Optimisation of Behind the Meter DER Generation Assets within Network Constraints: A Roadmap to Successful DR Program (Project 69)

Final Project Report

RMIT University, Melbourne

May 2023

Project Lead: A/Prof. Lasantha Meegahapola

Research Team: Prof. Mahdi Jalili

Dr Kazi Hasan

Dr. Richardt Wilkinson

Prof. Brendan McGrath

Dist. Prof. Xinghuo Yu

Prof. Flora Salim

Dr. Mingchen Gu

Dr. Reza Razzaghi

Dr. Hui Song

Dr. Ammar Kamoona

Dr. Moudud Ahmed

Dr. Mohsen Khorasany

Dr. Imran Azim

Mr. Chad Wanninayaka Mudiyanselage

Mr. Kian Keshavarzian

Prepared for: C4NET, AGL, AusNet Services

Contact: A/Prof. Lasantha Meegahapola

Email: lasantha.meegahapola@rmit.edu.au

Acknowledgements: The project team wishes to acknowledge the data support and the feedback received from Mr. Kedem Levy and the AGL team. The team also wishes to acknowledge the Gippsland Water Factory, Federation University, and Greater Western Water for sharing their energy data with the Project-69 team.

Executive Summary

Demand response (DR) programs can benefit electricity consumers, distribution network service providers (DNSPs), system operators and the energy market. However, the complexity and characteristics associated with loads connected to customer premises, utilisation of backup generators for DR and the baseline calculation process still require considerable research to optimise and further unlock the capabilities of DR programs. The challenges of DR programs are not limited to technical aspects, since there are several non-technical elements to consider when implementing DR programs, such as regulatory policy compliance. C4NET launched this DR research program to use the research expertise of member universities to solve some of the industry challenges concerning DR schemes, produce potential solutions for some DR challenges associated with commercial and industrial (C&I) customers and accelerate their deployment in electricity networks. The project was designed with three work packages, and this final project report outlines the summary of work completed under three work packages and project recommendations.

Work package 1 (WP-1) investigated the feasibility of interpretable machine learning (ML) tools for DR baseline determination. The study has analysed data from several C&I customers from telecommunications companies, water utilities, university, chemical plant, and shopping centre businesses. The study also investigated how temperature combined with consumption history may impact the customers' benefit by providing more accurate demand forecasts. The WP-1 has made the following recommendation:

R1: Machine Learning Techniques for Baseline Calculations

- Machine learning techniques can be applied to weather dependant loads, in particular, loads which has strong dependency on temperature, such as shopping malls, and universities.
- Linear and nonlinear regression techniques have outperformed the average baseline model, and hence it is recommended to use regression techniques instead of average baseline models in the future.
- The weather information, such as temperature, can further improve the accuracy of regression based interpretable machine learning techniques, and hence it is recommended to apply the weather parameters in the regression techniques to improve demand response baselines.

Work package 2 (WP-2) investigated the barriers to higher utilisation of backup generators in DR programs, as it is one of the most cost-efficient ways to add flexible capacity to the power grid. Under WP-2, the DNSP guidelines for backup generators and their synchronisation with the grid are reviewed, including ways to synchronise them and enable exporting. Simulation studies are conducted to explore the impacts of backup generators on power networks and factors affecting the export limit of backup generators. Three aspects of technical barriers are considered: location-based barriers, network-based barriers, and time-based barriers. WP-2 also analysed the feasibility of using biodiesel in backup generators in DR programs. The WP-2 has made the following recommendations to increase backup generator utilisation in DR programs:

R2 - Dynamic Export Limits for Backup Generators

- It is more beneficial to implement dynamic export limits for backup generators (i.e., the export limit varies based on the time of the day), instead of the static export limit. Since the dynamic export limit can increase the energy export capacity and consequently increase the potential for grid and network support services, without impacting the grid stability.

R3 - Flexible Operating Modes for Backup Generators

- Backup generators should be allowed to operate under flexible operating modes (i.e., P-V and P-Q control modes) as they can assist in mitigating network constraints and support the network.
- Moreover, export capacity can also be increased when they are allowed to operate under flexible operating modes. Also, this study recommends assessing the operating mode flexibility when conducting backup generator connection studies, as it could benefit the distribution network operator (e.g., assist in reducing network bottlenecks). This would also increase the potential for grid and network support services, without impacting the grid stability.

R4 - Consistent Inter-Tripping and Synchronisation Standards

- Each DNSP has rules and guidelines for generator inter-tripping and synchronisation. This lack of standardisation leads to complexity and uncertainty in enabling export from behind the meter generators. It also hinders the ability to identify new solutions that are lower cost but still meet the operational requirements of the network companies.
- Inter-tripping and technical synchronisation requirements can be standardised to achieve consistency across all DNSPs. That will encourage facilitate the process of enabling exports and a higher capacity for C&I customers to participate in DR programs.
- The Essential Services Commission can consider including consistent guidelines in the 'Electricity Distribution Code of Practice' on inter-tripping and synchronisation standards.

R5 - Biodiesel for Backup Generators

- Biodiesel can be used as a low carbon emission fuel for backup generators. There are ready made units that can be procured in Australia, and a complete supply chain exists from the manufacturer to the retailer.
- State and federal governments can provide subsidies to C&I customers to procure biodiesel ready generators, and also appropriate technology to upgrade their back-up generators to operate with biodiesel. This would also include support on the relevant operation costs with the aim of increasing the uptake until it becomes a standard solution.

Work package 3 (WP-3) investigated the use of battery energy storage systems (BESSs) in DR programs to benefit commercial customers in terms of electricity cost savings and return on investment (ROI). Under WP-3, standard and BESS trial network tariffs of four DNSPs are reviewed. Four commercial sites are selected, and a BESS optimising algorithm is developed for these commercial sites. Simulation studies are conducted to explore how selected sites are impacted if they are provided with different BESS sizes and charged under considered C&I tariff structures. The WP-3 has drawn the following recommendations to increase the uptake of batteries in DR programs:

R6: Reforming Energy Tariffs for Batteries

- From the analyses in this project, it is evident that tariffs designed for batteries, e.g., trial tariffs introduced by EvoEnergy, Essential Energy, SA Networks, and AusGrid, have the potential to be cost-effective for C&I customers in comparison to standard tariffs. Therefore, it is recommended to design specific tariffs for batteries.
- Tariff reforms such as introducing a larger gap between peak and off-peak prices as well as extending solar soak times could help customers achieve more savings that would ultimately promote higher uptake of batteries.

R7: Reducing Battery Costs

- From the project analyses, the payback period for C&I customers could be long due to the higher CapEx and OpEx associated with batteries. Therefore, in order to achieve the target payback period, it is recommended to consider potential grants and incentives to reduce battery deployment costs. While it is anticipated that batteries will provide various market and network services, the reduction in prices will help to make C&I batteries financially viable.

R8: Ensuring Network Integrity

- Deployment of a large number of behind-the-meter batteries by C&I customers can potentially result in violations of network constraints, such as voltage or line congestion. In order to effectively deploy behind-the-meter batteries at C&I facilities while safeguarding the long-term integrity of the network, it is recommended to explore the adoption of concepts such as the dynamic operating envelope (DOE). Insights and learnings from trials such as Project EDGE can be utilised to design and implement DOEs to ensure network integrity in the presence of a large number of behind-the-meter batteries.

The project recommendations benefit a wide range of stakeholders, such as C&I customers, DNSPs, system operators, aggregators, and retailers. Therefore, these stakeholders, state governments and policy-making bodies should consider implementing the project recommendations to exploit maximum benefits from DR programs in future.

Table of Contents

Executive Summary ii

Table of Contents v

List of Figures vii

List of Tables x

Acronyms and Terminologies xi

1. Project Overview 1

2. Scope of Work Packages 2

2.1. Scope of Work Package-1 2

2.2. Scope of Work Package-2 2

2.3. Scope of Work Package-3 3

2.4. Report Structure 3

3. Work Package 1 Key Findings 4

3.1. Results: The AGL Dataset 4

3.1.1. Case 0 results 4

3.1.2. Case 1 results 6

3.2. Demand Response Analysis 8

3.3. A Summary of Key Findings 10

4. Work Package 2 Key Findings 11

4.1. Investigation of Technical Barriers to Using Backup Generators in Demand Response 11

4.2. Representative Power Network Used in This Study 11

4.2.1. Medium voltage feeder taxonomy project 11

4.3. Impacts of Backup Generator Integration on the Power Grid 11

4.3.1. Impact of backup generator location 12

4.3.2. Impact of backup generator power export 13

4.3.3. Impact of system loading 13

4.4. Investigation of Dynamic Export Limits in Different Scenarios 14

4.4.1. Thermal limit 18

4.4.2. Short-circuit current limit 19

4.4.3. Dynamic export limit of a backup generator 21

4.5. Flexibility of Operating Modes 22

4.5.1. P-V control mode 22

4.5.2. P-Q control mode......22
4.5.3. Summary of operating modes......22
4.6. Feasibility Study of Using Biodiesel for Backup Generators......23
4.6.1. Technical Barriers to Biodiesel Generation......23
4.6.2. Supply-Chain of Biodiesel......24
4.6.3. GHG Emissions from Biodiesel......26
4.6.4. Economics of Biodiesel - Levelised Cost of Electricity......26
4.7. A Summary of Key Findings......27
5. Work Package 3 Key Findings......29
5.1. Overview of Solar PV and Load Profiles of Representative C&I Customers......29
5.2. Development of a battery Optimiser for C&I Customers......30
5.3. Financial Case Studies for C&I Customers with Battery......31
5.3.1. Financial Case Studies for Site 1......33
5.3.2. Financial Case Studies for Site 2......36
5.3.3. Summary of Key Findings......40
5.4. Network Impact Analysis with Battery......41
5.4.1. Overview of Representative Power Network......41
5.4.2. Network Case Studies with C&I Sites at Different Locations......42
5.4.3. Summary of Network Analysis with Battery......46
6. Recommendations and Implementation Roadmap......47
7. References......51
Appendix......55
Appendix A: Work Package 1 Base Line Methods and Machine Learning Techniques......55
Appendix B: Work Package 2 Methodology......59
Appendix C: DNSP Consultations and Feedback......61
Appendix D: Work Package 3 Methodology......65
Appendix E: Network Tariff Structures......66

List of Figures

Figure 1-1: Aims and objectives of project work-packages. 1
Figure 3-1: Testing accuracy performance for average baseline and SVR model for case 0.............4
Figure 3-2: Testing accuracy performance for average baseline and BLR model for case 0.............5
Figure 3-3: Testing accuracy performance over baseline and NLR model for case 0. 6
Figure 3-4: Testing accuracy performance over baseline and NLR, SVR, and BLR models for case 1..7
Figure 3-5: The accuracy of the shopping centre for case 0 and case 1 (denoted by C. 1). 7
Figure 3-6: Demand response predictions for NLR and baseline on AGL dataset with 11 C&I customers. 8
Figure 3-7: DR percentage difference (PD) and kW difference between the predicted value using NLR and the average baseline methods and the actual DR value, the green arrows indicate where there is a positive benefit. 9
Figure 4-1: Terminal voltage of Urban-NSW1 with different backup generator locations. 12
Figure 4-2: Terminal voltage of Urban NSW1 cluster with different backup generator power........13
Figure 4-3: Terminal voltage of Urban NSW1 cluster with different system loading.....................14
Figure 4-4: Net power profile of one load in Urban-NSW1 network. 15
Figure 4-5: Load profiles of Urban-NSW1 network on day 6...15
Figure 4-6: Voltage profile of terminal 17 on day 6. 16
Figure 4-7: The dynamic export limit of a backup generator on day 6 based on the voltage limit. ..16
Figure 4-8: Load profiles of Urban-NSW1 network on day 49...17
Figure 4-9: Voltage profile of terminal 17 on day 49. 17
Figure 4-10: The dynamic export limit of backup generator on day 49 based on voltage limit........18
Figure 4-11: The loading of line 16 on day 6. 19
Figure 4-12: The dynamic export limit of the backup generator based on thermal limit.................19
Figure 4-13: Short-circuit current of Urban-NSW1 with increase of backup generator capacity. 21
Figure 4-14: Overall GHG emissions of conventional diesel and several biodiesel types...............26
Figure 4 15: The LCOE for different generation sources...27
Figure 5-1: Solar PV and load profiles of Site 1..29
Figure 5-2: Solar PV and load profiles of Site 2..29
Figure 5-3: Flowchart of optimising BESS operation..31
Figure 5-4: Cost saving and PBP analysis of Site 1 considering unvaried tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F1) 33
Figure 5-5: Cost saving and PBP analysis of Site 1 considering unvaried tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F2) 31

Figure 5-6: Cost saving and PBP analysis of Site 1 considering reduction in tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F3) 33
Figure 5-7: Cost saving and PBP analysis of Site 1 considering reduction tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F4). 33
Figure 5-8: Cost saving and PBP analysis of Site 1 considering a reduction in CapEx with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F5) 34
Figure 5-9: Cost saving and PBP analysis of Site 1 considering a reduction in CapEx with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F6) 34
Figure 5-10: Cost saving and PBP analysis of Site 1 considering an increase in C rating with BESS: 200 kW, 252 kWh, 0.79 C (Case Study F7).. 34
Figure 5-11: Cost saving and PBP analysis of Site 1 considering an increase in C rating with BESS: 500 kW, 505 kWh, 0.99 C (Case Study F8) 35
Figure 5-12: Cost saving and PBP analysis of Site 1 considering a decrease in C rating with BESS: 200 kW, 1040 kWh, 0.19 C (Case Study 9) 35
Figure 5-13: Cost saving and PBP analysis of Site 1 considering a decrease in C rating with BESS: 500 kW, 1560 kWh, 0.32 C (Case Study F10) 35
Figure 5-14: Cost saving and PBP analysis of Site 2 considering unvaried tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F11) 35
Figure 5-15: Cost saving and PBP analysis of Site 2 considering unvaried tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F12). 36
Figure 5-16: Cost saving and PBP analysis of Site 2 considering reduction in tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F13) 42
Figure 5 17: Cost saving and PBP analysis of Site 2 considering reduction tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F14) 42
Figure 5-18: Cost saving and PBP analysis of Site 2 considering reduction in CapEx with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F15).. 38
Figure 5-19: Cost saving and PBP analysis of Site 2 considering reduction in CapEx with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F16) 38
Figure 5-20: Cost saving and PBP analysis of Site 2 considering increase in C rating with BESS: 200 kW, 252 kWh, 0.79 C (Case Study F17) 38
Figure 5 21: Cost saving and PBP analysis of Site 2 considering increase C rating with BESS: 500 kW, 505 kWh, 0.99 C (Case Study F18) 39
Figure 5-22: Cost saving and PBP analysis of Site 2 considering decrease in C rating with BESS: 200 kW, 1040 kWh, 0.19 C (Case Study F19). 39
Figure 5-23: Cost saving and PBP analysis of Site 2 considering decrease in C rating with BESS: 500 kW, 1560 kWh, 0.32 C (Case Study F20) 39
Figure 5-24: Single-line diagram of the representative power network 42
Figure 5-25: Net profiles of the representative network loads and selected four sites 42

Figure 5-26: Bus voltages and line loading under considered tariff structures if Site 1 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 8 (Case Study P1) 43
Figure 5-27: Bus voltages and line loading under different tariff structures if Site 1with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 8 (Case Study P2)....44
Figure 5-28: Bus voltages and line loading under different tariff structures if Site 1 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 18 (Case Study P3)....44
Figure 5-29: Bus voltages and line loading under different tariff structures if Site 1 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 18 (Case Study P4)....44
Figure 5-30: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 6 (Case Study P5)....45
Figure 5-31: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 6 (Case Study P6)....45
Figure 5-32: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 32 (Case Study P7)....45
Figure 5-33: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 32 (Case Study P8)....46
Figure A-1: Example of using historical data (10/10) in the prediction and excluding weekend days for DR calculation. 56
Figure B-1: Work package 2 methodology....59
Figure B-2: The simulation methodology....60
Figure D-1: Work package-3 methodology. 65

List of Tables

Table 3-1 AGL overall accuracy of ML models and baseline for both case 0 and case 1. 7
Table 4-1: The maximum fault levels and short-circuit levels under each voltage level……………20
Table 4-2: Results of short-circuit analysis with network Urban-NSW1..21
Table 4-3: Range of dynamic export limit of backup generators..22
Table 4-4: Generated energy of backup generator under different limit...22
Table 4-5: Summary of simulation results under different operating modes. 23
Table 4-6: Cloud point and pour point of biodiesels...24
Table 4-7: Biofuels production facilities available in Australia. 25
Table 5- 1: Overview of financial case studies. 32
Table 5-2: Overall costs associated with different BESS sizes. 32
Table 5-3: Overview of physical network case studies. 43
Table 6-1: Timeline for project recommendations...50
Table E.1: Tariff structure of Evo Energy without and with BESS trial...66
Table E.2: Tariff structure of Essential Energy without and with BESS trial.................................67
Table E.3: Tariff structure of SA Network without and with BESS trial..67
Table E.4: Tariff structure of AusGrid without and with BESS trial..68

Acronyms and Terminologies

- **AEMO:** Australian Energy Market Operator
- **AEMC:** Australian Energy Market Commission
- **AER:** Australian Energy Regulator
- **BESS:** Battery Energy Storage System
- **CBD**: Central Business District
- **CDD:** Cooling Degree Days
- **C&I:** Commercial and Industrial
- **CO:** Carbon Monoxide
- **DER:** Distributed Energy Resources
- **DFA:** Distribution Feeder Automation
- **DNSP:** Distribution Network Service Provider
- **DNP3:** Distributed Network Protocol 3
- **DR:** Demand Response
- **EDC:** Electricity Distribution Code
- **EG:** Embedded Generator
- **EIG:** Electricity Industry Guideline
- **ESR:** Electricity Safety Regulations
- **FEA**: Future Energy Australia
- **GHG**: Greenhouse Gases
- **HC**: Hydrocarbons
- **HDD:** Heating Degree Days
- **HMI**: Human-Machine Interface
- **HVO**: Hydrotreated Vegetable Oil
- **IES**: Inverter Energy System
- **LV:** Low Voltage
- **MMOF:** Multi-Mode Optic Fibre
- **MSO:** Model Standing Offer
- **NER:** National Electricity Rules
- **NOx:** Oxides of Nitrogen
- **PBP:** Payback Period
- **PMG:** Permanent Magnet Generator
- **RIO:** Remote Input/Output
- **ROI:** Return on Investment
- **RTU:** Remote Terminal Unit

- **SCADA:** Supervisory Control and Data Acquisition
- **SIR:** Service and Installation Rules
- **SO2:** Sulphur Dioxide
- **TNSP:** Transmission Network Service Provider
- **UE:** United Energy
- **VEDC:** Victorian Electricity Distribution Code
- **VSIR**: Victorian Service Installation and Rules
- **VT:** Voltage Transformer

- **Embedded Generator (EG)**: An entity that owns and operates generating units, which are connected within the distribution network and do not have direct access to the transmission network.
- **Micro EG:** If the generation system comprises only inverters and the total inverter capacity (AC nameplate rating) is 200kW or less, it is considered a 'micro' embedded generating unit. Rooftop solar panels and battery systems at residential and commercial premises are typical examples.
- **IES:** Inverter Energy Systems such as solar PV power generation units, wind turbine power generation units and battery storage systems.
- **Non-IES:** Non inverter energy systems such as synchronous or asynchronous generators are typically powered by crude oil engines.
- **Rural Area** (As per VEDC)**:** An area supplied electricity by an electric line which: (a) forms part of a distribution system and is a single feeder, (b) the length of which measured from the relevant zone substation is at least 15 km.
- **Long Rural Feeder** (As per VEDC)**:** A feeder, which is not a CBD feeder or an urban feeder, with a total length greater than 200 km.
- **Short Rural Feeder** (As per VEDC)**:** A feeder, which is not a CBD feeder or an urban feeder, with a total length less than 200 km.
- **Urban Feeder** (As per VEDC)**:** A feeder, which is not a CBD feeder, with a load density greater than 0.3 MVA/km.
- **Embedded Generator (EG):** Generating units, which are connected within the distribution network.
- **Generator synchronisation:** The process of connecting generators to the power grid without any /minimum disturbance.
- **Synchronisation Window:** The acceptable limits of the real-world mismatch of generator synchronising quantities.
- **Synchronism Time:** The time to initiate/close synchronising relay.

1. Project Overview

RMIT and Monash University were engaged by C4NET to provide a roadmap for successful demand response (DR) programs for commercial and industrial (C&I) customers. In response to the C4NET request and in collaboration with AGL, the RMIT and Monash team proposed a project with three work packages, which are as follows:

- **Work Package-1:** Machine learning for C&I customers' baseline improvement,
- **Work Package-2:** Unlocking the potential of participation of backup generators in DR,
- **Work Package-3:** Identify tariffs that can incentivise the uptake of batteries.

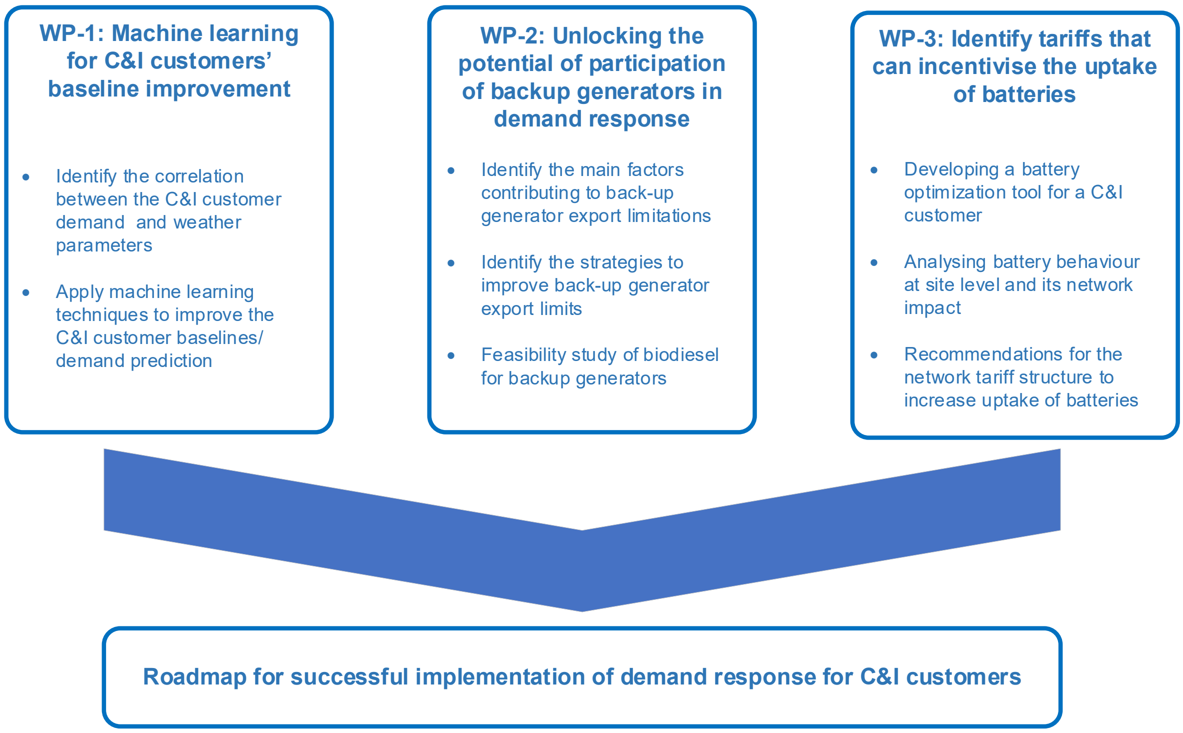


Figure 1-1: Aims and objectives of project work-packages.

The WP-1 investigated the potential of machine learning techniques to unlock the potential of demand response schemes, in particular focus on improving the baselines used in DR. WP-2 analysed the technical and regulatory barriers to backup generator utilisation in DR programs. Lastly, WP-3 explored the role of network tariffs in DR programs which can incentivise the uptake of batteries.

The project team has engaged with the Victorian distribution network service providers (DNSPs) to understand better the technical and regulatory barriers to deploying backup generators of C&I customers in DR programs. Moreover, the project team has reshaped the project outcomes and recommendations based on the feedback from Victorian DNSPs. Finally, this project created a roadmap for successful implementation of DR for C&I customers. It is envisaged that more C&I customers will sign up for the DR programs in the future after implementing recommendations of the project.

