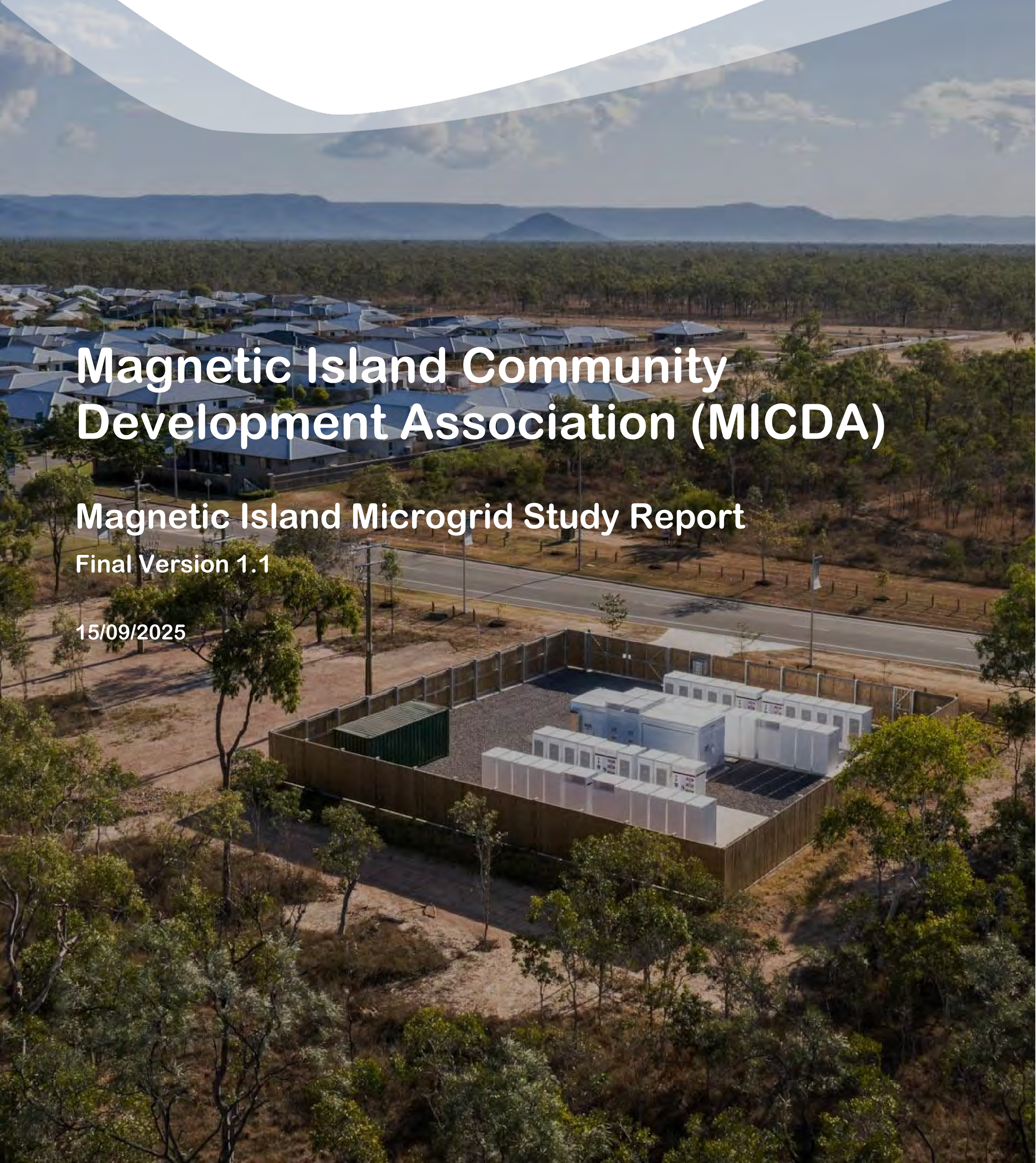
Part of Energy Queensland



Magnetic Island Community Development Association (MICDA)

Magnetic Island Microgrid Study Report

Final Version 1.1

15/09/2025

Connecting communities to a sustainable energy future

The traditional owners and custodians of Yunbenun (Magnetic Island) are the Wulgurukaba people. Yurika acknowledges the Traditional Custodians of the land on which we live and work, and recognise their continuing connection to land, waters and community. We pay respect to Elders past and present.

Important Notice

This report has been prepared under a Consultancy Agreement between Yurika Pty Ltd (Yurika) and Magnetic Island Community Development Association (MICDA) for the Magnetic Island (Yunbenun) Microgrid Feasibility Study and is subject to the assumptions, qualifications and exclusions set out in this report.

This report has been prepared solely for the benefit of MICDA and Yurika makes no representation, and disclaims all duty, responsibility and liability, to any third party in connection with or arising out of this report. Any third party recipient of this report should obtain its own independent expert advice in relation to the subject matter of this report.

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26 Reddacliff Street, Newstead QLD 4006 | yurika.com.au | 1300 624 122

Our staff are based Australia-wide.

Acronyms

ACR	Automatic Circuit Recloser
ADMD	After Diversity Maximum Demand
AEMO	Australian Energy Market Operator
AEP	Annual Exceedance Probability
AER	Australian Energy Regulator
ARENA	Australian Renewable Energy Agency
AS	Australian Standard
BESS	Battery Energy Storage System
BOL	Beginning Of Life
BTM	Behind The Meter
CAC	Connection Asset Customer
CER	Consumer Energy Resources
CSO	Customer Service Obligation
DAPR	Distribution Annual Planning Report
DCCEEW	Department Of Climate Change, Energy, The Environment and Water
DCR	Design Compliance Report
DEECA	Department Of Energy, Environment and Climate Action
DER	Distributed Energy Resources
DNSP	Distribution Network Service Provider
DOE	Dynamic Operating Envelope
EG	Embedded Generator
EPBC	Environmental Protection and Biodiversity Conservation
EPC	Engineering, Procurement & Construction
EWR	Electrical Work Request
FCAS	Frequency Control Ancillary Services
FID	Final Investment Decision
FiT	Feed-in Tariff
FTM	Front of The Meter
GBR	Great Barrier Reef
GBRF	Great Barrier Reef Foundation
GHG	Greenhouse Gas
GSD	Grid Signalling Device
GST	Goods and Services Tax
HV	High Voltage
ICC	Individually Calculated Customer
LGC	Large-scale Generation Certificate
LRET	Large-scale Renewable Energy Target
LREZ	Local Renewable Energy Zone
LV	Low Voltage
MCU	Material Change of Use
MI	Magnetic Island
MICDA	Magnetic Island Community Development Association
MV	Medium Voltage
NEM	National Electricity Market
NER	National Electricity Rules
NERL	National Energy Retail Law
NSP	Network Service Provider
O&M	Operation & Maintenance
OEM	Original Equipment Manufacturer
PPA	Power Purchase Agreement
PRE	Preliminary Response to Enquiry
PV	Photovoltaic
QA	Quality Assurance
QCA	Queensland Competition Authority
QECM	Queensland Electricity Connection Manual
QMPF	Queensland Microgrid Pilot Fund
REC	Renewable Energy Certificate
RET	Renewable Energy Target
RFP	Request For Proposal
RTE	Round Trip Efficiency
SAC	Standard Asset Customer
SCADA	Supervisory Control And Data Acquisition
SSER	Site Specific Enquiry Response
STC	Small-scale Technology Certificate
TCC	Townsville City Council
TMY	Typical Meteorological Year
TNSP	Transmission Network Service Provider
ToU	Time of Use
TRM	Totally Renewable Magnetic
UTP	Uniform Tariff Policy
VPP	Virtual Power Plant

Glossary

Consumer Energy Resources (CER)	Generally, the term CER refers to consumer assets that generate electricity, store electricity or are flexible loads such as: • rooftop solar • household and community batteries • electric vehicles • electric vehicle charging stations • controlled loads, including water heaters, pool pumps, air conditioners and smart devices.
Distributed Energy Resources (DER)	are consumer-owned devices that, as individual units, can generate or store electricity or have the 'smarts' to actively manage energy demand.
Distribution Network	transport electricity from transmission networks at lower voltages to end-use customers
Distribution Network Service Provider (DNSP)	A business that owns, operates, or controls an electricity distribution network.
Embedded Networks	private electricity networks which serve multiple premises and are located within, and connected to, a distribution system through a parent connection point in the National Electricity Market.
Final Investment Decision (FID)	a formal decision following project planning and development phase as to whether to proceed to the execution phase, where significant financial resources are allocated, and contracts are signed for construction, procurement, and operations.
High Voltage	Any voltage greater than 1,000 V a.c. or 1,500V d.c.
Inverter Energy System (IES)	A system comprising one or more inverters together with one or more energy sources (which may include an energy storage system) and controls, where the inverter(s) satisfies the requirements of AS/NZS 4777.2.
Low Voltage	A voltage of no more than 1,000 V a.c. or 1,500 V d.c.
Microgrid	a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid; either stand-alone or having the ability to operate in both grid-connected and island mode.
Reliability	The extent to which customers have a continuous supply of electricity.
Renewable Energy Fraction	The fraction of the energy delivered to the load that originated from renewable power sources.
Stand Alone Power Systems (SAPS)	An electricity supply arrangement that is not physically connected to the national grid and supplies a single customer.

1. Executive Summary

The Magnetic Island Community Development Association (MICDA) has a set vision for the island to be powered entirely by renewable energy sources by 2030. Its key objectives are to maximise renewable fraction, minimise outage duration, maximise benefits for community members. Their preferred concept to achieve this is an island/village wide microgrid.

With approximately 5.3 MW of solar PV installed, including over 600 kW added in the past 12 months, Magnetic Island ranks in the top 7% of populated postcodes in Australia for solar installations per capita. It is estimated that approximately 29% of the island's total electricity consumption is currently met by renewable energy sources. In 2024, for the first time, Magnetic Island exported solar PV generated electricity to Townsville via two 11 kV submarine feeder cables.

This study evaluates five different technical options aligned with MICDA's objectives. Two actionable concept solutions, involving solar PV and/or battery energy storage technologies, were assessed in greater depth to determine their technical and economic feasibility in two of the island's main villages: Horseshoe Bay and Picnic Bay.

Ergon Energy Network is currently developing their HV, grid-connected microgrid capabilities through a pilot project in Mossman Gorge. Insights from this pilot will inform the development of tools and standards, with a deployable solution not expected before is not expected until at least 2029. As such, a DNSP owned or third party owned HV microgrid is not currently considered an actionable solution.

The two concepts selected for detailed analysis included a third party owned centralised Battery Energy Storage System (BESS) and behind the meter (BTM) solar PV and BESS. The centralised BESS is viewed as a potential stepping stone towards the long-term vision of a HV microgrid.

A 1 MW/2 MWh centralised BESS solution was developed, considering factors such as land availability, network connection options, potential economic returns, operating models, and future development opportunities. Key barriers to implementation include network connection and ongoing operational costs, limited or uncertain revenue from arrangements with a retail partner, dynamic network connection constraints, and insurance challenges. While the BESS could support a higher renewable fraction, potentially reducing GHG emissions for each village by up to 500 t CO2-e as an additional 2 MW of solar PV is installed, it would not directly improve reliability or reduce electricity bills for customers. The financial analysis showed a tolling arrangement has no clear economic benefit if the asset owner is responsible for more than 10% of the capital investment costs. In comparison, a variable revenue option could provide greater economic benefits, however, carries higher risk due to due to uncertainty of market performance, this carries higher risk.

As an alternative, BTM solar PV and BESS solutions were analysed using typical residential and small business load profiles, with and without existing solar PV. A capital purchase option was considered in detail for each of the five typical customers, however it is noted that a purchase power agreement (PPA) with virtual power plant (VPP) offer is an alternative option. Based on an assumed uptake for Magnetic Island of 25% (530 homes and businesses), it was estimated that island's renewable fraction could increase to 50% with the addition of 3.1 MW of solar PV and 5.8 MWh of usable battery storage capacity. This is estimated to result in an annual GHG emission reduction of 3,455 t CO2-e and an additional $1.156 million in annual collective electricity bill savings.

Given the scale and complexity of the centralised BESS, Yurika does not recommend proceeding with this option in the short term. In contrast, the BTM option has become more favourable with the introduction of the federal government Cheaper Home Batteries program and strongly aligns with MICDA's objectives. Yurika recommends proceeding with the BTM solution.

2. Project Overview

Magnetic Island is located approximately 8km north of the coast of Townsville, North Queensland. The island, within the Townsville City Council (TCC) local government area (LGA), covers an area of 52km^2 with 78% of the land classified as national or conservation park.[1] The island population is 2,475 and has 4 main villages; Horseshoe Bay, Arcadia, Nelly Bay, and Picnic Bay.[2]

Magnetic Island has approximately 5.3 MW of solar PV installed[3], including over 600 kW added in the past 12 months. Magnetic Island ranks in the top 7% of populated Local Government Areas (LGAs) in Australia for solar installations per capita.[4]

2.1. Magnetic Island Community Development Association

Magnetic Island Community Development Association (MICDA) is a local community group based on Magnetic Island. The association works to support and promote sustainable community development, enhance the quality of life for residents, and advocate for the island's preservation and future development.

Totally Renewable Magnetic (TRM) is a community working group within MICDA. The objective of the group is ensuring Magnetic Island has reliable, resilient, renewable, and sustainable energy.

Community Engagement to Date

TRM has actively engaged with the Magnetic Island community on renewable energy initiatives, including the proposed microgrid feasibility study in 2023 and 2024. This engagement has included annual meetings with the community, presentations to the Magnetic Island Residents and Ratepayers Association, and consultations with residents on installing solar and battery systems. Overall, the community has shown strong support for proposals aimed at reducing costs and lowering the island's carbon footprint, including microgrids.

In June 2024, MICDA, with support from the Great Barrier Reef Foundation (GBRF), conducted a survey of 136 residents (about 5% of the population) on their attitudes towards energy and waste management. The most popular suggestion for improving energy consumption was the implementation of localised microgrids, capable of operating both independently and with the main grid. Increased solar energy use for buildings and public amenities was also widely recommended.

2.2. Objectives

MICDA has a vision to create a complete island microgrid for Magnetic Island. Yurika collaborated with MICDA to understand their high-level objectives for the microgrid, which can be summarised as follows:

- Maximise the renewable energy fraction
- Minimise outage duration
- Maximise benefits for community members

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[1] Queensland Government, About | Magnetic Island National Park | Parks and forests | Department of the Environment, Tourism, Science and Innovation

[2] Australian Bureau of Statistics, 2021 Magnetic Island, Census All persons QuickStats | Australian Bureau of Statistics

[3] Australian PV Institute, latest cumulative install total, June 2025 for postcode 4819, https://pv-map.apvi.org.au/postcode

[4] OnlyFacts, Solar installations in Postcode 4819, 805 installations of population 2,475, ranks 130 of 2096 populated postcodes in Australia, Solar Installations in Postcode 4819: 805 Units | Energy

MICDA's objectives align with the Energy Trilemma framework, developed by the World Energy Council[5], as follows:

Environmental Sustainability

Maximise the renewable energy fraction:

- This is the primary driver of the project.
- TRM aims to achieve 100% renewable electricity supply for Magnetic Island by 2030.
- As an island community located within the Great Barrier Reef World Heritage area, TRM aims for Magnetic Island to be a leader in combating climate change.
- TRM supports the implementation of the DCCEEW Reef 2050 Long-Term Sustainability Plan.[6]

Energy Security

Minimise outage duration:

- The TRM working group's goal is to ensure that Magnetic Island has reliable, resilient, and sustainable energy
- Resilience following natural disasters is particularly important to the community

Energy Equity

Maximise benefits for community members:

- Affordability is a key consideration. The microgrid solution must provide economic benefits or value that can be shared among community members

2.3. Study Methodology

The methodology Yurika implemented for this study can be described in three phases as follows:

Phase 1

- Work with MICDA to understand key objectives for Magnetic Island's electricity supply and for this study
- Understand key learnings from previous reports and studies relevant to a Magnetic Island microgrid
- Review existing state of Magnetic Island, Horseshoe Bay, and Picnic Bay in terms of network, grid consumption and existing solar PV

Phase 2

- Develop microgrid and non-microgrid concepts that help achieve overall objectives
- Review concept options and narrow down on preferred concept. This is done with a focus on what is currently achievable in the short term while considering future development to meet more objectives in the longer term.
- Further refine concept solution by exploring options for preferred concept including solution physical location, network connections, network tariffs, economic return, and operating models

[5] World Energy Council, World Energy Trilemma Framework, World Energy Trilemma Index | World Energy Council
[6] Department Of Climate Change, Energy, The Environment and Water (DCCEEW), Reef 2050 Long-Term Sustainability Plan 2021–2025

Phase 3

- Develop preferred solution concept for the short term while considering future development and options.
- Build out how the preferred solution concept could be developed, constructed, and operated including proposed operating model, capital and operational cost estimates, delivery timelines.
- Assess the preferred solution concept by distribution network service provider (DNSP) assessment, techno-economic analysis and evaluation of key benefits and risks.

3. Electricity Supply Overview

The electricity grid is a system of interconnected infrastructure designed to deliver electricity from power generation sources to end consumers. It is comprised of large-scale generation, transmission, sub-transmission, distribution, embedded generation (EG) and customers.

Figure 1 provides an overview of the typical electricity grid supply chain.

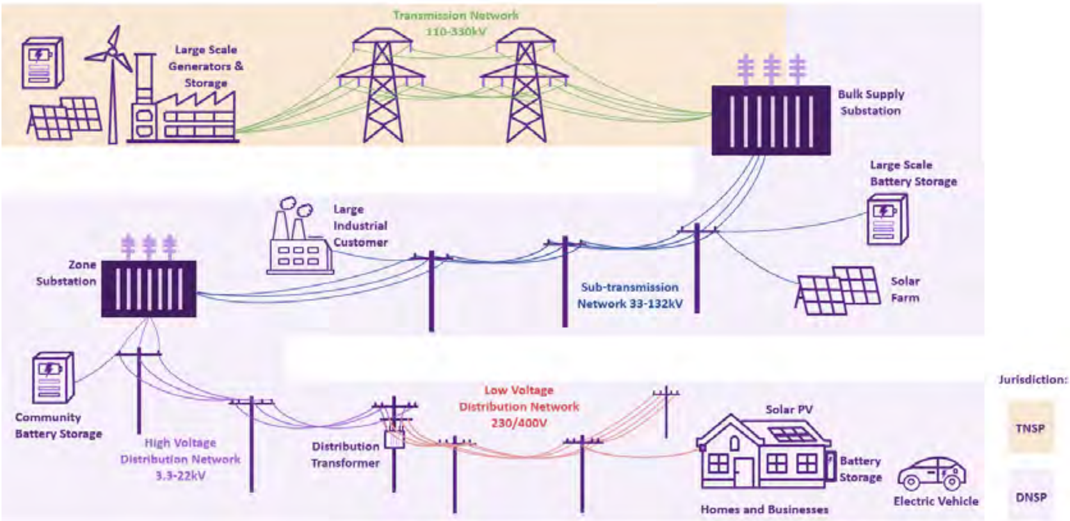


Figure 1 – Typical electricity grid supply chain

Electricity is produced by both large-scale generation plants, which include various energy sources such as coal, natural gas, hydro, solar PV, and wind, as well as by smaller distributed generation. The largest generators typically connect to the transmission network.

The transmission network carries electricity over long distances, from large-scale generators to bulk supply substations, at a voltage of 110 kV, 132 kV, 275 kV or 330 kV. Extremely large customers, typically with generators or loads greater than 50 MW, such as large-scale energy projects or industrial loads, are supplied from the transmission network[7]. The transmission network is built, maintained and operated by the Transmission Network Service Provider (TNSP), which in Queensland is Powerlink Queensland.

The Queensland transmission network is interconnected with the New South Wales transmission network. Together with ACT, Victoria, South Australia and Tasmania, these networks form the

[7] Powerlink, Connecting to the transmission network, Information sheet, https://www.powerlink.com.au/sites/default/files/2025-05/Connecting%20to%20the%20transmission%20network%20-%20Information%20sheet.pdf

national electricity market (NEM). The NEM is the longest interconnected power system in the world and covers around 5,000 km.[8]

The sub-transmission network, often considered part of the distribution network, transports electricity from bulk supply substations to zone substations at a voltage of 33 kV, 66 kV or 132 kV. The distribution network, typically operating at 22 kV or 11 kV, takes electricity from the zone substations to homes and businesses via distribution feeders, distribution transformers and low voltage networks. Some larger customers are connected to the network at high voltage (around 1.5 MW or higher) whereas most customers have a low voltage connection at 400/230 V. Distribution network service providers (DNSP) build, maintain and operate the sub-transmission and distribution networks. In Queensland, the two main DNSPs are Ergon Energy Network (regional Qld) and Energex (South East Qld).

Customers use the network to obtain electricity upon demand, and to export electricity when excess power is generated. Due to the ever-increasing number of embedded generators and energy storage systems being connected to the network, including small and large scale solar Photovoltaic (PV), battery storage and other renewable energy sources, electricity is now being generated and exported into the grid from customers' premises. Depending on the capacity and number of these systems within the same part of the distribution network, power flows in parts of the network are periodically in reverse, creating both challenges and opportunities for the network.[9]

3.1. Distribution Network Service Provider

Magnetic Island is within Ergon Energy Network's distribution service area. Ergon Energy Network is the DNSP for the majority of regional and rural Queensland. They are a government-owned corporation that distribute electricity to 792,127 customer connections, supporting a population base of approximately 1.5 million over an area of 1.7 million sq.km. Most connections are residential at 84%, with the remaining 16% related to commercial and industrial connections.

Ergon Energy Network own and operate 33 isolated power stations, with stand-alone electricity networks, that supply communities too remote to connect to the national grid.[10]

The Ergon Energy Network distribution service area is shown in Figure 2 below.

[8] Australian Energy Market Commission, Electricity supply chain, https://www.aemc.gov.au/energy-system/electricity/electricity-system/electricity-supply-chain

[9] Ergon Energy Network, Distribution Annual Planning Report (DAPR) 2024, https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report, February 2025, Section 1.2

[10] Ergon Energy Network, Distribution Annual Planning Report (DAPR) 2024, https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/distribution-annual-planning-report, February 2025, pg.10, 11

Figure 2 - Ergon Energy Network distribution service area [10]

3.2. Electricity Retailer

All electricity is centrally pooled and scheduled to meet demand. This pool is managed by the Australian Energy Market Operator (AEMO).

Electricity retailers are companies that buy energy from the wholesale market, managed by the AEMO, and sell energy to residential and business customers, as well as coordinate all the electricity bill charges.

Ergon Energy Retail is the fourth largest retailer in the National Electricity Market (NEM) (based on customer numbers) and is the electricity retailer for most customers on Magnetic Island.

Ergon Energy Retail charges the Queensland Government's notified prices, which are set by the Queensland Competition Authority (QCA) in line with the Queensland Government's uniform tariff policy (UTP). This enables regional Queenslanders to access the same regulated electricity tariffs (with the support of the government's Community Service Obligation (CSO) subsidy), keeping power prices on par with the southeast despite the additional cost involved in supplying electricity to regional Queensland. The CSO subsidy makes regional Queensland electricity bills 20% less on average than the cost of electricity supply.[11] The CSO is expected to be around $599.5 million in 2024–25 (including $93.9 million associated with isolated systems).[12]

As Ergon Energy Retail is the only retailer that has access to this subsidy, other unsubsidised retailers find it difficult to compete with Ergon Energy Retail. As a result, competition for customers in regional Queensland is limited.

[11] Energy Queensland, Annual Report 2023-24, https://www.energyq.com.au/__data/assets/pdf_file/0003/1406604/Energy-Queensland-Ltd-Annual-Report-2023-24.pdf

[12] Queensland Competition Authority (QCA), Electricity FAQs

4. Magnetic Island electrical characteristics

The following sections outline the electrical characteristics of Magnetic Island. Key considerations include network configuration, existing distributed energy resources, and load characteristics. Energy analysis for Magnetic Island, Horseshoe Bay, and Picnic Bay has been conducted using hourly internal data from 1 January 2020 to 30 June 2024.

4.1. Magnetic Island Total

Figure 3 shows Magnetic Island is supplied by two subsea 11 kV cables from the Townsville Marina switching station on the mainland to Nelly Bay. TM-03, shown in green, is rated at 4.5 MVA and supplies a portion of Nelly Bay and all of Picnic Bay. TM-10, shown in red, is also rated at 4.5 MVA and supplies a portion of Nelly Bay, as well as all of Arcadia and Horseshoe Bay.

Figure 3 - Magnetic Island Network Feeder Map[14]

Table 1 is a summary of the Ergon Energy Network assets and approved installed inverter capacity in each village on Magnetic Island.

Table 1 - Magnetic Island Network Summary

	Nelly Bay	Arcadia	Horseshoe Bay	Nelly Bay	Picnic Bay	TOTAL
Feeder	TM-10			TM-03		-
Feeder Capacity[13]	4,500 kVA			4,500 kVA		**9,000 kVA**
Max Historical Load[13]	3,604 kVA			2,268 kVA		-
No. of Distribution Transformers[14]	13	9	29	21	15	**87**
Sum of Distribution Transformer Capacity[14]	6,030 kVA	2,230 kVA	4,383 kVA	3,571 kVA	2,568 kVA	**18,782 kVA**
No. of Connections[14]	437	368	481	542	307	**2,135**
Installed Solar and Battery Inverter Capacity[14]	521 kVA	369 kVA	1,071 kVA	1,026 kVA	542 kVA	**3,529 kVA**

4.1.1 Planned Network Augmentation

As of December 2024, Ergon Energy Network were planning a series of projects to enhance the safety and reliability of the local electricity network, as well as improve environmental outcomes for the island.

These projects[15] include:

Arcadia & Nelly Bay network augmentation works - Upgrade several power poles, cross arms and network hardware in Arcadia and Nelly Bay, install a new switch, and reconductor over 400 metres of 11 kV powerline.

Townsville Marina cable upgrades - Upgrade the two 11 kV cables at Townsville Marina substation on The Strand foreshore to increase the maximum amount of power that can be supplied to Magnetic Island at any one time. This project was completed by end February 2025, upgrading each feeder capacity to 4.5 MVA.

Nelly Bay to Picnic Bay cable relocation - Relocate a section of the overhead 11 kV powerline (between Nelly Bay and Picnic Bay) that traverses the Magnetic Island National Park. This project will improve access to the powerline during maintenance and fault response activities and reduce the impact of our operations on the environment in the National Park.

Nelly Bay to Arcadia Bay cable relocation - Relocate a section of the overhead 11 kV cable (between Nelly Bay and Arcadia Bay) that traverses the Magnetic Island National Park. This project will improve access and reduce the impact of our operations on the environment.5

[13] Ergon Energy Network, Preliminary Response to Enquiry Preliminary Response to Enquiry for 0.99 MW/2.06 MWh BESS connection at Picnic Bay Lot 2 and Horseshoe Bay Park received 26th May 2025

[14] Ergon Energy Network, Network Load Capacity Map, November 2024 https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/network-load-capacity-map

[15] Ergon Energy Network, Magnetic Island network upgrade | Ergon Energy

4.1.2 Existing Solar PV Installations

A total of 5.294 MW of solar PV capacity is installed on Magnetic Island (June 2025 data).[16] Based on a conservative assumption that each kilowatt of solar PV installed produces 4 kWh of energy each day, this capacity is estimated to generate approximately 7.729 GWh of energy annually.

Figure 4 shows the cumulative capacity of solar PV installations on Magnetic Island. Over the last five years, the solar PV installed capacity has consistently grown by approximately 20% annually.

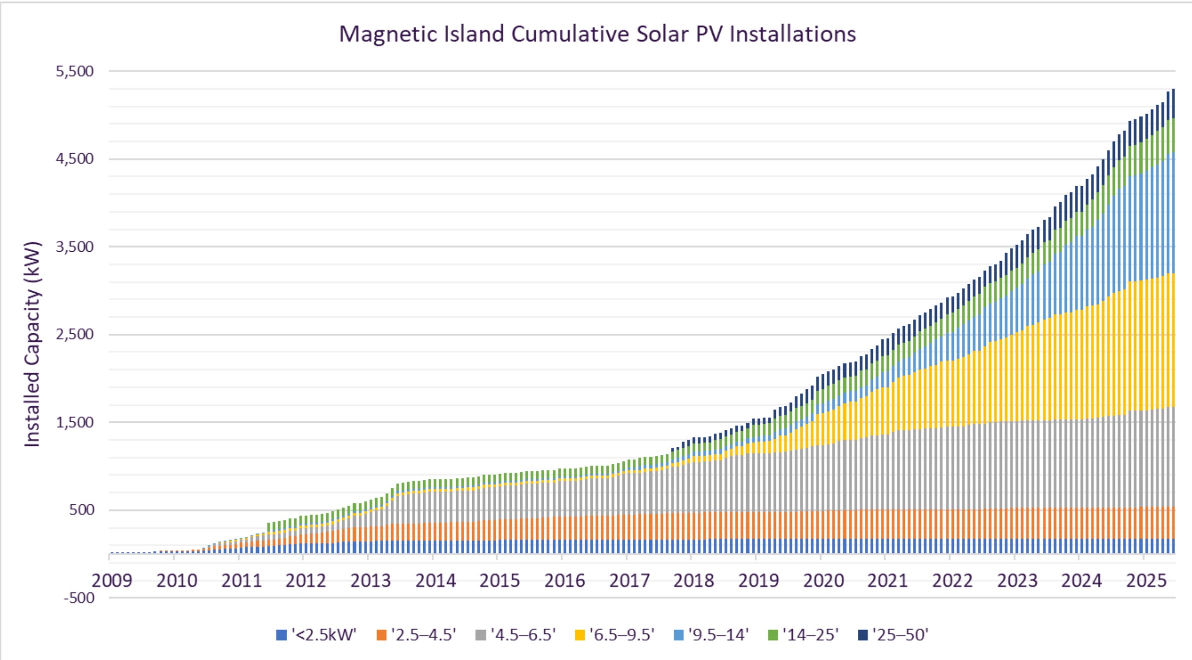


Figure 4 - Magnetic Island Cumulative Solar PV Installation Capacity 2008 - 2025[17]

4.1.3 Individual Customer Grid Consumption & Solar PV Export

Table 2 presents a consolidated summary of grid consumption and solar PV export for Magnetic Island. The data is sourced from each individual customer's meter and summated to get a consolidated total. The total energy shown for business and residential categories represents the sum of the energy consumed by each individual customer during the corresponding financial year. The total energy shown for solar PV export is the sum of the solar PV energy exported by each individual customer during the same period.

[16] Australian PV Institute, PV Postcode Data, Timeseries data by installation size (cumulative) for Magnetic Island J, QLD 4819, [Australian Photovoltaic Institute • PV Postcode Data]

[17] Australian PV Institute, PV Postcode Data, Timeseries data by installation size (cumulative) for Magnetic Island, QLD 4819, [Australian Photovoltaic Institute • PV Postcode Data]

Table 2 - Magnetic Island Consolidated Customer Connection Grid Consumption and Solar Export Summary[18]

Financial Year	Business Consumption		Residential Consumption		Solar PV Export	
	Total Energy	Average Customer Count	Total Energy	Average Customer Count	Total Energy	Average Customer Count
2020/21	8,431 MWh	187	9,480 MWh	1,837	1,817 MWh	468
2021/22	9,205 MWh	191	10,321 MWh	1,866	2,104 MWh	504
2022/23	9,204 MWh	193	10,074 MWh	1,899	2,365 MWh	547
2023/24	9,103 MWh	197	9,891 MWh	1,920	2,919 MWh	614

Table 3 shows business consumption, residential consumption, and solar PV export on a kWh/customer/day basis.

A key observation is that from the 2021/22 financial year onwards, the total energy consumed by both business and residential customers decreases, while the average customer count increases. The low consumption in 2020/21 can be attributed to the impact of COVID-19 on tourist numbers.

The decrease in energy consumption corresponds with a steady increase in solar PV generation from 2020/21 to 2023/24. The solar PV customer count increases by 8%, 9%, and 12% each year, while the total solar PV energy exported rises by 16%, 12%, and 23% annually. This suggests that newer solar PV installations are exporting more than older solar PV installations. This trend can be attributed to larger solar PV systems being installed in recent years (6.5 kW to 14 kW).

Table 3 - Magnetic Island Average Individual Customer Metered Usage and Solar PV Export Summary[19]

Financial Year	Business Consumption kWh/customer/day	Residential Consumption kWh/customer/day	Solar PV Export kWh/customer/day
2020/21	124	14	11
2021/22	132	15	12
2022/23	131	15	12
2023/24	127	14	14

4.1.4 Net Grid Consumption

Table 4 shows the total demand and consumption for both 11 kV feeders supplying Magnetic Island. In line with the increase in solar PV installations, the average demand and annual consumption have decreased from 2021/22, while the maximum demand has increased.

[18] Ergon Energy Network, Energy usage data by Postcode (XLSX) 1 Jan 2020 – 30 Sep 2024 for 4819, https://www.ergon.com.au/network/our-network/network-data/energy-usage-data-to-share

[19] Ergon Energy Network, Energy usage data by Postcode (XLSX) 1 Jan 2020 – 30 Sep 2024 for 4819, https://www.ergon.com.au/network/our-network/network-data/energy-usage-data-to-share

Table 4 – Magnetic Island Grid Consumption Summary

Financial Year	Maximum Demand (1hr avg.)	Average Demand	Annual Consumption	Average Daily Consumption	Average Customer Count
2020/21	5,033 kW	1,913 kW	16,759 MWh	45.92 MWh/day	2,024
2021/22	5,349 kW	2,054 kW	17,994 MWh	49.30 MWh/day	2,057
2022/23	5,269 kW	1,989 kW	17,424 MWh	47.74 MWh/day	2,092
2023/24	5,500 kW	1,879 kW	16,502 MWh	45.09 MWh/day	2,116

4.2. Horseshoe Bay

4.2.1 Net Grid Consumption

Table 5 shows the total demand and consumption for Horseshoe Bay. In line with the increase in solar PV installations, both the average demand and annual consumption have decreased since 2021/22, while the maximum demand has increased.

Table 5 - Horseshoe Bay Grid Consumption Summary

Financial Year	Maximum Demand (1hr avg.)	Average Demand	Annual Consumption	Average Daily Consumption
2020/21	969 kW	358 kW	3,150 MWh	8.63 MWh/day
2021/22	1,063 kW	399 kW	3,498 MWh	9.58 MWh/day
2022/23	1,013 kW	392 kW	3,442 MWh	9.43 MWh/day
2023/24	1,077 kW	367 kW	3,315 MWh	9.06 MWh/day

The load profile (1-hour interval data) in Figure 5 demonstrates a consistent pattern, with higher loads during the summer months and lower loads in the winter months.

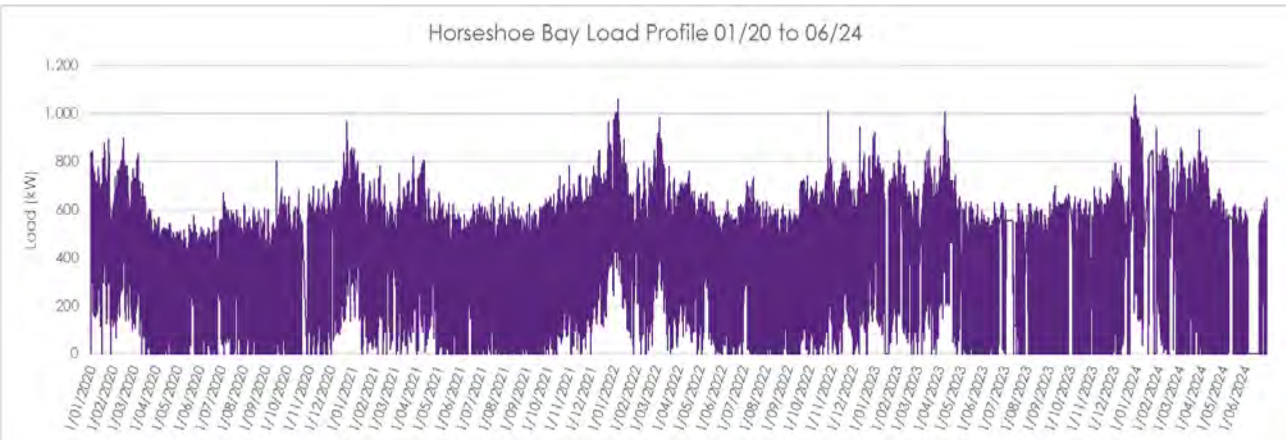


Figure 5 - Horseshoe Bay Load Profile 1/2020 to 06/2024

Within the dataset from January 2020 to June 2024, there were several periods of zero load, suspected switching events between feeders or data errors (representing 8% of the total dataset).

To estimate the values in Table 5, the suspect data was excluded and values adjusted to estimate actual consumption and average demand.[20]

The Horseshoe Bay monthly grid consumption is shown in Figure 6 below. Each financial year follows a consistent pattern, with typically higher loads in the summer months and around Easter, and lower loads in the winter months.

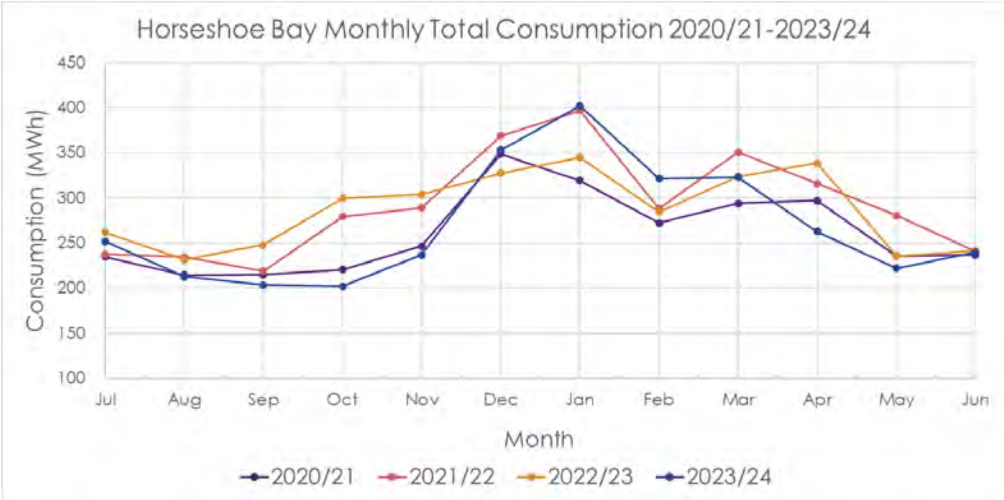


Figure 6 - Horseshoe Bay Monthly Total Consumption 2020/21 to 2023/24

Figure 7 shows the average daily load profile for Horseshoe Bay in the most recent financial year. The weekday and weekend load profiles are similar, showing slightly higher load on weekends than weekdays. The summer months show higher loads throughout the day compared to winter months. During winter months, the load reduces to zero in the middle of the day resulting in excess solar PV generation. On average, the solar PV in Horseshoe Bay covered the entire village load between 12pm and 3pm (with an average demand of -57 kW).

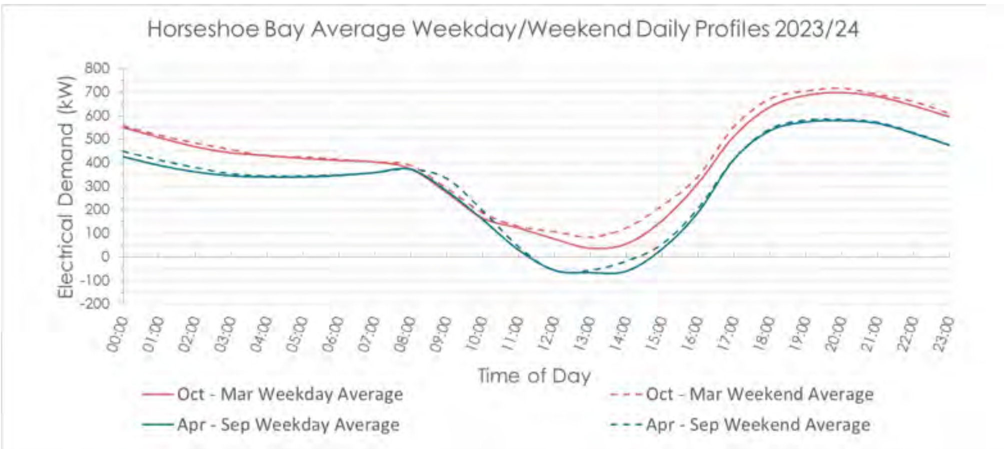


Figure 7 - Horseshoe Bay Average Weekday/Weekend Daily Load Profile 2023/24

Figure 8 shows the average daily profiles of each separate season in 2023/24. Majority of the feeder reverse flow occurs in spring. On average, the solar PV in Horseshoe Bay covers all the load between 11am and 4pm (with an average demand of -69 kW).

[20] For example, 7% of the data was suspect for 2022/23. This 7% was excluded and the annual consumption calculated. The actual annual consumption was then estimated by dividing that number by 93%.

Autumn and winter have similar profiles which on average, have excess solar PV generation each day. Unlike all other seasons, the summer average daily minimum demand was above zero, at 182 kW. There is likely higher air conditioning load in summer compared to all other seasons.

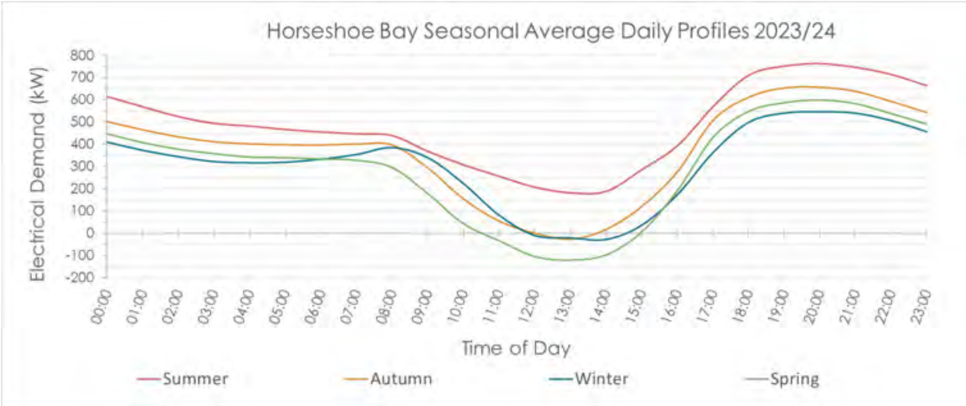


Figure 8 – Horseshoe Bay Seasonal Average Daily Load Profile 2023/24

Figure 9 shows the Horseshoe Bay, TM-10 feeder and TM-03 average daily profiles. The profile shapes are relatively consistent.

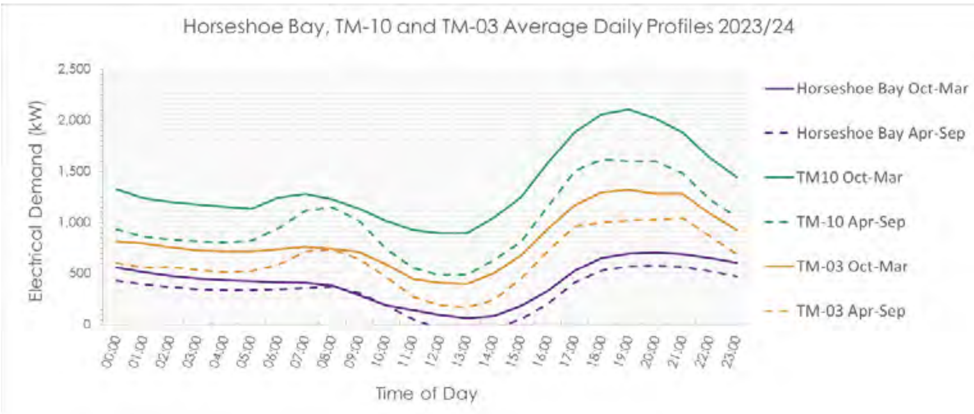


Figure 9 - Horseshoe Bay, TM-10 and TM-03 Feeder Average Daily Load Profile 2023/24

4.2.2 Net Existing Solar PV Export

Table 6 shows that, each year since 2020/21, there have been periods of significant excess solar PV generation, where solar PV power supplied the total load of Horseshoe Bay, with surplus energy flowing back towards Arcadia. Interestingly, until 2023/24, this surplus solar PV energy from Horseshoe Bay was consumed by Arcadia and Nelly Bay. However, in 2023/24, only two hourly average intervals showed reverse flow, totalling 200 kWh of excess solar PV energy that flowed from Magnetic Island to the Townsville Marina substation via the TM-10 feeder.

Table 6 – TM-10 Feeder and Horseshoe Bay Excess Solar PV Summary

	TM-10 Feeder Excess Solar PV		Horseshoe Bay Excess Solar PV	
	Maximum	Total Energy	Maximum	Total Energy
2020/21	-	-	141 kW	10 MWh
2021/22	-	-	119 kW	6 MWh
2022/23	-	-	157 kW	12 MWh
2023/24	100 kW	0.2 MWh	327 kW	91 MWh

4.3. Picnic Bay

4.3.1 Net Grid Consumption

Unlike for Horseshoe Bay where data can be obtained from the Arcadia Recloser, there is no available data for the net consumption of Picnic Bay. The net consumption for Picnic Bay was estimated using data from the TM-03 feeder and scaling it down to represent the Picnic Bay load (i.e. excluding the Nelly Bay load supplied by TM-03).

Picnic Bay accounts for 42% of the total distribution transformer capacity, 36% of the total number of customer connections and 35% of the approved installed inverter capacity on TM-03. As a result, the TM-03 dataset was scaled down to 36% to produce an estimated load profile for Picnic Bay. Given the greater number of higher loads in Nelly Bay, this assumption could overestimate the load of Picnic Bay.

Table 7 shows the estimated total demand and consumption for Picnic Bay. In line with the increase in solar PV installations, annual consumption has decreased since 2021/22.

Table 7 - Picnic Bay Estimated Grid Consumption Summary

Financial Year	Maximum Demand (1hr max)*	Average Demand	Annual Consumption	Average Daily Consumption
2020/21	756 kW	262 kW	2,296 MWh	6.29 MWh/day
2021/22	756 kW	282 kW	2,470 MWh	6.77 MWh/day
2022/23	664 kW	269 kW	2,357 MWh	6.46 MWh/day
2023/24	792 kW	261 kW	2,291 MWh	6.26 MWh/day

A limitation of using the TM-03 data is that switching events, where TM-03 temporarily supplied part or all the load normally provided by TM-10, appear as large demand spikes for TM-03. While a process was implemented to cleanse the data by removing these switching events, some may not have been captured, which could explain why the maximum demand does not consistently increase or decrease year over year.

The load profile (1-hour interval data) in Figure 10 shows a consistent pattern of higher loads during the summer months and lower loads during the winter months.

Within the dataset from January 2020 to June 2024, there were several periods of zero load, suspected switching events between feeders or data errors (representing 7% of the total dataset). To estimate the values in Table 7, the suspect data was excluded and values adjusted to estimate actual consumption and average demand.

A notable period of zero load can be seen in Figure 10 at the end of 2020, when TM-03 was supplied by TM-10 for 103 days from 4/9/2020 until 10/12/2020.

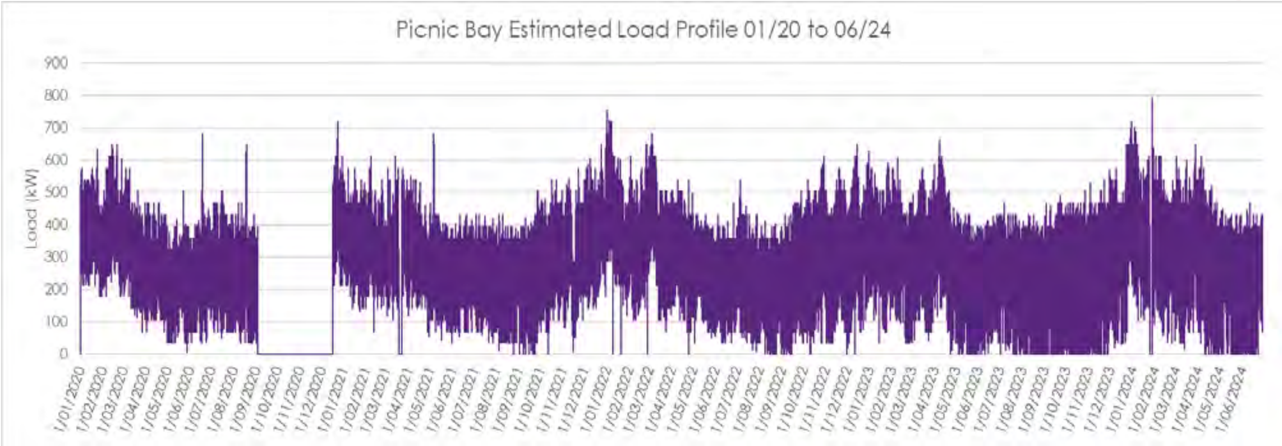


Figure 10 – Estimated Picnic Bay Load Profile 1/2020 to 06/2024

The estimated Picnic Bay monthly grid consumption is shown in Figure 11 below. The very low loads from September to December 2020 have not been shown in this plot as they are due to the switching event mentioned above. Excluding these months, each financial year follows a consistent pattern, with higher loads during the summer months and around Easter, and lower loads during the winter months.

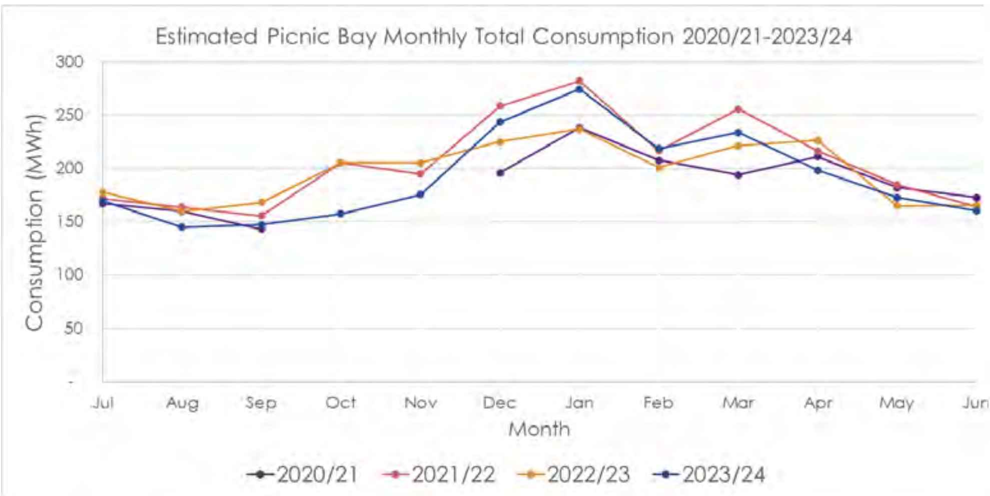


Figure 11 - Picnic Bay Monthly Total Consumption 2020/21 to 2023/24

The estimated average daily load profile for Picnic Bay in the most recent financial year is shown in Figure 12. Like Horseshoe Bay, the weekday and weekend load profiles are almost identical. As expected, the summer months (October to March) have higher loads throughout the day compared to the winter months (April to September).

During the winter, there is a noticeable dip in load in the middle of the day, likely due to reduced air conditioning demand. Most of the load between 12pm and 2pm is met by excess solar PV, resulting in an average demand of 65 kW. This aligns with the data in 'Table 1 - Magnetic Island Network Summary', which shows that the ratio of installed inverter capacity to customer connections is higher in Horseshoe Bay than in Picnic Bay.

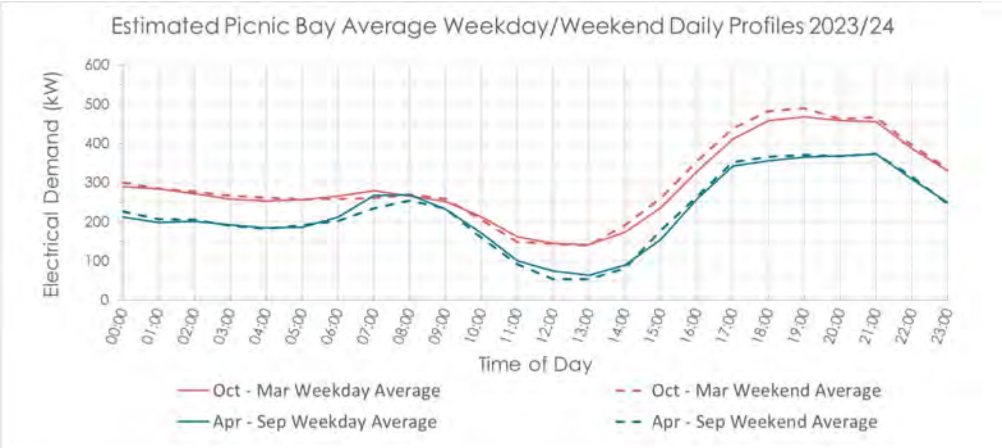


Figure 12 – Estimated Picnic Bay Average Daily Load Profile 2023/24

Figure 13 shows the average daily profiles of each separate season in 2023/24. Spring shows the lowest average minimum demand, falling to 32 kW between 12pm and 1pm due to solar PV generation. As expected, summer has the highest average minimum demand due to air conditioning load, falling to only 205 kW between 1pm and 2pm.

Each season has a similar profile however winter differs slightly with a higher morning peak, expected to be due to heating load.

