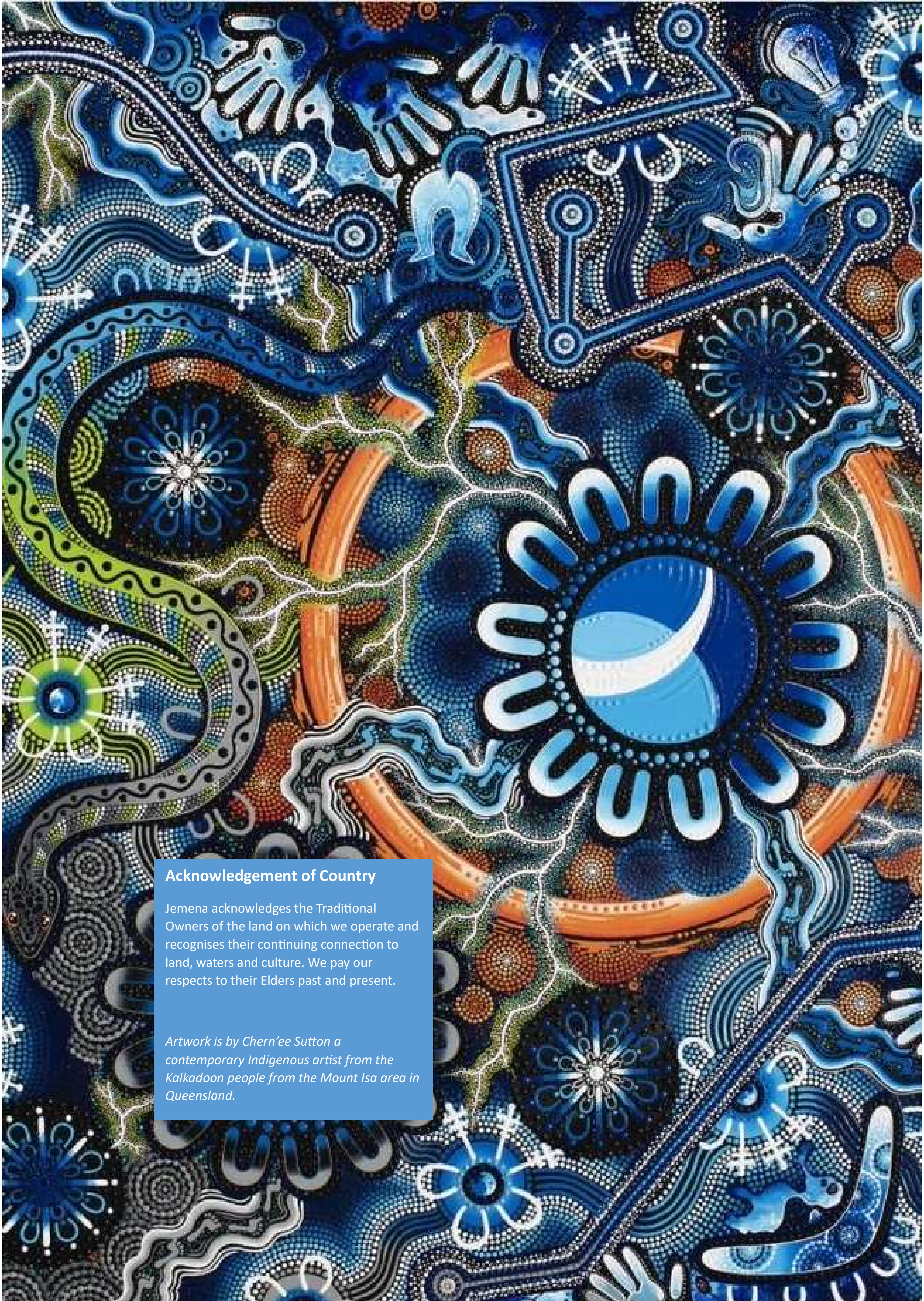
Jemena Electricity Networks

BATTERIES IN UNDERGROUND RESIDENTIAL DISTRIBUTION DEVELOPMENTS

BUSINESS CASE ASSESSMENT

Sep 2024



Acknowledgement of Country

Jemena acknowledges the Traditional Owners of the land on which we operate and recognises their continuing connection to land, waters and culture. We pay our respects to their Elders past and present.

Artwork is by Chern'ee Sutton a contemporary Indigenous artist from the Kalkadoon people from the Mount Isa area in Queensland.

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EXECUTIVE SUMMARY

Jemena set out to assess and develop business cases for the deployment of network-owned Neighbourhood Batteries (NBs) in residential and mixed-use greenfield developments. The business case development project received funding from the Victorian Government Department of Energy, Environment and Climate Action (DEECA) under the Neighbourhood Battery Initiative (NBI), Round 3 Stream 1.

Energy efficiency and optimisation is a key factor in decision making for the design of a new home or business premises. So too, should it be a key factor in the design of a new neighbourhood. With this in mind, as well as interest from the developer industry into front of meter storage solutions offering direct benefits for new communities, this study was initiated as a way to investigate pathways for commercial and technical viability within this type of setting.

Jemena currently applies its Underground Residential Distribution (URD) standard for the residential subdivisions created by new developments within its boundary, commonly within its north and western growth corridors. This standard has recently been updated to consider future increased demands arising from electrification, in particular provision for Electric Vehicle charging. The deployment of NBs in new developments has potential to provide significant network benefits, especially if coordinated within a larger fleet of NBs where operations are optimised to match the real-time network needs over the life of the fleet (ten or more years). Jemena, in its role as network operator, has the controls, systems, processes and knowledge to manage, build, own and operate these assets. This project has therefore considered the value stack of benefits and the approach for development of a business case for network owned NBs.

The business case development has assessed the deployment of network owned NBs in new greenfield developments from an Engineering, Financial, Regulatory, Commercial, Legal, and Community perspective.

Our assessments have found that there are significant network benefits that NBs can provide for URD developments based on our analysis of two developments in Jemena's northern growth corridor. Upfront cost for electricity infrastructure of these greenfield URD developments is going up due to increased demand caused by electrification. Most greenfield developments have high level of solar PV penetration, but networks are not capable of accepting increased solar export which leads to export curtailment. These new developments, aggregates of which are causing constraints in the high voltage distribution network, are generally concentrating in Jemena's northern growth corridor. NBs integrated in these developments are likely to have high network benefit value as they can address the above constraints. The challenge of finding suitable land to install the NBs is overcome when they are included in the master plan of the greenfield developments.

While NBs can be used to provide network support, including in new URD developments, the financial benefits of NBs are unlocked through energy market related services such as through arbitrage (buying and charging the battery when the market price is low, while selling and discharging the battery when the market price is high) and Frequency Control Ancillary Service (FCAS). Due to regulatory limitations, namely distribution ringfencing requirements, regulated networks such as Jemena must, and should, partner with third party Market Participants such as retailers / aggregators to maximise these benefits. Under these arrangements, Jemena would lease the battery to the third party, taking a fixed revenue, while the third party would undertake the commercial operation of buying, selling and providing market services within the National Electricity Market (NEM). In our benefit modelling we have included nominal values of energy arbitrage and Frequency Control Ancillary Service (FCAS).

Similar to other batteries, the economics of NBs are subject to the ability of the NBs to unlock multiple value streams, increasing the value stack and improving the overall financial viability. It is found that positive economic benefit for NB deployment in the two URD use cases is contingent on the availability of the network reliability benefits for at least five years. The table below shows positive Net Present Value (NPV) for Clarkefield URD when the network benefits last for 5 years, and positive NPV for both URD developments when network benefits last 10 years.

Development	Availability of network benefits (years)	Number of NBs considered	Cost* ($M)	Network Benefits# ($M)	Other Benefits# # ($M)	NPV ($M)
Merrifield	2	1	-0.74	0.06	0.18	-0.50
Merrifield	5	1	-0.74	0.26	0.18	-0.30
Merrifield	10	1	-0.74	1.84	0.18	1.28
Clarkefield	2	1	-0.68	0.29	0.18	-0.21
Clarkefield	5	1	-0.68	1.43	0.18	0.94
Clarkefield	10	1	-0.68	2.71	0.18	2.21

#Network benefits include reliability and PV export benefits

Other benefits include less distribution substations, NB tariff rebate, emission benefit and market benefits (arbitrage & FCAS)

Currently Jemena addresses network reliability risks and export curtailment in constrained areas of the network through implementing network upgrade (also referred to as augmentation) projects. Two network upgrade projects have been approved in 2024 to increase the capacity of the high voltage feeders supplying the two URD developments. The current regulatory process requires Jemena to compare non-network solutions, including NBs, with network solutions and select the option that addresses network reliability risks and PV export curtailment while maximising the present value of the net economic benefit to the electricity market.

Factoring in the current costs of NBs and value of network and market benefits, based on approved regulatory methodologies, our finding is that network owned NBs continue to result unfavourably when compared against the traditional network solution approach to address network risks. While this may be the case, NBs do have the potential to deliver short term economic benefits through network upgrade deferral while supporting storage of excess solar energy at the local level.

The financial assessment has considered deferring planned network upgrades by two or five years using NBs. The change in the project financials was then compared against the planned network upgrade projects occurring in 2024.

