University of Southern Queensland

Faculty of Engineering and Surveying

Optimal Model Designs for Community Batteries

A dissertation submitted by

Coenraad Wium

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Abstract

The Australian energy grid has a need for securing energy sources as centralised generation retire. The penetration of renewables in the form of rooftop photovoltaic systems has decreased apparent demand from the generator's perspective during the middle of the day. Renewable energy resources have the potential for a huge reduction in carbon emissions, but have highly intermittent power profiles. Solar energy is only available during the day, with the output depending on several external factors. Community batteries can facilitate the seamless integration of intermittent renewable energy resources as a solution. Community batteries operating on the distribution network, store the intermittent power generated by photovoltaic systems to generate a smooth load profile from the generator's perspective, reducing the need for generator shutdown and allowing for peak shaving.

This dissertation investigates and analyses community storage frameworks to achieve a smooth load profile that provides utilities benefits from increased distribution transformer lifespans. The method is to size the batteries by the expected reduction in peak demand required. Operate each battery under different frameworks to find the optimal battery size. The life extension of the distribution transformer is calculated alongside the cost recovery of the battery installation for utilities. Due to the community's lower peak demand, savings will be passed on to the consumers and prosumers of the distribution transformer network.

Results show that the community battery positively affects the management of load profiles and the storage of intermittent solar generation. There are complications in the implementation due to the high costs associated with lithium-ion storage. The utilities, under current operational restrictions set out by the Australian energy regulator, cannot access additional sources of revenue to breakeven on the capital expenditure.

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I certify that the ideas, designs and experimental work, results, analyses and conclusions set out in this dissertation are entirely my own effort, except where otherwise indicated and acknowledged.

I further certify that the work is original and has not been previously submitted for assessment in any other course or institution, except where specifically stated.

C. Wium

[redacted]

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List of Acronyms

- Application Programming Interface (API)
- Australian Energy Market Commission (AEMC)
- Australian Energy Market Operator (AEMO)
- Australian Energy Regulator (AER)
- Australian Renewable Energy Agency (ARENA)
- Distributed Energy Resources (DER)
- Distribution Network Service Provider (DNSP)
- Feed-in Tariffs (FIT)
- Frequency Controlled Ancillary Services (FCAS)
- Institute of Electrical and Electronics Engineers (IEEE)
- Integrated Resource Providers (IRP)
- International Electrotechnical Commission (IEC)
- Local Energy Model (LEM)
- Local use of service (LUOS)
- Market Ancillary Services Specification (MASS)
- National Energy Law (NEL)
- National Energy Market (NEM)
- National Energy Productivity Plan (NEPP)
- National Measurement Institute (NMI)
- Neighbourhood Battery Initiative (NBI)
- New South Wales (NSW)
- Photovoltaic (PV)
- Renewable Energy Resources (RER)
- Stand-alone Power System (SAPS)

Chapter 1 – Introduction

Background

The Australian energy grid is experiencing a considerable change with expanding volume of renewable energy sources [44]. There is a growing need for securing energy sources as critical systems of centralised generation, such as coal power, retire. The transition in Figure 1 illustrates the complexity of the modern energy system in comparison to the traditional linear energy system.

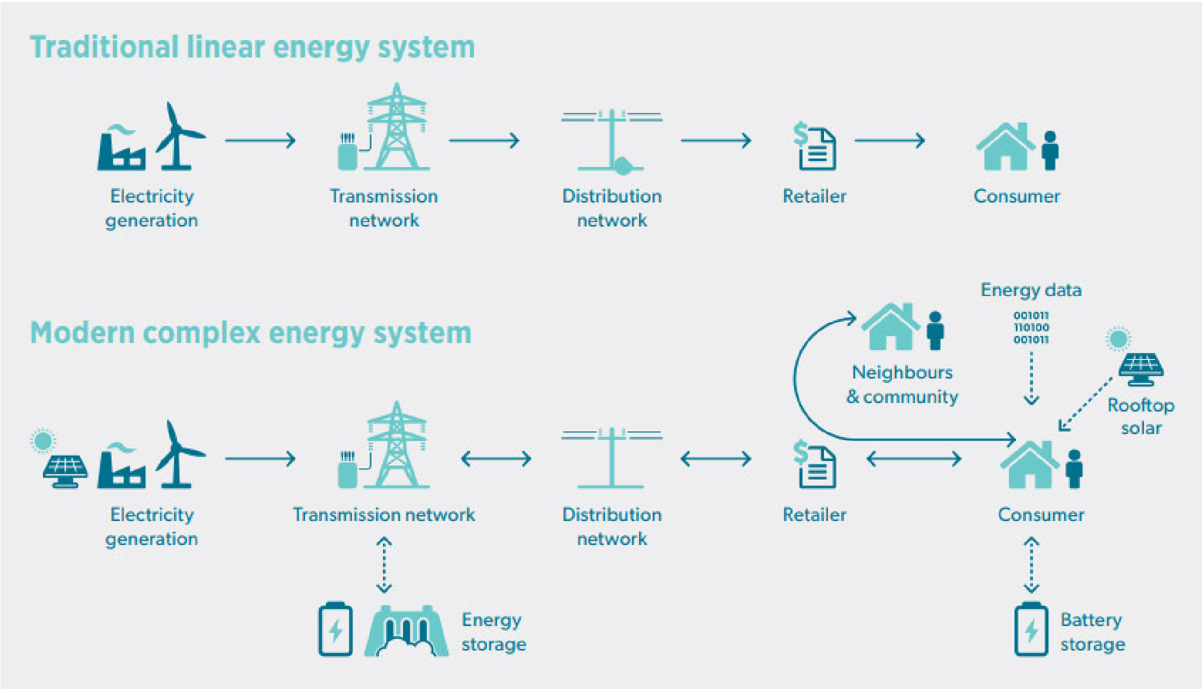


Figure 1: Comparison of changing energy system [21]

The arrangement of both the modern complex system and traditional linear transmission grid is referred to as the National Energy Market (NEM). NEM comprises the interconnection of five regional market jurisdictions [1]. The five market jurisdictions are South Australia, Victoria, Tasmania, New South Wales (NSW), including the Australian Capital Territory and Queensland. Western Australia and Northern Territory are not connected to the NEM. All five jurisdictions are interconnected, with meters monitoring power flows between them. The NEM is the generation and transport of power via high voltage transmission to local electricity distributors and large industrial energy users at wholesale [1]. NEM has several different bodies interacting to form the operators, commissioner and regulator. Three market bodies oversee the NEM:

- Australian Energy Market Operator (AEMO) is the market operator.
- Australian Energy Market Commission (AEMC) make the rules for the market.

- Australian Energy Regulator (AER) enforce the laws designed by AEMC.

All states and territories must work with the commonwealth minister through the energy council to make improvements to the NEM. The energy council has also set up the energy security board to strengthen NEM security and reliability. Four significant groups operate under NEM:

- Generation groups: These are significant generation groups like Photovoltaic (PV), wind, coal, gas, hydro etc.
- Transmission: The high-voltage poles and wires interconnect the generators to the substations.
- Distribution; The low and medium-voltage poles and wires interconnect substations to households or businesses. The distribution layer can also incorporate PV units from rooftops back to the network.
- Retail; Is the metering and billing but is commonly seen by consumers as the interface with the electrical industry.

No one participant may own all the levels of operation of the NEM, but some vertical integration is allowed to incentivise competition and reduce pricing for consumers. Rules and regulations outlined by the National Energy Law (NEL) are mandated for NEM participants that are increasing storage in the modern complex energy system.

Renewable Energy Resources (RER) are dense in South Australia than in other Australian states [1]. South Australia has implemented several components of the complex energy system, including large-scale storage at the transmission level. Reduced cost of battery technologies such as lithium-ion has caused an increased uptake in large-scale battery banks such as Hornsdale power reserve in South Australia. Storage in a residential setting has been slower to implement when compared with PV units [41]. Community storage is an intermediate step between household storage and transmission-level storage.

Community battery initiative trials have begun testing around Australia. Currently, there are thirteen active in Western Australia alone [47]. Distribution Network Service Providers (DNSP) are utilities that organise the control and hardware that make up the distribution network [1]. Analyses and feasibility studies in Australia for community batteries are still under review by DNSP [5, 19, 56, 20, 47, 60]. The community-scale batteries benefit from reduced customer energy costs, improved self-consumption of solar energy use and peak shaving, and reduced DNSP infrastructure load [53, 54].

Problem statement

Three issues are affecting the development of the future complex grid design [21]. The first is the retirement of thermal generators to transition to a net zero system [44]. The base load will transition to RER as an increasingly important role in the NEM to maintain the power supply of the retiring units [21]. The second is an increased number of PV units embedded at the distribution level, impacting security and reliability. The third is the national grid age, requiring more maintenance and equipment replacement to ensure power supply.

The Australian government has aimed to reduce carbon emissions with a goal of net zero by 2050 [16]. Dispatchable thermal generators are used in base load supply in the traditional linear energy system. The retirement of thermal generators is part of the National Energy Productivity Plan (NEPP) [14]. NEPP was designed to help meet the Paris Agreement and international treaties of the United Nations Framework Convention on Climate Change [48, 24]. NSW has announced the closure of four of the state's five remaining coal generators by 2035, with Liddell closing in April 2023 [21]. Steps are taken to implement new forms of generation that can meet power demand. NSW intends to replace the thermal generator's base load supply with dispatchable, non-dispatchable and semi-dispatchable renewables [21]. Generation via dispatchable renewables alone without storage solutions generates an inconstant power profile that does not meet the expected load profile of AEMO [1]. In 2019, an unplanned outage of the Loy Yang and Yallourn coal fire caused parts of the Victorian grid to be switched off during a heat wave. Increased storage can be used to supplement supply to help prevent short-term blackouts when power export is limited due to station outages, shut downs or other unforeseen circumstances. Storage in the form of a community battery could see the distribution transmission level fill some of the nation's storage concerns.

Increasing penetration of PV units embedded at the distribution level is seen in Australia [45]. The advancements in technology and the reduction in the price of solar have increased the rise of PV units [45]. Australian Governments Clean Energy Regulator found an increase of 28% of PV units in the distribution network from 2019 to 2020 [51]. High-density PV units can experience problems with frequency, phase voltage amplitude disruption, and demand drop below the baseload supply [10]. Network security and reliability become critical with high levels of PV penetration in the modern complex energy system [10]. Distributed Energy Resources (DERs) lack the large-scale thermal inertia-driven generations ability to absorb fluctuation in the ancillary service of NEM. Technology like the Tesla virtual machines at Hornsdale in South Australia is designed to provide inertia support at the cost of $90 million [29]. Hornsdale acts at the transmission level and supports the transmission network more than the community.

Most existing distribution and transmission network components where built between the 1950s and 1970s [21]. The aging network will require maintenance and replacement. When placed on load, distribution transformers experience a breakdown in insulation. The insulation life expectancy of a distribution transformer is a function of the loading [59]. A breakdown of the distribution transformer can cause power interruption to downstream consumers and increased costs to the DNSP in the form of upgrading or reconditioning of the unit. The greater the cost of exporting power to a customer, the higher the price of electricity. This includes costs in breakdowns and upgrades. Lowering the demand profile, particularly the maximum demand, will increase the insulation life of the unit and elevate the cost burden on DNSP [35].

Research objectives and scope

This dissertation investigates and analyses community storage frameworks to achieve a smooth load profile that provides DNSP benefits from increased distribution transformer lifespans. The life extension of the distribution transformer is calculated alongside the cost recovery of the battery installation for utilities. Due to the community's lower peak demand, savings will be passed on to the consumers and prosumers of the distribution transformer network.

The deliverables of this project are:

- Literature review of community battery projects around Australia and overseas. Analysis of the frameworks in pilot project implementation and design.
- Build a model of distribution transformer life based on load profile.
- Model different frameworks of the battery to optimise battery usage and transformer life.
- Analyse the models to determine the cost and benefit to the utility and flow on savings to the community.

The scope of work is to find the cost and benefits of different frameworks of community battery ownership for DNSP. Further, this work will optimise the operation of different battery sizes to extend the end-of-life for the distribution transformer. The cost savings to consumers under separate tariffs will be assessed as a flow-on saving from reduced power usage. The retailing mediation between houses and the battery will be theorised as no current formal AEMO implementation strategies exist, and current retail tariffs are used as a result. Ancillary services are out of the scope of work due to restrictions from the AER.

The assumptions made for design and modelling purposes within this project:

- The utility is the sole owner and operator of the community battery.
- Load and solar generation follow a characteristic trend.
- The power factor is 0.9.
- The distribution transformer costs $100000.
- The inflation rate is at 1.7% per annum.
- The interest rate is 5% per annum.
- All solar inverters produce an equivalent percentage of the solar profile.
- All consumers and prosumers use power equivalently.
- The battery is connected via a controllable bidirectional DC/AC converter.
- Battery round-trip efficiency is 90%.
- Battery max depth of discharge is 80%.
- Transformers have a life expectancy of 50 years.
- Lithium-ion batteries have a life expectancy of 10 years.

Research significance

The research is significant as it provides a comprehensive framework of operation for DSNP-owned community batteries and a cost-benefit analysis of the increased life expectancy of transformers. Consumers on the distribution level could see a reduction in the pricing of their electric bill, and utilities can extend the life of the distribution transformer. The increased self-consumption of PV unit power within the community reduces bi-directional power flow. The reduced loading on distribution lines during peak operations in high heat can increase the reliability of networks. The research will encourage continued deployment of PV units in communities with utilities achieving returns through end-of-life extension.

Ethical controls

Energy Queensland provided data under a signed confidentiality agreement. The agreement and subsidiary components of data shared for this project will not be transferred or published. Access to the data is restricted to those with signed confidentiality agreements, accessible via a secure portal controlled by two moderators. Additional steps have been taken to prevent the exact community location from being disclosed by Energy Queensland, reducing the likelihood of consumers' confidential information leaking.

Report layout

The dissertation is organised into the following chapters.

Chapter 2 - Literature Review provides background information on the current projects, community battery technology's limitations, and a review of modelling methods from other literature.

Chapter 3 – Methodology. Proposes a method to model the different site location's load and PV output. The algorithm is modified to optimise the battery framework for improved performance.

Chapter 4 – Results and discussion. Analyse algorithm changes' performance to find the battery's maximised usage for current technological constraints.

Chapter 5 – Conclusion. Summary of the dissertation and results. With recommendations and contributions for future research work.

Chapter 2 – Literature Review

This chapter reviews the requirements for the design of the community battery frameworks, the technical consideration of transformer age and battery design with market integration, and tariff structures. A comprehensive review of the literature on community battery frameworks and a review of current frameworks by utilities pilot projects is discussed.

Community battery

A community battery has a physical size of around a four-wheel drive car, with a capacity limited to 100 kW to 5 MW [50]. Lithium-ion and lead-acid batteries have been used in renewable energy storage, but lithium-ion is the main storage technology. Lithium-ion is ideal for storage due to its high energy density of 150 Wh/kg [27] and the relatively high-power density of 100 W/kg [22]. Lithium-ion has experienced large drops in prices over time [62]. Lithium-ion batteries are the dominant technology for energy storage in the marketplace [36]. Storage options allow for the stabilisation of renewable powers, frequency and voltage control, peak shaving, and demand load shifting that will provide utility options to defer upgrades in their infrastructure [46]. Due to the nature of the operation, community batteries have limitations in how they would participate. The coupling of the battery to the community demand would mean charging and discharging as customers fluctuate their behaviour. This could undermine participation in the wholesale market and remove any chance of battery-supporting ancillary services [38].

Battery cost

The cost of a lithium-ion battery varies with materials availability and design composition. Lithium-ion batteries come in family groups based on their anode and electrolyte solutions. Ralon et al. [49] identify the two primary anodes as lithium-metal and lithium-ion, with the major electrolyte identified as an organic solvent mixed with lithium salt solution. The lithium-ion with a polymer electrolyte is still designed but has become less abundant [49]. The trend in the pricing of lithium-ion batteries has decreased significantly over the years. Ralon et al. [49] found that the installation costs of lithium titanate were between USD 473 – 1260/kWh, and other designs cost between USD 200 – 840/kWh. These are very specific designs and chemical compounds to use. Carl et al. [11] and Shaw et al. [53] found that the community battery cost around AUD 1000/kWh. Yarra Energy Foundations FitzRoy’s neighbourhood battery project required a price of less than AUD 950/kWh to ensure the batteries were viable [20]. Yarra Energy Foundations is the more recent project varying by only 5% in price compared to Carl et al. [11] and Shaw et al. [53]. Table 1 shows the operational battery limitations.

Battery Life and efficiency

Christians et al. [11] reviewed energy storage options and found lithium-ion batteries have a life expectancy of five to fifteen years, with a cycle life of between 1000 and over 10000, with a round trip efficiency of 85-98% at the max discharge of 80%. Luo et al. [37] found the optimal life expectancy to be at a depth of 80% discharge. Arshad et al. [3] conducted a similar review as Christians et al. [11] on the life cycle characteristics of lithium-ion batteries, finding that the time to 60% capacity loss for the batteries was eight to twenty years. These findings are supported by Shaw et al. [53] using battery modelling of ten years at 90% efficiency. The battery cycle max was calculated at 1.21 cycles per day, equalling 4416.5 cycles if one charge cycle occurs per day over a year. This places the batteries expected cycle life within the range found by Christians et al. [11] and Arshad et al. [3]. Table 1 shows the current operational battery limitations.

Table 1: Battey design parameters

Parameter	Value
Battey design	Lithium-ion
Battery expected life	10 years
Cycles	10000
Efficiency	90%
Maximum Depth of Discharge	80%
Cost	$950/kWh

Regulation and market integration

AEMC makes energy rules under the NEL. AEMC amended the definition and operation of energy storage systems in 2021, introducing a new participant category, Integrated Resource Provides (IRP) [44]. IRP category incorporates storage and hybrid facilities where participants with bi-directional energy flows are accommodated. The majority of changes will come into effect on the 3rd of June 2024, with only two changes taking effect on the 31st of March 2023:

- Aggregators of small generating or storage units will be allowed to provide ancillary services.
- Hybrid systems will be allowed to use aggregate dispatch conformance.

Community batteries are prohibited from providing ancillary services until AEMC amendments take effect on the 31st of March, 2023. Hybrid or standalone systems experience more flexibility to participate in small or large storage units. Community batteries operated by DNSPs inside the current NEL are to deliver regular network services only.

AEMC must satisfy section 88 of the NEL, which outlines the need for long-term investments in the national electricity system's safety, reliability and security [34]. The assessment framework of the AMEC ruled that the benefits to reliability and security of IRP assist in balancing the power system [44]. AEMC identifies further work is needed on how network prices are set for storage to provide investment incentives and efficient operation. AEMC amendments have not outlined the network pricing needed for community batteries.

Tariffs

Retailer's tariff pricing is set by the electricity retail code's default market offer price. There are no existing regulatory or commercial mechanisms to monitor a customer's power flow to the community battery or battery to the consumer. The power flow goes via a retailer to settle the wholesale market [32].

There are three main tariff types that retailers provide to consumers, with a connection fee for every day of the year being the only consistent pricing:

- General use tariff charges a basic rate for kWh used.
- Time of use charge where different rates apply to different periods of the day, with the peak being between 16:00 and 21:00, shoulder between 21:00 to 09:00 and off-peak 09:00 to 16:00.
- Demand tariff with a lower kWh usage charge but a peak demand charge for the highest kW used in a month charged for every day that month.

Tariff 11 of Ergon energy charges the consumer for import at a rate of $0.24349 per kWh and provides a solar feed-in tariff of $0.093 per kWh [18]. The disparity of these charges will have residences paying $0.15049 per kWh for their own generated PV unit's power. Shaw et al. [54] suggest an appropriate pricing model could be theorised under a DNSP-modified network tariff like a local use of service tariff or a daily discount. Local use of service tariff is proposed as energy from the community battery to consumers and between consumers. Shaw et al. [54] support the local use of service tariffs which is better known as a peer-to-peer scheme but is not currently allowed by the AER. This can provide a lower energy cost as the transfer cost is significantly higher when transporting the same energy outside of the local use of the service area.

Queensland Energy is a major provider in Queensland; there are two retail groups, Ergon Energy and Energex. The three tariff types are compared in Table 2.

Table 2: Tariff comparison [18]

Charge Type	Tariff 11 ($)	Tariff 12B ($)	Tariff 14B ($)
Supply Charge per day	0.99449	0.99449	0.99449
All usage per kWh	0.24349		0.18402
Peak per kWh (1600 – 2100)		0.32929	
Shoulder per kWh (2100 – 0900)		0.19741	
Off Peak per kWh (0900 – 1600)		0.18959	
The peak of a month per kW			8.712

Transformer aging

Hotspot temperature is a critical factor in the aging of transformers. An overloaded transformer or one working near a nameplate value can experience a reduction in life expectancy. A transformer that exceeds the nameplate capacity without sacrificing life expectancy may be possible for short periods in low ambient temperatures and at a low initial load.