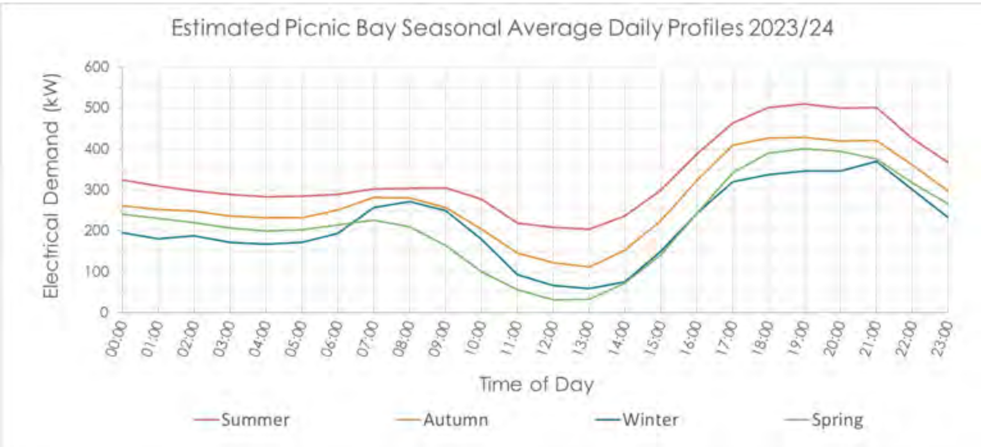


Figure 13 – Estimated Picnic Bay Seasonal Average Daily Load Profile 2023/24

Without interval data for Picnic Bay, it is not possible to compare average daily profiles of Picnic Bay and TM-03 however, Picnic Bay accounts for 36% of TM-03 network customer connections and 35% of TM-03 approved installed inverter capacity. For this reason, it is estimated that the Picnic Bay average daily profile is consistent with the TM-03 feeder average daily profile.

4.3.2 Net Existing Solar PV Export

Like the Horseshoe Bay TM-10 feeder, Table 8 shows that until 2023/24, there had been no excess solar PV energy flowing from Magnetic Island to the Townsville Marina substation via TM-03. However, in 2023/24, a total of 4,400 kWh of excess solar PV was recorded as reverse flow on the TM-03 feeder, occurring in 70 hourly average intervals. The Picnic Bay excess solar PV was estimated to be 36% of the TM-03 excess solar PV.

Table 8 – TM-03 Feeder and Picnic Bay Excess Solar PV Summary

	TM03 Excess Solar PV		Picnic Bay Estimated Excess Solar PV	
	Maximum	Total Energy	Maximum	Total Energy
2020/21	-	-	-	-
2021/22	-	-	-	-
2022/23	-	-	-	-
2023/24	100 kW	4.4 MWh	36 kW	1.6 MWh

Therefore, the total exports flowing from Magnetic Island to the mainland via TM-03 and TM-10 in 2023/24 totalled 4.6 MWh.

5. Microgrids

5.1. What is a microgrid?

A microgrid as defined by international standard IEEE 2030-09 is:

> *a group of interconnected loads and distributed energy resources with clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to enable it to operate in both grid-connected or island modes.*

Figure 14 and Figure 15 show the components of a grid-connected and stand-alone microgrid. The components can include a range of distributed energy resources (DER) (renewable generator, energy storage, backup diesel generator), controllable loads (e.g., electric vehicle charger), multiple consumer loads, microgrid controller and a grid connection.

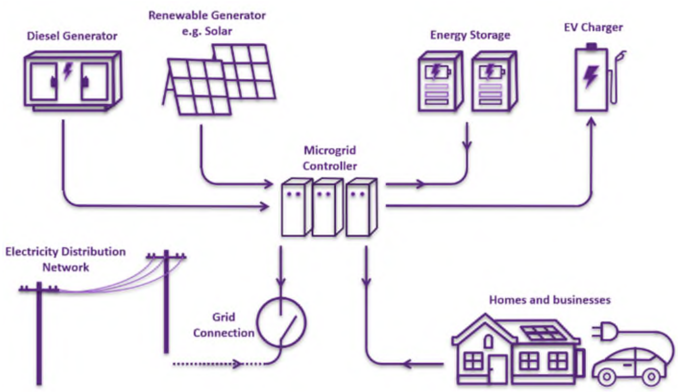


Figure 14 - Grid-connected microgrid components

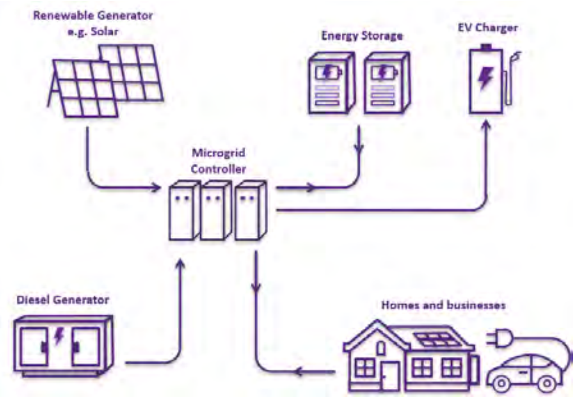


Figure 15 - Stand-alone microgrid components

The key defining characteristic of a microgrid is its ability to operate independently of the electricity distribution network, commonly referred to as "islanding". The microgrid controller coordinates the loads and energy resources to optimise the power flows in a microgrid. For grid-connected microgrids, it also controls the connection or disconnection of the system to the network.

Unlike grid-connected microgrids, stand-alone microgrids are completely reliant upon their own energy resources because they have no connection to the network. Stand-alone microgrids are an option when it is not economically or technically possible to connect to the electricity distribution network.

Definitions can vary and some electricity industry bodies consider the term 'stand-alone microgrid' to be interchangeable with 'stand-alone power system (SAPS)'. SAPS usually include renewable power generation (mainly solar PV) and battery storage with backup diesel generation. For this report, a SAPS is considered an individual power system with no grid connection, supplying a single customer whereas a stand-alone microgrid supplies multiple customers. The key difference being a single customer (SAPS) compared to multiple customers (microgrid).

Additional information on microgrids is provided in the Ergon Energy Network factsheet[21] in report Appendix A, Section 20.2.

The purpose of a microgrid is to obtain benefit through a combination of the following objectives:

Financial
Provide potential cost savings for communities, customers and DNSPs through reduced electricity costs or reduced grid operational costs that provide a suitable payback and return on investment.

Resilience
Provide backup power if grid supply is removed and or demand management to ensure electrical equipment ratings are not exceeded.

Sustainability
Increase local renewable energy generation that supports lower carbon emissions and avoids losses associated with transferring power through the network.

All communities generally want to maximise resilience and sustainability outcomes and minimise financial impact. This requires site specific analysis of existing network, generation, load, physical space, and weather inputs. All within broader constraints of legislation, regulation, and land tenure to understand what options are possible. Financial modelling of possible technical solutions provides an opportunity to consider alternatives compared to current state. Ideally, the benefits of a microgrid will include a combination of cost reductions, increased energy resilience, and enhanced sustainability.

5.2. Ergon Energy Network microgrids

Given Magnetic Island is within Ergon Energy Network's distribution service area and MICDA are open to various options for solution ownership, this section provides an overview of the following:

- Existing Ergon Energy Network owned community microgrids
- How Ergon Energy Network's microgrid capability is being developed and expected to continue to develop in the short to medium term
- Other relevant Ergon Energy Network projects that share similar solution components or benefits to a microgrid

5.2.1 Existing microgrids

Isolated Systems

The 33 stand-alone electricity networks owned and operated by Ergon Energy Network are considered microgrids. These microgrids supply 39 communities too remote to connect to the

[21] Ergon Energy Network, Community Microgrid Factsheet

national grid and are located throughout western Queensland, the Gulf of Carpentaria, Cape York, on numerous Torres Strait Islands, and on Palm and Mornington Islands.[22]

Most of the energy supplied to these communities has been produced by diesel generation. This has required transporting the diesel long distances and through environmentally sensitive areas, posing a range of environmental and economic challenges.

5.2.2 Current microgrid pilot projects

The Australian and Queensland governments have acknowledged the potential that microgrids provide to improve first nations and remote community resilience and the opportunity to participate in DER/CER ownership, while contributing to national emissions reduction targets. Several ARENA and Queensland Government funding grants have been made available in recent years specifically to develop microgrids in these communities. Ergon Energy Network has received grants under the Queensland Microgrid Pilot Fund (QMPF) to develop battery based microgrids for the Mossman Gorge and Jumbun communities.

Mossman Gorge – High voltage Grid-Connected Microgrid

Ergon Energy Network is set to build a high-voltage, grid-connected microgrid on Kaku Yalanji Country at Mossman Gorge. This pilot location was selected due to the higher-than-average frequency and duration of power outages.[23]

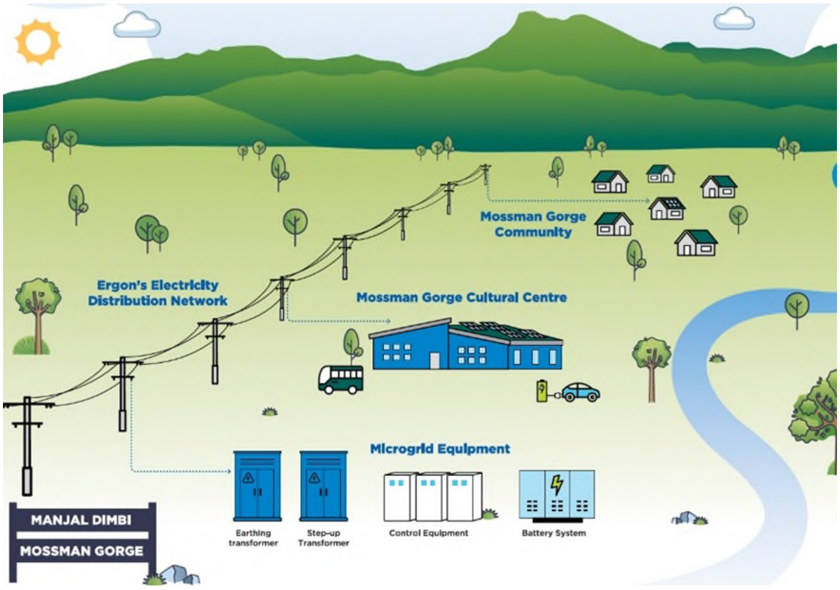


Figure 16 – Mossman Gorge Network Connected Microgrid[24]

The key components of the Mossman Gorge microgrid are shown in Figure 16. The microgrid will be grid-connected during normal operation and will island from the main grid during extended planned and unplanned network outages. The new BESS will provide an alternative supply during 'island mode', improving reliability for the 180 people (40 network connections) supplied by four distribution transformers, within the microgrid. Construction is expected to commence in 2025 and once complete, Energy Network will own, operate, and maintain the new microgrid and existing network assets.[24] This concept of a HV grid-connected microgrid, reliant on a BESS rather than diesel generator, has the potential to be deployed for communities elsewhere in the network. The community members supplied by the microgrid will not see any changes to how electricity is supplied to them or any changes to their electricity bill.

Jumbun – Low voltage Grid-Connected Microgrid

Ergon Energy will build a low-voltage, grid-connected microgrid at Jumbun. Jumbun is located between Tully and Cardwell, approximately 2 ½ hours' drive from Cairns. The community experiences poor telecommunications and reliability and it is difficult to access the area when it

[22] Isolated & remote power stations | Ergon Energy
[23] Mossman Gorge microgrid project | Ergon Energy
[24] Mossman Gorge Microgrid Project Factsheet

floods. Unlike the Mossman Gorge microgrid, the Jumbun microgrid will not include high voltage as the entire community of approximately 100 people (28 network connections) are supplied by a single 100 kVA distribution transformer. The community members supplied by the microgrid will not see any changes to how electricity is supplied to them or any changes to their electricity bill.

DNSP-Led Microgrid Initiatives Across the NEM

With a similar objective to that of Ergon Energy Network, Endeavour Energy is leading a microgrid pilot project in NSW to reduce power outages. Bawley Point and Kioloa are at the end of a long electricity line and experienced outages caused by bushfires, storms, and peak load during holiday periods. The DNSP identified the need for a new substation and additional overhead network to improve power reliability. As an alternative, a microgrid solution was launched as a pilot project at the end of December 2023 with commissioning taking place in 2025. Funded through bushfire recovery programs, the project includes over 100 subsidised home BESS (operating in a VPP) and rooftop solar PV systems in addition to a centralised 3 MW BESS.[25]

Another example of a DNSP-led microgrid project is the Mooroolbark Mini Grid trial. Launched in 2016 by AusNet Services in Victoria, was Australia's first residential microgrid trial in an established suburban setting.[26] It involved 14 homes equipped with solar PV and home BESS', a microgrid stabiliser BESS, coordinated via at third party platform to test peer-to-peer energy sharing and islanding capabilities. Although the trial successfully demonstrated technical feasibility, the microgrid was not maintained as a permanent operational system, and participating homes returned to standard grid connection after the project concluded in March 2019.[27]

5.2.3 Microgrid development

Ergon Energy Network recognise that microgrids are an emerging implementation of DER/CER that have the potential to improve customer experience with network reliability, enhance community resilience and provide potential cost savings for communities, customers and DNSPs. Their view is that this potential is provided through the ability of a grid-connected microgrid, which can be islanded from the network for a period, to leverage local generation and storage to maintain supply to loads during contingencies, improve quality of supply, and defer network augmentation.

Although they have extensive experience with planning, constructing, operating, and maintaining their stand-alone microgrids supplying remote communities, Ergon Energy Network have significant work required to develop how grid-connected microgrids might be implemented within their network. There are risks to the safety, security, and operability of the networks posed by grid-connected microgrids that must be mitigated through trials and testing, along with the development of standards and operating procedures. The Jumbun and Mossman Gorge projects are key in this development; they will be the first in Queensland to have distribution network coordinated high voltage and low voltage microgrids that don't contain a diesel generator.

Ergon Energy Network also recognise that third party microgrids may also provide economic benefits to proponents through retail, AEMO, and network support arrangements. The knowledge gained from the pilot projects will also be used to develop how third party microgrids will be incorporated into the network.

[25] Endeavour Energy, First community microgrid for NSW, First community microgrid for NSW | Endeavour Energy
[26] GreenSync, Mooroolbark community mini grid, 21/04/2016, Mooroolbark community mini grid - GreenSync
[27] AusNet Services, Mooroolbark, Community Mini Grid Project, Final Report – Public Release Version 1.1., AusNet Services Report Template

Ergon Energy Network expect to develop their capability to enable the network and their customers to leverage the benefits offered by microgrids, and mitigate the risks they introduce, as per the timeline shown in Figure 17 below.

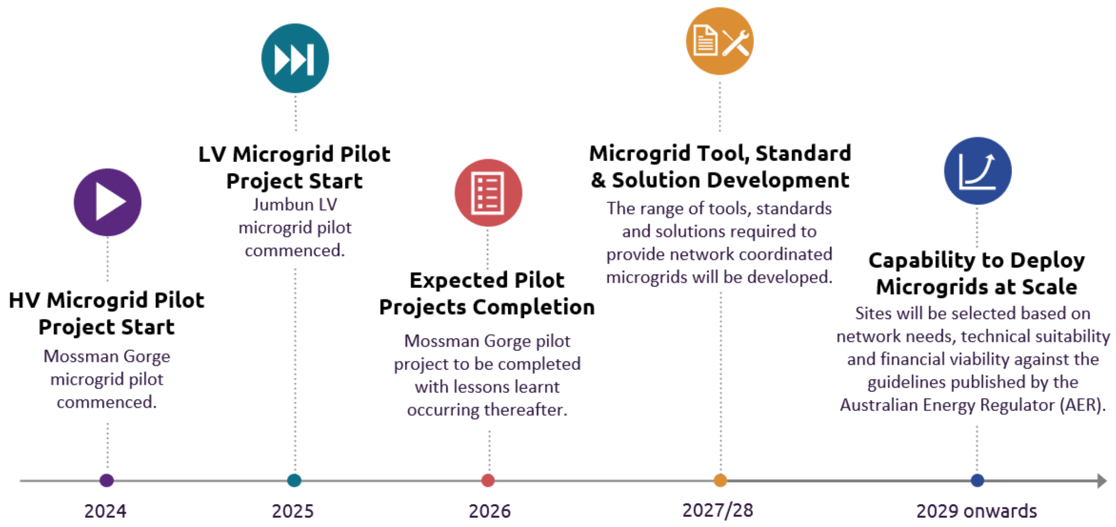


Figure 17 - Ergon Energy Network battery grid-connected microgrid development expected timeline

5.2.4 Ergon Energy Network Community Batteries

Ergon Energy Network acknowledge that battery storage is an essential tool for managing the renewable energy flowing into the electricity network and to addressing the capacity and security of supply challenges created by major reverse and negative flows, as well as changing demands at the system level.

Ergon Energy Network and Energex have rolled out, and are continuing to roll out, a number of BESS as part of their 'Local Network Battery Plan'[28]. The Local Network Battery Plan projects are summarised in Table 9 below.

[28] https://www.talkingenergy.com.au/batteryplan

Table 9 – Ergon Energy Network/Energex Local Network Battery Plan project overview[29]

Project	Timing	Battery Solution	Locations
Stage 1: Utility-scale batteries	March 2021 to early 2023	HV network connected BESS 5 x 4 MW/8 MWh	Townsville, Toowoomba, Yeppoon, Bundaberg, and Hervey Bay
Ipswich Neighbourhood Battery Trial	Late 2022 to 2025	LV network connected BESS 30 x 30 kW/60 kWh pole top 5 x ground mount	Raceview, Goodna, Flinders View, Silkstone, Bellbird Park, and Redbank Plains
Stage 2 & 3: Utility-scale batteries	Mid 2023 to early 2025	HV network connected BESS 12 x 4 MW/8 MWh	Regional Qld: Mundubbera, Howard, Townsville, Kewarra, Toowoomba, Gladstone, Emerald, Gordonvale, Marian South SEQ: Raby Bay, Bribie Island, Morayfield
Community Batteries (DCCEW)	Late 2023 – 2025	LV network connected BESS 9 x 90 kW/180 kWh mixture of pole-top and ground mount	Regional Qld: Cairns North SEQ: Caloundra, Caboolture, Kallangur, Griffin, Coorparoo, Moorooka, Birkdale, and Pimpama.
Community Batteries (ARENA)	Funding awarded January 2025	LV network connected BESS mixture of 50 kW/70 kWh pole-top and 90 kW/180 kWh ground mount	Regional Qld: Burnett Heads, Burrum Heads SEQ: Kingston North, Maclean, Jimboomba, Bribie Island, Morayfield, Scarborough

Although a BESS can be a key component of a microgrid, none of the BESS units being implemented as part of Ergon Energy Network/Energex 'Local Network Battery Plan' provide backup power to the HV or LV networks and therefore, are not microgrids. The intention for these BESS units are to provide network support during normal grid operation.

5.2.5 Local Renewable Energy Zone (LREZ)

Ergon Energy Network announced the Local Renewable Energy Zone (LREZ) pilot in mid-2024; a project funded by the Queensland Government. The two locations selected to be part of the pilot project were announced as Townsville and Caloundra. The proposed areas were chosen based on several factors[30] to maximise benefit and learnings including:

- mix of residential (greenfield and brownfield) and commercial and industrial areas
- portion of residential customers with existing solar PV
- portion of small business customers with existing solar PV
- number of customers with smart meters
- mix of residential renters and owner-occupiers
- distribution network configuration, capacities and forecasted load growth

The Townsville LREZ area is highlighted in Figure 18 below.

[29] Ergon Energy Network/Energex, Community Battery Council Introduction January.pdf, https://www.talkingenergy.com.au/community-batteries
[30] LREZ Stakeholder Forum – Townsville Presentation.pdf, https://www.talkingenergy.com.au/lrez

Figure 18 –Ergon Energy Network LREZ Townsville pilot project area[31]

The intent of LREZ is to bring together customers, retailers, and electricity networks for a coordinated collaborative approach to delivering on renewable energy targets. For the pilot, the Townsville LREZ area will include a group of interconnected loads and DER/CER with clear electrical boundaries where the focus will be to generate, store and consume energy locally within the zone. This is like a microgrid, however, LREZ is not a microgrid because the zone, or any part of the zone that is owned by the DNSP, will not be disconnected from the main grid to operate in 'island mode'. Ergon Energy Network do not intend to provide backup power to the community with network batteries installed as part of LREZ.

It is unclear if the Queensland Government's change in energy strategy will impact the LREZ pilot project.

What does LREZ mean for Magnetic Island?

Being outside of the specific Townsville LREZ area, residents and business owners on Magnetic Island will not be able to access products or services being trialled as part of LREZ (e.g., Ergon Retail trial offers). This is because trials and pilots like LREZ offer products and services in a controlled regulatory environment for the purpose of testing (regulatory sandpit) to inform future regulatory changes.

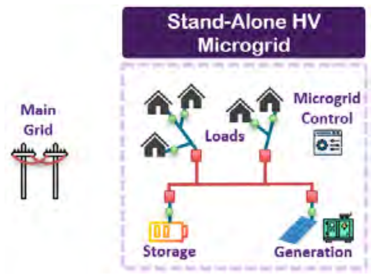
[31] https://www.ergon.com.au/network/manage-your-energy/smarter-energy/our-network-batteries/local-renewable-energy-zone-lrez-pilot

6. Solution Option Development

This section covers the high level concepts that were considered for this study and how the preferred concept was selected for detailed analysis of feasibility.

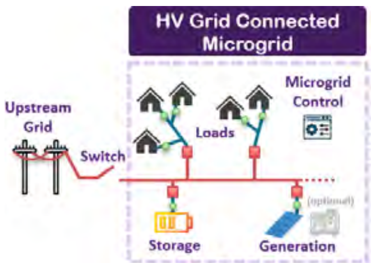
6.1. Solution Options Considered

The following five possible technical solutions were reviewed to determine if they would be relevant for Horseshoe Bay and Picnic Bay.



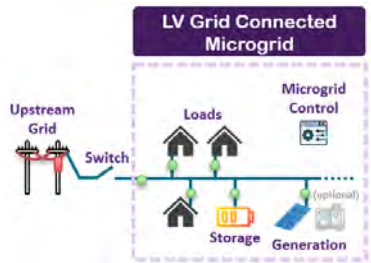
#1 High Voltage Community Stand-Alone Microgrid

Part of or all the village is disconnected from the grid at an 11 kV HV network point to operate permanently as a microgrid. The microgrid would be entirely self-sufficient with no backup option from the main grid. Backup diesel generation is not essential for a stand-alone microgrid however it is more economical than oversizing the BESS for supply redundancy.



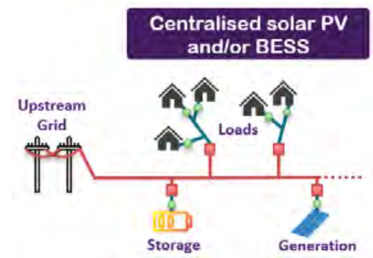
#2 High Voltage Community Grid-Connected Microgrid

Part of or all the village is capable of temporarily islanding from the grid at an 11 kV HV network point to operate as a microgrid when required. The microgrid will normally operate connected to the main grid and when possible, during extended planned and unplanned network outages, the microgrid will island from the network. Backup diesel generation is optional, providing power if the BESS runs out of charge before the grid or solar supply returns.



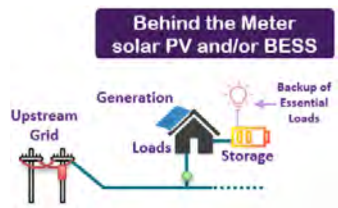
#3 Low Voltage Microgrid

Multiple adjacent sites that are electrically connected through a low voltage electrical network. During normal operation the microgrid will operate connected to the main grid. During extended planned and unplanned network outages, the microgrid will island from the network (e.g., after a severe weather event). Backup diesel generation is optional, providing power if the BESS runs out of charge before the grid supply returns.



#4 Centralised Solar PV and/or BESS [not a microgrid]

Centralised solar PV and/or BESS are connected directly to the network (i.e., not supply a load co-located with the solar PV and/or BESS). The BESS would not have the capability to provide backup power in the event of a grid outage.



#5 Behind the Meter Solar PV and/or BESS [not a microgrid]

Solar PV and/or BESS are connected at an existing single site that supplies a residential or business load. This option could provide backup power to the site if the BESS is designed to do so in the event of a grid outage.

6.2. Option Assessment

6.2.1 Concept #1 - High Voltage Community Stand-Alone Microgrid

Typically, stand-alone microgrids are used instead of grid-connected microgrids in instances where there is no existing grid connection and establishing a grid connection is not feasible. Typically, this is due to significant cost associated with the new connection to the grid.

Given Horseshoe Bay and Picnic Bay have an existing grid connection, converting either village to a stand-alone HV microgrid by abolishing the grid connection could be considered high risk. With no backup from the main grid, a stand-alone microgrid would need to be designed with greater redundancy, increasing capital and operational costs. This option may not improve the reliability of supply for residents and business owners within the microgrid, and instead could even worsen, depending on how the microgrid is designed.

To achieve a desired level of redundancy, the solution may also include backup diesel generation as it may not be feasible to oversize the BESS to provide this redundancy. Introducing large diesel generation does not align with MICDA's sustainability objectives.

A standalone microgrid is not a recommended option to provide financial savings or improve resilience for Horseshoe Bay or Picnic Bay and is not required to increase sustainability. There are other complexities and barriers relating to constructing and operating a HV microgrid; these are explored below for Concept #2.

6.2.2 Concept #2 - High Voltage Community Grid-Connected Microgrid

A grid-connected HV microgrid concept for Horseshoe Bay or Picnic Bay is shown in Figure 19 below.

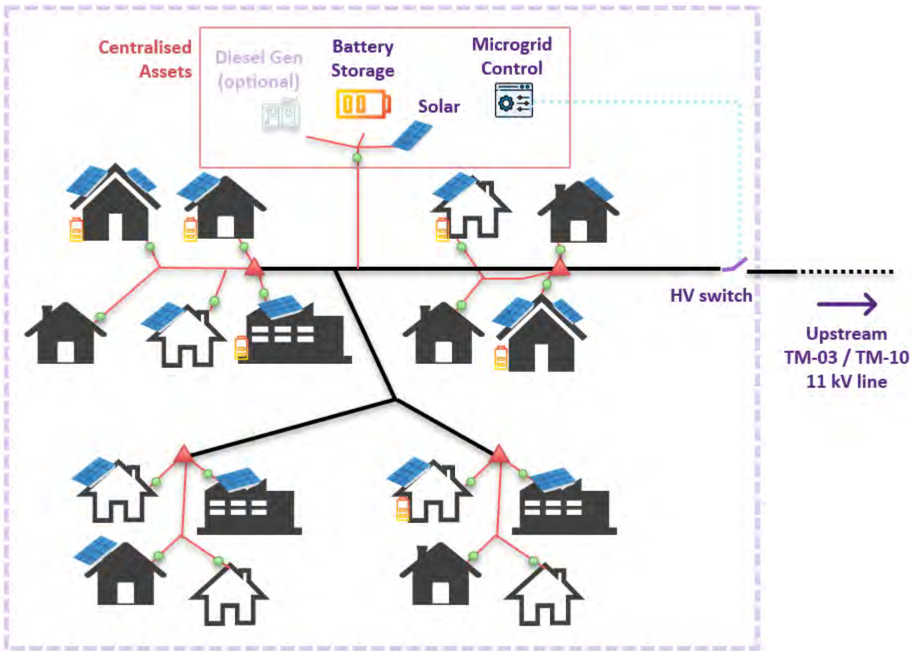


Figure 19 - Community grid-connected microgrid concept

During normal operation, the microgrid is connected to the main grid. The microgrid control system would monitor the microgrid HV network connection point and coordinate the centralised assets to maximise local use of renewable generation.

When an extended planned or unplanned outage on the main grid occurs, the microgrid control will open the HV switch, isolating the microgrid from the main grid. The microgrid generation and storage assets will then supply power to the microgrid loads. When the main grid power is restored, the microgrid control will close the HV switch and the microgrid will then be connected to the main grid (grid-connected mode). The microgrid does not provide an instantaneous change over between grid to microgrid and from microgrid to grid. Approximately 5 minutes is needed to change state and during this time there is no power supply available (microgrid or main grid).

Ergon Energy Network owned HV microgrid

As discussed in Section 5.2 of this report, Ergon Energy Network are currently developing their capability to integrate grid-connected microgrids into their network. Beyond their current pilot projects, a community grid-connected microgrid is not a service currently offered by Ergon Energy Network to communities connected to the main grid.

If the entirety of Horseshoe Bay or Picnic Bay were developed into a microgrid, that would be on a much larger scale than the Mossman Gorge HV grid-connected microgrid project. Which has 40 network connections compared to 481 and 307 network connections for Horseshoe Bay and Picnic Bay respectively. The Mossman Gorge microgrid is a first for Queensland and, as discussed in section 5.2.3 of this report, Ergon Energy Network has much to work through regarding the design, operation, and maintenance of the microgrid. It is not yet a fully developed and tested solution that can be rolled out to other communities.

If Ergon Energy Network decides to extend this solution to other communities when capable of deploying grid-connected microgrids at scale (expected 2029 onwards as per Figure 17), it is not expected it will be available to all communities. Locations will be selected based on where customers experience significant reliability issues, typically this is in fringe-of-grid locations.

Third Party owned HV microgrid

A private entity can operate electricity network infrastructure in Queensland without an appropriate electricity authority (licence) if the infrastructure is to be located wholly on land they own or lease.[32]

An example of this is a large resort, where due to the geographical size and/or load requirements, the resort has a HV network connection and power is distributed across the site at HV to supply the site's loads. The resort, as a HV electrical installation owner and operator, would need to adhere to requirements[33] as set out by the:

- Electrical Safety Act 2002
- Electrical Safety Regulation 2013
- Managing electrical risks in the workplace Code of Practice 2021

To operate HV electricity network infrastructure, approval is required as part of the Electrical Safety Act 2022 and requires either a distribution authority licence or 'special approval'. Special approval provides authorisation for activities which would usually be authorised under a distribution authority. It is generally issued in situations where the authorisation of the electricity activities may not be appropriate under the authority, or where the electricity activities are incidental to the main business of the applicant.[34] For the resort example, the main business is the resort operations, rather than the distribution of electricity.

[32] Electricity licences | Business Queensland
[33] Queensland Government, Duties of high voltage electrical installation owners and operators | WorkSafe.qld.gov.au
[34] Business Queensland, Special Approval Guidance

The microgrid would operate as an embedded network. The microgrid system would be connected to the network through a parent connection point where the microgrid owner would take ownership from the DNSP (a bulk metered connection). The owner of an embedded network usually buys energy from an energy retailer through the main energy meter (the 'parent meter'), and then 'onsells' the energy to the different consumers at the site metered by sub-meters ('child meters'). The energy sold by the owner may be generated on site. Each customer can elect to purchase their electricity from a retailer of their choice or from the microgrid owner.

To become a private microgrid, all customers connected to the existing electricity network must provide written consent to becoming part of the new microgrid and abolish their existing connection agreements with Ergon Energy Network.

Under the National Energy Retail Law, any person or business who sells energy to another person for use at premises must have either a retailer authorisation or a retail exemption.[35] Most owners that sell energy in embedded networks are known as "exempt sellers" and hold a valid retail exemption from the AER.[36] The Retail Exemption Guideline[37] provides guidance on whether an exemption or authorisation is required, types of exemptions (deemed, registrable and individual), the application procedures for an exemption and conditions exemption holders must comply with.

Under the National Electricity Rules (NER), a person must not engage in the activity of owning, controlling, or operating a distribution system unless that person is registered by AEMO as a Network Service Provider (NSP) or exempted from the requirement to be registered as an NSP by the AER.[38]

Exempt networks must be operated in accordance with the conditions set out in the Network Exemption Guideline[39] which sets out who needs to register for an exemption, the type of exemption required (deemed, registrable or individual), the process for obtaining an exemption and the conditions exemption holders must comply with.

A network connection agreement with the DNSP would be required for the connected generators (solar PV, BESS, diesel generators) within the microgrid. Network limitations may govern the amount of energy that can be imported from or exported to the main grid and how that may impact the microgrid's optimal operation or redundancy level (e.g., if major failure occurs to a key microgrid component).

Horseshoe Bay or Picnic Bay could be developed into a HV grid-connected microgrid if a separate entity purchased the electrical infrastructure from Ergon Energy Network. The 11 kV network in Horseshoe Bay and Picnic Bay is located on the road reserve (TCC controlled public land). In Queensland there is a general prohibition on operation of electricity line across another person's property boundary, unless you have a special approval or are an electricity entity.[40] Given the main business of the microgrid owner could be considered the distribution of electricity, the entity is not expected to be eligible for special approval and would need to have a distribution authority. A distribution authority, issued by the Queensland Department of Energy and Climate (the Regulator),

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[35] section 88 of the National Energy Retail Lar (Queensland)
[36] Australian Energy Regulator (AER), Embedded networks customers, https://www.aer.gov.au/consumers/understanding-energy/embedded-networks-customers#what-is-an-embedded-network
[37] Australian Energy Regulator (AER), Retail Exempt Selling Guideline, Version 6, July 2022, https://www.aer.gov.au/system/files/AER%20-%20Final%20Retail%20Exempt%20Selling%20Guideline%20%28version%206%29.pdf
[38] National Electricity Rules, clause 2.5.1
[39] Australian Energy Regulator (AER), Electricity Network Service Provider – Registration Exemption Guideline, Version 6 March 2018, AER electricity NSP Registration Exemption Guideline - Version 6 - 1 March 2018.pdf
[40] Electricity Act 1994, section 227

is a licence that authorises a distribution entity to supply electricity using a supply network within its distribution area.[41]

Although the microgrid will contain generation assets, a generation authority is not required to operate a generating plant with a capacity of 30 MW or less as deemed special approval applies[42].

If a separate entity, who would essentially need to be a DNSP, were to consider purchasing the network assets to develop Horseshoe Bay or Picnic Bay into a HV grid-connected microgrid, it would be a complex undertaking. Key considerations include the following:

- Permission from Ergon Energy Network. It is unclear whether Ergon Energy Network would permit the sale of their HV network, or what sell price they would ask.
- Ownership of all electrical infrastructure within the microgrid. The separate entity would need to own all infrastructure within the microgrid (including public lighting) and be responsible for its operation and maintenance.
- Network connection agreements with Ergon Energy Network for the microgrid connected load and generators (solar PV, BESS, diesel generators). Network limitations may govern the amount of energy that can be imported from or exported to the main grid and how that may impact the microgrid's optimal operation or redundancy level (e.g., if major failure occurs to a key microgrid component).
- DNSP obligations. Fulfil requirements of a DNSP for owning and operating a HV electrical network as per relevant rules and regulations:
    - The Electricity Act
    - The Electricity Regulation
    - The Electrical Safety Act
    - The Electrical Safety Regulation
    - The National Electricity Law
    - The National Electricity Rules
- HV Safety Management Plan. Queensland Electrical Safety legislation requires Persons conducting a business or undertaking with HV assets to have a site specific safety management plan. In addition, Ergon Network major connections also require HV safety management plan. Details of the HV safety plan inclusions are listed below in Appendix A Section 20.1.
    - While HV is a specialist asset class, there are competent service providers that can perform a range of contracted services from asset management, day to day operation, scheduled maintenance, and non-scheduled break fix activities. The private microgrid owner could discharge their safety obligations and reduce their risk by engaging a competent service provide to perform the management, operation, and maintenance of the community HV assets.
- HV grid-connected microgrid solution development. Similar to what Ergon Energy Network are in the process of developing, the third party would need to develop how the microgrid solution can be implemented while maintaining DNSP obligations of distributing power in a safe, reliable and affordable manner to the residents and businesses within the microgrid. The microgrid would require a sophisticated control system to operate effectively. This is

[41] Electricity Act 1994, section 37, 38
[42] Electricity licences | Business Queensland

achievable but adds significant cost and implementation time to the project design, installation, test, and commissioning.

- Retail services. Under the National Electricity Rules, a DNSP must comply with AER Electricity Distribution Ring-fencing Guideline. [43] The guideline states that a DNSP can provide distribution and transmission services but must not provide 'other services' unless in accordance with a waiver that is subject to AER approval.[44] Retail services are considered 'other services'. Without a ring-fencing waiver, this prevents a DNSP holding an electricity retailer authorisation or exemption, however an affiliate entity of the DNSP could. This means the microgrid would not be able to operate as a typical embedded network and would need another entity to provide retail services.
- Battery ownership regulation. Depending on how a centralised BESS within the microgrid is operated, it could be considered 'other services' a ring-fencing waiver from the AER may be required. For example, if part of the BESS is leased to a third party for participation in the wholesale electricity market it would not be strictly a 'network asset', and this would require a waiver.

The key barrier for a third party owned HV microgrid for Horseshoe Bay or Picnic Bay is the requirement for a distribution authority. This would mean the third party would need to have an existing distribution authority or obtain one, which would be a significant effort.[45] MICDA is not looking to own HV assets, nor have they investigated a separate entity interested in owning HV assets (e.g., a community energy entity).

If a HV grid-connected microgrid is the vision for Horseshoe Bay or Picnic Bay, an Ergon Energy Network owned microgrid is expected to be simpler, given they are the existing DNSP and are developing their microgrid capability. For Ergon Energy Network to support this concept as a future solution for a Magnetic Island village in 2029 onwards, there needs to be a clear network reliability issue that needs to be addressed as a priority above other locations.

[43] National Electricity Rules, Clause 6.17.2
[44] Australian Energy Regulator (AER), Ring-fencing Guideline Electricity Distribution, Version 4, Clause 3.1, Ring-fencing guideline (electricity distribution) version 4_0.pdf
[45] For information on the process to obtain a distribution authority, see Queensland Government Distribution Authority Guidance

6.2.3 Concept #3 – Low Voltage Microgrid

An LV grid-connected microgrid is shown in Figure 20 below.

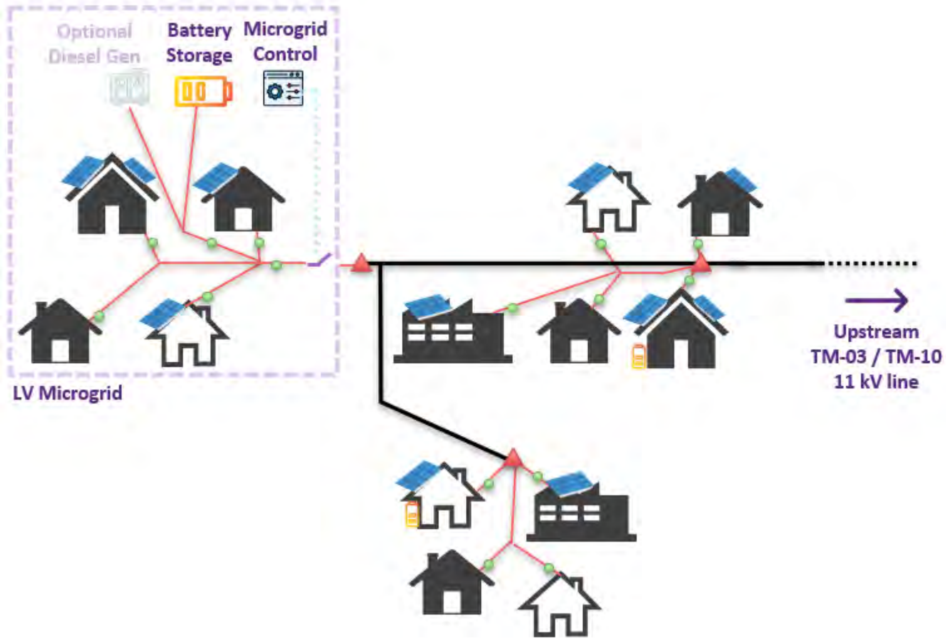


Figure 20 - Low voltage grid-connected microgrid

The LV microgrid would consist of multiple adjacent loads that are located on a single or separate parcel(s) of land, energised at the standard LV supply voltage (230 V single phase / 400 V three phase). It is preferable that the loads be within approximately 100-200 metre range as longer LV cables can lead to significant voltage drop and increases cost to comply with Australian Standards. For this reason, the size and impact of an LV microgrid is limited compared to a HV microgrid.

During normal operation the microgrid will operate connected to the main grid (grid-connected mode), then during extended planned and unplanned network outages, the microgrid will disconnect (island) from the grid (e.g., after a severe weather event). Even if appropriately sized, there is a risk that the BESS could run out of charge before solar PV is available to recharge the BESS or before the grid supply returns to supply the loads. The microgrid could be solar and BESS or also include diesel generation as a backup option if required.

A key advantage of an LV grid-connected microgrid compared to a larger HV grid-connected microgrid is the expected increased reliability. If the intention is for the microgrid to provide power during a grid outage post severe weather event such as a cyclone, the likelihood that the cyclone caused grid faults (e.g., fallen power pole or tree branch on overhead power lines) is greater for a larger microgrid due to the greater number of overhead network assets. An LV grid-connected microgrid could potentially avoid this issue.

An example of an LV microgrid is an emergency community hub where the intention would be to provide backup power for critical sites that would benefit the community post severe weather event such as community hubs, medical sites, fuel stations or supermarkets.

Third Party owned LV microgrid

Similar considerations apply for a third party owned LV microgrid as they do for a third party owned HV microgrid, including:

- Embedded network operation

- Customer permission to become child connection points within the LV microgrid embedded network
- NSP registration/network exemption and retailer authorisation/exemption
- Network connection agreement with Ergon Energy Network for solar & BESS

A third party owned LV microgrid does not have the same barriers as a private HV microgrid regarding ownership and operation of HV assets; an LV microgrid is an option that is available now without the need for special approval or a distribution authority.

Additional complexities arise when the separate loads are not located on the same parcel of land, but multiple parcels of land. In Queensland there is a general prohibition under the Electricity Act 1994 on operation of electricity line across another person's property boundary unless you have a special approval or have a distribution authority, other than under a regulation.[46] The operation of clause 24(1) of the Electricity Regulation 2006 allows a person to install and operate a low voltage electric line beyond a person's property where it has the consent of the supplier (network service provider) and each affected owner/occupier or lessee.

The LV microgrid embedded network owner would be required to consult with, and obtain written consent from, the following entities:

- Ergon Energy Network as the DNSP
- Townsville City Council as the local government
- Residents and businesses who may have an interest in the proposed location of the electric line as affected owners/occupiers or lessees

The consulted entities may impose requirements or conditions using the requirements of clause 24(3) of the Electricity Regulation.

If affected entities are properly engaged, the installation complies with the wiring rules and the electric line is installed and operated in a manner that does not pose a fire or electric shock risk, then no authority or special approval is required to install or operate the electric line.[47] However, under the NER, anyone that engages in an electricity distribution activity must either be registered with the AEMO as a DNSP or gain an exemption from the AER to do so.[48]

DNSP owned LV microgrid

A DNSP owned LV microgrid simplifies things, as the LV microgrid would be considered part of the distribution network rather than an embedded network. Ergon Energy Network are developing their LV grid-connected microgrid capability with the Jumbun pilot project. It is understood that the customers that will be supplied by the Jumbun LV microgrid, will not experience any change to their metering or retailer arrangements.

As is the same with the DNSP owned HV microgrid concept discussed above, Ergon Energy Network are currently developing their capability to integrate LV grid-connected microgrids into their network. Beyond the Jumbun pilot project, a community LV grid-connected microgrid is not a service currently offered by Ergon Energy Network to communities connected to the main grid. If offered in the future, it is not expected to be available to all communities.

[46] section 227 of the Electricity Act,1994
[47] section 24(7) of the Electricity Regulation, 2006
[48] Australian Energy Regulator (AER), Who needs to register for a network exemption?, https://www.aer.gov.au/industry/networks/exemptions

Emergency Community Hub

Being located off the North Queensland Coast, within Wind Region C (Cyclonic), Magnetic Island is particularly susceptible to tropical cyclones. An emergency community hub, supplied by an LV microgrid, could be established within Magnetic Island to provide a facility that will have power during a main grid power outage. The facility could be used to power portable devices (e.g., phones, tablets), access services/resources and engage with other community members.

A suitable location for an emergency community hub is difficult to identify since essential services are scattered across the island. It was suggested that the hub might be suitable in Nelly Bay; the largest village on the island where a lot of key community services are based. However, Nelly Bay's critical sites such as the medical centre, ambulance/fire station, supermarkets and fuel stations are not located on adjacent sites but are several hundred metres or more apart and hence does not provide the ability to operate as an LV microgrid.

Horseshoe Bay Park LV Microgrid Example

Horseshoe Park was suggested as a potential site for an LV microgrid that could be used as an emergency community hub.

The existing loads (separate network connections) at Horseshoe Bay Park are relatively small and include the following:

- Skate park and picnic pavilion
- Community centre building
- The Rural Fire Brigade
- Telstra cell tower

If the site were to be developed into a microgrid, the Telstra cell tower may be too far away to be connected via an LV cable run. Given the technical characteristics are unknown, it will be excluded from this example. An LV microgrid concept for Horseshoe Bay Park is shown in Figure 21 below.

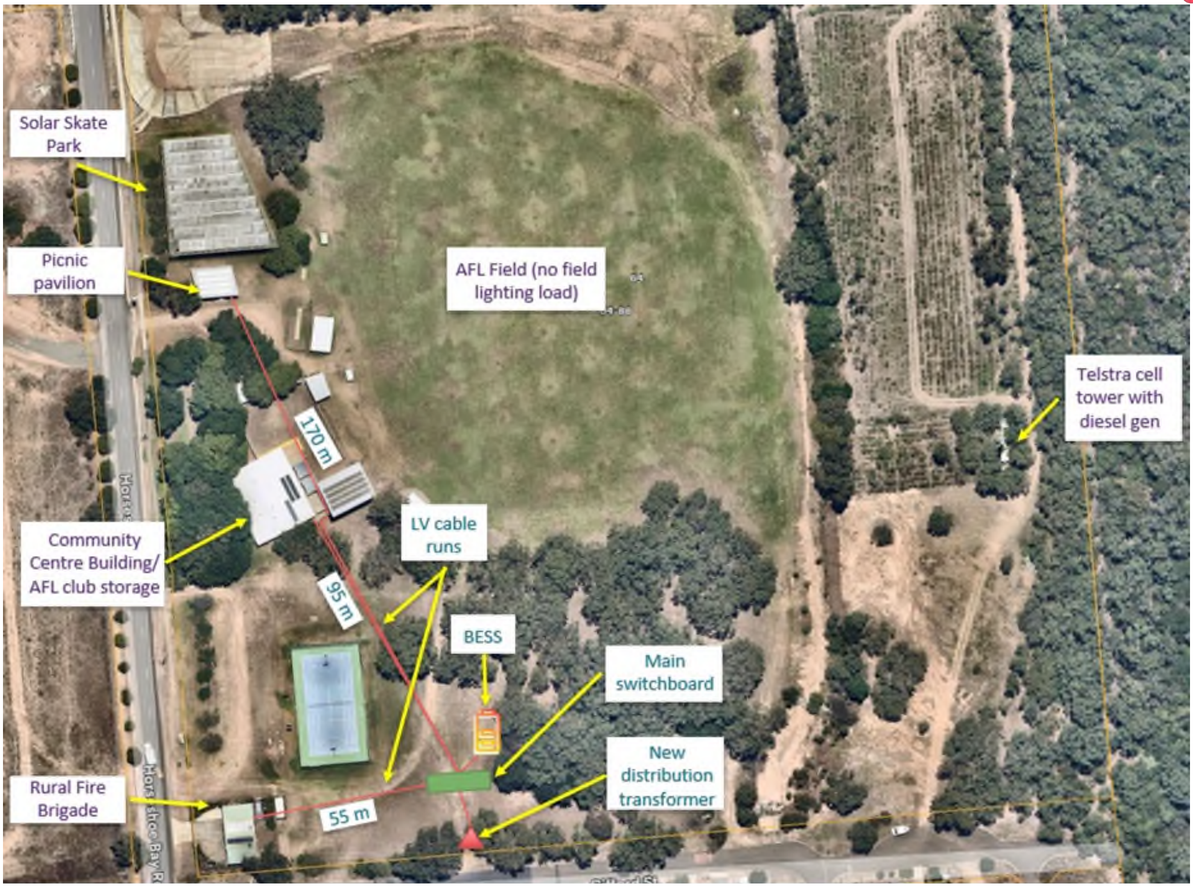


Figure 21 – Horseshoe Bay Park loads and LV microgrid example

For simplicity of this example, the following assumptions are made:

- The BESS is oversized so that the entire site's energy requirements can be supplied by the solar PV.
- The site is connected to the grid so the BESS can be used for front of meter market participation and excess solar PV can still be exported and used locally on the island.
- The site remains on Ergon Retail Tariff 20.

The maximum potential annual electricity bill savings for Horseshoe Bay Park based on the existing load and tariffs is approximately $5,153 ($1,334 from fixed costs and $3,819 from energy costs). Excluding the capital cost of a BESS, the augmentation works on site required to electrically combine the three separate loads is expected to be more than $300,000.

The addition of a BESS would not provide significant annual energy bill savings. The BESS could be charged "for free" from existing solar, however there is limited load that could be powered from the BESS. The BESS could also be used for front of the meter (FTM) market participation for additional revenue. FTM market participation could be FCAS, or FCAS and wholesale energy. For FTM market participation, there is additional upfront and ongoing costs to participate.

For a more detailed version of this example, see Appendix B Section 21.1 Horseshoe Bay Park LV Microgrid Example.

Potential BTM Value for Sites with Large Loads

A BESS can provide significant behind the meter cost savings with tariffs that have time of use (ToU) components or demand charge components, particularly with large business tariffs. For comparison, a small business demand tariff has a demand charge of approx. $6-12/kW, where a large business demand tariff has a charge of approx. $30/kW. With a substantial load, there is more potential for a battery to reduce demand charges.

Without substantial site loads, the more economical option for backup power would be a temporary diesel generator rather than a BESS. The largest loads within Horseshoe Bay and Picnic Bay are the sewage and water treatment plants owned by Townsville Water. Townsville City Council (TCC) requested that these sites not be considered as part of this study to locate a solar PV and/or BESS solution that would directly supply their site loads. TCC are already considering these sites for solar and BESS as part of an existing sustainability program.

Residential Street LV Microgrid Example

Existing embedded networks that supply residential customers are typically located on a single parcel of land or multiple adjacent parcels of land owned by a single entity. Common examples include:

- Lifestyle resorts
- Retirement villages
- Apartment complexes
- Caravan and long stay parks

A Horseshoe Bay residential street LV microgrid scenario differs from these typical examples. The key differences are the Horseshoe Bay option would be, spread across multiple parcels of land that are owned by various entities and electrical cables would traverse public land. As noted above, this adds considerable complexity to the potential development of a third party owned LV microgrid.

Figure 22 illustrates a conceptual LV microgrid for a residential street adjacent to Horseshoe Bay Park. This example is centred around distribution transformer TVS3729, located on Gifford Street, currently supplying 19 customers via an underground LV distribution network. In this scenario, the LV terminals of the 315 kVA transformer serve as the network connection point for the microgrid/embedded network.

The red lines in Figure 22 show the approximate reach of the LV network (approximately 250 meters), while the numbered residential sites are estimated to be supplied by TVS3729[49].

[49] As estimated based on information from Ergon Energy Look Up and Live map https://byda.maps.arcgis.com/apps/webappviewer/index.html?id=8a8f088ca9774464884d6711b347fff8 and Network Load Capacity Map https://www.energex.com.au/about-us/company-reports,-plans-and-charters/network-load-capacity-map

Figure 22- Example Horseshoe Bay residential Street LV microgrid concept

The reasons TVS3729 was selected for this example include the following:

- Largest capacity (315 kVA) in Horseshoe Bay and Picnic Bay enabling:
    - greater number of connections to residential customers
    - a larger total solar PV and BESS capacity without upgrading the transformer
- Supplying multiple residential sites. Six of the seven 315 kVA distribution transformers in Horseshoe Bay supply residential areas, supplying between 19 and 40 properties
- Proximity to land that may be suitable for the installation of a centralised/neighbourhood BESS (Horseshoe Bay Park or vacant blocks on land within street)

Additional solar PV and battery storage can be installed within the LV microgrid, this would include a centralised BESS capable of supplying backup power during islanded operation (main grid outage). It should be noted that when the microgrid is connected to the main grid, the combined solar PV and BESS inverter capacity must not exceed 120% the distribution transformer capacity[50]. Currently there is 55 kW of inverter capacity installed, leaving 323 kW available of the 378 kW capacity. As noted above, any further solar PV or BESS installation would require a connection application to Ergon Energy Network.

The existing LV network supplied by TVS3729 is underground, as shown in Figure 23 (pink dotted line representing LV underground line). For a third party to own or operate an LV microgrid supplying the same residential sites, they would need to:

- Purchase the LV distribution assets from Ergon Energy Network, or
- Construct a new LV network, which would duplicate existing infrastructure.

[50] Ergon Energy Network STNW3511 Dynamic Standard for Low Voltage Embedded Generation Connections Version 3 Table 11

However, it is unclear whether Ergon Energy Network would permit the sale or duplication of their LV network, or what sell price they would ask.

It is also unclear if Townsville City Council, as the local government, would permit private LV infrastructure to operate across public land, especially considering existing underground services (wastewater [red], water [blue], stormwater [purple]), shown in Figure 24. Even constructing an overhead LV network in close proximity might interfere with access to these essential services.

Figure 23 – Ergon Energy Network TVS3729 LV distribution network

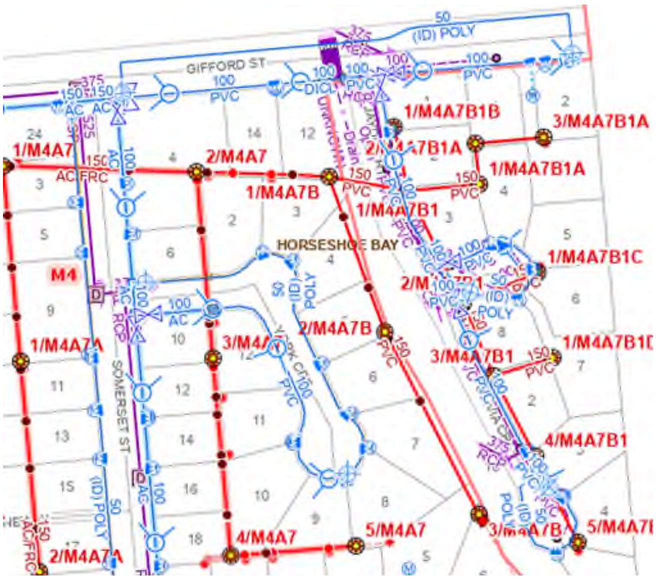


Figure 24 – Underground services adjacent to TVS3729 LV distribution network

As Ergon Energy Network currently do, the LV microgrid owner/operator would be responsible for operating and maintaining the electrical infrastructure. The objective for the operator would be to provide residents with a safe, reliable, and affordable power supply.