The financial assessment result is summarised in the following table:

Development	Network upgrade deferral (years)	Total number of NBs required*	Cost** ($M)	Network Benefits# ($M)	Other Benefits## ($M)	NPV ($M)	NPV difference ($M, compared with network upgrade in 2024)
Network upgrade (KLO13)	0	0	-5.78	13.08	0	7.30	NA
Merrifield NBs + KLO13 network upgrade	2	5	-8.97	13.08	1.36	5.46	-1.84
Merrifield NBs + KLO13 network upgrade	5	31	-24.56	13.08	7.67	-3.80	-11.10
Network upgrade (SBY24)	0	0	-5.45	30.35	0	24.9	NA
Clarkefield NBs + SBY24 network upgrade	2	16	-15.43	30.35	3.29	18.21	-6.69
Clarkefield NBs + SBY24 network upgrade	5	70	-45.87	30.35	13.00	-2.52	-27.42

* This number could be more than that possible to fulfil the load and space requirements/constraints in the URD, this has not been assessed as part of this project

** Based on competitive battery cost (equipment and install) of $1,500/kWh ($750/kWh plus $360k cost of design, install & commission per NB

Network benefits include reliability and PV export benefits

Other benefits include network upgrade deferral, less distribution substations, NB tariff rebate, emission benefit, market benefits (arbitrage & FCAS)

As can be seen from the table above, quite a number of NBs would need to be installed to address the reliability risk at the HV feeder level in order to defer the planned network upgrade. The cost of NB deployment is only partially offset by the additional benefits that NBs bring, resulting in a financial gap as indicated in the last column of the table. This means that network upgrade without deferral will provide the best overall economic outcome unless the financial gap created by NB deployment (and network upgrade deferral) can somehow be bridged.

As electricity network already exists extensively in the area where the two URD use cases are located, network capacity in the local area can often be added economically by upgrading existing network assets rather than building new assets. At the edge of the network where only sparse and low capacity network assets exist, the network upgrade cost could be much higher and this in turn will improve the economics of NB installation.

Once the network upgrade project is implemented, network benefits for alleviating the HV feeder constraint will no longer be available to the NB deployment business case.

This business case assessment also explores pathways where costs are reduced and benefits improved, and conducts sensitivity analysis of the various cost and benefit components. It is found that concerted effort to reduce NB cost as well as improvement in benefits could result in significant reduction in the financial gap.

4 INTRODUCTION

In order to support the business case development, Jemena has undertaken the technical analysis for the deployment of Neighbourhood Batteries (NBs) in residential and mixed-use greenfield developments. The business case development project received funding from the Victorian Government Department of Energy, Environment and Climate Action (DEECA) under the Neighbourhood Battery Initiative (NBI), Round 3 Stream 1[1].

Energy efficiency and optimisation is a key factor in decision making for the design of a new home or business premises. So too, should it be a key factor in the design of a new neighbourhood. With this in mind, as well as interest from the developer industry into front of meter storage solutions offering direct benefits for new communities, this study was initiated as a way to investigate pathways for commercial and technical viability within this type of setting.

Jemena currently applies its Underground Residential Distribution (URD) standard for the residential subdivisions created by new developments within its boundary, commonly within its north and western growth corridors. This standard has recently been updated to consider increased demands arising from electrification and in particular meeting Electric Vehicle charging demand. The development of a business case investigating NBs within a greenfield setting was an opportunity to better understand if NBs could partly offset the increased requirements from electrification and to quantify this and other benefits that NBs could offer.

The NBs are intended to be network owned and maintained, with the primary purpose to enable the electricity network to support the sustainability aspirations of the residential and business customers in the precinct.

The business case project has been based on two Underground Residential Distribution (URD) developments as case studies. The two developments are located in Jemena's northern growth corridor where significant new residential and commercial developments are occurring. The High Voltage network capacity to meet additional electricity consumption at peak usage time, and the capacity to accommodate excess solar generation during peak generation/low electricity usage, is stretched to the limit or even exceeded. The NB's ability to absorb excess solar generation and release the stored energy to meet network peak demand is expected to provide significant network benefits by reducing constraints, supporting more customers to install and export solar and improving supply reliability.

The business case development has assessed the deployment of network owned NBs in new greenfield developments from a Engineering, Financial, Regulatory, Commercial, & Legal, and Community perspective.

[1] https://www.vic.gov.au/neighbourhood-battery-initiative-round-3

5 SUMMARY OF ASSESSMENT CRITERIA

5.1 Engineering Assessment

The Engineering Assessment focused on the use case of energy storage from NBs in new Underground Residential Distribution (URD) developments. These developments have higher electricity consumption as they are all-electric, and high penetration of solar PV has led to high export back into the grid during the minimum consumption period. NBs in this application are likely to provide network benefits which will improve the business case for their deployment.

The Engineering Assessment has methodically examined the various design parameters of NB, including capacity, location, technical and control specifications, connection standards and lifecycle management. Through the engineering assessments of two URD developments in Jemena's network area, base case and option studies were selected for the financial modelling and assessment.

Contribution of the Engineering Assessment to the business case assessment process is detailed in the following subsections.

5.1.1 Updated Consumption and Export Requirements of New URD Developments

The Engineering Assessment has updated the electricity consumption and export requirements of new URD developments taking into account all-electric energy supply and emerging residential electric vehicle charging needs. The After Diversity Maximum Demand (ADMD) for import and export of residential premises are used to determine the need for on-site distribution substation infrastructure.

Table 1. 95th percentile ADMD (import and export) for new URD developments

URD Customer Type	ADMD – Import, summer (kVA)	ADMD - export, summer (kVA)	ADMD – import, winter (ADMD)	ADMD – export, winter (ADMD)	Dwelling characteristics
Existing URD customers	4.5	0	2.3	0	Access to gas, no significant solar PV uptake
New URD Customer Type 1	4.5	0	4.8	0	No solar PV, all electric
New URD Customer Type 2	3.1	3.9	4.8	3.9	Solar PV (5kW rating, 3.5kW export), all electric
New URD Customer Type 3	4.6	3.9	6.0	3.9	Solar, all electric, Electric Vehicles (EV)

5.1.2 Quantifiable benefits Used in Financial Modelling

The Engineering Assessment has identified the following quantifiable network benefits to be used in financial modelling based on AER approved methodologies:

- Reduced number of distribution substations (DSS) and associated easement. The initial beneficiary is the URD developer;
- Reliability benefits by managing the overload risks on upstream HV assets until network capacity upgrade or equivalent non-network solutions are implemented. The beneficiary is the customers supplied from the upstream HV assets;

- Reduced export constraints by allowing more solar export into the upstream HV assets. The beneficiary is the solar customers connected to the DSS and upstream HV assets;

To achieve the network benefits, it is crucial that Jemena is given the responsibility to coordinate the NB fleet it has in its network and optimise their operation to match the real-time network needs over the life of the NB fleet. Hence the proposal is for the NBs to be network owned, operated and maintained.

Additional revenue can be delivered by a Market Participant, on behalf of Jemena, for energy market services which currently include energy arbitrage and Frequency Control Ancillary Service (FCAS). The revenue generated, net of operating cost of the Market Participant, will form an on-going income stream for the NB, with Jemena receiving a lease fee from the Market Participant to cover the operational and maintenance costs of the NBs. The quantum of this revenue stream can only be ascertained through a market testing process which is yet to be conducted. An estimate is therefore used in the financial modelling.

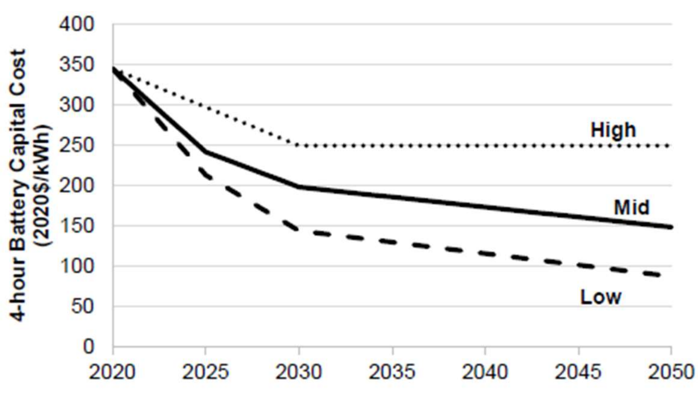
5.1.3 Methodology for Benefit Quantification

The Engineering Assessment proposed a methodology to extrapolate Jemena's maximum and minimum demand forecast for high voltage feeders, zone substations, sub-transmission lines and Jemena network (as a whole) into half-hourly demand forecast for the next 10 years so the data could be used to quantify NB network benefits in the financial modelling. Refer Appendix 1 for more details of the methodology.

5.1.4 Standardisation of NB Size, Siting, Control, Technical Specifications and Life Cycle Management

Battery cost is a large component of the total NB deployment cost (approximately 50%). We are seeing a trend that battery cost is coming down over time driven by worldwide demand. Jemena can further assist in bringing down the total system cost of NB by standardisation of equipment specification, design and construction methods. In addition, to ensure the battery remains fit-for-service during its expected life span, an effective lifecycle management plan is to be established similar to what Jemena does for other assets in its electricity network.

Figure 1. Battery cost projections (in US$) for 4-hour lithium-ion systems[2]



The proposed standardisation will result in a reduction in the implementation cost of network NBs in the short to medium term.

[2] NREL, Cost Projections for Utility-Scale Battery Storage: 2021 Update, 2021

5.2 Regulatory Assessment

In its most recent update of the Ring Fencing Guideline for Electricity Distribution (The Guideline) in November 2021, the Australian Energy Regulator (AER) concluded that DNSPs leasing battery capacity to another legal entity is specifically prohibited unless a waiver is granted under the Guideline.