There are two effective methods of calculating the life reduction of a transformer, one from the Institute of Electrical and Electronics Engineers (IEEE) and the other from the International Electrotechnical Commission (IEC) [42]. For oil-immersed transformers, IEEE C57.91 and IEC 354.91 are used to evaluate loading and the thermal effect [59, 42]. The life cycle of an asset will always correspond with a failure rate and time [35, 39]. Transformers are expected to have a life of more than 180 000 hours (20.55 years) and more when properly maintained [28]. Martin et al. [39] reviewed transformer failures in Australia, finding that aging-related failures appear after twenty years, matching the expected life from IEEE C57.91. Najdenkoski et al. [42] compare a distribution transformer's thermal aging with IEEE and IEC standards. Najdenkoski et al. [42] concluded in their research that the differences in the standards do not produce a significant change in life expectancy of a transformer. IEC does not provide a total life definition; as a result, the IEEE method predominantly favoured [42]. Given the Australian network's age, many transformers will have gone through reconditioning or replacement [39].

Both IEEE and IEC calculate the relative aging factor of a transformer based on the hot spot temperature. The IEEE model uses the equation below to calculate a hotspot in degrees celsius (θ_{hs}) [52]:

$$\theta_{hs} = \theta_a + \Delta\theta_{TO} + \Delta\theta_2 \qquad \text{Equation 1}$$

Where $\theta_a$is the ambient temperature, $\Delta\theta_{TO}$ is the average oil temperature change above ambient and $\Delta\theta_2$ is the hottest spot on the winding change above θ_{TO}. Temperature is the main degrading factor for a transformer insulation life and is key to determining the remaining life expectancy of a unit [28].

Transformers, even with low load levels, have a maximum life span. Shimomugi et al. [31] found that a transformer can last for 50 years at load factors of 40% to 60%. This life span can only be achieved if there are low levels of moisture in the transformers. Bohatyrewicz et al. [8] found that distribution transformer life span can range from one to fifty years. Bohatyrewicz et al. [8] do not include any study on transformers over 50 years due to the misleading analysis of the population sample. The transformers over 50 years are outliers and do not represent the expected life.

Transformer cost

Amoiralis et al. [2] analyse two transformers based on their Total Owning Cost (TOC). This method compares two units using the losses and costs inherent to those losses. Amoiralis et al. [2] research found this model best used when running a comparison for two or more transformers for a known age. Amoiralis et.al [2] TOC equation:

$$TOC = BP + (A \times NLL) + (B \times LL) \qquad \text{Equation 2}$$

$$A = \frac{LIC + EL \times AF \times HPY}{CRF} \qquad \text{Equation 3}$$

$$B = \frac{LIC + EL \times LF \times HPY}{CRF} \qquad \text{Equation 4}$$

BP is the initial purchasing price of a transformer, A is the equivalent no-load loss cost rate ($/W), NLL is the no-load loss (W), B is the equivalent load loss cost rate ($/W), and LL is the load loss (W) [2]. LIC is the annual generation and transmission investment cost ($/W), EL is the cost of electricity ($/kWh), AF is the transformer availability or predicted operation (less than unity), HPY is the hours per year of operation (8760 hours). The TOC proposed by Amoiralis et al. [2] does not account for the inflation of a new product, opportunity cost loss or the purchasing cost. A comparison model will require the future cost of purchasing both transformers and batteries represented in a future value. Future costs when comparing the past, present and future of different components are theorised by de Vries et al. [15]. de Vries et al. [15] concludes that a prolonged life has additional costs, but the optimal decision includes the related and unrelated costs. The future cost equation has the recommended components theorised by de Vries et al. [15].

$$F_v = P_v(1+i)^n \quad \textit{Equation 5}$$

Where F_v is the future cost, P_v is the present value, i is the inflation rate, and n is the number of years. A cost-benefit analysis is conducted by Awad et al. [6] and Tang et al. [58] using net present value equations which are variations on the future cost equation. These do not consider the purchasing cost of future components. A appropriate comparison is a time frame comparison based on Awad et al. [6], de Vries et al. [15] and Tang et al. [58].

Australian renewable energy agency

The Australian Renewable Energy Agency (ARENA) is a major financing group for projects contributing to accelerating a net-zero emissions goal. Australian National University's Shaw et al. [54] have received several grants for researching and analysing the application of community batteries in Australia. Shaw et al. [54] found a financial incentive for community-scale batteries that could be viable for their models. Still, significant returns are not present unless FCAS participation is allowed. The research followed different ownership models with and without profit models using different optimisation methods, including a game theory model of how users would need to change behaviours to optimise their savings. The stakeholders identified in the report found that more public trials would be needed to demonstrate the benefits. Shaw et al. [53] required future work for the estimated revenue as their research was a base case scenario. The models did not consider the PV energy of customers to the battery storage. All consumers were, therefore, uniformly able to take advantage of the battery storage. Another limitation of their financial revenue calculation is their participation in the FCAS market. Under current regulations identified by Shaw et al. [55], the AER regulations will prevent the utility from a financial gain in the ancillary services. They concluded that without FCAS, the financial viability would rely on the battery cost to their revenue asset base. The network would therefore have to lease storage to the market participants.

Shaw et al. [55] provide a model for the power flow within a community battery. It is defined in the literature as a Local Energy Model (LEM). In Figure 2Figure 2: Community Battery Energy Flows [55], the power flow's can be defined into variables.

Grid into the battery: (E_{gb})	Grid to the load: (E_{gl})
Battery into the grid: (E_{bg})	Battery to the load: (E_{bl})

PV to the grid: (E_{sg}) PV to the battery: (E_{sb})

PV to the load: (E_{sl})

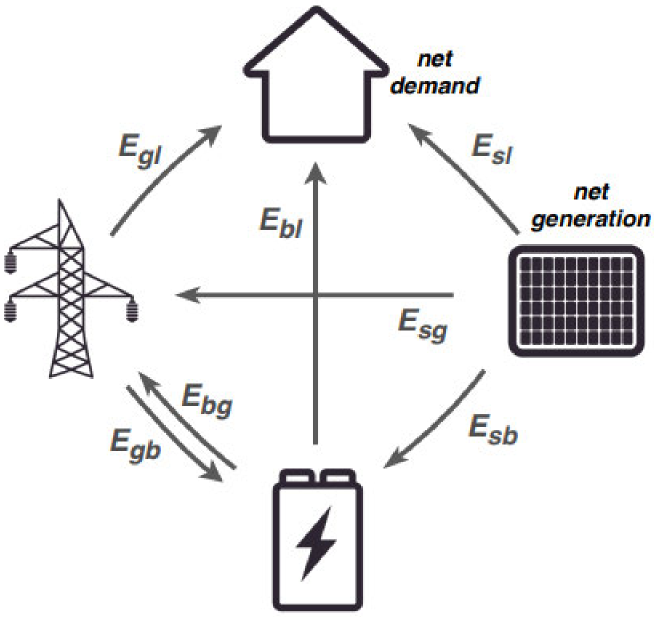


Figure 2: Community Battery Energy Flows [55]

Current Community battery projects

Across Australia, several projects have been established to optimise results for consumers and owners of community storage. Each operates uniquely due to AEMO requirements and regulations.

Western Australia

One of Australia's first installed community batteries was in 2016 at Alkimo beach. This was a 250 kW/1.1 MWh lithium-ion battery that allowed a subscription-based energy storage option, where the consumer paid for an allocation of the storage available [56]. Community battery storage is limited to 6 kWh and 8 kWh per customer [47] and is based on the average daily maximum quantity of virtual stored energy. In the city of Mandurah, meadow spring's 8 kWh service was charged at one dollar a day. A Time of Use (TOU) pricing model is used, where electricity cost is based on the period of the day to incentivise higher levels of participation at different times. Many homes are on an A1 home tariff plan that pays around 29.3273 cents per kWh [47]. PowerBank batteries are used in Western Australia, working with Western Power as the utility. The utility offers to purchase the power generation that remains in the storage unit at the end of the billing period [57]. Western Power is allowed to purchase the remaining power because they are not part of the NEM. Western Power can incentivise a higher participation rate by offering financial gain that members of the NEM cannot receive from their utility. The energy stored is only available between 15:00 and 23:59 when PowerBank deems the home solar panels not to meet household consumption [47]. The time frame does not allow for morning demand reduction even if the household has not used the allotted power from the night before. Western Power is still investigating whether a building of units could participate, given the low service area for PV unit installation. ARENA funded the trial with $3.3 million reducing the installation costs to Western Power. Synergy et al. [56] found that the participants saved $81 376 collectively on their electricity costs when compared with the A1 tariff. The community was selected because the homes come with an energy smart home package and a 80% solar orientation to maximise solar output [12]. The cost of new metering, data platforms, community battery and efficiency improvements on the homes are not represented as an overall cost versus savings. A list of the battery projects in Western Australia can be found in Table 3.

Victoria

The Neighbourhood Battery Initiative (NBI) has commenced trials in Victoria's suburbs following the success of United Energy's pole-mounted batteries. United Energy is continuing development with 40 pole-mounted batteries at a combined 1.2 MW/2.7 MWh of storage [12]. United Energy's batteries are designed for constraints in the network where there are low voltage distribution and PV exports that can help improve reliability [12]. The key objectives of the NBI project are to inform regulators of reforms needed for battery storage in the NEM, determine the battery scale that will be most beneficial, and understand the network tariff arrangements. The NBI has received $10.92 million in grants, with $3.68 million going to 16 projects across the state [60]. The NBI is expected to support networks by avoiding network upgrades and providing lower network charges to customers. The intention is to reduce the prices and maintain the security and reliability of the energy system with additional services. Similar to Western Australia, the batteries can offer customers virtual storage in some locations. Solar is stored during the day and used in the evenings; the power is also available to customers that do not participate in the shared storage scheme. NBI projects are still in design with United Energy focusing on congestion in the network to meet NEM requirements being the first to roll out over the state. A list of the battery projects in Victoria can be found in Table 4.

Tetris Energy is developing a feasibility study and revenue modelling for a 4.95 MW/ 4.95 MWh battery in the regional town of Port Fairy. The results of this and other stream-one-funded projects are still under review, with revenue modelling being a priority for the NBI. The majority of stream one is calculating the expected return on investment, particularly with FCAS. The NBI has a research partnership with ANU. Shaw et al. [54] found that there is a small financial incentive for community batteries without FCAS, and the NBI is exploring this option further with stream-two-funded projects. The NBI is modelling stage two funded projects with FCAS and arbitrage. Most projects installing community batteries are for constraints in the market. Given the research conducted by Shaw et al. [54], NBI is waiting for FCAS capabilities to boost revenue for community batteries.

New South Wales

Ausgrid has launched a set of community batteries with 10 kWh of virtual storage available per day for participating solar generators at no cost to the participants [5]. This energy storage is credited against the energy used on the premises for that day. Payment of credit in each quarter is received at the quarterly bill period. Ausgrid has designed an application for participants to monitor their contribution in real time; this can help participants use their energy more effectively.

Enova, in partnership with Enosis and the University of Newcastle's Beehive project, represents an area of future development for the community battery. A 1.07 MW/2.14 MWh Tesla battery is used to power around 115 homes daily based on the project's 19 kWh per household requirement [19]. This trial is run as peer-to-peer trading; the local distributor sells the electricity at a price that both producer and consumer are willing to accept. The beehive provides an energy trading project for 500 NSW households and uses the community battery as a storage system for trading [19]. Microgrids are to become more common as regulation changes allow distributors to roll out Stand-alone Power Systems (SAPS's) in the NEM [13]. Peer-to-peer trading has been permitted for the Beehive project as a future complex energy system. A list of the battery projects in NSW can be found in Table 5.

Queensland

All five Energy Queensland community batteries have a 4 MW/8 MWh storage capability and are designed for peak shaving. The high summertime temperatures cause a significant restriction to the line carrying capacity. These larger-scale community batteries assist the utilities during the peaks by reducing the demand. Energy Queensland community batteries represent the largest community batteries. They are the most recent to be added; an analysis of viability is still under review. A list of the battery projects in Queensland can be found in Table 6.

International

International projects in the United Kingdom, Nottingham's Trent Basin, are doing similar research [30]. The 500 kW/2.1 MWh storage battery is used in demand response combined with PV energy from the community [30]. The battery is connected to 45 homes and operates as storage between the grid and the community. A local energy company has been established just for the residents, with the intention that participants share in the profits in the form of lower energy costs.

Table 3: Western Australia Community Battery Projects

Location	Size	Owner	Battery Manufacturer	Operation Type	Year of Operation	NO of Homes
City of Mandurah, Meadow Springs	105 kW/420 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	8 kWh virtual storage purchase plan $1 per day.	2018	52
City of Mandurah, Falcon	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	8 kWh virtual storage purchase plan.	2019	55
City of Swan, Ellenbrook #1	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2019	55
City of Swan, Ellenbrook #2	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2019	55
City of Wanneroo, Two Rocks	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
City of Wanneroo, Ashby	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55

City of Canning, Canning Vale	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
City of Rockingham, Port Kennedy	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
City of Stirling, Yokine	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
City of Kwinana, Parmelia	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
City of Busselton, Vasse	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	6 kWh or 8 kWh of virtual storage costs $1.20 per day or $1.40 per day.	2020	55
Shire of Augusta-Margaret River, Margaret River	116 kW/464 kWh	Western Power and Synergy	Western Power and Synergy - Tesla battery	Behind the meter community battery (5-year trial)	2020	55
Alkimo beach	250 kW/1.1 MWh	Western Power and Synergy	Western Power and Synergy	subscription-based energy storage charged at TOU	2016	100

Table 4: Victoria Community Battery Projects

Location	Size	Owner	Battery Manufacturer	Operation Type	Year of Operation	NO of Homes
Gordon Crescent, Black Rock	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2020	50-75 homes
Telford Street, Highett	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2020	50-75 homes
Casey	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Frankston	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Glen Eira	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Greater Dandenong	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Kingston	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Monash	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Mornington	30 kW/66 kWh	United Energy	Thycon	Peak shaving: 5 pm – 9 pm	2021 - 2023	50-75 homes
Fitzroy north	110 kW/285 kWh	Yarra Energy Foundation and CitiPower	Pixii, PowerShaper	Peak shaving	2021	150 homes

Table 5: New South Wales Community Battery Projects

Location	Size	Owner	Battery Manufacturer	Operation Type	Year of Operation	NO of Homes
Cameron Park in Lake Macquarie	150 kW/267 kWh	Ausgrid	KPMG - tesla	10 kWh of virtual storage, no charge. Peak shaving: 5 pm – 9 pm	2021	250 homes
Beacon Hill on Sydney's Northern Beaches	150 kW/267 kWh	Ausgrid	KPMG - tesla	10 kWh of virtual storage, no charge. Peak shaving: 5 pm – 9 pm	2021	250 homes
Bankstown in Sydney's West	150 kW/267 kWh	Ausgrid	KPMG - tesla	10 kWh of virtual storage, no charge. Peak shaving: 5 pm – 9 pm	2021	250 homes

Table 6: Queensland Community Battery Projects

Location	**Size**	**Owner**	**Battery Manufacturer**	**Operation Type**	**Year of Operation**	**NO of Homes**
Black River Substation – Townsville, Bohle Plains	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500
Tanby Substation – Yeppoon	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500
Bargara Substation – Bundaberg, Bargara	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500
Torquay Substation – Hervey Bay	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500
Torrington Substation – Toowoomba	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500
Townsville, Black River	4 MW/8 MWh	Energy Queensland	Tesla battery	Peak shaving	2022	500

Research survey

The community battery literature review found that work has previously been done on site selection, load and solar profile management, and battery operational state modelling.

Xiao et al. [61] bi-level optimization model proposes an optimal site and the capacity of the storage to minimise the current cost. This dissertation only focuses on load smoothing, but insights into the optimal site are still valid. Both Hayat et al. [23] and Xiao et al. [61] recommended high-density PV units for optimised battery usage. Hayat et al. [23] also found a community battery site where the distribution transformer has a higher load than the rated capability to improve battery usage. The pilot projects have around 50-150 homes connected to the community battery, and this is reflected in Shaw et al. [54] project. The review found that optimisation is normally conducted on a predefined location with voltage and reactive power support as priorities.

Previous work has modelled the generation and load profiles by using probabilistic distribution. Atwa et al. [4] use a probabilistic approach to renewable energy for wind turbines. The study found the mathematical formula generic enough to apply to other renewables. Awad A et al. [6] and Hung et al. [26] used historical data to find the probability distribution function for solar irradiance using the work of Atwa et al. [4]. The probabilistic model in the literature requires large data sets and calculations.

Hayat et al. [23] use the two-state approach where the battery is either discharging if the conditions are correct or charging. In the charging state, the battery stores PV-generated power till the kWh threshold of the battery is met, or the discharge state is triggered. The discharge state is designed for when the algorithm detects the conditions are correct depending on the framework of operation. This state alleviates concerns for outlier events, such as higher demand in the middle of the day. Probabilistic modelling will not account for such moments [6, 7, 37].

Conclusion

This chapter provides an overview of community battery technology and design. The literature review conducted in this chapter found that some research works have already been conducted regarding community batteries. The following research gaps have been identified with regard to the allocation of community batteries in a distribution network:

- Limited studies have investigated the benefits of community batteries on distribution networks' peak load shaving and upgrade deferral. The benefits of distribution transformer deferred upgrades have not been considered.

- A comprehensive planning framework for determining the size and operational framework for community battery implementation has not been designed.

Profile modelling is done in the literature by the probability distribution function. Using a known load profile normalised with community power demand and solar generation is more simplistic. The know profile designed uses a similar method to compute the capacity discharge of the battery as in the probabilistic load following. The altered method is referred to as load following, where the demand shaving is the primary load to meet by the generator, in this case, the community battery. The design will require fewer data points while still drawing on Awad A et al. [6] and Hung et al. [26] load following design for load shaving.

The economic model is based on the net present value equations of Awad et al. [6] and Tang et al. [58], with variations for future comparison of components suggested by de Vries et al. [15]. The literature review provides a good source of economic modelling but does not simulate the DNSP cost over time. A time-based comparison provides a reasonable comparison for operational frameworks and battery sizes.

Using Hayat et al. [23], there are two states for the battery operation, charge or discharge. This approach provides a higher level of freedom to optimise the battery algorithm. The battery frameworks of discharge found are:

- The discharge time of 17:00-21:00. Found in United Energy and Ausgrid pilot programs.
- Discharge window at 17:00-21:00 and 07:00-09:00. This is proposed by Shaw et al. [53] as an additional moment of load control.
- Using the transformer rating and a set demand shaving limit.
- Shaving the load profile to a set demand shaving limit.

Chapter 3 – Research Design and Methodology

RERs have the potential for a huge reduction in carbon emissions, but are highly intermittent power profiles. Solar energy is only available during the day, with the output depending on solar irradiance, temperature and cloud. Community batteries can facilitate the seamless integration of intermittent RER as a solution. The storage can reduce the cost of electricity, enhance reliability, and reduce peak demand under the current AER rules [23]. The financial cost of batteries is a significant obstacle to their adoption [11]. Community batteries will rely heavily on location, size, and operational characteristics to maximise the techno-economic benefit for consumers, prosumers, and utilities.

This chapter proposes a methodology to determine the optimal site, size and framework by considering the costs and benefits incurred to the consumers, prosumers, and the utilities. Different community battery sizes and frameworks are modelled to analyse and compare the optimal behaviour for utility return on investment. The battery size is determined by the reduction in peak demand required as a percentage of the transformer rating, referred to as the clipping limit. The current battery conditions model is used to model the different operation frameworks. Peak shaving from 17:00 to 21:00, from Ausgrid and United Energy pilot project, is compared with the optimisation options. Optimisation options are an additional shaving window between 07:00 to 09:00 when the transformer rating and the clipping limit are exceeded and, finally, the peak shaving over the entire load profile. Community batteries cannot participate in ancillary services and arbitrage due to AER rules; ancillary services and arbitrage are outside this work's scope [13]. Figure 3 is the proposed methodology flow chart for the design in this chapter. The MATLAB code is given in Appendix E.