2. Scope of Work Packages

2.1. Scope of Work Package-1

Work Package-1 (WP-1) has applied Machine Learning (ML) tools to assess the concurrent inclusion of temperature information and consumption profiles in improving baselines used to calculate customer monetary benefits. In brief, this study has undertaken the following research activities:

1. Data preparation and pre-processing to feed numerical analysis models.
2. Investigating the baselines and adjusted baselines used in the market.
3. Analysis of historical meter data to qualitatively assess the potential of using an alternative baseline logic for a demand response program to impact market price outcomes.
4. Calculating the key average factors for each customer to provide a better general overview for each customer.
5. Considering metadata such as temperature, high- and low degree days (HDD and CDD), heat- and cold wave duration, weekends, and holidays to investigate their impact on improving baselines.
6. Categorising portfolios based on their key factors and providing insight by comparing the customer segmentation for each factor.
7. Assessing baselines based on explainable machine learning models and comparing them with the conventional baselines used in the market.

The project team used three primary datasets for the study:

- AGL dataset comprised of ten (10) C&I customer portfolios
- Gippsland Water Factory dataset
- Greater Western Water dataset

The application of ML techniques for each dataset is explained in the subsequent sections of the report.

2.2. Scope of Work Package-2

Work Package-2 (WP-2) has investigated the barriers to use backup generators in the DR programs. Since it is one of the most cost-efficient ways to add flexible capacity to the power grid, for example, adding a peaking plant such as gas-turbine generator would cost millions of dollars and take years to recover the investment.

In brief, this study has undertaken the following research activities:

1. Conducting consultation meetings with the DNSPs in Victoria to understand the various guidelines they apply for back-up/ embedded generator connections,
2. Reviewing DNSP guidelines for backup generator connections,

3. Reviewing backup generator synchronising mechanisms,
4. Identifying the barriers for using backup generators in DR programs,
5. Investigating the impact of backup generator integration on power grids,
6. Investigating the export limit of backup generators,
7. Exploring the impacts of operating modes of backup generators on power grids,
8. Assessing the feasibility of using biodiesel in backup generators,
9. Proposing recommendations for improving participation of C&I customers in DR programs.

The project team used data and power network models from the CSIRO Medium Voltage Feeder Taxonomy Project [1] to characterise the barries to use back-up generators and investigate various strategies to overcome the barriers.

2.3. Scope of Work Package-3

WP-3 has investigated the use of BESS in DR programs to benefit the C&I customers in terms of electricity cost savings and ROI. DR is one of the most cost-efficient ways to add flexible capacity to the electricity grid as adding a peaking plant, gas-turbine generator for example, would cost millions of dollars and take years to recover the investment.

In brief, this study has undertaken the following research activities:

1. Reviewing existing network tariff structures for C&I customers.
2. Selecting a set of network tariff structures in consultation with the AGL.
3. Developing a BESS optimiser for C&I customers.
4. Analysing the financial viability of the developed BESS optimiser under various case studies.
5. Conducting the network deployment assessment of the developed BESS optimiser.
6. Proposing recommendations to increase the uptake of batteries in DR programs.

2.4. Report Structure

The rest of the report is organised as follows:

Chapter 3 presents the key findings of work package 1,

Chapter 4 presents the key findings of work package 2,

Chapter 5 presents the key findings of work package 3, and

Chapter 6 presents the project recommendations and implementation roadmap.

3. Work Package 1 Key Findings

Work package 1 presents the comparison results of the average baseline (Baseline Type I) and prediction models in terms of prediction accuracy (i.e., ACC) for different C&I customers dataset. The prediction accuracy for each ML model compared to average baseline are also discussed. In this study the following predictive models are used, polynomial linear regression (a nonlinear predictor, denoted as NLR), support vector regression, denoted as (SVR), and Bayesian linear regression, denoted as (BLR). The details of the baseline types and the machine learning techniques are presented in the Appendix A.

3.1. Results: The AGL Dataset

This section presents the comparison results of the average baseline and prediction models in terms of prediction accuracy (i.e., ACC) for the AGL dataset. The prediction accuracy for each ML model compared to average baseline and for both cases are discussed.

3.1.1. Case 0 results

The section presents the accuracy results of predictive and average baseline models using only electricity data, not temperature. For all following models, the historical electricity data over the same time stamp is applied to predict the future event at the same time stamp.

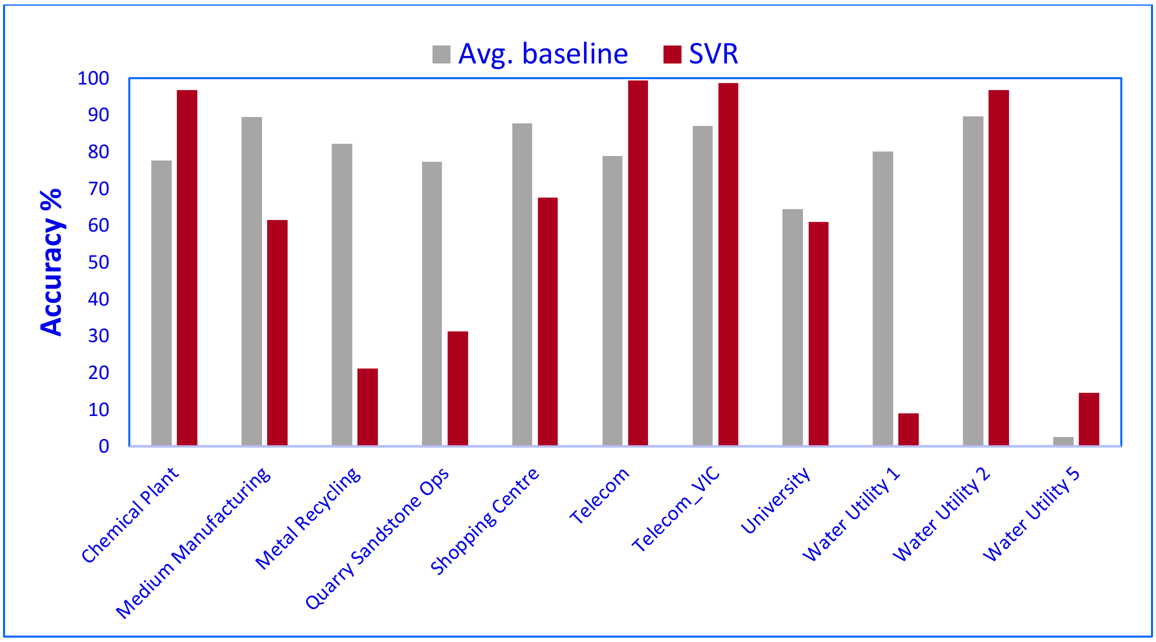


Figure 3-1: Testing accuracy performance for average baseline and SVR model for case 0.

Support vector regression results (SVR)

Figure 3-1 shows the percentage accuracy results on the test set for eleven (11) C&I customers compared to the average (shown as 'Avg. baseline' in plots) baseline model. For some C&I customers, such as (Chemical plant, Telecom, Telecom VIC, Water Utility 2, and Water Utility 5), the SVR performs better than the average baseline model. The overall accuracy on eleven (11) C&I

customers shows that the average baseline model has better performance with an accuracy of 74%, while SVR has an accuracy of 59%.

Bayesian linear regression results (BLR)

Figure 3-2 presents the accuracy results of the BLR model compared to the average baseline model. The BLR model shows better accuracy for 6 out of 11 C&I customers compared to the average baseline. The overall accuracy of the BLR model is 78%, with a 4% margin compared to the average baseline model.

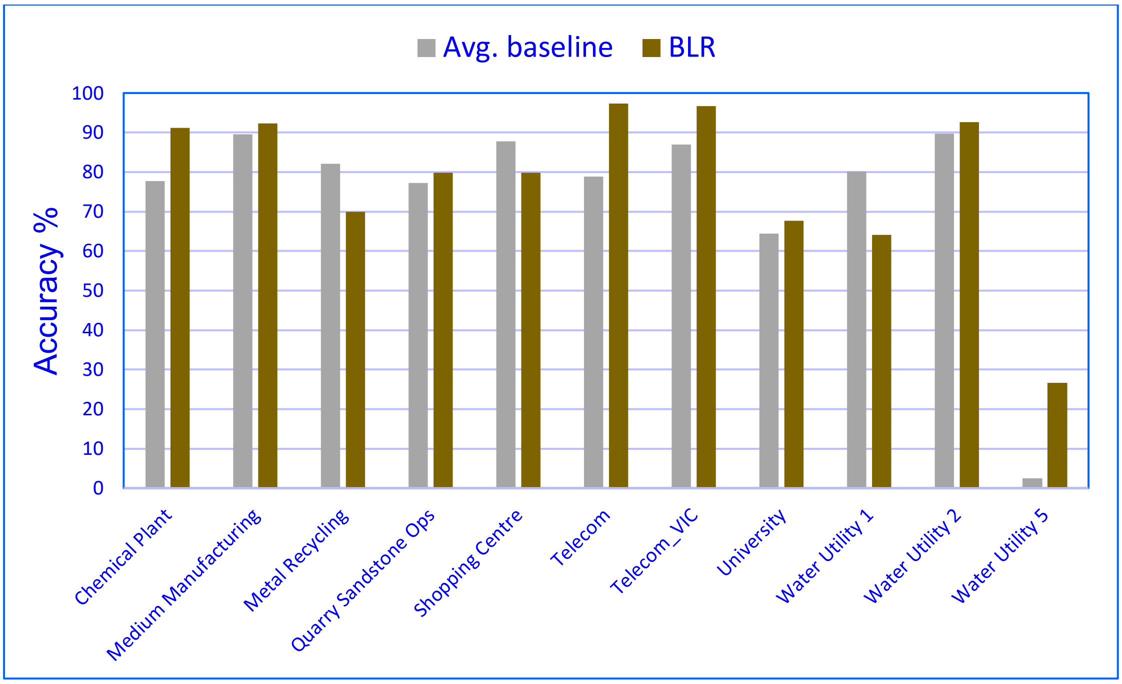


Figure 3-2: Testing accuracy performance for average baseline and BLR model for case 0.

Polynomial regression results (NLR)

Figure 3-3 reports the accuracy of the NLR model compared to the baseline model. The NLR achieves better accuracy for 8 out of 11 C&I customers compared to the average baseline model. There is a 5% margin increase in the overall accuracy (97%) compared to the average baseline model (74%).

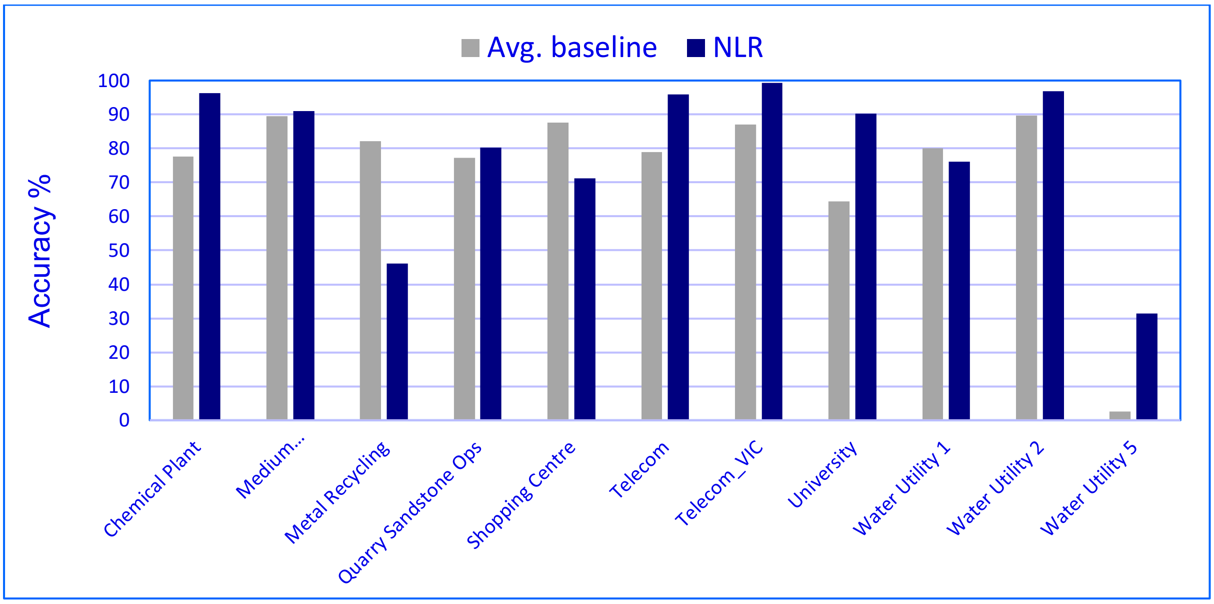


Figure 3-3: Testing accuracy performance over baseline and NLR model for case 0.

In general, we can observe that for the following C&I customers, ML performs better than the average baseline model. Thus, we highly recommend using ML for baseline calculation (e.g. NLR) for the following C&I customers:

- Chemical Plant
- Telecom
- Telecom VIC
- Water utility 2
- Water utility 5

3.1.2. Case 1 results

This section presents the accuracy results of predictive and baseline models using electricity data and maximum temperature data as an exogenous variable[1]. For all the following models, the historical electricity data with maximum daily temperature over the same time stamp is applied to predict the future event at the same time stamp. Figure 3-4 shows the results of the ML models using daily maximum temperature as the exogenous variable for the predictive model. In general, we see there is not much improvement in model performance compared to case 0. The only difference in the performance is observed for the Shopping Centre. Both the NLR and SVR accuracies have improved by including the maximum temperature, as shown in Figure 3-5. The general accuracy of the AGL dataset for case 0 and case 1 is shown in Table 3-1.

[1]Exogenous variable is *a variable that is not affected by other variables in the model.*

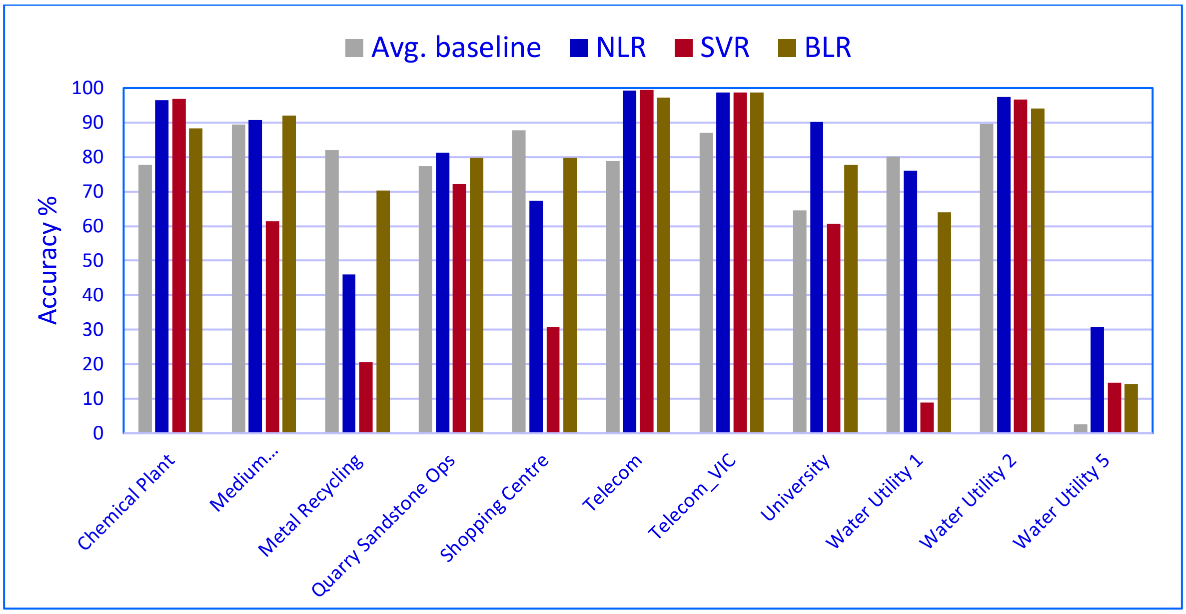


Figure 3-4: Testing accuracy performance over baseline and NLR, SVR, and BLR models for case 1.

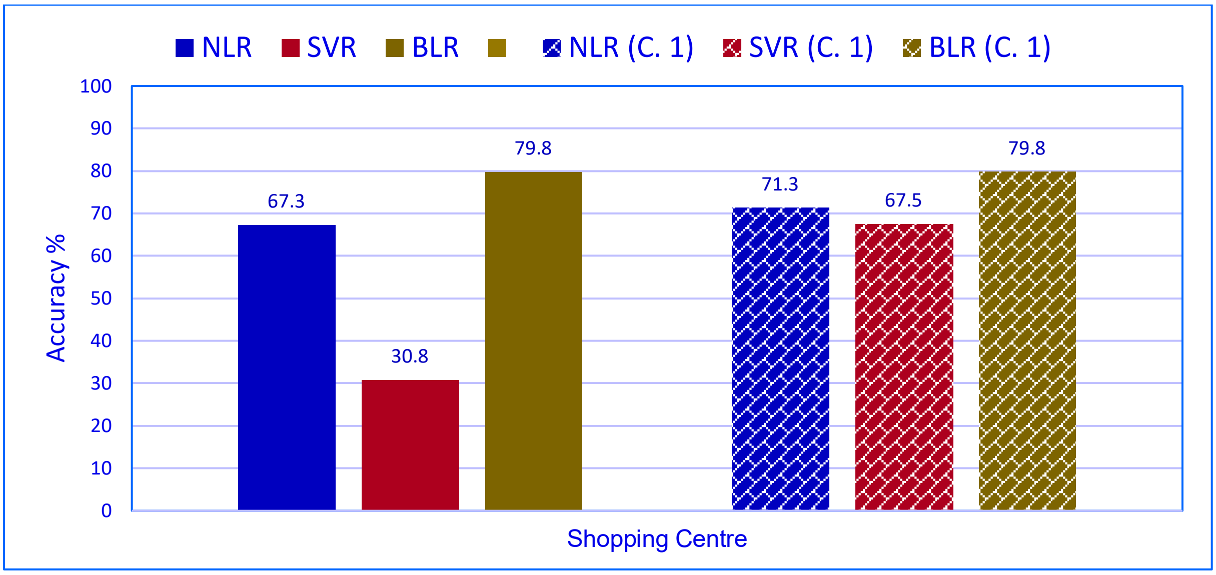


Figure 3-5: The accuracy of the shopping centre for case 0 and case 1 (denoted by C. 1).

Table 3-1: AGL overall accuracy of ML models and baseline for both case 0 and case 1.

Model	Overall Accuracy %	
	Case 0	*Case 1*
Avg. Baseline	74	74.0
NLR	79	79.4
SVR	59	60.0
BLR	78	77.8

3.2. Demand Response Analysis

This section presents an analysis of the ML models for the DR event compared to average baseline models. We choose the best model, i.e., NLR, based on the accuracy presented in the previous section for DR analysis and compared it with the average baseline model. Figure 3-6 shows the DR prediction of the NLR model and baseline model compared to the actual event consumption.

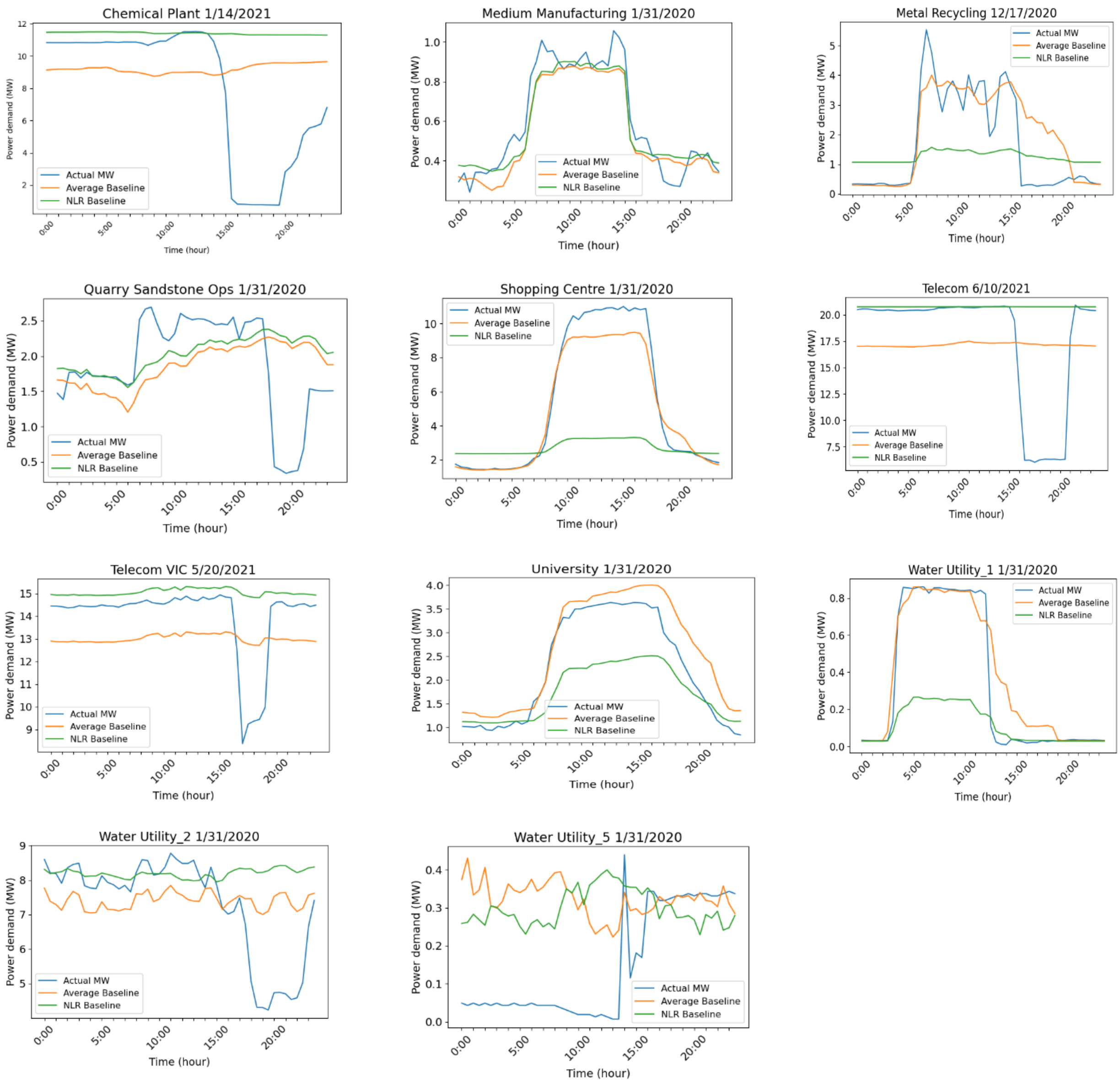


Figure 3-6: Demand response predictions for NLR and baseline on AGL dataset with 11 C&I customers.

We report the demand response percentage difference as follows:

$$DR\ Percentage\ Differnce\ (PD) = \frac{Predicated\ value - Actual\ DR\ value}{Actual\ DR\ value} \quad (1)$$

If the predicted NLR value or the baseline is lower than the actual event value, the demand variance will be negative. Otherwise, it is positive. The positive and negative values reflect if the C&I customer will receive positive or negative benefits by using an ML baseline calculation. Figure 3-7 shows the difference in DR for the Chemical Plant, Medium Manufacturing, and Metal Recycling profiles for NLR and the average baseline model. The symbol ↑ shows that NLR has a more positive benefit than the average baseline model.