The Guideline also recognises that ring-fencing obligations, in some circumstances, may result in outcomes that are not in the long-term interest of consumers and hence makes provision for ring-fencing class or individual waivers. Waivers can be an important regulatory provision that enable DNSPs to deliver market innovations for the benefit of their customers in specific cases. The Guideline includes a streamlined assessment process for battery waivers, with a supporting explanatory memorandum, to fast-track applications for DNSPs to lease spare battery capacity to other parties including in relation to NBs.

The AER requires a range of information to assess the streamlined waiver and provides a template for completion. In considering whether to apply the streamlined waiver process, the AER is likely to give most weight to how cross-subsidisation risks have been addressed through how the cost allocation of the project has been determined by the DNSP, and whether sufficient market testing has been undertaken by the DNSP (which also addresses discrimination risks). The customer engagement approach is likely to be important to provide the comfort that broader AER led stakeholder consultation is not needed.

The Regulatory Assessment outlines the type of information required by the AER for a streamlined waiver application and a market testing approach for Jemena to consider based largely upon a successful application obtained by Endeavour Energy in 2023 and subsequent AER commentary of relevance in their Federal class waiver determination.

The Regulatory Assessment noted that the Victorian Government has a stated aim to support the installation of 100 NBs through multiple funding rounds[3] (Round 1 closed on 31 October 2023, with future rounds expected in Q3 2024 and Q1 2025). In delivering on this commitment, it would be both prudent and timely for the Victorian Government to initiate discussions with the AER to consider a Victorian class waiver process. The class waiver process avoids the need for multiple individual waivers by DNSPs across Victoria, reducing the administrative burden and assisting to meet battery targets and other policy-related aims (e.g. resilience).

5.3 Financial Assessment

The Financial Assessment used a custom designed Excel spreadsheet based model to calculate the costs and benefits of NB deployment over a 10-year timeframe.

5.3.1 Project Costs

NB project costs consist of the following components:

- Upfront capital cost for installing a NB
- On-going operating and maintenance cost
- Network cost for charging and discharging
- Retail energy cost for battery charging
- Land cost of deploying the battery (to capture the opportunity cost of this additional network infrastructure)

The table below (Table 1) summarises the key Project Cost assumptions used in the financial analysis.

[3] 100 Neighbourhood Battery grant (energy.vic.gov.au)

Table 1. Project Cost Assumptions

Project cost	
Item	Cost ($)
NB equipment	$750/kWh
Design, installation & commissioning per NB	$360,000
On-going operating and maintenance	$0 (absorbed in existing Jemena O&M costs)
Network cost for charging & discharging	As per Jemena trial community battery tariff[4]
Retail energy cost for battery charging	Wholesale prices modelled with approach to buy in daytime while low and sell in afternoon / evening while high. Revenue modelled based on stochastic model of historical spot prices and forecast for future 10 years of NB operation.
Land cost	$1,116/$m^2$

5.3.2 Project Benefits

NB project benefits consist of the following quantifiable components:

- Reduced number of distribution substations (DSS) to meet demand for all customers on a local voltage network – calculated using updated ADMD
- Reduced land cost from less DSS and associated easement to meet demand for all customers on a local voltage network - estimated
- Reliability benefits - A battery has the potential to alleviate import constraint at any of the upstream network assets (e.g. DSS, 22kV, ZSS, 66kV). For both the Merrifield and Clarkefield URD developments, the analysis concluded that the maximum constraint benefits were associated with the upstream high voltage feeders, and in particular alleviating import rather than export constraints. Reliability benefits are quantified using AER's Value of Customer Reliability (VCR)
- Reliability benefits - A battery has the potential to alleviate import constraint at any of the upstream network assets (e.g. DSS, 22kV, ZSS, 66kV). For both the Merrifield and Clarkefield URD developments, the analysis concluded that the maximum constraint benefits were associated with the upstream high voltage feeders, and in particular alleviating import rather than export constraints. Reliability benefits are quantified using AER's Value of Customer Reliability (VCR)
- Energy arbitrage - estimated
- Frequency Control Ancillary Service (FCAS) - estimated
- Network community battery tariff rebate – based on current Jemena community battery trial tariff
- Value of emission reduction. With the addition of emissions reduction to the National Electricity Objective (NEO), the AER has issued a guideline on applying a value of emission reduction (VER) to regulatory processes such as regulatory investment tests and regulatory determination[5]. The guideline includes a table of interim VERs to be applied for each year from 2023 to 2050. To understand the quantum of this benefit to the NB business case, we have modelled the emission reduction by assuming that the NB is charged from zero emission generating sources and displaces the use of emission intensive generation when it discharges at peak time. The emission intensity of Victoria's generation is taken from AEMO's published data for 2023 and are daily averages. The indicative value of emission reduction for all options is assumed to be 0.7613 tCO_2e/MWh, the average emissions intensity for 2023 based on a time weighted average of every 30-minute interval in Victoria.

[4] Jemena, Trial Tariffs | Jemena

[5] AER, Valuing emissions reduction final guidance - May 2024 | Australian Energy Regulator (AER), May 2024

As the AER releases further guidance on incorporating VERs in cost benefit analysis, this benefit may change in future NB business cases.

The table below (Table 2) summarises the assumed project benefits

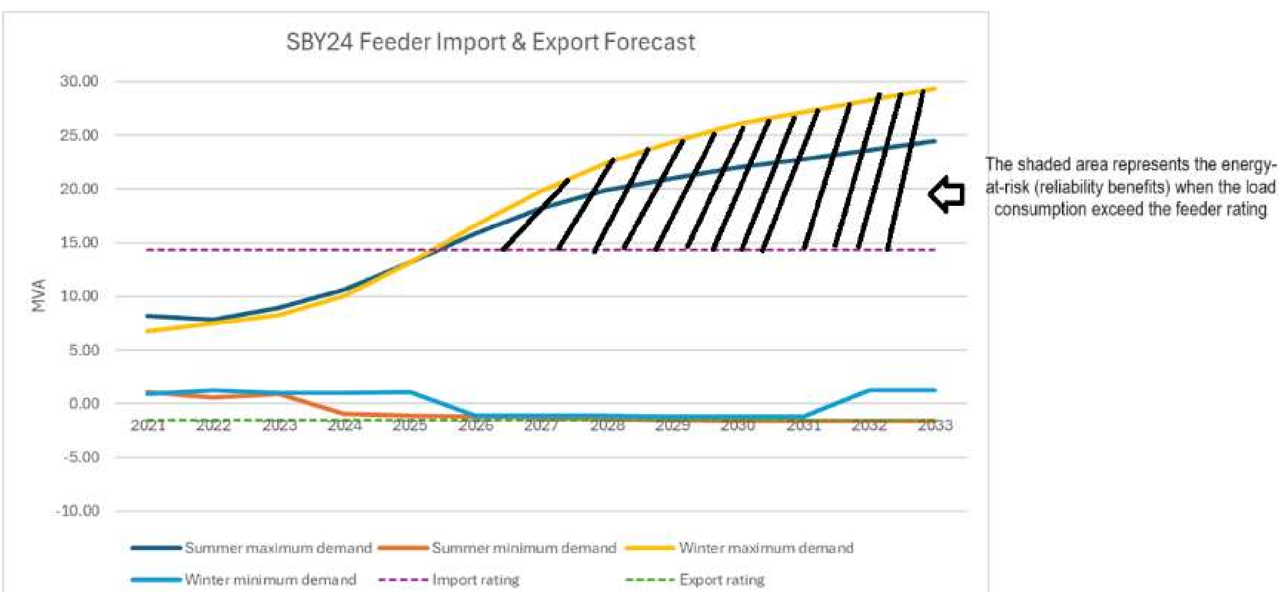
Table 22. Assumed Project Benefits

Project Benefits	
Item	Benefits ($)
Reduced number of DSS	25% reduction, installed cost of one DSS = $200,000
Reduced land cost	$1,116/m^2
Reliability benefits*	$45.01/kWh
Export curtailment benefits*	As per AER's CECV methodology
Energy arbitrage	Wholesale prices modelled with approach to buy in daytime while low and sell in afternoon / evening while high. Revenue modelled based on stochastic model of historical spot prices and forecast for future 10 years of NB operation and 80% of usable battery capacity
FCAS	$30,000 / MW / year revenue
Network tariff rebate	As per Jemena trial community battery tariff
VER	As per AER's VER guidance paper

5.3.3 Summary of Financial Modelling

A NB has the potential to alleviate import and export constraints at any of the network assets The Financial Assessment conducted for the two URD developments has revealed that significant network reliability benefits exist on the two High Voltage (HV) feeders connecting to the two developments, with Clarkefield producing higher reliability benefits than Merrifield due to higher load growth forecast on its connected HV feeder. The reliability benefit starts low initially but quickly escalates with time as represented by the shaded area in Figure 2:

Figure 2. Feeder forecast and reliability risk for SBY24 (Clarkefield URD HV feeder)



As the reliability benefit ceases when network upgrade or equivalent non-network solution is implemented to remove the HV feeder constraint, this benefit is heavily dependent on the timing of the network upgrade project. We initially carried out financial modelling for ten years, but then updated our approach with the network benefits lasting for different periods – two, five and ten years – and the results are summarised shown in Table 2.

