Jemena Electricity Networks (Vic) Ltd

Feeder Augmentation at Fairfield

Relief capacity constraint

Business Case

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Feeder Augmentation at Fairfield

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1. Executive Summary

Jemena is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The service area ranges from Gisborne South, Clarkefield and Mickleham in the north, to Williamstown and Footscray in the south, and from Hillside, Sydenham and Brooklyn in the west, to Yallambie and Heidelberg in the east.

Our customers expect us to deliver and maintain a reliable electricity supply at the lowest cost over the lifecycle of our assets. To do this, we must choose the most prudent and efficient solutions that address current and emerging network limitations. In the context of the National Electricity Market (**NEM**), this means choosing an investment plan that maximises the present value of net economic benefits to all those who produce, consume and transport electricity.

This document articulates the business case and plan for the area of the Jemena Electricity Network (**JEN**) servicing the suburbs of Fairfield, Alphington and Ivanhoe. This supply area is serviced by our Fairfield (**FF**) zone substation and by way of a network of 6.6 kV distribution feeders.

This business case presents the current and emerging limitations within this supply area over a 10-year planning horizon and articulates the need for augmentation and other capital works in order to address the identified network needs.

1.1 Identified Needs

The population of the supply area is 21,628 and this is forecast to grow to 26,845 by 2036, an increase of 24.1% (or 1.7% pa). Growth in the supply area is predominantly infill and subdivision of new residential developments.

Maximum electricity demand for the supply area is expected to grow on average by 5.7% per annum during the next 10-year period, driven primarily by population growth and business development. Given this growth, parts of the existing 6.6 kV distribution feeders supplying the area, will not have sufficient capacity to meet this expected increase in maximum demand.

A number of existing network assets in the area are already (or forecast to be) highly utilised including two 6.6 kV distribution feeders. Options to alleviate the forecast constraints of the two 6.6 kV feeders are needed, to connect new customers and maintain current levels of electricity supply reliability.

1.2 Options Considered

In order to meet the demand for increasing customer numbers and electricity demand within the supply area, some existing parts of the electricity distribution network require capital works. This business case presents a range of credible options to meet the forecast demand for electricity over a 10-year planning horizon, and maintain a safe and reliable supply to customers within the supply area. A number of options to alleviate the emerging network limitations were investigated. These include:

- Option 1: Do Nothing (base case)
- Option 2: Augment Feeder FF0-095
- Option 3: Augment Feeder FF0-093
- Option 4: Establish New FF Feeder
- Option 5: Grid Battery System
- Option 6: Demand Management followed by Option 3
- Option 7: Embedded Generation

A summary of the economic analysis of the various options is shown in Table 1-1.

Table 1-1: Economic Analysis Results Summary ($ Real 2024)

Option	1	*2*	3	4	5	6	7
Total costs	$0.00m	$2.25m	$1.98m	$4.02m	$10.18m	$2.08m	n/a
Present Value of market benefits	$0.00m	$3.57m	$3.45m	$4.25m	$3.83m	$3.48m	n/a
Net Present Value (NPV)	$0.00m	$1.32m	$1.46m	$0.23m	-$6.35m	$1.39m	n/a
Option ranking	6	*3*	1	4	5	2	*Note (1)*

(1) Not technically viable

1.3 Preferred Option

The assessment demonstrates that the preferred is to implement Option 3 – Augment Feeder FF0-093 is the option that maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. This option has a capital cost of $2.16 million. The preferred Option 2 provides a 10-year present value net market benefit of $1.5 million. The market benefits forecast to be delivered by the preferred solution are driven by a reduction in the amount of expected unserved energy over the analysis period.

2. Background

This section provides an overview of the supply area, describes the general arrangement of the FF distribution network, and presents the identified needs associated with existing and forecast feeder capacity limitations on FF0-093 and FF0-095.