Chemical plant					Shopping Centre				
DR event time	NLR		Avg. baseline		DR event time	NLR		Avg. baseline	
	PD	KW difference	PD	KW difference		PD	KW difference	PD	KW difference
1/14/2021 15:30	↑ 9.11	10242.35	↓ 6.96	7982.60	1/31/2020 18:00	↑ -0.53	2994.81	↓ -0.72	4065.80
1/14/2021 16:00	↑ 13.4	10555.24	↓ 10.33	8323.60	1/31/2020 18:30	↑ -0.34	1310.42	↓ -0.59	2268.80
1/14/2021 16:30	↑ 13.45	10533.62	↓ 10.43	8330.60	1/31/2020 19:00	↑ -0.12	339.08	↓ -0.44	1258.80
1/14/2021 17:00	↑ 13.79	10531.81	↓ 10.73	8350.60	1/31/2020 19:30	↑ -0.03	88.43	↓ -0.38	990.80
1/14/2021 17:30	↑ 13.9	10538.75	↓ 10.81	8356.60	1/31/2020 20:00	↑ -0.02	38.72	↓ -0.37	927.80
1/14/2021 18:00	↑ 13.91	10539.65	↓ 10.81	8356.60	1/31/2020 20:30	↑ -0.02	39.99	↓ -0.36	905.80
1/14/2021 18:30	↑ 14.09	10549.08	↓ 10.97	8366.60	Teleco				
1/14/2021 19:00	↑ 14.22	10552.83	↓ 11.06	8372.60	6/10/2021 16:30	↑ 2.34	14557.01	↓ 1.74	10811.30
1/14/2021 19:30	↑ 14.38	10559.42	↓ 11.19	8380.60	6/10/2021 17:00	↑ 2.34	14543.66	↓ 1.73	10799.30
Medium Manufacturing					6/10/2021 17:30	↑ 2.44	14740.59	↓ 1.82	10996.30
1/31/2020 18:00	↑ -0.01	17.08	↓ -0.23	96.20	6/10/2021 18:00	↑ 2.32	14516.82	↓ 1.72	10773.30
1/31/2020 18:30	↑ 0.37	131.69	↓ 0.07	20.80	6/10/2021 18:30	↑ 2.29	14452.83	↓ 1.70	10711.30
1/31/2020 19:00	↑ 0.46	148.52	↓ 0.13	37.80	6/10/2021 19:00	↑ 2.30	14465.30	↓ 1.70	10723.30
1/31/2020 19:30	↑ 0.47	145.22	↓ 0.17	45.80	6/10/2021 19:30	↑ 2.29	14459.83	↓ 1.70	10717.30
1/31/2020 20:00	↑ 0.48	145.55	↓ 0.18	48.80	6/10/2021 20:00	↑ 2.31	14498.21	↓ 1.72	10756.30
1/31/2020 20:30	↑ 0.14	63.23	↓ -0.09	31.20	6/10/2021 20:30	↑ 2.29	14461.77	↓ 1.70	10720.30
Metal Recycling					6/10/2021 21:00	↑ 0.16	2899.83	↓ -0.05	841.70
12/17/2020 15:00	↑ -0.4	2097.17	↓ -0.92	3316.10	6/10/2021 21:30	↑ -0.01	153.48	↓ -0.19	3894.70
12/17/2020 15:30	↑ -0.45	1757.10	↓ -0.91	2902.10	6/10/2021 22:00	↑ 0.01	201.41	↓ -0.17	3539.70
12/17/2020 16:00	↑ 4.21	1104.36	↓ 0.09	24.90	6/10/2021 22:30	↑ 0.01	262.63	↓ -0.17	3477.70
12/17/2020 16:30	↑ 2.2	970.68	↓ -0.04	13.10	6/10/2021 23:00	↑ 0.02	333.38	↓ -0.17	3406.70
12/17/2020 17:00	↑ 2.17	967.84	↓ -0.05	17.10	6/10/2021 23:30	↑ 0.02	354.58	↓ -0.17	3384.70
12/17/2020 17:30	↑ 2.29	985.66	↓ 0.13	33.90	Telco_VIC				
12/17/2020 18:00	↑ 1.74	937.56	↓ 0.02	4.90	5/20/2021 17:00	↑ 0.78	6566.71	↓ 0.54	4525.10
12/17/2020 18:30	↑ 1.18	885.44	↓ -0.01	3.10	5/20/2021 17:30	↑ 0.61	5638.31	↓ 0.40	3664.10
12/17/2020 19:00	↑ 1.34	903.28	↓ 0.01	2.90	5/20/2021 18:00	↑ 0.58	5461.63	↓ 0.38	3532.10
Quarry Sandstone Ops					5/20/2021 18:30	↑ 0.57	5375.39	↓ 0.37	3457.10
1/31/2020 18:00	↑ 0.35	618.01	↓ -0.06	102.10	5/20/2021 19:00	↑ 0.51	5104.59	↓ 0.29	2928.10
1/31/2020 18:30	↑ 4.43	1910.50	↓ 2.85	1228.90	5/20/2021 19:30	↑ 0.04	636.82	↓ -0.11	1529.90
1/31/2020 19:00	↑ 4.89	1900.94	↓ 3.27	1270.90	University				
1/31/2020 19:30	↑ 5.71	1931.47	↓ 3.91	1321.90	1/31/2020 18:00	↑ -0.23	634.43	↓ -0.52	1417.80
1/31/2020 20:00	↑ 5.01	1819.47	↓ 3.57	1296.90	1/31/2020 18:30	↑ -0.20	493.17	↓ -0.46	1104.80
1/31/2020 20:30	↑ 4.92	1859.39	↓ 3.39	1281.90	1/31/2020 19:00	↑ -0.16	345.20	↓ -0.40	861.80
Water Utility_1					1/31/2020 19:30	↑ -0.12	234.91	↓ -0.32	620.80
1/31/2020 18:00	↑ 0.22	5.90	↓ 0.14	3.70	1/31/2020 20:00	↑ -0.09	151.73	↓ -0.26	461.80
1/31/2020 18:30	↑ 0.04	1.32	↓ -0.01	0.30	1/31/2020 20:30	↑ -0.02	32.56	↓ -0.16	253.80
1/31/2020 19:00	↓ -0.03	0.77	↑ 0.02	0.70	Water Utility_2				
1/31/2020 19:30	↓ -0.09	2.88	↑ -0.04	1.30	1/31/2020 18:00	↑ 0.65	3268.01	↓ 0.53	2704.10
1/31/2020 20:00	↓ -0.17	5.85	↑ -0.12	4.30	1/31/2020 18:30	↑ 0.91	3910.23	↓ 0.80	3461.10
1/31/2020 20:30	↓ -0.21	7.87	↑ -0.17	6.30	1/31/2020 19:00	↑ 0.91	3923.64	↓ 0.81	3465.10
Water Utility_5					1/31/2020 19:30	↑ 0.96	4046.64	↓ 0.84	3539.10
1/31/2020 18:00	↓ -0.05	17.51	↑ 0.15	48.80	1/31/2020 20:00	↑ 0.77	3657.70	↓ 0.64	3036.10
1/31/2020 18:30	↓ -0.17	57.39	↑ 0.13	42.80	1/31/2020 20:30	↑ 0.78	3684.39	↓ 0.64	3027.10
1/31/2020 19:00	↓ -0.17	55.88	↑ 0.13	42.80					
1/31/2020 19:30	↓ -0.17	57.91	↑ 0.11	36.80					
1/31/2020 20:00	↓ -0.19	62.74	↑ 0.13	42.80					
1/31/2020 20:30	↓ -0.32	108.27	↑ 0.11	36.80					

Figure 3-7: DR percentage difference (PD) and kW difference between the predicted value using NLR and the average baseline methods and the actual DR value, the green arrows indicate where there is a positive benefit.

The Work Package 1 also analysed the following two datasets. Please refer to Work Package 1 final report for further information[2].

1) Application Case Study: The greater Western Water Dataset
2) Application Case Study: The Gippsland Water Dataset

3.3. A Summary of Key Findings

The WP-1 has made the following findings for each C&I customer group:

- The ML model, namely linear regression (LR) and nonlinear regression (NLR), performs better than the average baseline method with a varying level of significance depending on the customer profiles. Thus, this study recommends using LR and NLR for the baseline calculation for the following C&I customers: chemical plants, telecommunication industry, and water utilities.
- Since LR is much easier to understand than NLR, this study recommends using LR as the baseline model where possible (e.g., water utilities), in which the temperature information can enhance the prediction accuracy of the future energy demand.
- For other C&I customers (e.g., medium manufacturing, metal recycling, sandstone quarry) this study recommends using the average baseline method, since the performance difference is not significant.
- By considering the temperature information, ML models can make more accurate predictions, in particular for water utilities, and shopping centres, as the temperature influences the demand.
- Demand response analysis further shows that more accurate demand predictions provide more potential monetary benefits to C&I customers.

[2] Work Package-1 Final Report is available at https://c4net.com.au/projects/optimisation-of-behind-the-meter-der-generation-assets-within-network-constraints-a-roadmap-to-successful-dr-program/.

4. Work Package 2 Key Findings

Work Package-2 (WP-2) investigated the barriers to use backup generators in the DR programs. As outlined in Section 2, WP-2 has carried out several activities including a review of local, national and international guidelines for embedded generator connections, consultation and feedback meetings with the DNSPs, technical barriers and solutions analysis for backup generators via simulation studies, and use of biodiesel for backup generators. This chapter outlines the key results and findings of WP-2. The WP-2 methodology and summary of DNSP consultation meetings are presented in the Appendix B and Appendix C, respectively.

4.1. Investigation of Technical Barriers for Using Backup Generators in Demand Response

The barriers to backup generator utilisation in demand response schemes are investigated using simulation studies. Three types of barriers are investigated here: 1) network barriers, 2) location-based barriers, and 3) time-based barriers. Load-flow studies are carried out to explore the barriers regarding network and backup generator location. Time-based barriers are investigated with quasi-dynamic simulations and short-circuit calculations to identify the export limit of the backup generators.

4.2. Representative Power Network Used in This Study

4.2.1. Medium voltage feeder taxonomy project

The network models provided in the CSIRO Medium Voltage Feeder Taxonomy Project [1]-[2] are used as representative network models in this study. The Medium Voltage Feeder Taxonomy Project provides 19 networks across central business district (CBD), urban, short rural and long rural areas. The networks include typical elements of the Australian distribution network, i.e., residential, commercial, agricultural, industrial, mining loads.

Among the networks, four clusters are selected considering the following aspects: (1) covering both short rural and urban areas; (2) covering both commercial and industrial customers; (3) covering both NSW and VIC locations; (4) with a smaller number of busbars for ease of analysis and simulation. Therefore, the following four clusters are selected and listed in the sequence of size from small to large: (1) Urban-NSW1 (cluster 14); (2) Urban-NSW2 (cluster 15), (3) Urban-VIC (cluster 12); (4) Short rural-NSW (cluster 8). The details of these clusters can be found on WP-2 final report[3].

4.3. Impacts of Backup Generator Integration on the Power Grid

The following four clusters: (1) Urban-NSW1 (cluster 14); (2) Urban-NSW2 (cluster 15), (3) Urban-VIC (cluster 12); (4) Short rural-NSW (cluster 8) are analysed to investigate the impacts of

[3] Work Package-2 Final Report is available at https://c4net.com.au/projects/optimisation-of-behind-the-meter-der-generation-assets-within-network-constraints-a-roadmap-to-successful-dr-program/.

the backup generators. However, only urban-NSW1 (cluster 14) results are presented here. Please refer to the WP 2 final report for all other clusters results[3].

4.3.1. Impact of backup generator location

Three backup generator locations are investigated in this section, i.e., the beginning of the feeder, the middle of the feeder, and the end of the feeder. The power output of the backup generator is 50% of the total load in the feeder. The voltage of the terminals with loads along the feeder from upstream to downstream is presented in Figure 4-1.

The voltage profiles of cluster Urban-NSW1 indicates that if there is no backup generator, the terminal voltage decreases from upstream to downstream. When the backup generator is connected to the beginning of the feeder, the voltage performance of the network is similar to the situation that no backup generator is connected. When the backup generator is connected at the middle of the feeder, the voltage profile has improved, i.e., the voltage drop has reduced. If the backup generator is connected at the end of the feeder, the terminal voltage can be improved further, especially at the end of the feeder (near the backup generator). The voltage increase around the end of the feeder indicates that the power output of the backup generator is higher than the load demand at the downstream of the feeder, and the power flow is reversed (from downstream to upstream) at the downstream of the feeder. Therefore, the location of the backup generator has impact on the network voltage profile. The installation of backup generator can help reduce the voltage drop along the feeder. Moreover, when the backup generator is connected at the end of the feeder, the improvement is more significant than other locations.

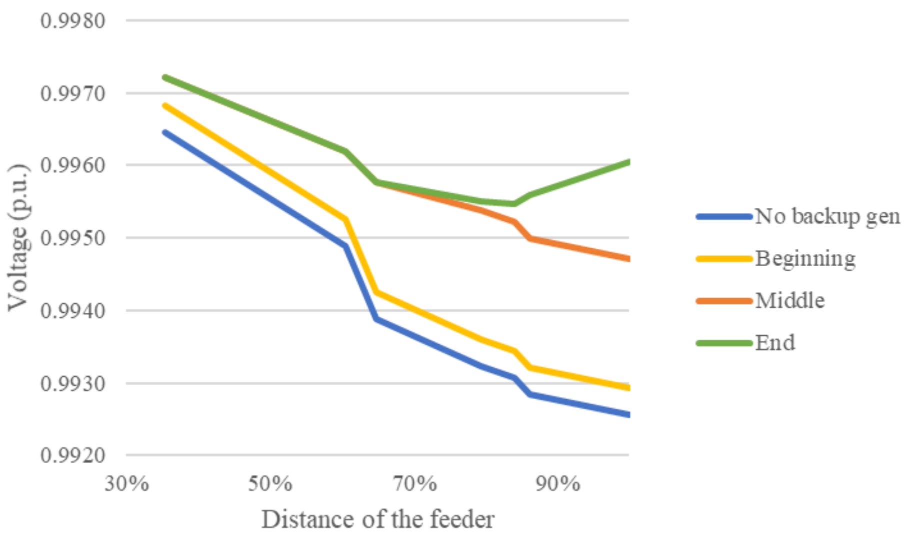


Figure 4-1: Terminal voltage of Urban-NSW1 with different backup generator locations.

4.3.2. Impact of backup generator power export

The impact of backup generator power export is investigated by comparing voltage profiles under different backup generator power outputs such as 10%, 20% and 50% of the rated load in the network. To show the significance of each scenario, the backup generator is connected at the end of the feeder. The voltage profiles of the four networks are shown in Figure 4-2. It can be noticed that the voltage support provided by the backup generator not only increases the voltage of the terminals around the backup generator but also enhances the voltage of the entire feeder. Moreover, with the increase of backup generator power output, the voltage profile along the feeder increases more significantly.

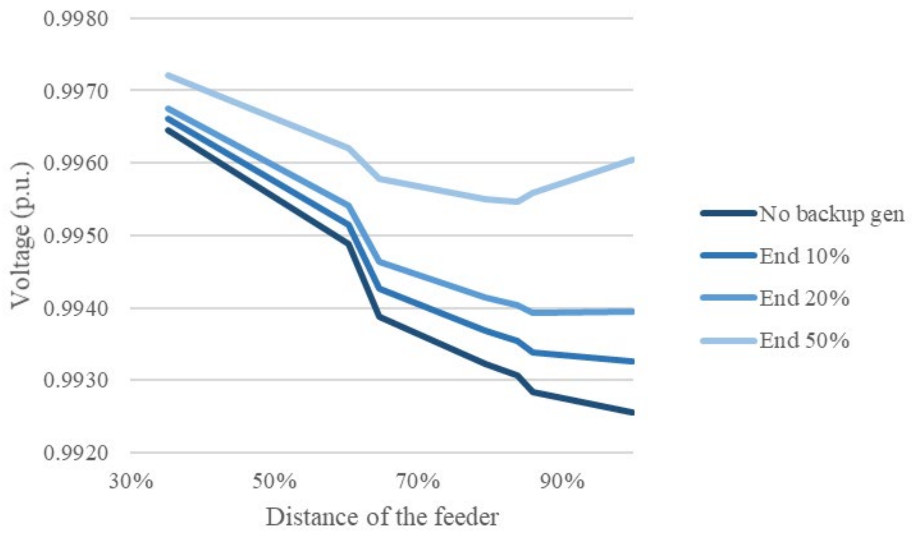


Figure 4-2: Terminal voltage of Urban NSW1 cluster with different backup generator power.

4.3.3. Impact of system loading

In this section, a comparison between different system loading is conducted, as shown in Figure 4.9. The power of each load in the system are set to be: (1) 100% of the rated load (blue lines), and (2) 50% of the rated load (yellow lines). The backup generator is connected at the end of the feeder, and the backup generator power output is increased in steps, such as 10%, 20% and 50% of the total rated load in the network.

According to voltage profiles in Figure 4-3, the yellow lines are above the blue lines. Therefore, when the system loading is lower (i.e., 50% of rated load), the voltage profile is higher, i.e., the voltage drop is lower. The reason is that per-length voltage drop reduces due to decrease in current flow in the feeder under low loading conditions. Moreover, with the same backup generator, the voltage increases by the same amount as the system loading varies. For example, in the Urban-NSW1 network, the backup generator generating 50% of the total rated load, and that can improve its terminal voltage from 0.9926 p.u. to 0.9960 p.u. (0.0034 p.u. increment) under 100% system loading. While under 50% system loading, the backup generator producing 50% of the total rated load can improve its terminal voltage from 0.9963 p.u. to 0.9997 p.u. (0.0034 p.u. increment).

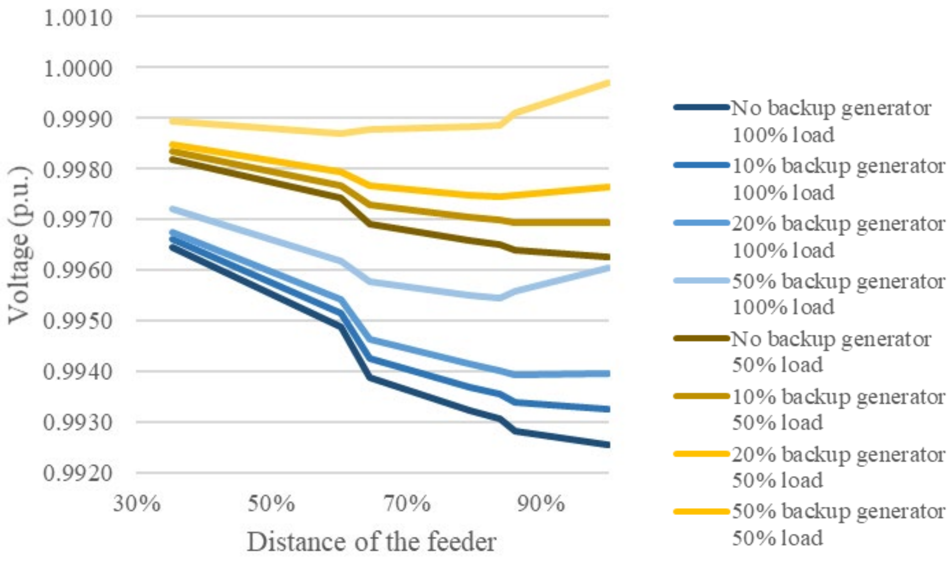


Figure 4-3: Terminal voltage of Urban NSW1 cluster with different system loading.

4.4. Investigation of Dynamic Export Limits in Different Scenarios

The power output of backup generator is limited due to multiple reasons: (1) the physical power limitation of the generator, (2) the limitation of the voltage in the network, (3) the thermal limitation of cables in the network and (4) the limitation of the short-circuit current in the network. In this section, the limitations relating to the network are explored. The physical power limitation of the generator is not considered here.

In the quasi-dynamic simulations, the power profiles of each load hours are required. In the Medium Voltage Feeder Taxonomy Project, the 62-day power profiles for loads in Urban-NSW1 are provided. Both power consumption and solar power generation are included in the load power profile, and both are time-variant values. Therefore, the net power of the load can be positive or negative. Positive value indicates the power consumption is more than the solar power generation at a given time instance, while the negative value means the solar power generation is more than the power consumption. For example, the net power profile of one load in the Urban-NSW1 network is shown in Figure 4-4.

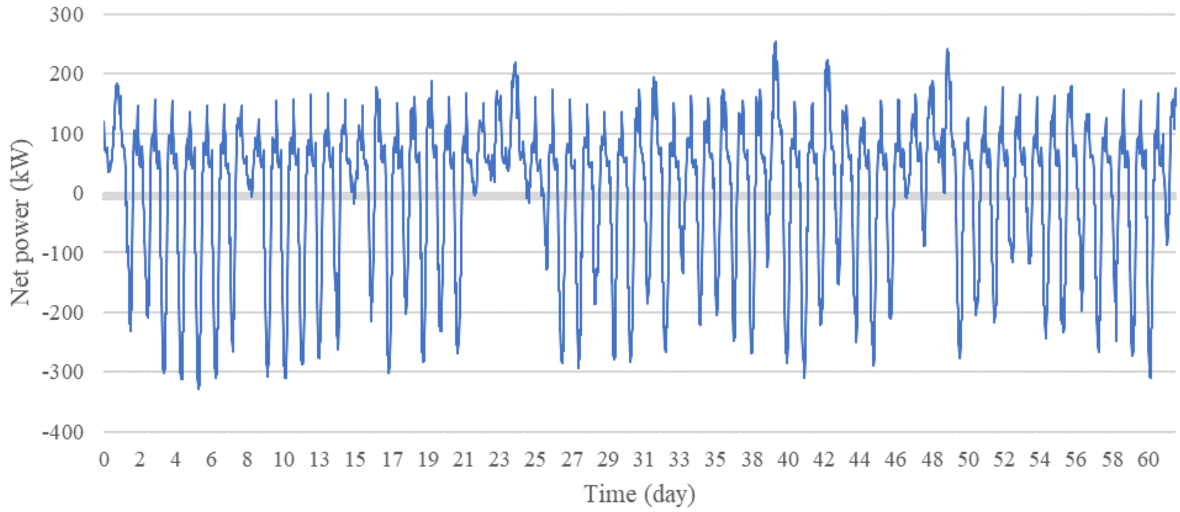


Figure 4-4: Net power profile of one load in Urban-NSW1 network.

According to the IEC Standard 61000.3, the voltage of the busbars in a MV network (11 kV or 22 kV) should be maintained in the range of 0.9 to 1.06 p.u. under steady-state conditions. According to the quasi-dynamic simulation results for 62 days, the highest busbar voltage is achieved on day 6. The profiles of each load are presented in Figure 4-5. The highest voltage is achieved at terminal 17 (at the end of the feeder). The voltage profile of terminal 17 is presented in Figure 4-6, where the highest voltage is 1.013 p.u. at 11:30.

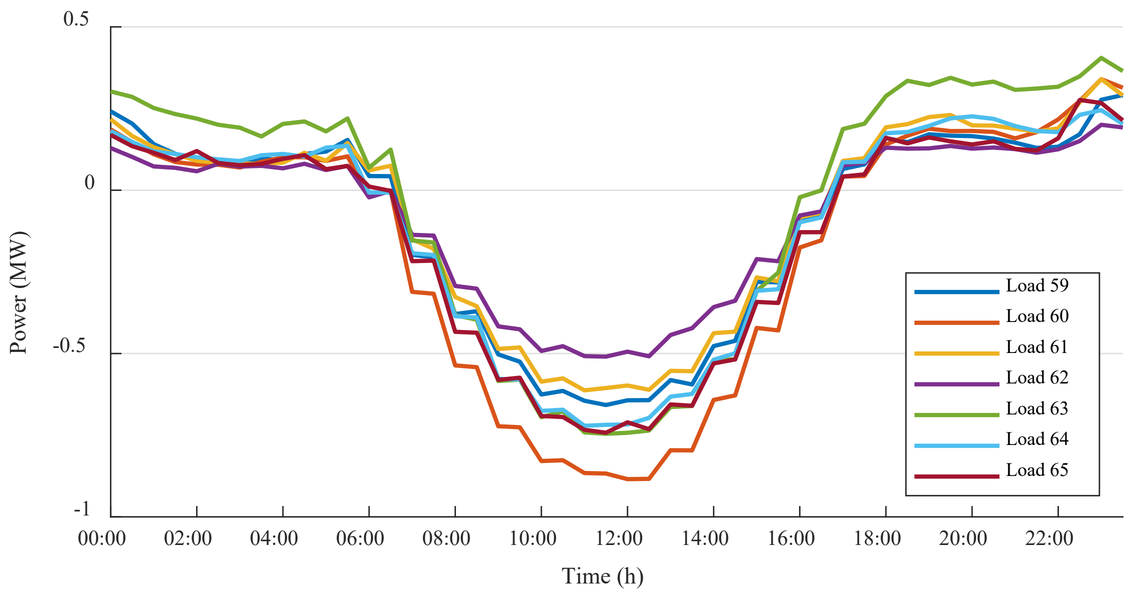


Figure 4-5: Load profiles of Urban-NSW1 network on day 6.

