceed efficiently with minimum risk of forecast inaccuracy and network reconfiguration changes. Given projects are created approximately 2 years in advance, this business case is not seeking funding for specific existing projects, but rather an overall Planned Augmentation program.

Please note that this business case does not include smaller, typically unplanned, less complex, and routine augmentation expenditure projects that forms work programs as part of Reactive Distribution Augmentation. A sperate business case has been produced to justify such expenditure, which is created to resolve customer Power Quality complaints, augment the LV network, upgrade overload distribution transformers, maintain statutory clearances, and address simple reliability problems reactively. Reactive Distribution Augmentation programs are applied to resolve issues raised by our customers and communities that are not identified or predicted as part of the network modelling or planned processes and are typically LV network focussed. This business case also does not cover improving the networks resilience to bushfire and flood events and a separate business case has been created to mitigate these network related risks.

This Planned Distribution Augmentation Capacity and Voltage business case seeks to continue to deliver sustainable outcomes for customers and the business, with no compromise to safety and legislative compliance. The objective is to provide an affordable, safe, resilient, reliable, and secure quality of supply to meet the changing needs of our customers.

2.1 Forecast

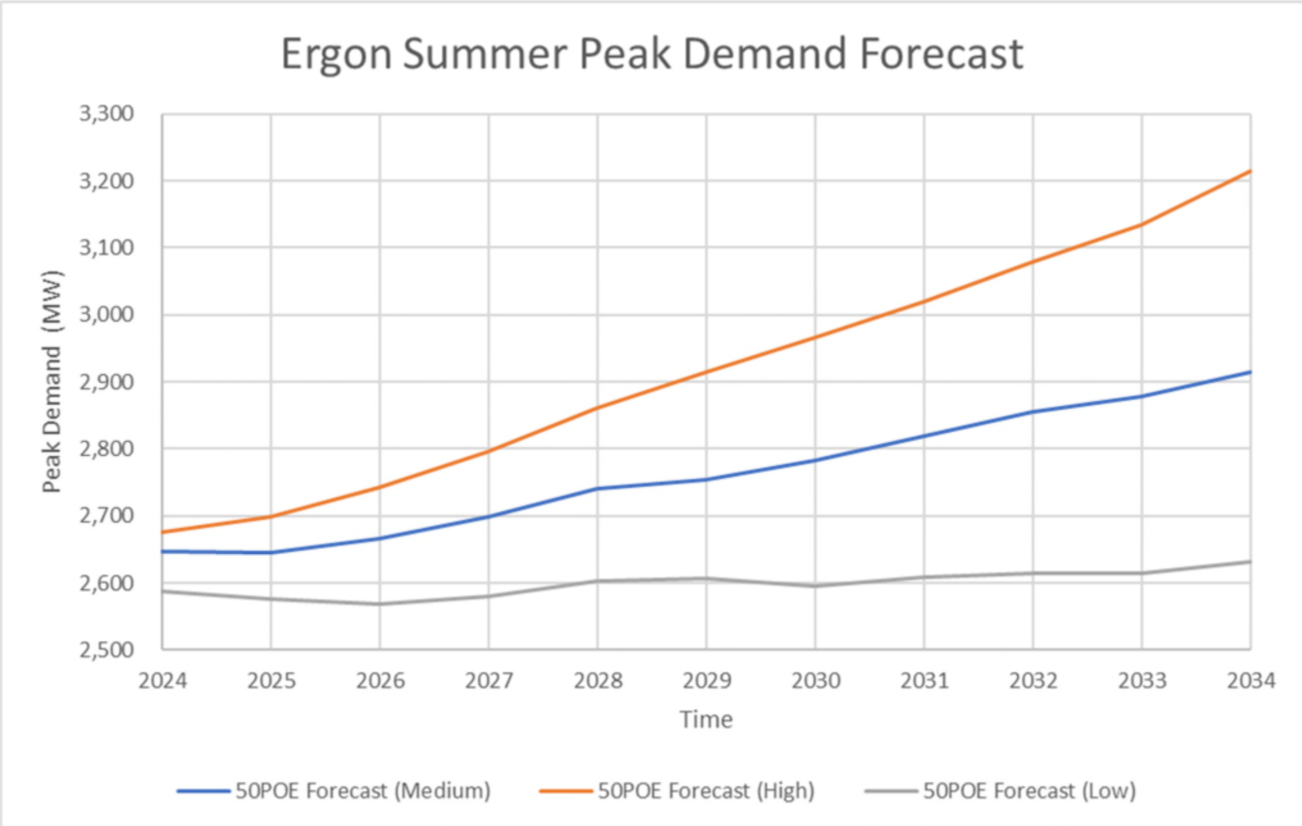
In the 2020-2025 regulatory period, systems wide growth on the Ergon Energy network has been moderate. Much of this growth has been driven at a more localised level primarily around the expansion of residential, industrial, and commercial subdivisions, rather than being caused by load increased from the existing customer base. It is expected this will change in the 2025-30 period such that not only will strong localised growth continue, but also growth from existing customers. This growth within the existing customer base is predicated on Australia's and Queensland's acceleration towards net zero. As detailed in AEMOs Electricity Statement of Opportunity 2021(ESSO) which provides and insight into the next 10 years, demand for electricity is expected to increase as part of the energy transformation to Net Zero. Consumers will transition to electric vehicles and households and business will move from carbon-based fuels to electricity. This transition will not only drive increase demand, but also create increased dependency on the reliability of supply to customers and the community.