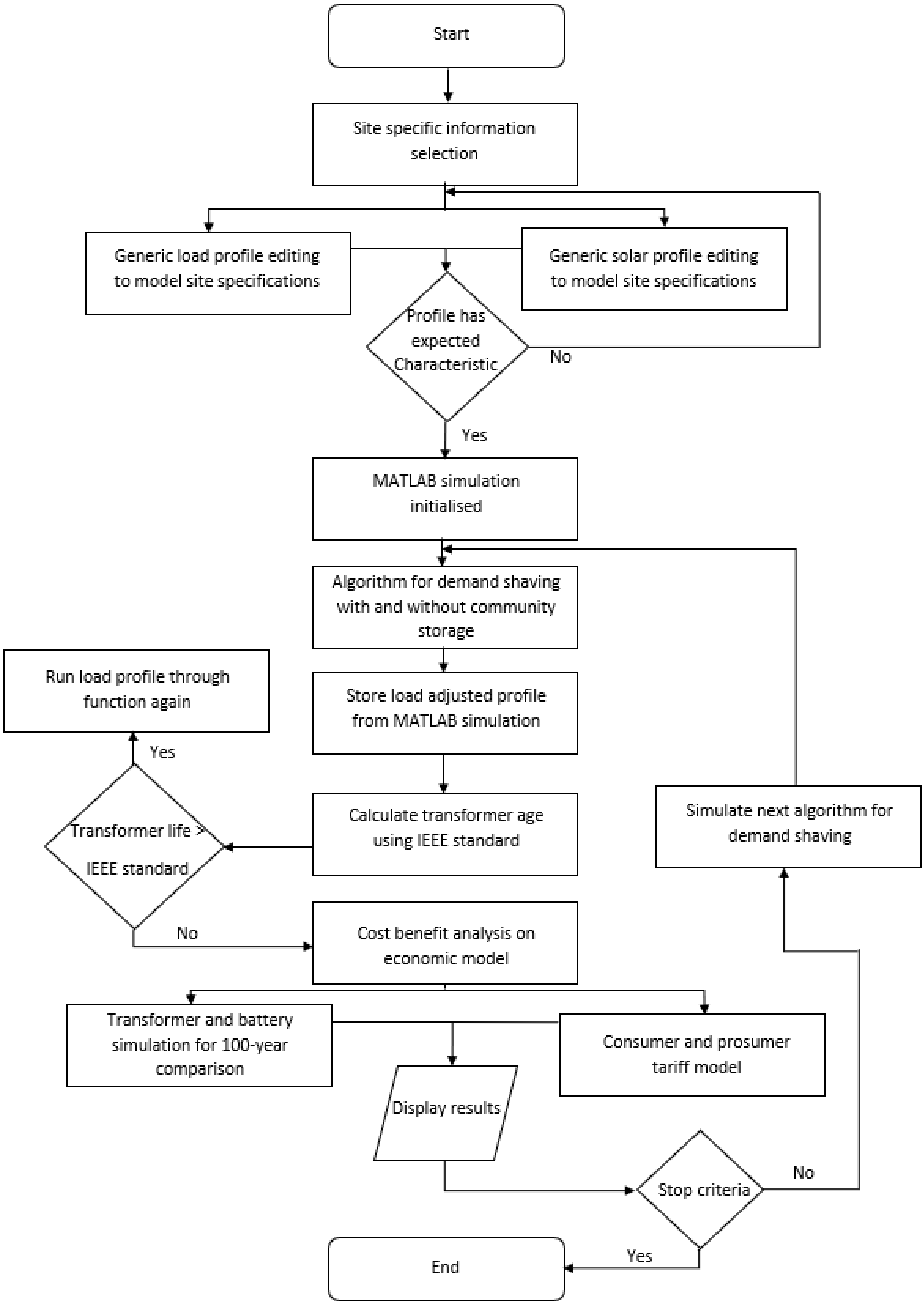


Figure 3: Flow chart of the proposed methodology

Data acquisition and editing

Site selection

The site selected is based on the recommendations in the literature review of community batteries:

- Hayat et al. [23] recommend frequent loads above the distribution transformer rating.
- Xiao et al. [61] recommend high-density PV in the community.
- The majority of pilot projects support 50-150 homes.

Queensland Energy provided aggregate site information; based on the literature, the information yielded several selections. One site with a distribution transformer frequently overloaded, high-density solar capacity and homes in the 50 to 150 range. Table 7 shows the site selected.

Table 7: Site values from Energy Queensland

Variable	Value
Consumers	96
Transformer	200 kVA or 180 kW
Solar capacity	209.46 kW
Yearly consumption	359.94 MWh

Solar and load modelling

Given the sit location information from Table 7, the information is normalisation across a known profile from NREL et al. [43] and Laboratory et al. [33].

Solar generation modelling

Solar energy is only available during the day, with the highest output depending on solar irradiance, temperature, and cloud cover. It is assumed that all PV units are generating proportional to their size for any generation profile, and variations occur during seasonal environmental changes. The solar generation is assumed to follow the characteristic generation found in NREL et al. [43] and can be seen in Figure 4. Solar data is provided in kW from NREL et al. [43] and can be normalised using the maximum value and solar capacity found in Table 7.

$$Normalised\ solar\ kW = \frac{Value\ of\ profile}{Max\ of\ the\ solar\ profile} \times Solar\ Capacity \qquad \text{Equation 6}$$

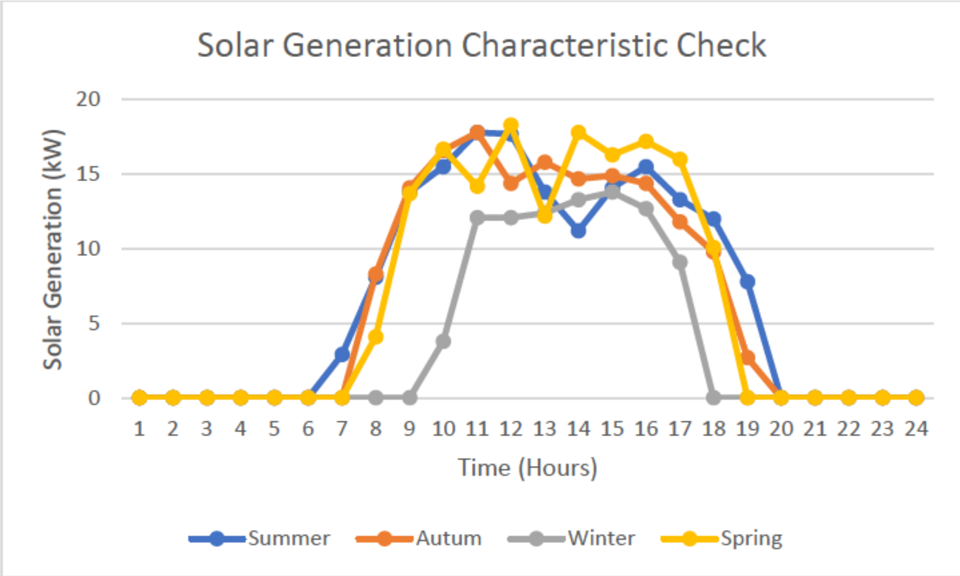


Figure 4: Hourly solar generation characteristic check

Load modelling

A consumer load is a time-variant based on individual habits. A distribution network is assumed to follow a normalized characteristic demand over 24 hours. Variations occur during seasonal changes in the environment. The distribution network is assumed to follow the characteristic demand. The load profiles were generated from historical data found by Laboratory et al. [33]. Figure 5 is a characteristic check for seasonal changes in the load generation using Laboratory et al. [33].

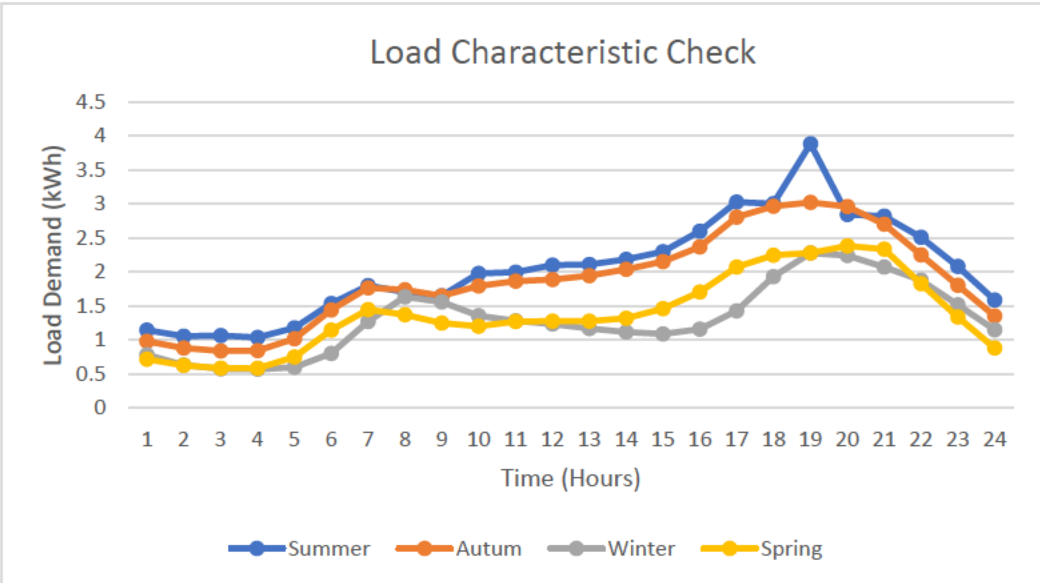


Figure 5: Load Profile of seasonal variations on a single day

Figure 5 illustrates the characteristic hourly residential load curve for the four seasons. Table 7's information is for the site location; the data from Laboratory et al. [33] is normalised using the equations below.

$$Normalised\ Load\ kWh = \frac{Value\ of\ profile}{Average\ of\ profile} \times \frac{load\ rating + \sum normalised\ solar}{Hours\ in\ a\ year} \qquad \text{Equation 7}$$

Figure 6 is the mean of each month's hours after normalisation. Figure 6 produces a seasonal variations characteristic check along with a power variation result.

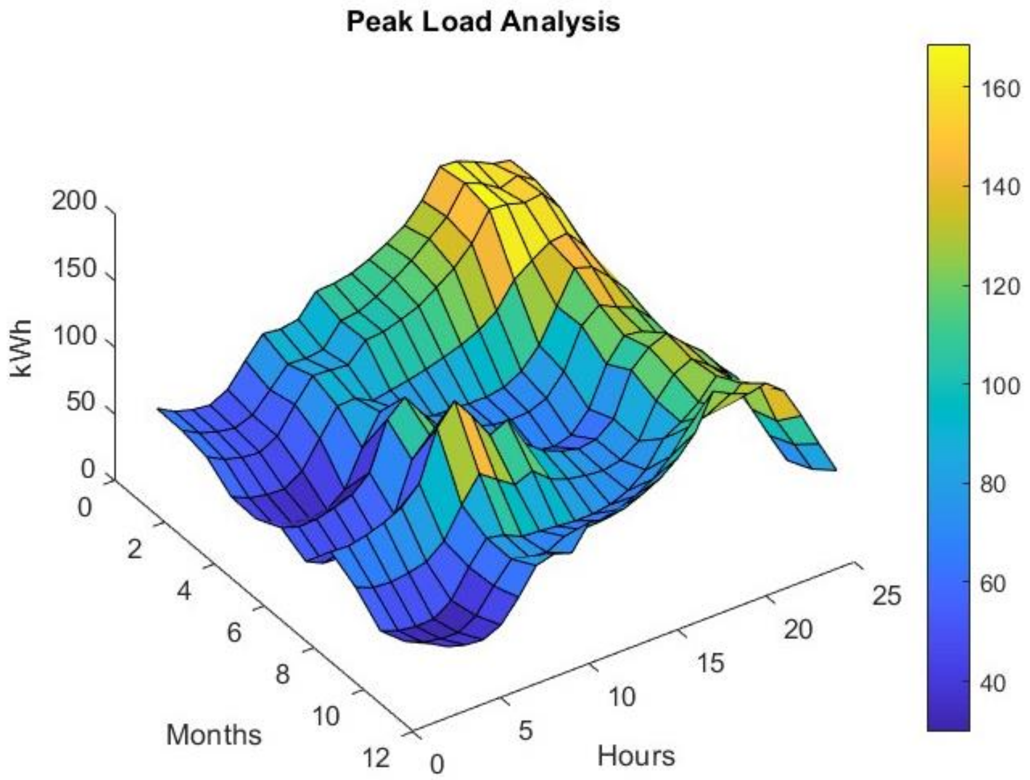


Figure 6: Peak Load Analysis of Seasonal Variations

Proposed community battery design

The community battery is assumed to be connected via a bi-directional DC/AC converter that can be controlled [9]. It can charge and discharge as desired for the power framework deployed, acting as a load during changing and an active power source during discharging. The power rating of the battery limits the discharge.

Integrating demand shaving modelling

This section presents the formulation of the battery size to achieve a smooth annual load profile. Hayat et al. [23] propose a battery size model based on the PV units. Given the varying nature of generation from PV units, a demand-based model will have the highest potential for smoothing the load profile. The sizing of the batteries in Tang et al. [58] and Xiao et al. [61] is based on the required demand reduction. For this model, the battery size is related to the demand experienced by the transformer. Using Figure 7 as an example, a theoretical clipping limit is placed over the load profile. The difference between the clipping limit and the load profile above the limit is calculated. The highest annual difference between the two determines the kWh storage needed for the battery. The clipping limits are set as percentages from 50% to 150% of the transformer kW rating. The transformer is assumed to have a 0.9 power factor. A no-clipping limit is representative of a no-battery mode operation. The no-battery mode is used to validate the models and for comparison with battery modes.

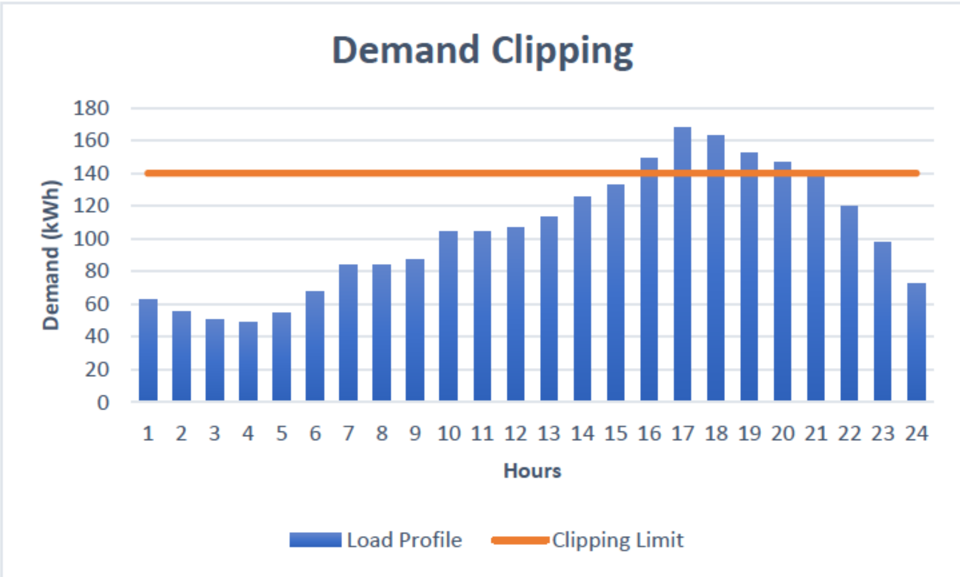


Figure 7: Clipping Limit for Load Profile

The load profile is hourly incremented over a year (8760 increments). Figure 7 represents 24 increments of the load profile or a day. Hayat et al. [23] use a similar method, representing the PV storage requirements. The adding of summed parts to find the integration is simplified by the rectangular representation of the load due to the increments. $P_{over\ clip}$ is the integration of the peak defined by the clipping limit where E_{CB} is the storage size of the community battery.

$$E_{CB} = \int_{t_{peak-start}}^{t_{peak-end}} P_{over\ clip} dt \qquad \textit{Equation 8}$$

Adjusted load profile for energy storage modelling

The two states of battery operation are charge or discharge, used by Hayat et al. [23]. The charge state is the default state of operations; the battery will remain in this state till the discharge state is triggered. The optimisation of the battery algorithm is the conditional changes made to the discharge state. This model operates to optimise discharge behaviour using current technology restrictions.

Frameworks for optimising battery storage size modelling

The energy storage model keeps track of the battery's new load profile, charge, and discharge. Several assumptions need to be made based on the literature. The round-trip efficiency is assumed to be 90% [53]. This assumption means that the total energy available to discharges is only equal to 90% of the total energy from charging. To increase battery life expectancy, the battery will only operate to the 80% discharge rate [53].

The model discharges based on the following four algorithm parameters:

- Test one - Existing discharge times 1700-2100. Found in United Energy and Ausgrid pilot programs.
- Test two - Including the morning discharge window 0700-0900. This is theorised by Shaw et al. [53] as an additional moment of load control.
- Test three - The transformer rating and clipping limit exceed, and it is reduced only for moments when the transformer is overloaded.
- Test four - The whole load profile is set to the clipping limit. The battery will operate as frequently as possible to reduce the load to the clipping limit.

A comparison of the transformer age, battery cycles used annually, total ownership cost and return on asset are used to assess the current battery condition model.

Transformer thermal aging factor model

A transformer age model is needed to calculate when the insulation life in years has elapsed on the unit. For this, the IEEE standards will be used. IEEE C57.91 provide a calculated hotspot θ_{hs} based on actual transformers per unit load data [28]. This is used to transfer from the load per unit to the transformer hotspot value θ_{hs}. Montsinger et al. [40] examines the correlation between losses of a transformer and the equivalent hotspots. The research found that there is a proportional constant, which is why a transformer's load results in increased hotspot temperatures. Using Montsinger et al. [40] theory and IEEE date, a regression calculation is used to predict the load to the hot spot. The validity is checked with the R^2 value being 0.949 representing a high correlation between the values, as seen in Figure 8.

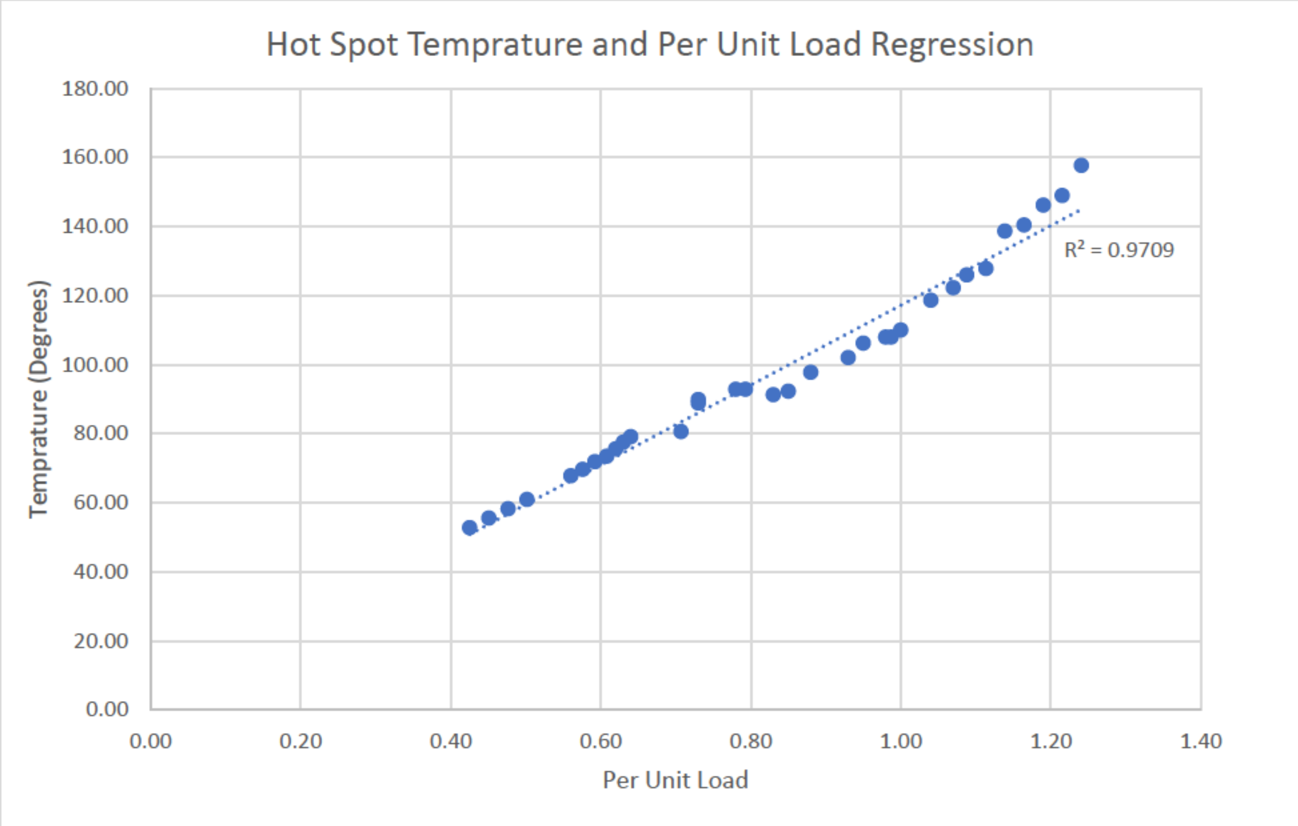


Figure 8: Hot Spot and Load Regression

The equations used to calculate aging are from IEEE [28]. The relative aging equation used with the found hotspot temperature (θ_{hs}) of the regression model. The relative aging factor (F_{AA}) is found in the equation below:

$$F_{AA} = e^{\left[\frac{1500}{383} - \frac{1500}{\theta_{hs}+273}\right]} \quad \text{Equation 9}$$

The summation of the aging factor, when related to time (t_n), will give the accumulated effect (F_{EQA}) of temperature on the unit life [28]:

$$F_{EQA} = \left(\frac{\sum_{n=1}^{N} F_{AA}\Delta t_n}{\sum_{n=1}^{N} \Delta t_n}\right) \quad \text{Equation 10}$$

The elapsed life should remain as low as possible to ensure the continued use and functionality of the distribution transformer [28]. The insulation life (I_{life}) is 180000 hours based on the IEEE standards.

$$Loss\ of\ life\ (\%) = \frac{F_{EQA} \times t \times 100}{I_{life}} \quad \text{Equation 11}$$

This model will track how much life is left in the transformer after one annual load cycle and then calculate how many years the transformer insulation can operate on the load profile.