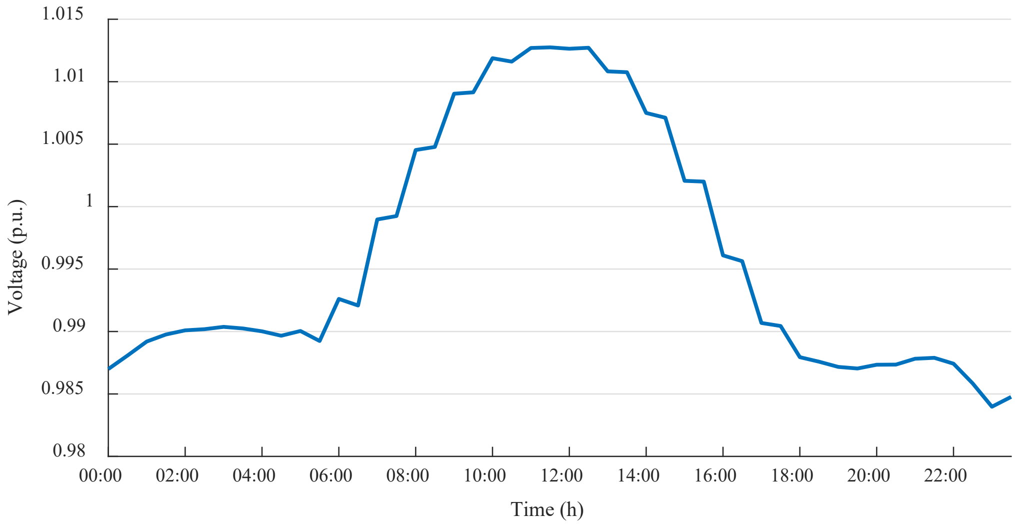


Figure 4-6: Voltage profile of terminal 17 on day 6.

On day 6, the dynamic export limit of backup generator based on voltage limit is illustrated in Figure 4-7. Around 12:00 when the solar power is high, the export limit is 8 MW, and the export limit increases to 11.5 MW during night-time.

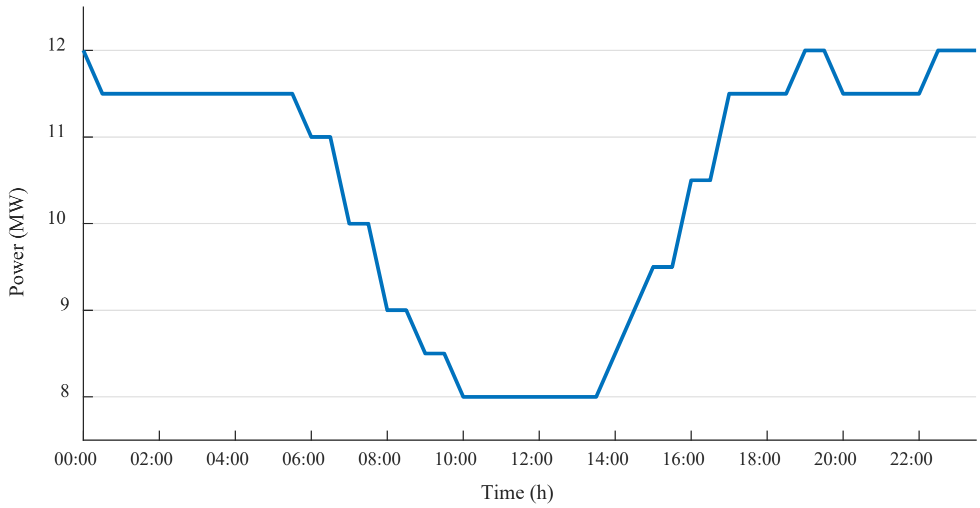


Figure 4-7: The dynamic export limit of a backup generator on day 6 based on the voltage limit.

According to the quasi-dynamic simulation results for 62 days, the lowest busbar voltage was recorded on day 49. The profiles of each load on day 49 are presented in Figure 4-8. The lowest voltage was recorded at terminal 17 (at the end of the feeder). The voltage profile of terminal 17 is presented in Figure 4-9, where the lowest voltage is 0.977 p.u. at 18:00.

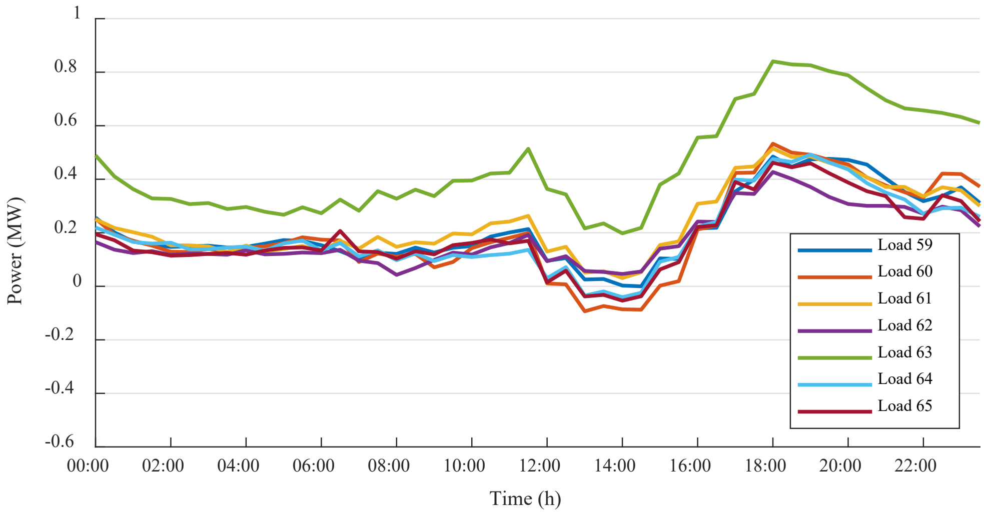


Figure 4-8: Load profiles of Urban-NSW1 network on day 49.

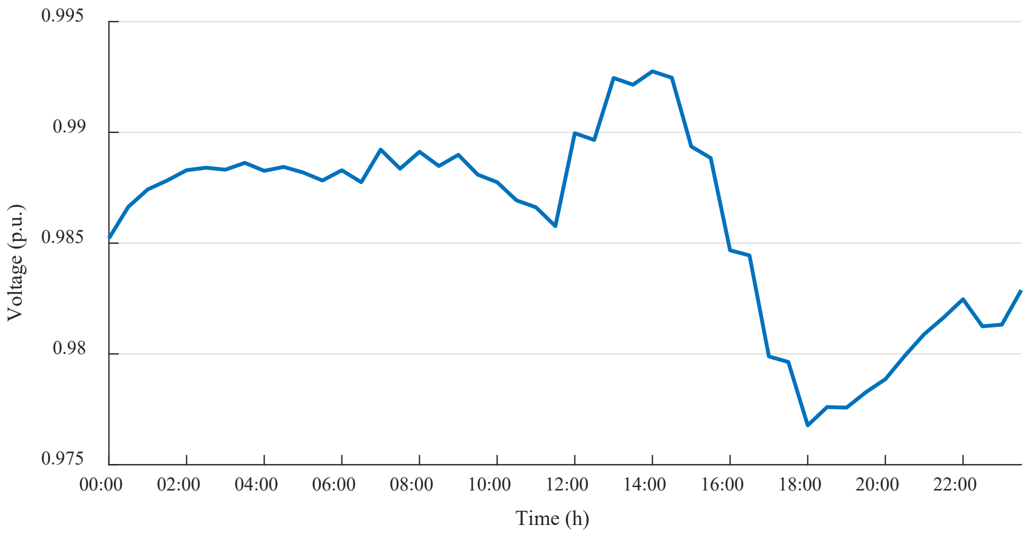


Figure 4-9: Voltage profile of terminal 17 on day 49.

On day 49, the dynamic export limit of backup generator based on voltage limit is illustrated in Figure 4-10. During peak load hours (around 18:00), the export limit of backup generator can go high as 13 - 13.5 MW. In off-peak hours (around 14:00), the export limit has reduced to 11 MW.

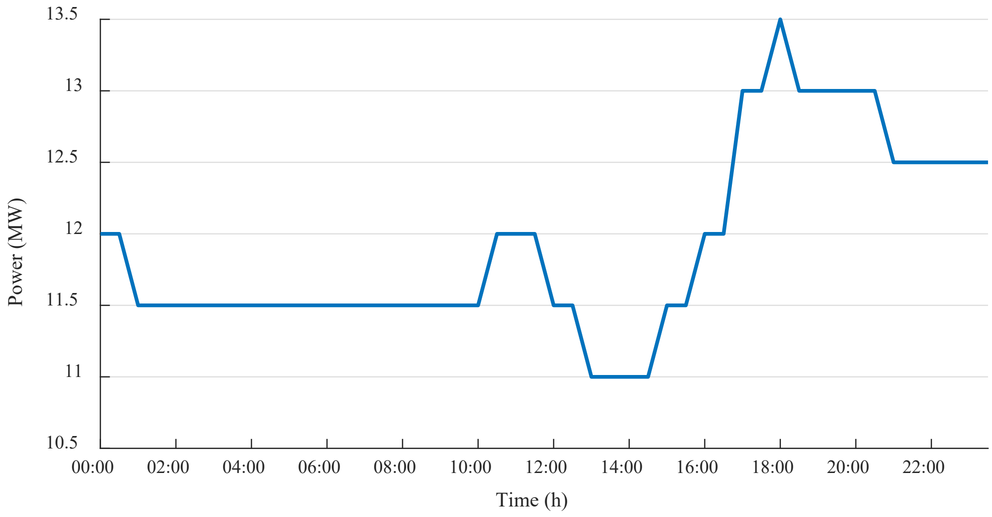


Figure 4-10: The dynamic export limit of backup generator on day 49 based on voltage limit.

By comparing the dynamic export limit on day 6 and day 49, it can be noticed that the limit on day 6 is lower, which means the power output range for the backup generator is narrower. Since day 6 is the day with the highest terminal voltage, less power output is allowed to be exported from the backup generator to maintain the network voltage within limits. Therefore, the dynamic export limit calculated on day 6 should be followed to ensure the voltage stays within limits on any day. Dynamic export limits for only day 6 are presented for other networks.

4.4.1. Thermal limit

Thermal limit defines the limitation due to the network's thermal capacity of lines and transformers. The loading of each line and transformer in the network should be lower than 100% to avoid damage to any equipment. For the representative networks used in this study, the line loading limit is achieved earlier than the transformer loading limit when increasing the backup generator power output. Therefore, here, export limits of backup generators are calculated according to the network's maximum line loading and maintained it should be maintained below 100% loading at every time.

For Urban-NSW1 network, the maximum line loading is achieved on day 6 at line 16. The loading of line 16 is presented in Figure 4-11, and the maximum loading is 87% at noon. The line loading is lower during evenings.

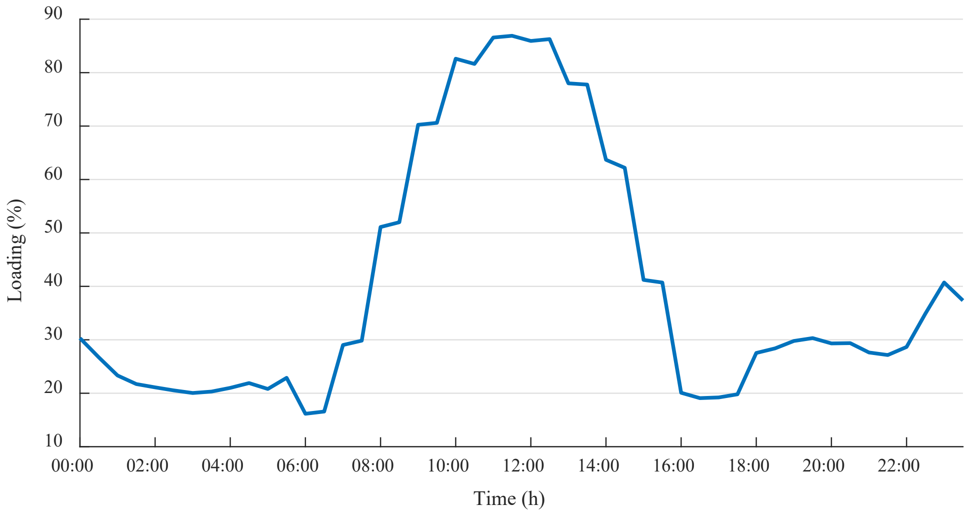


Figure 4-11: The loading of line 16 on day 6.

The dynamic export limit of the backup generator located at the end of the network is shown in Figure 4-12. At noon when line loading is higher, the export limit of the backup generator is relatively lower (1.5 MW, 146% of the rated network capacity 1.029 MVA) to avoid exceeding the thermal limit. At night, the output power of the backup generator can increase up to 4.5 MW.

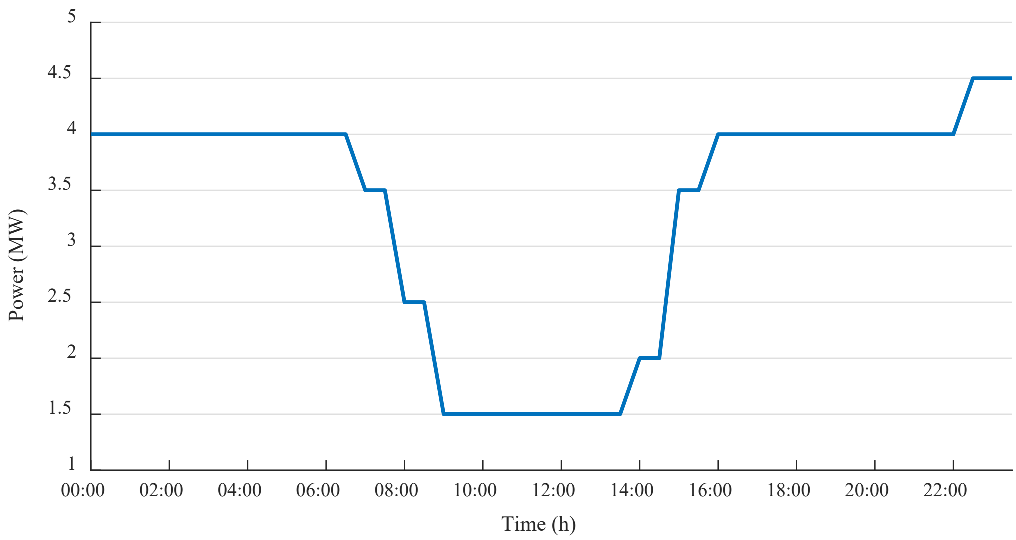


Figure 4-12: The dynamic export limit of the backup generator based on thermal limit.

4.4.2. Short-circuit current limit

The power grid equipment (e.g. switchgear) are typically designed to withstand a specific short-circuit current level. The fault-level or short-circuit capacity is calculated by (1), where $V_{nominal}$ is the nominal voltage (kV) of the network and I_f is the short-circuit current (kA).

$$Fault\ level\ (\text{MVA}) = \sqrt{3}V_{nominal}.I_f \qquad (2)$$

According to the distribution and transmission codes [3]-[4], the maximum fault levels and short-circuit levels under each voltage level are listed in Table 4-1. Since the test networks used in this study are 22 kV and 11 kV, they have short-circuit levels of 13.1 kA and 18.4 kA, respectively.

Table 4-1: The maximum fault levels and short-circuit levels under each voltage level.

Voltage Level	System Fault Level	Short Circuit Level
220 kV (TNSP)	15,000 MVA	40.0 kA
66 kV (TNSP&DNSP)	2,500 MVA	21.9 kA
22 kV	500 MVA	13.1 kA
11 kV	350 MVA	18.4 kA
230 V, 400 V, 460 V	36 MVA	50 kA
Residential 400 V	7 MVA	0 kA (phase to phase)
Residential 230 V, 460 V	1.4 MVA	6 kA (phase to ground)

Please refer to WP-2 final report for the datasheet of the generator model and the generator parameters. The short-circuit analysis is conducted to explore whether the backup generator will cause a higher short-circuit current beyond the maximum stipulated limit. The short-circuit analysis results for the Urban-NSW1 network are presented in Table 4-2.

When there is only one generator connected at the beginning of the feeder, the short-circuit current caused by the short-circuit event happening at the generator terminal is 1.218 kA. If the generator is located at the middle of the feeder and the end of the feeder, the short-circuit currents are 1.11 kA and 1.059 kA, respectively. By comparing with the short-circuit current limit (18.4 kA for 11 kV network), the short-circuit current in Urban-NSW network is much lower than the limit when one backup generator is connected. If the number of backup generator is increased by connecting more generators in parallel, the short-circuit current increases. For example, when the backup generator is connected at the end of the feeder, the short-circuit current is 1.059 kA for one generator, 1.705 kA for two generators and 2.131 kA for three generators. It can be noticed that the increase of short-circuit current is nonlinear, and the increment reduces with the increase of generator capacity.

Table 4-2: Results of short-circuit analysis with network Urban-NSW1.

Number. of paralleled generators	Rated capacity (MVA)	Percentage of feeder capacity	Short-circuit current (kA)		
			Location of backup generator		
			Beginning	Middle	End
1	1.4	136%	1.218	1.114	1.059
2	2.8	272%	2.181	1.862	1.705
3	4.2	408%	2.961	2.393	2.131

If the number of generators is increased further, the short-circuit current values are plotted in Figure 4-13. It can be observed that even if the capacity of backup generator is 50 times of the total feeder capacity, which is much higher than the required capacity for demand response, the short-circuit current limit is not exceeded. Therefore, the short-circuit current limit will not influence the export limit of the backup generator.

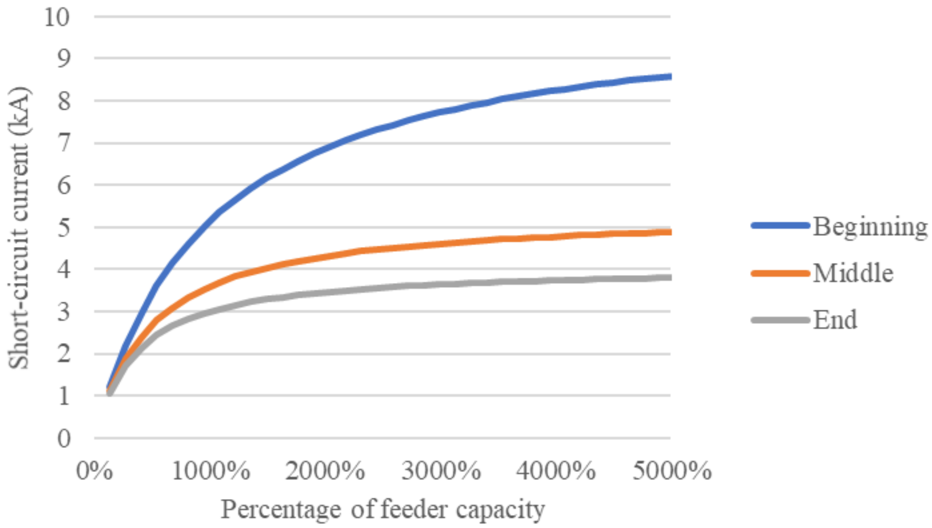


Figure 4-13: Short-circuit current of Urban-NSW1 with increase of backup generator capacity.

4.4.3. Dynamic export limit of a backup generator

According to the simulation results and above analysis, the dynamic export limits of backup generators in the representative networks are mainly constrained by the voltage limit and the thermal limit. The power ranges of the dynamic export limit for each network are summarised in Table 4.3. The dynamic export limit calculated with the thermal limit is lower than the export limits calculated with the voltage limit. Therefore, to avoid exceeding the thermal limit of cables in the network, the dynamic export limit calculated with the thermal limit should be followed.

Table 4-3: Range of dynamic export limit of backup generators.

Power range	Urban-NSW1	Urban-NSW2	Urban-VIC	Short rural-NSW
Voltage limit	8-12 MW	16-17.5 MW	19-26.5 MW	2-4.5 MW
Thermal limit	1.5-4.5 MW	1.5-6 MW	2.5-12 MW	0.5-4 MW

If the export limit of a backup generator is a static value, the static value can should be the lowest value of the dynamic export limit in a day. For example, for the backup generator in the Urban-NSW1 network, the static export limit should be no more than 1.5 MW. Otherwise, the thermal limit will be exceeded at noon. A comparison between the static export limit and dynamic export limits is presented in Table 4.4. In the table, the energy generated by the backup generator under tow limitations are calculated. It is obvious that by applying dynamic export limit, the backup generator can export more energy to the network, and the improvement is more than 100%.

Table 4-4: Generated energy of backup generator under different limits.

Generated energy	Urban-NSW1	Urban-NSW2	Urban-VIC	Short rural-NSW
Static limit	36.00 MWh	36.00 MWh	60.00 MWh	12.00 MWh
Dynamic limit	79.75 MWh	115.25 MWh	202.25 MWh	75.25 MWh
Improvement	122%	220%	237%	527%

4.5. Flexibility of Operating Modes

Backup generators can operate under different operating modes to control the active and reactive power output. In this section, two commonly used operating modes are investigated and compared their demand response performance.

4.5.1. P-V control mode

Under P-V control mode, the active power output and terminal voltage of the backup generator are directly controlled. The terminal voltage and output current are measured, and the output active power can be calculated. The active power and terminal voltage are required for the generator controller to regulate the current on d and q axes and reach the active power and terminal voltage setpoints.

4.5.2. P-Q control mode

The setpoints of active power and reactive power are 1 MW and 0 MVar, respectively. Therefore, the active and reactive power output of the backup generator are constant. The terminal voltage with the backup generator is time-variant and is higher than the voltage without the backup generator.

4.5.3. Summary of operating modes

The results for each representative networks are listed in Table 4-5. For all networks, the setpoints are P=1 MW, V= 1.0 p.u. for P-V control; P=1 MW, Q = 0 MVar for P-Q control. Since the reactive power and the terminal voltage are time-variant in P-V control and P-Q control, respectively, their maximum values are listed as well. It can be observed that the maximum line loading in the network is higher with P-V control compared with the P-Q control strategy.

Table 4-5: Summary of simulation results under different operating modes.

Operating mode	Parameters	Urban-NSW1	Urban-NSW2	Urban-VIC	Short rural-NSW
P-V control	Maximum reactive power	1.88 MVar	0.64 MVar	3.87 MVar	1.85 MVar
	Maximum line loading	115%	95%	93%	118%
P-Q control	Maximum terminal voltage	1.02 p.u.	1.00 p.u.	1.01 p.u.	1.04 p.u.
	Maximum line loading	104%	93%	86%	105%

In summary, with P-V control: (1) the terminal voltage of the backup generator is accurately controlled at a constant value, (2) the maximum line loading in the network is increased; while with P-Q control: (1) active and reactive power output of the backup generator are accurately controlled, (2) with constant P and Q setpoints, the terminal voltage is time-variant.

4.6. Feasibility Study of Using Biodiesel for Backup Generators

As part of the study biodiesel was examined as an alternative fuel to the standard fossil fuel of diesel. The following are the key advantages identified.

4.6.1. Technical Barriers to Biodiesel Generation

Biodiesel has different physical characteristics than fossil diesel. Cloud point and pour point are the two important parameters to describe the fuel state under low temperatures. If the temperature is lower than the cloud point, the crystals are visible, and the fuel becomes cloudy. If the temperature is below the pour point, the fuel becomes semi-solid, and its fluidity is reduced [5].

The cloud and pour points of different biodiesel types are presented in Table 4-6. It can be noticed that the cloud point and pour point for different biodiesels are different. Since biodiesel can have a combination of sources, the cloud and pour points of biodiesel are in a range. The cloud and pour points of diesel are -4 °C and -18 °C, respectively [6]. By comparing the cloud and pour points of biodiesel and diesel, it can be observed that biodiesel has a higher pour point. Thus, the fluidity of biodiesel is lower than diesel in cold weather. Therefore, the operation environment of biodiesel generators is more critical than diesel generators, and extra equipment may be required in cold weather.

Table 4-6: Cloud point and pour point of biodiesels [5].

Biodiesel type	Cloud point (°C)	Pour point (°C)
Sunflower	−3	−6
Soybean	2	−2
Peanut	5	–
Rapeseed	−2	−9
Palm	13	11
Mahua	–	6
Jatropha	–	6
Karanja	–	7
Rice bran	9	−2
Croton	−4	−9
Oleander	12	3
Neem	9	2
Pungam	6	–
Sesame	−6	−14
Pumpkin	−2	−8
Canola	–	−8

4.6.2. Supply-Chain of Biodiesel

Biodiesel availability in Australia

Biodiesel is available in Australia. Multiple producers produce biodiesel locally in Australia. Biodiesel Industries in Australia produce biodiesel with cooking oils. It has been in operation since 2003. The production capacity is 20 million litres per annum [7].

Macquarie Oil produces biodiesel via poppy oil [8]. Ecofuel is another company producing biodiesel. In their current key project MP Biodiesel Project, Ecofuel uses canola oil and canola meal in biodiesel production. Initial fuel production will be approximately 1,000,000 litres per annum, which will increase to 2,000,000 litres per annum in the future [9].