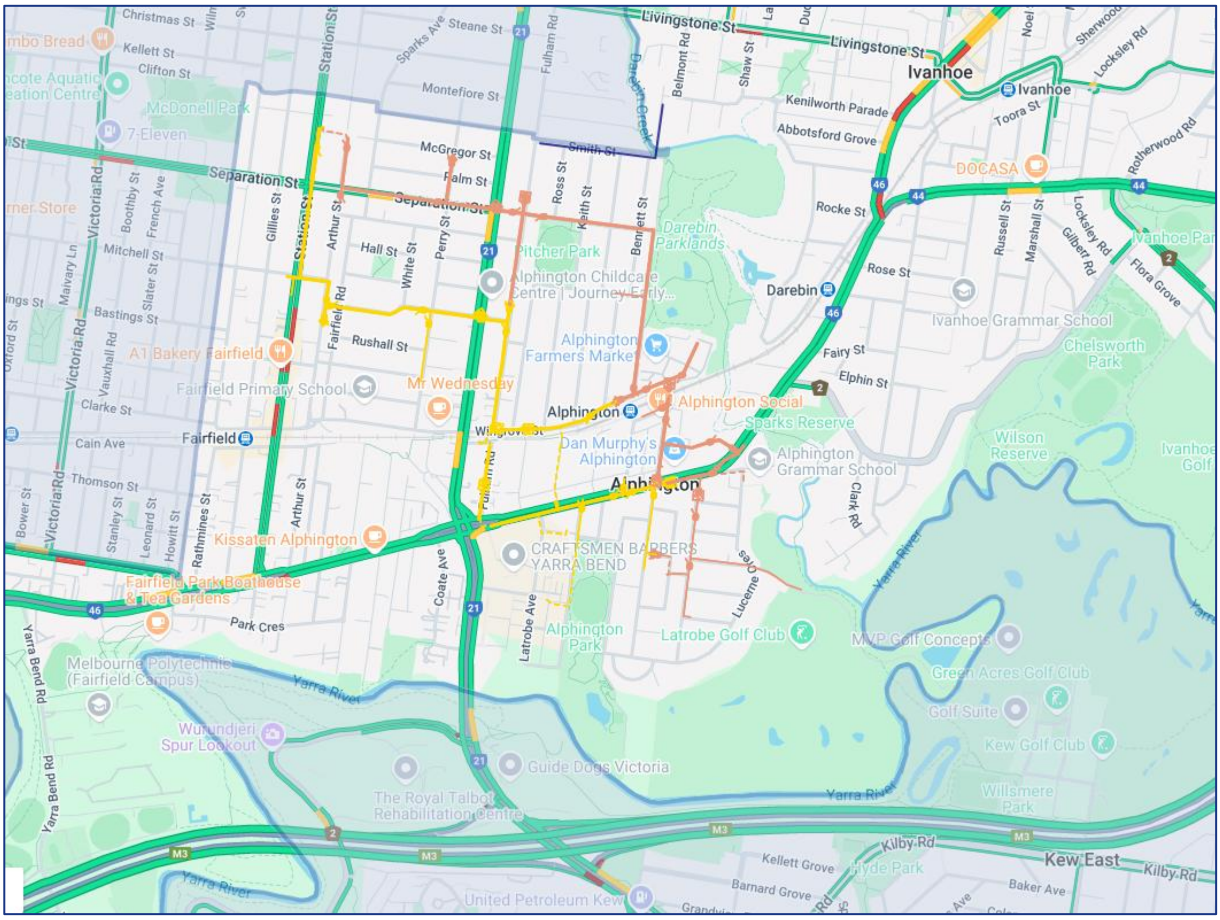
2.1 Business and socio-economic context

Fairfield Zone Substation (FF) comprises two new 22/6.6 kV 12/18 MVA transformers and one old 22/6.6 kV 10/13.5 MVA transformer (currently operating as cold-standby) as well as three 6.6 kV buses supplying eight JEN 6.6 kV feeders. The substation also supplies six CitiPower 6.6 kV feeders.

The distribution network in this area has operated on a legacy 6.6 kV network voltage, much of this distribution voltage in JEN has been phased out in favour of 22kV, meaning there is no load transfer to adjacent zone substations. There is difficulties providing additional ties to East Preston (EP) zone substation due to the Citipower boundary to the north west limiting potential new routes hence congesting the suburbs and surrounds with additional electrical infrastructure, effectively leaving FF as an island network. The forecast maximum demand growth will continually erode this no transfer capability and continue to increase the risk exposure of the area. The population of the supply area is 21,628 and this is forecast to grow to 26,845 by 2036, an increase of 24.1% (or 1.7% pa). This growth is due to significant increases in the number of new infill high and medium density residential townhouses and apartments, and commercial redevelopments with the largest being the [redacted] that is constructing residential high rises and commercial precincts located near the former [redacted]

Figure 1-1 below shows the JEN areas supplied by FF zone substation.