Shimomugi et al. [31] and Bohatyrewicz et al. [8] found that a distribution transformer's life expectancy is not expected past 50 years. The limitation on the transformer life is implemented to ensure the model reflects the studies. The transformer age is compared in the result section with the no battery mode to see the change in transformer end of life with each framework of operation.

Economic transformer and battery model

This section presents the formulation of an economic model to compare the base (no battery model) with varying battery model sizes. New batteries and transformers must be purchased over a distribution network's life. Transformers are assumed to have a max age of 50 years, while lithium-ion batteries have a life expectancy of ten years. A time frame comparison based on the work of de Vries et al. [15]. A simulated planning horizon of 100 years is compared to the economic model. In this simulation, future purchases of both transformers and batteries are added together to ensure a fair comparison.

Transformer cost equations

The transformer's insulation's end of life determines the point at which the new transformer will be purchased. The value of the new transformer will not be the same value as the present-day transformer. Transformer end of life is at simulated n years with i as the inflation rate. The current transformer cost (tx_{cost}) is multiplied by this to find the cost of the new transformer $(tx_{new\ cost})$ at the year of replacement.

$$tx_{new\ cost} = tx_{cost} \times (1+i)^n \qquad \textit{Equation 12}$$

The transformer purchase cost $(tx_{purchase})$ is the sum of all transformers purchased during the planning horizon. This is the new transformers cost added to all the previous values of the transformer purchase cost in the simulated years.

$$tx_{purchase} = \sum_{i=1}^{n} tx_{purchase_i} + tx_{new\ cost} \qquad \textit{Equation 13}$$

Opportunity cost $(tx_{opportunity})$ for the loss experienced is considered as well. The money spent on the upgrade cannot be spent in another area.

$$tx_{opportunity} = tx_{new\ cost} \times (1+i)^n \qquad \textit{Equation 14}$$

Battery cost equations

The battery age ($\mathrm{bat_{age}}$) of replacement can be either the max battery cycles (bat_{cycle}) or the max battery age. Battery life (bat_{life}) is ten years; the maximum battery cycles are 10000 and the maximum discharge ($bat_{discharge}$) is 80% [53].

Battery cycle per year per battery ($bat_{annual\ cycle}$)

Battery discharge ($bat_{discharge}$)

Battery kWh rating ($bat_{rating\ kWh}$)

$$bat_{annual\ cycle} = \sum \frac{bat_{discharge}}{bat_{rating\ kWh} \times bat_{discharge}} \quad \text{Equation 15}$$

$$(bat_{cycle}) = \frac{(bat_{cycle})}{bat_{annual\ cycle}} \quad \text{Equation 16}$$

$$\mathrm{bat_{age}} = \max\,(bat_{cycle,}\ bat_{life}) \quad \text{Equation 17}$$

The battery cost equations are the same as the transformer cost equations because they deal with the same simulation for the planning horizon.

New battery cost ($bat_{new\ cost}$)

Current battery cost (bat_{cost})

Battery purchase cost ($bat_{purchase}$)

Battery opportunity cost($bat_{opportunity}$)

$$bat_{new\ cost} = bat_{cost} \times (1+i)^n \quad \text{Equation 18}$$

$$bat_{purchase} = \sum_{i=1}^{n} bat_{purchase_i} + bat_{new\ cost} \quad \text{Equation 19}$$

$$bat_{opportunity} = bat_{new\ cost} \times (1+i)^n \quad \text{Equation 20}$$

Return on asset

The TOC is the summation of all the different components of the transformer and the batteries. The TOC of the no-battery mode is compared with each battery model and presented as a TOC or ROA.

$$TOC = Transformer\ Opportunity\ Cost + Transformer\ Purchase\ Cost + Battery\ Opportunity\ Cost + Battery\ Purchase\ Cost \quad \text{Equation 21}$$

$$ROA = \frac{TOC_{no\ battery} - TOC_{battery}}{TOC_{no\ battery}} \times 100 \quad \text{Equation 22}$$

The ROA and battery cycles or battery age are compared in the results section to find the economic and max usage benefits and changes of each battery size when compared to the no battery mode.

Economic consumer and prosumer model

This section is the economic model for consumers and prosumers in three different tariff structures. Consumers are grouped together for calculation and then separated to compare one household's price. The prosumers receive an incentive for solar production and are separated into different solar inverter sizes to reflect their individual prices. All inverters are assumed always to produce a percentage of the solar profile. The economic model sums the costs and profits in accordance with the tariff structure over a year and provides a value for each individual consumer. The equations below are used for each tariff structure:

$$\begin{aligned} &Individual\ solar\ production\ cost \\ &\quad = Individual\ solar\ production \times solar\ feed\ in\ charge \end{aligned}$$

Equation 23

Tariff 11

Tariff 11 is a general-use tariff where all power is charged at a fixed rate [18].

$$\begin{aligned} &Tariff\ 11\ consumer \\ &\quad = \left(\sum \frac{battery\ load\ profile}{number\ of\ consumers}\right) \times tariff\ 11\ charges + supply\ charge \end{aligned}$$

Equation 24

$$Tariff\ 11\ prosumer = Tariff\ 11\ consumer - individual\ solar\ production\ cost$$

Equation 25

Tariff 12B

Tariff 12B is a time of use tariff where a fixed rate is applied to a period [18].

Tariff 12B (T_{12B})	Tariff 12B at shoulder value ($T_{12B,Shoulder}$)
Tariff 12B at peak value ($T_{12B,Peak}$)	Tariff 12B at off peak value ($T_{12B,OffPeak}$)

$$T_{12B} = \begin{cases} T_{12B,Shoulder} & t < 9\ \ or\ t \geq 21 \\ T_{12B,OffPeak} & 9 \leq t < 16 \\ T_{12B,Peak} & 16 \leq t < 21 \end{cases}$$

Equation 26

$$T_{12B} = \sum_{i=1}^{24} T_{12B,i}$$

Equation 27

$$\begin{aligned} &Tariff\ 12B\ consumer \\ &\quad = \left(\sum \frac{battery\ load\ profile}{number\ of\ consumers}\right) \times Tariff\ 12B + supply\ charge \end{aligned}$$

Equation 28

$$Tariff\ 12B\ prosumer = Tariff\ 12B\ consumer - individual\ solar\ production\ cost$$

Equation 29

Tariff 14B

Tariff 14B is a demand tariff where the max power usage a month between set hours is charged at a higher rate for every day of that month [18].

$$Tariff\ 14B\ max = \max\left((16 \leq load\ profile)\ \&\ (load\ profile < 21)\right) \times tariff\ 14B\ rate$$ Equation 30

$$Tariff\ 14B = \sum Tariff\ 14B\ max \times days\ in\ month + \left(\sum \frac{battery\ load\ profile}{number\ of\ consumers}\right) \times tariff\ 14B\ consumption\ charge$$ Equation 31

$$Tariff\ 14B\ consumer = Tariff\ 14B + Supply\ charge$$ Equation 32

$$Tariff\ 14B\ prosumer = Tariff\ 14B\ consumer - Individual\ solar\ production\ cost$$ Equation 33

Chapter 4 – Result and Discussion

This chapter employs the methodology outlined in Chapter 3 – Research Design and Methodology. The results in this chapter aim to establish the optimal battery size under different frameworks and the distribution transformer life extension. The data tables of each scenario are given in Appendix G.

Frameworks for optimising battery storage size

This section presents the findings of the work conducted for the optimal size of the community battery for distribution transformer end-of-life extension, along with the financial comparison of the community battery conditions over the transformer's no-battery life expectancy.

The model discharges based on the following four scenarios:

- Test one - Existing discharge times 17:00-21:00. Found in United Energy and Ausgrid pilot programs.
- Test two - Including the morning discharge window 07:00-09:00. This is proposed by Shaw et al. [53] as an additional instance of load control.
- Test three – Discharge occurs when the transformer rating and clipping limit are exceeded.
- Test four - The whole load profile is caped at the clipping limit.

A comparison of the transformer age, battery cycles used annually, total ownership cost and return on the asset are used to assess the battery sizing.

Performance comparison

Figure 9 compares the four frameworks for transformer age across different battery sizes. The no-battery condition has a transformer life of 26.370 years. The transformer age always experiences an increase in life with any battery size under any operational framework. The 5-kWh battery only marginally improves the transformer age from 26.370 to 26.704 years. All frameworks have the same value for the 5-kWh battery. Test one produces the slowest rate of climb to the max transformer life of 50 years [8]. The additional window for clipping in test two deviates only at the 50-kWh battery storage compared to tests three and four. The bigger the window of discharge time, the greater the transformer extension of life. From **Error! Reference source not found.**, the t ransformer maximum life can be achieved by a 99-kWh battery in operational framework test two, test three and test four with no improvement to life for larger battery sizes.

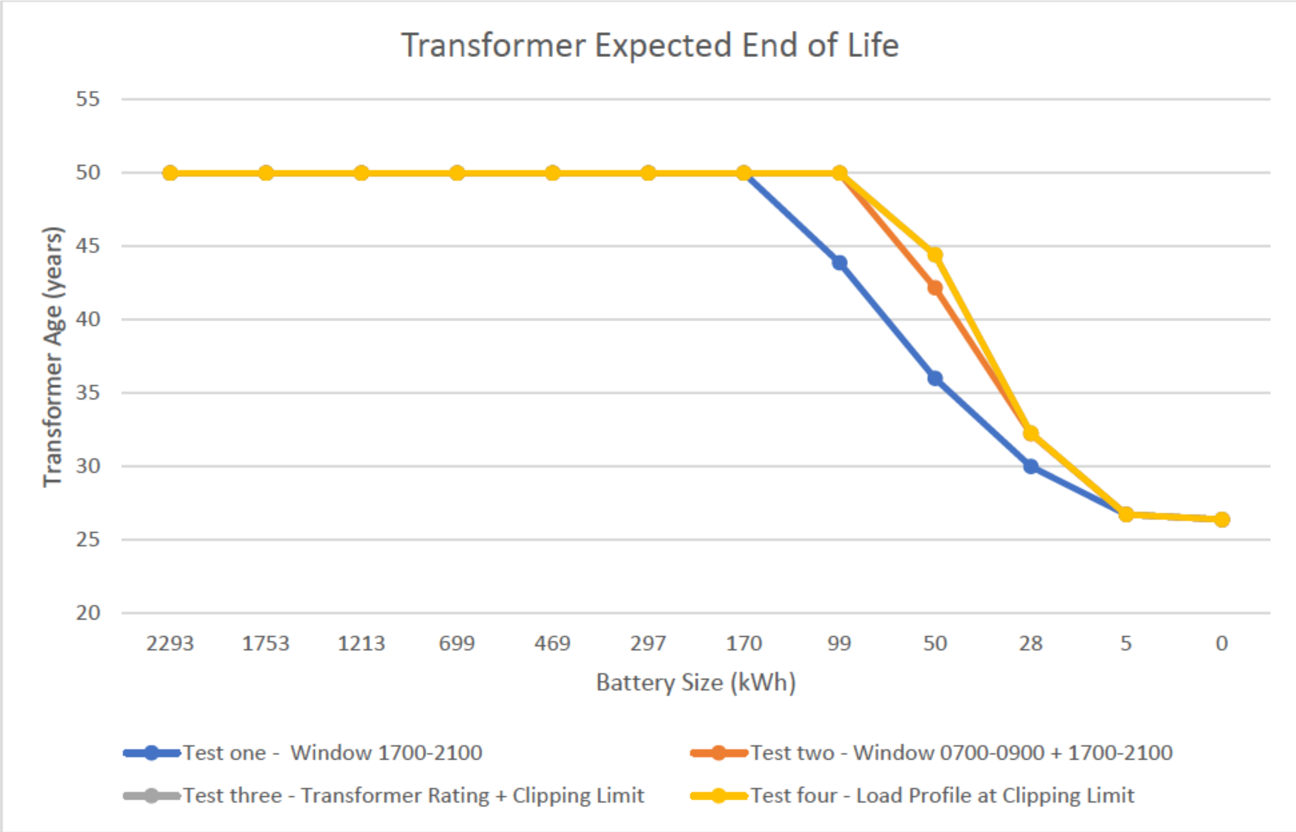


Figure 9: Transformer age comparison of current battery conditions

Figure 10 compares the four frameworks for battery cycle rates at different battery sizes. Battery cycle rate is a discharge to the 80% capacity limit of the battery. Battery cycle equations are presented in the methodology as Equation 15 and Equation 16.

The 5-kWh battery has a limited variation with a cycle rate of 0.994 in all operational frameworks. The single and two windows deviate at the five-kWh to the 28-kWh battery but trend together at a disparity of around four cycles for the remaining battery kWh s. The transformer rating and clipping limit hit a peak at 469-kWh. The battery size continues to increase, but cycle rates reduce as less of the battery is used to lower the load profile. The load clipping limit follows the transformer rating and the clipping limit of 297-kWh.

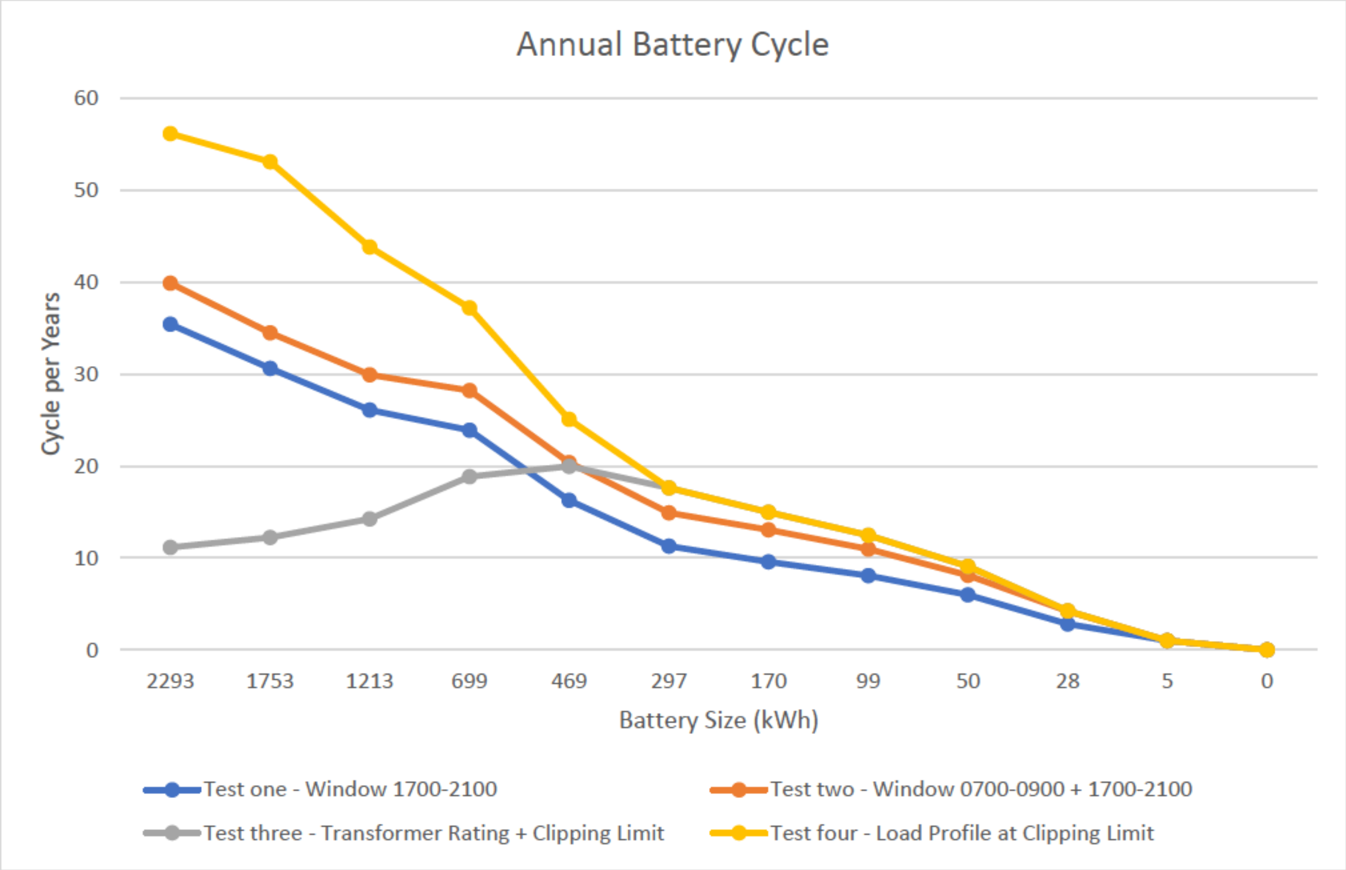


Figure 10: Annual battery cycle comparison of current battery conditions

In Figure 10, the rate of the cycles increases significantly after 297-kWh, with the highest rate of 56.202 cycles for test four. At 56.202 cycles a year with a battery max-age of ten years, the battery would only use 562.02 cycles at the battery's end of life, and it would take the battery proximity 178 years to reach its discharge cycle limit. The load profile of 5-kWh (Figure 12) and 2293-kWh (Figure 11) for test fours show two problems with battery cycles. In Figure 11, the load profile has spikes in demand. The 2293-kWh battery keeps the load at the clipping limit for most of the time but does not have sufficient charge to reduce the spike moments. Therefore, the cycle limit of the 229-kWh battery is lower than expected because there is insufficient generation from PV units to charge the battery. In Figure 12, the 5-kWh battery only deals with the highest-demand shaving. The 5-kWh battery is fully charged but is not used for most of the year. Therefore, the cycle limit is low for the 5-kWh battery as it has limited operation times.