Biodiesel produced by Ashoil in WA is sold under contract to Rio Tinto Iron Ore for use in their drill and blast operations [10]. The biodiesel production facility of Ecotech has been in operation since May 2006. It can produce up to 30 million litres, and a second facility can increase the production to 75 million litres [11].

One of the largest biodiesel production plants is Barnawatha BDI biodiesel plant of Just Biodiesel Pty Ltd, which was formed in 2018. The Barnawartha plant can produce up to 50 million litres of biodiesel annually, including B5, B20 and B100 fuels [12].

The biodiesel producers are summarised in Table 4-7 according to [13].

Table 4-7: Biofuels production facilities available in Australia [13].

Biofuel plant	Location	Owner (*BAA member)	Capacity (ML/year)	Feedstocks
ARFuels Barnawartha	Barnawartha, VIC	Australian Renewable Fuels*	60	Tallow, used cooking oil
ARFuels Largs Bay	Largs Bay, SA	Australian Renewable Fuels*	45	Tallow, used cooking oil
ARFuels picton	Picton, WA	Australian Renewable Fuels*	45	Tallow, used cooking oil
ASHOIL	Tom Price, WA	Ashburton Aboriginal Corporation*	Unknown	Used cooking oil
Biodiesel industries	Rutherford, NSW	Biodiesel Industries Australia Pty Ltd*	20	Used cooking oil, vegetable oil
EcoFuels Australia	Echuca, VIC	EcoFuels Australia Pty Ltd.	1.5	Canola oil
EcoTech BioDiesel	Narangba, QLD	Gull Group*	30	Tallow, used cooking oil
Macquarie oil	Cressy, TAS	Macquarie Oil Co.	15	Poppy oil and waste vegetable oil
Neutral fuels	Dandenong, VIC	Neutral Fuels (Melbourne) Pty Ltd	Unknown	Used cooking oil
Territory biofuels	Darwin, NT	Territory Biofuels Ltd.	140	Refined, palm oil, tallow, waste oil

Since back-up generators are deployed only for small number of hours to provide DR, the current production capacity is adequate to cater the biodiesel demand for back-up generators.

Biodiesel supply chain in Australia

The major elements in the biofuel supply chain are: (1) farms, (2) storage facilities, (3) biorefinery plants, (4) blending facilities, (5) retail outlets, and (6) transportation [14]. Biodiesel farms are listed in the previous section, such as ARFuels, ASHOIL, EcoFuels Australia, EcoTech Biodiesel, etc.

The major bulk storage facilities in Australia are Ampol, BP Australia, Viva Energy and Chevron Australia [15]. Ampol provides biodiesel suitable for cold weather [16]. BP Australia provides diesel blends with up to 5% biodiesel [17] as well as commercial customer services. Viva energy is actively engaged in the biodiesel industry. It has storage facilities and blending facilities. Viva energy is also the primary distribution partner of the Just Biodiesel Pty Ltd [18]-[19].

Australia has biorefinery plants in Queensland developed by Oceania Biofuels. This biorefinery plant can produce more than 350 million litres of biofuel annually [20]. Future Energy Australia (FEA) also developed its renewable diesel biorefinery project at Narrogin with support from the Western Australian government [21].

Caltex is Australia’s leading company providing biodiesel blends. It blends and distributes varieties of biodiesel blends [22]. Bioworks supply B20, B100 biodiesel and custom blends [23]. Biodiesel is available from the major fuel retailers in Australia, e.g., Ampol, Mobil [24], BP [17], Caltex, and Shell [25]. Mobil fuels are available in Mobil stations and 7-eleven stations. BP and Shell sell biodiesel blends up to 5%. Refuelling Solutions [26] and Viva energy are large fuel transportation service providers. They are the main distribution partner of the biodiesel farm Just Biodiesel Pty Ltd [27]. Bioworks also delivers biodiesel blends [23].

Therefore, Australia has a strong supply chain to produce, store and distribute biodiesel blends to consumers.

4.6.3. GHG Emissions from Biodiesel

Using biodiesel as a neat fuel or blended with conventional diesel will result in significant emission reduction. For example, biodiesel can reduce carbon emissions between 40 - 78% [28] compared with conventional diesel. Figure 4-14 illustrates the greenhouse gases (GHG) emissions from several biodiesel types (e.g. Soy biodiesel, Canola biodiesel, and Tallow biodiesel) and conventional diesel. The GHG emission from baseline conventional diesel is 94.4 g CO2e/MJ, while the soy biodiesel total GHG emission is 29.52 g CO2e/MJ, which is 68.7% lower than the baseline conventional diesel. Moreover, all three biodiesel types can reduce GHG emissions between 64.88 - 73.7 g CO2e/MJ compared with conventional diesel [28].

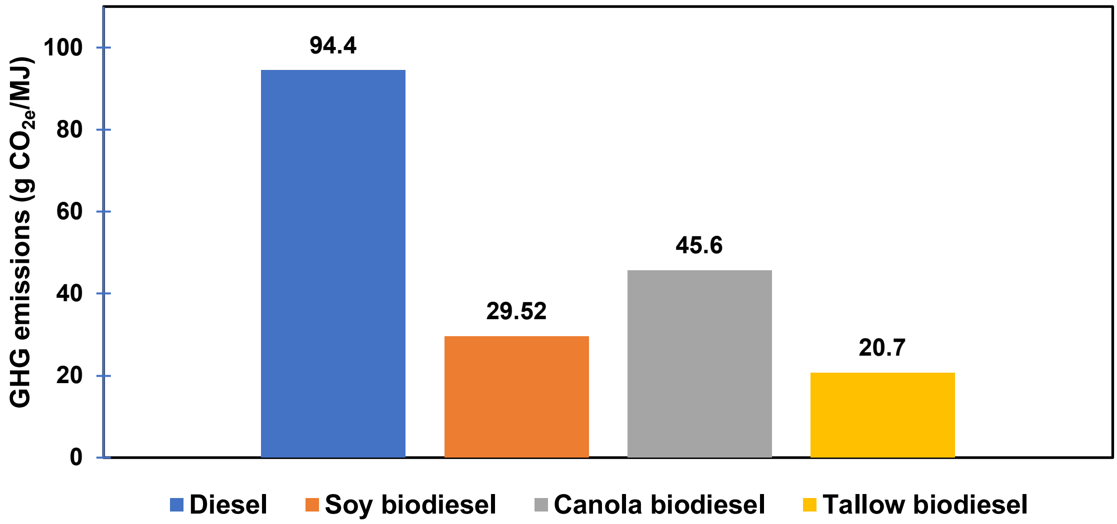
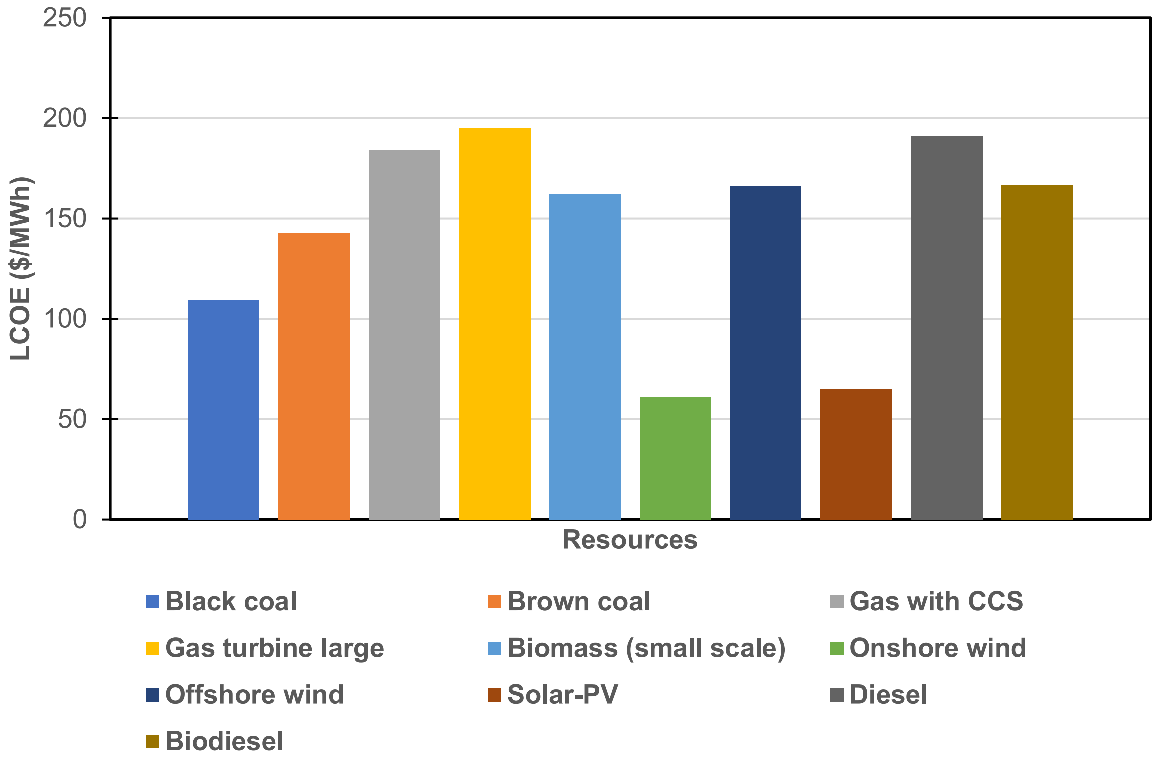


Figure 4-14: Overall GHG emissions of conventional diesel and several biodiesel types [28].

4.6.4. Economics of Biodiesel - Levelised Cost of Electricity

Investment in electricity generation sources requires an assessment of the economic competitiveness of generation technologies and that is determined as part of the system modelling process. The investment decision is determined by a parameter called the levelised cost of electricity (LCOE). The LCOE refers to the cost of generating electricity by a given system, including all costs over its lifetime, such as initial investment, operations and maintenance, fuel cost, and capital cost. Figure 4-15 illustrates the LCOE for several generation sources in the NEM. The LOCE for black coal, brown coal, gas with carbon capture and storage (CCS), large gas turbine, biomass, onshore wind, offshore wind and solar-PV are taken from the CSIRO Gen. Cost Report [29]. The LOCE of diesel and biodiesel were estimated from [30] and [31], as they were not available in the CSIRO Gen. Cost Report or any other reliable source.



*Based on the 2021 LCOE high values in CSIRO Gen. Cost Report.

Figure 4 15: The LCOE for different generation sources [29].

It can be seen from Figure 4-15 that the LCOE for biodiesel is comparable with the majority of other generation technologies (e.g. coal and gas turbines) in the NEM. More importantly, the LCOE for biodiesel is less than the conventional diesel.

4.7. A Summary of Key Findings

The study has found that a backup generator located at the end of the network can achieve better performance in supporting the network voltage. The voltage along the network feeder also increases with the increase of backup generator power injection. While under different network loading conditions, the voltage enhancement achieved by the backup generator remains the same under the same level of power generation. The voltage limit and thermal limit of the power network mainly constrain the export limit of backup generators. Moreover, according to the study, the short-circuit current limit does not act as a barrier for backup generator connection to medium voltage networks.

The WP-2 has made the following findings:

- A backup generator with a dynamic export limit can generate 1 to 5 times more energy than with a static export limit. Since backup generators with a static export limit must follow the minimum export limit determined at the peak generation hours (around midday), they cannot export extra power during off-peak hours.

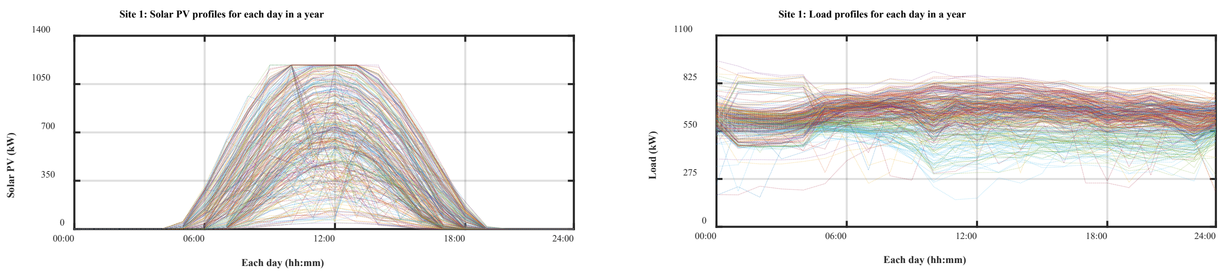
- Different operating modes offer advantages and disadvantages depending on network conditions Therefore, there is no single operating mode to satisfy all conditions. In this case, if the backup generator can select the suitable operating mode according to its capability and network requirements, the benefit to the power network and C&I customers can be maximised.
- Each DNSP has their own rules and guidelines on generator inter-tripping and synchronisation[3].
- Various biodiesel blends are available from local Australian producers. A complete supply chain of biodiesel is available from production to retail. Moreover, local generator producers provide generator sets that are suitable for biodiesel, which overcomes its technical barriers.

5. Work Package 3 Key Findings

Work Package-3 (WP-3) investigated the use of BESS in DR programs to benefit the C&I customers in terms of electricity cost savings and return on investment (ROI). Four different C&I customers are selected for the analysis, which include a cold storage warehouse (Site-1), a manufacturing plant in Melbourne metropolitan (Site-2), a shopping centre (Site-3) and a supermarket in regional Victoria (Site-4). This report only outlines results and analysis of Site-1 and Site-2, and Site-3 and site-4 results can be found in WP-3 Final Report[4]. The WP-3 methodology is presented in the Appendix D.

5.1. Overview of Solar PV and Load Profiles of Representative C&I Customers

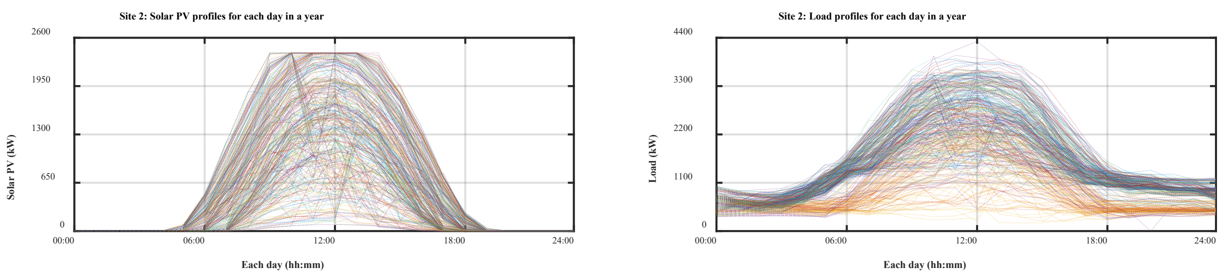
Each C&I customer is equipped with a solar PV system. The solar PV and load profiles of Site 1 and Site 2 are illustrated in Figure 5-1 and Figure 5-2 respectively.



(a) (b)

Figure 5-1: Solar PV and load profiles of Site 1.

The rated solar PV capacity of Site 1 and Site 2 are 1500 kW, and 3000 kW, respectively. The daily solar PV profiles of Site-1 and Site-2 are illustrated in Figure 5-1 (a), and Figure 5-2 (a), respectively. As illustrated in these figures, all sites have solar PV generation between around 5:30 am and 6:30 pm. Site 2 has the most solar PV generation. Each day load profiles, over the course of a year, of Site 1, and Site 2 are shown in Figure 5-1(b), and Figure 5-2(b), respectively. These figures illustrate that Site 2 has the maximum load demand.



(a) (b)

Figure 5-2: Solar PV and load profiles of Site 2.

[4]For more information on the other sites please refer to the Work Package-3 final report available at https://c4net.com.au/projects/optimisation-of-behind-the-meter-der-generation-assets-within-network-constraints-a-roadmap-to-successful-dr-program/

5.2. Development of a battery Optimiser for C&I Customers

A battery energy storage system (BESS) optimiser controls charging and discharging operations of the battery based on the tariff structure to benefit battery owners [32]. Three inputs are considered to operate the BESS, such as solar PV and load demand profiles of C&I customers, BESS specifications ─ that include kWh capacity, kW power, charging and discharging efficiencies, state-of-charge (SOC), CapEx, operational expenditure (OpEx), and tariff structures. The developed BESS optimiser generates three main outputs, namely optimum charging and discharging schedules, annual electricity cost saving estimation, and ROI with subsequent payback period (PBP) analysis.

Figure 5-3 demonstrates the flowchart of operating BESS in six different steps. In **Step 1**, solar PV and load demand profiles of C&I customers are recorded to determine their net profile. If net profile is zero, i.e., solar PV is equal to the load demand, then a BESS customer becomes solar PV-energy sufficient, i.e., no BESS charging/discharging is required. If net profile is not zero, then two cases can be possible:

- Net profile is negative, i.e., solar PV generation is higher than load demand. The difference between solar PV generation and load demand is termed as excess solar, by which BESS can be charged in **Step 2**.
- Net profile is positive, i.e., load demand is higher than solar PV generation. The difference between load demand and solar PV generation is termed as unmet demand, which can be satisfied by the BESS discharge in **Step 5.**

In **Step 2**, excess solar is used to charge BESS, subject to availability of excess solar and BESS constraints, including kW and kWh rating, SOC, and charging efficiency. If excess solar is more than available BESS charging capacity, the extra amount (excess solar – available BESS charging capacity) is exported to the grid at the FiT rate in **Step 3**. However, if the opposite is true, i.e., BESS has more charging capacity and excess solar, the deficient amount (available BESS charging capacity – excess solar) is taken from the grid at the off-peak rate in the next step (**Step 4).** Note that, grid charging is scheduled based on peak and shoulder demand requirements to avoid unnecessary BESS degradation.

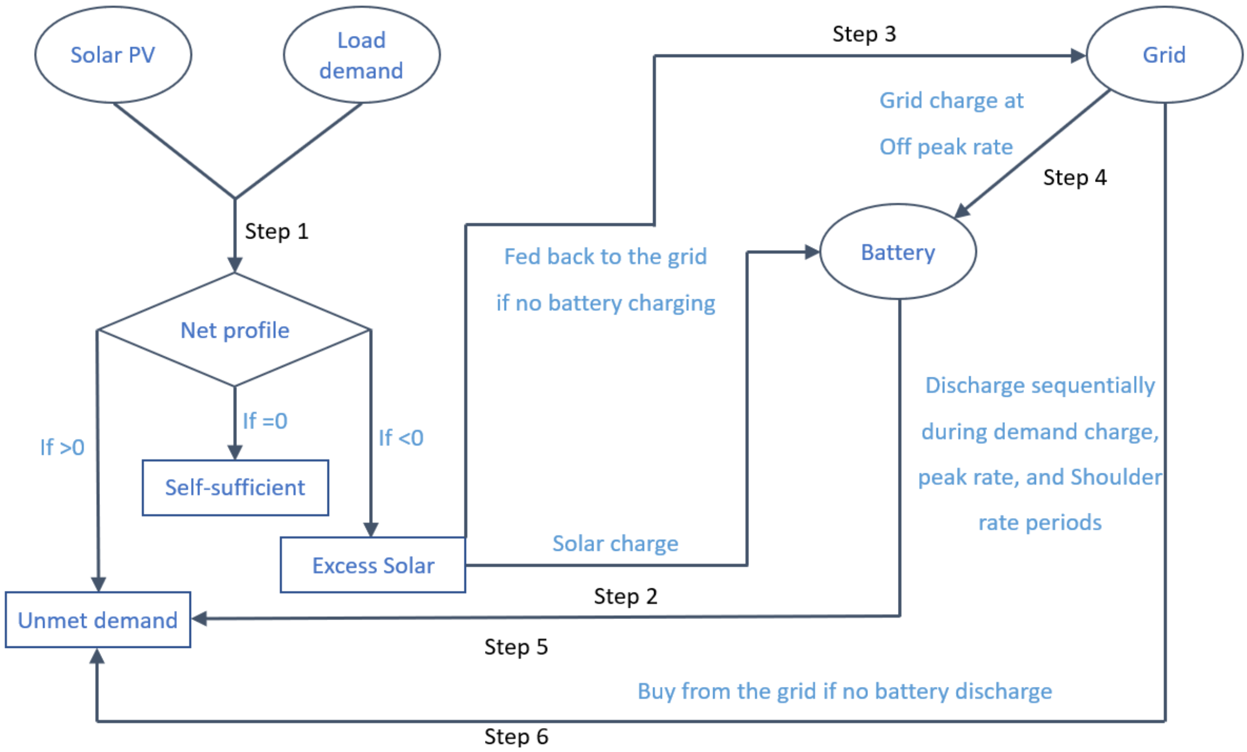


Figure 5-3: Flowchart of optimising BESS operation.

As for managing unmet demand, firstly BESS discharge is used in **Step 5**. The BESS is directed to discharge sequentially in accordance with the demand charge, peak rate, and shoulder rate periods ─ conforming to the considered tariff structure ─ to reduce the electricity purchasing cost and PBP optimally. BESS discharging is also bounded by the available BESS discharge capacity, SOC, and discharging efficiency. If available BESS discharge capacity is lower than unmet demand, the deficient amount (unmet demand - available BESS discharge capacity) is imported from the grid at the ToU rate in **Step 6**.

Using the BESS charge and discharge, grid export and import, and BESS trial tariffs, the BESS trial electricity cost of each C&I customer is calculated and compared with the standard electricity cost, which is calculated considering no BESS charge and discharge and by applying standard tariffs. The difference between standard and BESS trial electricity costs is termed as the electricity cost saving. Adopting the mathematical relation between the cost saving, BESS degradation cost, CapEx, and OpEx, the ROI and PBP are computed. The detailed mathematical formulations are provided in the Appendix.

5.3. Financial Case Studies for C&I Customers with Battery

Five financial scenarios are considered for each C&I customer under different tariff structures, namely Evo Energy, Essential Energy, SA Network, and AusGrid tariff structures, and BESS sizes. These scenarios include the consideration of unvaried existing tariff structures, reduction in tariff structures to receive the target PBP, reduction in CapEx and subsequent OpEx to attain the target PBP, increase in the BESS C rating with decreased capacity, and decrease in the BESS C rating with increased capacity. In total, forty financial case studies are demonstrated to assess the economic viability of the BESS for C&I customers. An overview of these case studies is illustrated in Table 5-1. Financial case studies for site 1 and site 2 are presented in this report. Please refer to the work package 3 final report for other sites results[4].

Table 5- 1: Overview of financial case studies.

Financial case study	Site No.	Tariff Structure	BESS Size	C rating
Case Study F1	1	Unvaried	200 kW, 520 kWh	0.39
Case Study F2	1	Unvaried	500 kW, 1040 kWh	0.48
Case Study F3	1	Reduced tariff	200 kW, 520 kWh	0.39
Case Study F4	1	Reduced tariff	500 kW, 1040 kWh	0.48
Case Study F5	1	Reduced CapEx	200 kW, 520 kWh	0.39
Case Study F6	1	Reduced CapEx	500 kW, 1040 kWh	0.48
Case Study F7	1	Increase in C rating	200 kW, 252 kWh	0.79
Case Study F8	1	Increase in C rating	500 kW, 505 kWh	0.99
Case Study F9	1	Decrease in C rating	200 kW, 1040 kWh	0.19
Case Study F10	1	Decrease in C rating	500 kW, 1560 kWh	0.32
Case Study F11	2	Unvaried	200 kW, 520 kWh	0.39
Case Study F12	2	Unvaried	500 kW, 1040 kWh	0.48
Case Study F13	2	Reduced tariff	200 kW, 520 kWh	0.39
Case Study F14	2	Reduced tariff	500 kW, 1040 kWh	0.48
Case Study F15	2	Reduced CapEx	200 kW, 520 kWh	0.39
Case Study F16	2	Reduced CapEx	500 kW, 1040 kWh	0.48
Case Study F17	2	Increase in C rating	200 kW, 252 kWh	0.79
Case Study F18	2	Increase in C rating	500 kW, 505 kWh	0.99
Case Study F19	2	Decrease in C rating	200 kW, 1040 kWh	0.19
Case Study F20	2	Decrease in C rating	500 kW, 1560 kWh	0.32

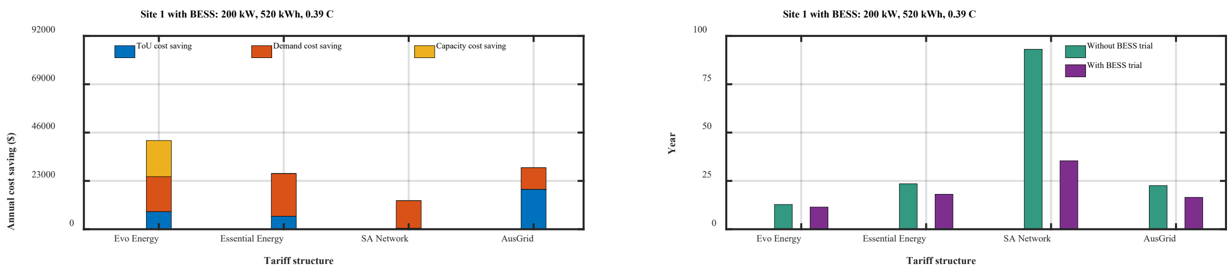
Table 5-2: Overall costs associated with different BESS sizes.