Table 3. NPV results for URD case studies with different network benefit periods

Development	Availability of network benefits (years)	Number of NBs considered	Cost* ($M)	Network Benefits# ($M)	Other Benefits# # ($M)	NPV ($M)
Merrifield	2	1	-0.74	0.06	0.18	-0.50
Merrifield	5	1	-0.74	0.26	0.18	-0.30
Merrifield	10	1	-0.74	1.84	0.18	1.28
Clarkefield	2	1	-0.68	0.29	0.18	-0.21
Clarkefield	5	1	-0.68	1.43	0.18	0.94
Clarkefield	10	1	-0.68	2.71	0.18	2.21

It can be seen from Table 2 that none of the case studies returns a positive Net Present Value (NPV), i.e. benefits outweigh costs, if the reliability benefits only exist for two years. Clarkefield starts to return positive NPV when the reliability benefits exist for five years, while all case studies return positive NPV when the reliability benefits exist for ten years.

Refer Section 8 - Appendix 3 for details of the financial re-modelling approach and results.

The implication of the financial modelling results are discussed in Section 4 – Jemena Investment Requirements.

5.4 Commercial Assessment

The Commercial Assessment examined possible Jemena options to reduce project costs and increase the certainty of the project benefits. From a business case perspective, the two most pertinent aspects to consider are summarised in the subsections below.

5.4.1 Market Testing to Support Regulatory Waiver Application

Ensuring the NB participates in the energy market through third party leasing arrangements could bring in additional revenues which are in the long-term interest of electricity consumers.

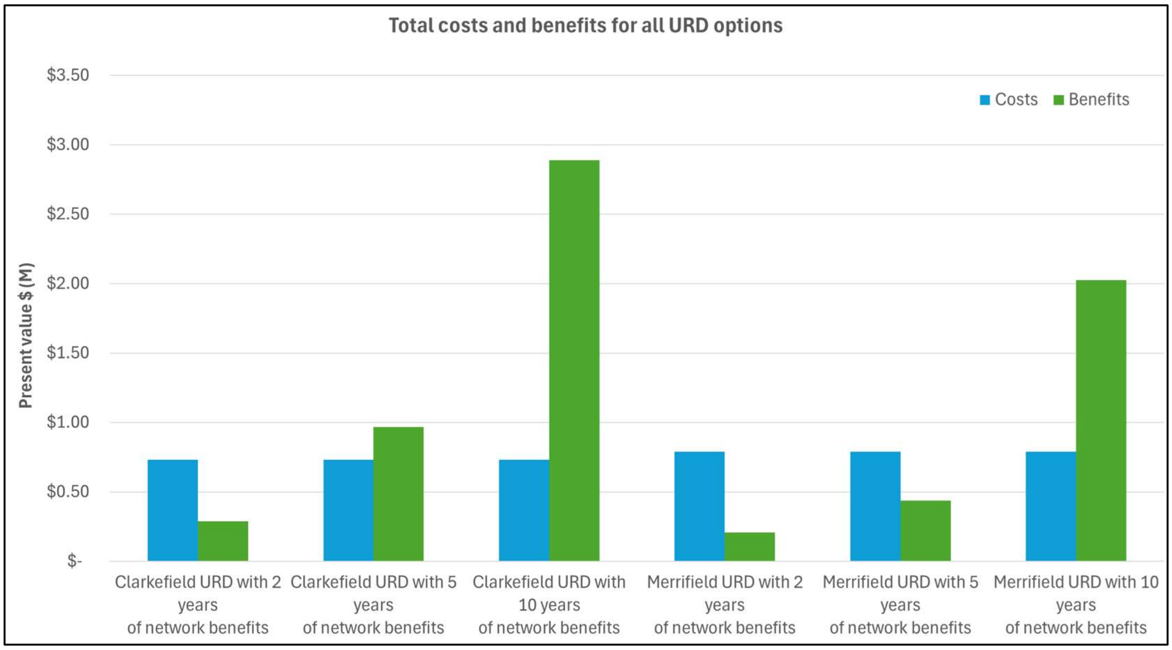
Jemena, however, is not a Market Participant and will have to contract a third party for energy market benefits. How the contract is structured can significantly affect this revenue stream.

The AER's regulatory waiver process requires certainty of revenue streams for the NB. The Regulatory Assessment Report outlines a market testing process to lock down the contracted cost for energy market services that could be used by Jemena to support the AER's streamlined or class waiver requirements.

5.4.2 Selection of Options to Address Network Constraints

The Financial Assessment finds that network constraints lead to significant benefits for the deployment of NB, in particular the import constraint. Positive NPV results are obtained for both Merrifield and Clarkefield *if the network constraint benefits are present for the full 10-year assessment period*. This is shown in Figure 3.

Figure 3. Total costs and benefits (over 10 years) for NB in the two URD use cases



Jemena, as part of its regulatory obligations, undertakes market benefit assessment of options to address emerging network constraints. In the case of relieving network import and/or export constraints, there are network options as well as non-network options to consider. Network options include upgrading or re-building the constrained assets whereas NB deployment is one of the non-network options. In selecting the investment option, Jemena is required to select the option that maximises the market benefits. In other words, having a positive NPV is a good start, but it is not a sufficient condition for the NB option to be selected. This aspect is further considered in Section 4.

6 JEMENA BUSINESS CASE PROCESS

There are a number of key steps in Jemena's process for developing a business case for investment in NBs. These are described below.

6.1 Business Need Assessment

In Jemena's northern growth corridor around Somerton, Coolaroo and Kalkallo, there are significant development activities occurring in the residential and mix-used commercial sectors. These new residential developments generally have high maximum electricity consumption per lot due to the larger homes built and the need for air conditioning during summer. With the recent moratorium on residential gas reticulation, gas cooking/hot water substitution is expected to add further to the summer maximum demand. The use of electricity for space heating is forecasted to lead to higher growth of the winter peak demand above summer peak demand in predominantly residential areas. In addition, the adoption of electric vehicles (EV) and the use of home charging is expected to add to the maximum electricity demand.

Penetration of roof-top photovoltaic (PV) systems is also high in these new residential developments, with average of 30% of customers taking up PV systems compared with the Jemena average of 15%. While PV systems help to reduce summer peak electricity demand, their effect on energy consumption is virtually zero on some rainy winter days. During midday the unused PV generation is reducing the minimum electricity demand, with net export back into the grid (reverse power flow) frequently occurring.

The increased divergence between maximum and minimum demand in these new developments has led to inefficient grid investment to meet peak electricity demand, and inefficient market outcome due to PV export curtailment.

Jemena, similar to other Victorian DNSPs, has revised its guideline to increase the average energy consumption in the planning of electricity infrastructure in new residential developments – known as After Diversify Maximum Demand (ADMD) – to cater for the expected increase in energy consumption. What this practically means is developers will have to fund a higher number of distribution substation (DSS) infrastructure on-site and the capacity in the upstream high voltage network.

NB offers a unique technical solution that addresses the maximum and minimum demand dilemma. With its ability to absorb excess local PV generation, NB will reduce export curtailment. Through discharging, NB reduces the local maximum demand and the need for more DSS and upstream network capacity.

For the two URD use cases, significant import capacity constraints are emerging on the two high voltage distribution feeders (Merrifield – 22kV feeder KLO13, and Clarkefield – 22kV feeder SBY24) necessitating actions to increase the network import capacity. Technically NB offers a possible solution for the emerging import capacity constraint of the two high voltage distribution feeders.- and should therefore be investigated alongside with other credible options.

6.2 Regulatory Consideration

Jemena's investment decisions are ultimately guided by the National Electricity Objective (**NEO**). Additionally, Jemena is required to meet the requirements of the National Electricity Rules (**NER**), Victorian Electricity Distribution Code of Practice (**EDCoP**), and public and industry expectations for distribution system performance, which require a number of capital expenditure objectives to be achieved.

A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the DNSP considers is required in order to achieve each of the following (the capital expenditure objectives):

(1) Meet or manage the expected demand for standard control services over that period

(2) Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services

(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 to:

(iii) Maintain the quality, reliability and security of supply of standard control services

(iv) Maintain the reliability and security of the distribution system through the supply of standard control services.

(4) Maintain the safety of the distribution system through the supply of standard control services.[6]

The investment in NBs to manage maximum and minimum demand on the electricity network satisfies the regulatory requirement, as it maintains the quality, reliability and security of standard control services.

6.3 Option Formulation

Once the investment need is identified and there is a regulatory basis to invest, Jemena then analyses credible options to address the need.

The credible options are considered for their commercial and technical feasibility, abilities to address the identified needs, deliverability, economic and financial benefits, as well as legal and regulatory implications.

Four credible options have been considered for the two URD use cases:

- Option 1 – do nothing. The do-nothing option is not considered appropriate as Jemena has a license obligation to connect new loas arising from the URD developments;
- Option 2 – Jemena invests in network asset (DSS) to connect the new loads and upgrade the upstream HV assets to address the emerging network import capacity constraint;
- Option 3a - Jemena invests in network assets (DSS) to connect the new loads, and network NB to reduce the number of DSS and defer the need for upgrading the upstream HV assets for two years;
- Option 3b - Jemena invests in network assets (DSS) to connect the new loads, and network NB to reduce the number of DSS and defer the need for upgrading the upstream HV assets for five years.

Detailed planning studies have already been undertaken to confirm the optimal network upgrade plans (Option 2). Network upgrade projects to increase import capacity of the two high voltage feeders have been approved in 2024 (KLO13 & SBY24), at a cost of $5.78M and $5.45M respectively.