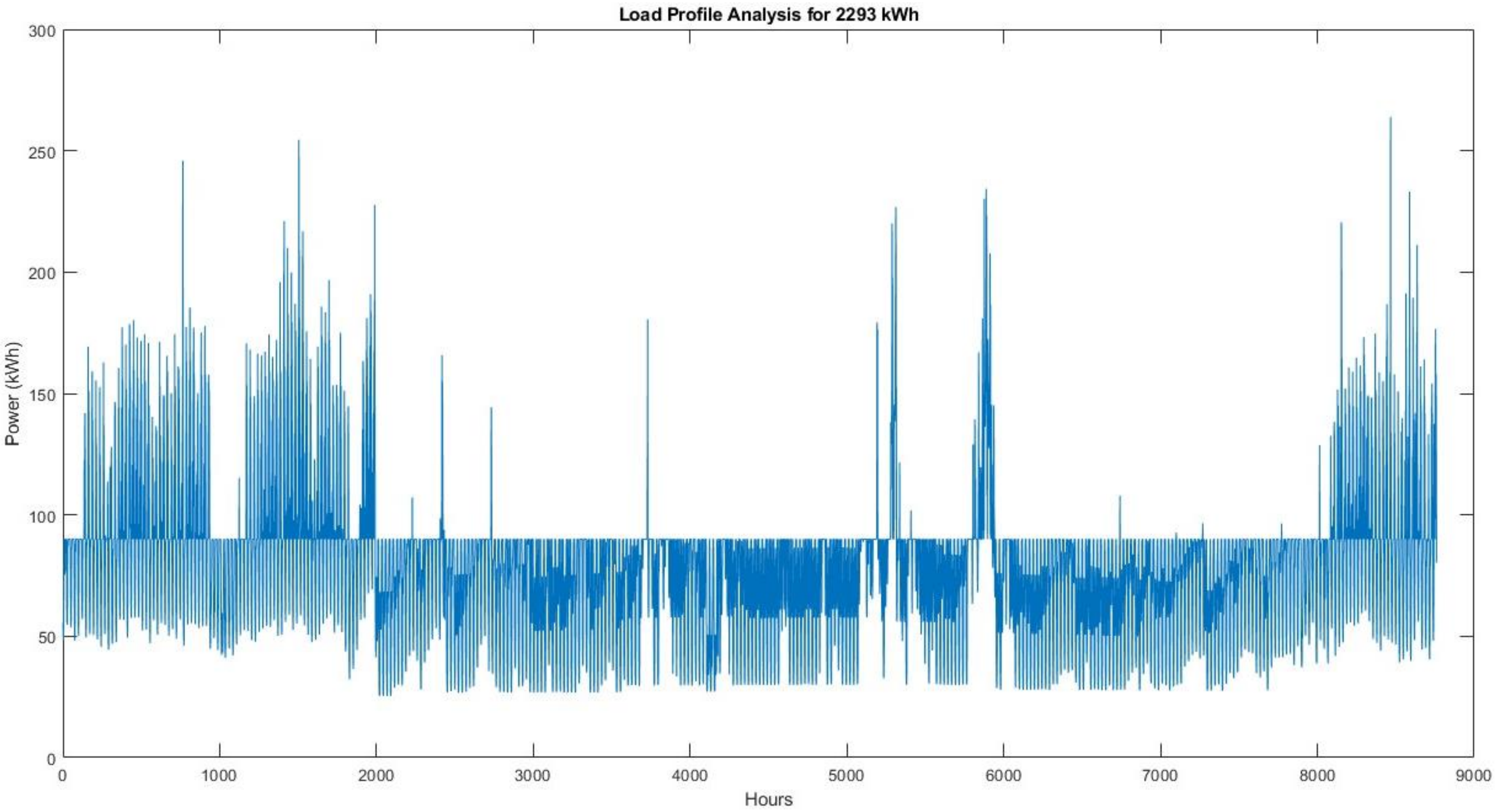


Figure 11: 2293 kWh load profile for test four

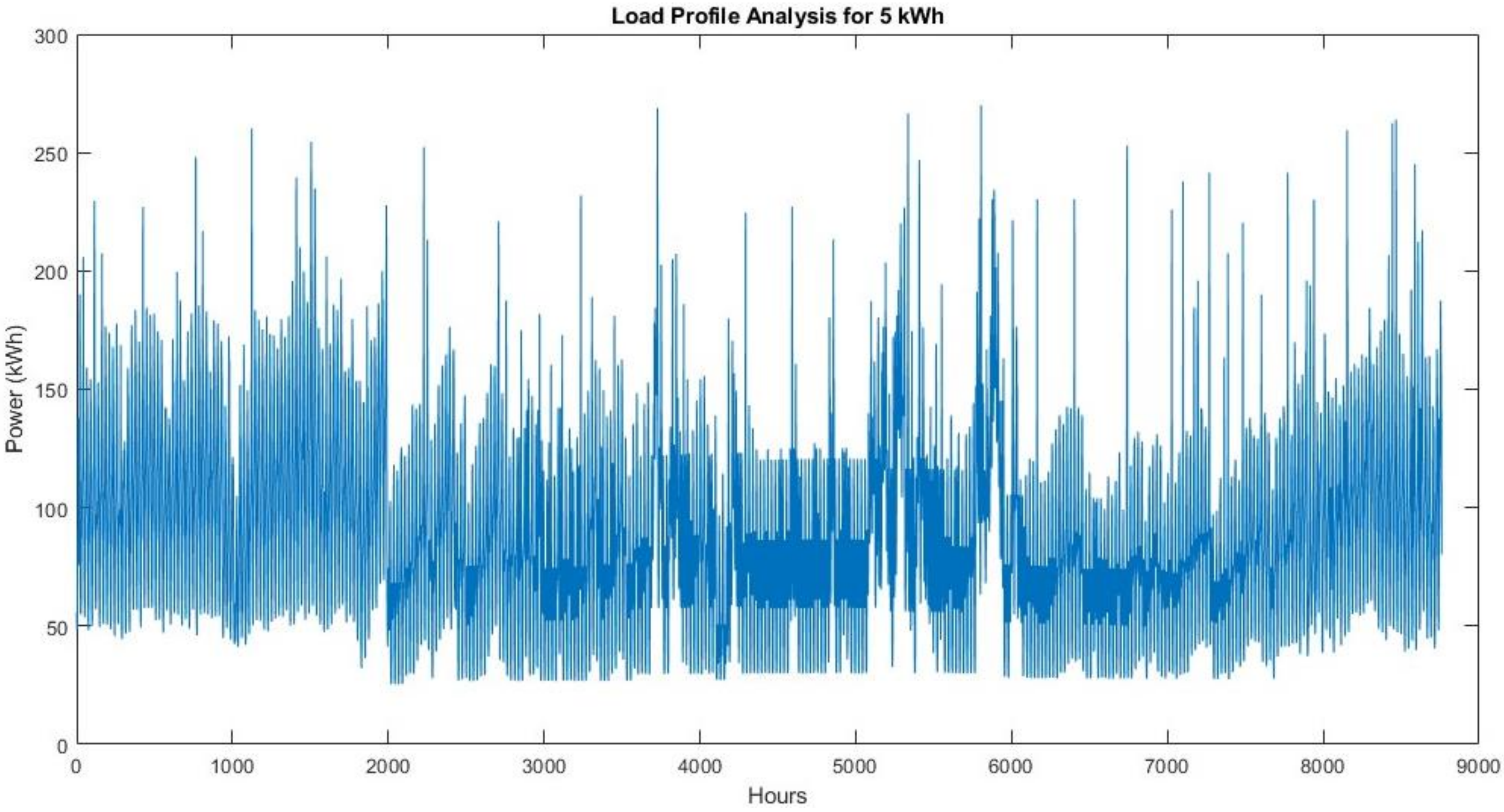


Figure 12: 5 kWh load profile for test four

In Table 8, the mean of the load profiles under different test conditions can be compared with Figure 13, the no-battery average load profile. Test one's evening window has a distinctive effect on the load profile. The battery has a significant enough charge to be able to reduce the mean of the load to the clipping limit. Test two's additional morning period has a smaller effect on reaching the clipping limit. This is due to the battery charge remaining after the evening clipping being too low for a full clip in the morning. Test three has a soothing effect on the overall load profile bringing the peak value to 150-kWh. Test four reduces the mean lower than other tests conducted. The battery operates to maintain the lowest profile possible.

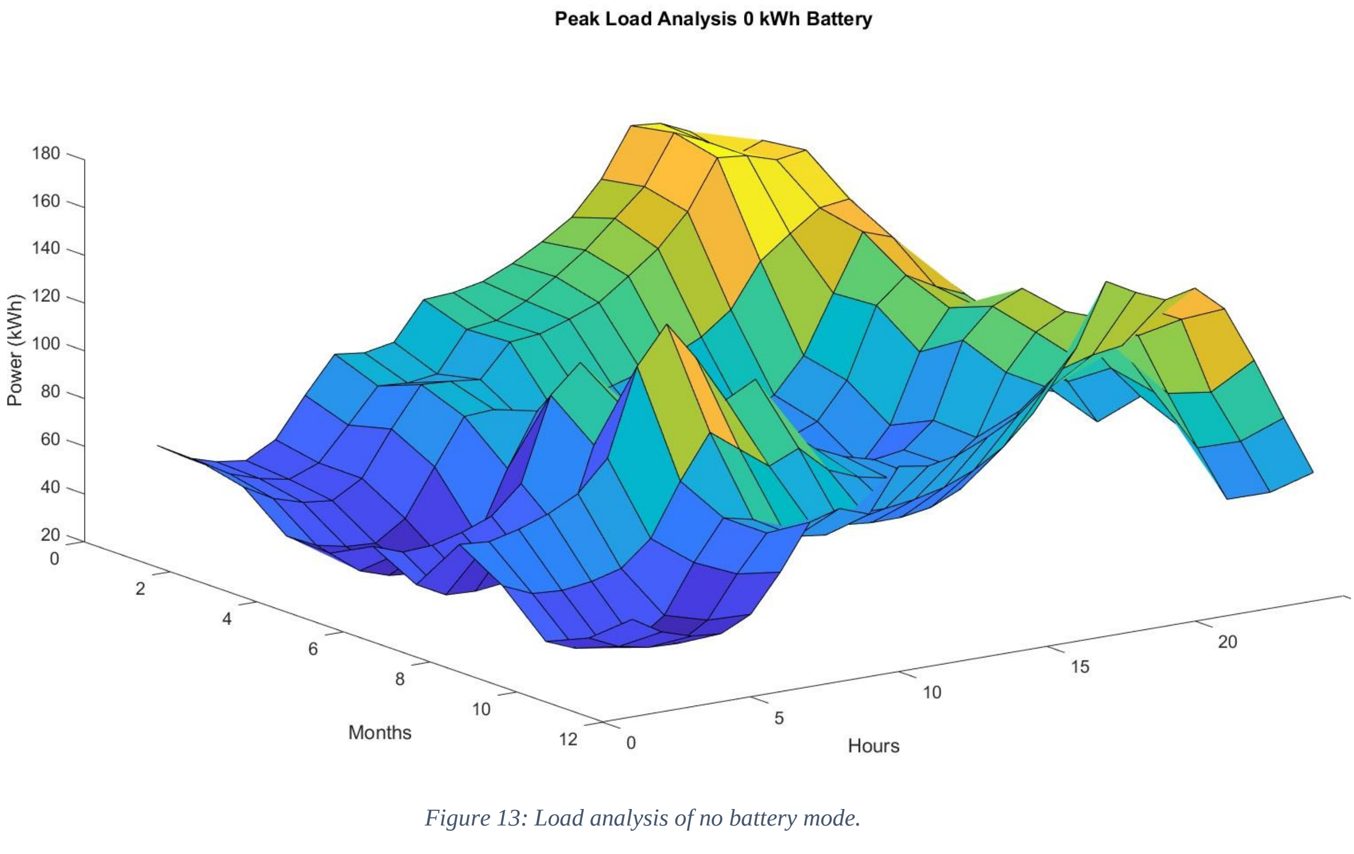
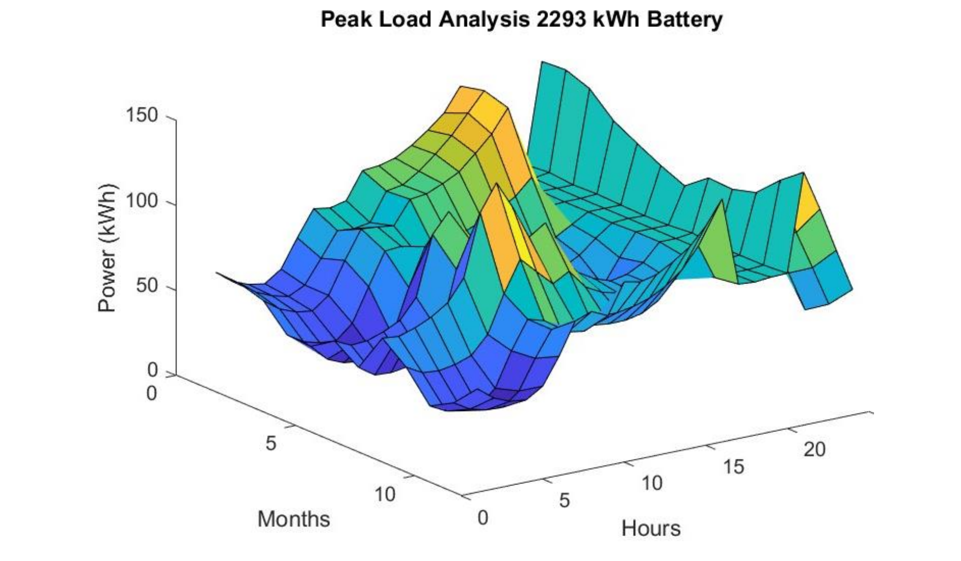
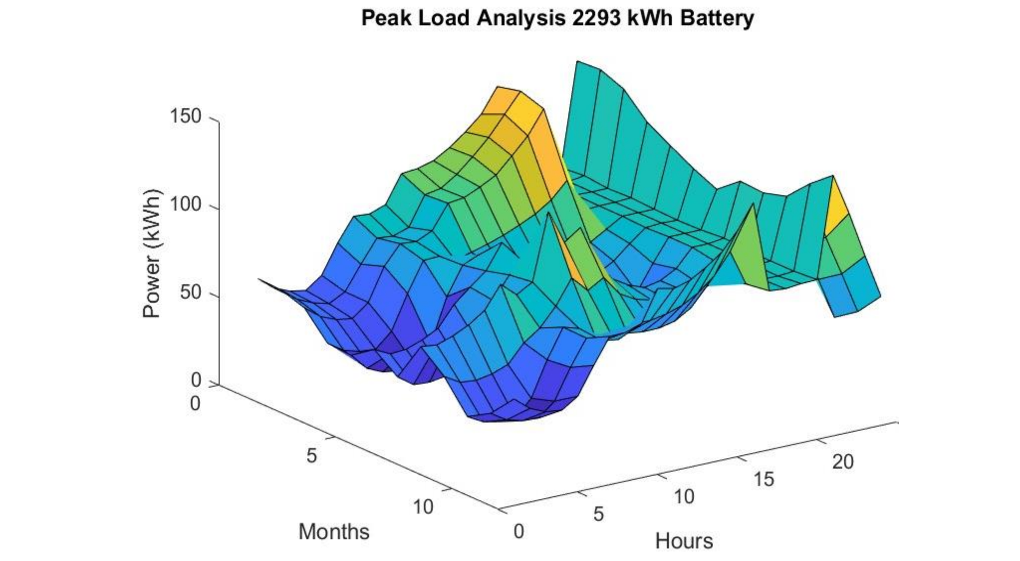
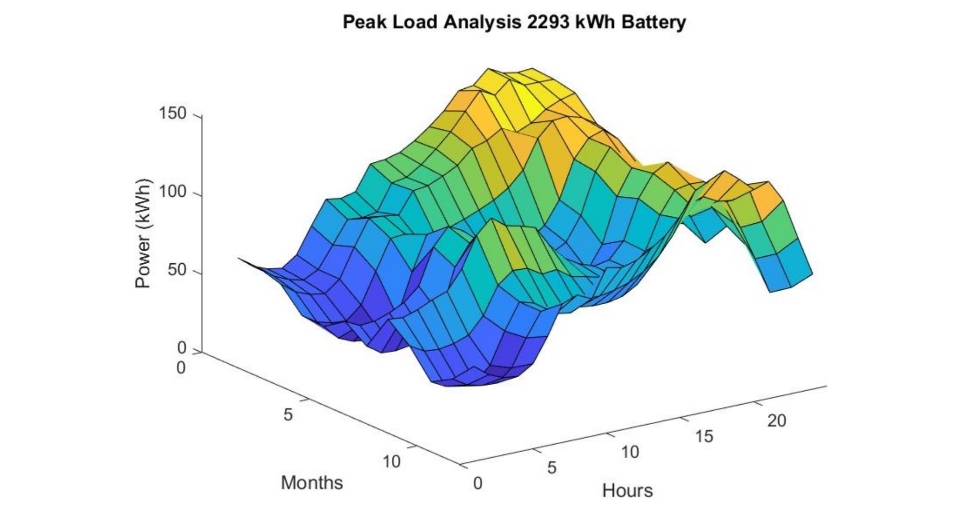
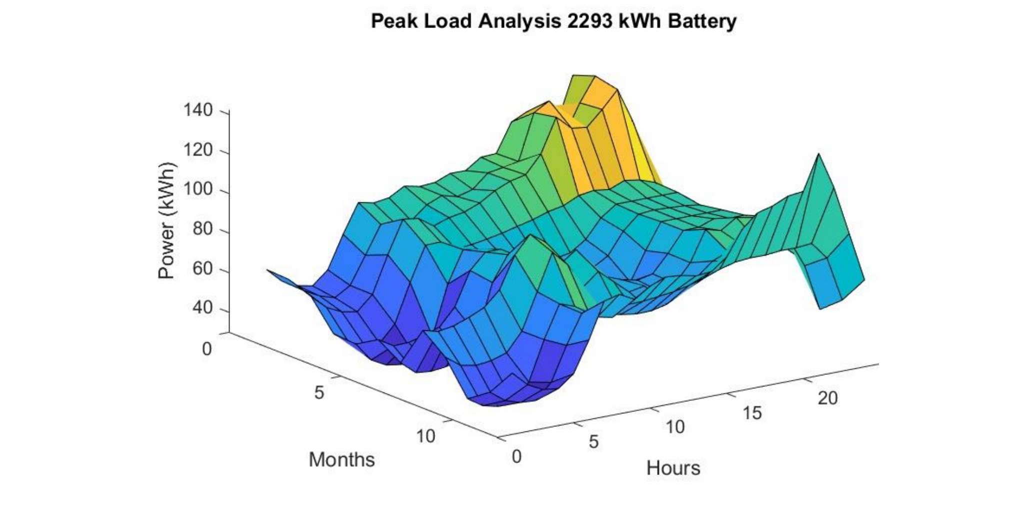


Figure 13: Load analysis of no battery mode.

Table 8: 2293 mean load comparison

<table>
<tr><td>Test one - Discharge times 17:00-21:00</td><td>Test two - Discharge times 17:00-21:00 and 07:00-09:00</td></tr>
<tr><td>
</td><td>
</td></tr>
<tr><td>Test three - Transformer rating and clipping limit exceeded</td><td>Test four - Whole load profile</td></tr>
<tr><td>
</td><td>
</td></tr>
</table>

Financial comparison

The total ownership cost is simulated to the max life of the no-battery transformer in years. In Table 9, the normalized to no battery TOC is shown. There is no difference financially between the different test scenarios, and there is no return over the simulated period of ownership, with the largest battery having the highest cost of $25 589 376.

Table 9: Total ownership cost comparison to no battery mode

Batter size (kWh)	Test one (AUD)	Test two (AUD)	Test three (AUD)	Test four (AUD)
2293	25589376	25589376	25589376	25589376
1753	19563095	19563095	19563095	19563095
1213	13536813	13536813	13536813	13536813
699	7800686	7800686	7800686	7800686
469	5233937	5233937	5233937	5233937
297	3314455	3314455	3314455	3314455
170	1897163	1897163	1897163	1897163
99	1104818	1104818	1104818	1104818
50	557989	557989	557989	557989
28	312473.8	312473.8	312473.8	312473.8
5	55798.9	55798.9	55798.9	55798.9
0	0	0	0	0

Consumer and prosumer Tariff comparison

The consumer and prosumer tariff structures are displayed to show variations within the data set under different tariff and battery sizes. The DNSP costs are not added to the tariffs. The utility holds the financial cost for the battery. The method for DNSP to pass on costs to the consumer through retail is not investigated in this work.

Tariff 11 current battery conditions

Figure 14 shows the comparative results of tariff 11 in minimum, maximum, median and quartile ranges. The price median (straight line in the boxes) for consumers and prosumers drops with the increased battery size, and the variation between each framework increases with the battery size. This larger interquartile range (box section) represents 50% of the results. Figure 15 uses the large quartile range to assess each test case's distribution because a larger quartile range allows a higher resolution in testing results.