BESS size	CapEx (AU$/kWh)	OpEx (% of CapEx)	Cost
BESS: 200 kW, 520 kWh, 0.39 C	860	1%	451672 AU$
BESS: 500 kW, 1040 kWh, 0.48 C	860	1%	903344 AU$
BESS: 200 kW, 252 kWh, 0.79 C	1100	1%	279972 AU$
BESS: 500 kW, 505 kWh, 0.99 C	1080	1%	550854 AU$
BESS: 200 kW, 1040 kWh, 0.19 C	760	1%	798304 AU$
BESS: 500 kW, 1560 kWh, 0.32 C	790	1%	1244724 AU$

The CapEx of BESS: 200 kW, 520 kWh, 0.39 C; BESS: 500 kW, 1040 kWh, 0.48 C; BESS: 200 kW, 252 kWh, 0.79 C; BESS: 500 kW, 505 kWh, 0.99 C; BESS: 200 kW, 1040 kWh, 0.19 C; and BESS: 500 kW, 1560 kWh, 0.32 C are 860 AU$/kWh; 860 AU$/kWh; 1100 AU$/kWh; 1080 AU$/kWh; 760 AU$/kWh; and 790 AU$/kWh, respectively. The OpEx is 1% of CapEx. The overall costs associated with different BESS sizes are depicted in Table 5-2.

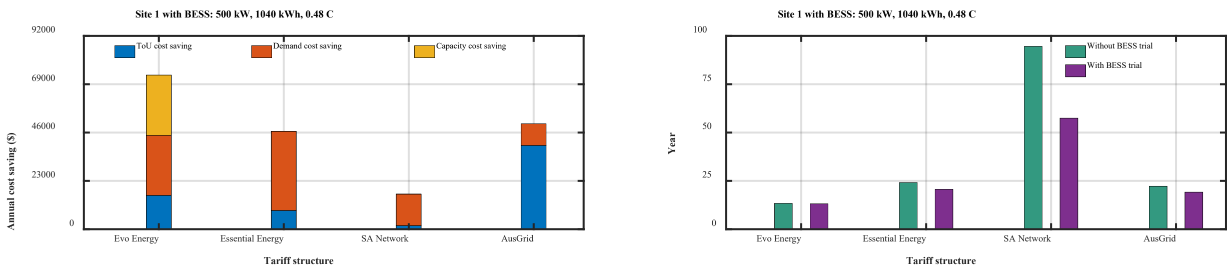
5.3.1. Financial Case Studies for Site 1

In *Case Study F1*, Site 1 is provided with the BESS size of 200 kW, 520 kWh, 0.39 C. The cost savings ─ calculated from the electricity cost differences between the consideration of BESS (charged at BESS trial tariff) and without BESS (charged at standard tariff), and PBPs of Site 1 under considered tariff structures without any variation in existing rates are depicted in Figure 5.4(a) and Figure 5.4(b), respectively. As is observed from these figures, Evo Energy tariff structure is more profitable for Site 1, resulting in lesser PBP compared to Essential Energy, SA Network, and AusGrid tariff structures. Also, PBPs with the BESS trial tariff are always lower than that of standard (without BESS trial) tariff, indicating the BESS trial tariff is beneficial for Site 1.



(a) (b)

Figure 5-4: Cost saving and PBP analysis of Site 1 considering unvaried tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F1).

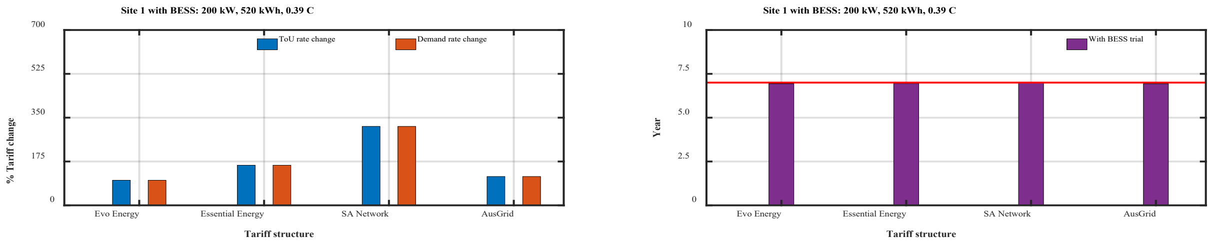


(a) (b)

Figure 5-5: Cost saving and PBP analysis of Site 1 considering unvaried tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F2).

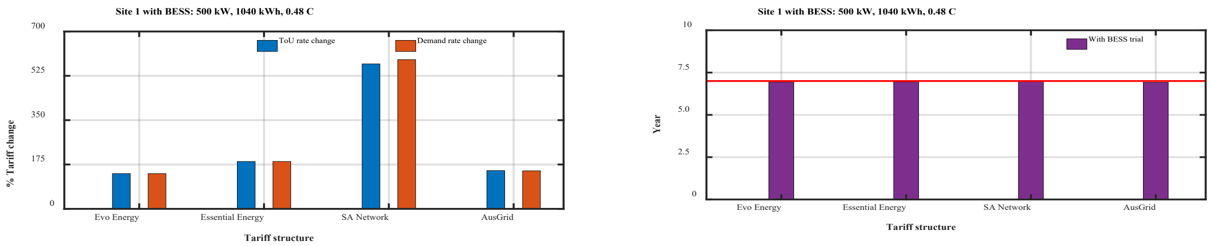
Case Study F2 is similar to *Case Study F1* except the consideration of a higher BESS size of 500 kW, 1040 kWh, 0.48 C. According to Figure 5-5(a), it is evident that cost saving increases with increase in BESS size for Site 1. However, PBP also increases, subject to CapEx and OpEx of the considered BESS. The PBP increase of Site 1 is captured in Figure 5-5(b).

To keep the PBP of Site 1 within the target 7 years (see Figure 5-6(b) and Figure 5-7(b)), based on *Case Study F3* and *Case Study F4,* Evo Energy tariff rates need to be decreased between 100% (see Figure 5-6 (a)) and 139% (see Figure 5-7(a)). The PBP of Site 1 can also be kept within the target 7 years by reducing the CapEx and subsequent OpEx. According to Figure 5-8(a) and Figure 5-9(a), CapEx needs to be decreased between 40% and 50%, respectively with Evo Energy tariff structure to achieve the target PBP (see Figure 5-8(b) and Figure 5-9(b)).



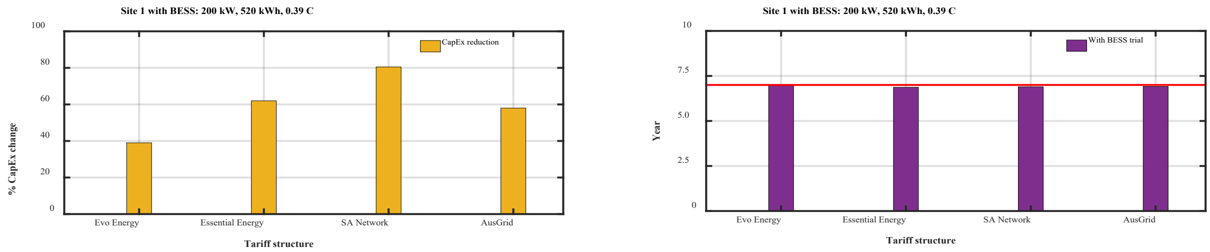
(a) (b)

Figure 5-6: Cost saving and PBP analysis of Site 1 considering reduction in tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F3).



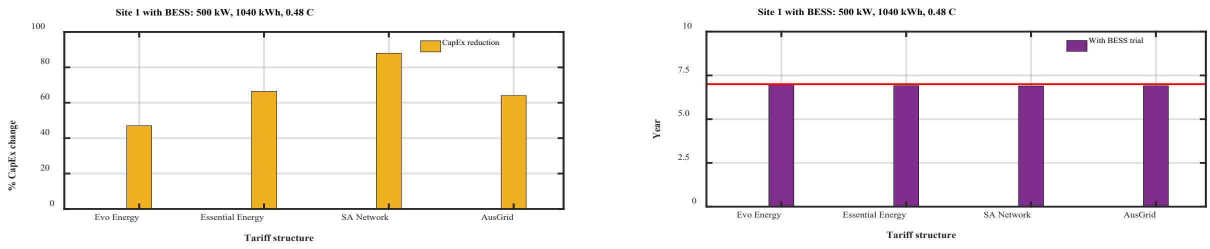
(a) (b)

Figure 5-7: Cost saving and PBP analysis of Site 1 considering reduction tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F4).



(a) (b)

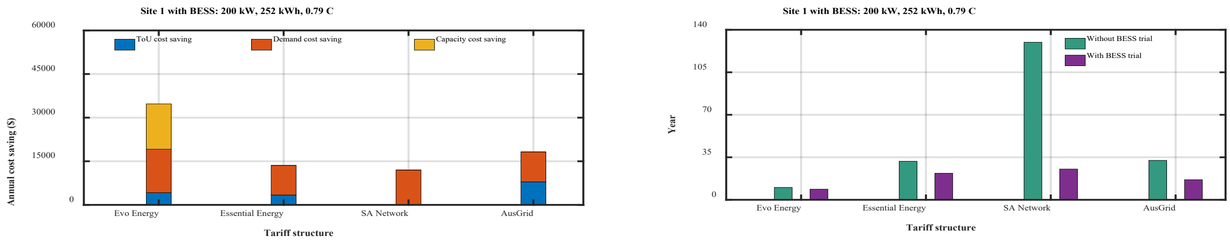
Figure 5-8: Cost saving and PBP analysis of Site 1 considering reduction in CapEx with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F5).



(a) (b)

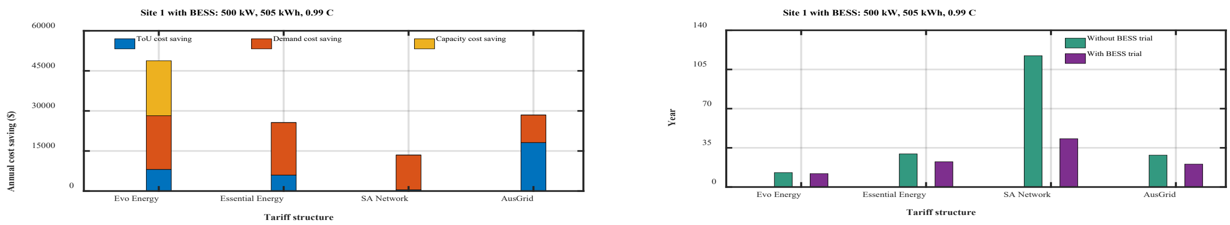
Figure 5-9: Cost saving and PBP analysis of Site 1 considering reduction in CapEx with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F6).

Case Study F7 and *Case Study F8* deal with the increase in the BESS C ratings, i.e., from 0.39 C to 0.79 C and from 0.48 C to 0.99 C respectively, while keeping the BESS kW ratings unchanged, i.e., 200 kW and 500 kW.



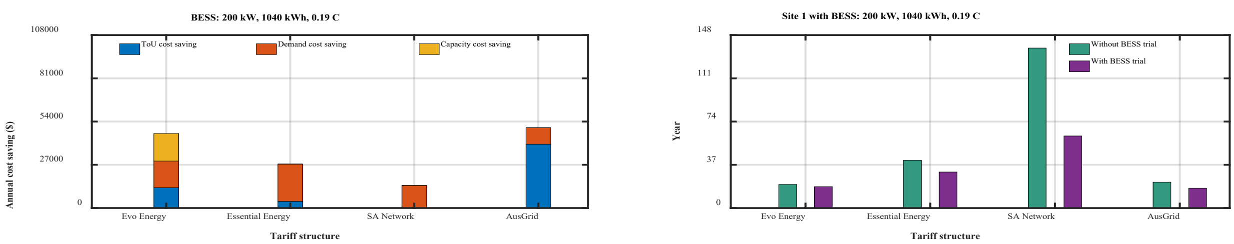
(a) (b)

Figure 5-3: Cost saving and PBP analysis of Site 1 considering increase in C rating with BESS: 200 kW, 252 kWh, 0.79 C (Case Study F7).



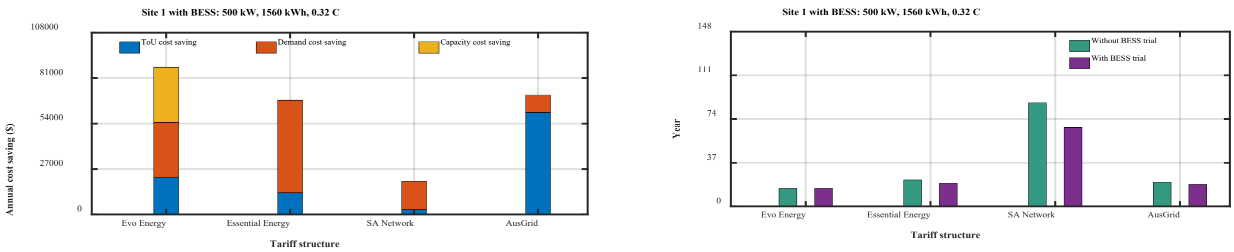
(a) (b)

Figure 5-4: Cost saving and PBP analysis of Site 1 considering increase in C rating with BESS: 500 kW, 505 kWh, 0.99 C (Case Study F8).



(a) (b)

Figure 5-5: Cost saving and PBP analysis of Site 1 considering decrease in C rating with BESS: 200 kW, 1040 kWh, 0.19 C (Case Study 9).



(a) (b)

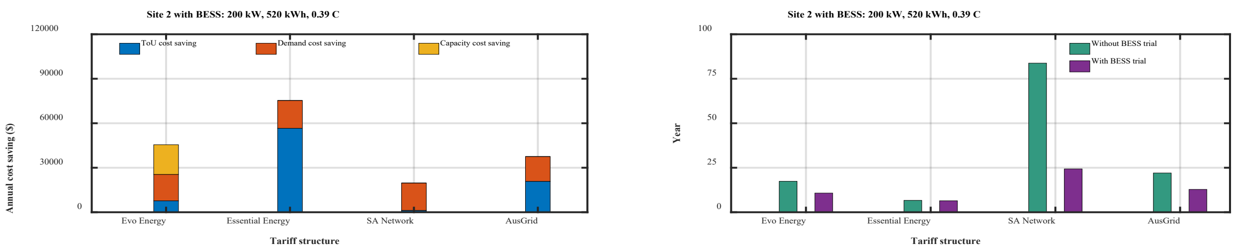
Figure 5-6: Cost saving and PBP analysis of Site 1 considering decrease in C rating with BESS: 500 kW, 1560 kWh, 0.32 C (Case Study F10).

The cost savings of Site 1 in *Case Study F7* and *Case Study F8* are displayed in Figure 5-10(a) and Figure 5-11(a), respectively. Figure 5-10(b) and Figure 5-11(b) show the PBPs, respectively. Based on these figures, cost savings are decreased compared to *Case Study F1* because of the fact of lesser BESS charging and discharging caused by the reduced BESS kWh capacities.

In contrast, the decrease in the BESS C ratings, i.e., from 0.39 C to 0.19 C and from 0.48 C to 0.32 C while keeping the BESS kW ratings unchanged, i.e., 200 kW and 500 kW, are demonstrated in *Case Study F9* and *Case Study F10*, respectively. Figure 5-12(a) and Figure 5-13(a) exhibit the cost savings of Site 1 while PBPs are captured in Figure 5-12(b) and Figure 5-13(b), respectively. These figures suggest that cost savings are increased in comparison with *Case Study F1* due to higher BESS charging and discharging capacities.

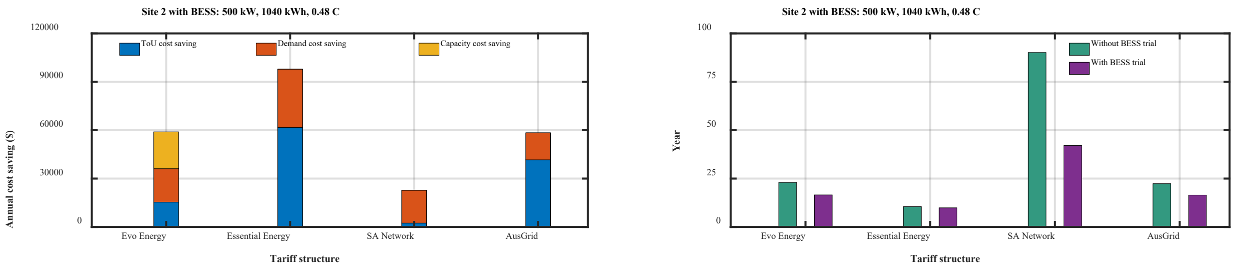
5.3.2. Financial Case Studies for Site 2

In *Case Study F11*, Site 2 is provided with the BESS size of 200 kW, 520 kWh, 0.39 C. The cost savings and PBPs of Site 2 under considered tariff structures without any variation in existing rates are depicted in Figure 5-7(a) and Figure 5-8(b), respectively. As is noticed from these figures, Essential Energy tariff structure is more profitable for Site 2, resulting in lesser PBP compared to Evo Energy, SA Network, and AusGrid tariff structures. Also, PBPs with the BESS trial tariff are always lower than that of standard (without BESS trial) tariff, indicating the BESS trial tariff is beneficial for Site 2 similar to Site 1.



(a) (b)

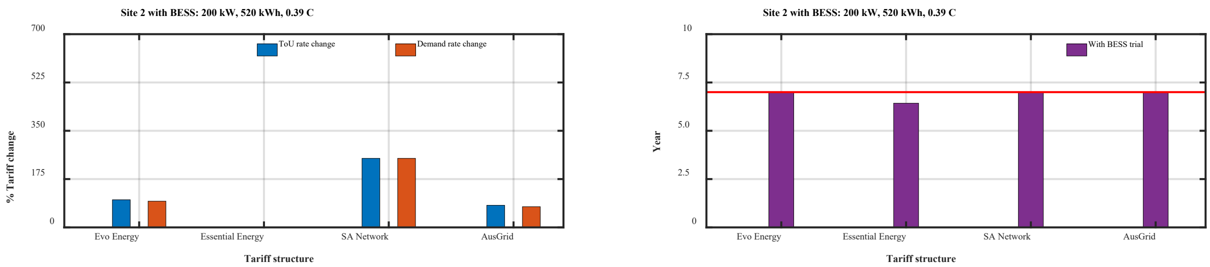
Figure 5-9: Cost saving and PBP analysis of Site 2 considering unvaried tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F11).



(a) (b)

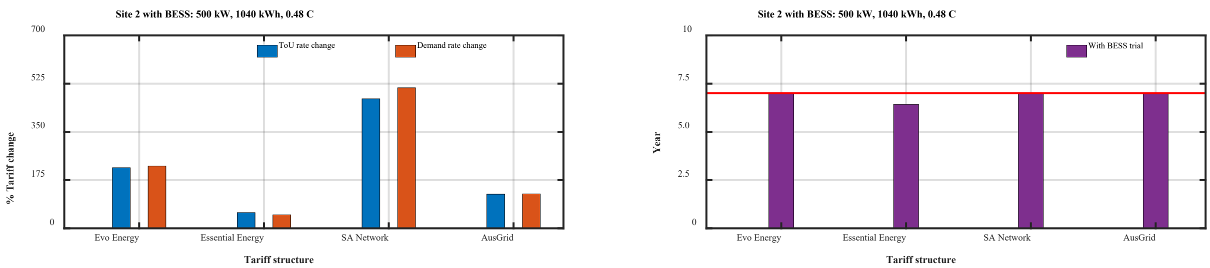
Figure 5-10: Cost saving and PBP analysis of Site 2 considering unvaried tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F12).

Case Study F12 is similar to *Case Study F11* except the consideration of a higher BESS size of 500 kW, 1040 kWh, 0.48 C. According to Figure 5-15(a), it is evident that cost saving increases with increase in BESS size for Site 2 (similar to Site 1). However, PBP also increases, subject to CapEx and OpEx of the considered BESS. The PBP increase of Site 2 is captured in Figure 5-11(b).



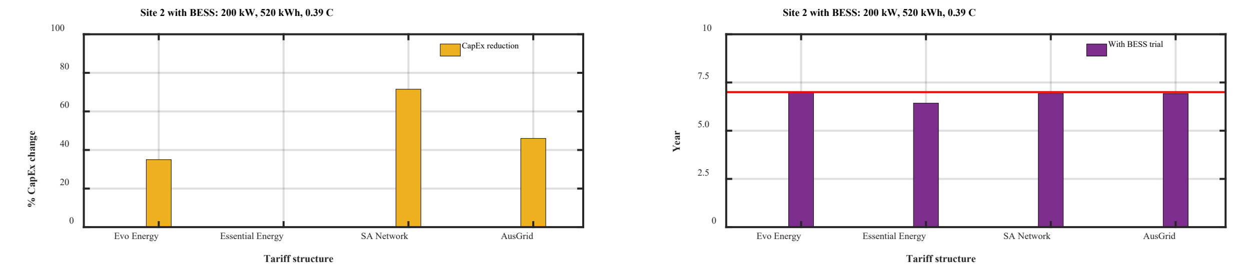
(a) (b)

Figure 5-12: Cost saving and PBP analysis of Site 2 considering reduction in tariff structure with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F13).



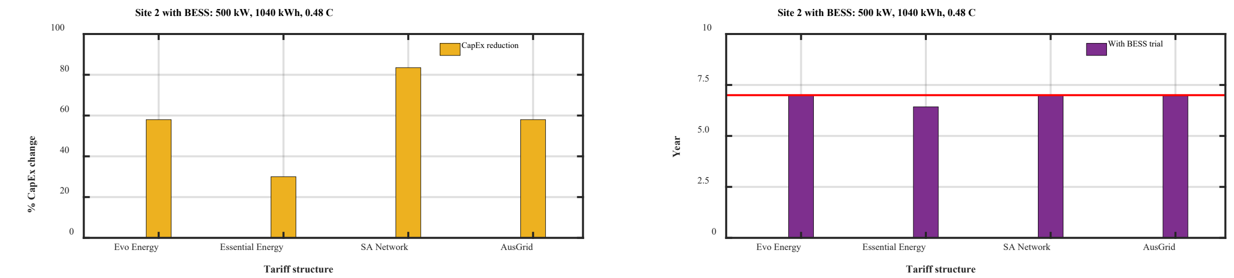
(a) (b)

Figure 5-17: Cost saving and PBP analysis of Site 2 considering reduction tariff structure with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F14).



(a) (b)

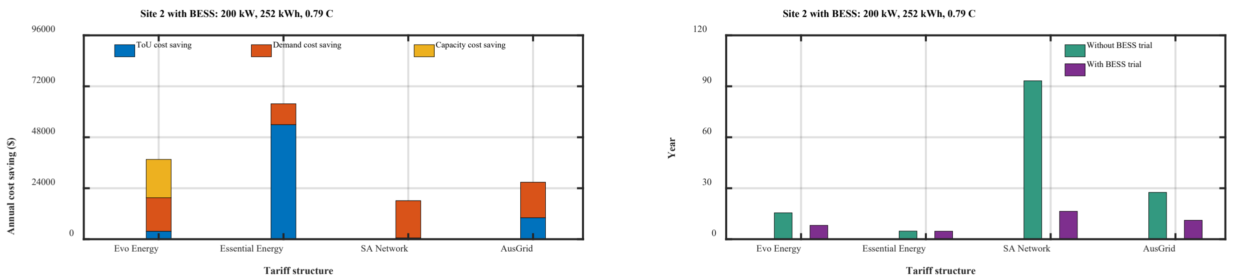
Figure 5-18: Cost saving and PBP analysis of Site 2 considering reduction in CapEx with BESS: 200 kW, 520 kWh, 0.39 C (Case Study F15).