Based on 2025-26 rates, Ergon Energy Retail Tariff 11 includes a usage charge of 30c/kWh and fixed charge of $1.54/day ($562/year ex GST). These charges cover services from the TNSP, DNSP, environmental, metering, AEMO and retail services. For more information on these individual components, see Appendix B, Section 21.3. Specifically, the DNSP services include:

- 24/7 electricity supply (with occasional planned and unplanned outages)
- Eligibility for solar feed-in tariff
- Timely fault response and reactive maintenance
- Preventative maintenance
- 24h call centre to provide customer service

As noted above, the microgrid owner/operator must have a retailer authorisation or a retail exemption in order to sell energy to residents. Whether with a retailer authorisation or a retail exemption, the LV microgrid embedded network owner/operator would need to follow certain rules that protect the residents' rights as consumers. These consumer protections include[51]:

- Flexible payment options if residents are experiencing financial difficulty
- Clear and set time frames for receiving and paying bills
- Complaints handling arrangements

[51] Australian Energy Regulator, Embedded networks customers, Embedded networks customers | Australian Energy Regulator (AER)

- Energy charges that are no higher than the standing offer prices that a local area retailer can charge contracted consumers
- Clear and reasonable disconnection procedures.

The total annual energy bill costs of all 19 residents is approximately $29,366[52]. It has been estimated that residents without solar pay approximatley $2,485 each and residents with solar pay approximately $1,210 each.

If all 19 residential customers were consolidated under a single connection with the installation battery storage and additional solar PV, the following impacts are expected:

- Embedded network parent connection customer category
  - The LV microgrid's annual grid consumption is estimated to be less than 100 MWh, classifying it as a small connection[53].
  - Although all 19 customers are residential, the embedded network owner/operator would be classified as a business. As a result, small business tariffs are expected to apply. For this example, small business Tariff 22E has been assumed.
- Choice of electricity retailer
  - Ergon Energy Retail is likely to be the only available retailer.
  - As discussed in Section 3.2, it is difficult for unsubsidised retailers to compete with Ergon Energy Retail for residential and small business customers due to the low volume of energy consumption.
- Loss of solar feed-in tariff eligibility with Ergon Retail
  - Potential that feed-in tariff income would be forfeited as the total solar PV inverter capacity for the single consolidated connection would exceed 30 kW.[54]
  - The embedded network operator may choose to (not mandatory) match the feed-in tariff to prevent residents from losing this income, or alternatively, compensate through cheaper tariff rates.
- Fixed electricity bill cost savings
  - Potential fixed charge savings of up to $10,059/year.[55]
  - However, if the site had a larger number of residents, with insufficient solar PV and battery storage causing annual grid consumption to exceed 100 MWh, a large customer tariff would apply.
  - On an Ergon Retail large business tariff, this could increase the fixed charge from $586/year to $18,985/year[56].
- Total electricity bill cost savings at parent connection
  - The maximum potential electricity bill savings are equal to the sum of the existing individual electricity bills ($ 29,366/year) minus the new consolidated fixed charge ($586/year).
  - Savings will be impacted by how much BESS capacity is reserved for unplanned grid outages, which reduces the ability to increase solar self-consumption and reduce grid energy usage.

[52] Based on estimated residential load consumption profile with and without solar on Ergon Retail Tariff 11. See Appendix B Section 21.2 for more detail.
[53] Ergon Energy Network Tariff Guide 2025-26, Table 2 Standard Asset Customer Small, Ergon Energy Network Tariff Guide 2025-26
[54] Queensland Government, Solar feed-in tariff for regional Queensland, https://www.qld.gov.au/housing/buying-owning-home/energy-water-home/solar/feed-in-tariffs/feed-in-tariff-regional-queensland
[55] Ergon Retail small business tariff with lowest fixed charge, Tariff 24C fixed charge of 160.673 c/day as per 25/26 rates = $586/yr excl. GST
[56] Ergon Retail large business tariff with lowest fixed charge, Tariff 50B fixed charge of 5201.456 c/day as per 2025/26 rates = $18,985/yr excl. GST

- The total cost savings at the connection point, may not be passed in full to residents. Considerations include how resident load and solar is priced and what the embedded network operator fees and margins are. The energy rates given to residents need to be the same or lower than Ergon Retail's residential tariffs.

- Additional FTM revenue
    - Additional revenue may be possible through BESS participation in FCAS and wholesale energy markets.
    - However, this could conflict with the need to reserve BESS capacity for unplanned outages and tariff savings.
    - There may also be limited interest from retailers or aggregators due to the small BESS capacity and constraint of the distribution transformer size. Until such time as a ubiquitous customer energy resource market is in place.

For this example, it is assumed that the microgrid includes an additional 80 kWp solar PV and a 110 kVA/225 kWh BESS. The expected outcomes include:

- Capability to meet the worst case maximum demand of the 19 customers.[57]
- 24 hours of backup supply, depending on the BESS's state of charge at the time of a grid outage.[58]
- A renewable energy fraction of 93% for the microgrid.[59]

High level estimates of revenue and cost of the LV residential street microgrid example are shown in Table 10 below. For comparison, a behind the meter option is also included, where the 19 residents are not consolidated into an embedded network and each resident has:

- a 10 kWh BESS
- either a new 6.5 kWp solar PV system (customers with no existing solar PV) or an additional 2 kWp of solar PV (customers with existing solar PV).

[57] Based on conventional housing development assumption, After Diversity Maximum Demand (ADMD) = 5 kVA per lot
[58] Based on using 90% of 225 kWh BESS capacity with assumed residential load profile with average load between 4pm and 8am of 15.76 kW, then reduced by 33% for more conservative use during outage. This equates to 19 hours backup supply from BESS only, however, the solar PV can then recharge the BESS during daytime hours.
[59] As modelled using assumed residential load profile with 80kWp solar PV and 110kVA/225kWh BESS on various electricity tariffs.

Table 10 - High level revenue and cost of LV residential street microgrid vs. behind the meter solar PV and BESS

LV Residential Street Microgrid – 80 kWp solar PV + 225 kWh battery storage ≈ 93% REF	
Costs	
Upfront	
• Supply and install BESS, **$360k** • Supply and install solar PV, **$50k** • Supply and install new parent connection switchboard, **$70k** • Supply and install new parent connection metering, **$15k** • Purchase of existing Ergon Network LV network 500m = **$400k**[60] • Embedded network metering, **$20k** • Fees associated with management, negotiations, legal and finance, **$100k**	**TOTAL: ≈ $1.015 million**
Ongoing	
• Microgrid operation and maintenance • Microgrid 24 hour call centre • Embedded network metering • Retail energy billing	**TOTAL: ≈ $50-100k+ /yr**[61]
Revenue	
• Potential annual electricity bill savings at parent connection, **$ 32,004 /yr**[62] • LGCs, **$ 1,500 in Yr 1**[63] • Additional FTM Revenue, **$ 5,000 /yr**[64]	**TOTAL: ≈ $38,504 /yr**
Behind the Meter Solar PV & BESS[65] - 61 kWp solar PV + 190 kWh battery storage ≈ 80% REF	
Capital	
Upfront	

• Solar PV and BESS
  ◦ Customers with solar **$6,926 x 14 customers**
  ◦ Customers without solar **$ 9,123 x 5 customers**
	TOTAL: ≈ $ 143k

Ongoing	
• Solar PV and BESS maintenance ◦ Estimated as 1% capital cost	**TOTAL: ≈ $ 1,430 /yr**
Revenue	

• Annual Electricity Bill Savings
  ◦ Customers with solar, **$909 x 14 customers**
  ◦ Customers without solar, **$ 2,164 x 5 customers**
	TOTAL: $ 23,546 /yr

Based on the estimated values in Table 10, the costs associated with constructing, operating and maintaining a third party owned LV microgrid for a residential street would not be recovered with an annual saving/revenue of $38k.

[60] High level estimate and not verified with Ergon Energy Network.
[61] High level estimate
[62] Based on estimated load profile and Ergon Retail Tariff 22E, a ToU energy small business tariff.
[63] Based on 82 MWh generation from 50kWp of solar PV in 2027. Assumed existing 70 kWp solar PV DC capacity with known 55 kVA inverter a.c. capacity, with an additional 80 kWp solar PV d.c. capacity = 150 kWp. Assumed LGCs for capacity above 100 kWp only. This will decrease in subsequent years.
[64] Estimated figure for BESS to be part of a VPP.
[65] Revenue and costs are based on Behind the Meter analysis in Section 18 for 6.5 kWp solar PV and 10 kWh BESS for each customer.

In contrast, a behind the meter option offers significantly lower capital and operational costs with the added benefits of retaining the Ergon Energy Retail feed-in tarif, increased individual electricity bill savings, and back up power with individual household control extending BESS backup duration.

For a more detailed version of this example, see Appendix B Section 21.2 Residential Street LV Microgrid Example.

6.2.4 Concept #4 - Centralised Solar PV and/or BESS

A centralised solar PV and/or BESS solution would increase Magnetic Island's renewable energy fraction with increased solar PV generation and the ability to store excess renewable energy to supply the load during the afternoon/evening period of higher demand.

A centralised BESS, which can also be referred to as a 'neighbourhood BESS' or 'community BESS', will not provide direct savings on the retail electricity bills of residents and businesses (unless a special retail offer/arrangement is available). In theory reducing peak demand by discharging the BESS at relevant times, has potential to favourably impact electricity system pricing, through deferring costly network upgrades and reducing wholesale energy prices.

Depending on the operating model, a centralised BESS has the potential to earn front of meter revenue with market participation which could benefit residents and businesses (e.g., fund community grants).

Incorporating both solar PV and BESS in a centralised solution would have a greater impact on increasing the island's renewable energy fraction. Co-locating solar PV and BESS has its advantages but depending on size could also have its challenges with regards to network connection, retail arrangement options, and land tenure for ground-mounted solar.

A centralised solar PV and/or BESS solution would require a new network connection, and depending on the desired connection capacity, is expected to involve costly network augmentation to enable the new connection.

DNSP owned BESS

As discussed in 5.2.4, Ergon Energy Network are continuing to roll out HV connected and LV connected BESS as part of their Local Network Battery Plan. At this stage, Magnetic Island has not been selected for the installation of an Ergon Energy Network owned BESS. The BESS locations are chosen based on the following criteria:

- Maximise the benefits of the batteries
- Within a community designated by funding framework
- On road reserve, council owned freehold land or Ergon Energy Network owned land
- Minimal community impact
- Considering other electrical assets/network benefit
- Flood free zone
- Clear land area available (e.g., 5m x 5m for ground mount LV connected BESS)
- Vehicle access

With the recent feeder capacity upgrades for both TM-10 and TM-03 completed end February 2025, there is no network capacity issue to be resolved. Given Magnetic Island does have a high penetration of solar PV, Ergon Energy Network may select it for the installation of a BESS in future.

Centralised or BESS vs. HV Grid-Connected Microgrid

A centralised BESS, although not a microgrid, would have very similar components. The key components of a centralised BESS solution and for a community HV grid-connected microgrid solution are highlighted side by side in Figure 25 below.

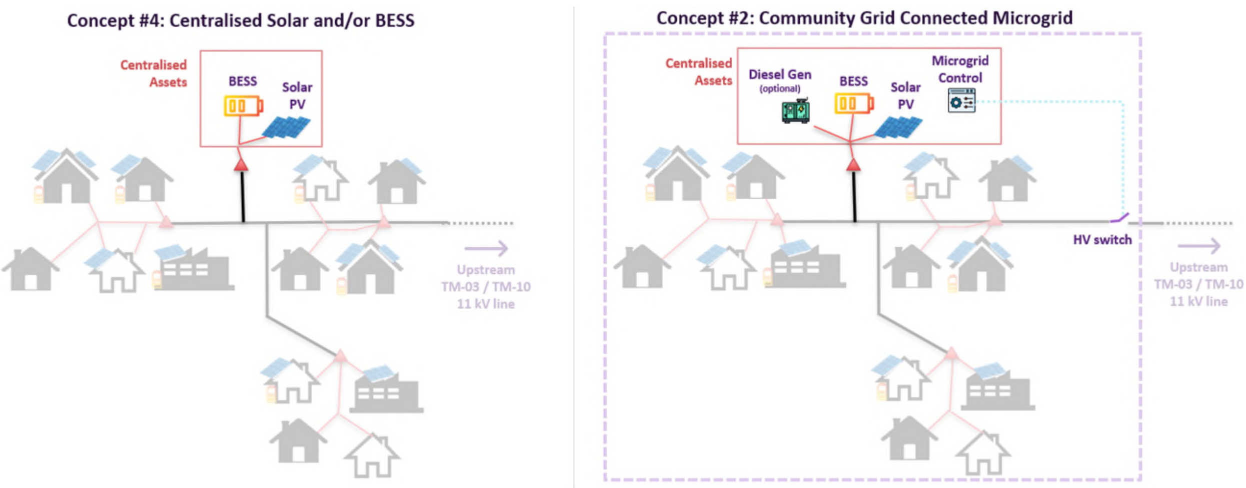


Figure 25 - Key solution components for a centralised solar PV and BESS solution and HV grid-connected microgrid solution

The key similarities between a centralised BESS and include:

- A large BESS

  The microgrid BESS would need to be sized to cover the expected maximum demand in island mode. A centralised BESS would not have this same requirement, however the larger the BESS, the more impact on renewable fraction and potential market revenues.

- New large network connection

  The largest existing distribution transformers within Horseshoe Bay and Picnic Bay are 315 kVA. If the capacity of a centralised BESS is greater than this, a new and larger network connection would be required.

- Operation when grid-connected

  The solar PV and/or BESS centralised assets for both concepts would essentially operate in the same manner. The microgrid would be expected to operate in island mode for a very small percentage of time.

The key differences between the concepts include:

- Integration with Ergon Energy Network

  Ergon Energy Network are developing this microgrid solution. The requirements for communication, control, protection as well as the operating procedures etc for this integration are important components to be developed to ensure this type of solution would operate safely, reliably, and efficiently.

- The ability to provide backup power to HV network

  Not all commercial and grid scale BESS can provide backup power. For a centralised BESS to be capable of providing backup power, additional equipment would be required for functionality, performance, and protection (e.g. earthing transformer).

- Optional backup diesel generator

  Not an essential component for microgrid.

If a HV grid-connected microgrid is the vision for Horseshoe Bay or Picnic Bay, a centralised solar PV and BESS solution (or BESS only solution) would be a step in that direction. When a HV grid-connected microgrid becomes an actionable solution in the future, the centralised BESS could be upgraded to be capable of providing backup power and the microgrid control integrated with Ergon Energy Network (HV switch and systems required for communication and control). The centralised solution could be designed to be “microgrid upgrade ready” where consideration is given for the desired future microgrid state in relation to BESS sizing, main switchboard sizing, network connection capacity, BESS equipment island mode capability, additional physical space for additional equipment expected etc.

6.2.5 Concept #5 - Behind the Meter Solar PV/BESS

Although not a microgrid, more solar PV and/or BESS installed by residents and businesses behind the meter will contribute to MICDA’s objectives with the following benefits:

- Increased renewable fraction for site and consequently Magnetic Island as a whole.
- Provide backup power during grid outages to individual sites with the use of a BESS; a relatively simple function for single phase connections (typically residential).
- Provide direct savings on electricity bill to individual sites. The installation of battery storage that will help reduce demand on the network during peak periods will contribute to putting downward pressure on electricity bills for all.
- Further benefit if the participation in a Virtual Power Plant (VPP) with the BESS is an option available.

A key advantage of a distributed, behind the meter option in comparison to Concept #1 - #4, is the avoidance of costly network augmentation to connect large solar PV/BESS assets to the Horseshoe Bay or Picnic Bay network, either for the new network connection or the upgrade of an existing connection.

Behind the meter solar PV and/BESS may not be an option for all residents and businesses due to the capital costs involved or they are locked out of installing (e.g., renting, or unsuitable roof area). Without co-locating solar PV and BESS, the benefit of BESS only can be limited, particularly for customers on a flat energy rate tariff (e.g., Ergon Retail Tariff 11 for residential or 20 for small business) where the main purpose of the BESS would be enhanced solar PV self-consumption.

BESS with backup power capability, is a technical option currently available to a lot of residential, small business and large business customers. MICDA, through their TRM working group, works with residents and business owners to educate and assist them in purchasing solar and/or BESS systems.

Behind the meter solutions could be orchestrated together, such as by means of a VPP. A VPP would aggregate numerous distributed BESS and operate them as if a single centralised BESS. An electricity retailer could then use the VPP to participate in the wholesale electricity market or FCAS market for additional revenue, the benefit of which could then be shared with residents and business owners.

VPP offerings available to residential and small business customers in Regional Queensland are very limited. Ergon Energy Retail, the electricity retailer for most of Magnetic Island, is under Queensland legislation, a regulated retailer and not a competitive retailer. Given this, they are not in a position to offer VPP products that competitive retailers can choose to provide.[66]

[66] Ergon Energy Retail, https://www.ergon.com.au/retail/help-and-support/faqs/faqs/tariffs-And-prices/special-deals-faq

Residents and Small Business

As discussed in Section 3.2, it is difficult for unsubsidised retailers to compete with Ergon Energy Retail for residential and small business customers due to the low volume of energy they consume. It is uneconomical for them to offer their services to small customers in regional Queensland, as their cost per customer is significantly higher compared to South East Queensland. As a result, competition for small customers in regional Queensland is limited.

There are a number of VPP offers available to Queenslanders through electricity retailers such as Origin, AGL, Diamond Energy and Energy Locals. Given it is generally a requirement to be a customer of the VPP provider electricity retailer, these offers are not typically available in regional Queensland.

Horan & Bird have recently advertised an offer for customers to join their 'Virtual Power Plant for North Queensland'.[67] Their main offer is a solar PV and battery system installed (with $0 capital from customer) with a solar Power Purchase Agreement (PPA) where there is the option available for VPP participation. This appears to be an actionable solution for Magnetic Island residents and business owners that can be implemented in the near future.

A new federal government discount is available through the Cheaper Home Batteries program. Households, businesses, and community organisations can access a discount available from 1 July 2025 until 2030 for small-scale battery systems (5 kWh to 100 kWh).[68]. This will reduce the cost of eligible battery systems for a capital purchase option and is also expected to reduce costs for a PPA option. The Cheaper Home Batteries program is discussed further in section 10.1.4 Government Incentives.

Large Business

Unlike for residential or small business customers, electricity retailers can see economic value offering services to large business customers in Regional Queensland, particularly if they have a portfolio of large sites.

For this reason, large business customers are more appealing to electricity retailers for BESS market participation opportunities. Large business customers are defined as consuming 100 MWh or greater each year. Typically, they have larger network connections that could enable a BESS of a larger size to be connected.

As discussed above in Section 6.2.3 for the LV microgrid behind the meter component, the largest loads within Horseshoe Bay and Picnic Bay that would significantly benefit from BTM solar PV and BESS are the sewage and water treatment plants. No BTM solution from this study will be considered for these sites as they are part of an existing sustainability program.

No other large business sites within Horseshoe Bay and Picnic Bay were identified for site specific BTM solution analysis as part of this study.

[67] Horan & Bird, https://horanandbirdsolar.com.au/virtual-power-plant/
[68] Australian Government, Department of Climate Change, Energy, the Environment and Water, Cheaper Home Batteries Program - DCCEEW

6.3. Preferred Option

6.3.1 Option Assessment Summary

Table 11 - Microgrid and non-microgrid option assessment summary

Concept	Summary	Opportunities	Barriers	Outcome
Microgrid Concepts				

#1 High Voltage Community Stand-Alone Microgrid	• Microgrid: village wide
	• No connection to main grid
	• High voltage (HV) assets
		• Increase renewable fraction
		• Potentially increase reliability for village
			• Ergon Energy Network are not looking to provide this as a solution for existing grid-connected customers
			• Oversizing of generation and storage assets for redundancy since no main grid
			• New large BESS network connection cost and time
			• Land requirements for large ground mount solar PV. Land tenure may be difficult.
			• No opportunity for market participation to earn additional revenue
			<u>Third party ownership:</u>
			• DNSP regulation
			    o QLD Electricity Licence (distribution authority)
			    o AEMO registration
			• Ergon Energy Network permission to sell HV network
			• Ownership and operation of high voltage (HV) assets on public land
			• Separate entity required with electricity retailer authorisation/exemption
				• Not preferred compared to Concept #2
				• Not an actionable solution now

Concept	Summary	Opportunities	Barriers	Outcome
#2 High Voltage Community Grid-Connected Microgrid	• Microgrid: village wide • Connection to main grid • High voltage (HV) assets	• Increase renewable fraction • Potentially increase reliability for village • Potential to earn revenue from market participation with BESS	• Ergon Energy Network are currently developing a HV grid-connected microgrid solution and if able to roll out at scale in the future, communities in fringe-of-grid areas with poor reliability will be prioritised • New large BESS network connection cost and time • New microgrid network connection point and control software (not an existing solution) • Land requirements for large ground mount solar PV. Land tenure may be difficult Third party ownership: • DNSP regulation: o QLD Electricity Licence (distribution authority) o AEMO registration • Ergon Energy Network permission to sell HV network • Ownership and operation of high voltage (HV) assets on public land • Separate entity required with electricity retailer authorisation/exemption or AER ring-fencing waiver	• Not an actionable solution now but expected to be in the future

Concept	Summary	Opportunities	Barriers	Outcome
#3 Low Voltage Microgrid	• Microgrid: Several adjacent sites (preferably within 100-200 metres) • Connection to main grid • Low voltage (LV) assets	• Increase renewable fraction for village • Increase reliability for microgrid • Better expected reliability with a smaller microgrid with underground assets than a HV microgrid with large amount of overhead assets • Provide a community resilience hub during widespread extended outages • Potentially provide direct electricity bill savings for customers within microgrid • Potential to earn revenue from market participation with BESS	• Limited impact to community reliability with only a small number of adjacent loads as part of the microgrid • Ergon Energy Network permission to sell HV network (if applicable). • Electricity retailer authorisation or exemption • Network Service Provider authority or network exemption • Embedded network management • New network connection cost and time • Low voltage electrical construction (to connect multiple sites and BESS) cost	• An actionable solution now • No adjacent large or critical loads identified as ideal for LV microgrid in Horseshoe Bay or Picnic Bay • Could be a step towards MICDA's microgrid vision (if BESS/network connection sized large enough)
Non-microgrid Concepts				
#4 Single Site Centralised BESS	• No microgrid capability • Grid-connected, front of the meter (FTM) only • Low voltage (LV) assets, one site	• Increase renewable fraction for village • Potential to earn revenue from market participation with BESS • Similarities with key components of a HV grid-connected microgrid	• Land requirements for large ground mount solar PV. Land tenure may be difficult • New large BESS network connection cost and time • Does not directly reduce electricity bill costs for residents and businesses	• An actionable solution now • A step towards MICDA's microgrid vision (if BESS sized appropriately)

Concept	Summary	Opportunities	Barriers	Outcome
#5 Behind the Meter Solar and/or BESS	• Individual residents or businesses • Grid-connected, behind the meter (BTM) • Low voltage (LV) assets, one site	• Increase renewable fraction for village • Provide backup power to site • Provide direct electricity bill savings for individual resident/business • Potential to earn revenue with BESS as part of a VPP • No large costly network connection upgrades to accommodate large assets • Contributes to all three of MICDA's objectives of maximising renewable energy fraction, minimise outage duration and maximise benefit for community members. • New federal government battery program discount available from 1 July 2025 until 2030.	• Capital costs for residents and businesses to install solar and/or BESS • Very limited retailer VPP offering for regional Queensland. Have only seen a Horan & Bird offer for a solar PV and BESS Power Purchase Agreement with a VPP participation option.	• An actionable solution now • Improves renewable fraction, reliability, and direct financial benefit but not a clear step towards MICDA's village/island microgrid vision

The key regulatory barriers and considerations for different microgrid solutions are summarised in a flowchart in Appendix B section 21.3.

6.3.2 Preferred Option

Given that a community microgrid is not currently offered by Ergon Energy Network, and the likelihood of establishing a third party owned microgrid is low due to its complexity, a village microgrid is not considered an actionable option now.

Ergon Energy Network will continue to develop their experience and capabilities with grid-connected HV microgrids. If Magnetic Island does not have a reliability issue for Ergon Energy Network to address, then its unlikely Magnetic Island will be seen as a priority site. They may or may not support a microgrid solution if funded by another group and gifted to them to operate and maintain.

Ergon Energy Network microgrid capability development may one day enable third parties to provide backup power to the HV network as a network support service.

The preferred actionable concept solution to take forward to a detailed feasibility assessment was chosen to be a centralised BESS (Concept #4). This option could serve as an interim step toward MICDA's preferred long-term solution of a community/island wide grid-connected microgrid. The remainder of this report primarily focuses on this centralised BESS solution.

Although not a microgrid solution, behind the meter Solar and/or BESS (Concept #5) contributes to all three of MICDA's objectives of maximising renewable energy fraction, minimise outage duration and maximise benefit for community members. For this reason, a behind the meter analysis was completed and presented in Section 18 of this report.

7. Solution Sizing Considerations

Preliminary modelling was conducted to explore how different sizes of additional solar PV and battery storage (as an aggregated total within Horseshoe Bay and Picnic Bay) could help increase the renewable energy fraction and minimise outage duration.

The modelling examined various combinations of additional solar PV and battery storage capacities to assess their impact on the renewable energy fraction and backup storage hours. While a community microgrid to provide backup power to the HV network is not currently an actionable option, the backup storage hours offer an indication of what may be possible in the future.

The renewable energy fraction is based on the following:

- The impact of additional solar and battery storage on estimated total load with existing solar PV rather than on existing grid consumption only. Each village has an existing renewable fraction from existing solar PV generation. This analysis estimates what the existing renewable fraction might be increased to, with the additional solar PV and battery storage.
- The 4.6 MW of installed solar PV capacity on Magnetic Island[69] (as at June 2024 to align with interval load data) is assumed to be split between the villages, proportional to the 'Approved Installed Inverter Capacity (kW)' as per Ergon Energy Network Load Capacity Map[70].
- Existing solar PV production conservatively assumed to be 4 kWh per day for every kW solar PV installed (4 kWh/day/kW).

[69] Australian PV Institute, latest cumulative install total June 2024 for postcode 4819, https://pv-map.apvi.org.au/postcode
[70] Ergon Energy Network, Network Load Capacity Map, https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/network-load-capacity-map

- Additional solar PV production assumed to be approximately 4.5 kWh per day for every kW solar PV to be installed (4.5 kWh/day/kW).
- No solar export limitations. If part or all the additional solar PV is not co-located with the battery storage, there could be limitations at the solar PV connection point, however this analysis assumes all excess solar can be exported to the battery storage.
- 2-hour BESS i.e., a 4 MWh battery storage capacity will have a power rating of 2 MW.

The backup storage hours are based on the following:

- The average load observed between 4pm and 8am in the 2023/24 data. This assumes that the solar PV would be available to supply the load and charge the battery between 8am and 4pm.
- A conservative energy use during an outage. The backup storage hours shown have been calculated using the average load observed (as per point above), reduced by one third (33%).
- A minimum battery state of charge (SOC) of 10%
- The battery being fully charged at the beginning of the outage (e.g., the battery has been charged and maintained at full charge in preparation for a cyclone event). This may not always be the case (e.g., for an unexpected, sustained outage).

7.1. Horseshoe Bay

The Horseshoe Bay load used in the modelling was based on the 2023/24 Arcadia Recloser hourly interval load data. Any periods of outages or irregular data readings in the 2023/24 dataset were substituted with data from previous years. The annual grid consumption modelled for Horseshoe Bay was 3,345 MWh and existing excess solar totalled 92 MWh.

The average load observed between 4pm and 8am was 479 kW for the 2023/24 grid consumption data used in the model. This value, reduced by 33% (320 kW), has been used to estimate conservative energy use and calculate the backup storage hours below.[71]

Horseshoe Bay is estimated to have an existing 1,397 kW total solar PV installed that produces approximately 2,040 MWh annually[72].

Figure 26 shows the potential impact that various sized of solar and BESS could have on sustainability and reliability for Horseshoe Bay.

[71] Backup storage hours = (Battery Storage Capacity (MWh) x 0.9) / 320 kW

[72] Total Approved Installed Inverter Capacity for Magnetic Island is 3,528 kVA in November 2024. The portion of this in Horseshoe Bay was 30%. This was multiplied by the total 4,603 kWp solar PV from APVI postcode data June 2024 to get the estimated existing solar PV capacity for Horseshoe Bay. The generation is then estimated based on an assumption of 4Wh/day/kWp.

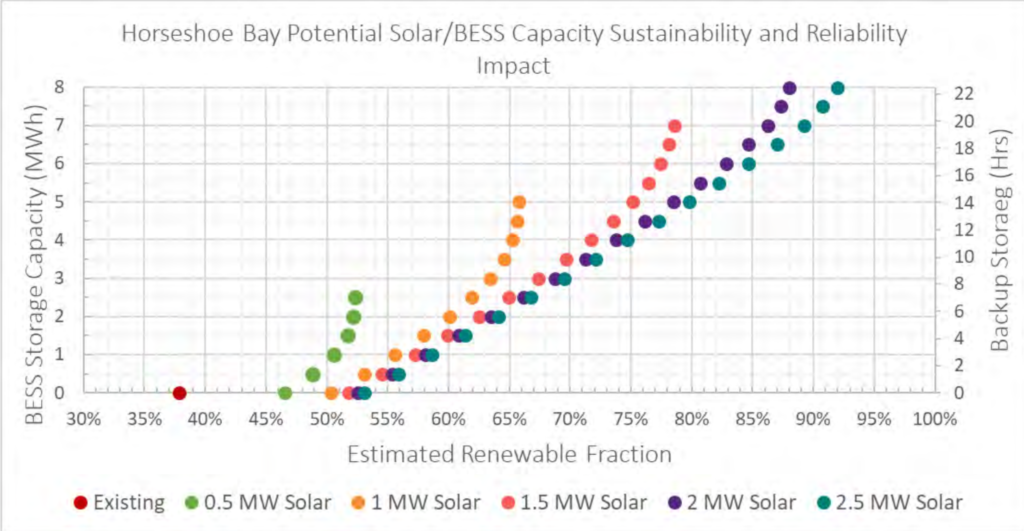


Figure 26 - Horseshoe Bay Potential Solar/BESS Capacity Sustainability and Reliability Impact

Figure 27 shows the estimated excess generation of the various sizes of additional solar PV and battery storage capacities.

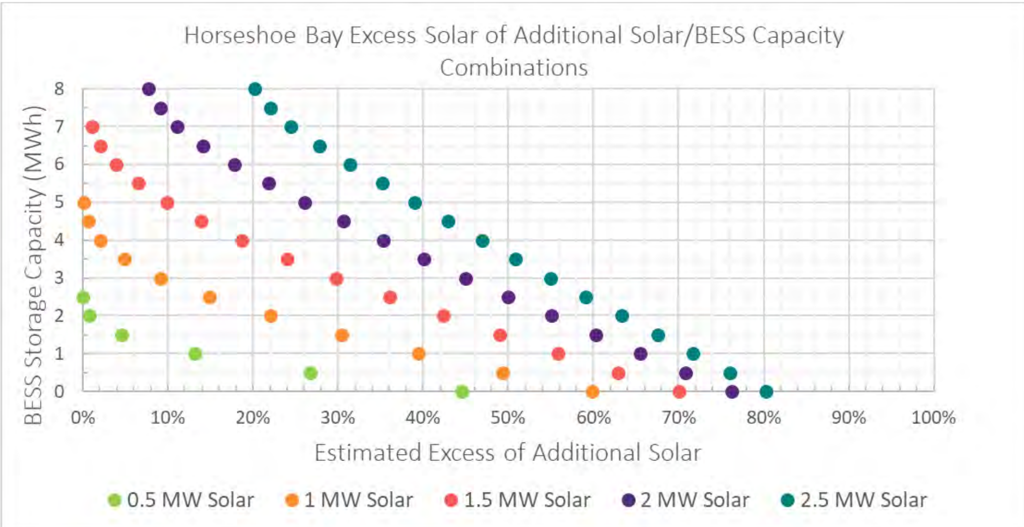


Figure 27 - Horseshoe Bay Excess Solar of Potential Additional Solar/BESS Capacity Sustainability and Reliability Impact

As shown in the Horseshoe Bay existing grid consumption and solar export analysis in Section 4.2.1 and 4.2.2, the existing solar PV covers on average almost the entire village load in in the middle of the day. Any additional solar PV installed (after June 2024), has the potential to increase the excess solar PV energy generated that will flow upstream TM-10 towards Arcadia Bay and Nelly Bay.

Figure 27 shows that even with an additional 500 kW of solar PV, approximately 45% of the energy generated by that additional 500 kW is estimated to be excess, not able to be consumed locally. Battery storage, particularly battery storage co-located with solar PV, will enable more of the energy generated by any new solar PV installed, to be locally consumed.

When considering different combinations of solar PV and battery storage capacities, larger sizes would achieve higher renewable fraction and longer backup supply however may not be efficiently utilised. For example, a 2.5 MW solar PV and 8 MWh of battery storage might achieve a 92% renewable fraction and 22 hours of backup supply for Horseshoe Bay (Figure 26), this combination would result in an estimated 20% excess solar PV generation (Figure 27).

To achieve close to 100% renewable fraction would require significantly large capacities. To achieve 99% renewable fraction would require a combination such as 5 MW solar PV and 15 MWh battery storage capacity, resulting in a BESS utilisation of only 48% and excess solar PV of 59%.

For detailed Horseshoe Bay modelling results table, including estimated greenhouse gas (GHG) emissions reductions, see Table 43 in Appendix C, Section 22.1.

7.2. Picnic Bay

The Picnic Bay load used in the modelling was based on the 2023/24 TM-03 (Nelly Bay and Picnic Bay total feeder) hourly interval load data, which was scaled down to 36% to represent Picnic Bay's portion[73]. Any periods of outages or irregular data readings in the 2023/24 dataset were substituted with data from previous years for consistency. The annual grid consumption modelled for Picnic Bay was 2,289 MWh and existing excess solar totalled 1.6 MWh.

The average load observed between 4pm and 8am for the scaled-down 2023/24 grid consumption data was 303 kW. This value, reduced by 33% (202 kW), has been used to estimate conservative energy use and calculate the backup storage hours below.[74]

Picnic Bay is estimated to have an existing 707 kW total solar PV installed that produces approximately 1,032 MWh annually[75].

Figure 28 shows the potential impact that various sized of solar and BESS will have on sustainability and reliability for Picnic Bay.

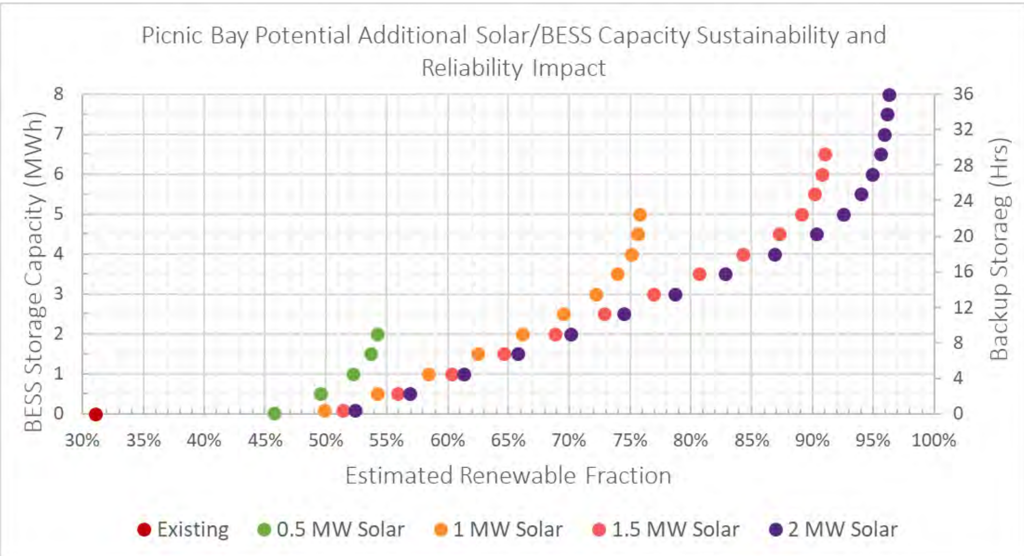


Figure 28 - Picnic Bay Potential Solar/BESS Capacity Sustainability and Reliability Impact

[73] Based on proportion of 'Number of Connections' listed within Picnic Bay relative to TM-03 feeder in Ergon Energy Network Load Capacity Map https://www.ergon.com.au/network/about-us/company-reports,-plans-and-charters/network-load-capacity-map

[74] Backup storage hours = (Battery Storage Capacity (MWh) x 0.9) / 202 kW

[75] Total Approved Installed Inverter Capacity for Magnetic Island is 3,528 kVA in November 2024. The portion of this in Picnic Bay was 15%. This was multiplied by the total 4,603 kWp solar PV from APVI postcode data June 2024 to get the estimated existing solar PV capacity for Picnic Bay. The generation is then estimated based on an assumption of 4Wh/day/kWp.

Figure 29 shows the estimated excess generation of the various sizes of additional solar PV and battery storage capacities.

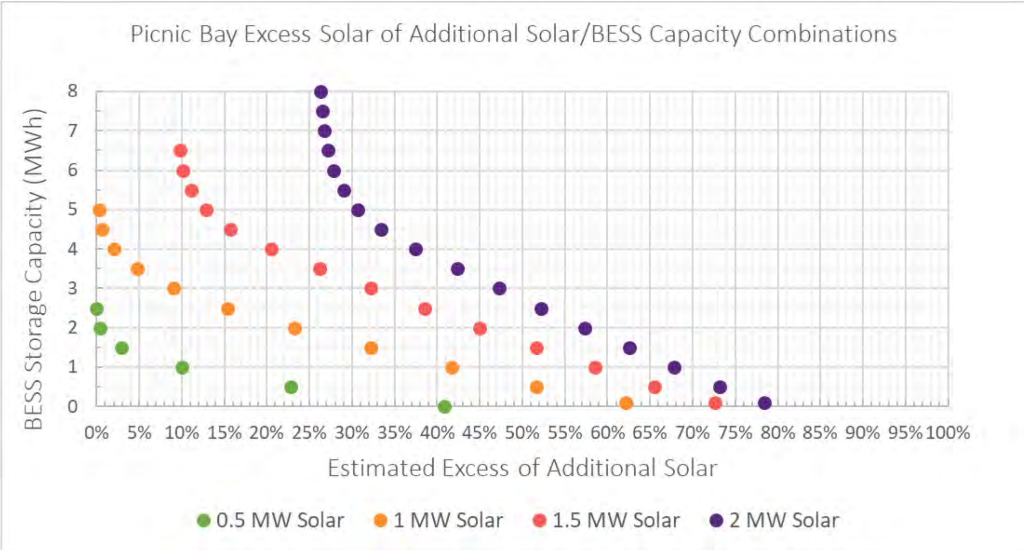


Figure 29 - Picnic Bay Potential Solar/BESS Capacity Sustainability and Reliability Impact

A limitation of using scaled down TM-03 interval data to estimate the Picnic Bay load profile is that the excess solar PV energy for Picnic Bay, may not be proportional to the excess solar PV energy for TM-03. As shown in Table 6 – TM-10 Feeder and Horseshoe Bay Excess Solar PV Summary, the 2023/24 excess solar PV energy for TM-10 was 0.2 MWh, whereas the Horseshoe Bay excess solar PV energy was 94 MWh (470 times larger).

The data used for Picnic Bay estimates only 13 kWh excess solar PV energy for 2023/24. Given there is some excess solar PV, this means that at times, the solar PV covered the total feeder load. Although less than Horseshoe Bay, any additional solar PV installed (after June 2024), has the potential to increase the excess solar PV energy generated that will flow upstream TM-03 from Picnic Bay.

Figure 29 shows that with an additional 500 kW of solar PV, approximately 41% of the energy generated by that additional 500 kW is estimated to be excess, not able to supply the village load. Battery storage, particularly battery storage co-located with solar PV, will enable more of the energy generated by any new solar PV installed, to be locally consumed.

The largest solar PV and battery storage combination shown in the figures above is 2 MW solar PV and 8 MWh battery storage capacity. This combination might achieve a 96% renewable fraction and 36 hours of backup supply for Picnic Bay (Figure 28). This results in an estimated 26% excess solar PV generation (Figure 29).

For detailed Picnic Bay modelling results table, including estimated greenhouse gas (GHG) emissions reductions, see Table 44 in Appendix C, Section 22.1.

8. Site Identification and Assessment

Multiple sites were considered for centralised solar PV and/or BESS. The key criteria for site identification and assessment included:

Environmental/Physical

1. Footprint/available space
2. Fire risk
3. Flood risk
4. Traffic risk
5. Noise
6. Vegetation disturbance
7. Visibility/visual impact

Stakeholders

8. Landholder support for site/project
9. Lease negotiation complexity and cost
10. Disruption to existing use of space
11. Community involvement/benefit-sharing
12. Awareness training & education opportunities
13. Accessibility impact

Electricity Network

14. Site load
15. Connection capacity
16. Connection & install complexity and cost

8.1. Horseshoe Bay

8.1.1 Sites Considered

The Horseshoe Bay sites considered as part of this study are listed in Table 12 and shown on a map in Figure 30 below.

Table 12 – Horseshoe Bay Potential Locations Considered for Centralised Solar and/or Battery Storage

Site #	Site Name	Site Details	Assessment Notes
1	**Horseshoe Bay Park**	Site Owner: Townsville City Council (TCC) Address: 64-88 Horseshoe Bay Road, Horseshoe Bay Plan Number: 13/E124292 Property Size: 75,606 m2, 270m (HB Rd) x 280m Site use: Skate park, AFL oval, community centre, tennis court, eucalyptus farm, cell tower, Rural Fire Brigade Ergon Network: TVS590326 315kVA, pole 6071492	Project support from TCC. Multi use site with limited spare land. Potential for structure over tennis court for rooftop solar – a potential option to increase social license.

2	**Vacant land across from Skate Park**	**Site Owner:** Private **Address:** 29 Gifford Street, Horseshoe Bay **Plan Number:** 1/RP714246 **Property Size:** 40,573m2, **Site use:** Undeveloped. recently leased area for road upgrade project **Ergon Network:** No existing connection, closest transformer TVS590326 315kVA, pole 6071492	Unknown support from owner for project and land lease arrangement. Potential for ground mount solar if land cleared.
3	**Vacant land for sale Gifford St**	**Site Owner:** Private **Address:** 105 Gifford Street, Horseshoe Bay **Plan Number:** 2/RP721586 **Property Size:** 40,584 m² **Site use:** Undeveloped. Currently for sale for $890,000. Approximately 70% is native forest and the rest is cleared with some established trees. **Ergon Network:** No existing connection, closest transformer TVS58 63kVA, pole 5135081	Potential for ground mount solar. May be environmental restrictions for clearing land with 70% being native forest. Land purchase instead of leasing adds significant capital expenditure to the project.
4	**Horseshoe Bay Water Recycling Facility**	**Site Owner:** Townsville Water **Address:** 1-13 Pollard Street, Horseshoe Bay **Plan Number:** 2/RP724194 **Property Size:** 40,597 m² **Site use:** Water Recycling Facility, native plant restoration/affluent irrigation, community access roads **Ergon Network:** TVS3758 200kVA, pole 5260545	No land available for solar – community access and native planted vegetation. Within 500 m of the ocean – could impact product warranties. TCC requested that this site be excluded from this study as they are already being considered for solar and BESS as part of an existing sustainability program.

Figure 30 - Sites Considered for Horseshoe Bay Centralised Solar and/or BESS

8.1.2 Preferred Site

Figure 31 shows the preferred site for the solution in Horseshoe Bay Park. Given the limited available area for solar PV installation, a BESS only solution is considered the preferred option.

Figure 31 - Horseshoe Bay Preferred Site: TCC Horseshoe Bay Park

When determining Horseshoe Bay Park as the preferred site to continue with for the remainder of the study, the following was considered:

Environmental/Physical

- The property is large and has many different uses however there appears to be several options for a centralised BESS location. There are some areas available that are existing grass or dirt and would require minimal vegetation disturbance.
- There is not suitable space for ground mount solar that would avoid the clearing of trees. Given the existing buildings have rooftop solar PV, there is not a lot of space for additional solar unless new structures are built. This could be an opportunity to provide a shade structure for the relatively new tennis court.
- The 1% Annual Exceedance Probability (AEP) flood event (also known as the Q100 flood) is shown in Figure 32 below. Other than the open drain and creek, waters no higher than 0.3 m are expected and there are some open areas at the south end of the site that are not expected to flood that would be potential locations for a centralised BESS.

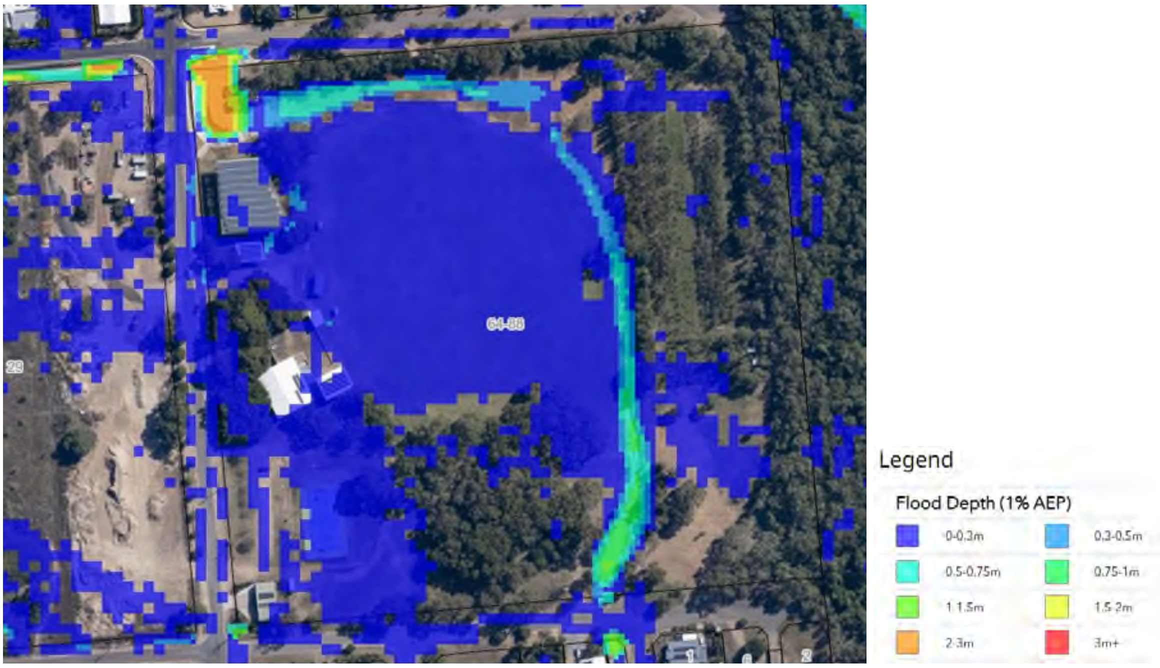


Figure 32 - Horseshoe Bay Park 1% AEP flood map[76]

- Almost half of the site is shown to be in a bushfire buffer area as seen in Figure 33 below. Consideration would need to be made to prevent a centralised BESS increasing the extent or the severity of bushfire hazard or increasing the risk to life, property, community, and the environment. There may be restrictions with the BESS being in the buffer zone.

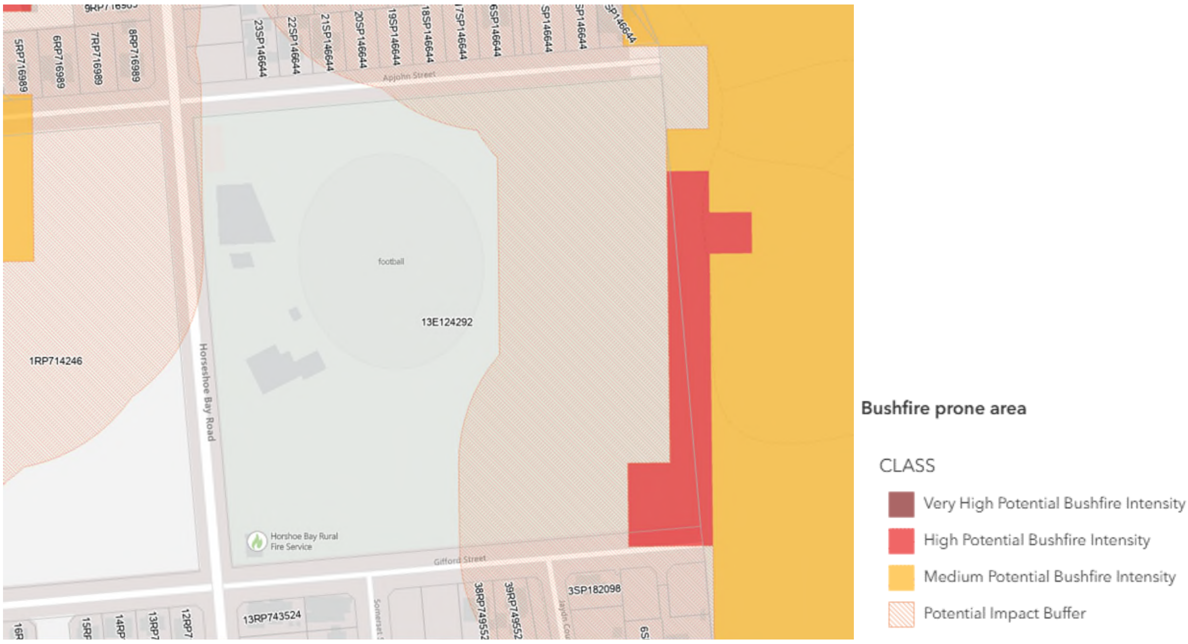


Figure 33 - Horseshoe Bay Park Bushfire Hazard Overlay[77]

- Regarding traffic risk, Horseshoe Bay Road is the main road into the village and to the bay beachfront area with a 60 km/h speed limit. Gifford Street and Apjohn Street are relatively quiet no-through roads to adjacent residential properties. Internal to the

[76] Townsville City Council, Flood Depths | TCC Flood Information Portal
[77] Queensland Government, Development Assessment Mapping System, sppims-dams.dsdilgp.qld.gov.au/dams/?tab=layers&accordions=SARA+DA+MAPPING%2CSPP+ASSESSMENT+BENCHMARK+MAPPING%2CNATURAL+HAZARDS+RISK+AND+RESILIENCE

property there are several dirt roads to parking areas, access to eucalyptus farm and mobile phone communications tower.

- Being a community site with multiple uses, the site is used regularly and there are neighbouring houses with a view of the site. Any infrastructure will have an impact on the parkland/bushland aesthetic, however there are options that could improve the visual impact of a centralised BESS including community artwork, or strategically planted gardens. This can be determined through community engagement.
- The cooling systems, namely fans, of inverters or battery systems within a BESS emit noise. If a centralised BESS is close to boundary near the neighbouring houses along Gifford Street and Apjohn Street, noise reduction measures may be required (e.g., an acoustic wall).
- Figure 34 shows the environmental importance map layer for Horseshoe Bay Park. Majority of the site is categorised as either medium or high environmental importance. This may impact the location of a centralised BESS on the site.

Figure 34 - Horseshoe Bay Park environmental importance map overlay[78]

Stakeholders

- Townsville City Council support community based initiatives to decarbonise Magnetic Island and are open to discussions regarding leasing arrangements for TCC sites.
- There are multiple uses of this site. Given the flood mapping, there is some available space towards the south of the property. A centralised BESS would only take up a portion (e.g., 15.5 m x 11.5 m) of the existing free area that is used for parking during events or if in the southeast corner of the property that appears to be an access track.
- Being an existing site that the community have access to and use for a multitude of reasons, there is opportunity for community involvement, not only as part of a community engagement process to provide feedback on specific location, but this could be in the form of artwork, or getting involved for awareness and education (residents, Magnetic Island State School or tourists).

[78] Townsville City Council, TownsvilleMAPS - Townsville City Plan

Electricity Network

- There is very little site load at Horseshoe Bay Park. This doesn't provide much opportunity for behind the meter advantages for solar and battery storage.
- Existing distribution transformer is 315 kVA, the largest capacity within Horseshoe Bay. If centralised solar/BESS is to be connected at this site larger than 315 kVA, the existing transformer would need to be replaced or a new distribution transformer be installed for a separate network connection to site.
- The Queensland Electricity Connection Manual (QECM) states that the DNSP shall install only one DNSP service point (network connection) to a premises. The property has multiple existing network connections. Adding an additional network connection to the site is possible if certain conditions are met and additional requirements may apply e.g., a minimum distance of 200m must be maintained between network connections.
- Horseshoe Bay Park is closer to the upstream of the feeder than most of Horseshoe Bay. This would increase the likelihood of being able to connect a larger solar and/or BESS capacity since the further upstream the feeder, the higher capacity rating of the feeder section.
- There is existing LV supply to the site. The TM-10 11 kV feeder backbone runs along Horseshoe Bay Road and with spurs along Apjohn Street and Gifford Street (shown in blue in Figure 35). If a new large transformer were installed to accommodate a large, centralised BESS along Gifford Street, less works are expected to be required by Ergon Energy Network.