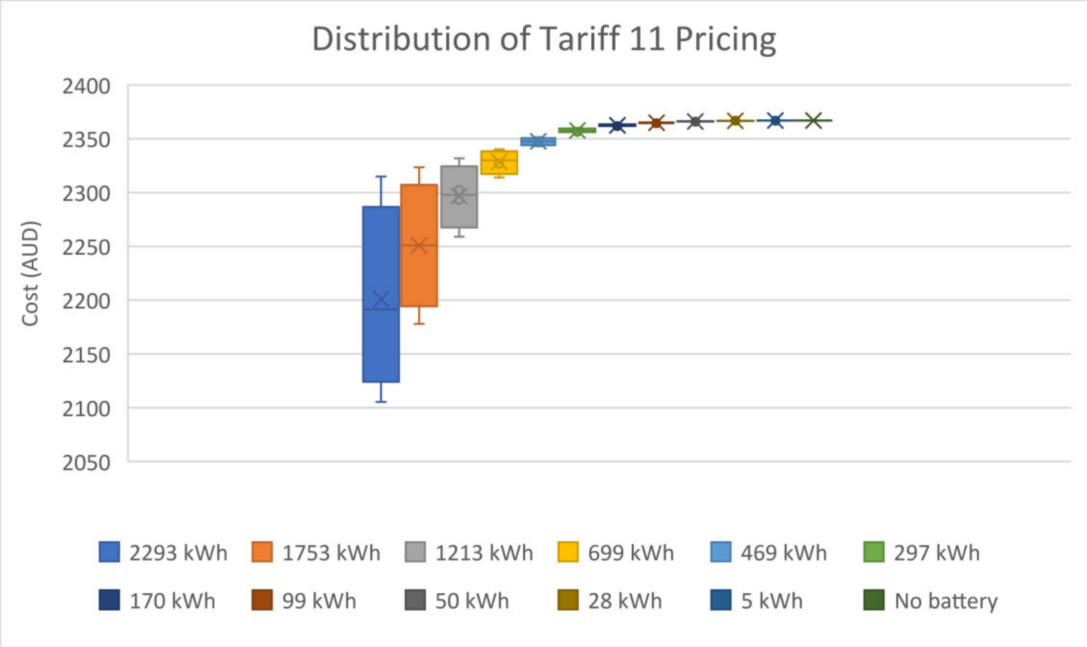


Figure 14: Tariff 11 price variations current battery conditions

In Figure 15, all batteries operating in any framework produced savings for consumers and prosumers. The larger the solar inverter rating, the greater the cost reduction. Compare no solar with a 7.2 kW solar inverter system in the no battery mode. No solar costs $2366.85 annually while the 7.2 kW cost $908.35, a saving of $1458.50, not including any set-up cost for the solar system. The test conditions all follow the same trend as the no battery condition. The full load clipping produces the highest savings to the consumers and prosumers, while the transformer and clipping limit together produce the lowest savings, slightly better than the no battery condition. The relationship of the test conditions means the difference will be the same for all test conditions when compared to the no battery condition.

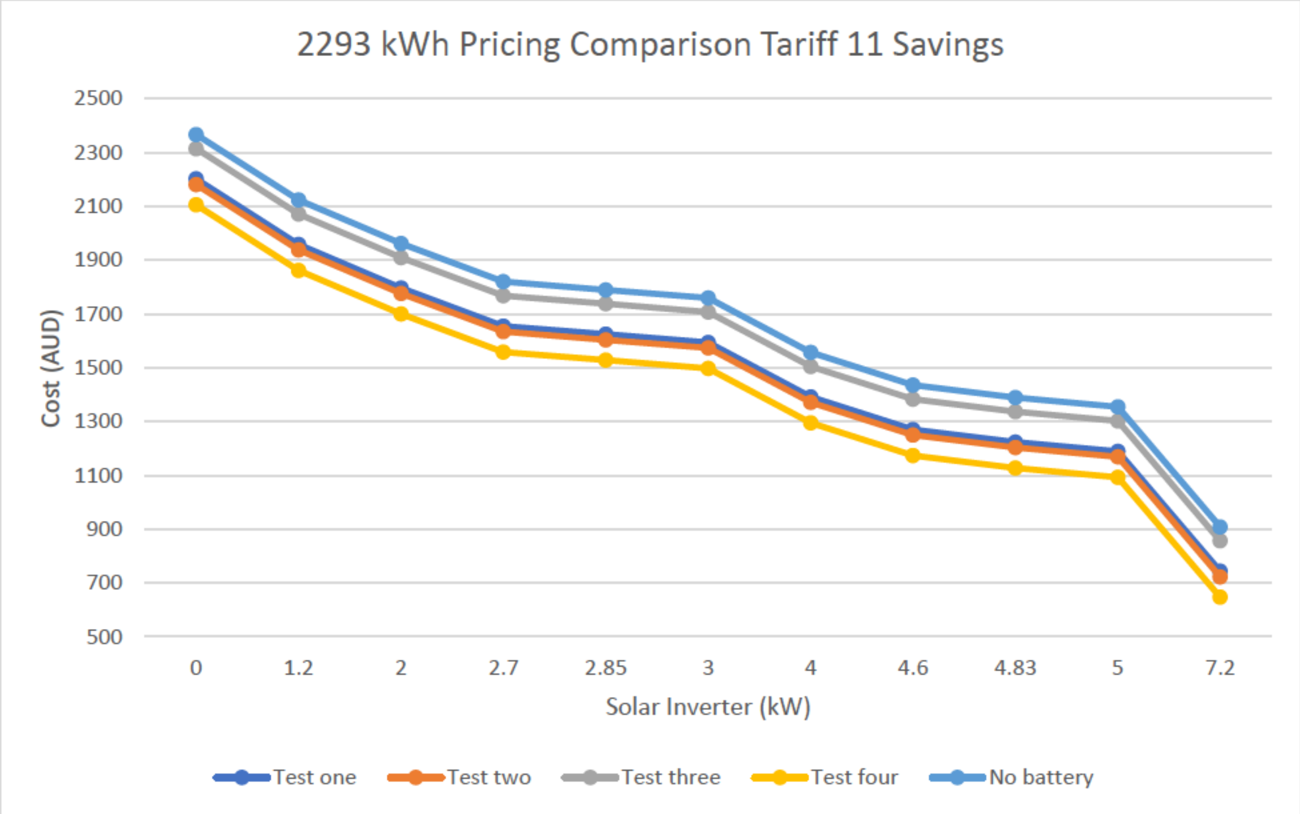


Figure 15: 2293 kWh comparison for tariff 11 current battery conditions

Tariff 12B current battery conditions

Figure 16 shows the comparative results of tariff 12B in minimum, maximum, median and quartile ranges. The price median (straight line in the boxes) for consumers and prosumers drops with the increased battery size. The variation between each framework increases with the battery size. This is a larger interquartile range (box section) which represents 50% of the results. Figure 17 uses the large quartile range to assess each test case's distribution because a larger quartile range allows a higher resolution in testing results.

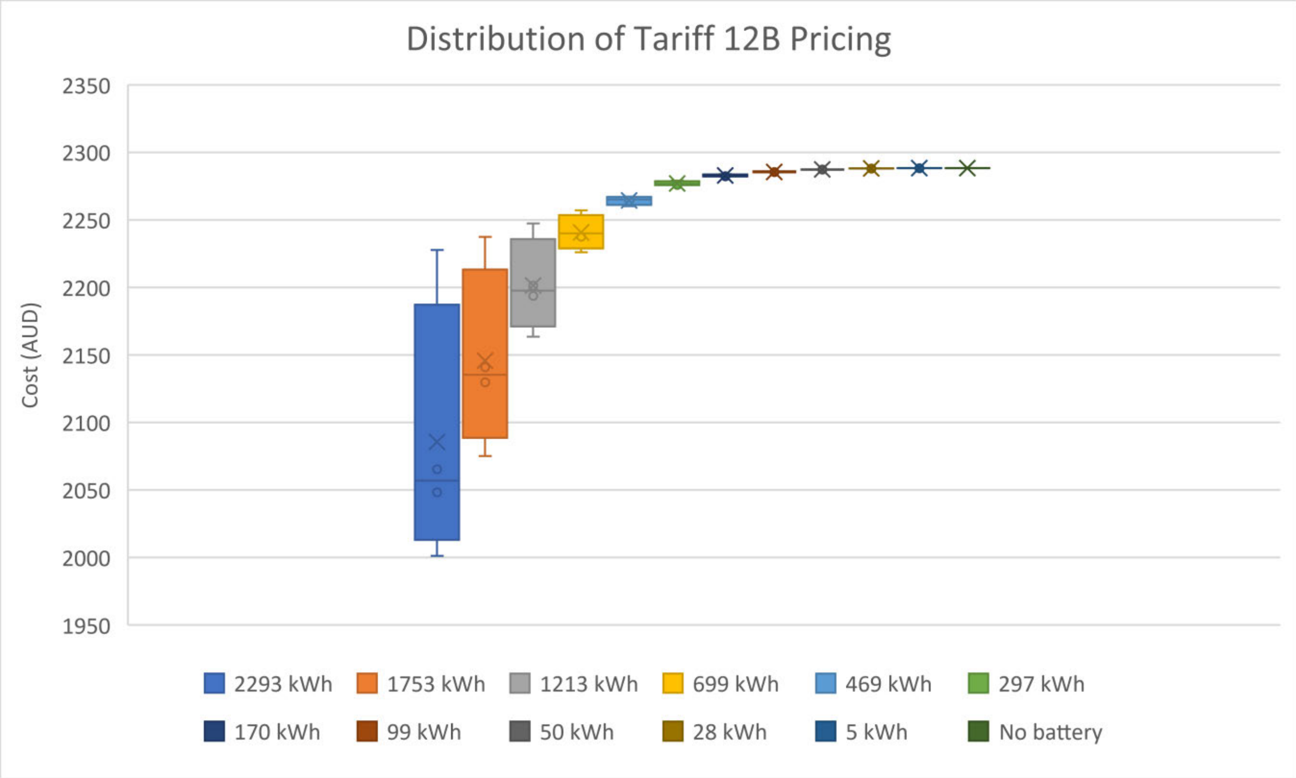


Figure 16: Tariff 12B price variations current battery conditions

In Figure 17, all batteries operating in any framework produced savings for consumers and prosumers. Test four, the full load clipping, has the highest savings to the consumers and prosumers, while the transformer and clipping limit together produce the lowest savings, slightly better than the no battery condition. Test one and two, the window conditions produced similar savings and closed the gap on test four when compared with tariff 11 in Figure 15. The relationship of the test conditions means the difference, compared to the no battery condition, will be the same for all test conditions.

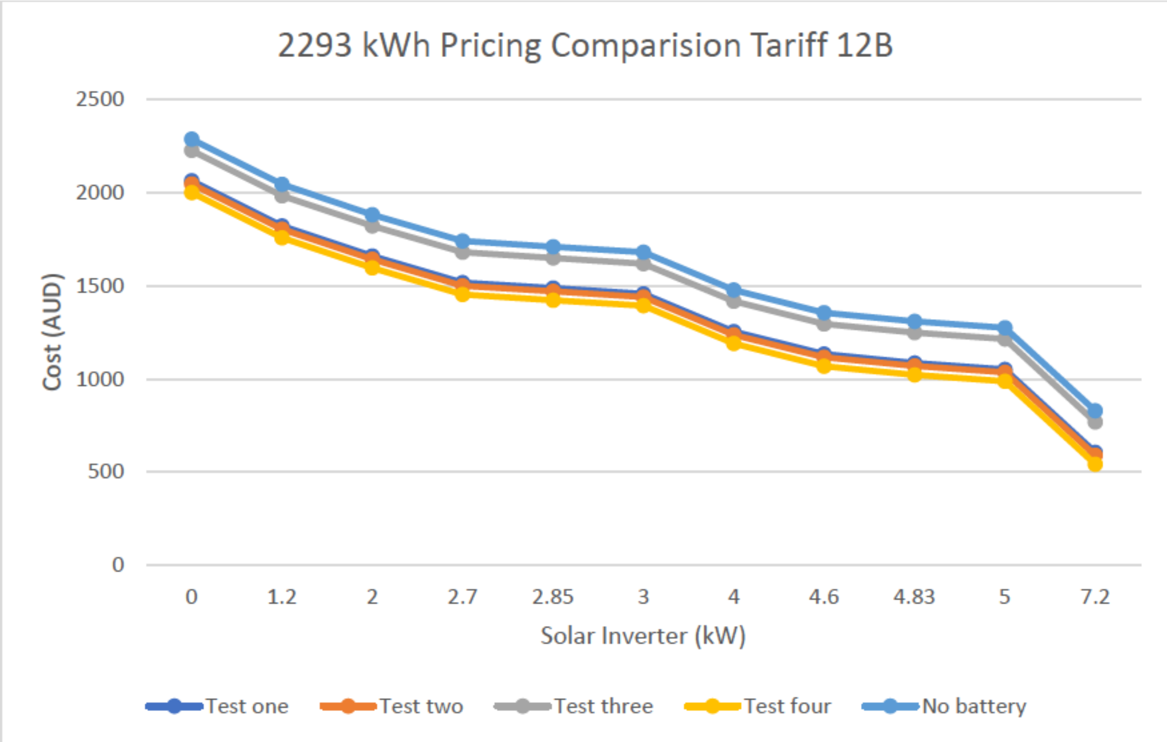


Figure 17: 2293 kWh comparison for tariff 12B current battery conditions

Tariff 14B current battery conditions

Figure 18 shows the comparative results of tariff 14B in minimum, maximum, median and quartile ranges. The price median (straight line in the boxes) for consumers and prosumers drops with the increased battery size. The quartile range (box section) representing 50% of the results are similar in all test conditions, with the cost being the most significant decrease. Figure 18 uses 2293 kWh to assess the distribution of each test case.

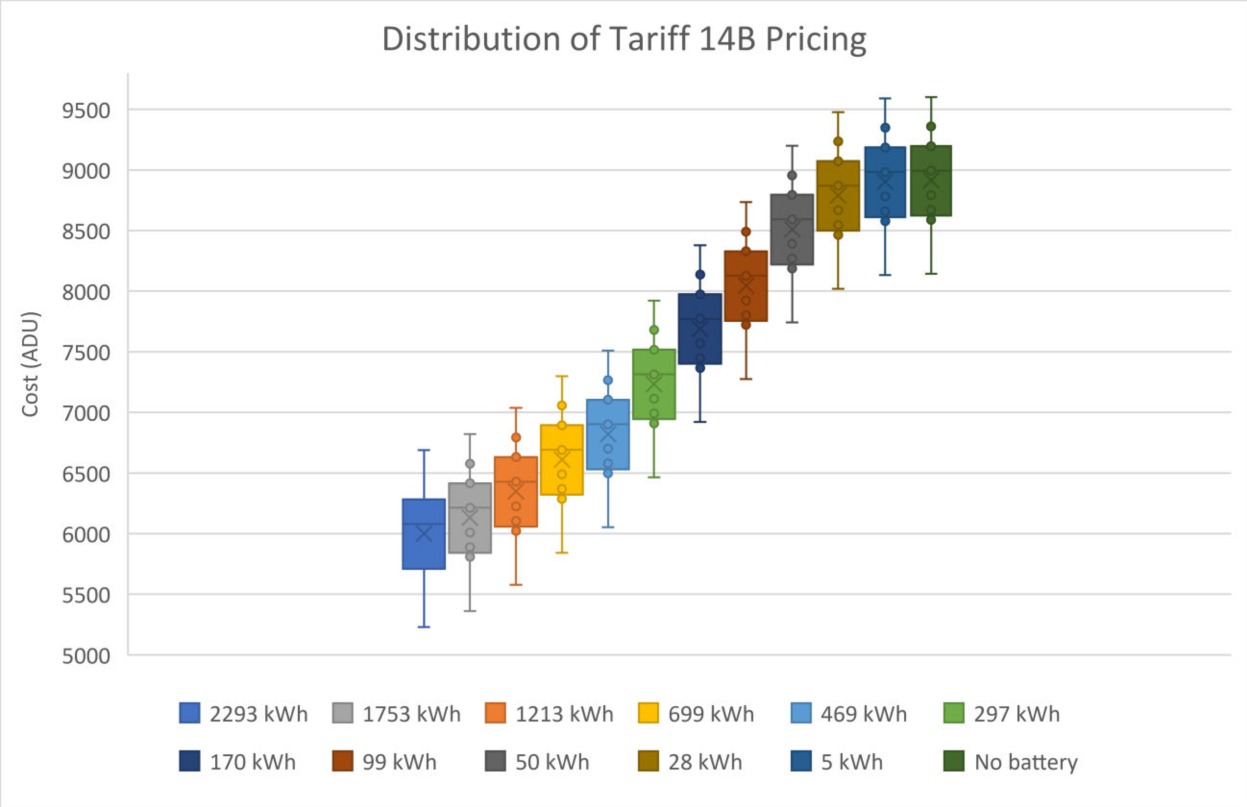


Figure 18: Tariff 14B price variations current battery conditions

In Figure 19, all batteries operating in any framework produced savings for consumers and prosumers when compared with no battery operation. Unlike Figure 15 and Figure 17, test four does not result in the best saving. Test one and two are the best for tariff 14B as they reduce power during the calculation window for the maximum power only.

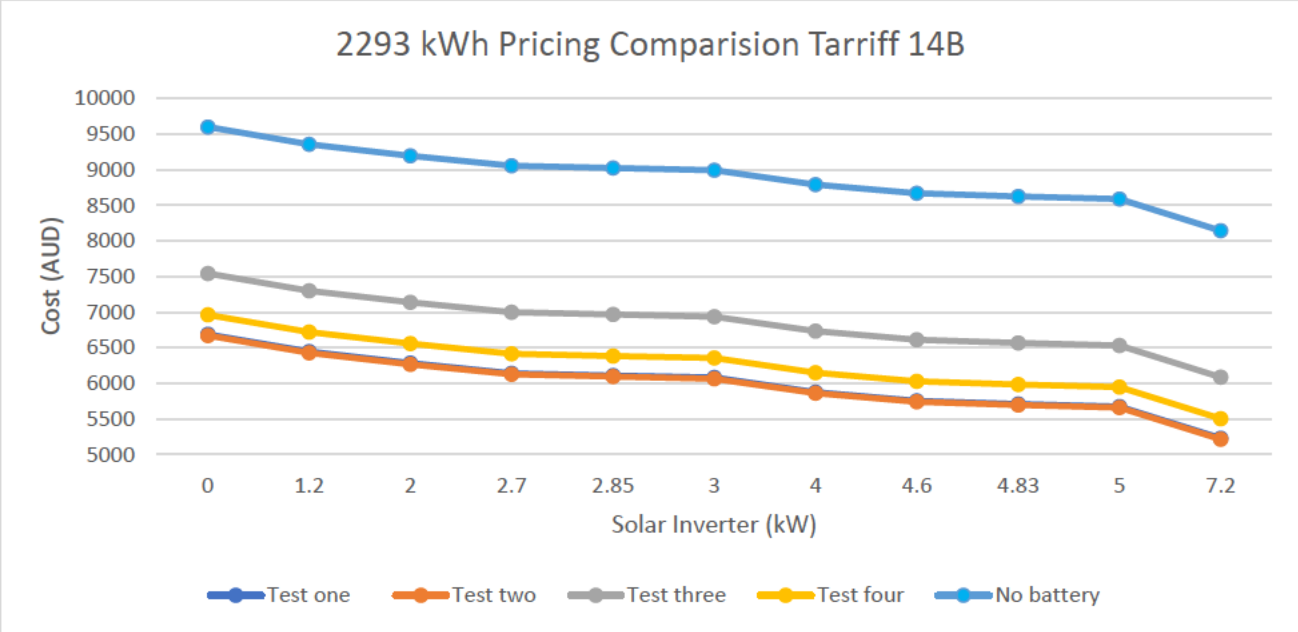


Figure 19: 2293 kWh comparison for tariff 14B current battery conditions

Optimal battery framework for utilities and customers

The optimal battery discharging scheme for the utility will provide the highest transformer end-of-life, the smallest battery size, the lowest total ownership cost, and the highest rate of return. The cycle life should be as close to the maximum battery life (ten years) to ensure the maximum battery usage is achieved. No operational framework will approach the cycle limit for the battery's max life of ten years. It would take the battery proximity 178 years to reach its discharge cycle limit for the 2293-kWh battery operating in test scenario four. As discussed, this is due to insufficient generation from PV units for battery storage and limited operation times for smaller battery sizes. In Figure 9, the smallest battery size to extend the transformer life to 50 years is 99-kWh.

The optimal battery framework for consumers and prosumers is dependent on their tariff arrangement. Tariff 11 and tariff 12B gained the most savings from clipping the whole profile (test four). Tariff 14B had the greatest savings of all tariffs with window shavings (test one and two). The most used tariff by the consumer base is tariff 11 [18].

When comparing the utilities and the customers, the best battery for the utility is 99-kWh. The 99-kWh battery has the lowest cost for the highest transformer age. Test two, three and four can achieve the 50 years max live using 99-kWh battery. The highest return for two out of the three tariff structures is clipping the whole profile (test four). The framework with the best utility benefit while providing the most for consumers and prosumers is clipping the whole profile.

Validity of results

This section aims to draw a comparison between the results of similar community battery projects and the findings of this project. The limits for optimal battery size are between the 99-kWh to 699-kWh range. In most projects in the Current Community battery projects section, battery sizes are found between the 99-kWh to 699-kWh range. Western Australia, except for Alkimo beach, use 464-kWh, and New South Wales uses 267 kWh. Victoria uses 66 kWh for a customer base roughly half the size of the site selected.