The rationale for Options 3a and 3b of NB deployment is based on the consideration that the high cost and limited capacity of NB cannot replace outright network upgrade solution. As an alternative, we investigate the use of NBs to defer network upgrade by two years (Option 3a) or five years (Option 3b).

[6] NER, cll 6.5.6(a), 6.5.7(a).

The design of this approach is to install sufficient number of NBs at the URD developments (for details refer Appendix 2) and control the NBs to eliminate network reliability risk and export constraint in the interim period, while bringing in other benefits of the NBs. After the network upgrade is completed, the NB reliability benefit becomes zero but other benefits will continue for the life of the NBs.

We have not conducted assessment to defer network upgrade by ten years as it is highly unlikely that this option is practical and economic.

6.4 Option Evaluation

Economic and financial analyses are carried out to identify the most efficient – preferred - option:

6.4.1 Economic Analysis

Cost-benefit analysis is performed to identify the option that maximises the present value of the net economic benefit to the electricity market – the preferred option. This economic analysis:

- Is based on market benefits and direct costs that include tangible residual and deliverability risk costs as identified in the options sections;
- Includes where applicable assessment of reasonable scenarios (alternative optimistic and pessimistic) of future supply and demand assumptions by ascribing reasonable probabilities to each scenario and weighting them to derive expected NPV market benefit for each credible option;
- Considers where applicable material uncertainty impacting project costs by assigning and weighting probabilities to each reasonable sensitivity to derive expected cost per credible option.

It is during the economic analysis of credible options that reveals Options 3a & 3b – the use of NBs to defer network upgrade – will not be cost effective compared with Option 2 (network upgrade). This is further discussed in Section 4.

6.4.2 Financial Analysis

Financial analysis is performed to assess the financial impact to Jemena if the preferred option (as identified from the economic analysis) is implemented. Where there is more than one preferred option, this analysis identifies the preferred option that maximises the present value of the net financial benefit to Jemena. The financial analysis is:

- Conducted from the viewpoint of Jemena rather than from the perspective of the market (as distinct from the economic analysis in previous section).
- Based on incremental financial costs and benefits (as identified in the option sections) associated with the preferred option compared to a do nothing or status quo scenario over a 20- year period;
- Performed also for those lower economically ranked options where their NPV economic benefits are not significantly lower than the preferred option.

As Options 3a & 3b – the use of NBs to defer network upgrade – are not the preferred options from the economic analysis, financial analysis for these options has not been performed.

7 ECONOMIC ANALYSIS AND OPTION RANKING

Under the current regulatory framework, Jemena's decision to invest would need to meet a number of requirements.

7.1 Costs and Benefits

In the absence of an obligation to invest in NBs, Jemena will have to choose an investment option that (1) provides positive net benefit (i.e. benefits outweigh costs), and (2) maximises the present value of the net economic benefit to the electricity market. When the investment option chosen does not meet both criteria, an external funding could potentially be injected into the project to produce a positive net benefit and maximise the present value of the net economic benefit. This should only be used as an interim measure on the basis that a sustainable model meeting both criteria will occur in the not-too-distant future. This can be achieved through a combination of cost reduction and additional benefit quantification.

7.1.1 Quantifiable Benefits

The Engineering Assessment has identified quantifiable benefits including reduced number of distribution substations and associated easement, reliability benefits by managing the overload risks on upstream HV assets until network capacity upgrade or equivalent non-network solutions are implemented, export constraint benefits by allowing more solar export into the upstream HV assets and revenue from energy market services by collaborating with a Market Participant on behalf of Jemena.

The modelling carried out in the Financial Assessment has identified significant reliability benefits on the HV feeders supplying the two URD developments as the two feeders are already loaded above their import limits. When compared with network upgrade option, many NBs will need to be deployed to produce comparable level of reliability benefit. Instead of using NB to replace network upgrade outright, we have conducted assessment of options where NBs are used in conjunction with network upgrade as described in Section 3.3.

With this approach, there is no difference in the network benefits (reliability and PV export curtailment) between Options 3a, 3b and Option 2. The differences lie in the additional cost of the NBs and the other NB benefits, namely, network upgrade deferral, less distribution substations, community battery tariff rebate, emission benefit and market benefits (energy arbitrage & FCAS).

7.1.2 Network Upgrade Deferral Benefits

Jemena currently publishes emerging network constraints and potential network upgrade options in its Distribution Annual Planning Report (DAPR). In addition, for project where the network upgrade option exceeds $6M, Jemena carries out the Regulatory Investment Test – Distribution (RIT-D) as per the AER required process.

The intention of the DAPR and RIT-D processes are to solicit non-network proposals from third parties that may defer or eliminate the need to build additional network capacity. Typical non-network options include demand management and embedded generation, of which NB is a potential candidate as it can help to reduce peak demand. The network upgrade deferral benefit is calculated based on the saving in interest cost as a result of the capital project deferral.

The capacity constraints on KLO13 and SBY24 HV feeders have been highlighted in Jemena's 2023 DAPR[7].

7.1.3 Measures to Improve Quantifiable Benefits

In an attempt to increase quantifiable benefits, we have investigated the effect of increasing the number of NB charge/discharge cycle to two to manage energy-at-risk during morning peak as well as evening peak. The modelling has found only modest improvement to reliability benefits with two charge/discharge

[7] Jemena 2023 Distribution Annual Planning Report, https://www.jemena.com.au/siteassets/asset-folder/documents/electricity/2023-distribution-annual-planning-report.pdf

cycles as the current feeder constraints occur primarily during the evening peak. As the increase in charge/discharge cycle effectively reduces the life span of the NB by half, it is not advisable to do so.

7.1.4 Measures to Reduce Costs

Nearly 50% of the NB project cost comes from the battery equipment. We are seeing a trend that battery cost is coming down over time driven by worldwide demand (see Section 2.1.4). The other 50% of the project cost comes from design, installation and commissioning. While this cost is based on estimate from similar Jemena community/neighbourhood projects, the cost includes some one-off items such as safety assessment, personnel training and new design/construction standards. Through standardisation Jemena believes this cost will be driven down after the first few NB installations.

7.1.5 Non-Quantifiable Benefits

Not all the benefits of NB can be quantified in monetary term for the cost-benefit assessment. There are unquantified benefits such as Victoria/Commonwealth net zero commitment, resilience against climate change and future energy market benefits. These unquantified benefits are more strategic and policy driving in nature.

Some examples of policy and regulatory reforms where emerging benefits may arise for network NB projects or where NB deployment would inform further market development opportunities include:

- Victorian Government's 100 Neighbourhood Battery grant funding program[8]
- ARENA grant funding in continuation of the $171M Community Batteries Fund (note: $121M already allocated in the 2023 Round 1)[9]
- A rule change currently being developed by the Victorian Government to take greater account of resilience in network regulatory proposals[10].
- The National Consumer Energy Resources (CER) Roadmap and implementation plan for reforms due for consideration in July 2024[11]
- Market assessments that will support a new statement in Australian Energy Market Operator (AEMO)'s 2026 Integrated System Plan (ISP), and subsequent ISPs, aimed at informing the market and policy makers about the expected development of CER and distributed resources. And in addition, the development of a suitable approach by AEMO to trade off the cost of unlocking increasing tranches of orchestrated CER and distributed resources against other investment options for use in the earliest ISP practicable[12].
- Other potential DER/CER incentives that could be introduced in the future to respond to delays in building sufficient energy transmission capacity, or via the evolution of market-based green energy certified DER/CER incentives over time.

7.2 Economic Analysis of the Selected Options

We have carried out economic assessment of deferring the planned network upgrade projects by two years (Option 3a) or five years (Option 3b) using NBs, and compared the change in the project NPV against

[8] 100 Neighbourhood Battery grant (energy.vic.gov.au)
[9] Community Batteries Funding Round 1 - Australian Renewable Energy Agency (ARENA)
https://www.energy.gov.au/sites/default/files/2024-03/ECMC%20Communique%201%20March%202024.docx
[10] Noted in 1 March 2024 Energy and Climate Change Ministerial Council Meeting:
https://www.energy.gov.au/sites/default/files/2024-03/ECMC%20Communique%201%20March%202024.docx
[11] Noted in 1 March 2024 Energy and Climate Change Ministerial Council Meeting:
https://www.energy.gov.au/sites/default/files/2024-03/ECMC%20Communique%201%20March%202024.docx
[12] Pages 8-9: ecmc-response-to-isp-review.pdf (energy.gov.au)

the planned network upgrade projects occurring in 2024 (Option 2), for the two URD use cases of Merrifield and Clarkefield. The financial assessment result is summarised in the following table:

Table 4. NPV change between Option 3a, 3b and Option 2 for the two URD use cases

Development	Network upgrade deferral (years)	Total number of NBs required	Cost* ($M)	Network Benefits# ($M)	Other Benefits## ($M)	NPV ($M)	NPV change ($M, compared with network upgrade in 2024)
Network upgrade (KLO13)	0	0	-5.78	13.08	0	7.30	NA
Merrifield NBs + KLO13 network upgrade	2	5	-8.97	13.08	1.36	5.46	-1.84
Merrifield NBs + KLO13 network upgrade	5	31	-24.56	13.08	7.67	-3.80	-11.10
Network upgrade (SBY24)	0	0	-5.45	30.35	0	24.9	NA
Clarkefield NBs + SBY24 network upgrade	2	16	-15.43	30.35	3.29	18.21	-6.69
Clarkefield NBs + SBY24 network upgrade	5	70	-45.87	30.35	13.00	-2.52	-27.42