Figure 1-1: FF Zone Substation Supply Area



Forecast 10POE summer maximum demand on FF0-093 is expected to exceed its N rating in summer 2029-2030, FF0-095 is expected to exceed its N rating in summer 2027-2028 due to new customer connection and residential developments.

2.2 Asset risk (or opportunity) analysis

2.2.1 Short description of the affected Jemena assets

The affected assets are HV distribution feeders FF0-093 and FF0-095. This document focuses on the forecast capacity limitations on JEN's HV distribution feeder FF0-93 and FF0-095 and its adjacent feeders within this growth area. FF0-093 and FF0-095 are forecast to exceed their rating by summer 2029-30 and 2027-28 respectively. This is illustrated in Table 2-1: Feeder forecast maximum demand (Amps) – Do Nothing which shows the actual maximum demand for 2024 and forecast maximum demand of the feeders in this area. Values in red represent overloads.

Table 2-1: Feeder forecast maximum demand (Amps) – Do Nothing

Feeder	Summer Forecast	Rating	2024 Actual	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	10% POE	285	258	278	278	279	281	284	290	296	303	310	316
	50% POE			257	258	259	262	264	269	275	282	288	294
FF0-095	10% POE	285	214	240	251	272	295	315	329	341	348	356	363
	50% POE			216	227	246	267	285	298	308	315	322	329

2.2.2 Risk assessment

To quantify the energy-at-risk, JEN applies a probabilistic planning method that consists of the following four key steps:

- Network limitation assessment, which involves determining the extent of network constraints for various system normal, network contingency and demand forecast scenarios.
- Energy-at-risk analysis, where the maximum energy that is at risk of not being supplied due to these network constraints (load shedding required to maintain the assets within rating) is determined.
- Expected unserved energy (EUE) calculation, which considers the forecast demand and the probability of the overload condition occurring (system normal or contingency). HV feeder contingency probability is calculated based on an average of historical data, where available, otherwise assumed to be one outage per year. JEN has weighted two maximum demand scenarios for the EUE calculation to take into account the year-on-year temperature variability[1]. The 10% PoE scenario is weighted 30%, and the 50% PoE scenario is weighted 70%.
- Value of EUE, where the EUE is expressed in dollars by multiplying it with the value of customer reliability (VCR) of $47,905/MWh (2024) which are based on the method derived and published by the Australian Energy Regulator (AER).

The overall forecast distribution feeder EUE and its value for the supply area over the next several years is

[1] This is in accordance with the approach applied by AEMO, and described on page 10 of its publication titled *Victorian Electricity Planning Approach*.

presented in Table 2-2.

Table 2-2: Forecast Expected Unserved Energy (FF0-093 and FF0-095)

Do Nothing	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
10% PoE load at risk (MVA) at N condition	0.0	0.0	0.0	0.1	0.3	0.6	0.8	0.9	1.1	1.2
10% PoE Hours at risk (h) above N condition	0	0	0	7	22	48	121	203	299	423
Expected Unserved Energy (EUE) (MWh)	0.0	0.0	0.0	0.4	4.1	7.1	12.6	19.9	32.0	50.5
Value of EUE ($k)	0	0	0	20	195	341	604	951	1,534	2,419

3. Credible Options

This section discusses how credible options are identified and developed. The credible options are considered for their commercial and technical feasibility, abilities to address the identified needs.

3.1 Identifying credible options

The following options are assessed to address the network need:

- Option 1: Do Nothing (base case)
- Option 2: Augment Feeder FF0-095
- Option 3: Augment Feeder FF0-093
- Option 4: Establish New FF Feeder
- Option 5: Grid Battery System
- Option 6: Demand Management followed by Option 3
- Option 7: Embedded Generation

3.2 Developing credible options

The credible options are discussed in the following sub-sections.