The Queensland Energy and Jobs plan is targeting 60% of energy will be delivered by renewables by 2030, 70% by 2032 and 80% by 2035. Businesses will transition from fossil fuel sources to renewable energy supported by the Distribution Network. At a residential level we expect a significant uptake of Electric Vehicles. The Queensland government has announced its new Zero Emission Vehicle Strategy (source: Queensland's new Zero Emission Vehicle Strategy | Transport and motoring | Queensland Government (www.qld.gov.au)) which details that:

- 50% of new light vehicle sales to be zero emissions by 2030, moving to 100% by 2036
- 100% of eligible Queensland Government fleet passenger vehicles to be zero emission by 2026
- every new TransLink-funded bus will be zero emissions from 2025 in South-East Queensland and from 2025-2030 across regional Queensland.

Figure 1 details the Ergon Energy system expected growth into the future.

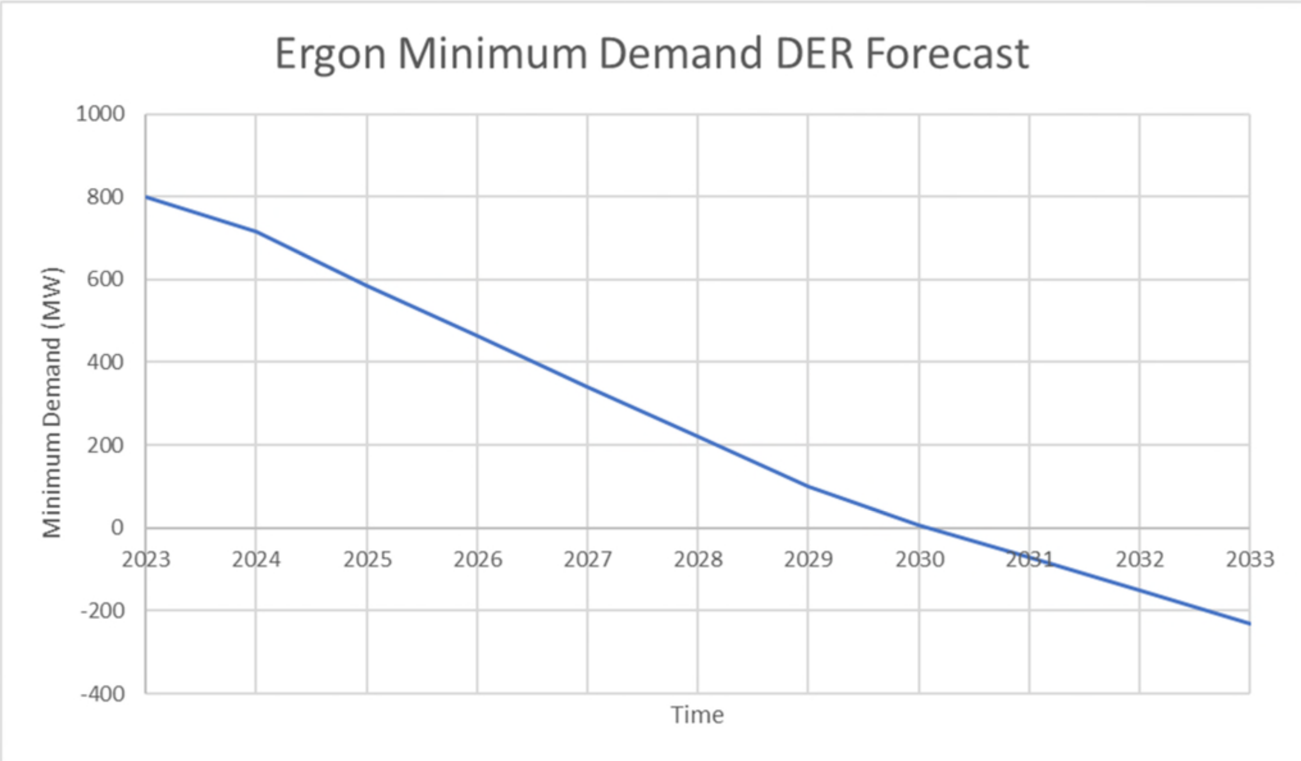
Figure 1 Maximum Demand Historical and Forecast



In Ergon Energy's network, approximately 30% of customers have a solar PV system connected, with an average inverter capacity of around 5.6kVA. The rapid uptake of solar PV has changed the way power travels through the network, from a purely one-way to bi-directional energy flows.

In addition to maximum demand growth, minimum demand is also expected to increasingly cause voltage and capacity constraints on the network. Analysis performed for this business case details that many constraints on feeder sections do not just arise from load growth, but also reverse power flows associated with solar generation. Figure 2 details the expected minimum demand for Ergon Energy at a system level.

Figure 2 Minimum Demand Forecast



2.2 Planned Distribution Augmentation