(a) (b)

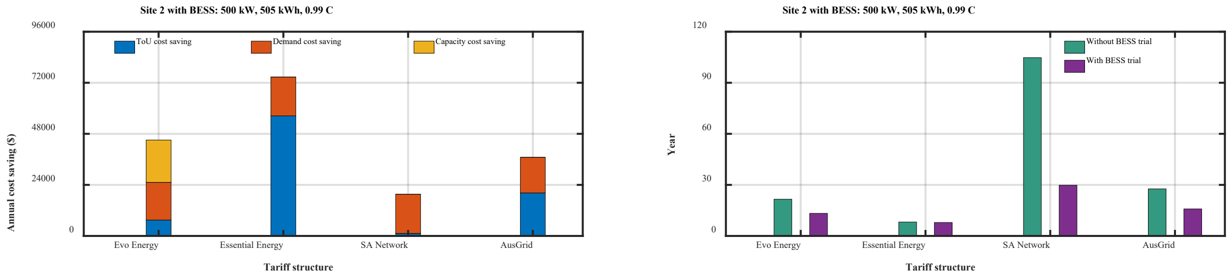
Figure 5-19: Cost saving and PBP analysis of Site 2 considering reduction in CapEx with BESS: 500 kW, 1040 kWh, 0.48 C (Case Study F16).

To keep the PBP of Site 2 within the target 7 years (see Figure 5-13(b) and Figure 5-14(b)), based on *Case Study F13* and *Case Study F14,* Essential Energy tariff rates need to be decreased between 0% (see Figure 5-15(a)) and 60% (see Figure 5-16(a)). The PBP of Site 2 can also be kept within the target 7 years by reducing the CapEx and subsequent OpEx. According to Figure 5-17(a) and Figure 5-18(a), CapEx needs to be decreased between 0% and 30% (as per *Case Study F15* and *Case Study F16)*, respectively with Evo Energy tariff structure to achieve the target PBP (see Figure 5-19(b) and Figure 5-20(b)).



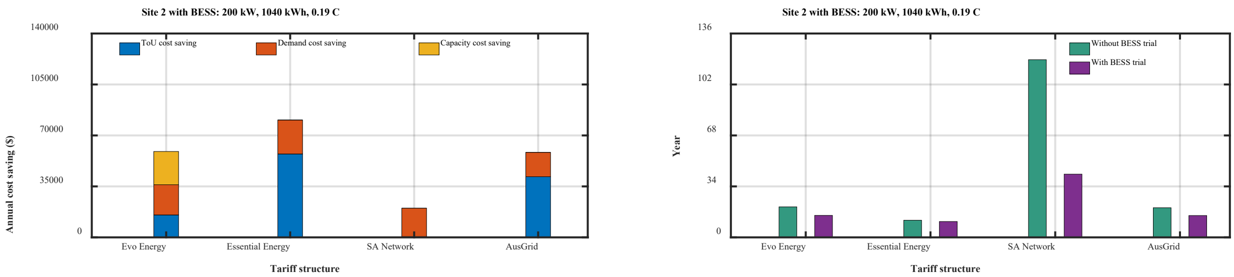
(a) (b)

Figure 5-20: Cost saving and PBP analysis of Site 2 considering increase in C rating with BESS: 200 kW, 252 kWh, 0.79 C (Case Study F17).



(a) (b)

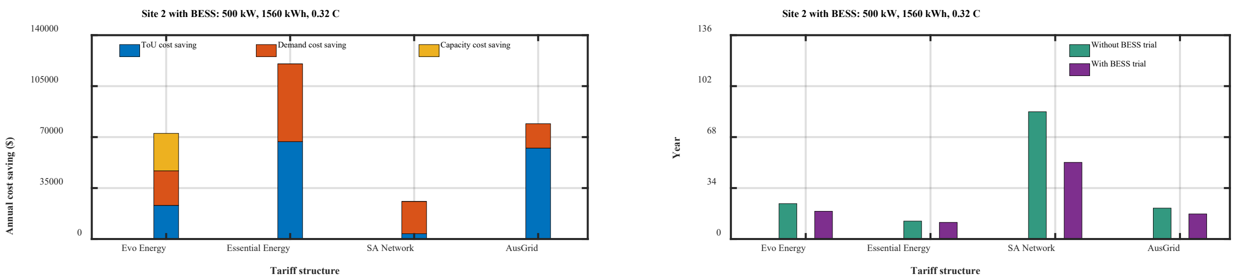
Figure 5-21: Cost saving and PBP analysis of Site 2 considering increase C rating with BESS: 500 kW, 505 kWh, 0.99 C (Case Study F18).



(a) (b)

Figure 5-22: Cost saving and PBP analysis of Site 2 considering decrease in C rating with BESS: 200 kW, 1040 kWh, 0.19 C (Case Study F19).

Case Study F17 and *Case Study F18* deal with the increase in the BESS C ratings, i.e., from 0.39 C to 0.79 C and from 0.48 C to 0.99 C respectively, while keeping the BESS kW ratings unchanged, i.e., 200 kW and 500 kW. The cost savings of Site 2 are displayed in Figure 5-20(a) and Figure 5-21(a), respectively. Figure 5-20(b) and Figure 5-21(b) show the PBPs of Site 2, respectively. Based on these figures, cost savings are decreased compared to *Case Study F11* because of the fact of lesser BESS charging and discharging caused by the reduced BESS kWh capacities.



(a) (b)

Figure 5-23: Cost saving and PBP analysis of Site 2 considering decrease in C rating with BESS: 500 kW, 1560 kWh, 0.32 C (Case Study F20).

In contrast, the decrease in the BESS C ratings, i.e., from 0.39 C to 0.19 C and from 0.48 C to 0.32 C while keeping the BESS kW ratings unchanged, i.e., 200 kW and 500 kW, are demonstrated in *Case Study F19* and *Case Study F20*, respectively. Figure 5-22(a) and Figure 5-23(a) exhibit the cost savings of Site 2 while PBPs are captured in Figure 5-22(b) and Figure 5-23(b), respectively. These figures suggest that cost savings are increased in comparison with *Case Study F11* as due to higher BESS charging and discharging capacities.

5.3.3. Summary of Key Findings

1) The cost saving, calculated from the electricity cost difference between the consideration of BESS (charged at BESS trial tariff) and without BESS (charged at standard tariff), of a C&I customer increases with BESS size.
2) The PBP increases with increase of the BESS size, subject to CapEx and OpEx of the BESS.
3) The PBP with the BESS trial tariff is always lower than that of standard (without BESS trial) tariff, indicating the BESS trial tariff is beneficial for a C&I customer.
4) Different tariff structures are beneficial for different C&I customers. For instance, Evo Energy tariff structure is profitable for Site 1 (with considerable high load and solar PV configurations). Essential Energy tariff structure is profitable for Site 2 (with high load and solar PV configurations). AusGrid tariff structure is profitable for Site 3 (with low load and solar PV configurations)[4]. For Site 4 (with low load and solar PV configurations), Evo Energy tariff structure is profitable if smaller BESS size is considered[4]. With the increase of BESS size, Essential Energy tariff structure becomes profitable. However, SA Network tariff structure is not profitable for any of these considered C& I customers.
5) A higher difference between peak and off-peak prices, as noticed from AusGrid tariff structure, allows BESS to charge from the power grid during off-peak hours, subject to solar charging constraint, at cheaper price and discharge during peak hours, resulting in greater ToU cost savings and lower PBPs for C&I customers. On the contrary, a lower difference between peak and off-peak prices, as noticed from SA Network tariff structure, causes lesser ToU cost savings and higher PBPs for C&I customers.
6) Higher solar soak period increases ToU cost savings and decreases PBPs as observed from Essential Energy tariff structure.
7) Higher demand and capacity charges lead to greater ToU cost savings and reduced PBPs as seen from Evo Energy tariff structure.
8) Significant reduction in tariff rates enables C&I customers to attain the target PBP. For example, to get ROI within 7 years under different BESS sizes, tariff rates need to be decreased between 100% and 139% (for Site 1 with Evo Energy tariff structure), between 0% and 60% (for Site 2 with Essential Energy tariff structure), between 180% and 344% (for Site 3 with AusGrid tariff structure), and between 140% and 200% (for Site 4 with Essential Energy tariff structure)[4].
9) Reduction in CapEx also facilitates C&I customers to achieve the target PBP. For instance, CapEx needs to be decreased between 40% and 50% (for Site 1 with Evo Energy tariff structure), between 0% and 30% (for Site 2 with Essential Energy tariff structure), between 70% and 80% (for Site 3 with AusGrid tariff structure), and between 60% and 70% (for Site 4 with Essential Energy tariff structures) to enable C&I customers to receive ROI within 7 years under different BESS sizes[4].

10) Increase in the BESS C rating, while keeping the BESS kW rating unchanged, decreases cost savings and enhances PBPs due to lesser BESS charging and discharging caused by the reduced BESS kWh capacity.
11) Decrease in the BESS C rating, while keeping the BESS kW rating unchanged, increases cost savings and reduces PBPs due to greater BESS charging and discharging caused by the increased BESS kWh capacity.

5.4. Network Impact Analysis with Battery

The impact of installing BESS at the customers-end on any representative power network can be analysed by following the below steps:

Step 1: Extract load values of the representative power network.

Step 2: Extract commercial site profiles with BESS under considered tariff structures ─ used in the financial analysis.

Step 3: Select a bus of the representative power network and replace load profiles of the bus with a commercial site profile with BESS under a tariff structure.

Step 4: Repeat **Step 3** for all considered tariff structures.

Step 5: Repeat **Step 4** for all considered BESS sizes.

Step 6: Incorporate bus voltage and line loading limits.

Step 7: Perform time series power flow for all structures considered in **Step 3, Step 4** and **Step 5**.

Step 8: Record bus voltages and line loading and check the network feasibility.

5.4.1. Overview of Representative Power Network

In this case study, a benchmark power system, i.e., IEEE 33 bus test distribution network, is used. The single-line diagram of this representative power network is exhibited in Figure 5-24. The network has 33 buses. Bus 1 indicates the distribution substation and other buses are load buses containing one C&I customer at each bus. All the buses are connected through 32 distribution lines [33]. The detailed line data and rated load values can be found in [34]. The supply voltage is considered as 11 kV in accordance with the Australian electricity supply standard [35]. According to the IEC Standard IEC 60038, the bus voltage limits of the representative power network are maintained in the range of 0.9 to 1.06 per-unit (pu) under steady-state conditions [36].

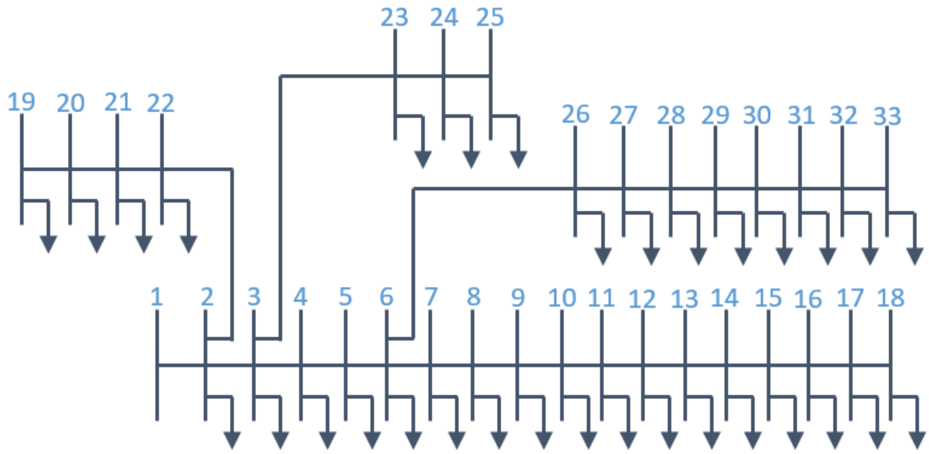
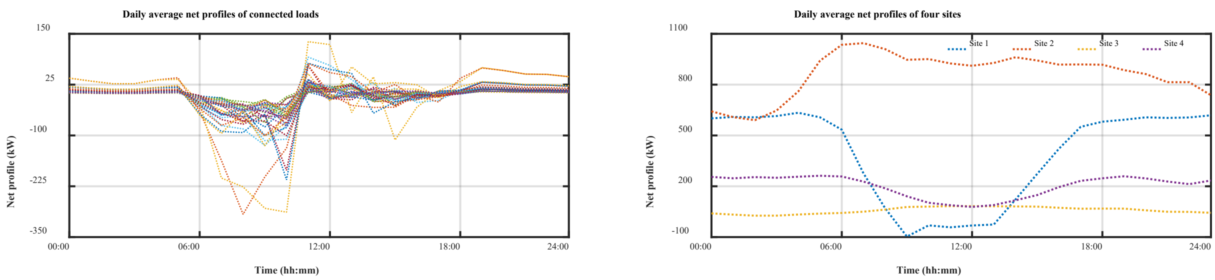


Figure 5-24: Single-line diagram of the representative power network.



(a) (b)

Figure 5-25: Net profiles of the representative network loads and selected four sites.

It is assumed that all the C&I customers of the representative network have solar PV with the rated ratings between 1 and 2 times higher than their rated load demand. The daily average net profiles of the representative network are given in Figure 5-25(a). The daily average net profiles of four sites considered for the financial analysis are illustrated in Figure 5-25(b). As is observed in Figure 5-25 (b), the daily average net profiles of Site 2, Site 3 and Site 4 are always positive, indicating load demand are always higher than the solar PV generation. In contrast, Site 1 has more solar PV generation than its load demand during some solar PV hours. Therefore, Site 1 (higher solar PV generation) and Site 2 (higher load demand) are chosen to connect to the 11 kV distribution network shown in Figure 5.24.

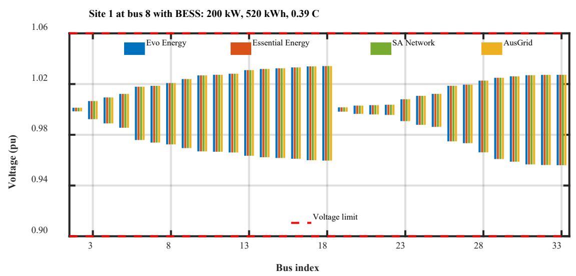
5.4.2. Network Case Studies with C&I Sites at Different Locations

Eight network case studies are conducted to investigate the impacts of incorporating BESS in Site 1 and Site 2 on bus voltages and line loading under considered tariff structures, namely Evo Energy, Essential Energy, SA Network, and Ausgrid BESS trial tariff structures. An overview of these case studies is demonstrated in Table 5-3. Only Site 1 and Site 2 case study results are presented here. Please refer to the work package 3 final report for other sites results[4].

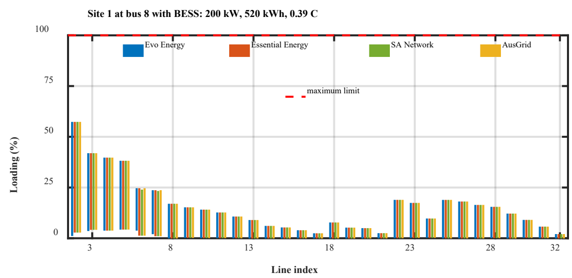
Table 5-3: Overview of physical network case studies.

Physical network case study	Site No.	BESS Size	C rating	Bus location
Case Study P1	1	200 kW, 520 kWh	0.39	8
Case Study P2	1	500 kW, 1040 kWh	0.48	8
Case Study P3	1	200 kW, 520 kWh	0.39	18
Case Study P4	1	500 kW, 1040 kWh	0.48	18
Case Study P5	2	200 kW, 520 kWh	0.39	6
Case Study P6	2	500 kW, 1040 kWh	0.48	6
Case Study P7	2	200 kW, 520 kWh	0.39	32
Case Study P8	2	500 kW, 1040 kWh	0.48	32

In *Case Study P1*, daily average net profiles at bus 8 of the representative network are replaced with daily average net profiles of Site 1, with BESS: 200 kW, 520 kWh, 0.39 C, under considered tariff structures. The impacts of *Case Study P1* on daily average network voltages and line loading are provided in Figure 5.26(a) and Figure 5.26(b), respectively. As is seen from these figures, insignificant variations in daily average bus voltages and line loading are found under Evo Energy, Essential Energy, SA Network, and AusGrid tariff structures. More importantly, both bus voltages and line loading are within the prescribed limits. Figure 5.27(a) and Figure 5.27(b) display daily average bus voltages and line loading in *Case Study P2*, respectively, considered tariff structures, in which Site 1, connected to bus 8, is provided with the increased BESS size of 500 kW, 1040 kWh, 0.48 C. It is noticed from Figure 5.27(a) and Figure 5.27(b) that daily average bus voltages and line loading do not vary substantially if there is an increase in BESS size.

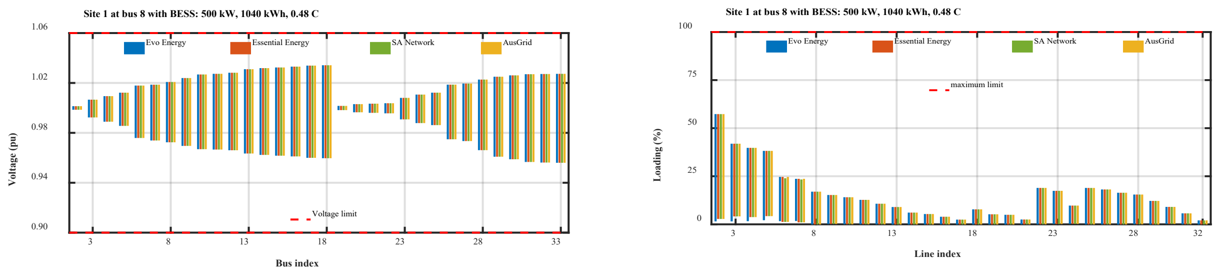


(a)



(b)

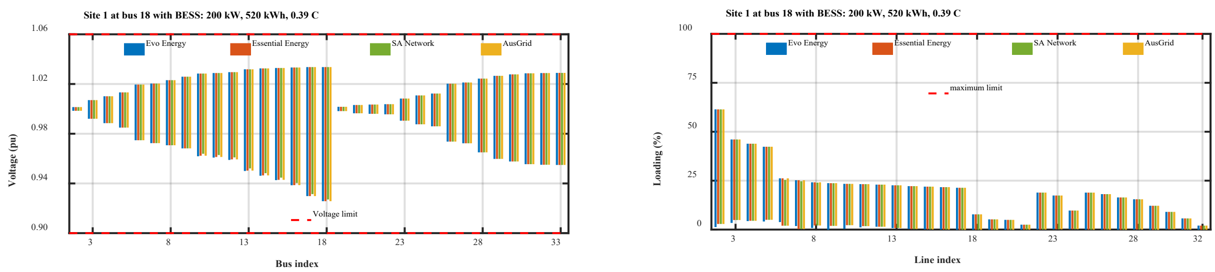
Figure 5-26: Bus voltages and line loading under considered tariff structures if Site 1 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 8 (Case Study P1).



(a) (b)

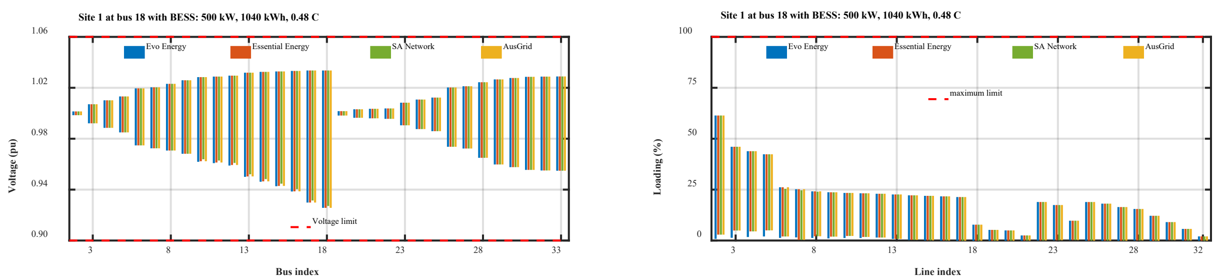
Figure 5-27: Bus voltages and line loading under different tariff structures if Site 1with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 8 (Case Study P2).

Case Study P3 and *Case Study P4* are similar to *Case Study P1* and *Case Study P2*, respectively, except the physical network location of Site 1. In *Case Study P3* and *Case Study P4*, Site 1 is connected to bus 18. Figure 5.28(a) and Figure 5.28(a) suggest that this can result in greater voltage drops over the course of 24 hours on average, compared to Figure 5.26(a) and Figure 5.27(a), respectively, as power flows through more lines to satisfy the load demand of Site 1. Due to the same reason, Figure 5.28(b) and Figure 5.29(b) show more line loading contrasting to Figure 5.26(b) and Figure 5.27(b), respectively.



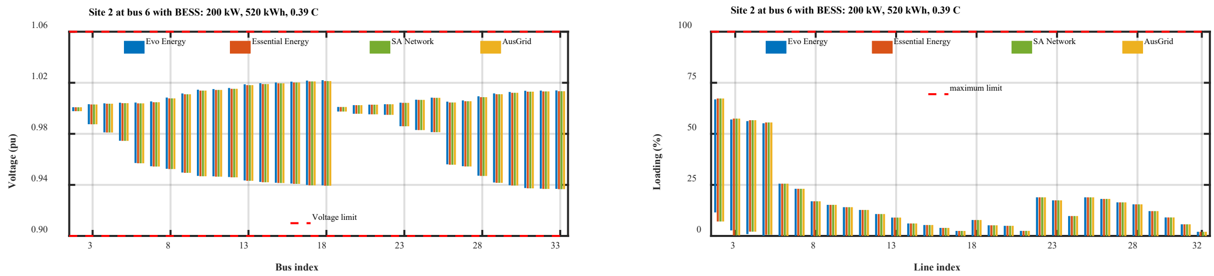
(a) (b)

Figure 5-28: Bus voltages and line loading under different tariff structures if Site 1 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 18 (Case Study P3).



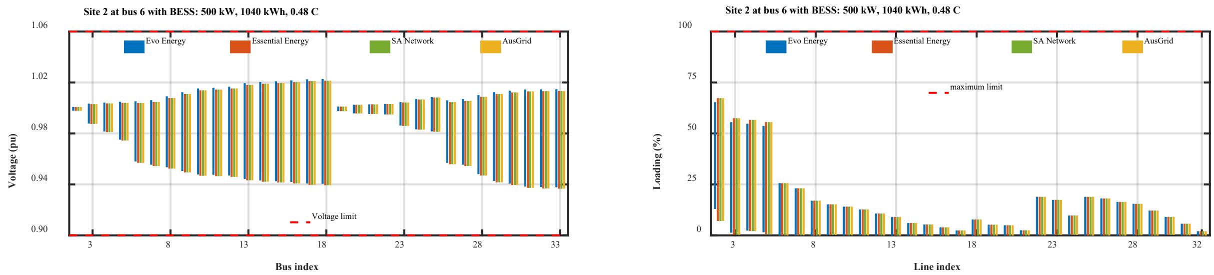
(a) (b)

Figure 5-29: Bus voltages and line loading under different tariff structures if Site 1 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 18 (Case Study P4).



(a) (b)

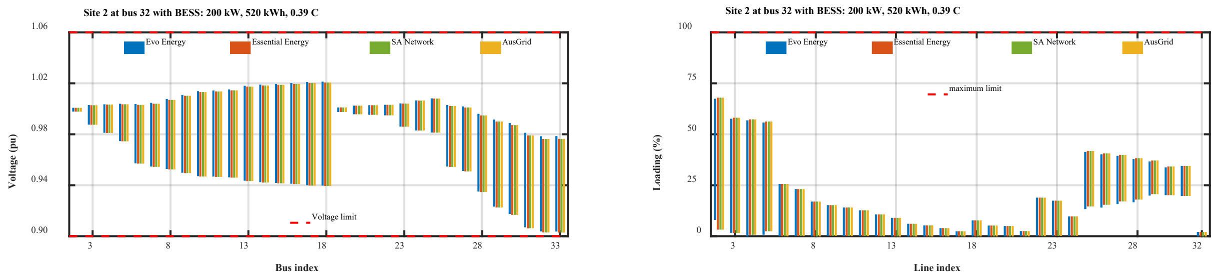
Figure 5-30: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 6 (Case Study P5).