Table 3-1 shows the extent to which each option addresses the identified issues.

Table 3-1: Options Analysis

Option	Project Cost	NPV of Net Market Benefits[2]	Meets Need	Technically Feasible	Timing	Ranking
1: Do Nothing	$0.00m	$0.00m	○	○	○	7
2: Augment Feeder FF0-095	$2.25m	$1.32m	●	●	●	3
3: Augment Feeder FF0-093	$1.98m	$1.46m	●	●	●	1
4: Establish New FF Feeder	$4.02m	$0.23m	●	●	●	4
5: Grid Battery System	$10.18m	-$6.35m	◑	◑	●	5
6: Demand Management	$2.08m	$1.39m	●	◑	●	2
7: Embedded Generation	n/a	n/a	○	○	○	6

●	Fully addressed the issue
◑	Partially addressed the issue
○	Did not address the issue

The preferred option is to Augment Feeder FF0-093 (Option 3) as it maximises the NPV of net market benefits.

[2] Present value of avoided risk less the present value of capital and ongoing incremental operational costs.

3.3 Options analysis

3.3.1 Option 1: Do Nothing

Option 1 is the 'do nothing' scenario, assuming that we continue to manage network loading within limitations by involuntary load shedding where required, such as during peak demand periods or following an asset failure. This is a zero capital cost option and is used as a base case to compare costs and benefits of the other potential options identified.

The risks associated with the "do nothing" option are:

- Inability to connect new customer load;
- Increased risk of breaching statutory clearances (green book) on bare overhead conductors;
- Increased risk of failure of equipment (e.g., cables, joints, etc.) when equipment operated above limits;
- Inability to restore all lost supplies in the event of loss of a critical asset during peak demand period;
- Deterioration of supply reliability due to capacity shortfall; and
- Intangible costs to Jemena arising from negative publicity due to longer supply restoration time during and following hot weather events.

Table 3-2 presents the weighted expected unserved energy (EUE) of Option 1 (Do Nothing) for FF0-093 and FF0-095.

Table 3-2: Do Nothing Weighted EUE (MWh pa)

Feeder	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	0.0	0.0	0.0	0.2	1.6	2.3	2.8	3.3	4.0	4.8
FF0-095	0.0	0.0	0.0	0.3	2.4	4.8	9.8	16.6	28.1	45.7
Total	0.0	0.0	0.0	0.4	4.1	7.1	12.6	19.9	32.0	50.5
Value of EUE $k	0	0	0	20	195	341	604	951	1,534	2,419

The risk is dominated by both, the forecast overloading of FF0-093 and FF0-095 under system normal conditions.

3.3.2 Option 2: Augment Feeder FF0-095

This option involves increasing the feeder rating of FF0-095 from 285A to 375A, this can be achieved by reconductoring approx. 2.3km of HV O/H, installing approx. 200m of HV U/G cable and rearranging HV switches to transfer 32A from FF0-093 to FF0-095.

Following completion of Option 2, the expected maximum demand is shown in Table 3-5. Values in red represent forecast overloads.

Table 3-3: Feeder forecast maximum demand (Amps) – After Option 2

Feeder	Rating	Forecast	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	285	10% POE	246	246	248	250	252	258	265	272	278	284
FF0-095	375	10% POE	271	282	303	326	347	360	372	380	388	394

Table 3-6 presents the residual weighted expected unserved energy (EUE) after completing Option 2.

Table 3-4: Residual Weighted EUE (MWh pa) – After Option 2

Feeder	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	0.0	0.0	0.0	0.0	0.1	0.2	0.5	0.8	1.1	1.5
FF0-095	0.0	0.0	0.0	0.3	1.9	2.4	2.9	3.5	4.3	5.1
Total	0.0	0.0	0.0	0.3	2.0	2.6	3.4	4.3	5.4	6.5
Value of EUE $k	0	0	0	15	94	124	163	207	258	312

The total cost for this project is estimated to be $2.45 million.

3.3.3 Option 3: Augment Feeder FF0-093

This option involves increasing the feeder rating of FF0-093 from 285A to 375A, this can be achieved by reconductoring approx. 2.6km of HV O/H, installing approx. 100m of HV U/G cable and rearranging HV switches to transfer 65A from FF0-095 to FF0-093.