The methodology applied to identify voltage and capacity constraints for planned distribution augmentation has been to model in PowerFactory (Ergon Energy's power system analysis / load flow software package) all the medium voltage distribution feeders in the network and apply the Ergon Energy forecast growth rates expected in the 2025-2030 regulatory period to these feeders. The Voltage and Capacity constraints that emerge in the 2025-2030 period determine the volumes of work required to address these regulatory constraint requirements. Slow, Medium, and Fast forecast scenarios were modelled and a weighted average of 20%, 60%, and 20% was applied to the resulting constraints in each forecast category, to determine the final proposed constraint numbers.

As the Ergon Energy network is very much characterised by longer rural type feeders significantly more voltage related constraints emerge on the network compared with capacity constraints (see Table 2).

2.2.1 Planned Distribution Augmentation - Capacity

As current flows through powerlines, the lines heat up. If the current is too great, this results in thermal overloading. As per Electrical Safety Regulation (2013) Qld, Ergon Energy is required to operate the network within thermal limits. Capacity projects are those projects created to meet and manage network growth, and to ensure that operation of the distribution network is within required standards and thermal limits. Thermal overloading of conductors and other network assets could cause failure of those assets. In addition, higher loads with over-utilised feeders may create under-voltage situations and reliability impacts during contingencies. As per the Electrical Safety Act 2002

Ergon Energy has an obligation to make sure the network the organisation owns and operates is electrically safe for customers, staff, and the broader community. To ensure this, Ergon Energy will not load plant above its design rating. Projects in this category are created to ensure that requirement is met.