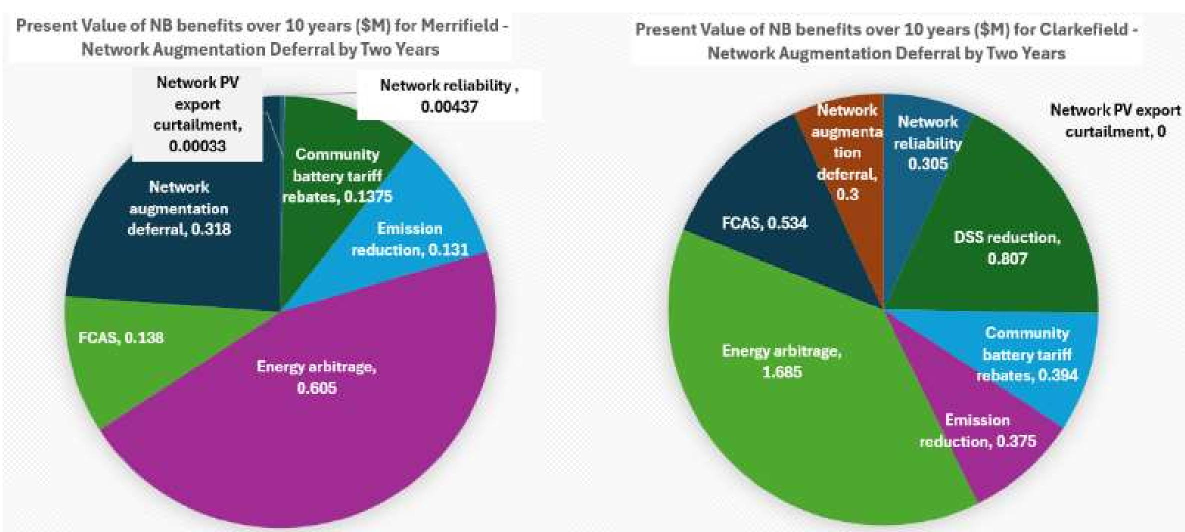
* Based on competitive battery cost (equipment and install) of $1,500/kWh ($750/kWh plus $360k cost of design, install & commission per NB

Network benefits include reliability and PV export benefits

Other benefits include network upgrade deferral, less distribution substations, community battery tariff rebate, emission benefit and market benefits (arbitrage & FCAS)

The pie charts in Figure 4 show the composition of the "other benefits" for the 2-year deferral scenario:

Figure 4. Composition of NB "Other Benefits" for the scenario of 2-year network upgrade deferral



7.3 Conclusions from Economic Analysis

As can be seen from Table 3, a significant number of NBs would need to be installed to address reliability risk in order to defer the planned network upgrade. The cost of NB deployment is only partially offset by the additional benefits that NBs bring, resulting in a financial gap as indicated in the last column of the table. This means that network upgrade planned for commencement in 2024 (Option 2) will provide the best overall outcome unless the financial gap created by NB deployment (Options 3a and 3b) can somehow be bridged.

Once the network upgrade project is carried out, the network reliability benefit is no longer available to support NB deployment, rendering this business case economically non-viable.

As electricity network already exists extensively in the area where the two URD use cases are located, network capacity in the local area can be added economically by modifying existing network assets rather than building totally new assets. It is a different situation for NBs as a network of NBs does not currently exist and every installation has to be constructed from scratch, not building upon existing assets. The situation could be quite different at the edge of the network where only sparse and low capacity network assets have been installed.

7.4 Closing the Gap

We have carried out sensitivity analysis of the current costs and benefits used in the economic assessment to understand what is realistically required to close the financial gap. The scenarios of cost reduction and benefit increase considered and their rationales are summarised in Table 4.

Table 5. Scenarios of cost reduction and benefit increase

Scenario	Increased/Decreased	Remarks
Network upgrade cost	Increased by 50%	Network upgrade cost is higher in areas where there is less existing network infrastructure, making NB a more competitive alternative
Community battery tariff rebate	Increased by 50%	The current community battery tariff trial finishes on 30 June 2026. Learnings from the tariff trial will help inform the design of a permanent community battery tariff. There may be an opportunity to increase the rebate after the current trial finishes and assessment is made.
Battery cost	Decreased by 30%	NREL forecasts that grid-scale battery system cost will decline by close to 30% in the 10-year period from 2020 to 2030.
Battery design, installation & commissioning cost	Decreased by 30%	There are one-off cost items for Jemena to introduce the new technology of NB into its network. Business-as-usual deployment cost will be lower.
FCAS revenue	Increased by 50%	The business case has used conservative estimate for FCAS.
Energy arbitrage revenue	Increased by 50%	The business case has used conservative estimate for energy arbitrage.
Curtailment benefit	Increased by 50%	The current AER methodology only accounts for energy market spot price during PV generation period.
Carbon price	Increased by 50%	The current carbon price is structured to increase over time as we get closer to 2050, which does not encourage early adoption and risks a tsunami of projects at the end. A more evenly spread pricing structure may be more appropriate.

The effect of each scenario of cost reduction/benefit increase on the NPV gap (compared with network upgrade undertaken in 2024) and their combined effect, for 2-year network upgrade deferral (option 3a), are shown in Figures 5 and 6.