Following completion of Option 3, the expected maximum demand is shown in Table 3-5. Values in red represent forecast overloads.

Table 3-5: Feeder forecast maximum demand (Amps) – After Option 3

Feeder	Rating	Forecast	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	375	10% POE	343	343	344	346	349	355	361	368	375	381
FF0-095	285	10% POE	175	186	207	230	250	264	276	283	291	298

Table 3-6 presents the residual weighted expected unserved energy (EUE) after completing Option 3.

Table 3-6: Residual Weighted EUE (MWh pa) – After Option 3

Feeder	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	0.0	0.0	0.0	0.6	2.9	3.6	4.0	4.3	4.6	4.9
FF0-095	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.6	1.1
Total	0.0	0.0	0.0	0.6	2.9	3.7	4.2	4.6	5.2	6.0
Value of EUE $k	0	0	0	30	140	177	200	221	249	286

The total cost for this project is estimated to be $2.16 million.

3.3.4 Option 4: Establish New FF Feeder

This option offloads FF0-093 and FF0-95 and involves establishing one new feeder at FF, installing approx. 1.4km of new HV U/G cable and approx. 650m of reconductor to achieve a feeder rating of 375 A and switching arrangements. This option is with the assumption that fourth 6.6 kV Bus at FF have already been establish as part of FF ongoing augmentation works.

Following completion of Option 4, the expected maximum demand is shown in Table 3-7. Values in red represent forecast overloads.

Table 3-7: Feeder forecast maximum demand (Amps) – After Option 4

Feeder	Rating	Forecast	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	285	10% POE	278	278	279	170	173	179	185	192	199	205
FF0-095	285	10% POE	240	251	272	136	157	170	182	190	198	204
FF0-044	375	10% POE	-	-	-	250	261	269	278	284	290	296

Table 3-8 presents the residual weighted expected unserved energy (EUE) after completing Option 4.

Table 3-8: Residual Weighted EUE (MWh pa) – After Option 4

Feeder	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
FF0-093	0.0	0.0	0.0	0.0	0.1	0.3	0.5	0.7	0.9	1.1
FF0-095	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	0.9
FF0-044	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.0	0.0	0.0	0.0	0.1	0.4	0.6	1.0	1.4	2.0
Value of EUE $k	0	0	0	0	7	17	30	47	69	97

The N overload risk is completely addressed with this option. The total cost for this project is estimated to be $4.38 million.

3.3.5 Option 5: Non-Network (Battery Storage)

This option looks at installing a total of 6.0MW/12.0MWh [3] battery systems distributed across FF0-093 and FF0-095 feeders to address the load-at-risk under contingency conditions.

There is insufficient controllable residential energy storage on these feeders available today to meet the need. Instead, grid-scale battery energy storage systems connected to the feeders can address the need. This option however requires further detailed assessment and community consultation to identify locations for the battery systems.

The capital cost of this option (for a 10-year asset life) is $12.0 million (based on a fully installed battery cost of A$1,000/kWh).This option addresses the capacity constraint on FF0-093 and FF0-095.

3.3.6 Option 6: Non-Network (Demand Management Followed by Option 3)

Demand side management, such as voluntary load reduction can alleviate supply risks caused by network inadequacies by reducing and/or shifting the peak demand. The resulting reduction in peak demand can potentially defer the need for major network augmentation, or help to better manage the risk until a major network augmentation can be commissioned or is economically feasible. It also mitigates the risk in demand forecasts that may not materialise.

Potential demand reduction solutions are limited by the demand of a customer, i.e., an individual customer can only reduce its demand to zero. Typically, the absence of large customers limits the potential for large demand-side solutions. The breakdown of customers on FF0-093 and FF0-095 is show below in Table 3–9.

[3] Load-at-risk on FF0-093 and FF0-095 is 2.7 MVA and 2.9 MVA respectively by 2030-31. Utilisation of FF0-093 and FF0-095 in 2031 is 104% and 120% respectively of rating requiring a E/P ratio of 2 times.