It is important to note that due to expected increasing reverse power flows caused by rooftop and other forms of Distributed Energy Resources (DER), constraints emerge on feeders, not only in the traditional forward direction but also in the reverse direction. When considering flow directions there is a significant correlation and overlap of constraints caused by these flows. For example, if a section of line is constrained in the forward direction, there is a relatively high likelihood it will also be constrained in the reverse direction. In summary whilst this business case is focussed on forward demand, resolving these forward demand constraints will inherently improve capability to host further renewable generation.

Start of Feeder Utilisation Solutions

Start of feeder constraints occur when feeder sections close to the substation become heavily loaded proportional to the rating. Examples of this include underground feeder exit cable sections from the substation or other overhead or underground sections near the substation where the feeder load is encroaching on the rating of those sections. Typically, solutions to resolve these constraints involve upgrading exit cables, creating ties to allow load to be transferred to adjacent feeders or creating new feeders to relieve load off the constrained feeder(s).

Downstream Feeder Utilisation Solutions

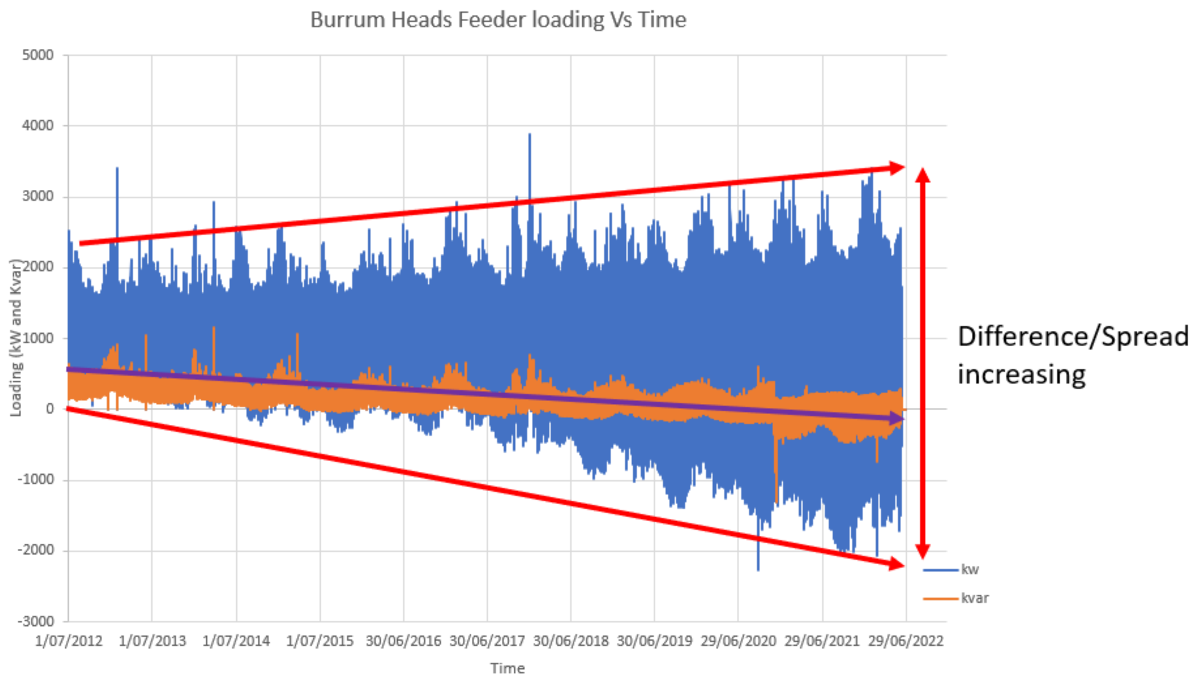
Downstream Feeder Utilisation occur further out on the feeder than Start of Feeder Constraints. Solutions typically involve reconductoring with a higher capacity conductor, re-tensioning of lines to increase the current carrying capacity while maintaining statutory clearances or creating ties further out in the network to allow load to be transferred off constrained sections.