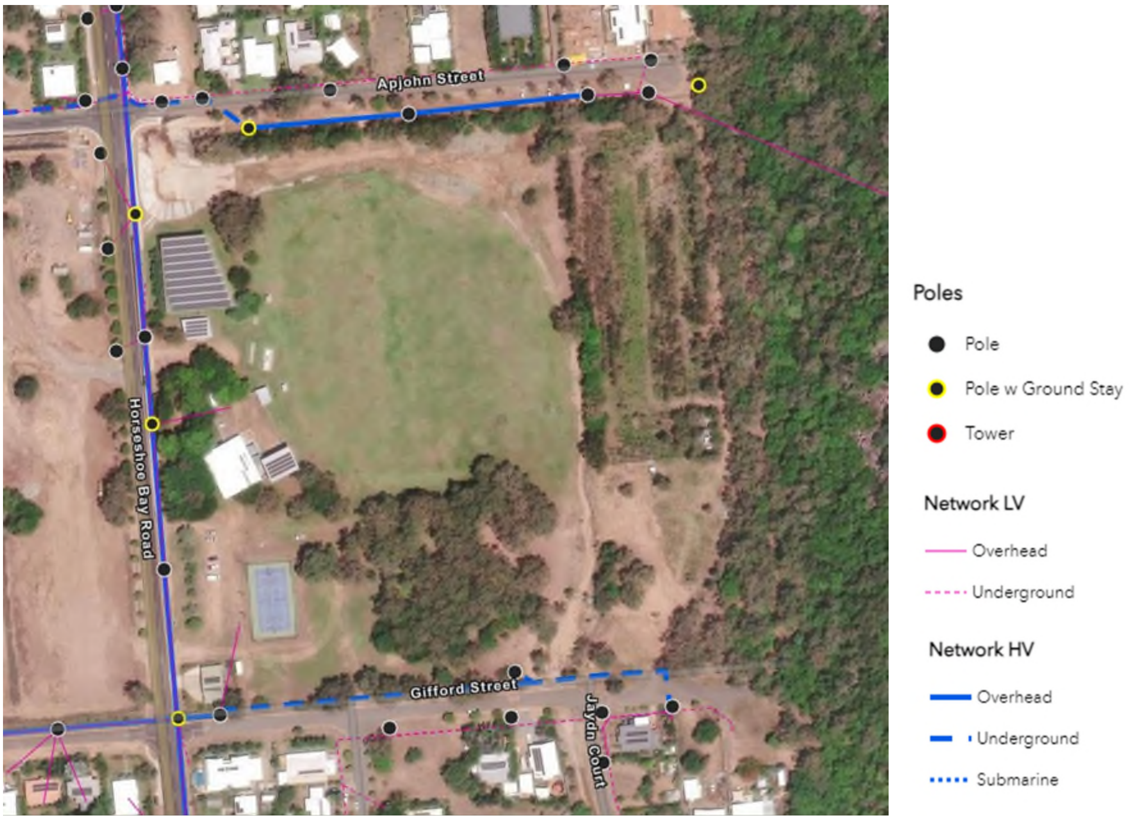


Figure 35 - Horseshoe Bay Park Ergon Energy Network[79]

[79] Ergon Energy Network, map Look up and Live

8.2. Picnic Bay

8.2.1 Sites Considered

The Picnic Bay sites considered as part of this study are listed in Table 13 and shown on a map in Figure 36 below.

Table 13 – Picnic Bay Potential Locations Considered for Centralised Solar and/or Battery Storage

Site #	Site Name	Site Details	Assessment
1	**Picnic Bay Landfill Lot 1**	Site Owner: Townsville City Council (TCC) Address: 38 Birt Street, Picnic Bay Plan Number: 1/P93835 Property Size: 19,276 m^2 Site use: Old landfill site Ergon Network: No active connection, closest transformer TVS468, 100 kVA	Landfill closed in 2016 and the land was capped in 2018. Potential for non-penetrative ground mount solar.
2	**Picnic Bay Landfill Lot 2**	Site Owner: Private Address: 38 Birt Street Picnic Bay (access Hurst St) Plan Number: 2/SP157592 Property Size: 23,906 m^2 Site use: Part old landfill site. Mostly undeveloped. Currently used as a location for mulching. Ergon Network: No existing connection, closest transformer TVS99 315 kVA	Landfill closed in 2016 and the land was capped in 2018. Potential for non-penetrative ground mount solar. Majority of lot is a creek and the old, capped landfill area. Not a lot of available land for solar but BESS is an option. No existing network connection could be costly to construct.
3	**Reserve Adjacent to Golf Course**	Site Owner: Townsville City Council (TCC) Address: 2 Hurst Street Picnic Bay Plan Number: 1/SP157592 Property Size: 6,366 m^2 Site use: Part golf course. Next to men's shed. Ergon Network: No existing connection, closest transformer TVS99 315 kVA	Part of the green for one of the holes at Magnetic Island Country Golf club is within the lot. Close to residential properties.
4	**Ergon Energy Network Depot**	Site Owner: Ergon Energy Network Address: Cnr Hobbs and Birt Street, Picnic Bay Plan Number: 15-17/P9389 Property Size: 2,429 m^2 Site use: Existing Ergon Network depot Ergon Network: Transformer TVS99 315 kVA	No available space inside depot fence. Potential area outside fence for a small community BESS which EQL Property were open to discussions about. Has an 11kV network connection to connect HV backup generator. Very close to residential properties.

5	**Picnic Bay Waste Transfer Station**	**Site Owner:** Townsville Water **Address:** 11-63 West Point Road, Picnic Bay **Plan Number:** 1/P93835 **Property Size:** 19,276 m^2 **Site use:** Waste Transfer Station, native plant restoration/affluent irrigation **Ergon Network:** Transformer TVS612708, 100 kVA	Available roof area and some ground around site boundary for solar PV. Towards the very end of the feeder, not a lot of network capacity expected. Within 500 m of the ocean – could impact product warranties.
6	**Picnic Bay Sewage Treatment Plant**	**Site Owner:** Townsville Water **Address:** 65-73 West Point Road, Picnic Bay **Plan Number:** 1/RP742477 **Property Size:** 23,020 m^2 **Site use:** Sewage treatment **Ergon Network:** Transformer TVS1753, 200 kVA	Within 400 m of the ocean – could impact product warranties. TCC requested that this site be excluded from this study as they are already being considered for solar and BESS as part of an existing sustainability program.
7	**Old Ergon Energy Network Site**	**Site Owner:** Ergon Energy Network **Address:** 68 Picnic Street, Picnic Bay **Plan Number:** 2/P93831 **Property Size:** 54 m^2 **Site use:** Old structure not currently in use **Ergon Network:** Transformer TVS592539, 100 kVA	Within 200 m of the ocean – could impact product warranties. Extremely small. Could be suitable for a small community BESS. Adjoining site is majority bushland however, residential properties across the streets on both Picnic Street and Magnetic Street.

Figure 36 - Sites Considered for Picnic Bay Centralised Solar and/or BESS

8.2.2 Preferred Site

Figure 37 shows the preferred site for the solution in Picnic Bay as Picnic Bay Landfill Lot 2. Given the limited available area for solar PV installation and the proximity to the golf course, a BESS only solution is considered the preferred option.

Figure 37 - Picnic Bay Preferred Site: TCC Landfill Site Lot 2

When determining Picnic Bay Landfill Lot 2 as the preferred site to continue with for the remainder of the study, the following was considered:

Environmental/Physical

- The property is large however the potential usable area is less than a third of the total size. The remainder of Lot 2 is the capped landfill, and a creek. The potential usable area is relatively flat and clear, meaning minimal vegetation disturbance.
- The potential usable area is currently being used for mulching. If a small part of this area were used for a centralised BESS, the site could remain in use as a mulching site.
- Lot 2 could fit approximately 350 kWp of solar PV however this area is 30 m from a golf course fairway which poses a higher risk of asset damage.
- Lot 1 was considered for use. It could potentially be an area for ground mount solar PV in the future however there are complexities with development of an old landfill site. This is discussed further in section 17.1.3. A BESS only solution on Lot 1 would be challenging as the only available land is along the edge of the property (adjacent to Birt St) is not flat and is at risk of flooding.
- The 1% AEP flood event is shown in Figure 38 below. Other than the creek, there are a few very small areas where waters no higher than 0.3 m are expected but majority of the potential usable area in Lot 2 is not a flood risk.

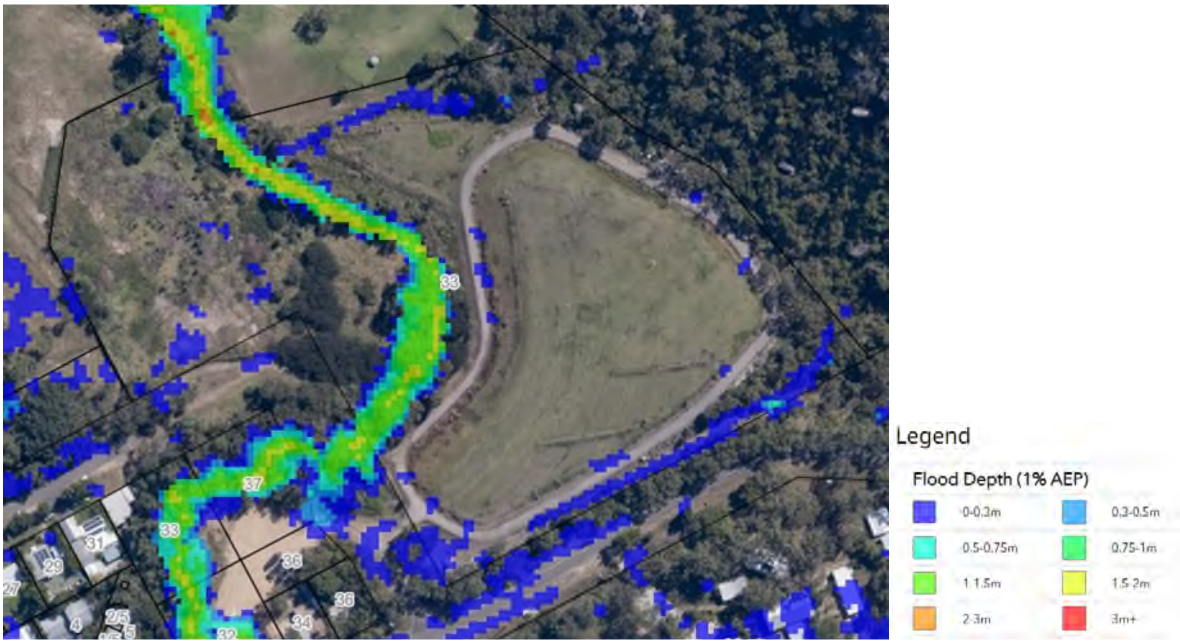


Figure 38 - Picnic Bay Landfill 1% AEP flood map[80]

- Figure 39 shows part of Lot 1 is within a medium potential bushfire intensity area. A large portion of Lot 1 and Lot 2 are within the bushfire buffer area; however, the potential usable area of Lot 2 is not. Given the surrounding natural vegetation, consideration would still need to be made to prevent a centralised BESS increasing the extent or the severity of bushfire hazard or increasing the risk to life, property, community, and the environment.

Figure 39 - Picnic Bay Landfill Bushfire Prone Area map[81]

- Regarding traffic risk, Lot 2 is accessed via Hurst Street, a no-though road along the Magnetic Island golf course and residential properties. Internal to the property there is a dirt road use by machinery and vehicles for mulching activity.

[80] Townsville City Council, Flood Depths | TCC Flood Information Portal
[81] Queensland Government, Development Assessment Mapping System, sppims-dams.dsdilgp.qld.gov.au/dams/?tab=layers&accordions=SARA+DA+MAPPING%2CSPP+ASSESSMENT+BENCHMARK+MAPPING%2CNATURAL+HAZARDS+RISK+AND+RESILIENCE

- The site is not open to the community. There are a very small number of neighbouring residential properties that have a partial view of the site. Additional infrastructure will have an impact on the bushland aesthetic, although not as visible to the public as a community park, there are still options that could improve the visual impact of a centralised BESS including community artwork, or strategically planted gardens. This can be determined through community engagement.
- The cooling systems, namely fans, of inverters or battery systems within a BESS emit noise. If a centralised BESS is close to the entrance/road near the neighbouring houses along Hurst Street, noise reduction measures may be required (e.g., an acoustic wall).
- Figure 40 shows the environmental importance map layer for Picnic Bay Landfill. The entire Lot 2 site is of environmental importance, categorised as either medium or high environmental importance. This may impact the location of a centralised BESS on the site.

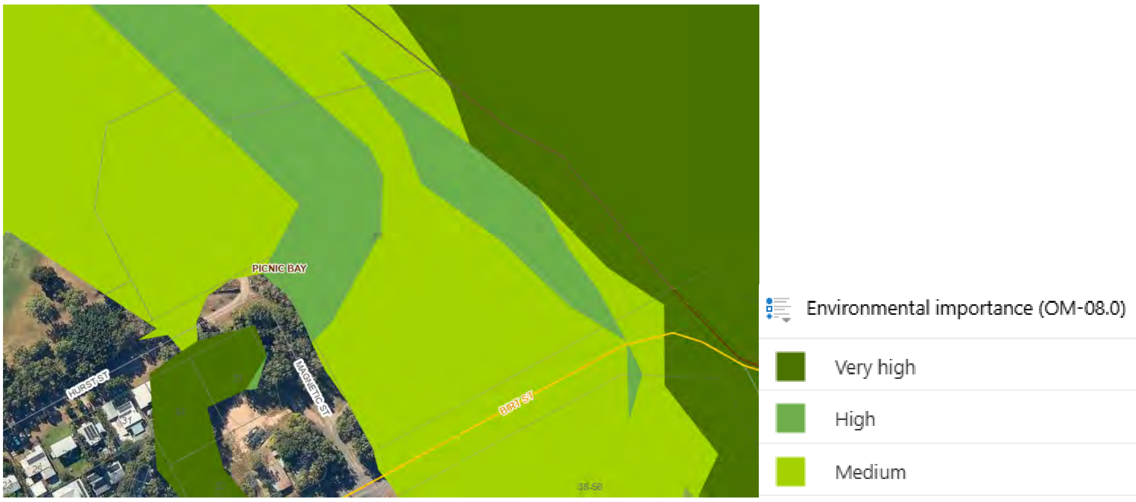


Figure 40 – Picnic Bay Landfill environmental importance map overlay[82]

Stakeholders

- Townsville City Council support community based initiatives to decarbonise Magnetic Island and are open to discussions regarding leasing arrangements for TCC sites.
- There is an existing use of this site for mulching however a centralised BESS would only take up a relatively small (e.g., 15.5 m x 11.5m) portion of the potential usable area.
- Although the site is not open to the community, there is still opportunity for community involvement. This could be part of a community engagement process to provide feedback on specific location, community artwork, or getting involved for awareness and education (residents, Magnetic Island State School or tourists).

Electricity Network

- There is no existing network connection at Picnic Bay Landfill Lot 2 and no site load for any behind the meter opportunities.

[82] Townsville City Council, TownsvilleMAPS - Townsville City Plan

- The closest transformer (TVS99) is on Birt Street, supplying 97 customers and rated 315 kVA, the largest capacity within Picnic Bay.
- In Figure 41 it can be seen that Picnic Bay Landfill Lot 1 is adjacent to the TM-03 feeder coming into Picnic Bay, however Lot 2 is not as close. If a new connection was established at Lot 2, supplied by a new, large transformer, the supply to the site would require more network augmentation.
- The TM-03 11 kV feeder backbone runs along Birt Street which is relatively upstream compared to most of Picnic Bay, increasing the likelihood of being able to connect a larger solar and/or BESS capacity.
- If a new, large transformer were installed to accommodate a large, centralised BESS at Picnic Bay Landfill Lot 2 at the end of Hurst Street, significant network augmentation by Ergon Energy Network would be required to connect the site to the network.

Figure 41 – Picnic Bay Landfill Ergon Energy Network[83]

[83] Ergon Energy Network, map Look up and Live

9. Network Connection

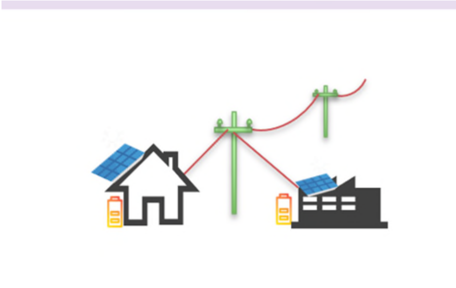
9.1. Connection

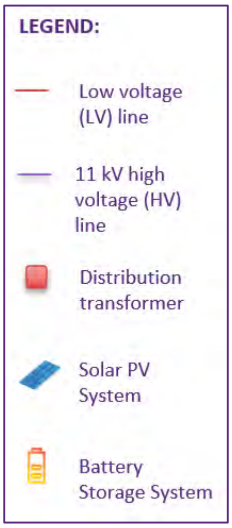
9.1.1 Connection Type

There are three physical grid connection types that can be considered for a BESS within Horseshoe Bay or Picnic Bay:

- Behind the meter (residential/business)

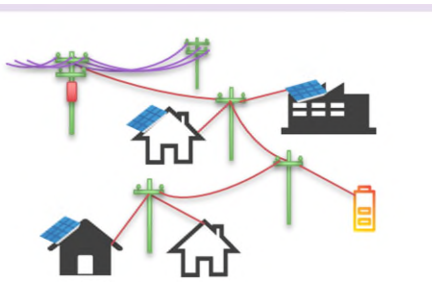
  Installed at a site with an existing load, typically to enable the storage of energy from solar panels to be used for the site load later.





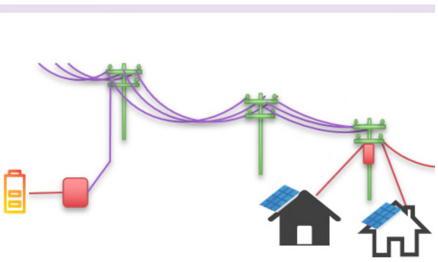
- Centralised – low voltage coupled

  Installed at a location that does not have a site load to service but shares a low voltage network with other customers as they are connected to the HV network via a shared distribution transformer.



- Centralised – high voltage couple

  Installed at a location that does not have a site load to service and does not share a low voltage network with other customers. Connected to the HV network via a dedicated distribution transformer.



The opportunities and barriers considered for Horseshoe Bay and Picnic Bay for each physical grid connection type are summarised in Table 14 below.

Table 14 - Opportunities and barriers of different grid connection types

	Connection Type	
	Opportunities	Barriers
Behind the Meter (Residential/ Business)	• Enables direct savings realisable on customer's regular electricity bill. • Locating generation, energy storage and load at the same site makes for more efficient use of energy as less is transported (hence less losses). This reduces the amount of solar PV generation that might be curtailed and as a result, increases renewable energy fraction and GHG emission reduction. • Demand management at an individual site still benefits the network and wider community. • If designed to provide backup power to the site in the event of a sustained outage, this would be more reliable than a community wide backup microgrid. With a microgrid, there is more overhead network that could have a sustained fault which prevents the whole microgrid from operating.	• The capital cost to individual households or business owners. Not everyone is in a financial position or has the interest to invest in a battery. • The onus is on the household or business to manage and fund the maintenance of the system to increase performance and longevity. • Added complexity and cost with communications and control if multiple behind the meter systems were aggregated and orchestrated together.
Centralised – Low Voltage Coupled	• Option to minimise network augmentation by connecting a battery to an existing distribution transformer low voltage network. • Locating generation, energy storage and load within a distribution transformer low voltage network makes for more efficient use of energy compared to a high voltage coupled solution as less energy is transported. This reduces the amount of solar PV generation that might be curtailed and as a result, increases renewable energy fraction and GHG emission reduction. • Targeting constrained distribution transformers with large amounts of solar PV installed for effective solar soaking to prevent solar PV curtailment and enable more solar. • Potential for transformer peak demand reduction, which would improve asset performance and increase asset life.	• Limited to less than 315kVA (largest distribution transformer in Horseshoe Bay and Picnic Bay). • For a larger aggregated battery capacity, more BESS are needed, therefore more suitable locations need to be identified and managed. • Pole mount could be an option but would likely need to upgrade pole (because of the BESS weight) and pole access is complex if BESS is not DNSP owned. • BESS with backup power capabilities to the shared LV network is not currently a network supported option.
Centralised – High Voltage Coupled	• Larger battery enabling more capacity for solar soaking for whole village/island with less sites required. • Larger battery capacity is more attractive to electricity retailers for market participation and hence asset owner would receive a revenue stream. • If backup power to village became a network support option in the future, having a central site with a battery sized to support the load is a step in that direction.	• Costly and time consuming network upgrades would be required to connect a battery larger than 315kVA. • Excess distributed solar PV energy to charge a centralised BESS could be curtailed at the distribution transformer level – this is not an existing issue in Horseshoe Bay or Picnic Bay but could become an issue in the future as more solar is installed. This could limit the village total renewable fraction and GHG emission reduction that could be achieved than if the same capacity of generation and storage were distributed and co-located with at the same site as load. • BESS with backup power capabilities to the shared HV network is not currently a network supported option.

9.1.2 Dynamic Connections

The recent shift towards dynamic connections by Ergon Energy Network allows more flexibility and optimisation of renewable energy systems like solar PV and BESS.

Previously, fixed connection agreements were the only option, where customers' solar PV systems could be limited to a set export amount, such as a 30kW solar installation with an export limit of 15kW. If the solar PV system were to reach this export limit, any excess solar would need to be curtailed. This curtailment reduces the overall renewable energy generation and caps the savings from feed-in tariffs, which is currently set at 8.66 c/kWh (excluding GST) for 2025/26 by the QCA.[84]

With dynamic connections, signals are sent from Ergon Energy Network to customers' solar PV and/or BESS in 5-minute intervals via an internet connection. These signals are referred to as Dynamic Operating Envelopes (DOE) and communicate to the solar PV and/or BESS how much power can be exported to the grid at that point in time.[85]

The difference between static export limits and dynamic operating envelope can be seen in with Figure 42 and Figure 43 below.

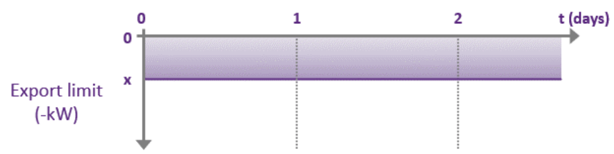


Figure 42 - Static Export Limit

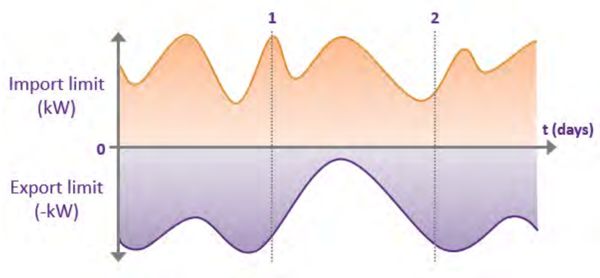


Figure 43 - Dynamic Operating Envelope

According to Ergon Energy Network's current dynamic connection standards, the minimum export/import limit for any IES connection is 1.5 kW. The maximum dynamic export/import limit ranges from 10 - 18 kW per phase for systems up to 30 kVA. For systems from 30 kVA to 1,500 kVA, the maximum dynamic export and import limit is determined by a technical study performed by the DNSP.[86] There is no guarantee for how often system export/import is reduced from the maximum dynamic limit.

In the example above, the business could be approved for 30kW of solar PV with a dynamic connection where most of the time, no restrictions on solar export are expected to be experienced. This is expected to allow the business to operate their solar PV with fewer export restrictions, thereby enabling greater export of renewable energy and increasing the financial benefits of feed-in tariffs. It also is expected to enable the connection of larger systems since Ergon Energy Network don't have to set fixed limits based on worst case scenario, they can allow larger systems and limit them only for periods of time when the network is constrained by excess solar.

For BESS only connections, a dynamic connection it is not expected to limit import or export if the BESS operates to support more renewable energy in the network. A centralised BESS would shift solar PV generation to times when it is more valuable by charging during the day when solar PV production is high and wholesale energy prices are lower, and discharging in the evening when

[84] Queensland Competition Authority (QCA), Solar feed-in tariff in regional Queensland 2025-26, Final determination, June 2025 solar-fit-fact-sheet.pdf
[85] Ergon Energy Network, Tariff Structure Statement, Explanatory Statement, Appendix A – Dynamic Connections Ergon - Tariff Structure Statement - Explanatory Statement - November 2024 - public_0.pdf
[86] Ergon Energy Network, Dynamic connection standards, STNW3510 and STNW3511, Dynamic Connections for installers | Ergon Energy

there is higher demand and higher wholesale energy prices. This offers both financial and environmental benefits by balancing energy consumption and reducing reliance on the grid.

Complexity may arise when a BESS participates in the FCAS market. An FCAS even can happen at any time of the day and if the BESS is not able to import or export the power required due to a conflict with a dynamic limit set by the DNSP, this could lead to non-compliance and reduced revenue.

9.2. Tariff Options

An electricity bill is made up of a combination of multiple elements and organisations, resulting in a monthly total. Table 15 shows the matrix of elements and organisations. Elements include fixed, energy, demand, and other charges. Fixed charges are dollars per day and not influenced by any solar or energy efficiency factors. Energy charges are based on the consumed energy (kWh) on site and can be reduced by onsite solar generation and efficiency measures. Demand charges are based on the maximum measured 30-minute power demand for the month. For example, a 30-day month has 1,440 intervals and the highest measured power demand would be used to calculate the demand charge for that month. The analogy for fixed, energy and demand elements is a bucket of water, where the fixed charge pays for the bucket, the energy charge pays for the volume of water in the bucket and the demand charge pays for the rate of water flow into the bucket.

There are multiple organisations participating in the makeup of an electricity bill, which include the following:

- Transmission Network Service Providers (TNSP), in Queensland there is only Powerlink.
- Distribution Network Services Providers (DNSP), in Queensland there are two main DNSPs, Energex (South East Queensland) and Ergon Energy Network (regional and rural Queensland).
- Environmental are the Nationally legislated renewable energy incentives schemes (LGCs and STCs).
- Metering are companies appointed to manage the electricity metering hardware and data requirements.
- Australian Energy Market Operator (AEMO) is responsible for technical and commercial operation of the national energy market.
- Retail companies buy energy from the wholesale market and sell energy to residential and business customers, as well as coordinate all the electricity bill charges.

Table 15 – Electricity bill elements

Electricity Bill Elements					
Organisation	Fixed charge ($/day)	Volume charge (S/kWh)	Demand charge ($/kW/month or $/kVA/month)	Capacity charge ($/kVA)	Other
TNSP	✓	✓	✓		
DNSP	✓	✓	✓	✓	
Environmental		✓			
Metering	✓				
AEMO		✓			
Retail		✓			✓

For a centralised BESS, the DNSP/TNSP network charges are expected to make up most electricity use costs. Energex and Ergon Energy Network have dedicated tariffs, based on customer type as well as energy and demand use. The following sections describe the Ergon Energy Network tariff options.

9.2.1 Ergon Energy Network Tariff Classes

Ergon Energy Network assign customers to one of three tariff classes; SAC, CAC, or ICC.[87]

Standard Asset Customer (SAC) are all customers connected at LV with installed capacity up to 1,000 kVA are assigned to the SAC tariff class.

> SAC Small – A small customer is defined in the National Energy Retail Law (Queensland) Act 2014 as an LV customer with annual energy consumption up to 100 MWh (typically residential and small business customers).
>
> SAC Large – A large customer is defined as an LV customer with annual energy consumption greater than 100 MWh or more (typically large business customers).

Connection Asset Customers (CAC) are customers with a network coupling point at 66kV, 33kV, 22kV or 11kV and installed capacity above 1,000 kVA who are not assigned to the ICC tariff class (typically large industrial customers).

Individually Calculated Customers (ICC) are all customers coupled to the network at 132kV, 110kV, 66kV or 33kV and with installed capacity above 10 MVA (typically very large customers e.g., mine sites). A customer may also be assigned to ICC with an installed capacity below 10MVA if other criteria are met.

9.2.2 Tariff Class Impact on BESS Sizing

With a network distribution voltage of 11kV on Magnetic Island, there can only be SAC Small, SAC Large and CAC customers connected.

SAC Small would equate to a centralised BESS size of approximately 140kW (assuming 280kWh capacity for a 2-hour BESS operating at 1 cycle / day) or smaller. As discussed above, this sizing is

[87] Ergon Energy Network, Tariff Structure Statement, 2025-30 Regulatory Determination Proposal, Section 2 & 3, Ergon - Tariff Structure Statement - Compliance Statement - November 2024 - public.pdf

likely too small for a centralised BESS as there would be limited interest from electricity retailers to enter into an agreement for market participation.

SAC Large would include a centralised BESS of 1MVA or smaller whereas a CAC would include a centralised BESS above 1MVA. The network tariffs costs for SAC Large and CAC customers can differ significantly.

9.2.3 Applicable Network Tariffs

The Ergon Energy network tariffs for SAC Large and CAC customers in the 2025-2030 regulatory period that would be an option for a centralised solar and/or BESS include:

SAC Large

- East Large ToU Demand & Energy (SACELTOUDT1)
- East Demand Small (SACEDSTT1)
- East Dynamic Flex Storage (SACETBA8T1) – (Storage only)

CAC

- East CAC22/11kVLine Anytime (CACEC22LT1)
- East HV Line ToU Demand (CACETBA1T1)
- East CAC Dynamic Flex Storage (CACECFLEXT1) – (Storage only)

Each of the applicable tariffs have different tariff components which are summarised in Table 16 below. For an explanation of each of the tariff components, see Appendix C, Section 22.2.

Table 16 - Components of Applicable Tariffs

Ergon Energy Network Tariff components – Applicable Tariffs									
Network Tariff	**Network Tariff Code**	**Fixed charge ($/day)**	**Volume charge (S/kWh)**		**Demand charge ($/kW/month or $/kVA/month)**		**Capacity charge ($/kVA)**	**Connection unit ($/day/unit)**	**Metering Services Charge ($/day)**
			Flat	Time of Use	Flat	Time of Use			
SAC Large									
East Large ToU Demand & Energy	SACELTOUDT1	✓		✓		✓			✓
East Demand Small	SACEDSTT1	✓	✓		✓				✓
East Dynamic Flex Storage	SACETBA8T1	✓		✓					✓
CAC									
East CAC22/ 11kVLine Anytime	CACEC22LT1	✓	✓		✓		✓	✓	
East HV Line ToU Demand	CACETBA1T1	✓	✓			✓			
East CAC Dynamic Flex Storage	CACECFLEXT1	✓		✓					

Storage Only Tariffs

From the 1st of July 2025, Ergon Energy Network will introduce Dynamic Flex Storage tariffs available for low voltage (SAC Large) and high voltage (CAC) connections.

Eligibility for the tariff will be based on technical and operational considerations associated with the connection, including:

- the connection demonstrating import from the network for the primary purpose of exporting back to the network
- customers entering a Dynamic Connection Agreement, which stipulates network determined DOEs

There are essentially only 2 components of the new LV and HV Dynamic Flex Storage tariffs:

- Fixed charge $/day
  - Daily supply charge
- Volume peak charge $/kWh
  - For energy consumption between the hours of 5pm and 8pm

Applicable Tariff Comparison

To compare all applicable SAC Large and CAC network tariffs, a 1 MW/2 MWh BESS has been modelled to participate in the wholesale and FCAS markets with each tariff. Table 17 shows the estimated annual charges for each applicable tariff using Ergon Energy Network's indicative prices for 2025/26.

Table 17 - Ergon Energy Network Applicable Tariff Annual Costs 1 MW/2 MWh BESS – 2025/26 Pricing

Ergon Energy Network Tariff Annual Costs 1 MW/2 MWh BESS – 2025-26 Pricing						
Tariff Name	**Network Tariff Code**	**Energy Charges**	**Demand Charges**	**Fixed Charges**	**Capacity Charges**	**Total**
SAC Large						
East Large ToU Demand&Energy	SACELTOUDT1	$36,406	$103,655	$17,506	-	$157,567
East Demand Small	SACEDSTT1	$34,721	$260,239	$19,066	-	$314,026
East Large Dynamic Flex Storage	SACETBA8T1	$11	-	$17,506	-	$17,518
CAC						
East CAC22/11kVLine Anytime	CACEC22LT1	$20,633	$125,847	$39,382	$106,424	$292,286
East CAC HV Line ToU Demand	CACETBA1T1	$9,767	$167,177	$61,998	-	$238,942
East CAC Dynamic Flex Storage	CACECFLEXT1	$7	-	$37,138	-	**$37,138**

The Dynamic Flex Storage tariffs are significantly more economical network tariffs. The storage tariffs have no demand charges, and the only usage charge applies between 5pm and 8pm daily, when the BESS is much more likely to discharge. This means that most of the total charges for the Dynamic Flex Storage tariffs are fixed charges.

The fixed charge component of the network tariff is very important to consider as no matter how the site operates (i.e., how energy is exported or imported from the site), the fixed charges cannot be changed.

The annual fixed costs range from $17,506 to $19,066 for SAC Large tariffs and from $37,138 to $61,998 for CAC tariffs. If comparing the Dynamic Flex Storage tariff, a BESS connection on this tariff would pay $17,506 per annum if sized 1 MVA or smaller, compared to $37,138 per annum if sized greater than 1 MVA. By keeping the BESS sized no greater than 1 MVA, approximately $19,140/year could be saved (based on 2025-26 published Ergon Energy Network tariff prices).

Network Tariff Trials

In 2025-26 Ergon Energy Network will trial Dynamic Price Storage tariffs. This trial will test how to implement prices that only signal costs during critical system events and the ability of storage customers to respond to these price signals. [88]

The intention is to incentivise BESS owners to export to the grid during DNSP critical peak events. Ergon Energy Network would notify customers, in the specific location of the constraint, of critical peak reward periods and prices where they could use their BESS to export and earn a $/kW and/or $/kWh reward.

Depending on the outcome of the trials to be conducted between 2025 and 2030, a network tariff like the Dynamic Price Storage Tariff may be formally introduced in the next regulatory period of 2030-2035.

10. Economic Return

10.1. Types of Economic Return

There are multiple avenues of achieving economic return for batteries. These include:

- Electricity Bill Savings
- Electricity Market Participation
- Network Support
- Emissions Reduction Incentives

10.1.1 Electricity Bill Savings

For a battery installed behind the meter at a site, this could achieve savings on electricity bills by:

- Storing excess solar PV energy on site to be used later and avoid paying grid consumption $/kWh cost.

  Storing excess energy that would otherwise be curtailed (if a zero-export connection agreement with the DNSP) or exported to the gird for no or little monetary reward, to be used to supply the site load later. If a feed in tariff is available, the $/kWh reward is typically much lower than the grid consumption $/kWh cost.

[88] Ergon Energy Network, Section 3.8 Network Tariff Trials, Ergon - Tariff Structure Statement - Compliance Statement - November 2024 - public.pdf

- Demand management to reduce electricity tariff charges with 'time of use' energy or demand charges.

  By storing solar PV energy or grid energy during off-peak or shoulder periods, when electricity is less expensive, the stored energy can be discharged during peak periods, when electricity is more expensive or when a demand charge applies. Time of use energy windows are shown as an example in Figure 44 below.

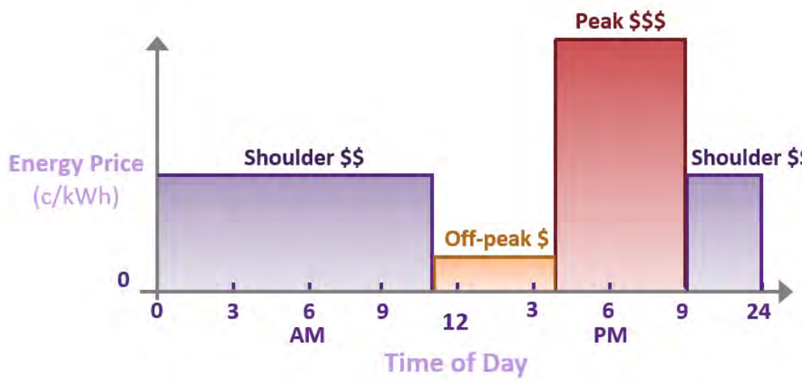


Figure 44 – Example time of use energy tariff periods

  If a time of use or anytime demand charge is applicable, the BESS can be programmed to charge from solar PV or the grid during low cost periods and discharge during high cost periods. This helps flatten the site's load during peak demand windows. A time of use demand charge window is shown as an example in Figure 45 below.

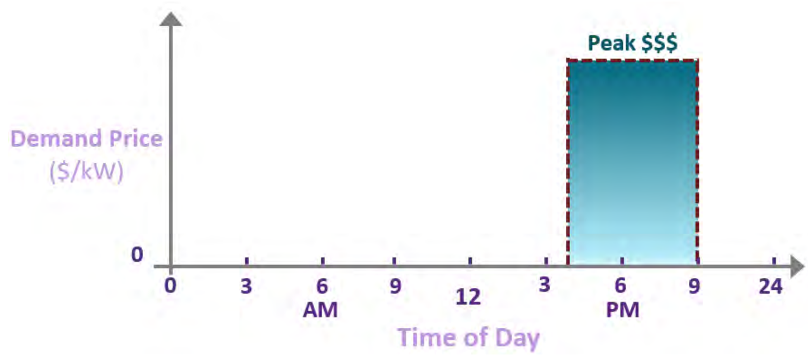


Figure 45 – Example time of use demand component period (4pm to 9pm)

  Typically, a demand charge is applied monthly and is calculated by identifying the highest average demand (in kW or kVA) over a 30-minute interval within the applicable time window. This peak demand value is then multiplied by the demand rate (in $/kW or $/kVA) to determine the total demand charge for the month.

In some scenarios, residents or business customers with solar PV installed can opt into arrangements where instead of using their own battery to store their excess solar PV energy to use later, they use a community battery. This can directly save the customer money if they can buy back their own solar PV energy at a cheaper price than energy they consume from the grid. This requires a specific arrangement with an electricity retailer.

10.1.2 Electricity Market Participation

Electricity retailers can operate batteries to generate revenue in markets via energy arbitrage and network auxiliary services. The asset owner of a BESS can earn additional revenue from market participation through an agreement with an electricity retailer, who have the necessary registrations to participate in the markets.

Wholesale

The National Electricity Market (NEM) is an integrated electricity market and power system operating across Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania, and South Australia.

AEMO is the independent energy market and system operator and system planner for the NEM. The transport of electricity from generators to consumers is facilitated through a wholesale energy 'pool', or spot market, where the output from all generators is aggregated and scheduled at five-minute intervals to meet demand.

Energy arbitrage refers to the buying energy at low prices and selling energy at high prices in the NEM. During low demand periods, wholesale prices are often low or even negative (when prices drop below zero, making it profitable for batteries to charge), allowing batteries to store energy at no cost or a reduced cost. Later, when demand rises and prices increase, the batteries discharge and sell back energy to the grid at a higher price, making a profit from the price differential.

Frequency Control Ancillary Services (FCAS)

FCAS is a market which groups services that help maintain the NEM power system frequency at 50 Hz, which requires maintaining the demand/generation balance across the NEM. The FCAS market allows AEMO to send price signals to generators/loads to increase generation/demand when needed. A battery can participate as both a generator and a load in the FCAS market.

The minimum generation/load quantity to participate in the FCAS market is currently 1MW. If a battery has a capacity less than 1 MW, it can still be used if participating in an aggregation scheme where individual assets at separate locations across the NEM can be aggregated to contribute as one group.

10.1.3 Network Support

Through an agreement with the local DNSP, a battery can be used to provide network support services by assisting to manage network demand. Demand Management can defer costly network upgrades, which would otherwise be passed on to all network customers through their electricity bills. To support the network, the battery would store electricity during times of low demand (typically middle of the day when solar PV generation is high) and discharge during high demand events (typically the evening) as determined by the DNSP.

Operating the BESS in this way increases the resilience of the network by reducing the risk of network failure during high demand events and increases network asset utilisation by helping to flatten the load on the network.

For Ergon Energy Network, this type of network support opportunity is currently offered through their feeder constraints program. Each year, the Ergon Energy Network Demand Management team release a Request for Proposal (RFP) for solutions to help manage network constraints and/or limitations in certain target areas. These solutions could comprise of one or a combination of embedded generation or battery storage systems, call-off load, load shift or other demand-side load management solutions.11

Ergon Energy Network offer between $20/kVA and $100/kVA per annum depending on the target area and network augmentation deferral benefit. In their RFP they advise that the demand response required is approximately 500 kVA per network event request, where additional kVA would be considered. The duration of each even could be up to 6 hours duration with up to 10 network support events during the nominated network support period.[89]

10.1.4 Government Incentives

Renewable Energy Target (RET)

The Renewable Energy Target (RET) is an Australian Government scheme, governed by the Clean Energy Regulator, that aims to reduce greenhouse gas emissions in the electricity sector and increase renewable electricity generation. Within the RET, there are two sub-schemes; the Large-scale Renewable Energy Target (LRET) and the Small-scale Renewable Energy Scheme (SRES).[90] The RET has a current end of 2030.

Small-scale technology certificates (STCs), the renewable energy certificates (RECs) as part of the SRES, are applicable to solar PV systems 100 kWp or less. Once an eligible solar PV system is installed, STCs can be created and sold. The quantity of STCs depends on geographical location, install date, system size and deeming period.

Large-scale generation certificates (LGCs), the RECs as part of the LRET, are applicable to solar PV systems greater than 100 kWp. LGCs can be created based on the energy output of the eligible solar PV system and sold (an LGC is equal to 1 MWh of renewable energy generated). LGCs are typically created annually and can be sold on the secondary market or directly to liable entities through power purchase agreements.

Large-scale Generation Certificates

When coupled with solar PV greater than 100 kWp, a BESS could enable more solar PV energy generation at a site if the solar PV would otherwise be curtailed. This would enable the asset owner to generate more LGCs.

If an existing solar PV system, 100 kWp or less, is upgraded to a larger size so that the new total system capacity exceeds 100 kWp, LGCs are applicable. It should be noted that LGCs can only be created from the additional capacity, and not the existing capacity that was already used to claim STCs. For example, if an existing 70 kWp solar PV system is upgraded to 150 kWp, LGCs can only be created based on the energy output of the additional 80 kWp and not the total 150 kWp.

If installed with a solar PV system that has been upgraded in this way, a BESS could enable more solar PV generation if it would be otherwise curtailed, enabling the asset owner to generate more LGCs for the additional solar PV capacity.

The Cheaper Home Batteries Program

The Cheaper Home Batteries Program is an Australian Government initiative launched on 1 July 2025, aiming to make small-scale battery systems more affordable for households, small

[89] Ergon Energy Network, Feeder limitations | Ergon Energy
[90] Australian Government, Clean Energy Regulator, https://cer.gov.au/schemes/renewable-energy-target

businesses, and community facilities. The program offers an approximately 30% upfront discount on eligible battery installations, delivered through the SRES.

Eligible battery systems must[91,]:

- Be connected to new or existing solar PV systems
- Have a nominal capacity between 5 kWh and 100 kWh however the rebate applies to the usable capacity of up to 50 kWh
- Have the technical capability to participate in a VPP (respond to remote signals)
- Be CEC approved

The rebate amount is calculated based on the battery's usable capacity and will gradually decrease until 2030, in line with reducing battery prices[92].

[91] Australian Government, Department of Climate Change, Energy, the Environment and Water, Eligibility information for the Cheaper Home Batteries Program - DCCEEW

[92] Australian Government, Department of Climate Change, Energy, the Environment and Water, Cheaper Home Batteries Program - DCCEEW

10.2. Options for Magnetic Island

Table 18 summarises the potential economic return opportunities for batteries on Magnetic Island.

Table 18 - Potential economic return for BESS for different grid connection types

	Connection Type		
	Home/Business – Behind the Meter (BTM)	Centralised Battery – Low Voltage Coupled Up to 315 KVA	Centralised Battery – Medium Voltage Coupled Up to 1,500 kVA
Economic Return Category			
Tariff Savings	✓ Beneficial for homes/businesses with excess solar PV and/or a retail tariff with a ToU or demand component. ✓ Eligible for regional solar feed-in tariff if solar is 30 kVA or less.	✗ No load behind meter to service.	✗ No load behind meter to service.
Electricity Market Participation	≈ Virtual Power Plant (VPP) opportunities with electricity Retailers – very limited VPP offering to residential and small business customers in Regional Queensland.	≈ Retailers interested in larger BESS capacities due to the cost per site. Potential to install multiple smaller BESS to aggregate to a capacity that retailers are interested in (~1 MW), which would introduce more complexities in other areas including land use.	✓ Available through agreement with an electricity retailer.
Network Support	✗ No network support opportunities for the foreseeable future. The Distribution Network Planning team at Ergon Energy Network advised that due to the current project to increase capacity, they are not forecasting any new capacity constraints on TM-03 or TM-10 until beyond 2030 based on current growth rates.		
Emissions Reduction Incentives	✓ If co-located with solar, Federal Government Cheaper Home Batteries Program from 1 July 2025 until 2030. ✓ If co-located with new solar PV, STCs available until 2030. ✓ If co-located with existing solar PV, could reduce solar curtailment.	≈ If co-located with solar PV, STCs/LGCs available until 2030.	≈ If co-located with solar PV, STCs/LGCs available until 2030.

11. Operating Model

11.1. Types

According to 'Fast-Tracking Neighbourhood Batteries: A guide for councils and community'[93], there are broadly three kinds of arrangements:

- The owner-operator is responsible for dispatch control, reporting and maintenance
- The owner contracts an operator to manage dispatch by the owner's rules and at a cost to the owner
- The owner leases the battery to an operator for a fee

The table from the published guide in Figure 46 below provides examples of arrangements and the advantages and disadvantages of each. They will not all be options for a Magnetic Island centralised BESS but provide an indication of potential arrangements for non-DNSP owned centralised BESS.

There are many different operating models for community batteries and the most appropriate depends on risk appetite, funding availability, resourcing capability, and the objectives of the battery.

Example arrangement	Owner	Operator	Description	Advantages for councils/ community groups	Disadvantages for councils/ community groups
Single owner-operator	Retailer	Retailer	Council supports a retailer to implement a neighbourhood battery in its LGA (Local Government Area)	• No liability for project/asset • Leverages private capital • Minimal financial contribution required • No additional resourcing or expertise required • Pathway to scaled deployment	• Minimal influence on operations and outcomes (e.g. environmental and community benefits) • No economic return • Reduced benefits from capacity-building, reputation and community element
Council ownership with contracted operator	Council	Retailer	Council facilitates neighbourhood battery implementation and contracts operation to a third-party FRMP	• Retain influence over operations • Receive financial returns • Opportunity for significant capacity-building, knowledge-sharing, reputation benefits, and community engagement • Can cite neighbourhood battery outcomes towards strategic objectives	• Liable for operating expenses (and/or contracted operating fees) • Engenders some financial risk • Resourcing/capacity required to monitor and liaise with operator
Private partnership	Asset developer	Retailer	Council supports project development with asset developer, which contracts operation to a third party FRMP	• See Single owner-operator	• See Single owner-operator
DNSP ownership, leased to operator with council partnership	DNSP	Retailer and council partnership	Council supports a neighbourhood battery project led by DNSP, which then leases the battery to a retailer/ council partnership	• Maintain influence over operations and outcomes with much-reduced risk/liability • Reduced requirement for technical resourcing/capacity due to retailer partnership • Streamlined project delivery through partnership with DNSP	• Potentially competing interests or divergent values between DNSP, retailer and council • May be challenging to establish partnerships that benefit all parties • Minimal economic return • Potentially complex contractual agreements required
Community ownership	Co-operative or community group	Retailer	As part of a neighbourhood battery project, council supports the establishment of a community co-operative which contracts operation to a third-party FRMP	• Reduced liability for council • Direct engagement with, and benefits for, community members • Innovative model and industry leadership	• Increased liability for community group • Financial risk for co-operative may implicate council • Co-operative may require ongoing council support given uncertain technical and commercial capability/capacity
Equity investment	Equity investors	Retailer	Council sources equity investment in a neighbourhood battery; council and the investor group contract operation to a third-party FRMP	• Reduced liability for council • Innovative model and industry leadership • Leverages private capital • If successful, potential for scaled deployment	• Minimal influence on operations and outcomes (e.g. environmental and community benefits) • No or reduced economic return • Unlikely to deliver return on investment

Figure 46 - Advantages and disadvantages of various owner-operator models [Fast-Tracking Neighbourhood Batteries Guide]

[93] Victorian Government Department of Energy, Environment and Climate Action (DEECA), April 2024, https://www.energy.vic.gov.au/__data/assets/pdf_file/0026/703646/fast-tracking-neighbourhood-batteries-guide-april-2024.pdf

11.2. Key Partnerships

11.2.1 Retailer

An agreement with a retailer is required to operate a community battery. Agreements vary depending on a specific retailer's offering. Some retailers offer turn-key solutions including network connection and BESS construction. Some retailers do not offer support for the whole project and are only involved with the ongoing arrangement for the operation of the BESS. If only involved in the ongoing arrangement, a formal agreement might be made only when the asset owner is at a final investment decision (FID), when it is decided that the community battery project is going ahead, providing the asset owner and retailer with a level of certainty.

For a battery that will generate revenue through participation in the wholesale and FCAS markets, arrangements include the following:

- Tolling arrangement
- Tolling arrangement with revenue sharing
- Fixed management fee arrangement

Tolling Arrangement

The BESS tolling arrangement is on a dollar per Megawatt per year rate paid to the asset owner. The retailer would operate and trade the energy charged and discharged by the BESS to maximise profits. The benefit of this arrangement is that the retailer takes the market trading risks and the asset owner can rely on a fixed revenue for the term of the agreement. The barrier for this arrangement is that there is no opportunity for the asset owner to increase revenue through market upside.

Tolling Arrangement with Revenue Sharing

This arrangement is like the tolling arrangement described above, however if the BESS performs significantly better than expected and the revenue exceeds a set amount, the retailer shares a portion of the revenue with the asset owner. This arrangement is not the starting position for retailers and negotiations would be more difficult, if only for 1 or 2 small sites.

Fixed management fee arrangement

A fixed management fee arrangement is the opposite of a tolling arrangement where instead of a fixed revenue to the asset owner, it is a fixed cost. The retailer operates the BESS on behalf of the asset owner for fixed price and the asset owner receives the profit from wholesale market or FCAS. The benefit of this arrangement is the increased potential revenue for the asset owner from market upside. The barrier is the asset owner takes the risk. If the BESS doesn't perform as expected in the markets and the revenue doesn't exceed the retailer fixed management fee, let alone BESS maintenance costs, there is no profit for the asset owner.

11.2.2 Operation and Maintenance Provider

If the asset owner's core business is not operating and maintaining battery energy storage systems, partnering with an operation and maintenance provider, such as an energy service provider, would be the preferred option.

In discussions with retailers during this study, their preference was to have an energy service provider as their agreement counterparty, as these providers possess the experience and technical expertise required to maintain the BESS. The energy service provider will ensure the BESS remains available to the retailer by minimising downtime through preventative and reactive maintenance activities, as well as ensuring the conditions of a performance guarantee are met through regular testing.

11.3. Proposed Operating Model

During this study Yurika approached multiple electricity retailers to gauge interest and understand what arrangements they would offer, if any, for the use of network connected batteries on Magnetic Island. The most developed offer Yurika received was a tolling arrangement with one of Australia's 'big three' energy retailers. The operating model for the proposed BESS is based on this tolling arrangement and the retailer's preference for the agreement counter party to be an energy service provider.

The operating model is shown in Figure 47. This is a low risk option for a BESS owner given the arrangement would provide fixed annual revenue.

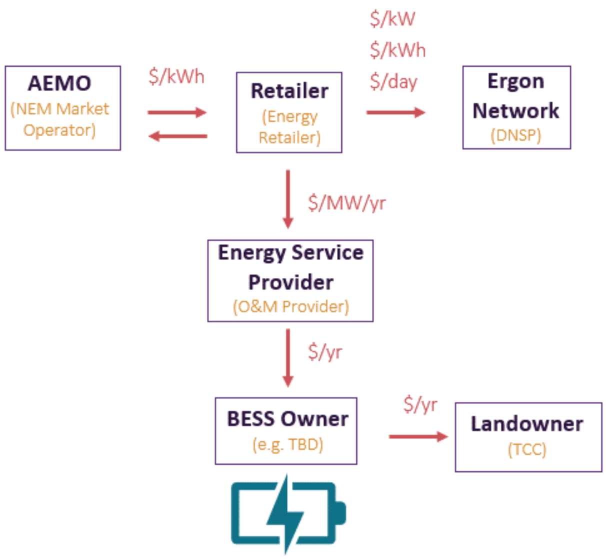


Figure 47 - Proposed Operating Model Magnetic Island Community BESS

The revenue and costs of the key stakeholders in the proposed model are listed in Table 19 below.

Table 19 - Operating model stakeholder revenue and costs

Revenue	Key Stakeholders	Costs
• Use of BESS agreement with Energy Service Provider	**BESS Owner** (e.g., TBD)	• Capital • Land lease • Decommissioning • Insurance
• Use of BESS agreement with Retailer	**Energy Service Provider** (O&M Provider)	• Performance monitoring and reporting • Preventative maintenance • Reactive maintenance
• Wholesale electricity market profit • FCAS market profit	**Retailer** (Electricity Retailer)	• Use of BESS agreement with Energy Service Provider • Ergon Network tariff • Wholesale energy market loss
• Land lease	**Landowner** (TCC)	

12. Concept Design

12.1. Overview

	Horseshoe Bay
BESS Sizing	1 MW / 2 MWh Battery
Village Load	• 23/24 Max Demand = 1,077 kW • 23/24 Average Demand = 366 kW • 23/24 Annual Consumption = 3,310 MWh • 23/24 Avg. Daily Consumption = 9.04 MWh/day
Site	• Horseshoe Bay Park
Reasoning	• Limitation of total inverter capacity to ≤ 1 MW to fit within 'low voltage' category with Ergon Energy Network for tariffs (access to SAC Large tariffs, rather than CAC) • BESS only site due to limited area for ground mount solar PV and to take advantage of new Storage Only network tariffs Ergon Energy Network are introducing 2025/26 • Limited site load to enable behind the meter savings and transformer sizing only 315 kVA • New BESS only network connection via new transformer preferred to achieve larger capacity

Technical Solution Details	• Aggregated 1 MW/2 MWh consisting of 9 x 110 kW/ 225 kWh BESS units - Sungrow ST225kWh-110kW-2h or similar (specific make and model, and individual BESS unit capacity will vary depending on product selection)
	    ◦ Total power capacity: 990 kW
	    ◦ Total energy capacity: 2,061 kWh at beginning of life (BOL)
	    ◦ Battery chemistry: lithium-ion phosphate (LFP)
	• BESS capable of performing FCAS
	• Expected annual throughput: 752 MWh
	• Noise: 70 dB (1 meter from single BESS cabinet)

Network Connection	• Low voltage (LV) connection via new 1 MVA padmount transformer to existing Ergon Energy Network feeder TM-10 • Dynamic Connection with Ergon Energy Network for BESS
Proposed BESS Location	

Figure 48 – Proposed Horseshoe Bay Park BESS location

Picnic Bay

Sizing

1 MW / 2 MWh Battery

Village Load

- 23/24 Max Demand = 792 kW
- 23/24 Average Demand = 259 kW
- 23/24 Annual Consumption = 2,272 MWh
- 23/24 Avg. Daily Consumption = 6.21 MWh/day

Site

- Picnic Bay Landfill Lot 2

Reasoning

- Limitation of total inverter capacity to ≤ 1 MW to fit within 'low voltage' category with Ergon Energy Network for tariffs (access to SAC Large tariffs, rather than CAC)
- BESS only site due to limited area for solar PV and to take advantage of new Storage Only network tariffs Ergon Energy Network are introducing 2025/26
- No site load, a new network connection would be required no matter what size BESS.