Shaw et al. [53] found that recommended battery cycles are between 435.6 and 255.6 cycles a year. The DNSP in Shaw et al. [53] supported a 200-home community more than double the amount supported in this study. Shaw et al. [53] does not discuss the algorithm used for charge/discharge pattern, but the research investigates purchasing power as a local network. This is theorised at a reduced cost and would allow the battery to operate with a retailer, not just be self-sufficient on solar output. Tang et al. [58], when using PV unit storage purely, restricted the short-term scheduling of the battery cycle to a max of once a day. Given that solar generation is not consistent the battery did not always have the available power to operate. The conditional framework tested in this dissertation is intended to maximise the transformer's life. The cycle rate may increase depending on the operational algorithm. Still, the max transformer life is set to 50 years and is easily achieved with a minor reduction to the transformer hot spots. The cycle rates of Shaw et al. [53] and Tang et al. [58] found that the intent of the operational algorithm was more significant than the battery cycle rate.

The total owning cost is high due to the simulation time and the expensive storage technologies available today. Dunn et al. [17] suggest a far more effective control for peak load serving is to expand the electric power network for a reliable power system instead of energy storage. The cost-benefit tools needed to calculate the most profitable storage technology are lacking [25]. There are many different methods of approaching the financials of a community battery [7, 45, 55]. Simulating the current, future and opportunity costs to a set time frame ensures that the transformer and battery have been equivalently assessed.

Critical evaluation of methodology

New technology faces challenges and obstacles for real-world deployment. Community batteries' adaptation into the modern complex energy system has significant integration concerns. Based on the current research and this dissertation, there are hurdles to be worked through.

Transformer modelling

Warm and sunny weather increases the effects of transformer hotspots. IEEE load and hotspot data are in a controlled environment at set increments. The IEEE model used the equation in the section Transformer aging has three components [28]:

- The ambient temperature;
- Average oil temperature changes above ambient;
- The hottest spot on the winding changes above-average oil temperature.

Temperature is the main degrading factor for a transformer insulation life and is key to determining the remaining life expectancy of a unit [28]. The hotspot results found in IEEE model do not accurately reflect the environment of the community transformer. The three components will vary with the ambient temperature range and provide discrepancies to the transformer life calculation.

The dielectric strength of the insulation deteriorates slowly with moisture, oxygen content and heat. Other less significant factors are the mechanical components of retaining tensile strength and the degree of polymerization. The IEEE model used in this dissertation does not consider additional fatigue factors. Only the main failure component of a hotspot is assessed in this dissertation. As a result, errors in transformer life may occur.

Profile modelling

Using a known load profile allows for the exact distribution of the stored power to a pre-set limit. The load profile can vary significantly depending on the community activity and weather. The probability modelling used by other research attempts to estimate the demand trend given seasonal information. Variations can occur in either model that is unexpected in real life. An unexpectedly warm day can throw out the algorithm and cause a discharge pattern that is not optimal for the load or transformer life. The windows used for peak shaving by the pilot projects remove the variation and deliver a load following control over the four hours to reduce any demand in the window. The mediation in load profile variations is not an asset in this dissertation.

Solar energy is only available during the day, with the highest output depending on solar irradiance, temperature and clouds. The PV generation is difficult to predict as environmental factors can negatively affect the output along with the location of each house and their PV units. The PV unit's capability is based on known values from DNSP Queensland Energy. This allows for some error reduction in the yearly variations but the individual tariff model will not be comparable to real world.

Chapter 5 – Conclusion

In this dissertation, an investigation and analysis into community storage frameworks were developed to smooth load profiles and increase distribution transformer lifespans. The dissertation found that the 99-kWh battery size was the highest benefit to the utilities, consumers and prosumers when always operated to reduce demand over the whole load profile. Furthermore, the cost of the battery was found to be $1 104 818 more when compared with no community storage over the distribution transformers with no battery mode life. The community battery did provide savings to consumers and prosumers. A breakeven point for community batteries will require additional revenue sources for the DNSP. The rules of the AER will change for community batteries to participate in ancillary services from the 31st of March, 2023 [44]. The battery price and technological constraints make the community battery unprofitable without additional revenue sources or technical advancements. The price of a distribution transformer is low in comparison to 99-kWh battery system making replacement cheaper.

Contribution

The main contributions of this dissertation can be summarized as follows:

- A review of literature on community battery projects around Australia and overseas defining frameworks of community battery operation.
- A model of distribution transformer life based on IEEE transformer standards. The approach to utility savings is based on end-of-life extension.
- An analytical planning framework for optimal battery size to achieve smooth load profiles.
- A model to determine the cost and benefit to the utility and flow on savings to the community.

Direction for future research

Studies in the following areas can be an extension of the work presented in this dissertation:

- Assessing the cost-effectiveness of community batteries to mitigate power quality issues. Using the utility statistics on power quality events and their monetary associated value due to interruption or damage is necessary for future study.
- Analysis of the challenges and economic benefits of community batteries for remote communities. Remote communities are characteristically high in the variability of power demand and high in PV penetration.

- Methods to integrate energy forecasting to estimate the community batteries discharge and charge rates more accurately.
- Asses the FCAS market benefits for the community battery for the effective changes to the AER.
- Planning a framework for the expected electric vehicle growth in the distribution network. This is in coordination with community batteries, PV and different ownership models.

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Appendices

Appendix A - ENG4111/4112 research project specifications

For: Coenraad Wium

Title: Optimal model designs for community batteries

Major: Electrical and Electronic

Supervisors: Joel Kennedy

Enrollment: ENG4111 – EXT S1, 2021

ENG4112 – EXT S2, 2021

Project Aim: There are two stakeholders, utility and community, that are downstream of distribution transformers. The project aims to embed all power supply externalities into the electricity prices between the community storage and the customers. The ideal size and pricing framework will be recommended to ensure that the community storage pays for itself over its lifetime.

Program: Version 1, the 17th of March 2022

1. Conduct background research on several pilot projects, storage pricing and previous research relevant to communal storage development. Analyse the rules and policies that the community batteries must operate within. Analyse the different structures of ownership available resulting in different usage for the utility provider and the community.
2. Identify an appropriate site as a case study and communicate with Energy Queensland to gather data. Data must contain load and PV data downstream along with additional impedances. The transformer nameplate data will identify limitations currently experienced by the unit.
3. Review and categorise different distribution centres' load requirements, PV densities and customer base at the sites with restrictions.
4. Design models for MATLAB that would operate from the perspectives of the utility and community. Simulate the models in MATLAB over the range of demands experienced on the local grid over a yearly cycle.
5. Propose alternate energy storage pricing frameworks that benefit utility and the community.
6. Analyse the data to find quality information that can determine the best mode of operation for the utility and customers providers on historical data. This includes pricing framework and battery size comparisons with existing frameworks to proposed options.

Appendix B - ENG4111/4112 Plan

The timeline for the project's completion is proposed in Figure 20

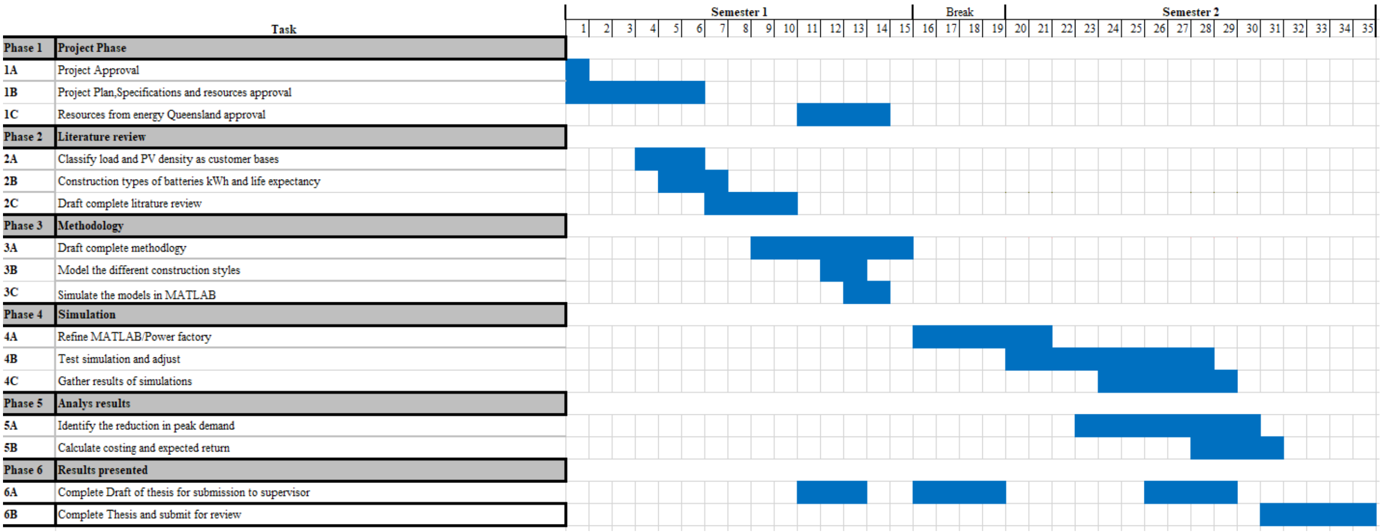

Figure 20: Planning of Dissertation

Appendix C - ENG4111/4112 Risk Assessment

The risk assessment is done in accordance with the five-by-five risk calculator Table 10.

Table 10: Risk Evaluation

Risk Level	Phase	Hazard	Minimisation	New Risk Score
	Phase 1	**Project Phase**		
3E	1A	Project Approval not granted	Gather appropriate information to strengthen project scope	**4B**
3E	1B	Project Plan, Specifications and resources not approval	Work with supervisor to understand requirements and design appropriate documentation	**4B**
3D	1C	Resources from Energy Queensland approved	Work with supervisor and energy Queensland to gain access to useful information	**3B**
	Phase 2	**Literature review**		
2D	2A	Classify load and PV density as customer bases is incorrectly assessed	Use information from AEMO, literature review and industry support	**3A**
3D	2B	Construction types of batteries kWh and life expectancy aren't accurate	Use information from literature review and industry support	**4B**
	Phase 3	**Methodology**		
2B	3B	Model the different construction styles is inaccurate	Use support from resources such as dissertation coordinator, internet and tutors	**3A**
2B	3C	Simulation of the model fails in MATLAB	Use support from resources such as dissertation coordinator, internet and tutors	**3A**
	Phase 4	**Simulation**		
3E	4C	Results of simulations are incorrect	Use literature to make assessments on results. Analyse support from dissertation support	**3A**

Appendix D - ENG4111/4112 Resources

Resources for the communal battery project to be achieved are listed in Table 11.

Table 11: Equipment and Software requirements

Item	Number Required	Source	Cost	Comment
Computer	2	Student owned University computers	Nil	Personal laptop plus the University computers if required
Microsoft Word	1	Student licence	Nil	For dissertation processing
Grammarly	1	Student Purchase	$40	Improve writing and error detection
Microsoft Excel	1	Student licence	Nil	For data analysis and demand calculations
Power Factory	1	Power Factory Dissertation Licence	Nil	Industry-standard if MATLAB is insufficient (free for dissertation work)
MATLAB's Simulink	1	University/Own Licence	Nil	Simulation running