Figure 5. Merrifield URD Option 3a - Sensitivity Analysis of Costs and Benefits

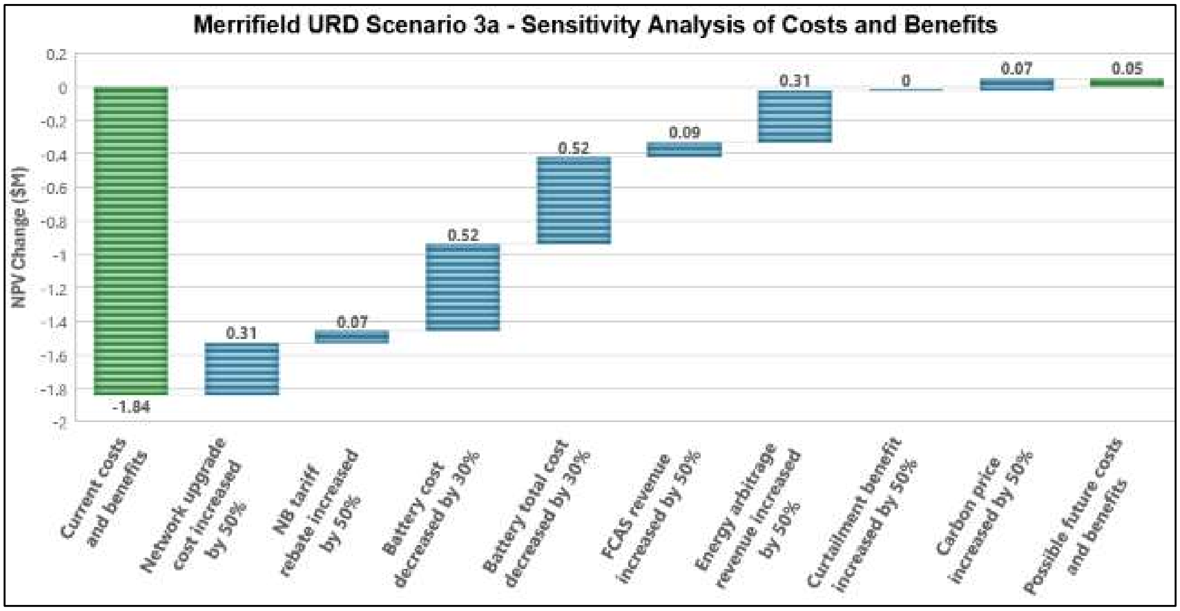


Figure 6. Clarkefield URD Option 3a - Sensitivity Analysis of Costs and Benefits

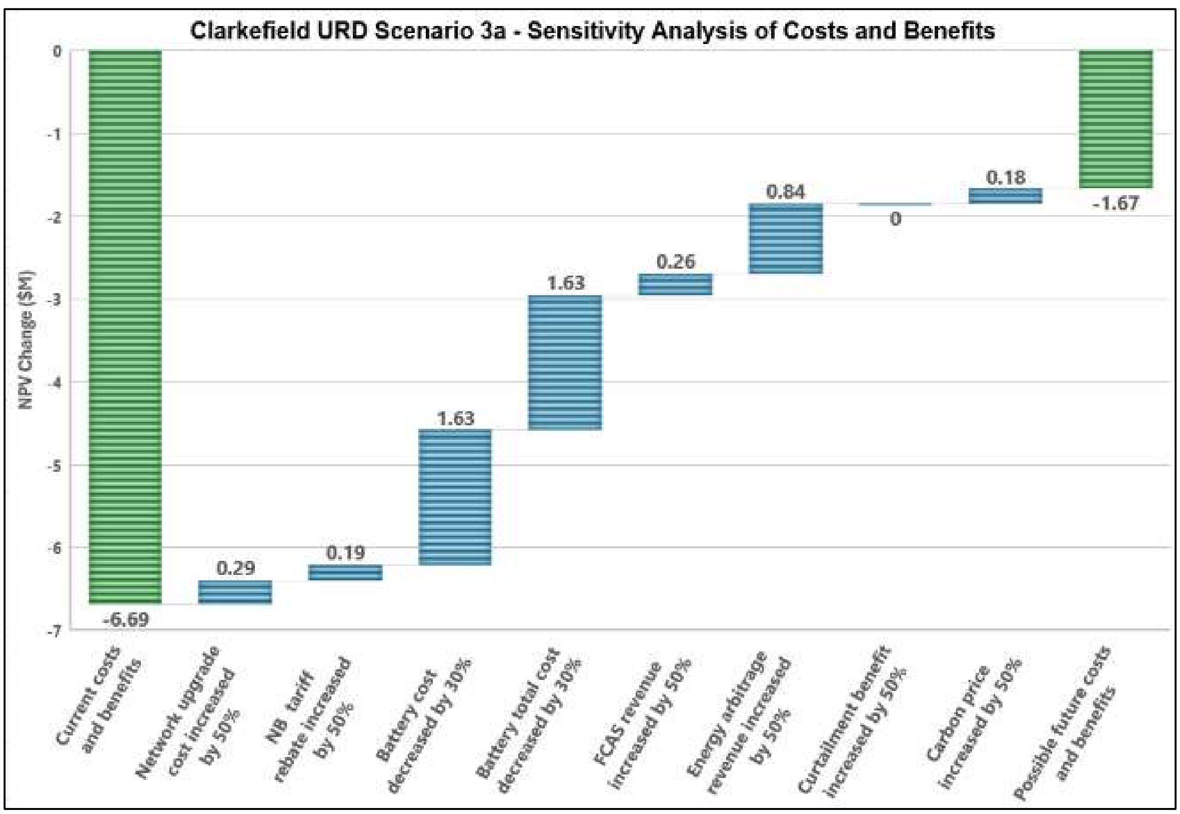


Figure 5 indicates that Merrifield NBs plus network upgrade could be a better option than network upgrade alone if the current costs and benefits are favourable as per Table 4. Figure 6 shows that while Clarkefield NBs still lack behind network upgrade in NPV, the gap is significantly reduced.

Additional benefits not included in the financial analysis will further improve the business case for NB deployment.

8 CONCLUSIONS

The business case project looks at the investment of network NBs in residential and mixed-use greenfield developments. The NBs are intended to be network owned and maintained, with the primary purpose in enabling the electricity network to support the sustainability aspirations of the residential and business customers in the precinct.

Majority of these new developments are occurring in Jemena's northern growth corridor. The HV network capacity to meet additional electricity consumption at peak usage time, and the capacity to accommodate excess solar generation during peak generation/low electricity usage is already stretched to the limit or even exceeded. The NB's ability to absorb excess solar generation and release the stored energy to meet network peak demand is shown to provide significant network benefits from reducing export constraint and improving supply reliability.

In addition, the developers will benefit from the reduced DSS infrastructure on-site and the support that NBs offer for the renewable aspirations of their future residents.

While the NBs are primarily there to support the network and new URD developments, revenue stream from leasing the NBs to Market Participants for energy market related service is included in the assessment to maximise the benefits that NB brings.

To address emerging network constraints, however, Jemena needs to consider other credible options including network upgrade. Even after stacking all the quantifiable benefits, NB deployment option is still found to be inferior to network upgrade in economic analysis for the two URD use cases. The current regulatory framework will require Jemena to adopt the network upgrade option to remove the HV network constraints as it maximises the net market benefits. The removal of the network benefits from the NB deployment business case will render the project non-viable as the costs outweigh the benefits.

Although the business case project does not find enough quantifiable benefits that outweigh the costs of NB implementation, there exist pathways where costs are reduced and benefits improved as shown through sensitivity analysis of the various cost and benefit components. The pathway to enabling and developing a sustainable model for NBs requires collaboration between various stakeholders (suppliers, retailers/aggregators, DNSPs, government and regulators).

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In this regard the Victorian Government's Neighbourhood Battery Initiative, which funds this business case project, has shown the foresight and leadership in this NB journey.

9 APPENDIX 1 - METHODOLOGY TO EXTRAPOLATE YEAR TIME-SERIES LOAD PROFILES

Blunomy and Jemena have developed spatial (bottom-up) forecasts of maximum and minimum demands for the various Jemena network assets for summer and winter seasons, up to 2033. We have made the assumption that these forecasts have accurately taken into account the impact of CER (solar PV, electrification, electric vehicles, household batteries) on the maximum and minimum demands.

For the financial models, we want to calculate the NB benefits in every 30 minutes. To do so we need to extrapolate current year historic time-series (every 30 minutes) load profile into future year time-series forecast. As we only have two "point" forecasts for future years (the maximum and minimum demands), we need a methodology to "stretch" the historic load profile using the maximum and minimum demand forecast.

The methodology we propose involves calculating the mid-point of the current year (average of max and min demand) and the delta between the max and min ('current delta'), and then the mid-point of the future year forecast (average of max and min demand) and the delta between the max and min ('future delta'). Every load point in the current year is then extrapolated to form a load point in the future year forecast using the following formula:

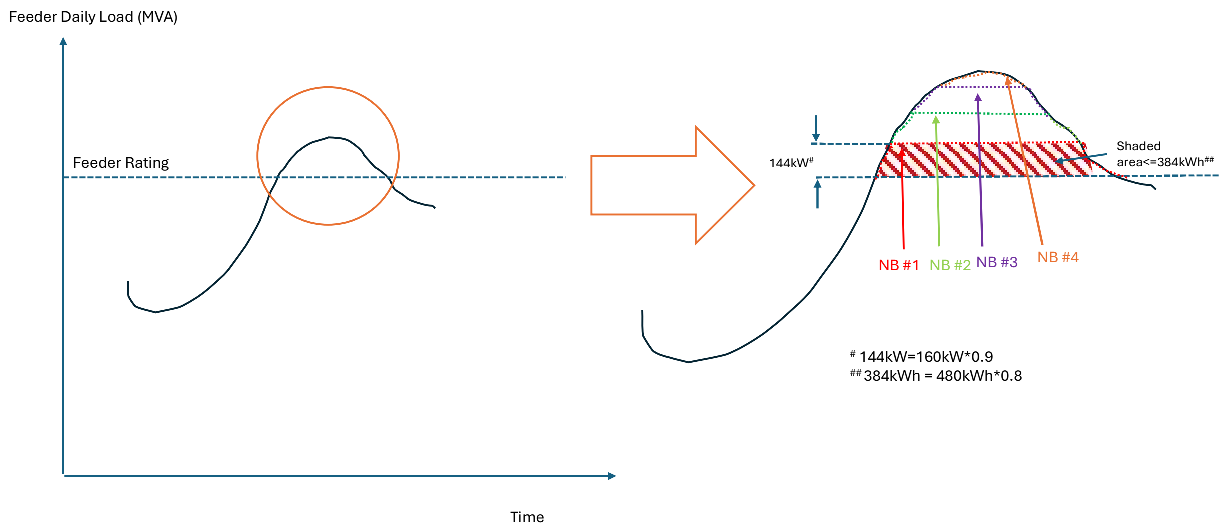
Load point in future year forecast = [(current year load point)-(current year min demand)] x [(delta in future year/delta in current year)] + (future year min demand)

10 APPENDIX 2 - METHODOLOGY TO DETERMINE THE NUMBER OF NBs TO DEFER NETWORK UPGRADE

The number of NBs required to defer network upgrade has been estimated by using the criterion of the NB's peak power (kW) and not its energy capacity (kWh). While this choice will simplify the modelling, we have carried out spot checks of the data to ensure that the chosen NB size has sufficient kWh capacity to cover the duration of the network peak events.

The methodology is illustrated in Figure 7. Note we have discounted the NB peak power by 0.9 to allow for power loss and the energy capacity by 0.8 (being the usable capacity as NB is generally recommended to keep a minimum state of charge of 20%).

Figure 7. Methodology to determine the number of NBs required to defer planned network upgrade*



*Note: the number of NB derived using this method needs to be assessed against load requirements and physical constraints of the proposed locations

11 APPENDIX 3 - FINANCIAL RE-MODELLING RESULTS

11.1 Reasons for Re-modelling

The Financial Assessment process used a custom designed Excel spreadsheet based model to calculate the NPV costs and benefits of NB deployment over a 10-yeear timeframe. Initial modelling assumed that all the benefits would last 10 years as reported in the Financial Assessment Report.

In subsequent re-modelling, we have calculated the NPV with network benefits lasting a 2-year, 5-year and 10-year period. The change in modelling network benefits was on the basis that network upgrade was likely to be implemented to address the high reliability risks and PV curtailment before the expiry of the 10-year timeframe. The benefits of an NB solution could therefore also be explored, through which interim reliability risks may be alleviated until the network upgrade is fully constructed.

11.2 Modelling Assumptions

The costs were assumed to be the same for all NPV calculations. That is, once Jemena commit to installing the battery, it is assumed that all capital costs will be accounted for, and it will be very hard to relocate the battery or in any way recoup that capital cost.

If the NB is only to be used for network benefits for two years, then there is an opportunity to increase the cycling of the battery, to increase the short-term benefit that this would deliver. The NPV is therefore presented twice, to illustrate the change in the NPV by cycling the battery twice a day, instead of once a day.

The model assumes the following in terms of charging and discharging the battery.