2.2.2 Planned Distribution Augmentation - Voltage

Ergon Energy is required to design, build, and maintain its network to maintain voltage compliant with the applicable standards as detailed in Part 2 of Queensland's Electricity Regulation 2006 and as further detailed in AS 60038 and AS61000. The network must also comply with voltage requirements as detailed in Chapter 5 of the National Electricity Rules. The objective of voltage related expenditure is to ensure compliance with these regulations and standards are achieved.

As current flows through the distribution network to the end consumer, voltage drops along the length of the feeder proportional to the current and resistance of the feeder. Conversely when current is flowing from customer back up into the network as a result of generation such as rooftop solar, voltage at and towards the customer-end of the feeder rises. Given the combination of strong reverse and continued strong forward flows on feeders, it is becoming more difficult to manage voltage over a wider range of power flow scenarios. This is demonstrated in Figure 3.

Figure 3 Example of Power flows in forward and reverse direction creating significant voltage spread.



3 IDENTIFIED NEED

The identified Capacity and Voltage augmentation need is directly driven by regulatory requirements as detailed in Table 1.

Table 1 Distribution Augmentation Justification Matrix

Program	Sub Program	Justification	Justification Detail
Planned Distribution Augmentation	Capacity	Compliance- Regulatory Obligation	Electrical Safety Regulation (2013) and Electrical Safety Act 2002
Planned Distribution Augmentation	Voltage	Compliance- Regulatory Obligation	Queensland's Electricity Regulation 2006, AS 60038 and AS61000 Chapter 5 of the National Electricity Rules

3.1 Compliance

Ergon Energy has an obligation to comply with the Electrical Safety Regulation (2013) and Electrical Safety Act 2002 when managing network capacity. When managing voltage, compliance is required with Queensland's Electricity Regulation 2006 and Chapter 5 of the National Electricity Rules. To determine the expected work that falls into these categories in the 25-30 regulatory period, Ergon Energy has performed load flow analysis across the entire distribution network based on projected growth to identify areas of non-compliance. The work required to address Non-compliance is a regulatory obligation and has not been justified by applying an investment value stream methodology/ resulting cost benefit analysis.

3.2 Counterfactual Analysis

The identified need outlined in this business case to address capacity and voltage requirements is a regulatory obligation. As this work is compliance driven there is no alternative counterfactual option, however individual projects which make up this program will be based on the lowest cost to meet Ergon Energy's obligations.

3.3 Impact of Doing Nothing

By doing nothing, Ergon Energy will fail to meet the regulatory obligations. In addition to the non-compliance, by not addressing these obligations, customers supplied from these feeders, or feeder sections, will experience unacceptable voltage performance and network plant and equipment will be loaded beyond plant capability leading to safety risk.

3.4 Assumptions/ Methodology

The methodology used to determine the threshold for feeder capacity constraints was to apply a 90% utilisation based on the 10 POE forecast using 30-minute averaged data. It is recognised that this is an extremely conservative approach and at these utilisation levels, network reliability is expected to deteriorate. Feeder utilisation needs to be maintained well below 100% to maintain supply reliability at a reasonable level during network contingencies. A separate *Planned Augmentation – Unplanned Reliability* business case has been included in our submission, which addresses network reliability performance. At 90% feeder utilisation, alarm limits will be reached triggering operational alarms in the control centres. Shorter duration peaks load will also be higher than when applying 30-minute averaged data, so protection overcurrent limits may be approached at times. Projects also do not always get delivered on time, feeder load growth may also be higher due to forecast inaccuracies, and hence clearly it is not reasonable or practical to plan at reaching 100% utilisation thresholds to trigger augmentation.

As part of the network modelling work undertaken, two main capacity solutions have been identified. As previously detailed the first involves the requirement to augment the network to manage feeder utilisation and ensure capacity/ratings are not exceeded at the start of the feeder. The second involves resolving capacity constraints further downstream on the feeder from the zone substation.