Technical Solution Details

- Aggregated 1 MW/2 MWh consisting of 9 x 110 kW/ 225 kWh BESS units - Sungrow ST225kWh-110kW-2h or similar (specific make and model, and individual BESS unit capacity will vary depending on product selection)
    - Total power capacity: 990 kW
    - Total energy capacity: 2,061 kWh at beginning of life (BOL)
    - Battery chemistry: lithium-ion phosphate (LFP)
- BESS capable of performing FCAS
- Expected annual throughput: 752 MWh
- Noise: 70 dB (single BESS cabinet)

Network Connection

- Low voltage (LV) connection via new 1 MVA padmount transformer to existing Ergon Energy Network feeder TM-03
- Dynamic Connection with Ergon Energy Network for BESS

Proposed BESS Location

Figure 49 – Proposed Picnic Bay Landfill Lot 2 BESS location

12.2. BESS Connection

The proposed connection of the centralised BESS for Horseshoe Bay and Picnic Bay is shown in a simplified single line diagram in Figure 50 below.

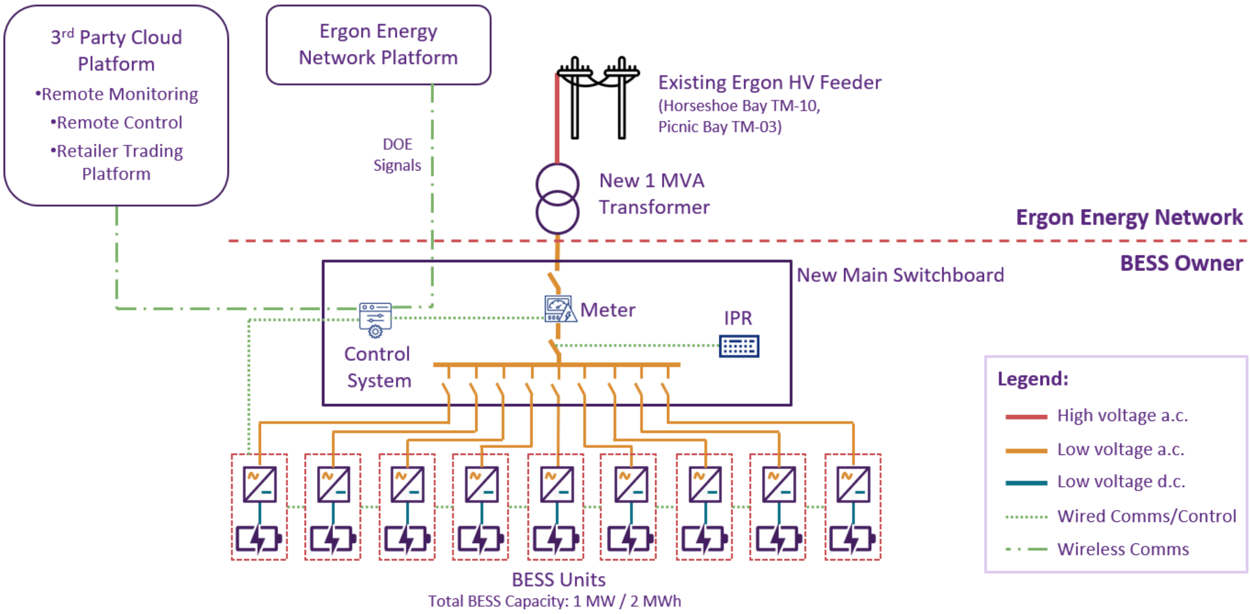


Figure 50 - Proposed BESS electrical diagram

New Main Switchboard - Provides a safe and secure enclosure for the isolators, control system, meters, and grid protection relay.

Control System - Communicates with the main components of the installation to enable remote access, control the operation of the BESS, and collect asset interval data.

Interface Protection Relay (IPR) - Provides a second level of system safety to ensure the BESS system is compliant with grid conditions and can safely disconnect from the grid if there are issues detected.

Meter - Captures the grid import/export data to provide as an input to the control system.

BESS Units - Manufactured in a dedicated enclosure as a complete integrated package with a battery system, power conversion equipment and protection devices. The BESS converts a.c. power to d.c. power, charging rechargeable batteries to store electrical energy as chemical energy. When required, the BESS converts the d.c. power to a.c. power to supply the grid.

3rd Party Cloud Platform - Enables the BESS asset owner and the O&M provider the ability to monitor and control the centralised BESS. As per an agreement, this platform will also allow the electricity retailer access to control the BESS for market participation.

Ergon Energy Network Platform – As part of the dynamic network connection agreement, the platform sends DOE signals to the centralised BESS in 5-minute intervals to communicate how much power can be exported to the grid at that point in time.

New 1 MVA Transformer – To connect a 1 MVA BESS to the 11 kV network, Ergon Network will install and maintain a new padmount transformer on an easement within the proposed parcel of land. This was specified in the Preliminary Response to Enquiry that Ergon Energy Network provided to connect the proposed BESS at each site as summarised in Section 13.

12.3. Land Requirements

Figure 51 shows the proposed BESS area layout. The total area is 15.5 m by 11.5 m (179 m^2).

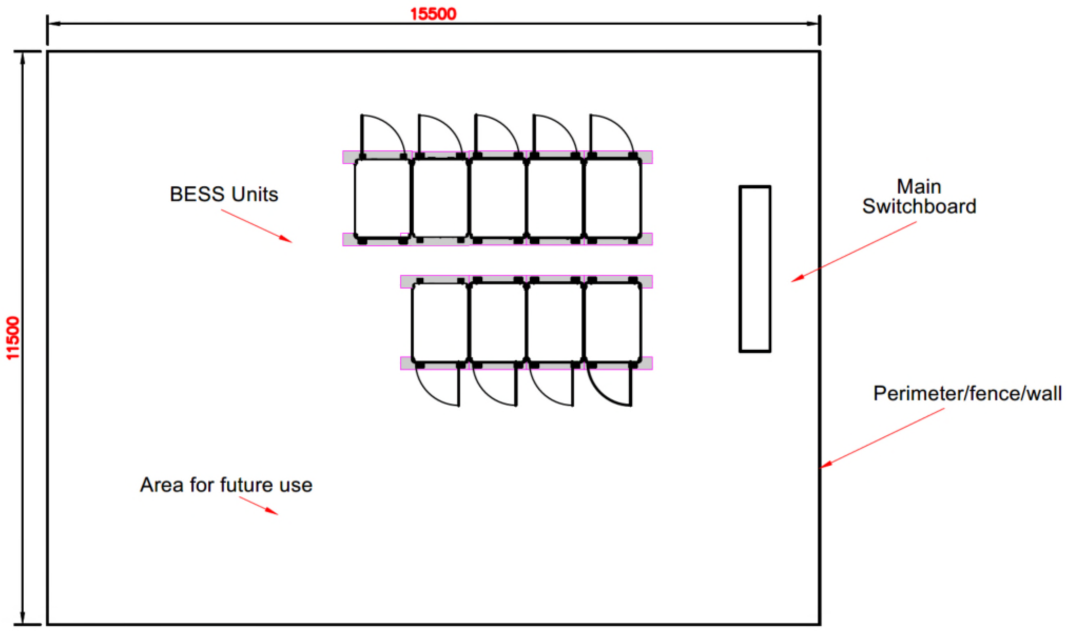


Figure 51 - Proposed BESS Area Layout

This concept is based on nine of the Sungrow 110 kVA/225 kWh PowerStack Liquid Cooled C&I Energy Storage System units (as shown in Figure 52). The physical dimensions of each unit are 1.15 m wide x 2.45 m high x 1.61 m deep.

The proposed BESS area layout allows for future expansion. If providing backup power to the 11 kV distribution network, for future network support service, additional equipment would be required. For the Sungrow BESS, an additional 250 kVA isolation transformer would be required per two BESS units (as shown in Figure 53). The physical dimensions of each unit are 1.20 m wide x 2.00 m high x 1.2 m deep.

Figure 52 - Sungrow 110 kVA/225 kWh PowerStack BESS

Figure 53 – Two Sungrow 110 kVA/225 kWh PowerStack BESS units with 250 kVA Isolation Transformer

The BESS area requirements will depend on the specific make and model of BESS units used, the quantity to achieve the desired total size and the manufacturer's clearance requirements between units for temperature control purposes and access.

13. Ergon Energy Network Preliminary Assessment

A site specific advice request for the proposed 1 MW/2 MWh BESS at each proposed site was submitted to Ergon Energy Network in October 2024. Ergon Energy Network provided a quote to Yurika on 15 January 2025 which was accepted to proceed with the preliminary assessment.

Ergon Energy Network provided a Preliminary Response to Enquiry (PRE) for each site on 26 May 2025. The PRE is to provide preliminary information based on a desktop assessment of the proposed connection. The PRE results are current at the time, however not guaranteed to stay the same into the future. Changes to the distribution system (e.g., network, load profiles, installed solar PV and BESS capacities) may impact the accuracy of the preliminary assessment results in the PRE.

13.1. Preliminary Response Summary

13.1.1 Horseshoe Bay Network Augmentation

Ergon Energy Network provided one available connection option to connect a 1 MW/2 MWh BESS at Horseshoe Bay Park which is to establish a new LV connection from TM-10.

It is proposed to install a new 1 MVA padmount distribution transformer within an Ergon Energy easement on the south-east corner of Horseshoe Bay Park. The response confirmed that the new connection must be a minimum of 200 m from any existing LV network connection on the same parcel of land (the nearest being the Rural Fire Brigade) to ensure compliance with the QECM.

To allow the connection of the proposed capacity of 1 MW, Ergon Energy Network has specified the following works:

1. Install new 1 MVA padmount distribution transformer
2. Upgrade 240 m of underground 11 kV cable
3. Install new 340 m of underground 11 kV cable
4. Install a new power pole
5. Implement necessary protection and communication schemes as required

Ergon Energy Network have provided an estimated cost of $274,811 (incl. GST and accuracy of ± 50%). This does not include fees associated with the connection application process, which Ergon Energy Network have estimated to be in the order of $43,802 - $46,000 (incl. GST).

13.1.2 Horseshoe Bay Preliminary Ergon Assessment

The outcome of the Preliminary Screening Study showed that the proposed capacity of 1 MW would need to have a dynamic network connection agreement rather than a fixed connection agreement.

If the BESS were to be connected to TM-10 via a fixed network connection agreement, the fixed export limitation is estimated to be only 77 kW. This ensures the voltage remains within the acceptable range to customers on the same HV feeder.

If the BESS were to be connected to TM-10 via a dynamic network connection agreement, a preliminary indication of maximum dynamic export and import limit is the full capacity of the proposed BESS.

13.1.3 Picnic Bay Network Augmentation

Ergon Energy Network provided two available connection options to connect a 1 MW/2 MWh BESS at Picnic Bay Landfill Lot 2 which include:

Option 1: Establish a new LV connection from TM-03.

Option 2: Establish a new 11 kV connection from TM-03.

To allow the connection of the proposed capacity of 1 MW, Ergon Energy Network has specified the following works:

Option 1 (LV):

- Install new 1 MVA padmount distribution transformer within an Ergon Energy easement on Picnic Bay Landfill Lot 2.
- Extend 230 m of 11 kV overhead line.
- Install new 80 m of underground 11 kV cable.
- Implement necessary protection and communication schemes as required.

Ergon Energy Network have provided an estimated cost of $198,340 (incl. GST and accuracy of ± 50%).

Option 2 (HV):

- Extend 300 m of 11 kV overhead line.
- Install new Automatic Circuit Recloser (ACR) with remote communications equipment on a new power pole within an Ergon Energy easement on Picnic Bay Landfill Lot 2.
- Implement necessary protection and communication schemes as required.

Ergon Energy Network have provided an estimated cost of $107,314 (incl. GST and accuracy of ± 50%). This option requires a customer owned transformer to step up the LV output of the BESS to connect to the 11 kV HV connection point. This increases the cost to the customer to construct and maintain.

Both Option 1 and Option 2 estimates do not include fees associated with the connection application process, which Ergon Energy Network have estimated to be in the order of $42,694 - $47,690 (incl. GST).

13.1.4 Picnic Bay Preliminary Ergon Assessment

The outcome of the Preliminary Screening Study showed that the proposed capacity of 1 MW would need to have a dynamic network connection agreement rather than a fixed connection agreement.

If the BESS were to be connected to TM-03 via a fixed network connection agreement, the fixed export limitation is estimated to be only 157 kW. This ensures the voltage remains within the acceptable range to customers on the same HV feeder.

If the BESS were to be connected to TM-03 via a dynamic network connection agreement, a preliminary indication of maximum dynamic export and import limit is the full capacity of the proposed BESS.

13.2. Project Impact

The key learnings from the Ergon Energy Network PREs that impact potential centralised BESS include the following:

- For a capacity over 77 kW for Horseshoe Bay and 157 kW for Picnic Bay, the BESS is not expected to be approved for a fixed network connection. A dynamic network connection is then the only option.

  As per the nature of a dynamic connection (discussed in Section 9.2 of this report), the import and export limit can be reduced to a minimum of 1.5 kW during times when the network is constrained. Although a preliminary indication shows a maximum import and export could be the full capacity of 990 kW, there is no guarantee for what percentage of time the full capacity will be allowed.

  This is not expected to be a problem for how the BESS is expected to operate when participating in the wholesale market as it will align with a solar soaking BESS operation profile. FCAS events are less predictable with what time of day they occur which poses a risk that the BESS will be constrained by a dynamic limit when required to be available for FCAS.

  The 77 kW and 157 kW preliminary fixed limits may provide an indication of what lower dynamic limit may be imposed on a 1 MW BESS in Horseshoe Bay and Picnic Bay respectively. However, this is based on current state and could change for better or for worse as more solar PV and BESS capacity is added and the feeder load profile changes.

- The network connection for Horseshoe Bay Park cannot be within 200 m of the existing LV network connection to the Rural Fire Brigade to comply with the QECM. As shown in Figure 54, this limits the potential location along Gifford St.

Figure 54 - Horseshoe Bay Park 200m distance from existing LV network connection

14. Project Implementation

14.1. Project Development

14.1.1 Community Engagement

As outlined in Section 2.1 of this report, TRM has undertaken community engagement over many years. During this study, Yurika did not directly conduct community engagement. Instead, the approach was for community engagement responsibility to remain with MICDA/TRM as they are an established part of the community and well-known to its members. Yurika provided support by offering information, materials, and participation in any community engagement events.

Community engagement is an important aspect in developing a centralised BESS project, particularly for a centralised BESS located close to or within shared public spaces or close to residential properties.

If a centralised BESS is the preferred solution, it is expected that MICDA/TRM will continue to build on their community engagement efforts to date as engaging local stakeholders is critical for project success. Feedback through community engagement can influence several project elements such as location, appearance and benefit sharing approaches. If local stakeholders are not engaged, community pushback could pose a risk to project delivery, costs, and reputation.

14.1.2 Land Access for Proposed Locations

The proposed centralised BESS locations, Horseshoe Bay Park and Picnic Bay Landfill Lot 2, are Council-controlled land. A leasing agreement to use the proposed BESS areas between the BESS owner and Townsville City Council will be required.

Townsville City Council have a Community Leasing and Licence Agreement Policy[94]. This policy applies to all tenure agreements for use of Council-controlled lands and provides guidance to Council works to negotiate tenure agreements. The policy does not apply to commercial leases.

It is not determined what entity would be the asset owner for the proposed centralised BESS options. As per the policy, to be eligible for tenure of Council-controlled land, a community organisation must:

- be an incorporated association or equivalent;
- maintain all necessary insurances as determined by Council; and,
- meet one of the following categories:
    - sport;
    - recreation;
    - community;
    - cultural; or,
    - environmental.

For the purposes of tenancy negotiation, all tenures shall be classified into one of the categories as outlined in Appendix A of the policy that outlines the classification of tenure categories. The tenure categories include the following:

- Category 1a – Small Volunteer Community Groups
- Category 1b – Not for Profit Community Groups and Organisations

[94] Townsville City Council, ECM_26336760_v2_Community Leasing and Licence Agreement Policy

- Category 2 – Sporting Clubs and Recreational Groups
- Category 3 – Large Not for Profit Organisations, State or National Clubs / Associations

If a community organisation, the BESS asset owner would most likely fit within Category 1b or Category 3 shown in Figure 55 and Figure 56.

Category 1b – Not for Profit Community Groups and Organisations

Locally based not-for-profit organisation, club, or community group run by volunteers or paid workers and are incorporated. Their primary base of operations located within the Townsville LGA. Demonstrates an affordable membership regime and land programs and activities that add value to the social and community fabric of Townsville. Has the capacity to generate revenue through membership, use of the premises, or activities consistent with the organisations purpose.

Category 1b - Not for Profit Community Groups and Organisations

Criteria: Locally based not-for-profit organisation, club, or community group run by volunteers or paid workers and are incorporated. Their primary base of operations located within the Townsville LGA. Demonstrates an affordable membership regime and land programs and activities that add value to the social and community fabric of Townsville. Has the capacity to generate revenue through membership, use of the premises, or activities consistent with the organisations purpose.	
Tenancy Term	Minimum term of 2 years - Maximum term of 10 years
Lease and fee charges	Annual rent: $1 Outgoings: • Emergency Services Levy • All utility costs related to the tenant's use of the premises • Waste charges • Annual routine maintenance charges applicable to the land • Rates (discounted)
Tenant Obligations	• Contents, Public Liability Insurance and any other insurances associated with the tenant's use of the land • Internal and external cleaning (including annual carpet cleaning) • Consumables associated with the land and the tenant's use. • Pest control • Minor general maintenance of the premises such as the repair and replacement of fittings and fixtures including light globes, taps, toilets, paper towel/roll dispensers and clearing of plumbing blockages caused by the tenant's use.
Council Obligations	• Structural maintenance • Capital improvements • Annual termite inspections and treatment as required (subject to tenant meeting pest control obligations outlined in the agreement) • Graffiti removal

Figure 55 - Townsville City Council Community Leasing and Licence Agreement Policy Category 1b

Category 3 – Large Not for Profit Organisations, State or National Clubs / Associations

Large not-for-profit groups that are professional organisations with paid staff and are generally government funded, externally funded, or generates its own revenue through membership fees, events, venue hire, services, or other means consistent with the organisations purpose.

Category 3 - Large Not for Profit Organisations, State or National Clubs / Associations

Criteria: Large not-for-profit groups that are professional organisations with paid staff and are generally government funded, externally funded, or generates its own revenue through membership fees, events, venue hire, services, or other means consistent with the organisations purpose.	
Tenancy Term	Minimum term of 2 years - Maximum term of 10 years
Lease and fee charges	Annual rent: Between 20%- 80% of market valuation plus GST, or as otherwise determined by Council following a tender process. Outgoings: • Emergency Services Levy • All utility costs related to the tenant's use of the premises • Waste charges • Annual routine maintenance charges applicable to the land • Rates (discounted)
Tenant Obligations	• Contents, Public Liability Insurance and any other insurances associated with the tenant's use of the land • Internal and external cleaning (including annual carpet cleaning) • Consumables associated with the land and the tenant's use. • Pest control • Minor general maintenance of the premises such as the repair and replacement of fittings and fixtures including light globes, taps, toilets, paper towel/roll dispensers and clearing of plumbing blockages caused by the tenant's use. • Capital improvements
Council Obligations	• Structural maintenance • Annual termite inspections and treatment as required (subject to tenant meeting pest control obligations outlined in the agreement) • Graffiti removal

Figure 56 - Townsville City Council Community Leasing and Licence Agreement Policy Category 3

If the BESS asset owner does not fall within one of these categories, a commercial lease would need to be explored with Townsville City Council.

14.1.3 Planning and Development Approvals

Battery storage facilities are not currently defined by the Townsville City Council planning scheme[95], however this use is being added to the list of defined uses in schedule 1 as part of an amendment to the planning scheme. This is likely to be finalised in the next few months[96].

TCC Planning and Development have advised the development of a Battery storage facility will be 'Impact Assessable', requiring a development application under the Planning Act 2016 for a Material Change of Use (MCU).

A development application for a similar battery storage facility development in Townville City Council LGA, the 4 MW battery in Bohle Plains, was lodged by a town planning service provider in 2019 (Ref number: MCU19/0035)[97]. Supporting documents for this development application included the following:

- Landowner's consent to making the development application
- Concept plan
- Proposal Plan
- Engineering Services Report
- Environmental Report

The duration from the submission of the development application to approval was 4 months.

After receiving MCU approval and the appeal period ends (usually 20 business days), the conditions of the development permit must be met. This may include getting further approvals from council, works onsite, or compliance assessment.

[95] Townsville City Council, Current City Plan
[96] Townsville City Council, Planning and Development team, January 2025
[97] Townsville City Council, Ref Number: MCU19/0035 development application, https://eplanning.townsville.qld.gov.au/Pages/xc.track/SearchApplication.aspx?id=2224827

TCC offer pre-lodgement meeting (free of charge) to provide feedback on proposed developments in the early planning stages. Issues can be identified to resolve before a development application is submitted to make the process more efficient.

Additional information on MCU is provided in the Townsville City Council factsheet in report section 20.3.

14.1.4 Environmental Approval

The Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act) is Australia's main environmental law. It provides a legal framework to protect and manage unique plants, animals, habitats, and places.[98]

If a project will have, or is likely to have, a significant impact on a matter of national environmental significance, that action must be referred to the minister for Environment and Water for a decision on whether assessment and approval is required under the Act.

The matters of national environmental significance relevant to Magnetic Island include the following:

- World heritage properties
- National heritage places
- Great Barrier Reef Marine Park
- Nationally threatened species and ecological communities

As Magnetic Island is part of the Great Barrier Reef World Heritage Area and has a number of listed threatened species for the area, a referral may be required under the Act.

If it is decided that a referral is required, the duration to prepare the referral information and supporting documents (e.g., results from environmental surveys) may vary. When submitting a referral and paying the fee (if applicable), it will take 20 business days for a decision (more if additional information is requested).

If the referral decision is not a controlled action (meaning the project is unlikely to have a significant impact on protected matters), no further assessment is needed, and the project can proceed as described in the referral.

If the referral decision is that the project is a controlled action, a formal assessment is required. Each method of assessment takes a different amount of time and additional fees may apply.

Australian Government Department of Climate Change, Energy, the Environment and Water (DCCEEW) offer a pre-referral meeting service (free of charge) where an assessment officer. The assessment officer cannot advise to refer the project but can discuss the project and outline the responsibilities under the EPBC Act to help decide if a referral is required.[99]

14.1.5 Key Partnerships for Operation

During the project development stage, key partnerships should be developed and locked in to have a clear understanding of the expected revenue and costs when operating the proposed centralised BESS. This could be done in many ways.

[98] Australian Government, Department of Climate Change, Energy, the Environment and Water, What's protected under the EPBC Act - DCCEEW
[99] Australian Government, Department of Climate Change, Energy, the Environment and Water, Referrals and environmental assessments under the EPBC Act, Referrals and environmental assessments under the EPBC Act - DCCEEW

Electricity Retailer

Electricity retailer offers, and their level of involvement in the development of a project such as this, will vary. This essential agreement with an electricity retailer should be developed and in place before the final investment decision so there is certainty on the revenue side of the financial model for the BESS.

O&M Provider

As discussed in Section 11.2, if the asset owner's core business is not operating and maintaining battery energy storage systems, an operation and maintenance (O&M) provider is required. If the preference of the electricity retailer is to have the O&M provider as the agreement counterparty, this partnership will need to be developed and put in place along with the electricity retailer.

14.2. Project Delivery

Once the project development phase is complete and the project is confirmed to go ahead. The asset owner can engage an energy service provider to engineer, procure & construct (EPC) the solution.

14.2.1 Estimated Timeline

A high-level timeline to deliver 1 MW/ 2 MWh BESS solution at Horseshoe Bay Park or Picnic Bay Landfill Lot 2 is shown in Figure 57. The project is expected to take approximately 72 weeks to complete.

Element	No. of Workdays	No. of Weeks
Electrical and Structural Design	**236 days**	**47**
5% Design	19 days	4
50% Design	42 days	8
85% Design	17 days	3
100% Design	15 days	3
Network Connections	**212 days**	**42**
Embedded Generation Enquiry	75 days	15
Embedded Generation Application - Technical Assessment	45 days	9
Embedded Generation Application - DCR/Additional Info	65 days	13
Embdedded Generation Offer & Acceptance	10 days	2
Procurement	**150 days**	**30**
BESS Units	150 days	30
MSB	70 days	14
Installation	**42 days**	**8**
Civil	29 days	6
Electrical	13 days	3
Test and Commission	**26 days**	**5**
Project Close out	**12 days**	**2**

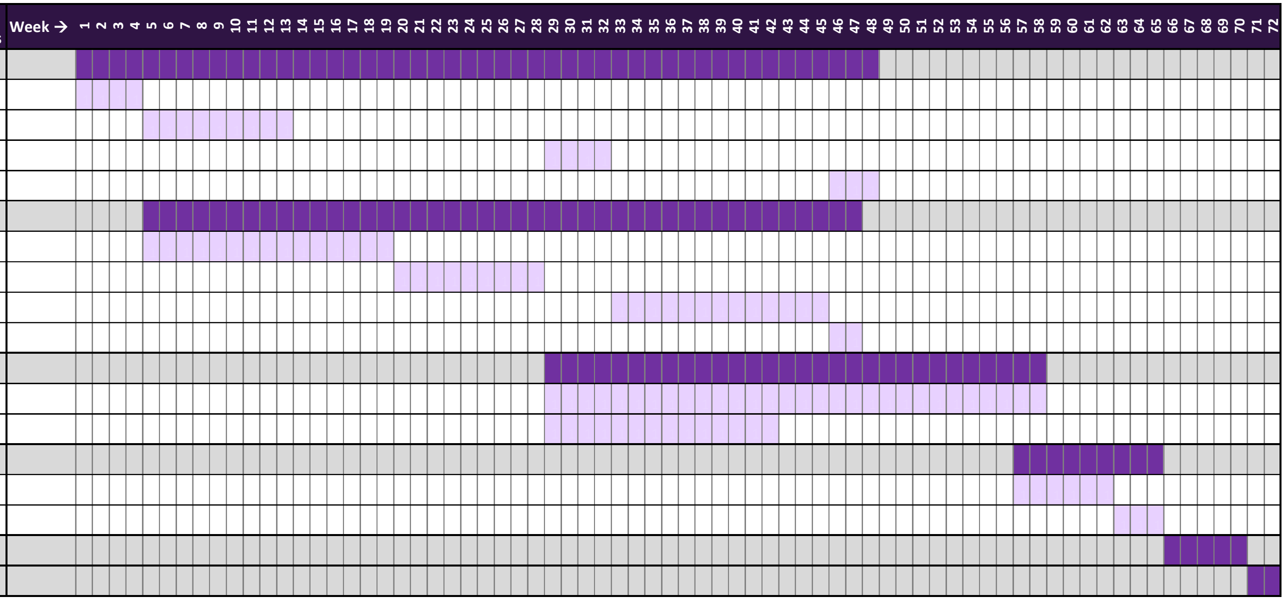


Figure 57 - Estimated high level timeline for delivery of 1 MW/2 MWh BESS

A significant portion of the timeline (37 weeks) is attributed to Ergon Energy Network embedded generation connection application. This does not include the time required for Ergon Energy Network to complete network augmentation works to connect the new sites to the network.

Another significant portion of the timeline is procurement as BESS units are a long lead item. The 30-week lead time shown in Figure 57 is based on the Sungrow PowerStack 110kVA-225kWh-2h units however, BESS lead time will differ with the selected make and model. Lead time depends on several factors including manufacturer location, manufacturing capacity and freight arrangements.

For a more detailed timeline, see Appendix C, Section 22.3.

14.2.2 Network Connection

A key component of delivering the solution is the network connection.

If a site load will be supplied at the new network connection, there would be two aspects to the network connection here:

1. New Network Connection
   An application to connect the proposed site to Ergon Energy's distribution network for the proposed capacity/load.
2. Embedded Generation Connection
   An application to connect the proposed BESS at the site.

This would require the proponent have been provided with a connection contract from the Ergon Energy Network Connection team for the new network connection, before submitting an application for the embedded generation connection to the Ergon Energy Solar and Renewable team.[100]

However, Ergon Energy Network have advised they will instead offer one entry point for this 'BESS only' new network connection, via an embedded generation connection application.[101] This process is outlined below.

Embedded Generation Connection[102],[103]

The Queensland Electrical Safety Regulations require any generation system connected to the public electrical network obtain approval from the relevant NSP prior to connection. The NSP for the proposed point of connection is Ergon Energy Network.

The connection process can be divided into four main stages:
1. Preliminary Enquiry;
2. Connection Application;
3. Connection Offer and acceptance;
4. Connection Works and Ongoing Services.

1. Preliminary Enquiry

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[100] Ergon Energy Network, Solar and Renewables (LV) >30 kVA New Build Connections, Solar & Renewables Over 30 kVA New Build Enquiries
[101] This could change in the future as although it has been advised for this project, it is not a requirement that Ergon Energy Network offer one entry point for a BESS only new network connection.
[102] Ergon Energy Network, Part A.1 Low Voltage Connection Process for LV > 30kVA – A Detailed View, Page 16-17 Ergon Embedded Generation Information Pack 2024_25
[103] Advice from Ergon Energy Network, Solar and Renewables Team, as part of preliminary enquiry for Horseshoe Bay Park and Picnic Bay Landfill Lot 2

The energy service provider will initiate the connection process by submitting a formal connection enquiry to Ergon Energy Network. Receipt of the enquiry will be acknowledged by Ergon Energy Network within 5 business days.

To ensure the proposed embedded generation will not adversely impact on the safety and security of the distribution network, an assessment must be performed to confirm the proposed configuration and operational conditions comply with Ergon Energy Network's relevant technical standards.

Given a 'BESS only' new network connection is not standard, further work is required by Ergon Energy Network in this stage to conduct a preliminary assessment. This is considered part of Ergon Energy Network's 'Site Specific Advice/Additional Services' at a price as quoted. Ergon Energy then provide a 'Preliminary Response to Enquiry' (PRE).

This preliminary enquiry step was completed for the Horseshoe Bay Park and Picnic Bay Landfill Lot 2 (the response summarised in Section 13 - Ergon Energy Network Assessment). PRE's are valid for 6 months. If not progressed to connection application within 6 months from when Ergon Energy Network provided the PRE, or if a BESS were to be proposed for a different site, a new preliminary enquiry would be required.

At an existing site:

For connection of a 1MW BESS at an existing site, these preliminary technical assessments are known as Site Specific Enquiry Responses (SSER). To initiate the technical assessments, an SSER fee must be paid ($1,258 based on 2025-26 prices[104]). Ergon Energy Network then have 45 business days to provide the SSER. At a minimum, a valid SSER is required to progress to the connection application.

2. Connection Application
   Connection Application – Technical Assessment:

   The application stage will include an analysis of the technical requirements to facilitate the lodgement of a complete application submission.

   The technical assessment will[105]:

   - Undertake analysis of constraints potentially resulting from the proposed Project
   - Determine the impact to network voltages and power quality as a result of the proposed Project
   - Determine the appropriate operational mode for the generating system!
   - Analyse the Distribution System and interconnection protection.

   Ergon Energy Network advise that to ensure efficiency of the technical assessment, the following information should be included:

   - Details of the proposed generating system (including number, size, type and unit data for inverters and battery modules)
   - Single line diagrams for protection and operation

[104] Ergon Energy Network, Over 30kVA Solar and Renewables (LV) Fees, How to connect - Larger systems over 30kVA | Ergon Energy
[105] Ergon Energy Network as part of Preliminary Response to Enquiry process for 0.99 MW/2.06 MWh BESS connection at Horseshoe Bay Park and Picnic Bay Landfill Lot 2

- annual half-hour profile of power output (in .csv or .xlsx format)
- system charging and discharge rates and duty cycle times, preferably 1 minute profile data in .csv or .xlsx format
- general arrangement of the site, including the preferred location for connection assets as relevant
- anticipated required maximum demand
- survey plan of land lot/s showing the general arrangement of the site

Ergon Energy Network will then provide a technical assessment to the proponent. There is no set timeframe that Ergon Energy Network is required to complete this in but have advised they will aim for 45 business days.

Connection Application – Complete Submission:

If technical assessment shows that connection of proposed size is an option, the proponent can then lodge a complete connection application. As per the PRE from Ergon Energy Network, this is expected to be upon completion of detailed design of the project. The application is to be submitted will all required information outlined in the technical assessment, including a Design Compliance Report (DCR).

Once Ergon Energy Network have completed the relevant due diligence of the application, and any required DNSP works have been scoped and costed, an Offer to Connect will be issued. Offers will be issued by Ergon Energy Network 65 business days from when they have all information.

At an existing site:

The connection application must contain all documentation and information required by Ergon Energy Network, as referred to in the SSER. This includes a Design Certification Report (DCR) certifying compliance of the generating system in accordance with the Standard for Low Voltage Embedded Generating Connections (STNW1174 or STNW3511 as applicable).

Once the application fee is paid ($4,648 based on 2024-25 prices), the application will transition to the Solar and Renewables team for review.

The connection offer type for a large BESS will be classified as 'Negotiated' and be assigned for the Technical Study, then approval to proceed to offer. Ergon Energy Network have 65 business days to provide a connection offer.

3. Connection Offer and acceptance
   Upon a successful application, the connection offer is issued to the asset owner to be executed and returned. The offer must be accepted within 20 business days.

4. Connection Works and Ongoing Services
   Once the network augmentation is complete by Ergon Energy Network and the proposed BESS is constructed, tested, and commissioned, the energy service provider prepares a compliance report and submits to Ergon Energy Network for review. Ergon Energy Network have 20 business days to provide their response.

   On receipt of approval, the energy service provider arranges the Electrical Work Request (EWR) within 10 business days. The EWR will transition to the asset owner's retailer.

The embedded generation connection process for the centralised BESS would then be complete.

A summary of the Ergon Energy Network connection application process for a 1 MW / 2 MWh BESS and new network connection is shown in Table 20 below.

Table 20 - Summary of Ergon Energy Network connection application process for a 1 MW / 2MWh BESS and new network connection

#	Stage	Cost	Timing[106]	Notes
1	Preliminary Enquiry	**As quoted.** Approx. **$7k** per site.	Ergon Energy Network Acknowledgement: **5 days** Ergon Energy Network Quote: **No set timeframe** Ergon Energy Network Preliminary Response to Enquiry (PRE): **55-60 days**	Completed for Horseshoe Bay Park and Picnic Bay Landfill Lot 2.
2	Connection Application – Technical Assessment	**As quoted.** PRE letter indicated **$42.7k** to **$47.7k** per site. This quote will need to be updated.[107]	Ergon Energy Network Technical Assessment: **No set timeframe** (Ergon Energy Network advised they will aim for 45 days)	If technical assessment shows that connection of proposed size is an option, Ergon Energy Network will come back and request updated Design Compliance Report (DCR)/additional information.
	Connection Application – Complete Submission		Ergon Energy Network Connection Offer/s: **65 days** (from when Ergon have all information)	The proponent will submit the DCR
3	Connection Offer/s and Acceptance	-	Proponent to accept: **20 days**	This may include two offers (load network connection offer + embedded generation connection offer).
4	Connection Works and Ongoing Services	**As quoted.** PRE indicated **$225k** to **$294k** ±50% per site.	Ergon Energy Network to construct new network connection: **TBC** (Ergon Energy Network advised this could be as long as 18-24 months)	Network connection cost estimated as part of preliminary assessment (±50%) but the connection offer will be provided with an updated cost.

[106] All days within 'Timing' column are business days.
[107] Ergon Energy Network advised the application fee provided in the PRE is based on 2024-25 rates and will need to be requoted after 1 July 2025. If Ergon Energy Network exhaust hours as quoted, additional invoices will be issued.

15. Financial Analysis

15.1. Cost Breakdown

15.1.1 Capital Costs

Table 21 and Table 22 provide a breakdown of the capital costs to deliver the concept 1 MW/2 MWh BESS at Horseshoe Bay Park and Picnic Bay Landfill Lot 2. At this preliminary stage, the project costs for each site are expected to be the same except for the Ergon Energy Network application and network augmentation costs.

Table 21 – Horseshoe Bay capital cost breakdown for proposed 1 MW/ 2 MWh BESS

Cost Description	Cost (excl. GST)
Studies & Design	$168,218
Materials & Freight	$2,312,115
Mobilisation, Installation, Commissioning, Plant Hire, Travel & Accommodation	$119,709
Project Management, Safety & Quality, Travel & Accommodation	$237,947
Network Application & Augmentation[108]	$293,763
Contingency	$156,588
Total	$3,288,339

Table 22 – Picnic Bay capital cost breakdown for proposed 1 MW/ 2 MWh BESS

Cost Description	Cost (excl. GST)
Studies & Design	$168,218
Materials & Freight	$2,312,115
Mobilisation, Installation, Commissioning, Plant Hire, Travel & Accommodation	$119,709
Project Management, Safety & Quality, Travel & Accommodation	$237,947
Network Application & Augmentation[109]	$225,858
Contingency	$153,192
Total	$3,217,040

Given the total estimated capital cost for Horseshoe Bay and Picnic Bay are similar, the average network application & augmentation capital cost ($259,811) was used for the financial analysis in the following sections. With the 5% contingency, this results in a total capital cost of $3,252,689.

[108] As quoted (±50%) by Ergon Energy Network as part of Preliminary Response to Enquiry process for 0.99 MW/2.06 MWh BESS connection at Horseshoe Bay Park

[109] As quoted (±50%) by Ergon Energy Network as part of Preliminary Response to Enquiry process for 0.99 MW/2.06 MWh BESS connection at Picnic Bay Lot 2

15.1.2 Operational Costs

Table 23 provides a breakdown of the estimated operational costs for the concept 1 MW/2 MWh BESS at Horseshoe Bay Park or Picnic Bay Landfill Lot 2.

Table 23 – Estimated operational cost breakdown for proposed 1 MW/ 2 MWh BESS

Cost Name	Description	Cost
Network Tariff Charges	The costs of Ergon Energy Network tariff charges. The proposed tariff is the East Large Dynamic Flex Storage tariff. This tariff has a fixed $/day charge in addition to a $/kWh charge when consuming energy from the grid between 5pm and 8pm.	$17,506 in Yr 1
Operation & Maintenance Service	The costs for an O&M provider to: • monitor the operation of the BESS and identify any issues to improve BESS availability and performance • implement a preventative maintenance schedule • provide quarterly performance reports to BESS owner • respond to any faults and manage reactive maintenance requirements • managing obligations and availability/performance guarantees as part of tolling arrangement with electricity retailer	$40,864 in Yr 1
SCADA	The costs of the BESS site SCADA system that provides enables remote monitoring, control, and data collection. This SCADA costs includes the platform that will allow the electricity retailer access to the BESS as part of a tolling arrangement.	Up to $12,336 in Yr 1
Land leasing	The costs of leasing the land from the landowner. TCC is the landowner of the proposed locations. It has been assumed the asset owner would lease the land as per the Community Leasing and Licence Agreement Policy. This may include additional fees including contribution to the site Emergency Services Levy and rates.	$1/annum
Insurance	The costs of obtaining insurance, which is expected to include, but may not be limited to public liability and fire/damage to the BESS.	unknown
BESS Replacement	The costs to replace BESS components with like for like solution at the end of life of the BESS. This includes the removal and disposal of the existing BESS components, and the procurement, installation, and commissioning of new like-for-like BESS components.	Estimated as 30% of CAPEX in Yr 16
Contingency	An allowance for unexpected costs or increases in known costs (applied to O&M Service and SCADA).	5% of annual OPEX

Insurance has been listed as unknown in Table 23 as insurance for a battery energy storage facility can be extremely difficult if the infrastructure is not owned by the DNSP or council. Community energy groups in Australia have had trouble securing insurance for community-owned batteries.

Groups, such as Village Power, Yarra Energy Foundation and Geni.Energy, have found that insurance companies have repeatedly rejected their requests, citing the lack of sufficient data to assess the risk of such batteries[110]. It is not determined what entity would be the asset owner of the proposed centralised BESS, therefore it is unknown if insurance could be obtained, and if so, it is difficult to estimate the annual cost of this insurance.

15.1.3 Revenue

Fixed Revenue Option

Table 24 provides the estimated revenue for the concept 1 MW/2 MWh BESS at Horseshoe Bay Park or Picnic Bay Landfill Lot 2.

Table 24 - Revenue for proposed 1 MW/ 2 MWh BESS

Revenue Description	Revenue
Tolling Arrangement Annual Payment	$130-164k/MW/annum flat nominal (7-year term)

Variable Revenue Option

As a comparison to the fixed revenue option, a variable revenue option has been modelled. One example of a variable revenue option is where the asset owner has a shared revenue agreement with an aggregator.

The historical Queensland average wholesale energy price is shown in Figure 58 below, where a high level of price variability can be seen in recent years. Based on this observation, there is likely to be uncertainty in future wholesale energy and FCAS market prices. This would impact potential future revenue under a variable revenue option, increasing the risk of this option compared to a fixed revenue option.

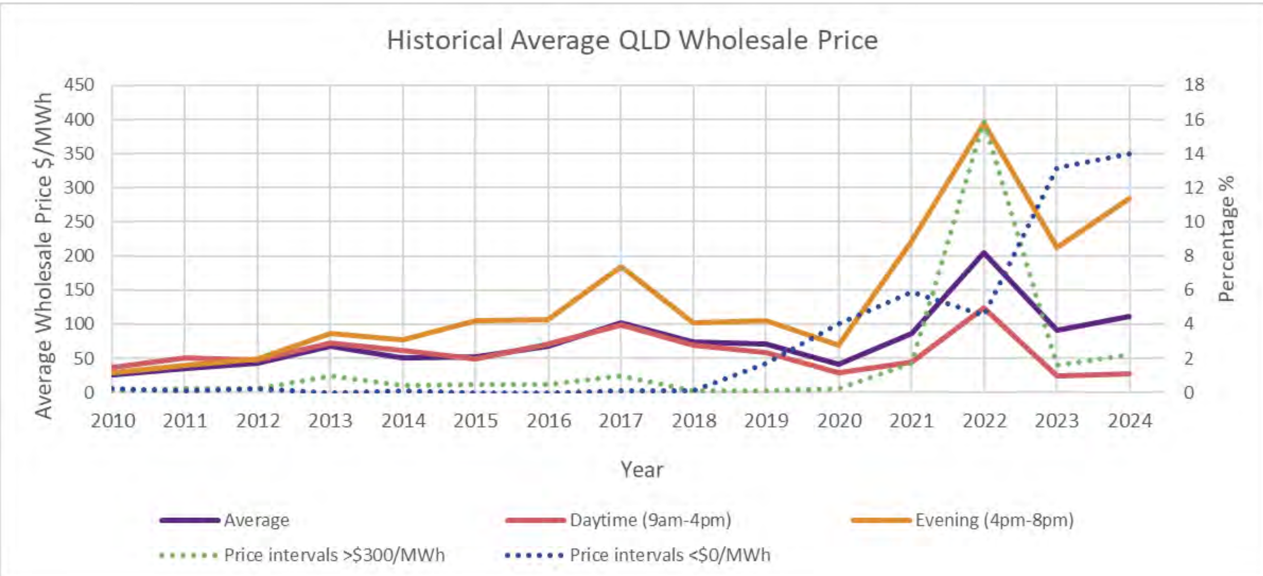

Figure 58 - Historical average Qld wholesale energy price

[110] One Step Off the Grid, Real community batteries are uninsurable in energy game of "snakes and ladders" - One Step Off The Grid

To model this variable revenue option, the following assumptions have been made for a high and a low scenario with different wholesale price forecasts:

Wholesale

- High – full calendar year 2021[111] wholesale price dataset (30 min) with a real annual escalation of 7.5% (over the 15-year modelling term)
- Low – forecasted wholesale price dataset 2026 - 2045 (30 min) provided by Endgame Economics (2027 – 2041 was used for the 15-year modelling term)

FCAS

- High & Low – Latest full calendar year (2024) FCAS price dataset (30 min) with a real annual escalation of -12.5% (over the 15-year modelling term)

The forecasted average wholesale energy price for the 'High' and 'Low' scenario is shown in Figure 59 below.

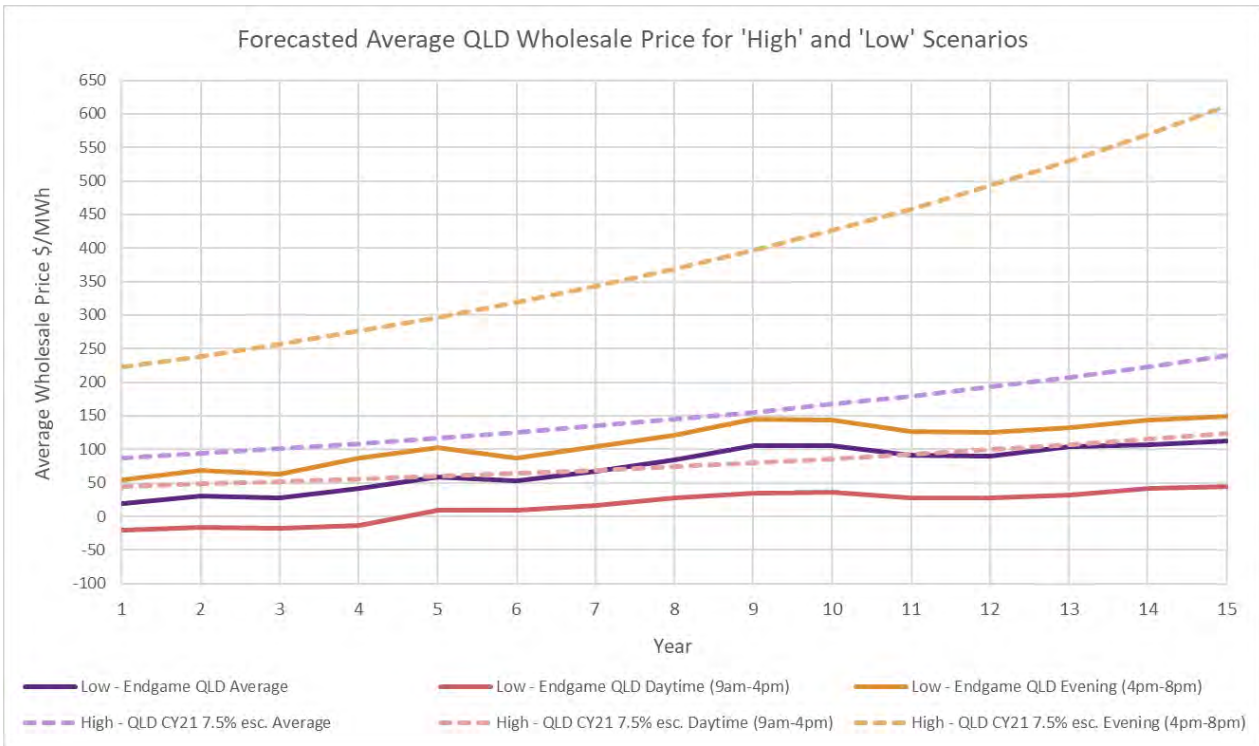

Figure 59 - Forecasted average Qld wholesale energy price for 'High' and 'Low' scenarios ($ in real terms)

[111] Calendar year 2021 was used as Year 1 prices in the model as it was the most recent year before the extremely high prices in 2022 and the large increase in the percentage of negative price intervals in 2023 and 2024 (as shown in Figure 58).

15.2. Techno-Economic Modelling

15.2.1 Model Assumptions

- General economics and financial assumptions
  - **Project life:** 15 years
  - **BESS Asset life:** 15 years
  - **CPI:** 2.5%
  - **Real Discount Rate:** 4.4%
  - **Contingency:** 5% Contingency CAPEX and OPEX
- Fixed Revenue Option
  - **Tolling Arrangement:** $145,530/MW/annum flat nominal for 7 years as quoted by retailer
  - To estimate Year 8-15, total present value of Year 8-15 was assumed to be 93% of the total present value of Year 1-7[112]
  - Based specifically on a 990 kW BESS a.c. capacity:
    - Year 1 – 7, $144,075/annum, adjusted to real terms using assumed CPI
    - Year 8-15, $193,835/annum, adjusted to real terms using assumed CPI
- Variable Revenue Option
  - High Scenario
    - Wholesale prices – full calendar year 2021 wholesale price dataset (30 min) with a real annual escalation of 7.5%
    - FCAS – Latest full calendar year (2024) FCAS price dataset (30 min) with a real annual escalation of -12.5%
  - Low Scenario
    - Low – forecasted wholesale price dataset 2026 - 2045 (30 min) provided by Endgame Economics (2027 – 2041 was used for the 15-year modelling term)
    - FCAS – Latest full calendar year (2024) FCAS price dataset (30 min) with a real annual escalation of -12.5%
  - Aggregator receives 30% profit from wholesale and FCAS market participation
- Operating costs
  - **Network Tariff Charges** in Year 1 to Year 5 as per Ergon Energy Network 2025 pricing model indicative prices[113]:

Table 25 - Ergon Energy Network Large Dynamic Flex Storage tariff rates

	Year 1	Year 2	Year 3	Year 4	Year 5
Fixed $/day	47.962	50.162	53.112	61.713	74.875
Energy c/kWh (5pm–8pm)	2.289	2.390	2.500	2.580	2.690

    - Year 6+, fixed prices increase with real escalation of 0%/annum
    - Year 6+, energy prices increase with real escalation of 0%/annum

[112] 93% was based on the estimated market revenue of operating a 1 MW/ 2MWh BESS to participate in the wholesale and FCAS markets using the Variable Revenue - High Scenario assumptions over a 15-year term, comparing the total market value in Year 1-7, to Year 8-15.
[113] Ergon Energy Network, Ergon Energy 2025-26 - Final - annual SCS pricing model - 2 May 2025.xlsm

- Operation & Maintenance Service: $ 42,864 in Year 1 with real escalation of 0%/annum
  - SCADA: Up to $12,336 in Year 1 with real escalation of 0.5%/annum
  - Land leasing: $1 in Year 1 with nominal escalation of 0%/annum
  - Insurance: Unknown, omitted from model
- Capital costs
  - Total capital expenditure: $1,578/kWh
  - Funding contribution: Varies

15.2.2 Fixed Revenue Results Summary

Table 26 shows the tolling arrangement techno-economic results over the 15-year period for various capital funding contribution percentages.

Table 26 headings are as follows:

- Upfront costs, the initial capital expenditure of the project
- Net Present Value (NPV), the total of all future cashflows (positive and negative) over the life of the investment discounted to the present
- Internal Rate of Return (IRR), the discount rate that equates to an NPV of zero
- Payback Period, the time it takes to pay back the upfront cost of the solution
- Ongoing costs, present value ongoing costs over the 15-year period
- Revenue, present value revenue over the 15-year period

Table 26 – Tolling Arrangement techno-economic modelling results summary

BESS Size	Total CAPEX	Funding Contribution	Techno-Economic Results					
			Upfront cost	NPV	IRR	Payback period (yrs)	Ongoing costs	Revenue
1 MW/ 2 MWh	$3,252,691	0%	-$ 3,252,691	-$ 2,562,575	-	-	-$ 889,502	$ 1,595,796
		25%	-$ 2,439,518	-$ 1,749,402	-	-		
		50%	-$ 1,626,345	-$ 936,230	-	-		
		75%	-$ 813,173	-$ 123,057	1.97%	13		
		90%	-$ 325,269	$ 364,847	19.44%	6		
		100%	$ 0	$ 690,116	N/A	0		

The results for all but the 90% and 100% funding contribution scenario are unfavourable with negative NPVs, as there are not enough annual earnings to recover the initial cost.

A sensitivity analysis was completed for the scenario with 50% funding contribution. The analysis determines the impact of changing several financial model inputs by ±20% on NPV. Figure 60 shows the results of the sensitivity analysis. Modifying the capital cost and the tolling payment has the largest impact to the NPV of the project, where a ±20% change results in a difference of over $300k to the NPV.

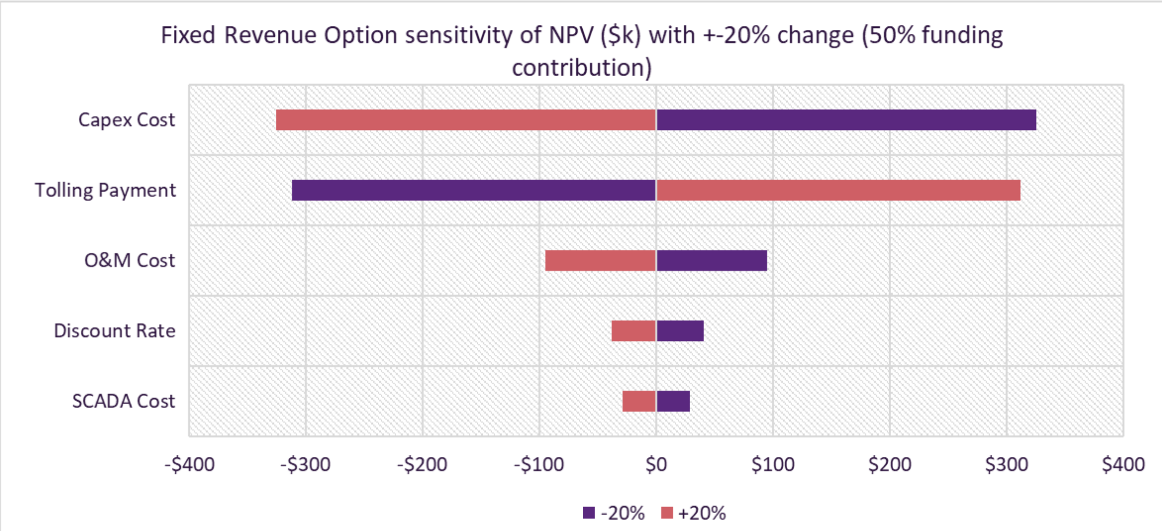

Figure 60 – Fixed Revenue Option – High Scenario sensitivity of NPV ($k) with ±20 change (50% funding contribution)

15.2.3 Variable Revenue Option Results Summary

Table 27 shows the 'high' at risk scenario techno-economic results over the 15-year period for various capital funding contribution percentages.