Table 3–9: Customer numbers on FF0-093 & FF0-095

Feeder	FF0-093	FF0-095
Commercial	38	88
Industrial	0	2
Residential	1,266	1,259
Total	1,304	1,350

Feeders FF0-093 and FF0-095 supply 2,525 residential customers in total. Residential demand management could achieve demand reductions through behavioural demand response or air-conditioner control. Up to 0.35MW (assuming 10% recruitment, 70% participation and 30% demand reduction per customer) could be delivered with a customer recruitment and communications cost of $100k pa plus a $5/kWh rewards payment is assumed.

This option also looks at engagement with commercial and industrial customers to reduce the feeders' loading during maximum demand periods which could potentially defer the preferred network option. The feeders have potential demand reduction on commercial and industrial demand of 0.12MW with an estimated availability price of $120k pa, plus dispatch costs in the order of $1/kWh.

The total demand management operating cost is $0.22 million[4] for 0.47MW over 1 year starting in 2027-28, followed by Option 3 capital cost of $2.16 million in readiness for the summer 2028-29.

3.3.7 Option 7: Non-Network (Embedded Generation)

Dispatchable embedded generation can be an alternative for the alleviation of network limitations, thereby deferring the need for augmentation projects. To defer any network augmentation projects, the embedded generation would need to be connected to, and supply into, the 6.6 kV distribution network where constraints exist and to be able to defer the augmentation by at least one year.

JEN does not have a generation licence and must therefore procure generation to provide network support from third parties. There are currently no known proponents for connection of embedded generation to the JEN network in the FF0-093 and FF0-095 supply area. Therefore, this option has not been assessed further. Proponents for embedded generation are encouraged to apply or express their interest to JEN at any time through our demand-side engagement and Distribution Annual Planning Report (DAPR) processes. The feasibility and cost of any non-network option proposed will be evaluated over the project life-cycle cost before committing to the preferred network solution.

[4] ($100k + $120k) x 1 year + (0.97 + 0.07) MWh x ($1/kWh x .35MW + $5/kWh x 0.12MW) / 0.47MW = $0.22m

4. Option Evaluation

This section presents the results of an economic cost-benefit analysis undertaken on each option. It takes into account the present value of capital and additional operating costs, and the present value of the EUE over an analysis period of 10-years.

4.1.1 Economic evaluation

A summary of the cost-benefit analysis assessed for each option is present in Table 4-1. Option 3 maximises the NPV, relative to all other options assessed.

Table 4-1: Economic Analysis Results Summary ($'000 Real 2024)

	Option 1	Option 2	Option 3	Option 4	Option 5	Option 6	Option 7
Total costs	$0	$2,248	$1,980	$4,018	$10,178	$2,082	n/a
Present Value of market benefits	$0	$3,567	$3,455	$4,252	$3,826	$3,475	n/a
Net Present Value (NPV)	$0	$1,319	$1,475	$234	-$6,351	$1,393	n/a
Option ranking	6	3	1	4	5	2	*Note (1)*

(1) Not technically viable

[5] Followed by Option 3 after 1 year

5. Recommendation

The assessment demonstrates that the preferred network development plan is to implement Option 3 (Augment feeder FF-093) because this option maximises the net economic benefit to all those who produce, consume and transport electricity in the NEM. The preferred Option 3 provides a 10-year present value net market benefit of $1.5 million, with a present value of $1.98 million of investment. The market benefits forecast to be delivered by the preferred solution are driven by a reduction in the amount of expected unserved energy over the planning period.

The estimated total capital cost of Option 3 to address the identified network limitations is $2.16 million ($2024, Real) by November 2027.