A step-by-step methodology used to formulate and justify this business case and program is detailed below:

1 PowerFacotry (Ergon's Load Flow package) modelling was applied across the entire Ergon Distribution network to identify constraints.

    a. This modelling was completed using Low, Medium, and High growth forecasts.

    b. Modelling was completed for the year 2030 using the forecasts to determine expect constraints.

2 The volume of constraints was then identified in the following three categories from the PowerFactory modelling.

    a. Start of Feeder Utilisation Constraints

    b. Downstream Utilisation Constraints

c. Voltage Constraints.

3 A weighted average of 20%, 60%, and 20% was applied to the resulting constraints in each forecast category (Low, Medium and High) to determine final applicable volumes for the categories.

4 Cost Estimates were formulated using historic costs. To do this, typical project costs for the type of constraints were determined by categorising projects initiated over the last two years and averaging the direct costs for the project type.

5 Any overlaps were removed to ensure that there was no double counting. To do this, it was assumed that if a project is performed on a feeder, it will resolve all constraints. For example, if a feeder has a voltage constraint as well as a downstream capacity constraint it is assumed both constraints will be resolved with the one project. This is a conservative assumption that allowed final expected project volumes to be determined. Project volumes are detailed in Table 2

6 Costs for each category were then determined by multiplying the multiplying the cost estimates by the volume of projects in each category.

7 Cost for each category were summated to provide and expected distribution augmentation expenditure requirement out until 2030.

8 Expenditure proposed for the remainder of the 2020-2025 regulatory period was then subtracted from the projected 2030 expenditure amount to determine a final amount of expenditure required in the 2025-2030 regulatory period.

9 Minimum demand modelling was also performed based on minimum demand forecasts. To do this PowerFactory modelling was performed across the network based on 2030 minimum demand forecast and the resulting constraints were recorded. Please note whilst any resulting constraints are not considered or costed for resolution in this business case, it did highlight that there is a considerable overlap between maximum demand and minimum demand constraints, which further reinforces the value derived from this proposed program.

Table 2 Quantity of Proposed Projects

Start of Feeder Utilisation Constraints	Downstream Utilisation Constraints	Voltage Constraints
63	97	184

3.5 Economic Summary

3.5.1 Cost summary 2025-30 Planned Distribution Augmentation

A summary of the proposed Planned Distribution Augmentation expenditure is provided in Table 3. The timing of the work has been balanced across the regulatory period to ensure a deliverable program.

Table 3 Planned Distribution Augmentation Expenditure (in $m)

Planned Distribution Augmentation Capacity and voltage	25/26	26/27	27/28	28/29	29/30
Total Planned Augmentation	$15.32	$16.19	$17.51	$18.84	$20.23

3.6 Optimal Timing

The individual projects that make up the Planned Distribution Augmentation program are typically shorter duration projects of two years and under. Operating on a relatively short duration ensures projects can proceed efficiently with minimal risk of timing inaccuracy. The project timing is created to meet the associated timing of constraints and associated regulatory obligations whilst balancing deliverability of a large overall program of work.

The programs of work presented in this business case are formed by a large number of smaller projects. A prudent level of investment is assured by prioritising the timing and need for projects that make up this program based on risks, ensuring a range of viable alternative options are considered to minimise the cost and optimise the timing of any investments made within the network. Each individual investment that forms part of this program will be approved via an individual stand-alone business case and delegate approval before funding is released.

4 RECOMMENDATION

It is recommended to establish the program or work and breakdown as detailed in this business case. Table 4 summarises the key components of this program.

Table 4 Options Analysis Scorecard

Criteria	Detail
Net Present Value	Only applicable for investments that make up this program that are not a regulatory requirement.
Investment cost (TCO)	$88.09m
Investment Risk	Medium
Benefits	Meet Regulatory Obligations
Delivery time	This business based is for a rolling program made up of numerous individual projects that typically have a life cycle of less than 24 months
Detailed analysis – Benefits	By implementing this business case Ergon Energy will be able to meet its regulatory requirements in terms of capacity and voltage management of the network.
Detailed analysis – Risks	Conservative assumptions have been applied to the analysis in this business case and hence the funding requested is low in comparison to the amount that could otherwise be justified. This business case does not consider constraints in the 2020-2025 regulatory period that may not have been addressed during this period or associated work/investment that carry over from the 2020-2025 period into the 2025-2030 period which is expected to be significant.
Detailed analysis - Advantages	This option results in a distribution network where capacity and voltage are managed and associated regulatory obligations are met.