Table 27 – Variable revenue option, high scenario techno-economic modelling results summary

BESS Size	Total CAPEX	Funding Contribution	Techno-Economic Results					
			Upfront cost	NPV	IRR	Payback period (yrs)	Ongoing costs	Revenue
1 MW/ 2 MWh	$3,252,691	0%	-$ 3,252,691	-$ 112,531	3.9%	12	-$4,692,867	$7,917,676
		25%	-$ 2,439,518	$ 700,642	8.4%	10		
		50%	-$ 1,626,345	$ 1,513,814	16.2%	7		
		75%	-$ 813,173	$ 2,326,987	37.8%	3		
		90%	-$ 325,269	$ 2,814,891	115.3%	2		
		100%	$0	$ 3,140,160	N/A	0		

Table 28 shows the 'low' at risk scenario techno-economic results over the 15-year period for various capital funding contribution percentages.

Table 28 – Variable revenue option, low scenario techno-economic modelling results summary

BESS Size	Total CAPEX	Funding Contribution	Techno-Economic Results					
			Upfront cost	NPV	IRR	Payback period (yrs)	Ongoing costs	Revenue
1 MW/ 2 MWh	$3,252,689	0%	-$ 3,252,691	-$ 2,839,900	-	-	-$1,669,101	$2,094,279
		25%	-$ 2,439,518	-$ 2,026,728	-	-		
		50%	-$ 1,626,345	-$ 1,213,555	-	-		
		75%	-$ 813,173	-$ 400,382	-	-		
		90%	-$ 325,269	$ 87,521	-	4		
		100%	$0	$ 412,790	N/A	0		

A sensitivity analysis was completed for the high and low scenario with 50% funding contribution. The results of the sensitivity analysis are shown in Figure 61 and Figure 62. For the high scenario, modifying the wholesale profit share has the greatest impact with over $600k difference to NPV. For the low scenario, modifying the capex has the greatest impact with over $300k difference to NPV.

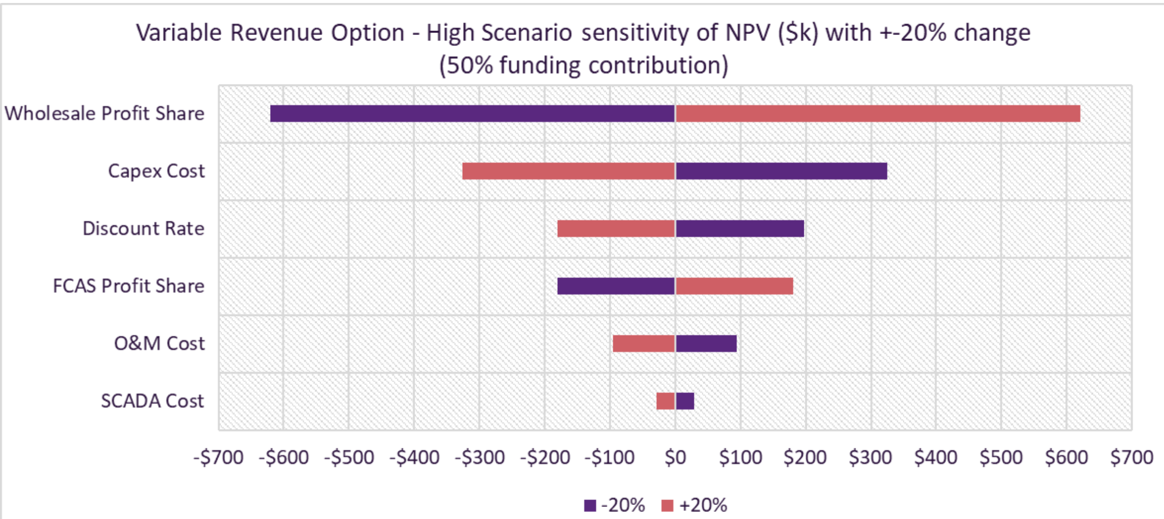

Figure 61 – Variable Revenue Option – High Scenario sensitivity of NPV ($k) with ±20 change (50% funding contribution)

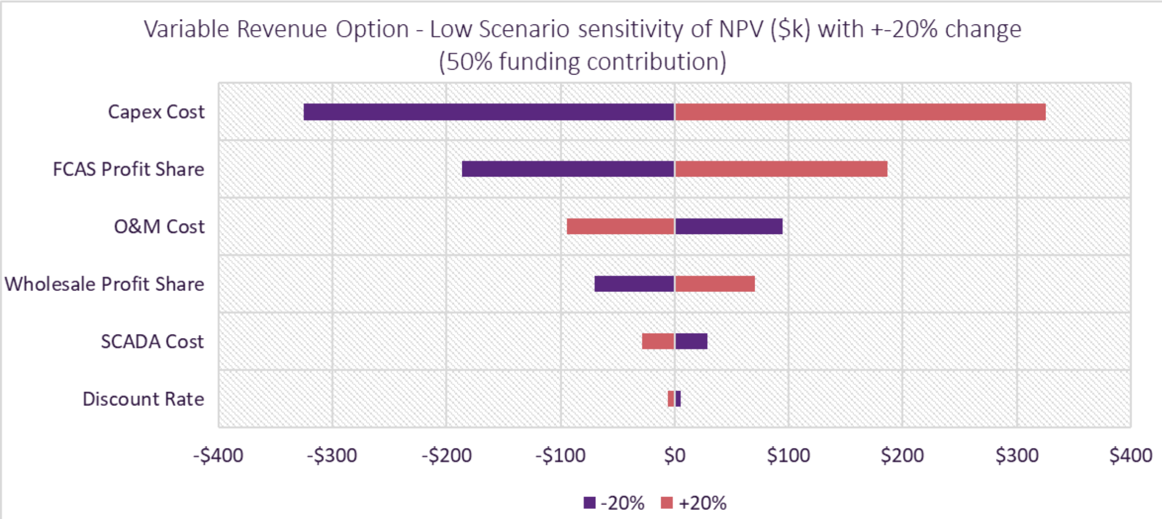

Figure 62 - Variable Revenue Option – Low Scenario sensitivity of NPV ($k) with ±20 change (50% funding contribution)

15.2.4 Future Impacts

It is impossible to accurately predict future prices, key partnership arrangements/offerings and the regulatory environment. The techno-economic results could be impacted by so many changes, particularly with the following:

- Electricity retailer and/or aggregator arrangements
  - The structure of the arrangements on offer could change and evolve, impacting how much revenue the BESS owner will receive. The wholesale and FCAS market will also significantly impact the value of these arrangements.
- Ergon Energy Network tariff structures and pricing
  - Changes to the prices for Dynamic Flex Storage tariffs will impact operational costs. Tariff prices are updated and published by Ergon Energy Network each year and they only provide indicative prices for the next regulatory period. There is currently no indication on pricing beyond 2030.
  - The proposed Dynamic Flex Storage tariffs only have a fixed $/day and a $/kWh volume peak charge (grid consumption charge between 5pm–8pm). Based on indicative tariff pricing from 2025-2030, all time outside of the peak window is free for the battery to charge. This is because the Volume Off-Peak (11am–1pm) and Volume Shoulder (all other times) components of the tariff are set to $0/kWh. If this changes, it would no longer be free to charge the battery most of the time.
- Ergon Energy Network storage tariff trials with critical peak rewards
  - In 2025-26 Ergon Energy Network will trial Dynamic Price Storage tariffs. This trial will test how to implement prices that only signal costs during critical system events and the ability of storage customers to respond to these price signals. This trial tariff could be a suitable alternative to the proposed Dynamic Flex Storage tariff however there is not enough information available to estimate the additional revenue form the critical peak rewards.

- Feeder limitation program network support service
    - Ergon Energy Network's distribution planning team advised that, given a project recently completed to increase capacity on TM-10, there is not expected to be capacity constraints for feeder TM-10 and TM-03 until beyond 2030 based on current growth rates. The annual maximum demand continues to increase while installed solar PV capacity on Magnetic Island also continues to increase. If these trends continue over the term of the techno-economic analysis, demand management network support opportunities may become an option. This would provide additional revenue (currently valued between $20/kVA and $100/kVA per annum) however may reduce the value of a tolling arrangement with the retailer. Providing network support would require a portion of the BESS be reserved for a network support event, and not be available for the retailer to use for market participation.

16. Key Benefits & Risks

16.1. Benefits

If the installed solar PV capacity on Magnetic Island continues to increase by 20% annually, as it has over the last five years, it will continue to lower demand in the middle of the day. This will cause more frequent occurrences of distribution feeder reverse power flow.

Through market participation strategy, the proposed centralised BESS is expected to operate similar to a BESS with the primary objective to solar soak. The BESS will charge during the day when solar PV production is high and wholesale energy prices are lower, and discharge in the evening when there is higher demand and higher wholesale energy prices.

The key benefits of a centralised 1 MW/ 2 MWh BESS in Horseshoe Bay or Picnic Bay include the following:

- Increased renewable energy fraction of the community

  The BESS will lower the community's carbon footprint by storing excess energy generated from solar PV within the community, to store and later supply the community's evening load. This will reduce the amount of excess solar PV energy that flows back upstream of the community, keeping it locally.

  As the total installed solar PV capacity continues to steadily increase in Horseshoe Bay and Picnic Bay, the addition of a 1 MW / 2 MWh BESS in each village is estimated to increase renewable fraction and GHG emission reduction as shown in Table 29.

Table 29 - Estimated Renewable Fraction and GHG Emission Reduction with 1 MW / 2 MWh BESS

	Additional Solar PV Capacity	Renewable Fraction Solar PV Only (%)	Renewable Fraction with Solar PV and BESS (%)	Renewable Fraction Increase Due to BESS (%)	GHG Emission Reduction[114] (t CO2-e)		
					Solar PV Only	Solar PV and BESS	Due to BESS
Horseshoe Bay	0.5 MW	47%	52%	6%	1,772	2,027	256
	1 MW	50%	60%	10%	1,917	2,357	440
	1.5 MW	52%	63%	11%	1,973	2,455	483
	2 MW	53%	64%	11%	2,003	2,496	493
	2.5 MW	53%	64%	11%	2,023	2,518	495
Picnic Bay	0.5 MW	46%	54%	9%	986	1,264	278
	1 MW	50%	66%	16%	1,136	1,551	415
	1.5 MW	51%	69%	17%	1,171	1,613	442
	2 MW	52%	70%	18%	1,192	1,642	450

The BESS is also expected to reduce the amount of solar PV that would otherwise be curtailed. With the transition to dynamic connections, where Ergon Energy Network will be able to reduce solar PV export to 1.5 kW when network is constrained, the BESS could reduce the need to limit export. This would apply if the limiting constraint were at a feeder level and not a distribution transformer level.

Increased battery storage will support the continued uptake of solar PV. By reducing the impact of challenges the distribution network experiences with solar PV, this will enable more solar PV to be approved for installation at a feeder level.

- Downward pressure on household electricity costs

  As discussed in Section 4 of this report, due to the increase in installed solar PV capacity, the grid consumption of Horseshoe Bay and Picnic Bay villages are decreasing over time while the maximum demand increases. The maximum demand occurs in the evening, usually between 4pm–9pm, largely due to residential load. The DNSP then needs to invest in upgrading network infrastructure to increase capacity to meet the maximum demand, preventing power outages at peak demand times. By reducing the feeder demand on the grid with a centralised BESS during peak demand times, it could help defer costly network upgrades.

- Improved grid stability at system level

  Australia's electricity system was originally designed for power to flow one way from large power stations through a network of substations and power lines into homes and businesses. High volumes of rooftop solar PV can reduce the need for electricity from grid-

[114] Based on 2024 QLD Emissions Factor 0.71 kg CO_2-e/kWh, Table 1, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2024.pdf

scale generation, known as minimum system load. This can pose a risk to grid security.[115] A BESS will help flatten the load on the power system and reduce the likelihood of minimum system demand impacts.

Since the 6 February 2024, all solar PV systems are to be installed with a Generation Signalling Device (GSD). The GSD is an emergency backstop mechanism that, when required, allows Ergon Energy Network to stop the output from solar PV systems to maintain grid stability. A BESS could help reduce the likelihood of Ergon Energy Network initiating GSDs and curtailing solar PV output.

- Community contribution to energy transition

  A centralised BESS installed within the local area can make the community feel they are contributing to the energy transition, fostering a sense of ownership and responsibility. A centralised BESS could also provide educational benefits that further encourage or assist the community members in transitioning to cleaner, more sustainable sources of energy.

  Depending on how the operating model is further refined for the proposed centralised BESS, the asset owner could use the profits, or a portion of the profits, to help fund community initiatives that benefit everyone.

- Scaled up delivery of operational models for community scale batteries

  Majority of community batteries are DNSP owned. Delivering a non-DNSP owned centralised BESS in regional Queensland will help generate new knowledge and address existing barriers. This will help enable similar projects, where centralised battery storage is driven by local communities.

- Economic benefit depending on operating model and market performance

  A centralised BESS has the potential to provide economic benefit depending on the risk appetite of the asset owner, the chosen operating model, and future wholesale energy and FCAS market performance.

In summary, a 1 MW/2 MWh community battery can offer environmental, economic, and reliability benefits while promoting greater use of renewable energy, and potentially putting downward pressure on electricity bill costs for residents and businesses in Queensland.

16.2. Risks

The key risks identified for a Horseshoe Bay and Picnic Bay centralised BESS are included in Table 30, Table 31 and Table 32 below.

[115] AEMO | Fact sheet: Minimum system load (MSL)

16.2.1 Project Development Risks

Table 30: Summary of project development risks

Risk		Risk Rating			Mitigation
#	*Description*	*Impact*	*Likelihood*	*Risk Rating*	*Strategy*
1	Community Support Without effective community engagement, there could be some adverse community reactions.	Major	Likely	Very High	• Continue with previous successful engagements (20% YoY solar increase) • Engage experienced community engagement professionals • Develop a community engagement plan • Commence community engagement early
2	Obtaining Project Capital It's likely that the only option for a favourable financial model is to have a portion of project capital provided at zero cost.	Major	Likely	Very High	• Investigate sourcing some capital through grants and donations
3	Grid Connection Understanding of grid connection requirements and approvals required, resulting in increased capex and delays to schedule.	Major	Possible	High	• Engage early with Ergon Energy Network • Commence new grid connection applications as soon as practicable in the project delivery timeline
4	Inability to Obtain Suitable Key Partnerships Obtaining effective partners for retailing, project development, design, construction, and operation is critical for reducing risk and increasing likelihood of success.	Moderate	Possible	Medium	• Engage partners with local knowledge and relevant demonstrated experience • Engage partners early in project development phase
5	Development Application BESS site will require TCC development application, material change of use and environmental review, which could cause delays and require significant resources and effort.	Moderate	Possible	Medium	• Utilise ability to obtain free feedback and advice from TCC and environmental officers • Commence process early
6	Insurance Insurance for non DNSP owned community BESS is challenging and may not be available.	Moderate	Possible	Medium	• Engage with insurance providers early to understand risks and premium costs

16.2.2 Delivery Risks

Table 31: Summary of delivery risks

Risk		Risk Rating			Mitigation
#	*Description*	*Impact*	*Likelihood*	*Risk Rating*	*Strategy*
1	Delayed Grid Connection Approval Delays in grid connection approvals required given introduction of inverter-based generator / load, resulting in delays to project delivery.	Major	Possible	High	• Engage early with relevant DNSP • Commence grid connection applications as soon as practicable in the project delivery timeline
2	Increased Project Costs Significant increase in project delivery cost due to variability arising from supply conditions, changing geopolitical landscape and /or inflationary pressures.	Major	Possible	High	• Sufficient contingency has been built into the budget
3	Inability to Obtain Land Access/Approval for Further Development from Site Owners (mostly local council) Delays in site access resulting in project delivery delays.	Moderate	Possible	Medium	• Engage with site owners early and promote ongoing collaboration
4	Supplier Delays Delays in obtaining critical equipment for project delivery arising from supply chain instability, resulting in delays to project delivery.	Moderate	Possible	Medium	• Engagement with BESS suppliers • Ensure lead time is a key consideration for product selection
5	Occupational Health and Safety (OHS) Delays in project delivery due to safety incidents.	Moderate	Unlikely	Low	• Have a dedicated OHS resource on the project • Ensure continued application of mature and robust risk management processes

16.2.3 Operational Risks

Table 32: Summary of operational risks

Risk		Risk Rating			Mitigation
#	*Description*	*Impact*	*Likelihood*	*Risk Rating*	*Strategy*
1	Fire Increased fire hazard at BESS location resulting from possible thermal runaway of the battery system.	Severe	Unlikely	High	• Bushfire risk assessment • Ensure design appropriately addresses fire risk • Ensure stringent monitoring and maintenance schedules of battery assets, using experienced operations and maintenance resources and teams • Use reputable battery suppliers, with stringent QA standards
2	Cyber security Threat to energy infrastructure.	Severe	Unlikely	High	• Ensure highest level of cyber security on remote connection
3	Dynamic Network Limits Dynamic import/export limits when network constrained that could impact ability to participate in FCAS market, reducing potential revenue and tolling arrangement value.	Major	Likely	High	• Discuss with potential retail partner during project development how this might impact arrangement (i.e., wholesale only or risk share for FCAS participation). • Engage with DNSP about estimated limit duration or forecasts if/when available.
4	Asset Damage Damage to the battery asset due to poor security (e.g., from vandals) or poor environmental protections.	Moderate	Possible	Medium	• Ensure enclosure (including security) for the battery system is suitable. Key considerations include bollards, fixing and ingress protection.
5	Noise Disruption to community due to excessive noise due to fan cooled battery installation. The suggested BESS make and model emits noise up to 70 dB.	Minor	Likely	Medium	• Conduct noise assessment and determine appropriate noise minimizing controls
6	Environmental Damage Environmental damage resulting from battery disposal.	Moderate	Unlikely	Low	• Ensure lifecycle of the asset is part of product selection criteria and design to determine options for re-use or recycling

17. Future State

The proposed centralised BESS are solutions that are technically feasible under the current rules and regulations. The solutions could work as a stepping stone towards a longer term solution that will further enable MICDA's objectives to be met. Some potential future state options are discussed in the following sections.

17.1.1 Potential Horseshoe Bay Park Renewable Hub

Consumer energy resources (CER) are consumers' resources that generate or store electricity as well as flexible loads that can alter demand in response to external signals. CER includes rooftop solar PV, batteries, electric vehicle chargers and controlled loads such as water heaters and air conditioners.[116]

In August 2024, the Australian Energy Market Commission (AEMC) initiated rule changes that will unlock substantial benefits from CER. The AEMC advise that the rule changes will enable arrangements that will make it easier for energy service providers to offer products and services to households, businesses, and the public sector, to unlock the value of flexible CER.[117]

Currently it does not make financial sense to install the centralised BESS behind the meter at Horseshoe Bay Park. This is due to the low energy consumption and demand of the existing loads on site and the associated network tariff costs and categorisations, complexities with retail and metering arrangements when participating in the markets.

These rule changes could present an opportunity to create a Horseshoe Bay Park Renewable Hub where all loads, the proposed centralised BESS and additional solar PV (e.g. rooftop solar PV on a new shade structure for the tennis court) could all be electrically connected. The proposed centralised BESS could then be a step towards a renewable hub at Horseshoe Bay Park.

17.1.2 Village Microgrid Concept

Ergon Energy Network is currently working to develop a solution for their first community grid-connected microgrid with their pilot project in Mossman Gorge, Far North Queensland. In the future, providing backup power may become a network support service provided by third parties.

The proposed centralised BESS could be modified in the future to provide backup power to the electricity distribution network to operate as a microgrid during network outages. This concept is represented in Figure 63 below.

[116] Australian Government, Energy and Climate Change Ministerial council, National Consumer Energy Resources: Powering Decarbonised Homes and Communities, national-consumer-energy-resources-roadmap.pdf

[117] Australian Electricity Market Commission, Unlocking CER benefits through flexible trading | AEMC

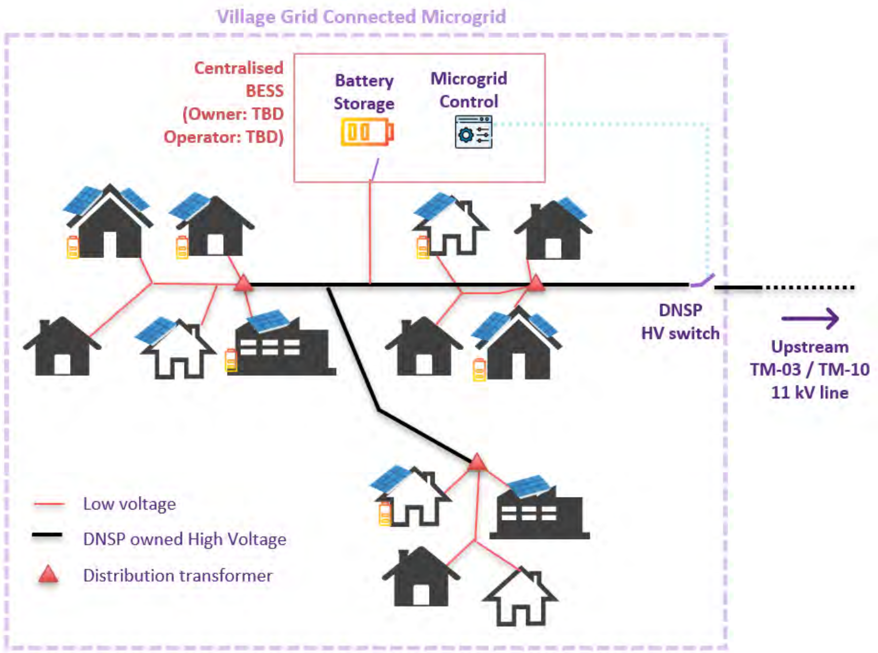

Figure 63 - Village Grid-Connected Microgrid Concept

The most recent maximum demand for Horseshoe Bay and Picnic Bay is 1,077 kW and 792 kW respectively. The existing grid consumption data assessment showed on average a maximum demand growth of 3–4% over the last four years.

A 1 MW centralised BESS would have the ability to cover the annual maximum demand of Picnic Bay, but not Horseshoe Bay. If this concept were to become an option, the centralised BESS could be increased in size (adding cost and complexity to upgrade network connection size) or alternatively demand management could be implemented to ensure the microgrid load can be supplied.

To provide backup power to the village, the required modifications of the centralised BESS are expected to include the addition of isolation transformers (to enable the BESS to act as the 'grid') and new Ergon Energy Network HV connection hardware and communication systems. A deeper understanding of what additional requirements would be required is expected to be a result of the Ergon Energy Network community grid-connected microgrid pilot project.

17.1.3 Picnic Bay Centralised Solar PV

Tenure of land suitable for large ground mount solar PV on Magnetic Island is expected to be challenging. The Picnic Bay Landfill Lot 2 (preferred location for a BESS) could fit approximately 350 kW of ground mount solar PV but is not an ideal location as it is currently used by TCC, and it is adjacent to a golf course.

Picnic Bay Landfill Lot 1 site, shown in Figure 64, has been highlighted as a prospective site for a future ground mount solar PV installation, however, the suitability of the capped landfill area for such a development remains uncertain pending further assessment.

Figure 64 - Picnic Bay Landfill: Lot 1 and Lot 2

The landfill was closed in early 2016 after the opening of Magnetic Island Waste Transfer Station. The land was rehabilitated in 2018 to permanently cap and cover the landfill to prevent seepage into waterways or nearby bushland and preparing the site for revegetation. TCC have an obligation to monitor the site for 30 years after the capping work has been done to make sure the land has been properly rehabilitated.[118]

Repurposing landfill sites for solar farms has been done in Australia. An example of this is Albury Waste Management Centre, where 1.1 MW solar PV power station consisting of 4,000 solar panels was installed in 2019.[119]

A ground mount solar PV structure that penetrates the ground would not be suitable for this location. A ballasted system that doesn't drive foundations deep into the ground is an option. This would avoid piercing the landfill cap and disturbing the waste underground. An example of this is Solpod's Ground product, shown in Figure 65 where each pod is supported by four concrete ballast blocks, poured onsite into low cost planter bags. Solpod state this product is suitable for wind regions A, B & C. [120]

[118] Townsville City Council, 'Tender awarded to rehabilitate former Picnic Bay landfill', 25 January 2018, Tender awarded to rehabilitate former Picnic Bay landfill - Townsville City Council

[119] Albury City, Energy from waste, The Albury Renewable Energy Hub, https://www.alburycity.nsw.gov.au/services/waste-and-recycling/alternative-energy

[120] Solpod Ground brochure v1.2, Solpod Ground brochure v1.2.pdf

Figure 65 - Solpod Ground ballasted steel frame pod

The land area could potentially fit approximately 1.2 MW of ballasted ground mount solar PV as shown in Figure 66.

Figure 66 - Picnic Bay Landfill Lot 1 1.2 MW Solar PV

Environmental and landfill settlement studies would be a critical step to ensure the land is suitable for ground mount solar PV.

18. Behind the Meter Solar PV & BESS

Behind the meter (BTM) solar PV and BESS will help increase Magnetic Island's renewable energy fraction, minimise outage duration for individual sites and provide direct benefit through electricity bill savings.

This could be achieved through a capital purchase or through alternative finance options such as PPAs, now more economical with the introduction of the Cheaper Home Batteries program discussed in Section 10.1. MICDA have had discussions with Horan & Bird relating to implementing their PPA & VPP offer for Magnetic Island residents and small business owners, however a detailed analysis of this option has not been included in this report.

This section includes an analysis of the following:

- Impact of BTM solar PV and BESS on energy flow and electricity retail bill for individual customers as well as Magnetic Island as a whole
- Individual customer impact of capital purchase

18.1. Modelling & Assumptions

For this analysis, four types of Magnetic Island customers have been included:

1. Typical residential, no existing solar PV
2. Typical residential, existing solar PV
3. Typical small business, no existing solar PV
4. Typical small business, existing solar PV

Large business has been excluded from this analysis as it is expected that majority of the business loads on Magnetic Island are small business (annual consumption <100 MWh/year). The residential and small business consumption was estimated primarily based on the energy and customer count data as per 'Table 2 - Magnetic Island Consolidated Customer Connection Grid Consumption and Solar Export Summary' (excluding the known TCC major loads) and the installed solar PV capacity data as per 'Figure 4 - Magnetic Island Cumulative Solar PV Installation Capacity 2008 - 2025'.

The following assumptions have been made for this analysis:

Load, Solar & Battery

- Residential load
  - Annual load consumption: 6,420 kWh
  - Any existing solar PV capacity = 4.5 kW
  - Usage pattern: generic residential
  - Daily load profile:

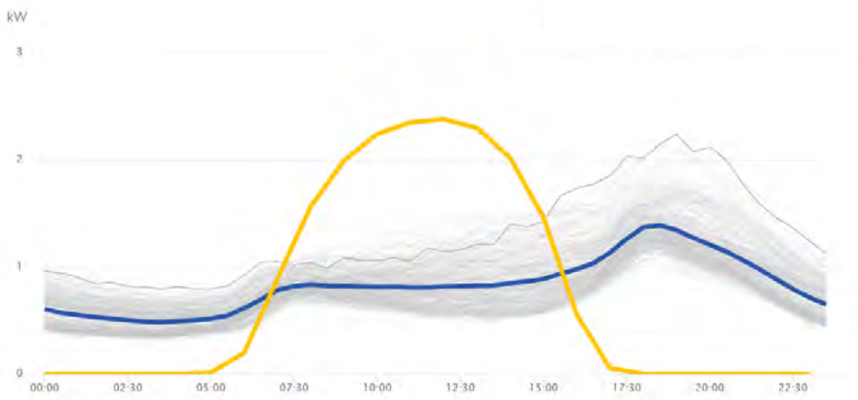

Figure 67 – Estimated typical Magnetic Island residential daily load profile and 4.5 kW solar PV average daily generation profile

- Small business load
  - Annual load consumption: 50,806 kWh
  - Any existing solar PV capacity = 10 kW
  - Usage pattern: generic accommodation, cafes, and restaurants
  - Daily load profile

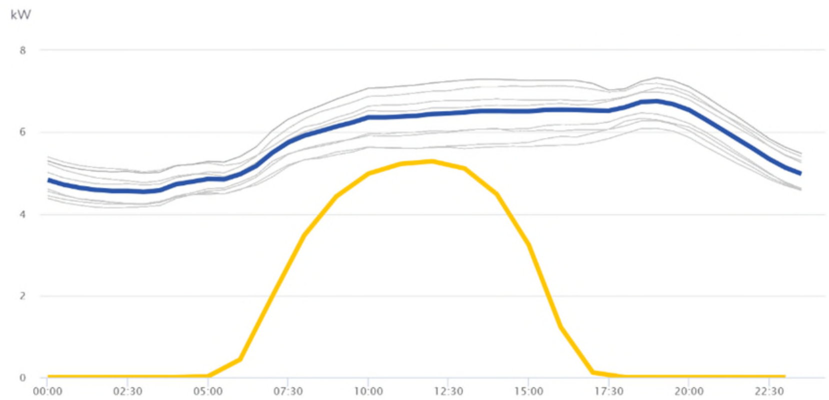

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Figure 68 – Estimated typical Magnetic Island small business daily load profile and 10 kW solar PV average daily generation profile

- Solar production
  - Existing solar PV daily production of 4 kWh/ kW
  - New solar PV daily production of 4.5 kWh/kW
- Battery energy storage system performance
  - Round trip efficiency (RTE) = 90% (i.e., 10% of energy used to charge the battery energy storage system will be "wasted" due to system losses)
  - Annual battery degradation = 2%
- Installation year = 2025

Tariffs

- Primary tariffs considered only, no secondary tariffs (i.e., Tariff 31 and Tariff 33)
  - Residential: Ergon Retail Tariff 11
  - Small business: Ergon Retail Tariff 20

- No sites with existing solar PV receive the 44 c/kWh Solar Bonus Scheme feed-in tariff, expiring on 1 July 2028
- Tariff rates based on QCA June 2025 final determination for 2025-26, excluding GST

Table 33 - Tariff Assumptions

	Residential	Small Business
Tariff	Ergon Retail Tariff 11	Ergon Retail Tariff 20
Energy rate[121]	29.975 c/kWh	32.365 c/kWh
Fixed rate[121]	153.493 c/day	182.788 c/day
Feed-in tariff rate[122]	8.660 c/kWh	

Solar PV and battery packages

- Solar PV and battery sizing is typically driven by site load usage patterns, customer objectives, and the specific products available within a rapidly evolving industry. Indicative sizing of solar PV and battery systems have been selected for this analysis.

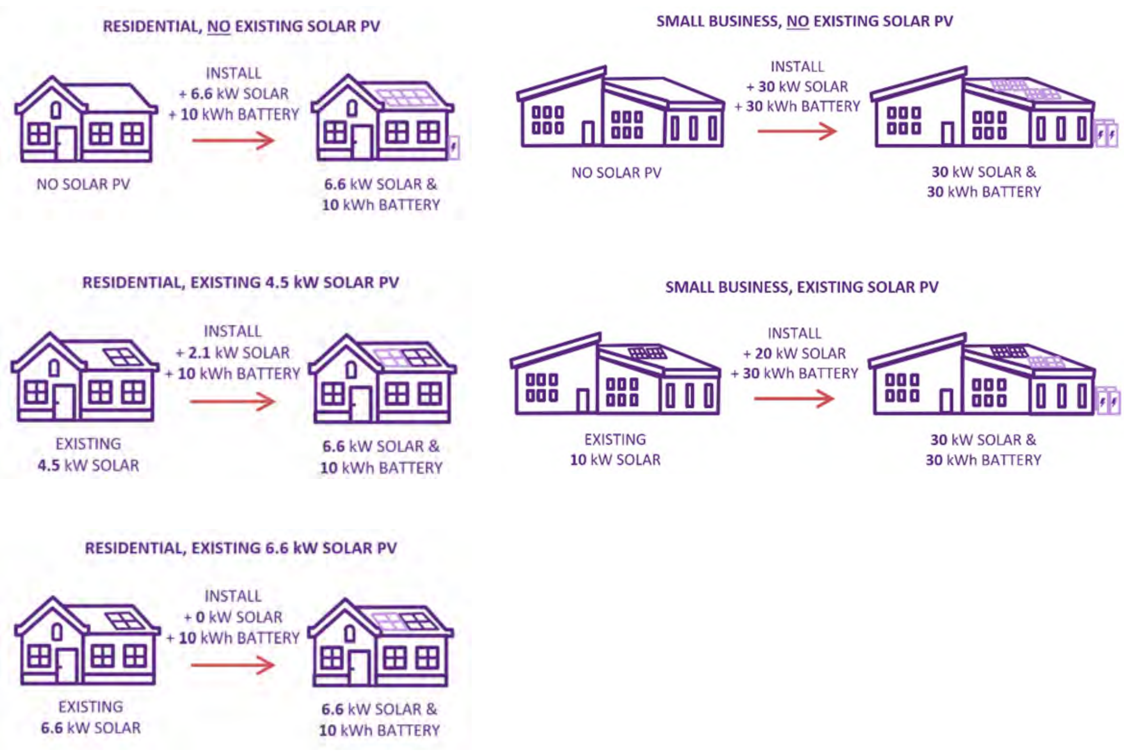


Figure 69 – Indictive solar PV and battery package assumed for each customer type

[121] Queensland Competition Authority, regulated retail electricity prices for regional Qld 2025-26, June 2025 final determination, 06.06.25 - [28] Extra Gazette.fm

[122] Queensland Competition Authority (QCA), Solar feed-in tariff in regional Queensland 2025-26, Final determination, June 2025 solar-fit-fact-sheet.pdf

18.2. Individual Results

18.2.1 Technical Results

The individual analysis results for each customer type are shown in Table 34 and Table 35 below.

Table 34 – Energy flow and electricity bill analysis results for typical residential and small business customers on flat rate tariffs

	Residential			Small Business	
	No Existing Solar PV	Existing 4.5 kW Solar PV	Existing 6.6 kW Solar PV	No Existing Solar PV	Existing Solar PV
BEFORE					
Annual Load Consumption	6,420 kWh			50,750 kWh	
Annual Grid Consumption	6,420 kWh	4,320 kWh	3,657 kWh	50,750 kWh	36,187 kWh
Existing Solar PV	-	4.5 kW	6.6 kW	-	10 kW
Annual Solar PV Generation	-	6,570 kWh	9,652 kWh	-	14,625 kWh
Existing Excess Solar PV	-	*3,641 kWh (55%)*	*6,889 kWh (71%)*	-	*61 kWh (0.4%)*
Tariff	11	11	11	20	20
Total Electricity Bill Annual Charges	$2,485	$1,350	$1,060	$17,092	$12,373
Annual Energy Charge	*$1,924*	*$1,130*	*$1,096*	*$16,425*	*$11,711*
Annual Fixed Charge	*$560*	*$560*	*$560*	*$667*	*$667*
Annual Feed-In Tariff	-	*$340*	*$597*	-	*$5*
Annual GHG Emission Savings	-	1.8 t CO2-e	1.96 t CO2-e	-	10.3 t CO2-e
Renewable Energy Fraction	-	41%	43%	-	29%
AFTER					
New solar PV	6.6 kW	2.1 kW	0 kW	30 kW	20 kW
Total solar PV	6.6 kW	6.6 kW	6.6 kW	30 kW	30 kW
New battery storage capacity	10 kWh	10 kWh	10 kWh	30 kWh	30 kWh
New solar PV generation	10,825 kWh	3,449 kWh	0 kWh	49,264 kWh	32,843 kWh
Total annual solar PV generation	10,825 kWh	10,030 kWh	9,652 kWh	49,264 kWh	47,468 kWh
Excess Solar PV	*4,731 kWh*	*3,868 kWh (39%)*	*3,678 kWh*	*17,136 kWh (35%)*	*14,843 kWh (31%)*
Solar PV to Load	*2,758 kWh*	*2,795 kWh*	*2,763 kWh*	*21,988 kWh*	*22,344 kWh*
Solar PV to Battery	*3,337 kWh*	*3,368 kWh*	*3,211 kWh*	*10,141 kWh*	*10,281 kWh*
Battery Output	3,042 kWh	3,070 kWh	2,925 kWh	9,228 kWh	9,356 kWh
Battery Losses	*301 kWh*	*303 kWh*	*289 kWh*	*913 kWh*	*925 kWh*
Annual Grid Consumption	621 kWh	556 kWh	733 kWh	19,535 kWh	19,051 kWh
Annual GHG Emission Savings	4.33 t CO2-e	4.4 t CO2-e	4.2 t CO2-e	23.0 t CO2-e	23.2 t CO2-e
Annual GHG Emission Reduction	4.33 t CO2-e	2.5 t CO2-e	2.3 t CO2-e	23.0 t CO2-e	12.8 t CO2-e
Renewable Energy Fraction	90%	91% *(+ 50%)*	89% *(+ 46%)*	62%	62% *(+ 34%)*
Tariff	11	11	11	20	20
Total Electricity Bill Annual Charges	$337	$392	$461	$5,505	$5,548
Annual Energy Charge	*$186*	*$167*	*$220*	*$6,322*	*$6,166*
Annual Fixed Charge	*$560*	*$560*	*$560*	*$667*	*$667*
Annual Feed-In Tariff	*$410*	*$335*	*$319*	*$1,484*	*$1,285*
Annual Electricity Bill Savings (Yr 1)	$2,148 *(86%)*	$958 *(71%)*	$598 *(56%)*	$11,587 *(68%)*	$6,825 *(55%)*

Table 35 – Energy flow and electricity bill analysis results for typical residential and small business customers switching to ToU tariffs

	Residential			Small Business	
	No Existing Solar PV	Existing 4.5 kW Solar PV	Existing 6.6 kW Solar PV	No Existing Solar PV	Existing Solar PV
BEFORE					
Annual Load Consumption	6,420 kWh			50,806 kWh	
Annual Grid Consumption	6,420 kWh	4,320 kWh	3,657 kWh	50,750 kWh	36,187 kWh
Existing Solar PV	-	4.5 kW	6.6 kW	-	10 kW
Annual Solar PV Generation	-	6,570 kWh	9,652 kWh	-	14,625 kWh
Existing Excess Solar PV	*-*	*3,641 kWh (55%)*	*6,889 kWh (71%)*	*-*	*61 kWh (0.4%)*
Tariff	11	11	11	20	20
Total Electricity Bill Annual Charges	$2,485	$1,350	$1,060	$17,111	$12,373
Annual Energy Charge	*$1,924*	*$1,130*	*$1,096*	*$16,443*	*$11,711*
Annual Fixed Charge	*$560*	*$560*	*$560*	*$667*	*$667*
Annual Feed-In Tariff	*-*	*$340*	*$597*	*-*	*$5*
Annual GHG Emission Savings	-	1.8 t CO2-e	1.96 t CO2-e	-	10.3 t CO2-e
Renewable Energy Fraction	-	41%	43%	-	29%
AFTER					
New solar PV	6.6 kW	2.1 kW	0 kW	30 kW	20 kW
Total solar PV	6.6 kW	6.6 kW	6.6 kW	30 kW	30 kW
New battery storage capacity	10 kWh	10 kWh	10 kWh	30 kWh	30 kWh
New solar PV generation	10,825 kWh	3,449 kWh	0 kWh	49,236 kWh	32,850 kWh
Total annual solar PV generation	10,825 kWh	10,030 kWh	9,652 kWh	49,264 kWh	47,468 kWh
Excess Solar PV	*4,731 kWh (44%)*	*3,868 kWh (39%)*	*3,678 kWh (38%)*	*19,716 kWh (34%)*	*17,951 kWh (38%)*
Solar PV to Load	*2,758 kWh*	*2,795 kWh*	*2,763 kWh*	*21,988 kWh*	*22,344 kWh*
Solar PV to Battery	*3,337 kWh*	*3,368 kWh*	*3,211 kWh*	*7,553 kWh*	*7,172 kWh*
Battery Output	3,042 kWh	3,070 kWh	2,925 kWh	9,705 kWh	9,672 kWh
Battery Losses	301 kWh	303 kWh	289 kWh	959 kWh	956 kWh
Annual Grid Consumption	621 kWh	556 kWh	733 kWh	22,149 kWh	22,170 kWh
Grid to Load	*531 kWh*	*497 kWh*	*526 kWh*	*19,058 kWh*	*18,734 kWh*
Grid to Battery	*98 kWh*	*64 kWh*	*224 kWh*	*3,091 kWh*	*3,436 kWh*
Annual GHG Emission Savings	4.33 t CO2-e	4.4 t CO2-e	4.2 t CO2-e	21.0 t CO2-e	22.2 t CO2-e
Annual GHG Emission Reduction	4.33 t CO2-e	2.5 t CO2-e	2.3 t CO2-e	21.0 t CO2-e	10.6 t CO2-e
Renewable Energy Fraction	90%	91% *(+ 50%)*	89% *(+ 46%)*	56%	56% *(+ 28%)*
Tariff	14C	14C	14C	22E	22E
Total Electricity Bill Annual Charges	$166	$225	$282	$4,386	$4,483
Annual Energy Charge - Peak	*$0*	*$0*	*$0*	$0	$0
Annual Energy Charge - Shoulder	*$132*	*$126*	*$131*	*$5,194*	*$5,118*
Annual Energy Charge – Off-peak	*$23*	*$14*	*$48*	*$215*	*$236*
Peak Demand Charge	*$0*	*$0*	*$0*	*-*	*-*
Annual Fixed Charge	*$420*	*$420*	*$420*	*$684*	*$684*
Annual Feed-In Tariff	*$410*	*$335*	*$319*	*$1,707*	*$1,555*
Annual Electricity Bill Savings (Yr 1)	$2,319 *(93%)*	$1,124 *(83%)*	$778 *(73%)*	$12,706 *(74%)*	$7,890 *(64%)*

The results show that with the addition of a battery, greater savings can be expected when switching to a ToU tariff (as per Table 35) compared to remaining on a flat rate tariff (as per Table 34). Actual electricity bill savings will differ depending on the site's load profile for both flat rate and ToU tariffs, though the variability is greater under ToU tariffs.

For flat rate tariffs, the total electricity usage and the timing of that usage determine how much solar generation can offset grid consumption (saving the flat rate c/kWh) and how much excess solar is exported to the grid (earning the feed-in tariff c/kWh).

For ToU tariffs, electricity usage during peak, shoulder, and off-peak periods allows for more targeted savings opportunities. A battery enhances this by storing solar energy or less expensive off-peak electricity and discharging during expensive peak periods. However, this also introduces additional risks:

- Battery sizing - if the battery is not appropriately sized for the site's energy needs, it may run out of charge during peak periods. This would force reliance on grid electricity at higher rates, reducing expected savings.
- Battery failure - in the event of battery malfunction or degradation, the site may be exposed to higher peak charges without the ability to shift consumption.
- Load flexibility - without a functioning battery, customers may only be able to reduce costs by manually shifting their energy usage to off-peak times. This has not been considered in this analysis and may not be practical or sufficient for all homes or businesses.

Therefore, while ToU tariffs paired with batteries offer greater potential for savings, they also require careful consideration of battery sizing, reliability, and the site's ability to adapt its load profile.

18.2.2 Capital Purchase Analysis

This section provides an analysis of the capital purchase of the BTM solar PV and BESS for each customer type.

The following assumptions have been made for this analysis:

Costs & Discounts:

- Capital:
  - $800/kW for Solar PV excl. GST
  - $1,000/kWh for BESS excl. GST
- Maintenance:
  - Annual cost of 1% of capital cost
- Solar STC = 8.2 STCs per kWp additional solar
- BESS STC = 9.3 STCs per usable kWh
- STC price = $38
- Installation year = 2025

Analysis:

- No VPP participation
- Real discount rate = 4.4%
- Tariff rates real escalation = 0%
- Term = 10 years

The capital purchase analysis results are shown in Table 36 below.

The key analysis metrics in Table 36 are as follows:

- Payback Period, the length of time required to recover the initial capital investment through electricity bill savings
- Rate of Return, the discount rate that equates to an NPV of zero
- Net Present Value (NPV), the total of all future cashflows (positive and negative) over the life of the investment discounted to the present
- Accumulated cashflow, the total net cash generated or expended by a project over the analysis term, calculated as the cumulative sum of annual net cashflows

Table 36 – Behind the Meter (BTM) estimated capital purchase payback for typical residential and small business customers

	Residential			Small Business	
	No Existing Solar PV	Existing 4.5 kW Solar PV	Existing 6.6 kW Solar PV	No Existing Solar PV	Existing Solar PV
New solar PV	6.6 kW	2.1 kW	0	30 kW	20 kW
Total solar PV	6.6 kW	6.6 kW	6.6 kW	30 kW	30 kW
New battery storage capacity	10 kWh	10 kWh	10 kWh	30 kWh	30 kWh
Estimated Total Capital Cost	$14,480	$10,880	$9,200	$52,000	$44,000
Estimated Capital Cost Solar	*$5,280*	*$1,680*	*-*	*$24,000*	*$16,000*
Estimated Capital Cost Battery	*$9,200*	*$9,200*	*$9,200*	*$28,000*	*$28,000*
Estimated Total Discount	$5,308	$3,906	$3,251	$19,243	$16,127
Estimated Solar STC Discount	*$2,057*	*$654*	*-*	*$9,348*	*$6,232*
Estimated Battery STC Discount	*$3,251*	*$3,251*	*$3,251*	*$9,895*	*$9,895*
Estimated Capital Purchase Price	$9,172	$6,974	$5,949	$32,757	$27,873
Flat Rate Tariff					
Tariff	11	11	11	20	20
Annual Electricity Bill Savings (Yr 1)	$2,148 *(86%)*	$958 *(71%)*	$598 *(56%)*	$11,587 *(68%)*	$6,825 *(55%)*
Payback Period	4.6 years	8.3 years	-	3.0 years	4.3 years
10-Year Rate of Return	19.9%	3.8%	-	38%	23%
10-Year Net Present Value	$6,965	-$182	-$1,882	$56,238	$25,522
10 Year Accumulated Cashflow	$10,660	$1,350	-$969	$76,730	$40,080
Time of Use Tariff					
Tariff	14C	14C	14C	22E	22E
Annual Electricity Bill Savings (Yr 1)	$2,319 *(93%)*	$1,124 *(83%)*	$778 *(73%)*	$12,706 *(74%)*	$7,890 *(64%)*
Payback	4.2 years	6.8 years	8.7 years	2.8 years	3.8 years
10-Year Rate of Return	22.9%	8.3%	3%	42.9%	27.3%
10-Year Net Present Value	$8,436	$1,247	-$367	$65,592	$32,026
10-Year Accumulated Cashflow	$12,480	$3,120	$902	$88,280	$45,760

The analysis was conducted over a 10-year period. While the expected lifespan of a typical residential battery system ranges from 10 to 15 years, most products come with a standard 10-year warranty. If the battery continues to operate beyond the warranty period, higher financial returns (including increased net present value and accumulated cash flow) are expected.

Solar PV panels typically have a lifespan of around 25 years. However, the associated inverter/s generally require replacement after 10 to 15 years. As such, the benefits of the solar PV systems are expected to extend well beyond the 10-year analysis period but the cost of inverter replacement should be accounted for.

The payback period is highly influenced by the solar PV and/or BESS purchase price offered by installers, as well as the total electricity consumption of the home or business. To account for this variability, a high-level analysis was conducted to generate a matrix showing simple payback periods across a range of capital costs and scaled grid consumption levels (amount of energy purchased from the grid, not total energy use).

Figure 70 below presents the simple payback matrix for a residential scenario without existing solar PV, based on the flat rate Tariff 11.

Simple Payback

Capital Cost ($) (excl. GST)							
$ 17,600	10.8	10.5	8.9	8.5	8.2	7.9	7.7
$ 16,400	10.0	9.8	8.3	7.9	7.6	7.3	7.1
$ 15,200	9.2	9.0	7.6	7.3	7.0	6.8	6.5
$ 14,000	8.4	8.2	7.0	6.7	6.4	6.2	6.0
$ 12,800	7.6	7.5	6.3	6.1	5.8	5.6	5.5
$ 11,600	6.9	6.7	5.7	5.5	5.3	5.1	4.9
$ 10,400	6.1	6.0	5.1	4.9	4.7	4.5	4.4
$ 9,200	5.4	5.2	**4.5**	4.3	4.1	4.0	3.9
$ 8,000	4.6	4.5	3.9	3.7	3.6	3.4	3.3
$ 6,800	3.9	3.8	3.3	3.1	3.0	2.9	2.8
Per year →	4,200	5,300	**6,400**	7,500	8,600	9,700	10,800
Per day →	11.5	14.5	17.5	20.5	23.6	26.6	29.6
	Grid Consumption (kWh)						
Annual Savings (Year 1) →	$ 1,800	$ 1,850	$ 2,150	$ 2,240	$ 2,320	$ 2,400	$ 2,480

Figure 70 - Simple payback matrix, residential no existing solar PV scenario (flat rate Tariff 11)

The analysis in Table 37 incorporates solar PV and battery degradation, which results in a gradual reduction in annual electricity bill savings over time. Consequently, the payback periods shown in the matrix above may be slightly lower than those in Table 37. For example, a scenario with 6,400 kWh grid consumption and a capital cost of $9,200 yields a simple payback of 4.5 years in the matrix, compared to 4.6 years in Table 37.

Simple payback matrices for all scenarios are provided in Appendix D, Section 23.1.

18.2.3 Energy and Electricity Payment Flow

The estimated energy flows and electricity payments for each customer type are shown in Figure 71 to Figure 75 below.