Appendix E – MALAB Code

```
%% Optimal model design for community batteries
% Prepared by Coenraad Wium
% This code analyses community storage frameworks to achieve a smooth
% load profile that provides DNSP benefits from increased
% distribution transformer lifespans
%-------------------------------------------------------------------
%% clear all variables from workspace & close all figures,clear command window
clc, clear, close all
figure_count = 0;                       % Set up figure count

fprintf('<strong>Battery Mode</strong>\n');

timeYears = 8760;                       % Hours in a year
dayYears = timeYears/24;
solarFeedIn = 0.093;                    % $/kWh
supplyCharge = 0.99449;                 % $
supplyCharge = supplyCharge*dayYears;   % $/day
%-------------------------------------------------------------------
% Tariffs
tariff11 = 0.24349;               % $/kWh
tariff12BShoulder = 0.19741;      % $/kWh 2100 - 0900
tariff12BOffPeak = 0.18959;       % $/kWh 0900 - 1600
tariff12BPeakUsage = 0.32929;     % $/kWh 1600 - 2100
tariff14BPeakDemand = 8.712;      % $/kW 1600 - 2100
tariff14B = 0.18402;              % $/kWh
%-------------------------------------------------------------------
% Tx Data
ieeeStandardlife = 180000;        % Hours according to IEEE standard
txCost = 100000;                  % Assumed cost of a transformer
transformerVA = 200;              % kVA
PF = 0.9;                         % Assumed Power factor
noLoadLoss = 1.018;               % kW
loadLoss = 3.808;                 % kW
maintainCost= 200;                % Maintenance cost annualy
inflationRate = 0.017;            % Assumed inflation
%-------------------------------------------------------------------
interestRate = 0.05;              % Interest rate assumed 5%
txCost_kWh = 0.075;               % kWh price for transformer
customers = 96;                   % Total number of customers
solarCapacity_kW = 220.77;        % Solar capacity in kW
yearlyConsumption_kWh = 309180;   % Comunity usage kWh
%-------------------------------------------------------------------
% Battery Data
batteryMaxDischargePerc = 0.8;
batteryMinLevelPerc = 1-batteryMaxDischargePerc;
batteryEfficency = 0.9;                          % Round trip efficency
batteryPrice_kWh = 950;                          % Battery price per $/kWh
batteryCycleMax = 10000;
batteryLifeYears = 10;                           % Battery max life
simulationTimeYears = 26.3695;   % Comparitive simulation to no battery tx max
%-------------------------------------------------------------------
%% Load TX hotspot and Load Profile Data
% PU load vs hotspot table
trans = readtable('trans.xlsx');
load_PU = table2array(trans(:,1));
hotSpot=table2array(trans(:,2));
```

```
% Use regression function to calculated expected value of hotspot
regrestion = fitlm(load_PU,hotSpot);
regrestion = regrestion.Coefficients.Estimate;
hotSpotFunc = @(Load_PU)  regrestion(2)*Load_PU + regrestion(1);

% PV and Load data table
profile = readtable('setScaled.xlsx');
monthProfile = table2array(profile(:,1));
dayProfile = table2array(profile(:,2));
hourProfile = table2array(profile(:,3));
loadProfile = table2array(profile(:,5));
pvProfile = table2array(profile(:,7));
netProfile = table2array(profile(:,8));

%---------------------------------------------------------------------
%% Solar inverters kW
% Inverter power, quantity, total power
solarInverters = [...
    [7.2,1];...
    [5,20];...
    [4.83,6];...
    [4.6,4];...
    [4,5];...
    [3,7];...
    [2.85,3];...
    [2.7,3];...
    [2,3];...
    [1.2,2]...
    ];
solarInverters = flip(solarInverters,1);
solarInverters(:,3) = solarInverters(:,1).*solarInverters(:,2);
solarInverterRatios = solarInverters(:,3)./solarCapacity_kW;
solarInverterQty = size(solarInverters,1);

transformer_kW = transformerVA*PF;

% Calculate individula solar production and cost
for i = 1:length(solarInverterRatios)

    solarProduced(:,i) = (sum(solarInverterRatios(i).*pvProfile));
    individualSolarProduction(i,:) = solarProduced(i)/solarInverters(i,2)';

end

individualSolarProductionCost = individualSolarProduction*solarFeedIn;
%---------------------------------------------------------------------
%% Upper integral
% Shaving to the limit of battery requieres the integral line to move down
% to max 80% battery capacity.

% loadProfile  max value
% vector each of the shaving values needed
% integrals for each value of the vector (LUT)
% LUT shaving value that satisfies the max total discharge less that 80%
% battery kWh and shaving less than battery kW value

loadProfileSafetyFactor = 1;             % Safety factor for load profile
loadProfileIntegrand = loadProfile*loadProfileSafetyFactor; % Add safety factor
loadProfileIntegrandMax = max(loadProfileIntegrand);
```

```
peakTxLoadValues.perc = 0.5:0.1:1.5;                          % Store in perc
peakTxLoadValues.abs = peakTxLoadValues.perc*transformer_kW;  % Steps of
transformer ability
peakTxLoadValues.count = length(peakTxLoadValues.abs);

loadProfileIntegrandPerDay = cell(1,dayYears);
dt = 1;
% Integrands per day
for i = 1:dayYears

    loadProfileIntegrandPerDay{i} = loadProfileIntegrand((i-1)*24+1:i*24); %
Profile seperation into 24 hours for every day in a year

    for j = 1: peakTxLoadValues.count

        loadProfileIntegrandPerDayClipped =  loadProfileIntegrandPerDay{i} -
peakTxLoadValues.abs(j); % Difference between the Tx load capability and the day
profile
        loadProfileIntegrandPerDayClipped =
loadProfileIntegrandPerDayClipped(loadProfileIntegrandPerDayClipped>=0); % Only
take indexes that are positive value
        loadProfileIntegral(j,i) = sum(loadProfileIntegrandPerDayClipped*dt); %
Rectangulare intergral

    end
end
loadProfileIntegralMax = zeros(peakTxLoadValues.count,2);  % This is only for the
80% cap add 20% for battery size needed
[loadProfileIntegralMax(:,1),loadProfileIntegralMax(:,2)] =
max(loadProfileIntegral,[],2); % Store the max load profile with index of day

for i = 1: peakTxLoadValues.count
    peakTxMinBatteryRequirements(i,1) =
max(loadProfileIntegrandPerDay{loadProfileIntegralMax(i,2)}-
peakTxLoadValues.abs(i));  % find kW of battery
end

peakTxMinBatteryRequirements(:,2) =
(loadProfileIntegralMax(:,1)/batteryMaxDischargePerc); % find kWh for the battery
%-----------------------------------------------------------------------
%% Battery List
% Create array of batteries kW and kWh ratio
batteryInterval = 1;
batteryList(:,1:2)
=[ceil(peakTxMinBatteryRequirements/batteryInterval)*batteryInterval; ...
    0,0 ...
    ]; % round up to the nearest batteryInterval and add a no battery mode (0,0)


batteryList(:,3) = batteryList(:,2) * batteryPrice_kWh;
batteryQty = size(batteryList,1);                          % Number of battery to
test
stdBatteryDataSizeZeros = zeros(batteryQty,1);             % Pre allocation for use
inside code
%-----------------------------------------------------------------------
%% Adjust load profile for battery usage
% Load profiles for battery levels and battery discharge per hour
batteryLifeCycleData = cell(size(stdBatteryDataSizeZeros,1),3);
```

```
for batteryNum = 1:batteryQty
    % Load battery data in temp variables
    batterykW_temp = batteryList(batteryNum,1);
    batterykWh_temp = batteryList(batteryNum,2);
    batteryOperationalState = {'Charging',''};

    % Loading peak shaving data
    if batteryNum ~= batteryQty
    peakTxLoadValueIndex = batteryNum;   % Matching batteryNum to the peak Tx load
index
    peakTxLoadValue =  peakTxLoadValues.abs(peakTxLoadValueIndex);
    else
        peakTxLoadValue = max(loadProfile);
    end

    % Pre allocate battery life cycle data
    loadProfilePerBattery = loadProfile;                    % load profile of
transformer with battery
    batteryLevels = ones(size(loadProfile))*batterykWh_temp; % Battery level over
time
    batteryDischarges = zeros(size(loadProfile));           % Battery discharge
per hours (over set time)


    for i = 1:size(loadProfile)

        if i == 1                                   % Inital condition of battery
            batteryLevelStart = batterykWh_temp;    % Assumed to start at full
charge
        else
            batteryLevelStart = batteryLevels(i-1); % Need previouse battery level
        end

        t = hourProfile(i);
        m = monthProfile(i);


        batteryOperationalStateChangeIndicator = false;
        % Peak Shaving check
        % Discharge based on algorithem parameters set here
        if (loadProfile(i) > peakTxLoadValue) && ...
                (batteryLevelStart > batteryMinLevelPerc*batterykWh_temp) %&& ...

            %                 (loadProfile(i) > transformer_kW)
            %                 ((17<=t && t<21) || (7<=t && t<9))
            %                 (17<=t && t<21)
            batteryOperationalState{2} = batteryOperationalState{1};
            batteryOperationalState{1} = 'Discharging';
            batteryOperationalStateChangeIndicator = true;
        end

        if batteryOperationalStateChangeIndicator == false   % Update battery
operation state cell array to remain charging
            batteryOperationalState{2} = batteryOperationalState{1};
            batteryOperationalState{1} = 'Charging';
        end

        batteryOperationalStateCurrent = batteryOperationalState{1};
```

```
        switch batteryOperationalStateCurrent
            % switch statment for the battery charging and discarging
            case 'Charging'
                batteryChargeInPossible = min(...               % checking the the
kw rating draw is not exceded
                    pvProfile(i)*batteryEfficency, ...  % Battery efficency factor
applied to the PV profile
                    batterykW_temp...
                    );
                batteryLevelEnd = min(...               % checking the battert kwh
rating isnt exceded
                    batteryLevelStart + batteryChargeInPossible,...
                    batterykWh_temp...
                    );

            case 'Discharging'
                batteryChargeOutPossible = min([...                             %
How much can the battery discharge
                    batterykW_temp, ...                                         %
Most important its the highest draw possable
                    loadProfilePerBattery(i) - peakTxLoadValue, ...             %
Dont draw more than the load pulls (peakTxLoadValue is cap)
                    batteryLevelStart - batteryMinLevelPerc*batterykWh_temp, ... %
Prevents over drawing the battery
                    ]);


                loadProfilePerBattery(i) = max(...
                    loadProfilePerBattery(i) - batteryChargeOutPossible,...
                    0 ...
                    );

                batteryDischarges(i) = loadProfile(i)-loadProfilePerBattery(i);  %
How much battery actually discharges

                batteryLevelEnd = max(...
                    batteryLevelStart - batteryDischarges(i),...
                    0 ...
                    );

            otherwise
                error('Unrecognised Battery Operation State')
        end
        batteryLevels(i) = batteryLevelEnd;

    end

    % Store the battery values
    batteryLifeCycleData{batteryNum,1} = loadProfilePerBattery;         % load
profile of transformer with battery
    batteryLifeCycleData{batteryNum,2} = batteryLevels;                 % Batterly
level over time
    batteryLifeCycleData{batteryNum,3} = batteryDischarges;             % Battery
discharge per hours (over set time)
end
batteryLifeCycleCheck = stdBatteryDataSizeZeros;

% Check for which battery meets the transformer and clipping size requierements
```

```
for batteryNum = 1:batteryQty
    if batteryNum ~= batteryQty
        batteryLifeCycleCheck(batteryNum,1) =
max(batteryLifeCycleData{batteryNum,1}) <= transformer_kW;    % kW rating of the
tx is not exceeded
        batteryLifeCycleCheck(batteryNum,2) =
max(batteryLifeCycleData{batteryNum,2}) <= peakTxLoadValues.abs(batteryNum); %
Clipping limit is not exceeded
    else
        batteryLifeCycleCheck(batteryNum,1) = NaN; % For no battery senario
        batteryLifeCycleCheck(batteryNum,2) = NaN; % For no battery senario
    end
end
%-------------------------------------------------------------------
%% Peak load anaylasis
% Find the peak load of each month and day for characteristic check

for i =1:batteryNum
    loadProfiles_avperhour(i) =
peakLoadAnalysis(hourProfile,monthProfile,batteryLifeCycleData(i,1));
end

for i = 1: batteryNum
    figure_count = figure_count+1;
    figure(figure_count);
    surface(loadProfiles_avperhour{1,i})
    view([55 30])
    colorbar
    title(['Peak Load Analysis ' , num2str(batteryList(i,2)),' kWh Battery'])
    xlabel('Months')
    ylabel('Hours')
    zlabel('Power (kWh)')
    fontsize(gca,scale=1.5)

end
%-------------------------------------------------------------------
%% Convert load to per Unit
% Convert batteries new load data to PU then find the hot spot using
% hot spot function.
loadProfileBattery_PU = cell(size(stdBatteryDataSizeZeros));
loadProfileBatteryHotspot = cell(size(stdBatteryDataSizeZeros));

for batteryNum = 1:batteryQty
    loadProfileBattery_PU{batteryNum,1} =
batteryLifeCycleData{batteryNum,1}./transformer_kW;
    loadProfileBatteryHotspot{batteryNum,1} =
hotSpotFunc(loadProfileBattery_PU{batteryNum,1});
end
% -------------------------------------------------------------------
%% Transformer age
% Calculate the lost life of the transformer
maxTxLife = 50;              % Tx max expected life
TxInsulationLifePerBattery = cell(size(stdBatteryDataSizeZeros));
TxInsulationLifePerYearPerBattery = stdBatteryDataSizeZeros;

for batteryNum = 1:batteryQty

    TxInsulationLifePerBattery{batteryNum,1} =
transformerAge(ieeeStandardlife,loadProfileBatteryHotspot{batteryNum,1});
```

```
    TxInsulationLifePerYearPerBattery(batteryNum,1) =
length(TxInsulationLifePerBattery{batteryNum,1})/timeYears;

end

for i = 1:batteryNum

    if (TxInsulationLifePerYearPerBattery(i) > maxTxLife)

        TxInsulationLifePerYearPerBattery(i) = maxTxLife;

    end
end
%-------------------------------------------------------------------
%% Battery Life Cycle
batteryCyclePerYearPerBattery = stdBatteryDataSizeZeros;
for batteryNum = 1:batteryQty
    batteryCyclePerYearPerBattery(batteryNum,1) =
sum(batteryLifeCycleData{batteryNum,3})/(batteryList(batteryNum,2)*batteryMaxDisch
argePerc); % Cycle per year
end
batteryCyclePerYearPerBattery(isnan(batteryCyclePerYearPerBattery)) = 0;
%-------------------------------------------------------------------
%% Transformer return on cost yearly


for i = 1:batteryNum

    txPurchaseCost(i) = 0;
    txOpportunityCost(i) = 0;
    n = 0;

    while n < simulationTimeYears
        nStep = min(TxInsulationLifePerYearPerBattery(i), simulationTimeYears -
n);
        txCostNew = txCost*(1 + inflationRate)^n;                          %
Account for inflation of tx cost
        txPurchaseCost(i) = txPurchaseCost(i) + txCostNew;
        txOpportunityCost(i) = txOpportunityCost(i) +
txCostNew*(1+interestRate)^(simulationTimeYears-n);
        n = n +nStep;

    end
    n = 0;
    batteryPurchaseCost(i) = 0;
    batteryOpportunityCost(i) = 0;
    while n < simulationTimeYears
        batteryLife =
min(batteryLifeYears,batteryCycleMax/batteryCyclePerYearPerBattery(i));
        nStep = min(batteryLife, simulationTimeYears - n);
        batteryCostNew = batteryList(i,3)*(1 + inflationRate)^n;             %
Account for inflation of battery cost
        batteryPurchaseCost(i) = batteryPurchaseCost(i) + batteryCostNew;
        batteryOpportunityCost(i) = batteryOpportunityCost(i) +
batteryCostNew*(1+interestRate)^(simulationTimeYears-n);
        n = n +nStep;
    end

end
```

```
TOC = txPurchaseCost + txOpportunityCost + batteryPurchaseCost +
batteryOpportunityCost;
TOC = TOC';

ROA = ((TOC(batteryNum)-TOC)/TOC(batteryNum))*100;

figure_count=figure_count+1;
figure(figure_count);
subplot(2,1,1)
plot(txPurchaseCost)
title(['Purchase Cost for Simulated ' , num2str(simulationTimeYears),' Years'])
subtitle('Transformer')
xlabel('Battery size (kWh)')
xlim([1 batteryNum])
xticklabels({batteryList(:,2)})
ylabel('Cost (AUD)')
ytickformat('usd')
grid on
fontsize(gca,scale=1.5)

subplot(2,1,2)
plot(batteryPurchaseCost)
subtitle('Battery')
xlabel('Battery size (kWh)')
xlim([1 batteryNum])
xticklabels({batteryList(:,2)})
ylabel('Cost (AUD)')
ytickformat('usd')
grid on
fontsize(gca,scale=1.5)


figure_count=figure_count+1;
figure(figure_count);
plot(TOC)
title(['Total Owning Cost for Simulated ' , num2str(simulationTimeYears),'
Years'])
xlabel('Battery size (kWh)')
xlim([1 batteryNum])
xticklabels({batteryList(:,2)})
ylabel('Cost (AUD)')
ytickformat('usd')
grid on
fontsize(gca,scale=1.5)

%--------------------------------------------------------------------
%% Tariff defaults
% Pre allocation for use inside tariff location
tariffXConsumerPerBattery = zeros(batteryQty,1);
tariffXProsumerPerBattery = zeros(batteryQty,solarInverterQty);
%--------------------------------------------------------------------
%% Tariff 11 Battery
% tarrif 11 is general use tariff at a base rate
tariff11ConsumerPerBattery = tariffXConsumerPerBattery;
tariff11ProsumerPerBattery = tariffXProsumerPerBattery;

for batteryNum = 1:batteryQty
```

```
    tariff11ConsumerPerBattery(batteryNum,1) =
(sum(batteryLifeCycleData{batteryNum,1})/customers)*tariff11+supplyCharge;
    tariff11ProsumerPerBattery(batteryNum,:) =
tariff11ConsumerPerBattery(batteryNum,1) - individualSolarProductionCost';

end
%-------------------------------------------------------------------
%% Tariff 12B
tariff12BConsumerPerBattery = tariffXConsumerPerBattery;
tariff12BProsumerPerBattery = tariffXProsumerPerBattery;
tariff12B = zeros(size(hourProfile,1),1);

tariff12B= tariff12B + ((21 <= hourProfile)+(hourProfile < 9))*tariff12BShoulder;
tariff12B= tariff12B +((9 <= hourProfile) & (hourProfile < 16))*tariff12BOffPeak;
tariff12B= tariff12B +((16 <= hourProfile) & (hourProfile < 21)) *
tariff12BPeakUsage;

for batteryNum = 1:batteryQty
    tariff12BConsumerPerBattery(batteryNum,1) =
((sum(tariff12B.*batteryLifeCycleData{batteryNum,1}))/customers)+supplyCharge;
    tariff12BProsumerPerBattery(batteryNum,:)=
tariff12BConsumerPerBattery(batteryNum,1) - individualSolarProductionCost';
end
%-------------------------------------------------------------------
%% Tariff 14B
tariff14BConsumerPerBattery = tariffXConsumerPerBattery;
tariff14BProsumerPerBattery = tariffXProsumerPerBattery;

for batteryNum = 1:batteryQty

    tariff14BBasic = tariff14B*sum(batteryLifeCycleData{batteryNum,1})/customers +
supplyCharge;
    tariff14BPeakDemandCharge = zeros(size(hourProfile,1),1);


    for month = min(monthProfile): max(monthProfile)

        logicArrayMonth = monthProfile == month;
        logicArrayHour = (16 <= hourProfile) & (hourProfile < 21); % $/kW 1600 -
2100
        logicArray = logicArrayMonth & logicArrayHour;
        indexArray = find(logicArrayMonth);
        peakValue = max(logicArray.*batteryLifeCycleData{batteryNum,1});

        tariff14BPeakDemandCharge(indexArray) = peakValue*tariff14BPeakDemand/24;

    end

    tariff14BConsumerPerBattery(batteryNum,1) =
sum(tariff14BPeakDemandCharge/customers)+tariff14BBasic;
    tariff14BProsumerPerBattery(batteryNum,:) =
tariff14BConsumerPerBattery(batteryNum,1) - individualSolarProductionCost';

end
%-------------------------------------------------------------------
%% Tariff plots
% Plot results of the consumer and prosumer battery size
% Tariff 11
figure_count=figure_count+1;
```

```
figure(figure_count);
for i = 1:batteryQty

plot([tariff11ConsumerPerBattery(i,1),tariff11ProsumerPerBattery(i,:)],'DisplayNam
e',sprintf('%d kWh',batteryList(i,2)))
    hold on

    title('Tariff 11', 'Consumer and Prosumer per Battery')
    xlabel('Inverter Size (kW)')
    ylabel('Cost (AUD)')
    ytickformat('usd')
    xticklabels({'0','1.2','2','2.7', '2.85', '3', '4', '4.6', '4.83', '5',
'7.2'})
    legend
    grid on
    set(gca,'fontsize', 14)

end

hold off
%---------------------------------------------------------------------
% Tariff 12B
figure_count=figure_count+1;
figure(figure_count);
for i = 1:batteryQty

plot([tariff12BConsumerPerBattery(i,1),tariff12BProsumerPerBattery(i,:)],'DisplayN
ame',sprintf('%d kWh',batteryList(i,2)))
    hold on
    title('Tariff 12B', 'Consumer and Prosumer per Battery')
    xlabel('Inverter Size (kW)')
    ylabel('Cost (AUD)')
    ytickformat('usd')
    xticklabels({'0','1.2','2','2.7', '2.85', '3', '4', '4.6', '4.83', '5',
'7.2'})
    legend
    grid on
    set(gca,'fontsize', 14)

end
hold off
%---------------------------------------------------------------------
% Tariff 14B
figure_count=figure_count+1;
figure(figure_count);
for i = 1:batteryQty

plot([tariff14BConsumerPerBattery(i,1),tariff14BProsumerPerBattery(i,:)],'DisplayN
ame',sprintf('%d kWh',batteryList(i,2)))
    hold on

    title('Tariff 14B', 'Consumer and Prosumer per Battery')
    xlabel('Inverter Size (kW)')
    ylabel('Cost (AUD)')
    ytickformat('usd')
    xticklabels({'0','1.2','2','2.7', '2.85', '3', '4', '4.6', '4.83', '5',
'7.2'})
    legend
    grid on
```

```
    set(gca,'fontsize', 14)

end
hold off
%-------------------------------------------------------------------
%% Utility Cost table per battery

utilityCostPerBattery = table( ...
    batteryList(:,1),...
    batteryList(:,2),...
    batteryList(:,3), ...
    TxInsulationLifePerYearPerBattery, ...
    batteryCyclePerYearPerBattery, ...
    TOC, ...
    ROA, ...
    'VariableNames',{ ...
    'kW', ...
    'kWh', ...
    'Battery Price', ...
    'TX Max Age', ...
    'Yearly Battery Cycles', ...
    'Total Ownership Cost',...
    'Return on Asset',...
    });
%-------------------------------------------------------------------
%% Consumer/Prosumer cost table per battery
ConProCostPerBattery = table( ...
    batteryList(:,1),...
    batteryList(:,2),...
    [tariff11ConsumerPerBattery,tariff11ProsumerPerBattery], ...
    [tariff12BConsumerPerBattery,tariff12BProsumerPerBattery], ...
    [tariff14BConsumerPerBattery,tariff14BProsumerPerBattery], ...
    'VariableNames',{ ...
    'kW', ...
    'kWh', ...
    'Tariff 11', ...
    'Tariff 12B', ...
    'Tariff 14B', ...
    });
%-------------------------------------------------------------------
figure_count=figure_count+1;
figure(figure_count);
plot (batteryLifeCycleData{1,1})
title('Load Profile Analysis for 2293 kWh')
xlabel('Hours')
ylabel('Power (kWh)')

figure_count=figure_count+1;
figure(figure_count);
plot (batteryLifeCycleData{11,1})
title('Load Profile Analysis for 5 kWh')
xlabel('Hours')
ylabel('Power (kWh)')
```

MATLAB function – Transformer Age

```
% Optimal model design for community batteries
```

```
% Prepared by Coenraad Wium

% Function to calculate the transformer age

function [txLife] = transformerAge(ieeeStandardlife,loadProfileHotspot)

F_eqa_old = 0;
txLife(1) = ieeeStandardlife;
i = 2;

    while (txLife(i-1) > 1) && (i < 750000)
        n = mod(i-1,length(loadProfileHotspot));

        if n == 0
            hs = loadProfileHotspot(end);
        else
            hs = loadProfileHotspot(n);
        end

        F_AA = exp((15000/383)-(15000/(hs+273))); % Relative aging factor
        F_eqa = (F_eqa_old*(i-1)+F_AA)/(i);       % F_eqa_old recovers old mean
        LOL = (F_eqa*(i-1))/txLife(1);            % Loss of life
        txLife(i) = txLife(1)*(1-LOL);

        i = i + 1;
        F_eqa_old=F_eqa;
    end
end
```

MATLAB function – Peak load analysis

```
% Optimal model design for community batteries
% Prepared by Coenraad Wium

% Function to calculate the peak load anaylasis
% Find the peak load of each month and day for characteristic check

function [loadProfile_avperhour] = peakLoadAnalysis(hourProfile,monthProfile,data)

loadProfile_avperhour = zeros(25,13); % 13 and 25 to store mean
data = cell2mat(data);

for i = 1:12                % Month
    for j = 1:24            % Day

        loadProfile_avperhour(j,i) = mean(data(find((hourProfile ==
j)&(monthProfile == i))));

    end
end

loadProfile_avperhour(:,13) = mean(loadProfile_avperhour(:,1:12),2);
loadProfile_avperhour(25,:) = mean(loadProfile_avperhour(1:24,:),1);
loadProfile_avperhour(25,:)=[];
loadProfile_avperhour(:,13)=[];
loadProfile_avperhour = mat2cell(loadProfile_avperhour,24,12);
```

```
end
```

Appendix G – Results

Table 12: Discharge times 17:00-21:00

Test one - Discharge times 17:00-21:00						
145	2293	2178350	50	35.44672	26051412	-5538.4
127	1753	1665350	50	30.64537	20025131	-4234.11
109	1213	1152350	50	26.12272	13998849	-2929.82
91	699	664050	50	23.90383	8262722	-1688.33
93	469	445550	50	16.27084	5695973	-1132.8
75	297	282150	50	11.28714	3776491	-717.359
57	170	161500	50	9.60381	2359199	-410.609
58	99	94050	43.88733	8.102708	1566854	-239.12
40	50	47500	35.98584	5.983352	1020025	-120.767
22	28	26600	29.98059	2.80782	774509.8	-67.6298
4	5	4750	26.70377	0.993673	517834.8	-12.0767
0	0	0	26.36952	0	462035.9	0

Table 13: Discharge times 07:00-09:00 and 17:00-21:00

Test two - Discharge times 17:00-21:00 and 07:00-09:00						
145	2293	2178350	50	39.91594	26051412	-5538.4
127	1753	1665350	50	34.50939	20025131	-4234.11
109	1213	1152350	50	29.9485	13998849	-2929.82
91	699	664050	50	28.23584	8262722	-1688.33
93	469	445550	50	20.38157	5695973	-1132.8
75	297	282150	50	14.92437	3776491	-717.359
57	170	161500	50	13.06769	2359199	-410.609
58	99	94050	50	10.99629	1566854	-239.12
40	50	47500	42.17192	8.130802	1020025	-120.767
22	28	26600	32.21039	4.207782	774509.8	-67.6298
4	5	4750	26.70377	0.993673	517834.8	-

						- 12.0767
0	0	0	26.36952	0	462035.9	0

Table 14: Tx and clipping limit

Test three - Transformer rating and clipping limit exceeded						
145	2293	2178350	50	11.16262	26051412	-5538.4
127	1753	1665350	50	12.23953	20025131	-4234.11
109	1213	1152350	50	14.27526	13998849	-2929.82
91	699	664050	50	18.84963	8262722	-1688.33
93	469	445550	50	19.99109	5695973	-1132.8
75	297	282150	50	17.62903	3776491	-717.359
57	170	161500	50	14.99547	2359199	-410.609
58	99	94050	50	12.46993	1566854	-239.12
40	50	47500	44.42568	9.089527	1020025	-120.767
22	28	26600	32.25445	4.246407	774509.8	-67.6298
4	5	4750	26.70377	0.993673	517834.8	-12.0767
0	0	0	26.36952	0	462035.9	0

Table 15: Load profile clipping

Test four - Whole load profile						
145	2293	2178350	50	56.20189	26051412	-5538.4
127	1753	1665350	50	53.13401	20025131	-4234.11
109	1213	1152350	50	43.84694	13998849	-2929.82
91	699	664050	50	37.2504	8262722	-1688.33
93	469	445550	50	25.09068	5695973	-1132.8
75	297	282150	50	17.62903	3776491	-717.359
57	170	161500	50	14.99547	2359199	-410.609
58	99	94050	50	12.46993	1566854	-239.12
40	50	47500	44.42568	9.089527	1020025	-120.767
22	28	26600	32.25445	4.246407	774509.8	-67.6298
4	5	4750	26.70377	0.993673	517834.8	-12.0767

0	0	0	26.36952	0	462035.9	0

Table 16: TOC comparison

TOC comparison				
batter kWh	Test one	Test two	Test three	Test four
2293	25589376	25589376	25589376	25589376
1753	19563095	19563095	19563095	19563095
1213	13536813	13536813	13536813	13536813
699	7800686	7800686	7800686	7800686
469	5233937	5233937	5233937	5233937
297	3314455	3314455	3314455	3314455
170	1897163	1897163	1897163	1897163
99	1104818	1104818	1104818	1104818
50	557989	557989	557989	557989
28	312473.8	312473.8	312473.8	312473.8
5	55798.9	55798.9	55798.9	55798.9
0	0	0	0	0