Appendix A
Project Scope of Works

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A1. High Level Scope of Work (Option 3)

Augment FF0-093

1. From FF0-093 Feeder CB to A166628 (FF0-093)
    a. Confirm approx. 100m of existing HV U/G cable is rated to a minimum summer cyclic rating of 375A along McGregor St, Arthur St
2. From A166628 to A131612 (FF0-093)
    a. Replace approx. 160m of existing 19/.083 Cu with 19/3.25 AAC designed to 65/30°C along Arthur St
    b. New conductor to achieve a minimum summer rating of 375A
3. From A131612 to A107850 (FF0-093)
    a. Replace approx. 330m of existing 6/4.75 7/1.60 ACSR with 19/3.25 AAC designed to 65/30°C along Separation St
    b. New conductor to achieve a minimum summer rating of 375A
4. From A107850 to A110369 (FF0-093)
    a. Replace approx. 240m of existing 19/.083 Cu with 19/3.25 AAC designed to 65/30°C along Seperation St
    b. New conductor to achieve a minimum summer rating of 375A
5. From A110369 to A143927
    a. Confirm approx. 110m of existing 19/3.25 AAC is designed to 65/30°C along Seperation St
    b. New conductor to achieve a minimum summer rating of 375A
6. From A143927 to A040297 (FF0-093)
    a. Replace approx. 370m of existing 6/4.75 7/1.60 ACSR with 19/3.25 AAC designed to 65/30°C along Separation St, Smith St
    b. New conductor to achieve a minimum summer rating of 375A
7. From A040297 to A110357 (FF0-093)
    a. Replace approx. 750m of existing 19/.083 Cu with 19/3.25 AAC designed to 65/30°C along Yarana Rd, Wingrove St
    b. New conductor to achieve a minimum summer rating of 375A
8. From A110357 to A119895 (FF0-093)
    a. Replace approx. 100m of existing HV U/G cable with new HV U/G cable and 2 spare HV conduits at rail crossing
    b. New conductor to achieve a minimum summer rating of 375A
9. From A119895 to A014496 (FF0-093)

   a. Replace approx. 350m of existing 19/.083 Cu with 19/3.25 AAC designed to 65/30°C along Yarralea St, Heidelberg Rd

   b. New conductor to achieve a minimum summer rating of 375A

Other works and switching arrangements

10. From A1576764 to 20221761 (FF0-095)

    a. Replace approx. 350m of existing 7/.080 Cu with 19/3.25 AAC designed to 65/30°C along Fulham Rd, Wingrove St

    b. New conductor to achieve a minimum summer rating of 375A

11. At A160052 open MGS (SW10132) (Wingrove St) (FF0-093/FF0-095)

12. At A110352 close HV ISOLS (SW12716) (Wingrove St) (FF0-093)

13. At A015024 close MGS (SW12685) (Yarralea St) (FF0-093)

14. At A119881 replace HV ISOLS (SW12780) with MGS (N.O.) (Heidelberg Rd) (FF0-093/FF0-095)

The proposed will transfer the following:

- 65A from FF0-095 to FF0-093

Figure A1–1: Proposed works on feeder FF0-093

[redacted]

Appendix B
Economic Evaluation Spreadsheets

B1. Economic Evaluation Spreadsheets

Overview of Options Analysis						
Options	Option 1 - Status Quo	Option 2 - Upgrade FF95	Option 3 - Upgrade FF93	Option 4 - New Feeder	Option 5 - Battery	Option 6 - DM
Recommended Option			✓			
Customer						
NPV of Net Customer Benefits on Regulated Assets ($000)	-	1,319.0	1,475.0	234.0	(6,351.5)	1,392.9
Financial						
NPV of Net Financial (Investor) Benefits ($000)	-	158.7	139.8	283.7	769.3	140.7
[redacted]						
Risk						
Mandatory Risk	N					
Dominant Risk Type	Brand / Reputation / Stakeholders					
Risk Rating	Significant	Low	Low	Low	Low	Low
Strategic						
Customer Performance	n/a	2	2	2	2	2
Operational Reliability	n/a	2	2	2	2	2
Safety	n/a	1	1	1	1	1
People Engagement	n/a	-	-	-	-	n/a
Emissions Reduction	n/a	-	-	-	-	n/a
Reputation	n/a	1	1	1	1	1