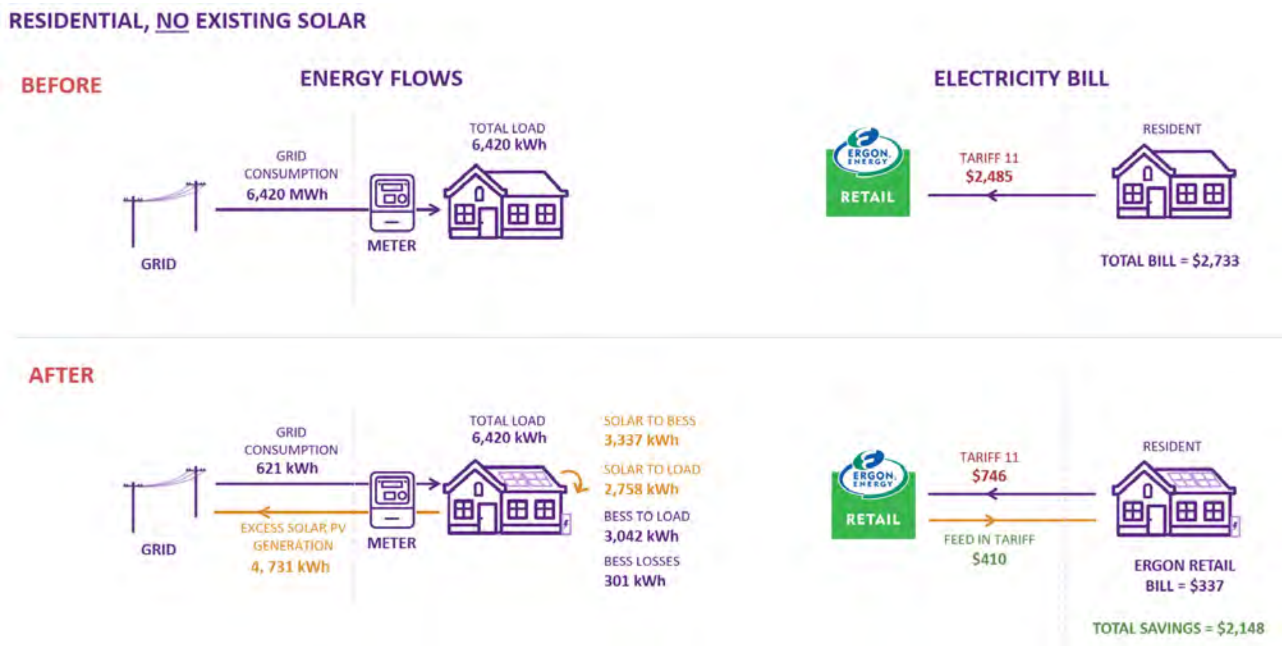


Figure 71 – Estimated impact 6.6 kW solar PV & 10 kWh battery to energy flows and electricity bill payments for residential customers with no existing solar PV

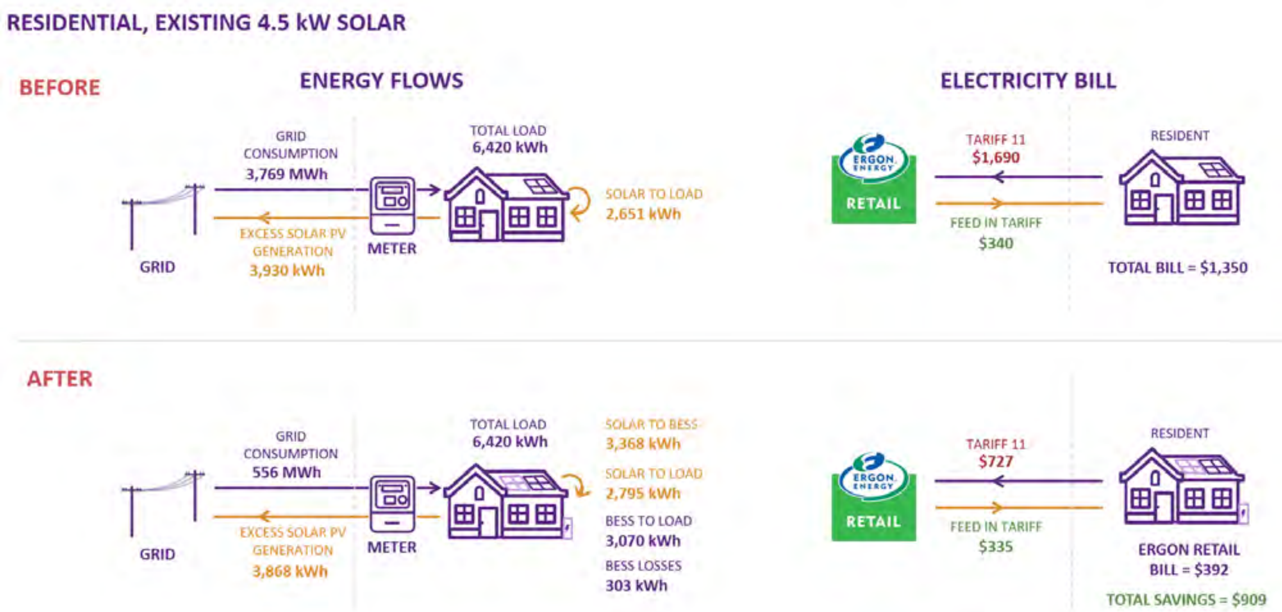


Figure 72 – Estimated impact of 2.1 kW additional solar PV & 10 kWh battery to energy flows and electricity bill payments for residential customers with 4.5 kW existing solar PV

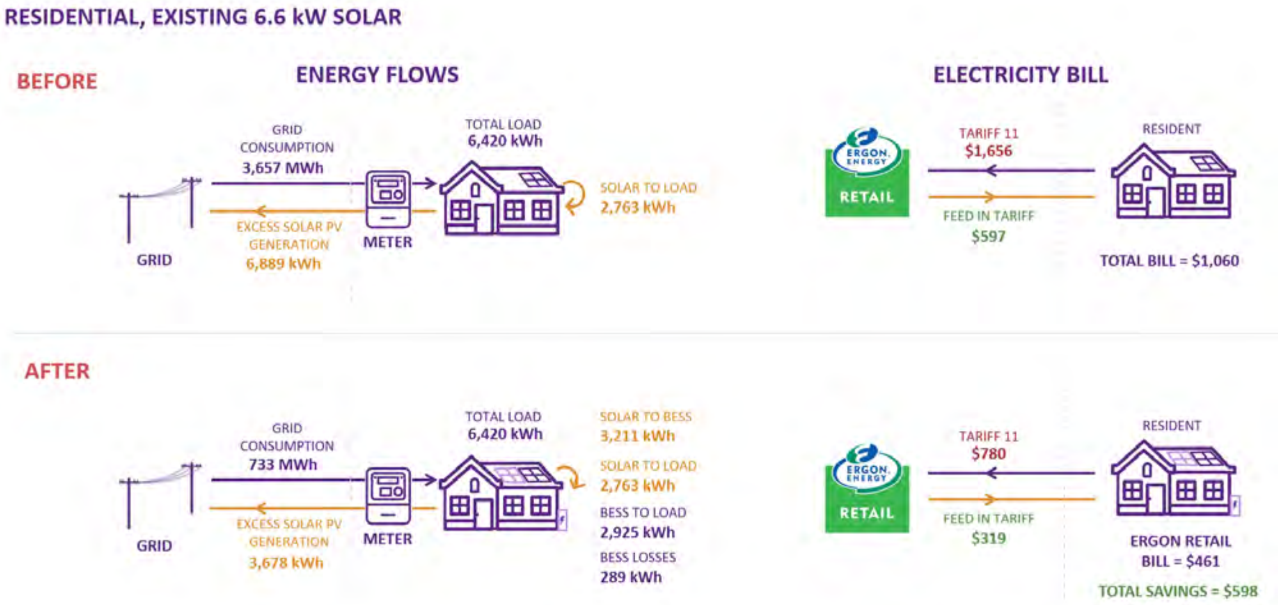


Figure 73 – Estimated impact of 0 kW additional solar PV & 10 kWh battery to energy flows and electricity bill payments for residential customers with 6.6 kW existing solar PV

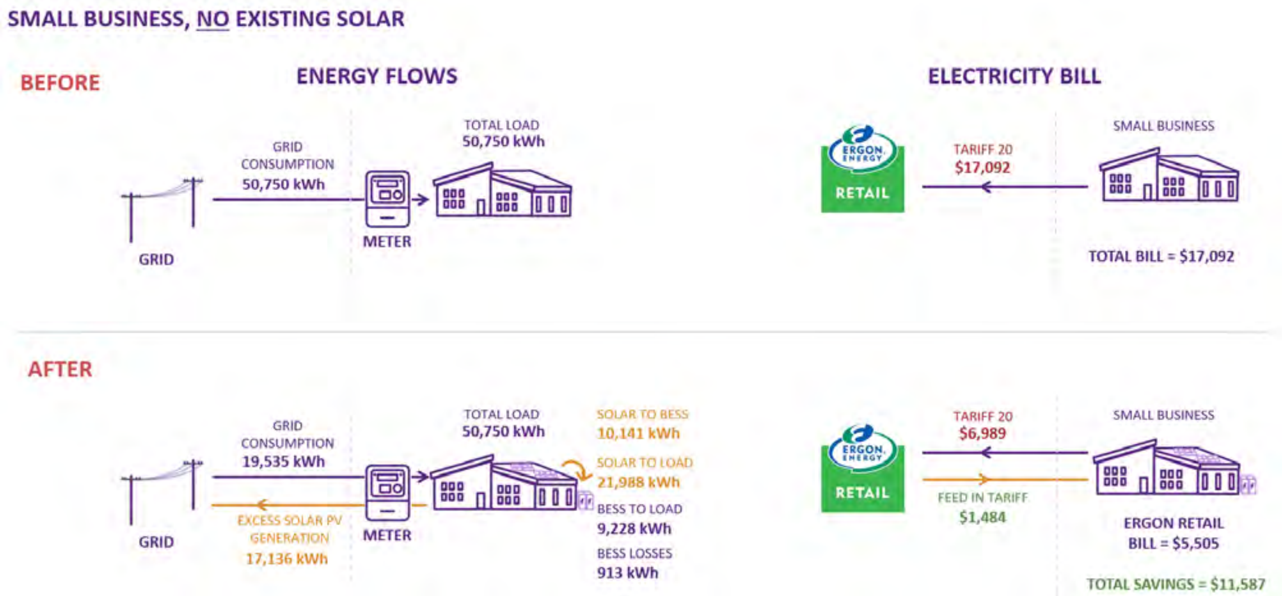


Figure 74 – Estimated impact of 30 kW solar PV & 30 kWh battery to energy flows and electricity bill payments for small business customers with no existing solar PV

Figure 75 – Estimated impact of additional 20 kW solar PV & 30 kWh battery to energy flows and electricity bill payments for small business customers with 10 kW existing solar PV

18.2.4 Analysis Limitations & Future Impacts

The behind the meter analysis provides an indication of the potential impact for typical residential and business customers over 10 years. Actual results will differ depending on multiple factors including the following:

- Site specific Solar PV and BESS sizing.
- Solar & BESS sell price offered by installers.
    - The modelling has assumed a nominal $/kW and $/kWh for installation. Pricing is variable depending on site specific conditions and contractor market rates.
- Load profile.
    - This includes how it differs to the assumed load profiles now and how it may change over 10 years as load usage behaviour changes. This will change how much solar PV energy can directly supply load and how much then needs to be exported or curtailed once the BESS is fully charged. As discussed above, this will also impact savings when switching to a ToU tariff.
- Actual solar PV generation.
    - The analysis has used an estimated solar PV generation profile based on a typical meteorological year. This means that 50% of the time, the actual solar PV generation is expected to be more than the estimated, and 50% of the time it is expected to be less. This would impact the amount of energy purchased through the PPA, supplied to the load, and exported to the grid.
- Any new Ergon Energy Retail optional or compulsory tariff changes beyond 2025/26.
- Ergon Energy Retail primary tariff prices beyond 2025/26.
- Ergon Energy Retail feed-in tariff price beyond 2025/26.

- If secondary tariffs are used for controlled loads.
    - It was assumed that all load is on a primary tariff. Analysis results would vary if customers have a secondary tariff. Loads on a secondary tariff cannot be supplied directly by the solar PV and BESS.
- The 44 c/kWh FIT ending 30 June 2028.
    - It has not been assessed the difference between upgrading to a larger solar PV system with BESS now and losing the 44 c/kWh feed-in tariff versus waiting until 2028 when less STCs are available for both solar PV and BESS.
- Any fixed or dynamic export limitations.
    - It has been assumed that all excess solar PV can be exported and benefit from the solar FiT however if export limits applied, this will reduce overall savings.
- Installation timing.
    - Install year has been assumed to be 2025. The later the install, the less STCs available to discount the capital purchase.

18.3. Magnetic Island Results

This section uses the results of the individual analysis to demonstrate the impact of additional BTM solar PV & BESS to Magnetic Island based on an assumed uptake.

The following assumptions have been made for this analysis:

- Existing Magnetic Island consolidated energy consumption and solar export as per 2023/24 data presented in 'Table 2 - Magnetic Island Consolidated Customer Connection Grid Consumption and Solar Export Summary'[123]
- Solar PV & BESS installations:
    - 25% of 1,920 total residential customers (480 residential customers). Of those 480 customers, 50% have existing solar PV (240 with, 240 without). Of those 240 customers with solar, 50% have 4.5 kW existing solar PV and 50% have 6.6 kW solar PV (120 with 4.5 kW existing solar PV, 120 with 6.6 kW existing solar PV).
    - 25% of 197 total business customers (50 small business customers). Of those 50 customers, 50% have existing solar PV (25 with, 25 without).
- All residential customers are on Tariff 11 only.
- All business customers are on Tariff 20 only.
    - Large business customers would be on a different Ergon Retail tariff to Tariff 20 (e.g. Tariff 44, 45, 46), or with a different electricity retailer. The analysis will still demonstrate the small business customer savings on Tariff 20.
- Solar PV and BESS capacity are installed proportionally to TM-03 and TM-10.
    - Modelling has been completed based on Magnetic Island as a total load. Solar PV and BESS capacities and load profile is expected to differ for each 11 kV feeder.

[123] Ergon Energy Network, Energy usage data by Postcode (XLSX) 2023/24 for 4819, https://www.ergon.com.au/network/our-network/network-data/energy-usage-data-to-share

- No existing energy storage. The existing BESS capacity is unknown for Magnetic Island. It has been considered negligible for this analysis.

The Magnetic Island total impact analysis results are shown in Table 37 below.

Table 37 – Energy flow and electricity bill impact analysis results for Magnetic Island with assumed uptake

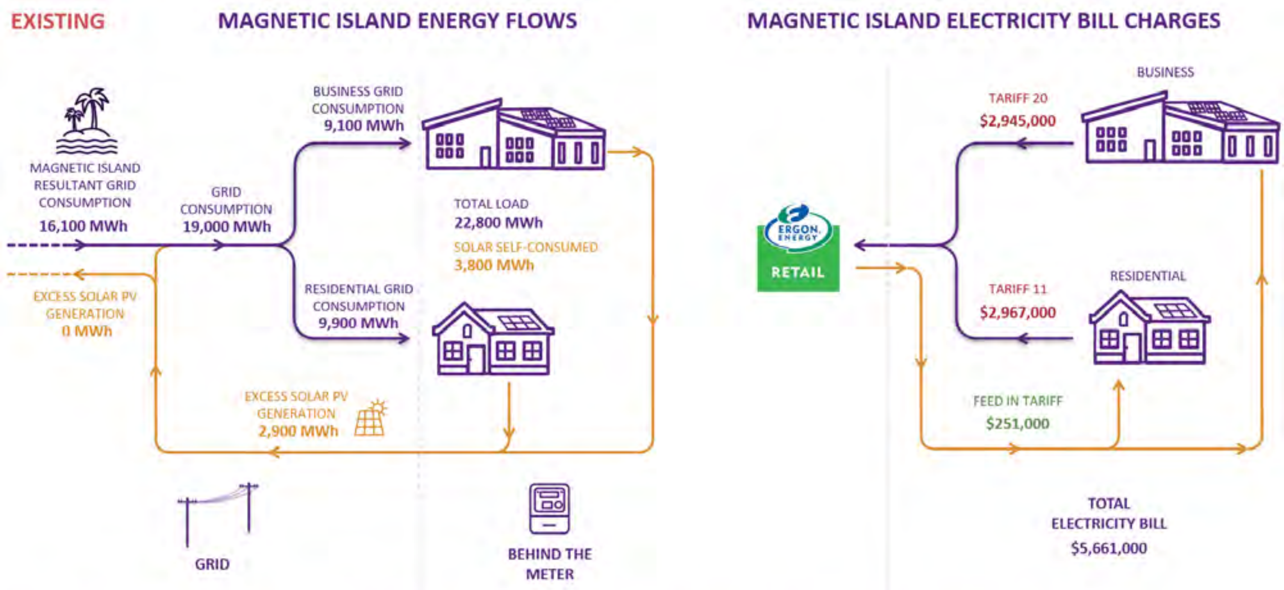
	Existing	After	Change
Estimated Total Annual Load Consumption	22,800 MWh	22,800 MWh	-
Total Annual Consolidated Grid Consumption	19,000 MWh	15,600 MWh	*-3,400 MWh*
Business	9,100 MWh	7,900 MWh	*-1,200 MWh*
Residential	9,900 MWh	7,800 MWh	*-2,100 MWh*
Solar PV Capacity	4,603 kWp[124]	7,689 kWp	*3,086 kWp*
BESS Capacity	-	6,350 kWh	*6,350 kWh*
Customer Count with Solar PV	614	879	*265*
Estimated Total Annual Solar PV Generation	6,720 MWh	11,790 MWh	*5,070 MWh*
Estimated self-consumed solar PV energy[125]	*3,800 MWh*	*7,100 MWh*	*3,300 MWh*
Exported solar PV energy (from individual sites)	*2,900 MWh (43%)*	*4,500 MWh (38%)*	*-1,706 MWh*
Exported solar PV energy (from Magnetic Island)	*0 MWh*	*200 MWh*	*-200 MWh*
Resultant Grid Consumption	16,100 MWh[126]	11,400 MWh	*-4,700 MWh*
Total Annual Charges	$5,661,000	$4,505,000	*$1,156,000*
Residential Annual Energy Charge (Tariff 11)	*$2,967,000*	*$2,338,000*	*-$629,000*
Business Annual Energy Charge (Tariff 20)	*$2,945,000*	*$2,556,000*	*-$389,000*
Annual Feed-In Tariff	*$251,000*	*$389,000*	*138,000*
Annual GHG Emission Savings	4,771 t CO2-e	8,226 t CO2-e	*3,455 t CO2-e*
Renewable Energy Fraction	29%	50%	*21%*

The estimated energy flows and electricity payments for all residential and business customers on Magnetic Island, before and after the assumed uptake, are shown in Figure 76 and Figure 77 below.

[124] As of end June 2024

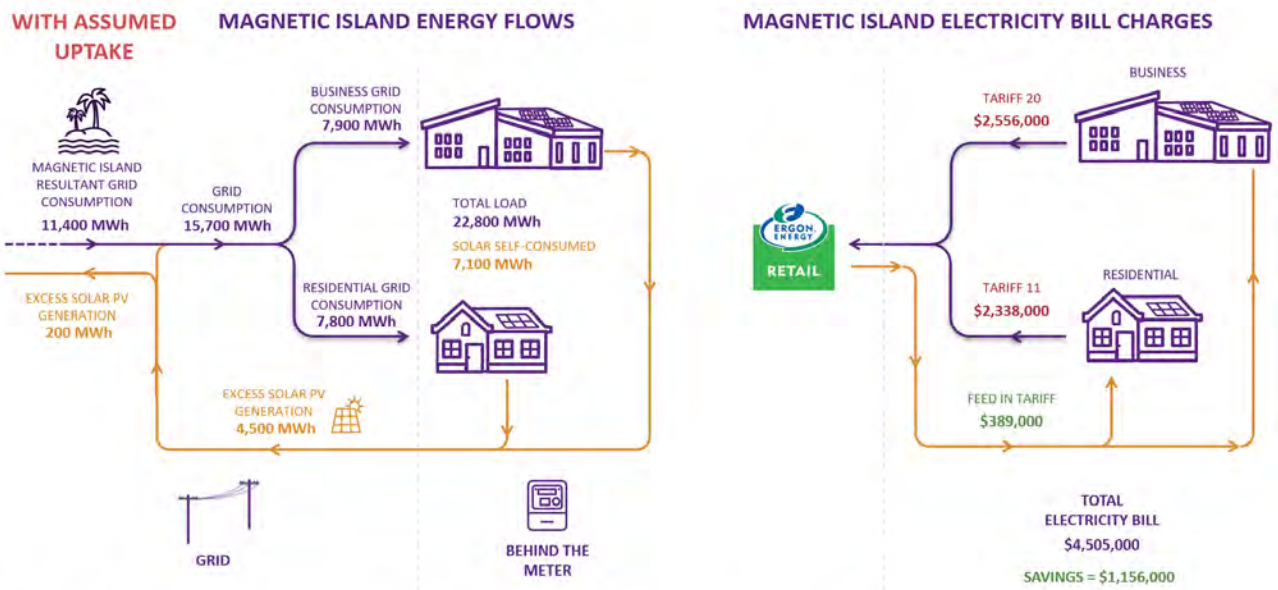
[125] Estimated self-consumed solar PV energy estimated by 'Estimated Total Annual Solar PV Generation' minus 'Exported solar PV energy (from individual sites)' minus 'Exported solar PV energy (from Magnetic Island)'

[126] Calculated from 'Total Annual Consolidated Grid Consumption' minus Exported solar PV energy (from individual sites). Sourced from 2023/24 data, Ergon Energy Network, Energy usage data by Postcode (XLSX) 1 Jan 2020 – 30 Sep 2024 for 4819, https://www.ergon.com.au/network/our-network/network-data/energy-usage-data-to-share



NOTE: Energy flows do not include distribution losses as they are based on consolidated energy consumption and solar PV export from individual customer meters.

Figure 76 - Estimated existing energy flows and electricity bill payments for Magnetic Island



NOTE: Energy flows do not include distribution losses as they are based on consolidated energy consumption and solar PV export from individual customer meters.

Figure 77 - Estimated impact of assumed uptake of BTM solutions (3.09 MW solar PV & 6.35 MWh battery storage capacity) to energy flows and electricity bill payments for Magnetic Island

19. Findings and Recommendations

This report evaluated multiple technical concepts for Horseshoe Bay and Picnic Bay to achieve a microgrid solution. A village wide microgrid is not a viable short term option, due to technical, regulatory and commercial barriers. However, the project found two options that are feasible, actionable now and are steps towards a future village or Island wide microgrid. Option one is a centralised 1 MW / 2 MWh BESS and option two is a BTM solar PV and BESS solution.

Centralised Option

The centralised solution was developed based on current technical feasibility, considering key influencing factors such as land availability, network connection options, potential economic return, operating model types, and future development opportunities.

The centralised BESS will operate in a way that shifts solar PV energy to times of higher demand which predominantly contributes to achieving MICDA's objective of maximising the village renewable energy fractions. Table 38 shows how a 1 MW/2 MWh centralised BESS is estimated to help reduce GHG emissions as solar PV continues to be installed within each village.

Table 38 - Estimated Renewable Fraction and GHG Emission Reduction with 1 MW / 2 MWh BESS

	Additional Solar PV Capacity	Renewable Fraction Solar PV Only (%)	Renewable Fraction with Solar PV and BESS (%)	Renewable Fraction Increase Due to BESS (%)	GHG Emission Reduction[127] (t CO2-e)		
					Solar PV Only	Solar PV and BESS	Due to BESS
Horseshoe Bay	0.5 MW	47%	52%	6%	1,772	2,027	256
	1 MW	50%	60%	10%	1,917	2,357	440
	1.5 MW	52%	63%	11%	1,973	2,455	483
	2 MW	53%	64%	11%	2,003	2,496	493
	2.5 MW	53%	64%	11%	2,023	2,518	495
Picnic Bay	0.5 MW	46%	54%	9%	986	1,264	278
	1 MW	50%	66%	16%	1,136	1,551	415
	1.5 MW	51%	69%	17%	1,171	1,613	442
	2 MW	52%	70%	18%	1,192	1,642	450

The centralised BESS does not directly support MICDA's goal of minimising outage duration. However, it can enhance system stability and reduce the likelihood of outages. If network backup becomes a formal support service in the future, the BESS could be upgraded to provide this function, thereby directly contributing to outage reduction.

Depending on how the centralised BESS project is developed and implemented, particularly with how the operating model is further refined, it has the potential to provide economic benefits for the asset owner and community members, although not directly on their individual electricity bills.

[127] Based on 2024 QLD Emissions Factor 0.71 kg CO_2-e/kWh, Table 1, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2024.pdf

The key activities in the project development stage include business case development, community engagement, land access arrangement for the proposed locations, planning and development approvals, environmental approval, and the development of key roles within an operational model.

Following the project development stage, the estimated timeline for delivering the 1 MW / 2 MWh centralised BESS is approximately 72 weeks. A significant portion of the delivery duration is the network connection assessment and the network embedded generation enquiry and assessment stages, ranging from 45 to 65 business days each.

The financial analysis indicates that a fixed revenue tolling arrangement offers no clear economic benefit if the asset owner is responsible for more than 10% of the capital investment. This is primarily due to the combination of high capital and operational costs, coupled with limited revenue from tolling. In comparison, a variable revenue option could provide greater economic benefits depending on market performance; however, it carries higher risk.

Key barriers for non-DNSP owned centralised BESS include the following:

- Network tariff costs, especially fixed charges, in addition to network application and augmentation costs and connection timeframes.
- Difficulty securing agreements with electricity retailers and uncertainty regarding their future value.
- In Regional Queensland, there is a lack of interest from retailers (other than Ergon Energy Retail) in offering residential or small business customers cost saving arrangements with a community battery due to high per customer costs.
- Ownership risk and challenges obtaining insurance.
- Lack of regulatory incentives to deploy centralised batteries.
- In Horseshoe Bay and Picnic Bay, a 1 MW capacity is currently limited to a dynamic network connection, creating uncertainty in BESS operation and revenue potential.

If MICDA proceeds with the centralised BESS concept, Yurika recommends:

1. Developing a clear business model to define stakeholders.
2. Investigating key project partnerships to determine arrangements and forecasted revenues and costs.
3. Progressing with acquisition of expected capital, either through, donations, grants, debt, equity, or combinations.
4. Developing a detailed business case using above inputs to evaluate whether to proceed.
5. Update concept design and submit Ergon Energy Network request for preliminary response if proposed solution has changed (e.g., different site) or if existing PRE has expired.
6. Evaluate Ergon Energy Network response and update business case for Final Investment Decision (FID).

Behind the Meter (BTM) Option

BTM solar PV and BESS solutions offer an alternative that increases the renewable fraction, reduces electricity costs, and improves supply reliability through battery backup for homes and businesses.

The assumed typical solar PV and BESS solution is estimated to have the following impact:

- Save residents between 56 and 93% on their Ergon Energy Retail electricity bills.
- Save small business owners between 55 and 74% on their Ergon Energy Retail electricity bills.
- Increase renewable fraction by between 28 to 50% for those with existing solar PV.
- Increase renewable fraction by 56 to 90% for those with no existing solar PV.
- Depending on configuration of backup loads supplied by the BESS, it is estimated to supply backup power for 5 hrs for an average small business load and 12 hrs for an average residential load.[128]

Capital purchase is a feasible finance option for BTM solar PV and BESS. The key results of the analysis are shown in Table 39 below. For households with existing solar PV, the added value of a small amount of additional solar PV and a BESS is lower compared to those without solar. The analysis found that the payback period for a capital purchase could be as long as 8.3 years (for the existing 4.5 kW solar PV) or no payback within a 10-year period (for the existing 6.6 kW solar PV scenario on a flat rate tariff).

Table 39 – BTM Analysis finance option key results

	Residential			Small Business	
	No Existing Solar PV	Existing 4.5 kW Solar PV	Existing 6.6 kW Solar PV	No Existing Solar PV	Existing 10 kW Solar PV
New solar PV	6.6 kW	2.1 kW	0	30 kW	20 kW
Total solar PV	6.6 kW	6.6 kW	6.6 kW	30 kW	30 kW
New battery storage capacity	10 kWh	10 kWh	10 kWh	30 kWh	30 kWh
Estimated Capital Purchase Price	$9,172	$6,974	$5,949	$32,757	$27,873
Flat Rate Tariff					
Tariff	11	11	11	20	20
Annual Ergon Retail Electricity Bill Savings (Yr 1)	$2,148 *(86%)*	$958 *(71%)*	$598 *(56%)*	$11,587 *(68%)*	$6,825 *(55%)*
Payback	4.6 years	8.3 years	-	3.0 years	4.3 years
10 Year Accumulated Cashflow	$10,660	$1,350	-$969	$76,730	$40,080
Time of Use Tariff					
Tariff	14C	14C	14C	22E	22E
Annual Ergon Retail Electricity Bill Savings (Yr 1)	$2,319 *(93%)*	$1,124 *(83%)*	$778 *(73%)*	$12,706 *(74%)*	$7,890 *(64%)*
Payback Period	4.2 years	6.8 years	8.7 years	2.8 years	3.8 years
10 Year Accumulated Cashflow	$12,480	$3,120	$902	$88,280	$45,760

The most suitable financial option depends on a customer's goals, cash flow preferences, risk tolerance, and specific installation offers. A customised analysis would include:

[128] Small business estimate based on an average small business load of 5.8 kW and BESS full usable capacity of 28 kWh. Residential estimate based on an average residential load of 0.7 kW and BESS full usable capacity of 9.2 kWh.

- Estimated site-specific savings.
- A quote for capital purchase.
- Appropriately sized solar PV and BESS systems matched to the site's load profile.
- Specific PPA offer and rate (if opting into a PPA as opposed to capital purchase e.g., Horan & Bird PPA/VPP).

A key consideration for a PPA option would include ensuring the solar PV and BESS sizing is suitable for the site’s specific load profile. Oversized systems that export most energy to the grid may be financially inefficient. For instance, a customer buying solar energy at a 20 c/kWh PPA rate and exporting it at the 2025/26 FiT rate of 8.66 c/kWh would incur losses on excess generation.

Assuming a 25% uptake from homes and businesses across Magnetic Island (of which, half have existing solar PV, and half do not), there would be an increase of approximately 3.1 MW of solar PV and 6.4 MWh of battery storage capacity (5.8 MWh usable). This is projected to result in a collective $1.156 million in annual savings on Ergon Energy Retail electricity bills and an increase of the island’s renewable energy fraction from 29% to 50% (a GHG emission reduction of 3,455 t CO2-e).

Overall Conclusion

A centralised BESS represents a step towards establishing a village or island wide microgrid, however, there are significant barriers that may be reduced or removed over time. A non-DNSP owned centralised BESS faces significant regulatory and economic challenges, while a DNSP owned centralised BESS is unlikely within the next 5–10 years.

Ergon Network have commenced a HV and LV grid-connected microgrid pilot projects with the sole objective to reduce grid outages for the connected customers. The outcomes of these initiatives are expected to support the implementation of microgrid solutions as a standard solution in 4–5 years’ time. Following this, third party owned BESS or microgrid solutions may become a more feasible for deployment on Magnetic Island.

BTM solar PV and BESS solutions are very well aligned with MICDA’s objectives, delivering tangible benefits to both residents and businesses. BTM solutions avoid many of the challenges faced by a centralised BESS, including the need for a new, large scale network connection, dynamic connection limitations, land acquisition and insurance complexities for non-DNSP owned BESS. Additionally, by generating and storing energy closer to the point of consumption, BTM solutions reduce network losses and improve overall system efficiency. The federal government Cheaper Home Batteries program introduced July 2025, has improved the economic case for BTM battery solutions.

Given the complexity and scale of a centralised BESS, Yurika does not recommend pursuing this option in the short term unless a more effective commercial model can be identified to support its implementation. In contrast, the BTM approach has become increasingly favourable and closely aligns with MICDA’s objectives. Yurika recommends proceeding with the BTM solution.

Magnetic Island Solar Skate Park

20. Appendix A

20.1. Electrical Safety legislation for HV assets

https://www.worksafe.qld.gov.au/__data/assets/pdf_file/0025/72637/managing-electrical-risks-in-the-workplace-cop-2021.pdf

Managing electrical risks in the workplace Code of practice 2021 Page 45 of 60

9. High voltage electrical work

Requirements for electrical work on high voltage equipment after switching, isolation, short circuiting and earthing are specialised requirements. Only competent electrical workers who have received appropriate training in high voltage electrical work are permitted to work on high voltage electrical equipment.

For more information you should seek further advice about working on or near high voltage electrical installations from a specialist electrical contractor or the local electricity entity.

9.1 Additional risks associated with high voltage

The electrical risks and consequences of an electrical incident involving high voltage may be significantly higher than with low voltage. Under fault conditions, the higher voltages (potentials) and fault current levels release massive quantities of energy.

9.2 Planning for high voltage installation work

A person conducting a business or undertaking (PCBU) that has a high voltage electrical installation should prepare an installation safety management plan for their workplace. The plan should address the risks associated with the operation and maintenance of the high voltage installation. This may include:

- a single line diagram for the installation, showing all switches and circuit breakers and their identifying labels or numbers
- site-specific operating rules covering all aspects of operating the high voltage installation, including procedures for arranging isolation of the installation from the local electricity network
- procedures for identifying hazardous areas including any confined spaces associated with the installation
- competency requirements for persons who may be permitted to operate or work on the high voltage installation, including appropriate requirements for re-training, re-testing and re-accreditation
- induction procedures for new contractors
- regular inspection and maintenance programs to ensure the installation remains serviceable and safe
- procedures for ensuring there is no extension or alteration of the installation without permission from the local electricity supply authority
- procedures for the safe handling of insulating oils and other substances that may be required for maintenance or repair
- procedures including warning signs for ensuring that no parts of the high voltage installation (e.g. underground cables and high voltage overhead powerlines) are damaged by heavy vehicles or other mobile plant, for example mobile cranes.

20.2. Microgrid factsheet

What is a Microgrid?

Ergon Energy NETWORK | energex

Part of Energy Queensland

A microgrid[1] is a group of interconnected electrical loads and energy resources such as solar, wind, diesel generators and batteries operating as a single controllable system that can function independently of the electricity distribution network.

They can range in scale from supporting a single customer, to powering an entire community. Grid-connected[1] microgrids maintain a connection to the electricity distribution network while being able to temporarily disconnect and operate in an 'islanded' mode. Stand-alone[1] microgrids have no connection to the network and operate in a permanently disconnected state.

Energex and Ergon Energy Network treat a grid-connected microgrid as an embedded network, and a stand-alone microgrid as a stand-alone power system (SAPS).

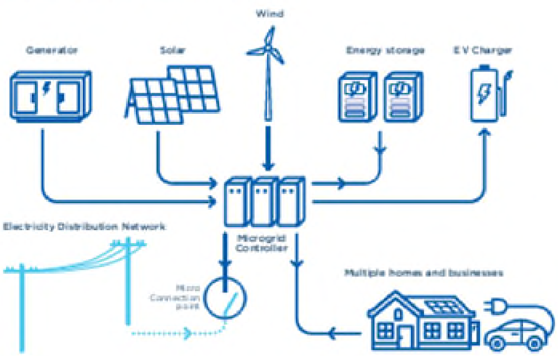
How do they work?

A smart technology microgrid controller co-ordinates the loads and energy resources to optimise the power flows in a microgrid. For grid-connected microgrids, it also controls the seamless connection or disconnection of the system to the network.

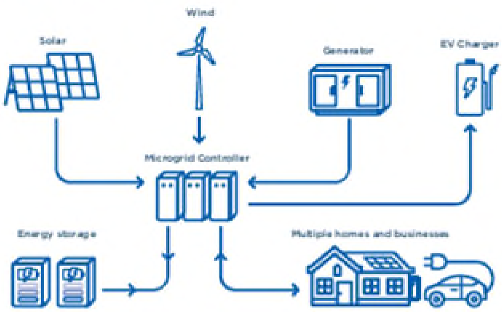
While the energy resources in a grid-connected microgrid have enough capacity to supply the electrical loads, it can disconnect from the network making the system self-sufficient when required. A driver for operating in this mode may be to maintain supply to critical loads during a network outage. While connected to the electricity distribution network, the microgrid controller will also control the import and export of electricity from the network to optimise local use of generation and storage, or to sell excess electricity back into the grid.

Unlike grid-connected microgrids, SAPS are completely reliant upon their own energy resources because they have no connection to the network. SAPS are an option when it is not economically or technically possible to connect to the electricity distribution network.

Grid-Connected Microgrid



Stand-Alone Microgrid



[1] Please note the definition of the terms "microgrid", "stand-alone microgrid" and "grid-connected microgrid" used in this fact sheet are technical definitions based on international standard IEEE 2030.9:2019 'IEEE Recommended Practice for the Planning and Design of the Microgrid'. The definition of the term "microgrid" in the AER's Regulated SAPS context does not include grid-connected systems, referring to stand-alone systems only. The IEEE definition has been used in this document to align with more common use.

Who owns the Microgrid?

Micrograds may be:

- privately owned, like embedded networks or privately owned SAPS, or
- owned by distribution network service providers (DNSP) such as Energex and Ergon Energy Network.

All electrical network infrastructure in a private microgrid must be owned, operated, and maintained by the microgrid owner. In privately owned grid-connected microgrids, the owner is responsible for their network up to the Connection Point (CP) to the DNSP-owned network.

If you propose to acquire infrastructure owned by the DNSP to create a private microgrid you must also consider whether the area includes other electrical infrastructure such as public lighting owned by the Local Government Authority (LGA), Department of Transport and Main Roads (DTMR), or other utilities. Transfer of ownership of these assets requires approval from the owner and commercial negotiation based on the function and value of the assets. Some DNSP assets cannot be privately owned due to their role in the operation and security of the electricity distribution network.

Do customers connected to a microgrid still pay a power bill?

In a grid-connected microgrid where the owner is the only customer, the microgrid owner will still purchase electricity supplied from the network through a retailer. For a micro-grid supplying multiple customers, each customer will have a contract with a retailer and still be charged for access to the microgrid and the energy they use. The retailer may be the microgrid owner or it could be another retailer in the market.

How to connect a private microgrid to the Energex or Ergon Energy Network

Privately owned SAPS are not connected to Energex or Ergon Energy Network electricity networks and therefore no connection application is required for this type of microgrid. You should be aware that state and national regulations governing the construction and operation of the SAPS will still apply.

It is likely your connection of a private grid-connected microgrid that supplies multiple customers will be treated as an embedded network. A summary of regulatory information regarding embedded networks can be found on this website Embedded electricity networks. A connection enquiry can be submitted through the Energex or Ergon Energy Network portals: Portals - Energex or Portals - Ergon Energy.

To help determine if a microgrid is appropriate for your requirements, you should speak to a suitably qualified consultant.

What to consider when thinking about creating a private microgrid

Ownership - Who will own the electrical infrastructure in your microgrid? Under present arrangements, you must own the infrastructure in your private microgrid, including any public lighting, and have responsibility for its operation and maintenance. This may require you to negotiate the purchase of existing DNSP, DTMR or LGA assets that are within the proposed microgrid.

Customers - If the private microgrid includes customers who are currently connected to the electricity distribution network, they must **all** provide written consent to becoming a part of the microgrid. This will require the abolishment of their existing connection agreements with the DNSP and may impact their options for energy retailer choice.

Network Regulations - Where a private microgrid supplies multiple customers the microgrid owner may need to register the system with the AER or receive an exemption from registration. Consideration also needs to be given to Queensland jurisdictional requirements relating to authorisations. There are a range of regulatory, technical and safety obligations relating to the specification of equipment, the sale of energy, and the operation and maintenance of the system that will apply. More information can be found on these websites: AEMO - Register as a Network Service Provider (NSP) in the NEM, AER - Authorisations & Network exemptions and Energy | Business Queensland.

Storing and Exporting Energy - Will the grid-connected microgrid store or export energy back to the electricity distribution network? Network limitations and dynamic operating envelopes (DOE) may govern the amount of energy that can be imported from or exported to the distribution network and when this is permitted. Read more on Dynamic Customer Standards FAQ.

Operating Mode - Will the microgrid run permanently stand-alone with no connection to the main electricity distribution network i.e. is it a SAPS? Will it have a connection to the network and operate in a connected mode for most of the time, only islanding as a back-up function? Or will it operate in an islanded mode for most of the time, only using the network as a back-up? The operating mode will determine the rules and regulations the microgrid must comply with and the type of switching and protection equipment required. See the Qld Electricity Connection Manual for more information.

For more information visit
ergon.com.au | energex.com.au

Part of Energy Queensland

20.3. Townsville City Council Material Change of Use Fact Sheet

MATERIAL CHANGE OF USE

What is a Material Change of Use?

A Material change of use is when a property is developed by altering the way it is utilised. A Material change of use, applies to any of the following:

- start of new use of a building or land;
- re-establishment of a use on the premises that has been abandoned;
- increase in the intensity or scale of the existing use of the land.

If your development constitutes a Material change of use, a development permit may be required from Council. If you are unsure if the development constitutes a Material change of use please confirm with Council.

Do I need planning approval?

The Townsville City Plan identifies whether your development requires a Development Permit to operate. Firstly, you must determine the defined use of your development by reviewing the use definitions in Schedule 1. Once the use is determined, visit the Table of Assessment in Part 5, which determines the level of assessment for the use within a particular zone. If the site is subject to an overlay you will also need to confirm if the overlay elevates the level of assessment.

The four levels of assessment are as follows:

Accepted Development	Development does not require a development permit from council to operate.
Accepted development subject to requirements	Development must comply with the Acceptable Outcomes of the applicable codes. If non-compliant, development requires a development permit from Council
Code Assessable	A development permit is required from Council. Assessment is against the applicable codes.
Impact Assessable	A development permit is required from Council. Assessment is against the entire Townsville City Plan and Public Notification is required.

Timeframe

The *Planning Act 2016* and related material sets out the assessment timeframes which vary by assessment level. The below illustration demonstrates the legislative timeline for a code assessable application requiring referral. For impact assessable applications add 15 b.d for Public notification (30 b.d for a variation request application) and 10 b.d for the assessment manager to consider submissions. Timeframes can be extended by mutual agreement.

Lodging an application

Confirmation Notice
10 business days

Infomation Request
10 business days

Referral
20 business days

Decision Period
35 business days

Decision Notice
5 business days

Planning and Development
MATERIAL CHANGE OF USE

How to lodge an application

An application can be submitted to Council by one of the following methods:

- Townsville Online Lodgement System (TOLS)
- Email developmentassessment@townsville.qld.gov.au
- In person at Councils Customer Service Centre, 103 Walker Street Townsville
- Post to PO Box 1268 Townsville QLD 4810.

What is required to lodge an application?

When lodging an application the following materials are required to allow the application to be considered 'properly made' and the assessment process to start:

- DA Form 1 (Development application forms and templates | Planning (statedevelopment.qld.gov.au))
- landowners consent
- plans of the development
- report addressing the applicable codes of the Townsville City Plan
- payment of the development application fees.

Depending on the nature of the application, technical reports may also be required for Council's assessment of the application (traffic, flood, stormwater, noise etc). Well prepared applications may proceed through the assessment process faster.

Application fees

Fees are applicable to each application lodged with Council. To find the fees associated with a Material Change of Use application for a particular use, please refer to Fees and Charges schedule.

Infrastructure Charges

Council levies infrastructure charges for development which generate additional demand upon trunk infrastructure networks. For more information, please read Councils infrastructure charges information sheet or contact the council for a fee-free infrastructure charge estimate before engaging in any development activity.

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Planning and Development

MATERIAL CHANGE OF USE

Frequently asked questions

How long is an approval valid?

Typically, a development approval, for a Material change of use is current for 6 years from when the approval takes effect. This means that the operation of the use must commence before this period ends. Before a development approval lapses, you can apply to council to extend the currency period.

Can I discuss my proposal with Council before I lodge an application?

Yes. To streamline the development assessment process and improve development outcomes, we recommend discussing the development proposal in detail with the Council before lodging an application. To arrange a free pre-lodgement meeting with the Council, please complete the following form (link).

Difference between Code and Impact Assessable

A code assessable application is required for uses that align with the property's zoned intent and is assessed against the applicable codes from the Townsville City Plan.

An impact assessable application is required for uses that are not anticipated by the planning scheme and assessed against the entirety of the Townsville City Plan, which includes strategic intent. During the 15-day public notification period, members of the public can make submissions for or against the proposed development. The assessment manager reviews all properly made submissions and considers valid planning grounds raised.

Referral Agencies

During the development assessment process, some applications require assessment by referral agencies. Referrals are commonly required for properties that are subject to state interest or private entity infrastructure. It is the applicant's responsibility to ensure the application is referred to all applicable referral agencies.

Will I need to carry out public notification?

Public notification is mandatory for Impact Assessable Development Applications. The notification process must last at least 15 business days and include:

- notice in the newspaper
- notice posted at the subject site
- notice given to adjoining landowners.

Council will consider any submissions received during the public notification period during its assessment.

What other approvals do I need?

Once you obtain a Material change of use development permit, you may need additional permits. These typically include permits for:

- Operational works, such as earthworks, roads, stormwater, and drainage
- Building work
- Plumbing and drainage
- Road works

It's important to note that there may be additional approvals required beyond the permits listed above.

When can I commence operating my development?

After receiving approval and the appeal period ends (usually 20 business days), you must meet the conditions of the development permit. This may include getting further approvals from council, works onsite, or compliance assessment. You will also need to pay any infrastructure charges that may be applicable.

Can I change an existing development approval?

Yes. If an approval for an existing use on the site already exists, you may request alterations to the development. Depending on the scale of the changes, the approval can be achieved through the 'minor change', or 'other change' mechanism.

Need further info?

For further information regarding the Material change of use process, please contact Council's Planning and Development to discuss.

For more information please contact Planning and Development: 13 48 10 enquiries@townsville.qld.gov.au townsville.qld.gov.au

20.4. Townsville Local Renewable Energy Zone (LREZ) Flyer

More clean energy. Stored locally. Used locally.

Townsville's Local Renewable Energy Zone – sharing the benefits of the energy transition.

Townsville's Local Renewable Energy Zone (LREZ) pilot project site, to the north of the city, will help the community generate more renewable energy, and store it and share it locally across the poles and wires infrastructure that already exists.

LREZs aim to put customers at the centre of the energy transition where local customer energy resources, like solar, batteries, electric vehicles, hot water systems and other appliances can work closely with network-connected batteries, and the state's existing electricity infrastructure to take full advantage of the scale and value of the roof tops of Queenslanders.

Along with the second LREZ site in Caloundra, this is a nation-first project to maximise the value of locally produced renewable energy for all customers, including renters, low-income households and those who live in unit complexes and do not have access to solar power.

Roof top solar is already a significant contributor to our emissions reduction targets, however, there remains untapped potential for roof tops to host even more solar. The LREZ seeks to encourage increased levels of renewable energy generation in the community, with support from batteries, to get the most benefit from the existing poles and wires.

The LREZ enables communities to lead the way in the renewable energy transition and will bring together customers, retailers, and electricity networks for a co-ordinated collaborative approach to delivering on renewable energy targets supporting not only the local area, but also the Queensland energy system.

The pilot project will include partnerships with universities and other stakeholders, to help inform customer incentive programs, economic models, customer adoption and behavioural change strategies, and technical standards.

Townsville's Local Renewable Energy Zone is in the growth corridor north of the city.

Households with solar	46%
Households with smart meters	41%
Dwellings rented	35%
Small business with solar	18%

Community batteries, connected into the local network, will play an important role.

What does the LREZ involve?

Across Townsville's LREZ we are looking to install up to 8.4MW/18.8MWh of energy storage and support up to an additional 2.8MW of rooftop solar, with 0.9MW of demand management across residential and commercial customer sites. It will work with behind the meter customer assets, such as solar, batteries, and home energy management systems.

The communities proposed for the pilot zone include Mount St John, Bohle, Burdell, Deeragun, Jensen, Beach Holm, Mount Low, Bushland Beach, Rangewood, Bohle Plains, Shaw, Cosgrove and Mount Louisa.

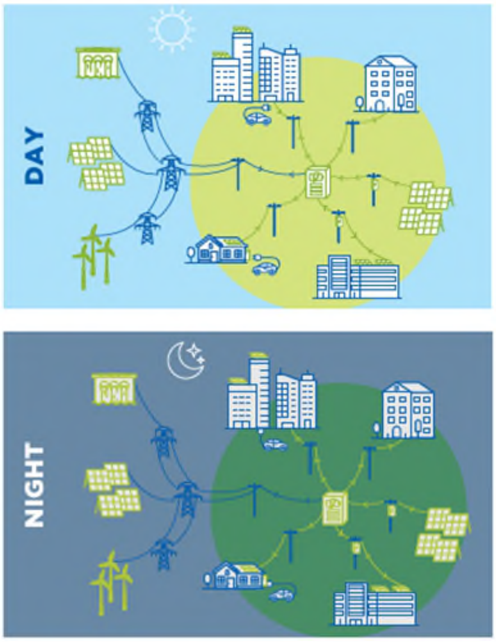
The LREZ is being funded by the Queensland Government, and will be rolled out over the coming three to four years.

It is being expanded by the Queensland Solar Bank project, funded by the Australian Government, which aims to roll out an additional 5.3MW of rooftop solar focusing initially on the LREZ zones and surrounding areas, with the benefits shared across 5,500 low-income households. We are engaging now on how to best ensure equitable access to the benefits of new technologies, and the energy transition more broadly.

The outcome of the two pilot sites will provide pathways for policy, economic, social and technical solutions to sustain a delivery model for future LREZ roll-out across Queensland.

LREZ aims to:

- Improve the reliability and resilience of energy supply, by providing a self-sufficient source of clean energy and storage locally
- Reduce the infrastructure investment required in our electricity distribution system by smoothing Queensland's peak solar energy profile
- Enable the grid to be ready for more EVs by co-locating solar, storage, and EV charging to reduce the need to upgrade the grid as demand for EV infrastructure grows
- Help move Queensland to a renewable energy future and towards the Queensland Government's target of net zero emissions by 2050.



The LREZ will be a coordinated, local energy system, led by customers, to support the renewable energy transition.

For updates visit
ergon.com.au/lrez

ERGON ENERGY NETWORK
Part of Energy Queensland

21. Appendix B

21.1. Horseshoe Bay Park LV Microgrid Example

Horseshoe Park was suggested as a potential site for an LV microgrid that could be used as an emergency community hub.

The existing loads (separate network connections) at Horseshoe Bay Park are relatively small and include the following:

- Skate park and picnic pavilion
- Community centre building
- The Rural Fire Brigade
- Telstra cell tower

If the site were to be developed into a microgrid, the Telstra cell tower may be too far away to be connected via an LV cable run. Given the technical characteristics are unknown, it will be excluded from this example. An LV microgrid concept for Horseshoe Bay Park is shown in Figure 78 below.

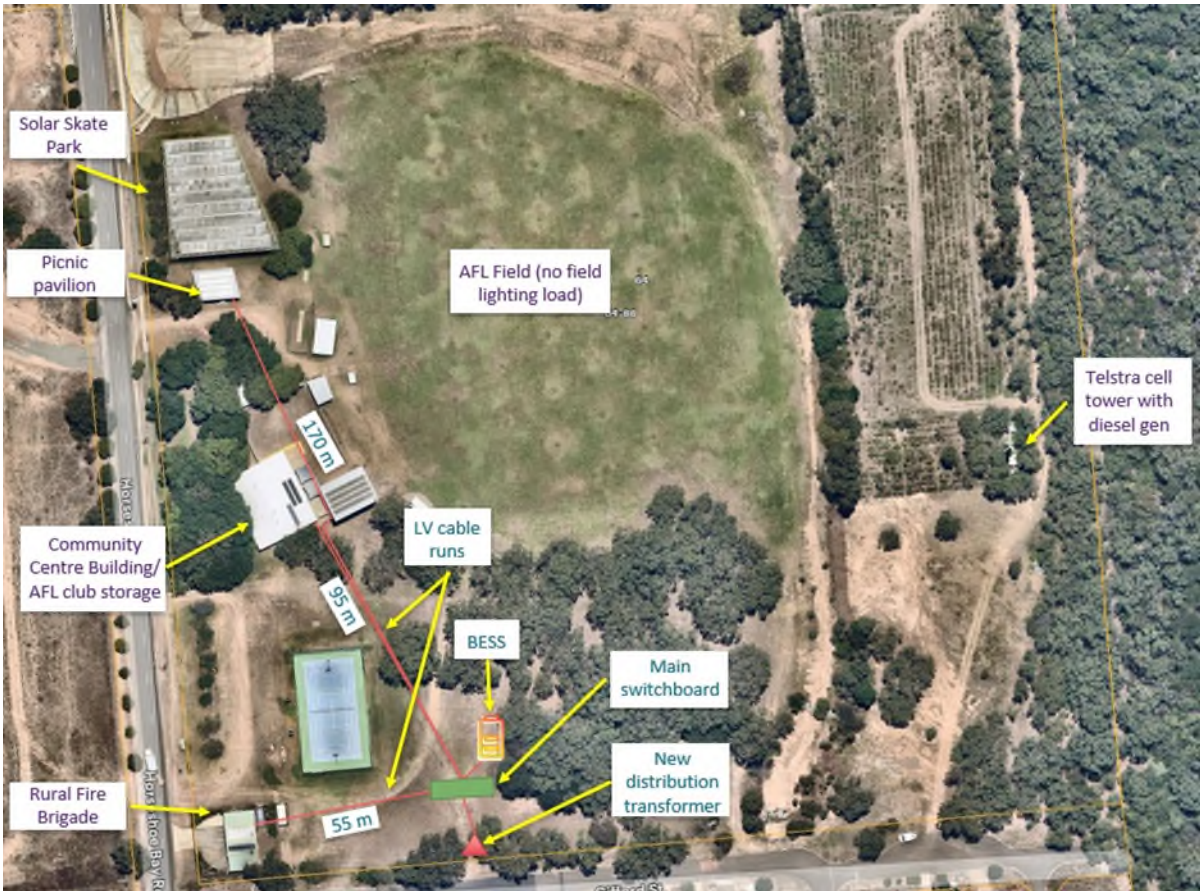


Figure 78 - Horseshoe Bay Park loads and LV microgrid example

A summary of the existing solar PV at Horseshoe Bay Park is shown in Table 40 below.

Table 40 - Horseshoe Bay Park existing solar PV

	Skate park and picnic pavilion	Community centre
Solar PV Capacity	99.5 kW 91.1 kW (skate park) 8.4 kW (picnic pavilion)	Estimated 14 kW 3 kW (main building) 11 kW (stage)
Install Year	2011	2009 (main building) 2011 (stage)
Solar PV Panels	474 x 210 W Kyocera KD210 panels 434 panels (skate park) 40 panels (picnic pavilion)	23 x 130 W Kyocera KC130 panels (main building) 52 x 210 W Kyocera KD210 panels (stage)
PV Inverters	1 x Sungrow SG30CX 6 x 15kW SMA STP 15000TL	2 x 1.7 kW SB1700 2 x 5kW SMC5000A

The existing solar PV system could be upgraded to a larger capacity system by replacing the solar panels and installing more solar PV inverters. Solar panels have an expected lifetime of 25 years so an assessment of the current condition and performance of the solar panels would need to be completed. Any future replacement of the skate park PV panels would have additional complexities given the custom shade structure built as part of the solar PV installation is constructed using the solar PV panels as the roof.

With very small site loads, combining into a single network connection would provide minimal energy bill savings, particularly given the existing loads would each be on a flat rate small business tariff (Ergon Retail Tariff 20). There is no potential to save on demand charges with a flat rate tariff.

When operating at full capacity, the existing 114 kW solar at Horseshoe Bay Park is estimated to generate approximately 410 kWh/day[129]. The total energy requirements of Horseshoe Bay Park are estimated to be 27 kWh/day. Without a BESS, the majority of solar PV generated would be exported to the main grid without receiving the regional solar feed-in tariff (8.66 c/kWh[130]) as systems greater than 30 kW are not eligible. The addition of the BESS enables greater solar PV self-consumption, avoiding energy being exported to grid.

Table 41 shows the individual annual tariff charges for each Horseshoe Bay Park load and the annual tariff charges applied at single parent connection for an LV microgrid. For the simplicity of this example, the following assumptions are made:

- The BESS is oversized so that the entire site's energy requirements can be supplied by the solar PV.
- The site remains connected to the grid so the BESS can be used for front of meter market participation and excess solar PV can still be exported and used locally on the island.
- The site remains on Ergon Retail Tariff 20.

[129] Based on assumption 4 kWh solar energy generated per kW of solar installed per day x 90% (to account for PV panel degradation since installation).
[130] Queensland Competition Authority (QCA), Solar feed-in tariff in regional Queensland 2025-26, Final determination, June 2025 solar-fit-fact-sheet.pdf

Table 41 - Horseshoe Bay Park load estimated tariff charges

	Skate park and picnic pavilion	Community centre	Rural Fire Brigade	Combined + BESS
Tariff	Ergon Retail Tariff 20	Ergon Retail Tariff 20	Ergon Retail Tariff 20	Ergon Retail Tariff 20
Energy Rate[131]	33.404 c/kWh	33.404 c/kWh	33.404 c/kWh	33.404 c/kWh
Fixed Rate[124]	182.788 c/day	182.788 c/day	182.788 c/day	182.788 c/day
Annual Grid Consumption[132]	3,300 kWh	4,000 kWh	4,500 kWh	0 kWh
Annual Energy Charge	$1,068	$1,295	$1,456	$0
Annual Fixed Charge	$667	$667	$667	$667
Total Annual Tariff Charge	$1,735	$1,962	$2,124	$667
	$5,921			

With an existing flat energy rate tariff, the potential savings include:

- Fixed charges
  Instead of paying three sets of fixed charges, there is only one set. This is an annual saving of $1,334.
- Energy charges
  Depending on BESS size, it could potentially remove all energy charges. This is an annual saving of $3,819.