- If the estimated load (at the DSS, or feeder or upstream) is less than the rated asset capacity, then the battery will charge
- If the battery is charging once a day, it will only charge between 10am and 3pm, up to 80% of the capacity of the battery, and charge at 90% rating of the kW connection
- The battery will discharge between 4pm and 9pm, consistent with the Jemena Community Battery Tariff Trial.
- There is no review or checking of estimated spot prices, so the battery is not checking possible market prices (low or high), but it is generally charging in low demand periods of the day, and discharging in higher demand periods of the day
- If the battery is charging twice a day, then it will start charging again from 12am to 6am, and discharge from 6am to 10am.
- The battery will not discharge if there is a negative power flow forecast through the DSS.

Another output from the analysis was a packaged up database and Excel spreadsheet to vary the key parameters (like capital costs of batteries, and opex percentage, land values, and discount value) to help all stakeholders better understand the inputs to the NPV calculation and the sensitivity to various input parameters.

Other parameters that are important to note in the financial modelling are:

- Opex was assumed to be 0-3% of capital costs (consistent with other assumptions for network upgrade)
- The battery charges with zero emissions energy intensity generation sources, and therefore there are emissions savings from the discharge of kWh from the BESS)

- The emissions savings were calculated using the average emissions intensity for Victoria in 2023, which was 0.7613 tCO_2e/MWh
- There is no additional cost to cycle the battery twice a day, as opposed to once a day

11.3 Modelling Results

The results from the NPV analysis are shown below.

Table 6. NPV re-modelling results

Development	Availability of network benefits (years)	Number of NBs considered	Cost* ($M)	Network Benefits# ($M)	Other Benefits# # ($M)	NPV ($M)
Merrifield	2	1	-0.74	0.06	0.18	-0.50
Merrifield	5	1	-0.74	0.26	0.18	-0.30
Merrifield	10	1	-0.74	1.84	0.18	1.28
Clarkefield	2	1	-0.68	0.29	0.18	-0.21
Clarkefield	5	1	-0.68	1.43	0.18	0.94
Clarkefield	10	1	-0.68	2.71	0.18	2.21

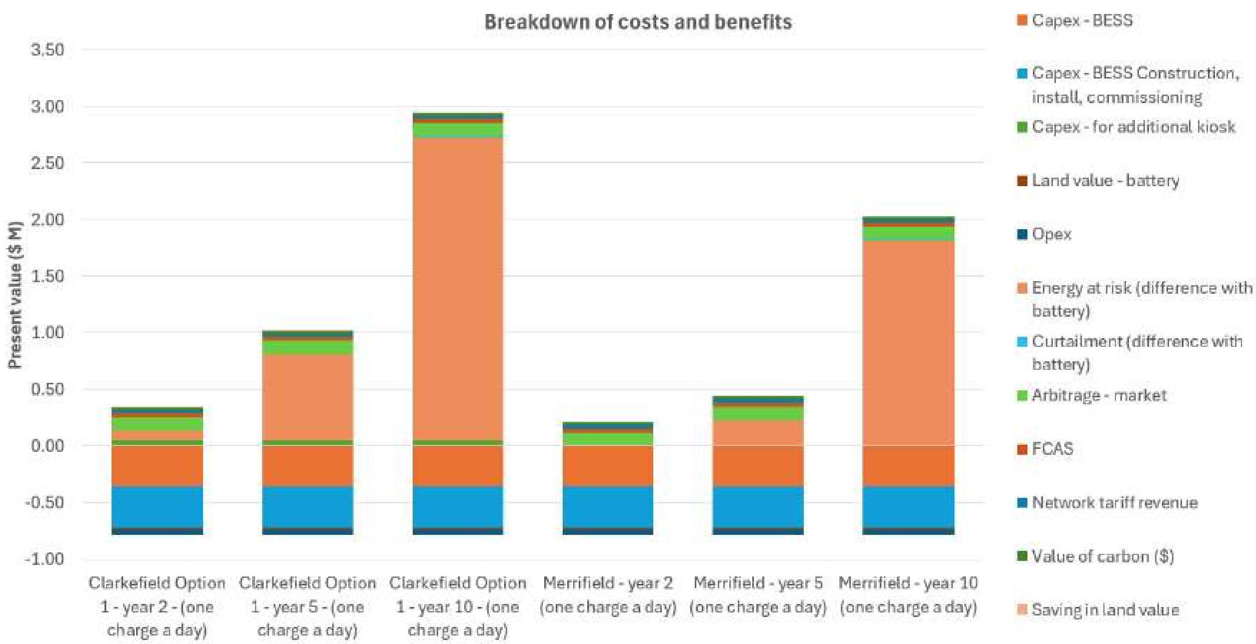
Table 5 notes that despite alleviating the forecast reliability issues, there is insufficient benefit to create a positive NPV if the reliability benefit from investment in the battery is assumed to last only 2 or 5 years.

The forecast constraints on the network are more extreme between 2029 and 2034, but it is assumed a network upgrade will alleviate these risks.

The Present Value (PV) of “other benefits” is improved by approximately 50% if the battery is cycled twice a day.

The next chart illustrates the relative contribution of the different benefits that go into all options. It highlights that the benefits are driven by the avoidance of the reliability risk, which is then costed using the Value of Customer Reliability that is weighted for the Jemena customer demographics ($45.01 per kWh).

Figure 8. Breakdown of costs and benefits for reliability benefits lasting 2, 5 or 10 years



11.4 Additional Modelling for Comparison with Network Upgrade Option

Due to the emerging reliability risks on the two HV feeders supplying into the two URD developments, Jemena has scoped and approved business cases in 2024 to upgrade the HV feeders to address the reliability risks. The business cases have considered other credible options including battery storage but concluded that network upgrade option maximises the present value of the net economic benefit to the electricity market and is therefore the preferred option. Armed with the latest NB costs and benefits from our BURDD assessments, we proceed to test the scenario if NBs can work with the planned network upgrade to produce an outcome that has a better net economic benefit to the electricity market. The rationale for NB deployment is based on the consideration that the high cost and limited capacity of NB cannot replace outright network upgrade solution. As an alternative, we investigate the use of NBs to defer network upgrade by two years or five years. The design of this approach is to install sufficient number of NBs (noting that for this project one NB was defined to have a 160 kW/480 kWh specification) at the URD developments and control the NBs to eliminate network reliability risk and export constraint in the interim period, while delivering other benefits of the NBs. After the network upgrade is completed, the NB reliability benefit becomes zero but other benefits will continue for the life of the NBs.

Financial assessments are conducted for the following options:

- Option 1 – do nothing. The do-nothing option is not considered appropriate as Jemena has a license obligation to connect new loas arising from the URD developments and to address reliability risks. This option is therefore not considered further;
- Option 2 – Jemena invests in network asset (DSS) to connect the new loads and implement the planned upgrade of the upstream HV feeder to address the emerging network import capacity constraint;
- Option 3a - Jemena invests in network assets (DSS) to connect the new loads, network NB to reduce the number of DSS and defer the planned upgrade of the upstream HV feeder by two years;

- Option 3b - Jemena invests in network assets (DSS) to connect the new loads, network NB to reduce the number of DSS and defer the planned upgrade of the upstream HV feeder by five years.

While there are some benefits to network upgrade deferral, and benefits from the operation of the NB, investing in both NBs and deferred network upgrade do not result in a higher NPV than network upgrade carried out in 2024 i.e. no deferral, as shown in the following table:

Table 7. NPV change considering network upgrade deferral for the two URD use cases

Development	Network upgrade deferral (years)	Total number of NBs required	Cost* ($M)	Network Benefits# ($M)	Other Benefits# # ($M)	NPV ($M)	NPV change ($M, compared with network upgrade in 2024)
Network upgrade (KLO13)	0	0	-5.78	13.08	0	7.30	NA
Merrifield NBs + KLO13 network upgrade	2	5	-8.97	13.08	1.36	5.46	-1.84
Merrifield NBs + KLO13 network upgrade	5	31	-24.56	13.08	7.67	-3.80	-11.10
Network upgrade (SBY24)	0	0	-5.45	30.35	0	24.9	NA
Clarkefield NBs + SBY24 network upgrade	2	16	-15.43	30.35	3.29	$18.21	-6.69
Clarkefield NBs + SBY24 network upgrade	5	70	-45.87	30.35	13.00	-$2.52	-27.42

What the modelling shows is the additional costs in the deployment of NBs are not fully compensated by additional benefits that NBs bring, resulting in less market benefits to electricity consumers.

12 ACKNOWLEDGEMENT

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Dr. Peter Wong of Eagles Engineering Consultants

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Benjy Lee of Benjyleeconsulting

13 GLOSSARY

ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
BURDD	Batteries for Underground Residential Distribution Development
CECV	Customer Energy Curtailment Value
CER	Consumer Energy Resource
DAPR	Distribution Annual Planning Report
DEECA	The Victorian Government Department of Energy, Environment & Climate Action
DER	Distributed Energy Resource
DNSP	Distribution Network Service Provider
DSS	Distribution Substation
EV	Electric Vehicle
FCAS	Frequency Control Ancillary Service
HV	High Voltage
ISP	Integrated System Plan
kW	Kilowatt
kWh	Kilo-Watt-hour
LV	Low Voltage
Market Participant	Retailer or aggregator capable and appropriately licenced to participate in wholesale market functions.
MCR	Marginal Cost of Reinforcement
NB	Neighbourhood Battery
NBI	Neighbourhood Battery Initiative
NEO	National Electricity Objectives
NER	National Electricity Rules
NPV	Net Present Value
PV	Photovoltaic
RIT-D	Regulatory Investment Test - Distribution
URD	Underground Residential Distribution
VCR	Value of Customer Reliability
VER	Value of Emission Reduction