Customer Benefit Analysis (Regulated Assets)						
Options	Option 1 - Status Quo	Option 2 - Upgrade FF95	Option 3 - Upgrade FF93	Option 4 - New Feeder	Option 5 - Battery	Option 6 - DM
Recommended Option			✓			
NPV of Net Customer Benefits ($000)	-	**1,319.0**	**1,475.0**	**234.0**	**(6,351.5)**	**1,392.9**
NPV of Total Customer Benefits ($000)	-	3,567.3	3,455.0	4,252.1	3,826.4	3,475.1
Avoided cost at asset failure	-	-	-	-	-	-
Improved energy reliability	-	*3,567.3*	*3,455.0*	*4,252.1*	*3,826.4*	*3,475.1*
Reduced energy losses	-	-	-	-	-	-
Increase in customer DER exports	-	-	-	-	-	-
Other customer benefits	-	-	-	-	-	-
NPV of Incremental Total Costs ($000)	-	2,248.3	1,980.0	4,018.2	10,177.8	2,082.1
Total Incremental Net Capex	-	*2,129.8*	*1,875.6*	*3,806.4*	*9,765.7*	*1,806.9*
Total Incremental Opex - One-off	-	-	-	-	-	*189.0*
Total Incremental Opex - Ongoing	-	*118.5*	*104.3*	*211.7*	*412.1*	*86.3*
Sensitivity on Customer NPV ($000)						
Customer Benefits turn out to be 10% lower	-	962.3	1,129.5	(191.2)	(5,968.9)	1,740.4

Financial Analysis						
Options	Option 1 - Status Quo	Option 2 - Upgrade FF95	Option 3 - Upgrade FF93	Option 4 - New Feeder	Option 5 - Battery	Option 6 - DM
Recommended Option			✓			
NPV of Net Financial Benefits ($000)	-	**158.7**	**139.8**	**283.7**	**769.3**	**140.7**
NPV of Total Revenue ($000)	-	2,398.6	2,112.4	4,286.9	10,982.3	2,221.5
Regulated Revenue	-	*2,398.6*	*2,112.4*	*4,286.9*	*10,982.3*	*2,221.5*
Unregulated Revenue	-	-	-	-	-	-
NPV of Total Costs ($000)	-	2,239.9	1,972.6	4,003.2	10,213.0	2,080.9
Total Net Capex	-	*2,119.7*	*1,866.8*	*3,788.4*	*9,793.2*	*1,804.8*
Total Opex - One-off	-	-	-	-	-	*188.3*
Total Opex - Ongoing	-	*120.2*	*105.8*	*214.8*	*419.8*	*87.8*
[redacted]						
Sensitivity on Financial NPV ($000)						
Cost Overrun - Capex by 10%, Opex by 10%	-	(53.2)	(46.9)	(95.2)	(210.1)	(58.7)
Discount Rate increased by 1.0%	-	(142.3)	(125.3)	(254.4)	(614.3)	(114.9)
Discount Rate increased by 0.5%	-	(3.4)	(3.0)	(6.0)	19.0	2.5
Discount Rate decreased by 0.5%	-	348.3	306.7	622.4	1,659.0	303.6
Discount Rate decreased by 1.0%	-	570.3	502.3	1,019.3	2,715.8	496.1

Scenarios including prices on carbon emissions						
Sensitivity on Financial NPV ($000)						
NPV of Net Financial Benefits - Carbon Price of 75 $/tonne	-	158.7	139.8	283.7	769.3	140.7
NPV of Net Financial Benefits - Carbon Price of 100 $/tonne	-	158.7	139.8	283.7	769.3	140.7
Sensitivity on Payback Period (Years)						
Payback Period - Carbon Price of 75 $/tonne	n/a	17.2	17.2	17.2	18.9	17.2
Payback Period - Carbon Price of 100 $/tonne	n/a	17.2	17.2	17.2	18.9	17.2

Output | Tables in Business Case

Total Project Costs

Total costs ($000, $nominal)	Option 1 - Status Quo	Option 2 - Upgrade FF95	Option 3 - Upgrade FF93	Option 4 - New Feeder	Option 5 - Battery	Option 6 - DM
Recommended Option			✓			
Total Net Capex (Gross Capex less Capital Contributions)	-	2,582.9	2,274.6	4,616.2	13,202.9	2,331.5
Total Opex (one-off)	-	-	-	-	-	235.1
Total Opex (ongoing)	-	181.5	159.8	324.3	655.8	136.5
Total costs	-	**2,764.3**	**2,434.5**	**4,940.5**	**13,858.7**	**2,703.1**