The maximum potential annual electricity bill savings for Horseshoe Bay Park, based on the existing load and tariffs, is approximately $5,153 ($1,334 from fixed costs and $3,819 from energy costs). Excluding the capital cost of a BESS, the augmentation works on site required to electrically combine the three separate loads is expected to be more than $300,000.

The addition of a BESS would not provide significant annual energy bill savings. The BESS could be charged “for free” from existing solar, however there is limited load that could be powered from the BESS. The BESS could also be used for front of the meter (FTM) market participation. FTM market participation could be FCAS, or FCAS and wholesale energy. For FTM market participation, there is additional upfront and ongoing costs to participate.

[131] Tariff rates based on QCA June 2025 final determination for 2025-26, excluding GST.
[132] Estimated annual grid consumption.

21.2. Residential Street LV Microgrid Example Current State Estimate

Table 42 shows the existing energy bill costs for the residents. Residents without solar pay approximatley $2,485 each and residents with solar pay approximately $1,210 each. The total annual energy bill costs of all 19 residents are approximately $29,366.

Table 42 - Horseshoe Bay TVS3729 residential street LV microgrid estimated existing tariff charges

	Individual Resident Without Solar	Individual Resident with Solar
Tariff	Ergon Retail Tariff 11	Ergon Retail Tariff 11
Energy Rate[133]	29.975 c/kWh	29.975 c/kWh
Fixed Rate[126]	153.493 c/day	153.493 c/day
Feed in Tariff	-	8.660 c/kWh
Annual Energy Consumption[134]	6,240 kWh	6,240 kWh
Annual Grid Consumption	6,240 kWh	3,454 kWh[135]
Annual Solar Export	-	4,450 kWh
Annual Energy Charge	- $ 1,924	- $ 1,035
Annual Fixed Charge	- $ 560	- $ 560
Annual Solar Feed In	-	$ 385
Individual Total Annual Tariff Charge	- $ 2,485	- $ 1,210
No. of customers	5 of 19	14 of 19
Annual Energy Consumption	121,980 kWh	
Annual Grid Consumption	80,452 kWh	
Annual Solar Export	62,292 kWh	
Annual Energy Charge	- $ 24,115	
Annual Solar Feed In	$ 5,395	
Annual Fixed Charge	- $ 10,645	
Combined Total Annual Tariff Charge	- $ 29,366	

133 Tariff rates based on QCA June 2025 final determination for 2025-26, excluding GST.
134 Estimated annual energy consumption.
135 Estimated annual grid consumption based on estimated 71 kWp solar PV capacity from 54.7 kW inverter capacity (as listed in Ergon Energy Network Load Capacity Map). Estimated that 14 of the 19 houses supplied by TVS3729 have solar PV installed (based on aerial imagery, Ergon Energy Network Look up and Live, and Load Capacity Map), an average of 5.1 kWp solar PV capacity. 4,283 kWh grid consumption is based on assumed 4 kWh/kWp/day solar PV generation and 60% of which is exported to grid.

21.3. QLD Residential Electricity Price Components

The Australian Energy Market Commission publishes an annual 'Residential Electricity Price Trends' report. To produce the report, the AEMC models each component of electricity costs using publicly available data from industry and government bodies. These sources include AEMO's latest system plan and revenue determinations from the AER. A range of assumptions is incorporated to reflect how the market is expected to operate.[136]

Based on the AEMC's 2025 estimates for QLD and the NEM, as outlined in the 2024 report, the residential electricity cost components for QLD are estimated as shown in Figure 79 below.

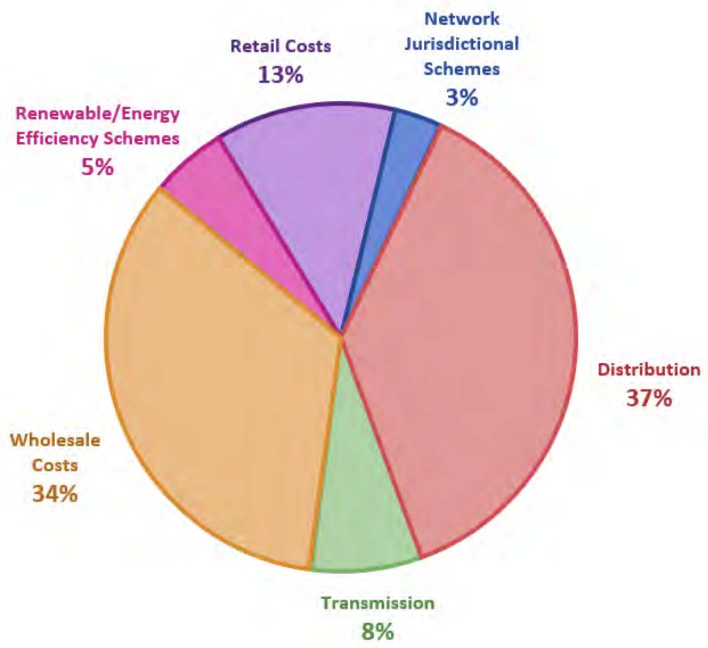


Figure 79 – Estimated QLD residential electricity price components 2025

[136] Australian Energy Market Commission (AEMC), Residential Electricity Price Trends 2024, https://www.aemc.gov.au/market-reviews-advice/residential-electricity-price-trends-2024

21.4. Microgrid regulatory analysis

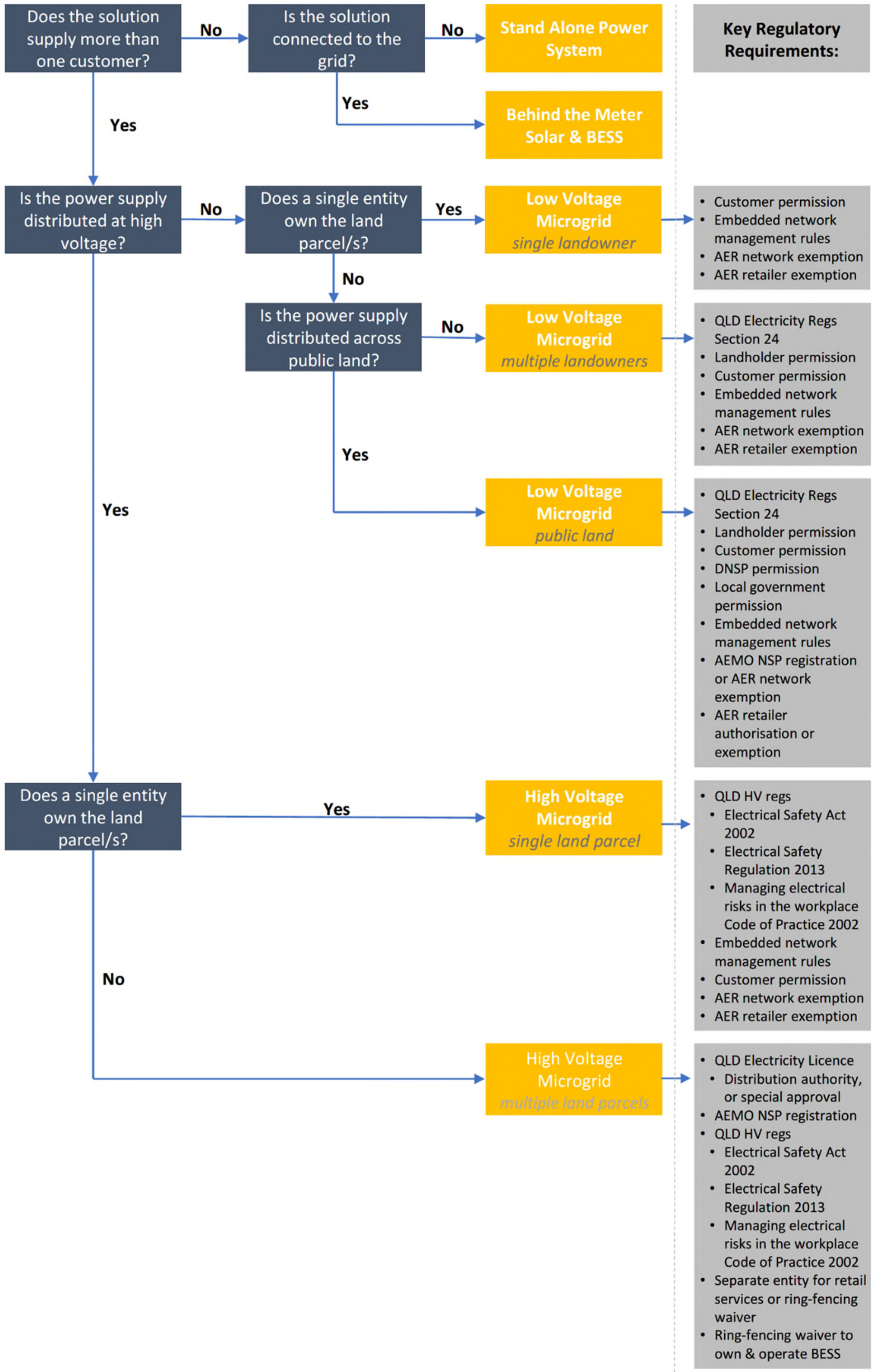


Figure 80 – Microgrid regulatory flowchart[137]

[137] Assembled from Yurika's understand of electricity rules and regulations as discussed in Section 6.2 'Option Assessment' of this report.

22. Appendix C

22.1. Solar PV & Battery Storage Capacity Modelling Results

Table 43 – Horseshoe Bay Additional Solar PV and Battery Storage Modelling Results

Additional Solar PV Size (MW)	Additional Battery Storage Capacity (MWh)	Grid Energy (MWh)	Existing Solar Production (MWh)	Additional Solar Production (MWh)	Excess Solar (MWh)	Excess Solar (%)	Actual Renewable Fraction (%)	Backup Storage (Hours)	BESS Utilisation (%)	GHG Emission reduction (t CO2-e)[138]		
										Existing Solar	Total Additional Solar	Consumed Additional Solar Only
Existing	-	3,354	2,040		92		38%			1449		
0.5 MW Solar	0 MWh	2,885	2,040	821	366	45%	47%	-	0%	1,449	583	323
	0.5 MWh	2,759	2,040	821	219	27%	49%	1.4	76%	1,449	583	427
	1 MWh	2,665	2,040	821	108	13%	51%	2.8	67%	1,449	583	506
	1.5 MWh	2,604	2,040	821	37	5%	52%	4.2	57%	1,449	583	557
	2 MWh	2,578	2,040	821	6	1%	52%	5.6	47%	1,449	583	579
	2.5 MWh	2,573	2,040	821	-	0%	52%	7.0	38%	1,449	583	583
1 MW Solar	0 MWh	2,680	2,040	1,642	982	60%	50%	-	0%	1,449	1,166	469
	0.5 MWh	2,532	2,040	1,642	809	49%	53%	1.4	90%	1,449	1,166	591
	1 MWh	2,396	2,040	1,642	648	39%	56%	2.8	86%	1,449	1,166	706
	1.5 MWh	2,270	2,040	1,642	500	30%	58%	4.2	83%	1,449	1,166	811
	2 MWh	2,152	2,040	1,642	362	22%	60%	5.6	80%	1,449	1,166	909
	2.5 MWh	2,053	2,040	1,642	245	15%	62%	7.0	76%	1,449	1,166	992
	3 MWh	1,972	2,040	1,642	149	9%	63%	8.4	72%	1,449	1,166	1,060
	3.5 MWh	1,912	2,040	1,642	80	5%	65%	9.8	67%	1,449	1,166	1,109
	4 MWh	1,873	2,040	1,642	34	2%	65%	11.3	61%	1,449	1,166	1,142
	4.5 MWh	1,854	2,040	1,642	11	1%	66%	12.7	56%	1,449	1,166	1,158
	5 MWh	1,845	2,040	1,642	1	0%	66%	14	51%	1,449	1,166	1,165
1.5 MW Solar	0 MWh	2,601	2,040	2,462	1,724	70%	52%	-	0%	1,449	1,748	524
	0.5 MWh	2,451	2,040	2,462	1,548	63%	55%	1.4	91%	1,449	1,748	649
	1 MWh	2,304	2,040	2,462	1,375	56%	57%	2.8	90%	1,449	1,748	772
	1.5 MWh	2,161	2,040	2,462	1,207	49%	60%	4.2	89%	1,449	1,748	891
	2 MWh	2,022	2,040	2,462	1,044	42%	63%	5.6	88%	1,449	1,748	1,007
	2.5 MWh	1,889	2,040	2,462	887	36%	65%	7.0	87%	1,449	1,748	1,118
	3 MWh	1,759	2,040	2,462	734	30%	67%	8.4	85%	1,449	1,748	1,227
	3.5 MWh	1,637	2,040	2,462	591	24%	70%	9.8	84%	1,449	1,748	1,328
	4 MWh	1,525	2,040	2,462	459	19%	72%	11.3	82%	1,449	1,748	1,422
	4.5 MWh	1,426	2,040	2,462	342	14%	74%	12.7	79%	1,449	1,748	1,505
	5 MWh	1,341	2,040	2,462	242	10%	75%	14.1	77%	1,449	1,748	1,576
	5.5 MWh	1,271	2,040	2,462	160	6%	76%	15.5	74%	1,449	1,748	1,634
	6 MWh	1,217	2,040	2,462	97	4%	77%	16.9	70%	1,449	1,748	1,679
	6.5 MWh	1,179	2,040	2,462	52	2%	78%	18.3	67%	1,449	1,748	1,711
	7 MWh	1,157	2,040	2,462	26	1%	79%	19.7	63%	1,449	1,748	1,730

[138] Based on 2024 QLD Emissions Factor 0.71 kg CO_2-e/kWh, Table 1, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2024.pdf

Additional Solar PV Size (MW)	Additional Battery Storage Capacity (MWh)	Grid Energy (MWh)	Existing Solar Production (MWh)	Additional Solar Production (MWh)	Excess Solar (MWh)	Excess Solar (%)	Actual Renewable Fraction (%)	Backup Storage (Hours)	BESS Utilisation (%)	GHG Emission reduction (t CO2-e)		
										Existing Solar	Total Additional Solar	Consumed Additional Solar Only
2 MW Solar	0 MWh	2,558	2,040	3,283	2,502	76%	53%	0.0	0%	1,449	2,331	555
	0.5 MWh	2,408	2,040	3,283	2,326	71%	55%	1.4	91%	1,449	2,331	679
	1 MWh	2,261	2,040	3,283	2,152	66%	58%	2.8	90%	1,449	2,331	803
	1.5 MWh	2,114	2,040	3,283	1,980	60%	61%	4.2	90%	1,449	2,331	925
	2 MWh	1,968	2,040	3,283	1,808	55%	64%	5.6	90%	1,449	2,331	1,047
	2.5 MWh	1,826	2,040	3,283	1,641	50%	66%	7.0	89%	1,449	2,331	1,166
	3 MWh	1,686	2,040	3,283	1,477	45%	69%	8.4	88%	1,449	2,331	1,282
	3.5 MWh	1,549	2,040	3,283	1,316	40%	71%	9.8	88%	1,449	2,331	1,397
	4 MWh	1,416	2,040	3,283	1,159	35%	74%	11.3	87%	1,449	2,331	1,508
	4.5 MWh	1,285	2,040	3,283	1,005	31%	76%	12.7	86%	1,449	2,331	1,617
	5 MWh	1,159	2,040	3,283	857	26%	79%	14.1	85%	1,449	2,331	1,722
	5.5 MWh	1,040	2,040	3,283	716	22%	81%	15.5	84%	1,449	2,331	1,823
	6 MWh	927	2,040	3,283	584	18%	83%	16.9	83%	1,449	2,331	1,916
	6.5 MWh	826	2,040	3,283	465	14%	85%	18.3	81%	1,449	2,331	2,001
	7 MWh	741	2,040	3,283	365	11%	86%	19.7	79%	1,449	2,331	2,072
	7.5 MWh	685	2,040	3,283	299	9%	87%	21.1	76%	1,449	2,331	2,119
	8 MWh	647	2,040	3,283	254	8%	88%	22.5	73%	1,449	2,331	2,151
2.5 MW Solar	0 MWh	2,530	2,040	4,104	3,295	80%	53%	0.0	0%	1,449	2,914	574
	0.5 MWh	2,380	2,040	4,104	3,119	76%	56%	1.4	91%	1,449	2,914	699
	1 MWh	2,232	2,040	4,104	2,944	72%	59%	2.8	91%	1,449	2,914	824
	1.5 MWh	2,084	2,040	4,104	2,771	68%	61%	4.2	91%	1,449	2,914	946
	2 MWh	1,937	2,040	4,104	2,598	63%	64%	5.6	90%	1,449	2,914	1,069
	2.5 MWh	1,791	2,040	4,104	2,426	59%	67%	7.0	90%	1,449	2,914	1,191
	3 MWh	1,646	2,040	4,104	2,255	55%	69%	8.4	90%	1,449	2,914	1,313
	3.5 MWh	1,504	2,040	4,104	2,088	51%	72%	9.8	89%	1,449	2,914	1,431
	4 MWh	1,365	2,040	4,104	1,924	47%	75%	11.3	89%	1,449	2,914	1,548
	4.5 MWh	1,226	2,040	4,104	1,762	43%	77%	12.7	88%	1,449	2,914	1,663
	5 MWh	1,090	2,040	4,104	1,601	39%	80%	14.1	88%	1,449	2,914	1,777
	5.5 MWh	957	2,040	4,104	1,444	35%	82%	15.5	87%	1,449	2,914	1,889
	6 MWh	826	2,040	4,104	1,290	31%	85%	16.9	86%	1,449	2,914	1,998
	6.5 MWh	698	2,040	4,104	1,140	28%	87%	18.3	86%	1,449	2,914	2,104
	7 MWh	581	2,040	4,104	1,002	24%	89%	19.7	85%	1,449	2,914	2,202
	7.5 MWh	497	2,040	4,104	903	22%	91%	21.1	83%	1,449	2,914	2,273
	8 MWh	435	2,040	4,104	831	20%	92%	22.5	80%	1,449	2,914	2,324

Table 44 - Picnic Bay Additional Solar PV and Battery Storage Modelling Results

Additional Solar PV Size (MW)	Additional Battery Storage Capacity (MWh)	Grid Energy (MWh)	Existing Solar Production (MWh)	Additional Solar Production (MWh)	Excess Solar (MWh)	Excess Solar (%)	Actual Renewable Fraction (%)	Backup Storage (Hours)	BESS Utilisation (%)	GHG Emission reduction (t CO2-e) [139]		
										Existing Solar	Total Additional Solar	Consumed Additional Solar Only
Existing	-	2289	1,032	0	0.044		31%			732		
0.5 MW Solar	0 MWh	1,802	1,032	821	335	41%	46%	-	0%	671	534	316
	0.5 MWh	1,675	1,032	821	187	23%	50%	2.2	77%	732	534	412
	1 MWh	1,586	1,032	821	82	10%	52%	4.5	66%	732	534	480
	1.5 MWh	1,537	1,032	821	24	3%	54%	6.7	54%	732	534	518
	2 MWh	1,519	1,032	821	3	0%	54%	8.9	43%	732	534	532
	2.5 MWh	1,517	1,032	821	-	0%	54%	11.1	35%	732	534	534
1 MW Solar	0 MWh	1,666	1,032	1,642	1,021	62%	50%	0.4	0%	732	1,067	404
	0.5 MWh	1,519	1,032	1,642	848	52%	54%	2.2	89%	732	1,067	516
	1 MWh	1,380	1,032	1,642	685	42%	58%	4.5	87%	732	1,067	622
	1.5 MWh	1,247	1,032	1,642	528	32%	62%	6.7	85%	732	1,067	724
	2 MWh	1,123	1,032	1,642	382	23%	66%	8.9	83%	732	1,067	819
	2.5 MWh	1,013	1,032	1,642	253	15%	69%	11.1	80%	732	1,067	903
	3 MWh	924	1,032	1,642	148	9%	72%	13.4	75%	732	1,067	971
	3.5 MWh	865	1,032	1,642	78	5%	74%	15.6	70%	732	1,067	1,017
	4 MWh	827	1,032	1,642	34	2%	75%	17.8	64%	732	1,067	1,045
	4.5 MWh	808	1,032	1,642	11	1%	76%	20.0	58%	732	1,067	1,060
	5 MWh	803	1,032	1,642	5	0%	76%	22.3	53%	732	1,067	1,064
1.5 MW Solar	0 MWh	1,613	1,032	2,462	1,788	73%	51%	0.4	0%	732	1,600	438
	0.5 MWh	1,464	1,032	2,462	1,613	66%	56%	2.2	91%	732	1,600	552
	1 MWh	1,318	1,032	2,462	1,441	59%	60%	4.5	90%	732	1,600	664
	1.5 MWh	1,174	1,032	2,462	1,272	52%	65%	6.7	89%	732	1,600	774
	2 MWh	1,035	1,032	2,462	1,108	45%	69%	8.9	88%	732	1,600	880
	2.5 MWh	900	1,032	2,462	949	39%	73%	11.1	87%	732	1,600	983
	3 MWh	767	1,032	2,462	794	32%	77%	13.4	86%	732	1,600	1,084
	3.5 MWh	641	1,032	2,462	645	26%	81%	15.6	85%	732	1,600	1,181
	4 MWh	523	1,032	2,462	506	21%	84%	17.8	83%	732	1,600	1,271
	4.5 MWh	423	1,032	2,462	388	16%	87%	20.0	81%	732	1,600	1,348
	5 MWh	362	1,032	2,462	316	13%	89%	22.3	76%	732	1,600	1,395
	5.5 MWh	326	1,032	2,462	274	11%	90%	24.5	71%	732	1,600	1,422
	6 MWh	306	1,032	2,462	250	10%	91%	26.7	66%	732	1,600	1,438
	6.5 MWh	298	1,032	2,462	241	10%	91%	29.0	62%	732	1,600	1,444

[139] Based on 2024 QLD Emissions Factor 0.71 kg CO_2-e/kWh, Table 1, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2024.pdf

Additional Solar PV Size (MW)	Additional Battery Storage Capacity (MWh)	Grid Energy (MWh)	Existing Solar Production (MWh)	Additional Solar Production (MWh)	Excess Solar (MWh)	Excess Solar (%)	Actual Renewable Fraction (%)	Backup Storage (Hours)	BESS Utilisation (%)	GHG Emission reduction (t CO2-e)		
										Existing Solar	Total Additional Solar	Consumed Additional Solar Only
2 MW Solar	0 MWh	1,580	1,032	3,283	2,576	78%	52%	0.4	0%	732	2,134	460
	0.5 MWh	1,431	1,032	3,283	2,401	73%	57%	2.2	91%	732	2,134	573
	1 MWh	1,284	1,032	3,283	2,227	68%	61%	4.5	90%	732	2,134	686
	1.5 MWh	1,137	1,032	3,283	2,054	63%	66%	6.7	90%	732	2,134	799
	2 MWh	991	1,032	3,283	1,883	57%	70%	8.9	90%	732	2,134	910
	2.5 MWh	848	1,032	3,283	1,715	52%	74%	11.1	89%	732	2,134	1,019
	3 MWh	708	1,032	3,283	1,551	47%	79%	13.4	88%	732	2,134	1,126
	3.5 MWh	571	1,032	3,283	1,389	42%	83%	15.6	88%	732	2,134	1,231
	4 MWh	436	1,032	3,283	1,231	37%	87%	17.8	87%	732	2,134	1,334
	4.5 MWh	321	1,032	3,283	1,095	33%	90%	20.0	85%	732	2,134	1,422
	5 MWh	247	1,032	3,283	1,008	31%	93%	22.3	81%	732	2,134	1,479
	5.5 MWh	200	1,032	3,283	952	29%	94%	24.5	76%	732	2,134	1,515
	6 MWh	168	1,032	3,283	915	28%	95%	26.7	72%	732	2,134	1,539
	6.5 MWh	147	1,032	3,283	891	27%	96%	29.0	67%	732	2,134	1,555
	7 MWh	136	1,032	3,283	878	27%	96%	31.2	63%	732	2,134	1,563
	7.5 MWh	129	1,032	3,283	869	26%	96%	33.4	59%	732	2,134	1,569
	8 MWh	124	1,032	3,283	864	26%	96%	35.6	55%	732	2,134	1,572

22.2. Ergon Energy Network Tariff Components

As described further in Ergon Energy Network's Tariff Guide 2024-25[140], different types of tariff components (or charges) and their application are listed below.

Fixed charge

- A fixed $/day charge that is applied to each energised connection point where energy or demand is recorded.

Volume charge

- A volume charge, either flat or variable, for the energy consumed at a connection point calculated in $/kWh.
- A flat volume charge is a single volume charge applied to all energy consumed regardless of when it is consumer whereas a variable volume charge has a time-of-use (ToU) component. Typically, an off-peak volume charge during the day, peak volume charge during the evening and sometimes a shoulder charge in between off-peak and peak.

Demand charge

- A monthly demand charge calculated as a $/kVA/month or $/kW/month for demand recorded at the connection point.
- These charges are applied to the maximum half hourly kVA or kW power reading that occurred during either:
  - The maximum demand recorded anytime in the month, or
  - The maximum demand recorded within a specific peak demand window

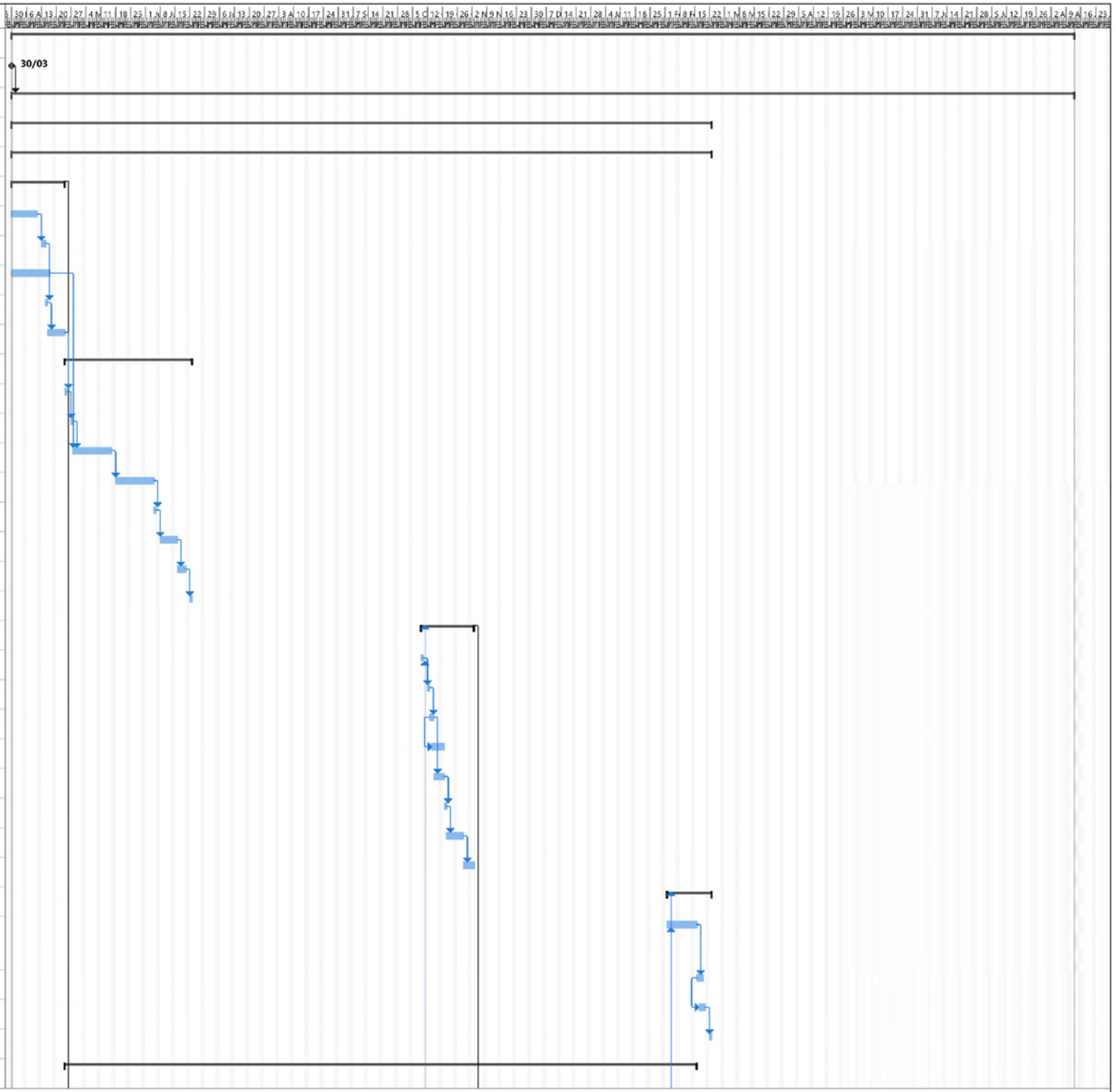
Capacity charge (applicable to CAC and ICC customers only)

- Capacity charge is a monthly charge calculated as a $/kVA/month for the network capacity provided for a connection point.

[140] Ergon Energy Network Tariff Guide 2024-25, Ergon Energy Network Tariff Guide 2024-25

22.3. Estimated Delivery Timeline 1 MW/ 2MWh BESS

ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors
1		**MAGNETIC ISLAND BESS PROGRAM**	**359 days**	**Mon 30/03/26**	**Thu 12/08/27**	
2		Execute Contract	0 days	Mon 30/03/26	Mon 30/03/26	
3		**Magnetic Island BESS**	**359 days**	**Mon 30/03/26**	**Thu 12/08/27**	**2**
4		**Electrical and Structural Design**	**236 days**	**Mon 30/03/26**	**Mon 22/02/27**	
5		**Magnetic Island BESS Design**	**236 days**	**Mon 30/03/26**	**Mon 22/02/27**	
6		**5% DESIGN STAGE**	**19 days**	**Mon 30/03/26**	**Thu 23/04/26**	
7		Concept development	10 days	Mon 30/03/26	Fri 10/04/26	
8		Concept drawings	2 days	Mon 13/04/26	Tue 14/04/26	7
9		External civil eng studies	14 days	Mon 30/03/26	Thu 16/04/26	
10		Submit to client for review and approval	1 day	Wed 15/04/26	Wed 15/04/26	8
11		Obtain feedback from client	6 days	Thu 16/04/26	Thu 23/04/26	10
12		**50% DESIGN STAGE**	**42 days**	**Fri 24/04/26**	**Mon 22/06/26**	
13		Safety in Design	1 day	Fri 24/04/26	Fri 24/04/26	11
14		BESS modelling	1 day	Mon 27/04/26	Mon 27/04/26	13
15		Engineering reports	14 days	Tue 28/04/26	Fri 15/05/26	9,14
16		Drawings	14 days	Mon 18/05/26	Thu 4/06/26	15
17		Submit 50% design for review and approval	1 day	Fri 5/06/26	Fri 5/06/26	16
18		Obtain feedback from client	6 days	Mon 8/06/26	Mon 15/06/26	17
19		Update design based on feedback	4 days	Tue 16/06/26	Fri 19/06/26	18
20		Major equipment details for procurement	1 day	Mon 22/06/26	Mon 22/06/26	19
21		**85% DESIGN STAGE**	**17 days**	**Fri 9/10/26**	**Mon 2/11/26**	**37**
22		Safety in Design	1 day	Fri 9/10/26	Fri 9/10/26	37
23		BESS modelling	1 day	Mon 12/10/26	Mon 12/10/26	22
24		Engineering reports	2 days	Tue 13/10/26	Wed 14/10/26	23
25		Drawings	4 days	Wed 14/10/26	Mon 19/10/26	24SS+1 day
26		Test and Commissioning Plan	3 days	Thu 15/10/26	Mon 19/10/26	24
27		Submit 85% design for review and approval	1 day	Tue 20/10/26	Tue 20/10/26	26
28		Obtain feedback from client	6 days	Wed 21/10/26	Wed 28/10/26	27
29		Update design based on feedback	3 days	Thu 29/10/26	Mon 2/11/26	28
30		**100% DESIGN STAGE**	**15 days**	**Tue 2/02/27**	**Mon 22/02/27**	**38**
31		Update based on network connection application response	10 days	Tue 2/02/27	Mon 15/02/27	38
32		Drawing review and approval	3 days	Tue 16/02/27	Thu 18/02/27	31
33		Test and Commissioning Plan	3 days	Wed 17/02/27	Fri 19/02/27	32SS+1 day
34		IFC package	1 day	Mon 22/02/27	Mon 22/02/27	33
35		**Network Application**	**212 days**	**Fri 24/04/26**	**Mon 15/02/27**	



Project: Magnetic Island BESS P
Date: Mon 4/08/25

Task	Summary	Inactive Milestone	Duration-only	Start-only	External Milestone	Manual Progress
Split	Project Summary	Inactive Summary	Manual Summary Rollup	Finish-only	Deadline	
Milestone	Inactive Task	Manual Task	Manual Summary	External Tasks	Progress	

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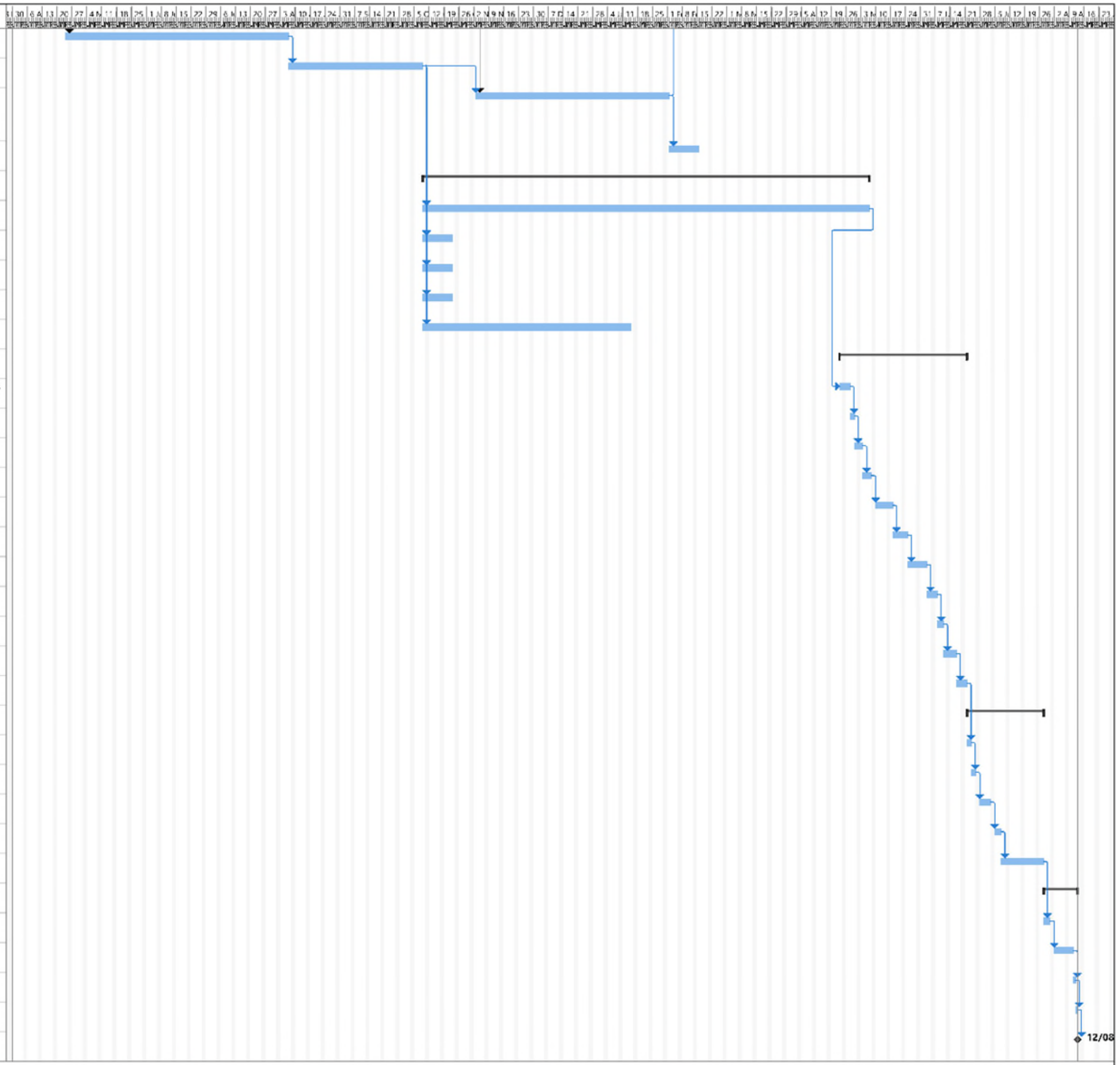
ID	Task Mode	Task Name	Duration	Start	Finish	Predecessors
36		Submit embedded generation enquiry	75 days	Fri 24/04/26	Thu 6/08/26	6
37		Submit connection application - Technical Assess	45 days	Fri 7/08/26	Thu 8/10/26	36
38		Submit full connection application - DCR/Additional Info	65 days	Tue 3/11/26	Mon 1/02/27	37FS+5 days,21
39		Embedded generation offer and acceptance	10 days	Tue 2/02/27	Mon 15/02/27	38
40		**Procurement**	**150 days**	**Fri 9/10/26**	**Thu 6/05/27**	
41		BESS Units	150 days	Fri 9/10/26	Thu 6/05/27	37
42		Conduit and pits	10 days	Fri 9/10/26	Thu 22/10/26	37
43		AC cabling	10 days	Fri 9/10/26	Thu 22/10/26	37
44		AC accessories	10 days	Fri 9/10/26	Thu 22/10/26	37
45		MSB	70 days	Fri 9/10/26	Thu 14/01/27	37
46		**Installation**	**42 days**	**Fri 23/04/27**	**Mon 21/06/27**	
47		Mobilise to site	3 days	Fri 23/04/27	Tue 27/04/27	41FS-10 days
48		Site establishment	2 days	Wed 28/04/27	Thu 29/04/27	47
49		Site survey	2 days	Fri 30/04/27	Mon 3/05/27	48
50		Site clearing	4 days	Tue 4/05/27	Fri 7/05/27	49
51		Site pad works	6 days	Mon 10/05/27	Mon 17/05/27	50
52		Site pit and pipe works	5 days	Tue 18/05/27	Mon 24/05/27	51
53		Plinth form and pour	7 days	Tue 25/05/27	Wed 2/06/27	52
54		Installation of comsumer mains	3 days	Thu 3/06/27	Mon 7/06/27	53
55		Installation of BESS Submains	3 days	Tue 8/06/27	Thu 10/06/27	54
56		Installation of MSB	4 days	Fri 11/06/27	Wed 16/06/27	55
57		Termination of AC cabling and comms cabling to	3 days	Thu 17/06/27	Mon 21/06/27	56
58		**Test and Commission**	**26 days**	**Tue 22/06/27**	**Tue 27/07/27**	
59		Complete all Mandatory Tests DC	2 days	Tue 22/06/27	Wed 23/06/27	57
60		Complete all Maditory Tests AC	2 days	Thu 24/06/27	Fri 25/06/27	59
61		Commission communications	5 days	Mon 28/06/27	Fri 2/07/27	60
62		Energise and commission BESS Units	3 days	Mon 5/07/27	Wed 7/07/27	61
63		Collate all QA documentation	14 days	Thu 8/07/27	Tue 27/07/27	62
64		**Project Close out**	**12 days**	**Wed 28/07/27**	**Thu 12/08/27**	
65		Mark up all as constructed drawings	3 days	Wed 28/07/27	Fri 30/07/27	63
66		Complete Customer Operating Manual	7 days	Mon 2/08/27	Tue 10/08/27	65
67		Handover with Customer	1 day	Wed 11/08/27	Wed 11/08/27	66
68		Training with customer	1 day	Thu 12/08/27	Thu 12/08/27	67
69		Project complete	0 days	Thu 12/08/27	Thu 12/08/27	68



Project: Magnetic Island BESS P
Date: Mon 4/08/25

Task, Split, Milestone, Summary, Project Summary, Inactive Task, Inactive Milestone, Inactive Summary, Manual Task, Duration-only, Manual Summary Rollup, Manual Summary, Start-only, Finish-only, External Tasks, External Milestone, Deadline, Progress, Manual Progress

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23. Appendix D

23.1. Behind the meter simple payback results

23.1.1 Residential, Flat Rate Tariff

Simple Payback

Capital Cost ($) (excl. GST)							
$ 17,600	10.8	10.5	8.9	8.5	8.2	7.9	7.7
$ 16,400	10.0	9.8	8.3	7.9	7.6	7.3	7.1
$ 15,200	9.2	9.0	7.6	7.3	7.0	6.8	6.5
$ 14,000	8.4	8.2	7.0	6.7	6.4	6.2	6.0
$ 12,800	7.6	7.5	6.3	6.1	5.8	5.6	5.5
$ 11,600	6.9	6.7	5.7	5.5	5.3	5.1	4.9
$ 10,400	6.1	6.0	5.1	4.9	4.7	4.5	4.4
$ 9,200	5.4	5.2	**4.5**	4.3	4.1	4.0	3.9
$ 8,000	4.6	4.5	3.9	3.7	3.6	3.4	3.3
$ 6,800	3.9	3.8	3.3	3.1	3.0	2.9	2.8
Grid Consumption (kWh) Per year →	4,200	5,300	**6,400**	7,500	8,600	9,700	10,800
Per day →	11.5	14.5	17.5	20.5	23.6	26.6	29.6
Annual Savings (Year 1) →	$ 1,800	$ 1,850	$ 2,150	$ 2,240	$ 2,320	$ 2,400	$ 2,480

Figure 81 - Simple payback matrix, residential no existing solar PV scenario (flat rate Tariff 11)

Simple Payback

Capital Cost ($) (excl. GST)							
$ 15,303	24.4	20.8	19.1	18.7	18.5	18.4	18.2
$ 14,113	22.0	18.9	17.3	17.0	16.8	16.7	16.6
$ 12,923	19.8	17.0	15.6	15.3	15.2	15.1	15.0
$ 11,733	17.7	15.2	14.0	13.7	13.6	13.5	13.4
$ 10,544	15.6	13.4	12.4	12.2	12.1	12.0	11.9
$ 9,354	13.6	11.7	10.8	10.7	10.6	10.5	10.4
$ 8,164	11.7	10.1	9.3	9.2	9.1	9.0	9.0
$ 6,974	9.8	8.5	**7.9**	7.7	7.7	7.6	7.6
$ 5,785	8.0	7.0	6.4	6.3	6.3	6.2	6.2
$ 4,595	6.2	5.4	5.0	5.0	4.9	4.9	4.9
Grid Consumption (kWh) Per year →	2,385	3,057	**3,800**	4,474	5,216	5,976	6,752
Per day →	6.5	8.4	10.4	12.3	14.3	16.4	18.5
Annual Savings (Year 1) →	$ 780	$ 890	$ 960	$ 970	$ 980	$ 990	$ 990

Figure 82 - Simple payback matrix, residential 4.5kW existing solar PV scenario (flat rate Tariff 11)

		Simple Payback						
	$ 14,277	44.8	34.8	31.4	31.5	32.1	32.8	33.5
	$ 13,087	39.6	31.0	28.0	28.1	28.7	29.3	29.9
	$ 11,897	34.7	27.4	24.8	24.9	25.4	25.9	26.5
	$ 10,708	30.2	24.0	21.8	21.9	22.3	22.7	23.2
Capital	$ 9,518	26.0	20.8	18.9	19.0	19.3	19.7	20.1
Cost ($)	$ 8,328	22.0	17.7	16.2	16.2	16.5	16.8	17.2
(excl. GST)	$ 7,138	18.3	14.8	13.6	13.6	13.8	14.1	14.4
	$ 5,949	14.8	12.1	**11.1**	11.1	11.3	11.5	11.7
	$ 4,759	11.5	9.4	8.6	8.7	8.8	9.0	9.1
	$ 3,569	8.4	6.9	6.3	6.4	6.5	6.6	6.7
	Per year →	2,339	2,985	**3,657**	4,314	5,003	5,707	6,429
	Per day →	6.4	8.2	10.0	11.8	13.7	15.6	17.6
		Grid Consumption (kWh)						
Annual Savings (Year 1) →		$ 460	$ 550	$ 600	$ 600	$ 590	$ 580	$ 570

Figure 83 - Simple payback matrix, residential 6.6kW existing solar PV scenario (flat rate Tariff 11)

23.1.2 Residential, Time of Use Demand Tariff

		Simple Payback						
	$ 17,600	9.9	8.9	8.2	7.8	7.4	7.1	6.8
	$ 16,400	9.2	8.3	7.6	7.2	6.9	6.6	6.3
	$ 15,200	8.5	7.6	7.0	6.6	6.3	6.1	5.8
	$ 14,000	7.8	7.0	6.4	6.1	5.8	5.6	5.3
Capital	$ 12,800	7.0	6.3	5.8	5.5	5.3	5.1	4.9
Cost ($)	$ 11,600	6.3	5.7	5.3	5.0	4.8	4.6	4.4
(excl. GST)	$ 10,400	5.6	5.1	4.7	4.5	4.3	4.1	3.9
	$ 9,200	5.0	4.5	4.1	3.9	3.7	3.6	3.4
	$ 8,000	4.3	3.9	3.6	3.4	3.2	3.1	3.0
	$ 6,800	3.6	3.3	3.0	2.9	2.7	2.6	2.5
	Per year →	4,200	5,300	**6,400**	7,500	8,600	9,700	10,800
	Per day →	11.5	14.5	17.5	20.5	23.6	26.6	29.6
		Grid Consumption (kWh)						
Annual Savings (Year 1) →		$ 1,950	$ 2,150	$ 2,320	$ 2,440	$ 2,550	$ 2,660	$ 2,760

Figure 84 - Simple payback matrix, residential no existing solar PV scenario (time of use Demand Tariff 14C)

Simple Payback

Capital Cost ($) (excl. GST)							
$ 15,303	19.9	17.3	15.8	15.1	14.6	14.1	13.7
$ 14,113	18.1	15.7	14.4	13.8	13.3	12.8	12.5
$ 12,923	16.3	14.2	13.0	12.4	12.0	11.6	11.3
$ 11,733	14.6	12.7	11.7	11.2	10.8	10.5	10.1
$ 10,544	12.9	11.3	10.4	9.9	9.6	9.3	9.0
$ 9,354	11.3	9.9	9.1	8.7	8.4	8.2	7.9
$ 8,164	9.7	8.5	7.8	7.5	7.3	7.1	6.9
$ 6,974	8.2	7.2	6.6	6.4	6.1	6.0	5.8
$ 5,785	6.7	5.9	5.4	5.2	5.0	4.9	4.8
$ 4,595	5.2	4.6	4.3	4.1	4.0	3.8	3.7
Grid Consumption (kWh) Per year →	2,385	3,057	**3,800**	4,474	5,216	5,976	6,752
Per day →	6.5	8.4	10.4	12.3	14.3	16.4	18.5
Annual Savings (Year 1) →	$ 920	$ 1,040	$ 1,120	$ 1,170	$ 1,200	$ 1,240	$ 1,270

Figure 85 - Simple payback matrix, residential 4.5kW existing solar PV scenario (time of use Demand Tariff 14C)

Simple Payback

Capital Cost ($) (excl. GST)							
$ 14,277	30.7	25.2	22.5	21.5	20.8	20.2	19.7
$ 13,087	27.5	22.6	20.3	19.3	18.8	18.2	17.7
$ 11,897	24.4	20.1	18.1	17.3	16.8	16.3	15.9
$ 10,708	21.4	17.8	16.0	15.3	14.8	14.4	14.1
$ 9,518	18.6	15.5	14.0	13.4	13.0	12.6	12.3
$ 8,328	15.9	13.3	12.0	11.5	11.2	10.9	10.6
$ 7,138	13.3	11.2	10.1	9.7	9.4	9.2	9.0
$ 5,949	10.9	9.2	8.3	8.0	7.7	7.5	7.3
$ 4,759	8.5	7.2	6.5	6.3	6.1	5.9	5.8
$ 3,569	6.2	5.3	4.8	4.6	4.5	4.4	4.3
Grid Consumption (kWh) Per year →	2,339	2,985	**3,657**	4,314	5,003	5,707	6,429
Per day →	6.4	8.2	10.0	11.8	13.7	15.6	17.6
Annual Savings (Year 1) →	$ 610	$ 710	$ 780	$ 810	$ 830	$ 850	$ 870

Figure 86 - Simple payback matrix, residential 4.5kW existing solar PV scenario (time of use Demand Tariff 14C)

23.1.3 Small Business, Flat Rate Tariff

Simple Payback

Capital Cost ($) (excl. GST)							
$ 55,900	8.0	6.5	5.8	5.1	4.6	4.2	3.9
$ 52,600	7.5	6.1	5.4	4.8	4.3	3.9	3.7
$ 49,300	7.0	5.7	5.1	4.4	4.0	3.7	3.5
$ 46,000	6.5	5.3	4.7	4.1	3.7	3.4	3.2
$ 42,700	6.0	4.9	4.4	3.8	3.4	3.2	3.0
$ 39,400	5.5	4.5	4.0	3.5	3.2	2.9	2.7
$ 36,100	5.0	4.1	3.7	3.2	2.9	2.7	2.5
$ 32,800	4.5	3.7	3.3	2.9	2.6	2.4	2.3
$ 29,500	4.1	3.3	3.0	2.6	2.4	2.2	2.0
$ 26,200	3.6	2.9	2.6	2.3	2.1	1.9	1.8
Per year →	14,300	24,900	35,500	**50,750**	66,000	81,200	96,400
Per day →	39.2	68.2	97.3	139.0	180.8	222.5	264.1
	Grid Consumption (kWh)						
Annual Savings (Year 1) →	$ 7,580	$ 9,190	$ 10,210	$ 11,590	$ 12,810	$ 13,870	$ 14,780

Figure 87 - Simple payback matrix, small business no existing solar PV scenario (Flat Tariff 20)

Simple Payback

Capital Cost ($) (excl. GST)							
$ 51,000	12.3	10.3	9.6	8.1	6.7	5.9	5.4
$ 47,700	11.4	9.6	8.9	7.5	6.3	5.5	5.1
$ 44,400	10.5	8.9	8.2	7.0	5.8	5.1	4.7
$ 41,100	9.6	8.1	7.6	6.4	5.4	4.7	4.3
$ 37,800	8.8	7.4	6.9	5.9	4.9	4.3	4.0
$ 34,500	8.0	6.8	6.3	5.3	4.5	3.9	3.6
$ 31,200	7.2	6.1	5.6	4.8	4.0	3.5	3.3
$ 27,900	6.4	5.4	5.0	4.3	3.6	3.2	2.9
$ 24,600	5.6	4.7	4.4	3.7	3.1	2.8	2.5
$ 21,300	4.8	4.1	3.8	3.2	2.7	2.4	2.2
Per year →	7,983	14,925	22,739	36,185	51,328	66,517	81,706
Per day →	21.9	40.9	62.3	99.1	140.6	182.2	223.9
	Grid Consumption (kWh)						
Annual Savings (Year 1) →	$ 4,670	$ 5,450	$ 5,850	$ 6,830	$ 8,070	$ 9,110	$ 9,910

Figure 88 - Simple payback matrix, small business 10kW existing solar PV scenario (Flat Tariff 20)

23.1.4 Small Business, Time of Use Energy Tariff

Simple Payback

Capital Cost ($) (excl. GST)							
$ 55,900	7.9	6.4	5.6	4.6	4.0	3.7	3.4
$ 52,600	7.4	6.0	5.3	4.3	3.8	3.4	3.2
$ 49,300	6.9	5.6	4.9	4.0	3.5	3.2	3.0
$ 46,000	6.4	5.2	4.6	3.8	3.3	3.0	2.8
$ 42,700	6.0	4.8	4.2	3.5	3.0	2.8	2.6
$ 39,400	5.5	4.4	3.9	3.2	2.8	2.6	2.4
$ 36,100	5.0	4.0	3.5	2.9	2.6	2.3	2.2
$ 32,800	4.5	3.7	3.2	2.7	2.3	2.1	2.0
$ 29,500	4.0	3.3	2.9	2.4	2.1	1.9	1.8
$ 26,200	3.6	2.9	2.5	2.1	1.8	1.7	1.6
Grid Consumption (kWh) Per year →	14,300	24,900	35,500	**50,750**	66,000	81,200	96,400
Per day →	39.2	68.2	97.3	139.0	180.8	222.5	264.1
Annual Savings (Year 1) →	$ 7,590	$ 9,310	$ 10,540	$ 12,700	$ 14,500	$ 15,820	$ 16,940

Figure 89 - Simple payback matrix, small business no existing solar PV scenario (time of use Energy Tariff 22E)

Simple Payback

Capital Cost ($) (excl. GST)							
$ 51,000	12.2	9.9	9.0	6.9	5.6	4.9	4.4
$ 47,700	11.3	9.2	8.4	6.4	5.2	4.5	4.1
$ 44,400	10.5	8.5	7.8	6.0	4.8	4.2	3.8
$ 41,100	9.6	7.8	7.2	5.5	4.4	3.9	3.5
$ 37,800	8.8	7.1	6.5	5.0	4.1	3.6	3.2
$ 34,500	8.0	6.5	5.9	4.6	3.7	3.2	2.9
$ 31,200	7.1	5.8	5.3	4.1	3.3	2.9	2.6
$ 27,900	6.3	5.2	4.7	**3.7**	3.0	2.6	2.4
$ 24,600	5.5	4.5	4.2	3.2	2.6	2.3	2.1
$ 21,300	4.8	3.9	3.6	2.8	2.2	2.0	1.8
Grid Consumption (kWh) Per year →	7,983	14,925	22,739	**36,185**	51,328	66,517	81,706
Per day →	21.9	40.9	62.3	99.1	140.6	182.2	223.9
Annual Savings (Year 1) →	$ 4,680	$ 5,670	$ 6,160	$ 7,880	$ 9,690	$ 11,020	$ 12,120

Figure 90 - Simple payback matrix, small business 10kW existing solar PV scenario (time of use Energy Tariff 22E)

yurika

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