APPENDICES

Appendix 1: Alignment with the National Electricity Rules

Table 5 Recommended Option's Alignment with the National Electricity Rules

NER capital expenditure objectives	Rationale
A building block proposal must include the total forecast capital expenditure which the DNSP considers is required in order to achieve each of the following (the capital expenditure objectives):	
6.5.7 (a) (1) meet or manage the expected demand for standard control services over that period	See Section 3.1 of this report
6.5.7 (a) (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;	See Section 3.1 of this report
6.5.7 (a) (3) to the extent that there is no applicable regulatory obligation or requirement in relation to: (i) the quality, reliability or security of supply of standard control services; or (ii) the reliability or security of the distribution system through the supply of standard control services, to the relevant extent: (iii) maintain the quality, reliability and security of supply of standard control services; and (iv) maintain the reliability and security of the distribution system through the supply of standard control services	Not Applicable as this business case is compliance based.
6.5.7 (a) (4) maintain the safety of the distribution system through the supply of standard control services.	See Section 3 of this report
NER capital expenditure criteria	**Rationale**
The AER must be satisfied that the forecast capital expenditure reflects each of the following:	
6.5.7 (c) (1) (i) the efficient costs of achieving the capital expenditure objectives	See Section 3.4 of this report
6.5.7 (c) (1) (ii) the costs that a prudent operator would require to achieve the capital expenditure objectives	See Section 3.4 of this report
6.5.7 (c) (1) (iii) a realistic expectation of the demand forecast and cost inputs required to achieve the capital expenditure objectives	See Section 3.4 of this report

Appendix 2: Reconciliation Table

Table 6 Reconciliation

Expenditure	DNSP	2025-26	2026-27	2027-28	2028-29	2029-30	2025-30
Expenditure in business case $m, direct 2022-23, in alignment with the Input sheet in the capex model	Ergon Energy	$15.32	$16.19	$17.51	$18.84	$20.23	**$88.09**

Appendix 3: Glossary

Term	Definition
10 PoE Forecast	Peak load forecast with 10% probability of being exceeded in any year (i.e. a forecast likely to be exceeded only once every 10 years), based on normal expected growth rates and temperature corrected starting loads. 10 PoE forecast load is not to exceed NCC for system normal (network intact) in all cases excepting distribution substations network element category.
50 PoE Forecast	Peak load forecast with 50% probability of being exceeded in any year (i.e. an upper range forecast likely to be exceeded only once every two years), based on normal expected growth rates and temperature corrected starting loads.
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPEX / capex	Capital Expenditure
Cyclic Load	Power load that occurs in such a way that periods of overloads are followed by periods of light load. A piece of equipment may be cyclically loaded and its life expectancy not reduced, if the accelerated rate of deterioration of the insulation during heavily loaded periods, is counterbalanced by the decelerated rate of deterioration during the light loaded periods.
DA	Distribution Authority
DER	Distributed Energy Resources
DF	Distribution Feeder
DNSP	Distribution Network Service Provider
EV	Electric Vehicle
Feeder Utilisation	Percentage of feeder rating utilised under network maximum demand conditions with thermal rating of the feeder measured at the time and season of maximum demand.
High Voltage (HV)	(1.) For distribution networks in Australia, HV normally refers to 11,000 V or higher. (2.) For the purpose of the Electrical Safety Act 2002 (Qld), HV is defined as voltage above 1000V AC or 1500V DC. (3.) HV and LV may also be used to distinguish between the higher voltage side of a transformer and the lower voltage side of a transformer.