(a) (b)

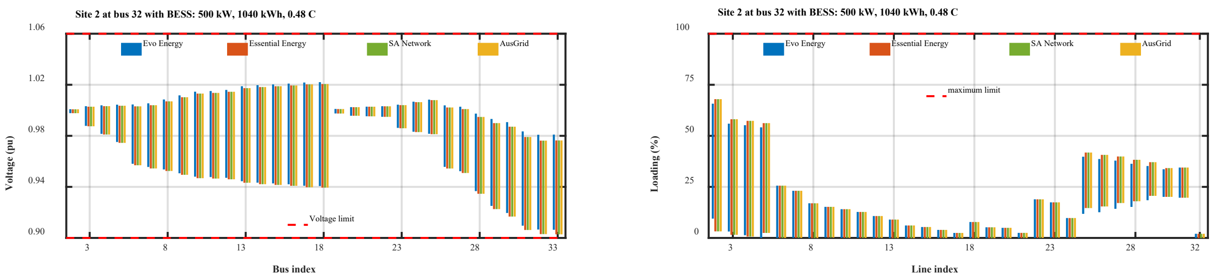
Figure 5-31: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 6 (Case Study P6).

Figure 5-30(a) and Figure 5-30(b) depict daily average bus voltages and line loading, respectively, in *Case Study P5,* in which net profiles at bus 6 of the representative network are replaced with net profiles of Site 2, with BESS: 200 kW, 520 kWh, 0.39 C, under considered tariff structures. Since Site 2 has larger load demand in comparison with Site 1, greater voltage drops and line congestion are observed compared to Figure 5-26(a) and Figure 5-26(b), respectively. The same results are also found in *Case Study P6* (considering greater BESS size contrasting to Case Study P5) if Figure 5-31 (a) and Figure 5-32(b) are compared with Figure 5-27(a) and Figure 5-27(b), respectively.



(a) (b)

Figure 5-32: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 200 kW, 520 kWh, 0.39 C is connected to bus 32 (Case Study P7).



(a) (b)

Figure 5-33: Bus voltages and line loading under different tariff structures if Site 2 with BESS: 500 kW, 1040 kWh, 0.48 C is connected to bus 32 (Case Study P8).

Case Study P7 and *Case Study P8* consider that Site 2 is connected to bus 32 of the representative network with BESS: 200 kW, 520 kWh, 0.39 C and BESS: 500 kW, 1040 kWh, 0.48 C, respectively, under considered tariff structures. The bus voltages of both case studies are captured in Figure 5-32 (a) and Figure 5-33(a), respectively, which suggest that noticeable voltage drops are caused in contrast with Figure 5-30(a) and Figure 5-31(a), respectively. This is because power flows to an increased number of lines to reach bus 32 to meet higher load demand of Site 2. Owing to the same reason, increased amounts of line loading are found in Figure 5-32(b) and Figure 5-33(b) compared to Figure 5-30(b) and Figure 5-31(b), respectively. However, both bus voltages and line loading still abide by the defined limits.

5.4.3. Summary of Network Analysis with Battery

1) The consideration of BESS at the C&I sites does not create network issues, such as voltage violations and line congestion, in the test distribution network. This is because BESS prevents local export during solar PV hours through its charging operation. Also, it discharges to satisfy load demand of C&I sites during peak demand periods, requiring less supply from the power grid.
2) Bus voltages and line loading do not vary significantly when different BESS trial tariff structures are considered, e.g., Evo Energy, Essential Energy, SA Network, and AusGrid tariff structures.
3) Bus voltages and line loading do not vary significantly if there is a moderate increase in BESS sizes.
4) More voltage drops and line congestion are found if sites are located at the end of the distribution feeder as greater amounts of power need to flow through more lines to satisfy the load demand of sites. In this study, sites have more load demand compared to the load profiles of the test network.
5) Improved voltage profiles are observed for Site 1 in contrast with Site 2 as Site 2 has more load demand than Site 1.

6. Recommendations and Implementation Roadmap

To successfully implement the project recommendations, it is imperative to develop a clear roadmap for the project recommendations. This section delineates the project recommendations with the organisations that can take these recommendations on board to improve the benefits of demand response programs.

R1) Machine Learning Techniques for Baseline Calculations (WP-1)

- Machine learning techniques can be applied to weather dependant loads, in particular, loads which has strong dependency on temperature, such as shopping malls, universities and etc.
- Linear and nonlinear regression techniques have outperformed the average baseline model, and hence it is recommended to use regression techniques instead of average baseline models in the future.
- The weather information, such as temperature, can further improve the accuracy of regression based interpretable machine learning techniques, and hence it is recommended to apply the weather parameters in the regression techniques to improve demand response baselines.
- Therefore, demand response providers and aggregators can improve their baseline calculation methods by adopting the machine learning techniques outlined above to increase the benefits of demand response.

R2) Dynamic Export Limits for Backup Generators (WP-2)

- It is more beneficial to implement dynamic export limits for backup generators (i.e., the export limit varies based on the time of the day), instead of the static export limit. Since the dynamic export limit can increase the energy export capacity and consequently increase the potential for grid and network support services, without impacting the grid stability.
- Therefore, the DNSPs can consider implementing the dynamic export limits for backup generators in demand response programs to maximise benefits to networks and C&I customers.

R3) Flexible Operating Modes for Backup Generators (WP-2)

- Backup generators should be allowed to operate under flexible operating modes (i.e. P-V and P-Q control modes) as they can assist in mitigating network constraints and support the network.
- Moreover, export capacity can also be increased when they are allowed to operate under flexible operating modes. Also, this study recommends assessing the operating mode flexibility when conducting backup generator connection studies, as it could bring benefits to the distribution network operator (e.g., assist to reduce network bottlenecks). This would also

increase the potential for grid and network support services, without impacting the grid stability.

- Therefore, in connection studies, the DNSPs can consider evaluating the benefits of operating backup generators under flexible operating modes.

R4) Consistent inter-tripping and Synchronisation Standards (WP-2)

- Each DNSP has rules and guidelines for generator inter-tripping and synchronisation. This lack of standardisation leads to complexity and uncertainty in enabling export from behind the meter generators. It also hinders the ability to identify new solutions that are lower cost but still meet the operational requirements for the network companies.
- Inter-tripping and technical synchronisation requirements can be standardised to achieve consistency across all DNSPs. That will encourage facilitate the process of enabling exports and a higher capacity for C&I customers to participate in DR programs.
- The Essential Services Commission can consider including consistent guidelines in the 'Electricity Distribution Code of Practice' on inter-tripping and synchronisation standards.
- The state government can also consider providing additional funding to achieve consistent inter-tripping and synchronisation standards across C&I customers in Victoria.

R5) Biodiesel for Backup Generators (WP-2)

- Biodiesel can be used as a low carbon emission fuel for backup generators. There are ready made units that can be procured in Australia and a complete supply chain exists from the manufacturer to the retailer.
- State and federal governments can provide subsidies to C&I customers to procure biodiesel ready generators, and also appropriate technology to upgrade their back-up generators to operate with biodiesel. This would also include support on the relevant operation costs with the aim of increasing the uptake until it becomes a standard solution.
- The state government can consider providing subsidies for biodiesel and procure technologies suitable for biodiesel in diesel generators. This would help achieving carbon emission reduction targets.

R6) Reforming Energy Tariffs for Batteries (WP-3)

- From the analyses in this project, it is evident that tariffs designed for batteries, e.g., trial tariffs introduced by EvoEnergy, Essential Energy, SA Networks, and AusGrid, have the potential to be cost-effective for C&I customers in comparison to standard tariffs. Therefore, it is recommended to design specific tariffs for batteries.

- Tariff reforms such as introducing a larger gap between peak and off-peak prices as well as extending solar soak times could help customers achieve more savings that would ultimately promote higher uptake of batteries.
- Therefore, it is recommended for DNSPs and retailers design specific tariffs for batteries to increase the uptake of batteries.

R7) Reducing Battery Costs (WP-3)

- From the project analyses, the payback period for C&I customers could be long due to the higher CapEx and OpEx associated with batteries. Therefore, in order to achieve the target payback period, it is recommended to consider potential grants and incentives to reduce battery deployment costs. While it is anticipated that batteries will provide various market and network services, the reduction in prices will help to make C&I batteries financially viable.
- State and Federal governments can continue to offer subsidies and funding for battery deployment.

R8) Ensuring Network Integrity (WP-3)

- Deployment of a large number of behind-the-meter batteries by C&I customers can potentially result in violations of network constraints, such as voltage or line congestion. In order to effectively deploy behind-the-meter batteries at C&I facilities while safeguarding the long-term integrity of the network, it is recommended to explore the adoption of concepts such as the dynamic operating envelope (DOE). Insights and learnings from trials such as Project EDGE can be utilised to design and implement DOEs to ensure network integrity in the presence of a large number of behind-the-meter batteries.
- It is recommended for DNSPs to deploy DOEs in both the MV and LV networks to ensure the integrity of their networks.

The proposed timelines for project recommendations with the responsible organisations are illustrated in Table 6-1.

Table 6-1: Timeline for project recommendations.

Recom. No.	Short-Term	Medium-Term	Long-Term
R1	Demand Response Providers / Aggregators		
R2	DNSPs		
R3	DNSPs		
R4		State Government/ DNSPs/ Essential Services Commission	
R5	C&I Customers/ State Government		
R6	DNSPs and Retailers		
R7	State Government/ Federal Government		
R8		DNSPs	

WP-1 WP-2 WP-3

As shown in Table 6-1, various stakeholders in the demand response industry (i.e., demand response providers/aggregators, DNSPs) can implement the project recommendations from short-term to long-term timeframes. In addition, some recommendations (R4) should be implemented through rulemaking/ policy-making organisations. Financial support is required for some recommendations (R5 and R7), and hence state and federal governments can provide funds to implement those recommendations.

7. References

[1] A. Berry, T. Moore, J. Ward, S. Lindsay, K. Proctor, and T. Mitchell, "National Feeder Taxonomy: Describing a Representative Feeder Set for Australian Electricity Distribution Networks," CSIRO, Newcastle, 2013.

[2] E.L. Oliver, and C. Perfumo, "Technical report: Load and solar modelling for the NFTS feeders Part of the Virtual Power Station 2," CSIRO, Newcastle, 2015.

[3] Jemena, "Embedded Generation Guidelines." [Online]. Available: https://jemena.com.au/getattachment/25d5d563-1087-4619-ac93-ff2148c6e07a/Embedded-Generation-Guidelines-(1).aspx.

[4] AEMC, "National Electricity Rules S5.2.8." [Online]. Available: https://energy-rules.aemc.gov.au/ner/175/24642.

[5] R. Mythili, P. Venkatachalam, P. Subramanian, and D. Uma, "Production characterization and efficiency of biodiesel: a review: Production characterization and efficiency of biodiesel: a review," Int. J. Energy Res., vol. 38, no. 10, pp. 1233–1259, Aug. 2014, doi: 10.1002/er.3165.

[6] A.H. Saeedi Dehaghani and R. Rahimi, "An experimental study of diesel fuel cloud and pour point reduction using different additives," Petroleum, vol. 5, no. 4, pp. 413–416, Dec. 2019, doi: 10.1016/j.petlm.2018.06.005.

[7] Bioenergy Australia, "Biodiesel Industries Australia." Accessed: Dec. 31, 2022. [Online]. Available: https://www.bioenergyaustralia.org.au/join-us/biodiesel-industries-australia.

[8] Macquarie Oil Co, "Poppy oil." [Online]. Available: https://macquarieoils.com.au/poppy/poppy-oil/.

[9] Ecofuels Australia, "Intergrated Agricultural solutions." [Online]. Available: https://www.ecofuels.com.au/biofuels.html.

[10] Ashoil Pty Lttd., "Biodiesel." [Online]. Available: https://ashburton.net.au/enterprise/ashoil-pty-ltd/.

[11] Ecotech Biodiesel, "The power behind change." [Online]. Available: https://www.ecotechbiodiesel.com/company.

[12] ABC News, "Barnawartha biodiesel plant bounces back to life, as industry calls for more government support." [Online]. Available: https://www.abc.net.au/news/2019-07-17/biodiesel-bounces-back-as-barnawartha-plant-reopens/11318966.

[13] A. K. Azad, M. G. Rasul, M. M. K. Khan, S.C. Sharma, and M. A. Hazrat, "Prospect of biofuels as an alternative transport fuel in Australia," Renewable and Sustainable Energy Reviews, vol. 43, pp. 331–351, Mar. 2015, doi: 10.1016/j.rser.2014.11.047.

[14] I. Awudu and J. Zhang, "Uncertainties and sustainability concepts in biofuel supply chain management: A review," Renewable and Sustainable Energy Reviews, vol. 16, no. 2, pp. 1359–1368, Feb. 2012, doi: 10.1016/j.rser.2011.10.016.

[15] IBIS World, "Biggest companies in the Bulk Fuel Storage industry in Australia." [Online]. Available: https://www.ibisworld.com/au/industry/bulk-fuel-storage/5349/.

[16] AMPOL, "Biofuels." [Online]. Available: https://www.ampol.com.au/your-vehicle/petrols-and-diesels/biofuels.

[17] BP Australia, "Diesel blend with biodiesel." [Online]. Available: https://www.bp.com/en_au/australia/home/products-services/fuels/diesel/diesel-blend-biodiesel.html.

[18] Viva Energy Australia, "Shell Fuels." [Online]. Available: https://www.vivaenergy.com.au/motorists/shell-fuels.

[19] Viva Energy Australia, "Viva Energy joins Bioenergy Australia." [Online]. Available: https://www.vivaenergy.com.au/media/news/2020/viva-energy-joins-bioenergy-australia.

[20] Queensland Government, "New $500 million biorefinery planned for Gladstone." [Online]. Available: https://statements.qld.gov.au/statements/94951.

[21] Upstream Energyexplored, "First commercial-scale renewable diesel biorefinery project in Australia secures funding." [Online]. Available: https://www.upstreamonline.com/energy-transition/first-commercial-scale-renewable-diesel-biorefinery-project-in-australia-secures-funding/2-1-1201588.

[22] Bioenergy Australia, "Liquid biofuel." [Online]. Available: https://www.bioenergyaustralia.org.au/resources/liquid biofuel/#:~:text=Caltex%20is%20Australia's%20leading%20supplier,variants%20of%20bioethanol%20and%20biodiesel.

[23] Bioworks, "Biodiesel Supply." [Online]. Available: https://www.bioworks.com.au/BioDiesel-Supply.shtml.

[24] Mobil, "Mobil Fuels FAQs." [Online]. Available: https://www.mobil.com.au/en-au/our-fuels/faqs.

[25] Shell, "Shell Diesel and Adblue." [Online]. Available: https://www.shell.com.au/motorists/shell-fuels/shell-diesel-and-adblue.html#:~:text=Shell%20Biodiesel%20may%20contain%20up,that%20run%20on%20conventional%20diesel.

[26] Refuelling Solutions, "Refuelling Solutions - Australia's First Choice for Over 30 Years." [Online]. Available: https://www.rfs.com.au/fuel-solutions/future-fuels.

[27] Just biodiesel, "Just biodiesel." [Online]. Available: https://justbiodiesel.com.au/.

[28] R. Chen, Z. Qin, J. Han, M. Wang, F. Taheripour, W. Tyner, D. O'Connor, and J. Duffield, “Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts,” Bioresource Technology, vol. 251, pp. 249-258, March 2018, doi: 10.1016/j.biortech.2017.12.031.

[29] P. Graham, J. Hayward, J. Foster, and L. Havas, "GenCost 2021-22: Final report," CSIRO, 2022. [Online]. Available: https://doi.org/10.25919/mb22-c107.

[30] M.M. Fawzy, V. Kazulis, I. Veidenbergs, D. Blumberga, "Levelized cost of energy analysis of co-firing solid, liquid and gaseous fuel," Energy Procedia, vol. 128, pp. 202–207, 2017.

[31] Lazard, “Lazard’s levelized cost of energy analysis—version 11.0,” 2017. [Online]. Available: https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf.

[32] IEEE 33 bus distribution system information, available at: https://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=7059767 [Accessed on April 4, 2023].

[33] Power flow data for 33 bus distribution system from Baran & Wu, available at: https://matpower.org/docs/ref/matpower6.0/case33bw.html [Accessed on April 4, 2023].

[34] ENA customer guide to electricity supply, available at: https://www.energynetworks.com.au/assets/uploads/ENA-Customer-Guide-to-Electricity-Supply1.pdf [Accessed on April 4, 2023].

[35] Optimisation of behind the meter DER generation assets within network constraints: A roadmap to successful DR program (Project 69), Work Package-2 final report, 2023.

[36] Battery optimisation, available at: https://www.habitat.energy/battery-optimisation-and-trading/ [Accessed on April 4, 2023].

[37] F. Pallonetto, M. De Rosa, F. Milano, and D. P. Finn, “Demand response algorithms for smart-grid ready residential buildings using machine learning models,” Applied Energy, vol. 239, pp. 1265–1282, Apr. 2019.

[38] Y. Ozturk, D. Senthilkumar, S. Kumar, and G. Lee, “An Intelligent Home Energy Management System to Improve Demand Response,” IEEE Transactions on Smart Grid, vol. 4, no. 2, pp. 694–701, Jun. 2013.

[39] M.D. Hu Ninghao Liu, Xia, “Techniques for Interpretable Machine Learning,” Communications of the ACM, vol. 63, no. 1, pp. 68–77, Jan. 2020.

[40] Y. Zhang, W. Chen, R. Xu, and J. Black, “A Cluster-Based Method for Calculating Baselines for Residential Loads,” IEEE Transactions on Smart Grid, vol. 7, no. 5, pp. 2368–2377, Sep. 2016.

[41] Y. Chen et al., “Short-term electrical load forecasting using the Support Vector Regression (SVR) model to calculate the demand response baseline for office buildings,” Applied Energy, vol. 195, pp. 659–670, Jun. 2017.

[42] D. Deltetto, D. Coraci, G. Pinto, M. S. Piscitelli, and A. Capozzoli, “Exploring the Potentialities of Deep Reinforcement Learning for Incentive-Based Demand Response in a Cluster of Small Commercial Buildings,” Energies, vol. 14, no. 10, Jan. 2021.

[43] H. Lee, H. Jang, S.-H. Oh, N.-W. Kim, S. Kim, and B.-T. Lee, “Novel Single Group-Based Indirect Customer Baseline Load Calculation Method for Residential Demand Response,” IEEE Access, vol. 9, pp. 140881–140895, 2021.

[44] K. Li, F. Wang, Z. Mi, M. Fotuhi-Firuzabad, N. Duić, and T. Wang, “Capacity and output power estimation approach of individual behind-the-meter distributed photovoltaic system for demand response baseline estimation,” Applied Energy, vol. 253, p. 113595, Nov. 2019.

[45] EnerNOC, Inc., “The Demand Response Baseline,” EnerNOC, Inc., Boston, USA, White Paper, 2011. [Online]. Available: https://library.cee1.org/sites/default/files/library/10774/CEE_EvalDRBaseline_2011.pdf.

Appendix

Appendix A: Work Package 1 Base Line Methods and Machine Learning Techniques

Baseline Type I

The existing baseline methodology is referred to in this report as Baseline Type I. A baseline performance assessment based on historical interval meter data may also include other parameters, such as weather and calendar data. The Baseline Type I method is the most popular method used in DR programs today. Variations of this method include Averaging, Regression, Rolling Average, and Comparable Day.

Characteristics of Baseline Type I methods are as follows:

- Baseline shape is the average load profile.
- Utilises meter data from each individual site.
- Relies upon historical meter data from days immediately preceding a DR event.
- May use weather and calendar data to inform or adjust the baseline.

Averaging Methods

The most broadly used Baseline Type I approaches are the averaging methods, which create baselines by averaging recent historical load data to shape load approximations for specific time intervals. Averaging methods are often called representative day methods or High X of Y methods.

"*A High X of Y baseline considers the Y most recent days preceding an event and uses the data from the X days with the highest load within those Y days to calculate the baselin*e." [45]

A simple example is a simple average across the Y most recent days.

Maximum Base Load

A maximum base load (MBL) evaluates the demand resource's capability to reduce to a certain level of electricity demand. MBL methods find the maximum energy usage expected from each customer and then set a specific level of electricity usage equal to the maximum level minus the dedicated capacity of the customer. MBL methods are sometimes referred to as "drop to" methods because the customer must drop to a specific usage level during an event. On the contrary, most Baseline Type I methods are referred to as "drop by" because the customer knows the amount of committed capacity they must reduce. However, the usage level is not necessarily constant. The MBL is an example of a static baseline because it remains at one level compared to a Baseline Type I method that generates a dynamic, changing load profile throughout the day. Note that with the MBL baseline, it is entirely possible for a customer to "perform" by doing nothing at all, as long as the load is already at or below the "drop to" level [45].

Meter Before – Meter After

The baseline is calculated using only actual load data from a time interval immediately before an event.

Baseline Type II

Most baselines are created using historical meter data from the individual site of the customer. There are cases where data from individual sites are not available, but data from an aggregating meter or a meter representative of several sites are available. In these cases, the meter data can be used to create a baseline for a group of sites and then a method used to allocate the load to specific sites. For example, consider a group of homogenous sites with similar load behaviour. A Baseline Type II method could analyse a few of the sites to develop an average load estimate per site and then allocate load from the aggregated baseline.

In DR programs with commercial and industrial customers, which is the focus of this report, Baseline Type II methods are not common, because most sites either have or can be cost-effectively equipped with interval meters. The Baseline Type II method is more often used in residential DR programs, where it has been cost-prohibitive to install interval meters at every house. However, as the deployment of residential interval meters increases, the need for Baseline Type II methods will likely also decrease [9].

Generation

The baseline is set as zero and measured compared to usage readings from behind-the-meter emergency backup generators. This type of baseline is only applicable to facilities with on-site generation.

The second part of this discussion is allocated to the baseline logic and our findings of implementing an averaging baseline method.

Predictive models and evaluation methods

For all predictive models, to predict the power consumption at a particular time stamp, e.g., 11:00, the model uses ten historical data points, as illustrated in Figure A-1.

kWh Historical readings										Predict
11:00 AM 2/01/2020	11:00 AM 3/01/2020	11:00 AM 6/01/2020	11:00 AM 7/01/2020	11:00 AM 8/01/2020	11:00 AM 9/01/2020	11:00 AM 10/01/2020	11:00 AM 13/01/2020	11:00 AM 14/01/2020	11:00 AM 15/01/2020	11:00 AM 16/1/2020
20	30	15	33	25	30	24	28	27	29	?

Figure A-1: Example of using historical data (10/10) in the prediction and excluding weekend days for DR calculation.

For evaluation of all models the following accuracy metric is used:

$$Accuarcy\ (ACC) = 1 - \frac{\frac{1}{n}\sum_{i=1}^{n}(|\hat{y_i} - y_i|)}{\frac{1}{n}\sum_{i}^{n} y_i} \tag{A.1}$$

where $\hat{y_i}$ is the predicted power consumption, y_i is the real power consumption, and n is the number of prediction samples that depends on the time series length in the test set.

Mathematical models of ML predictors

Linear regression (LR):

$$\hat{y} = a_1 x_1 + \ldots + a_n x_n + b \tag{A.2}$$

Quadratic polynomial regression (NLR):

$$\hat{y} = a_1 x_1^2 + \ldots + a_n x_n^2 + b_1 x_1 + \ldots + b_n x_n + c \tag{A.3}$$

$x_1, \ldots, x_n$ represent the inputs for each predicted $\hat{y}$. For both LR and NLP, the coefficients $a_1, \ldots, a_n$ and $b_1, \ldots, b_n$, and the constants b and c are obtained via the training process. To evaluate how the predicted $\hat{y}$ is accurately corresponding to the real value, the prediction result is evaluated via mean absolute error (MAE), root mean squared error (RMSE), defined as follows:

$$MAE = \frac{1}{n}\sum_{i=1}^{n}\left|y_i - \hat{y}_i\right|$$
$$RMSE = \sqrt{\frac{\sum_{i=1}^{n}\left(y_i - \hat{y}_i\right)^2}{n}} \tag{A.4}$$

where n represents the number of samples. $\hat{y}_i$ and y_i are the predicted and real values of the i-th sample, respectively.

Support vector regression (SVR):

Another way to represent the model is in the matrix form. For linear regression (LR), the matrix form can be represented as follows:

$$\hat{y} = \boldsymbol{w} \cdot \boldsymbol{x} + b \tag{A.5}$$

where $\boldsymbol{w}$ and b are the parameters of the model to be learned during the training. For SVR, the model tries to find the best set of parameters that reduce the distance between the predicted values and real values within some margin of error ε by minimising the following:

$$\boldsymbol{w} \cdot \boldsymbol{x} + b - \hat{y} \leq \varepsilon \tag{A.6}$$

This distance defines the boundary between the predicated and real values. For a nonlinear boundary, a kernel trick is used, such as Radial basis kernel as follows:

$$Radial\ basis\ kernels\ \ K(x, \hat{y}) = \exp\left(-\frac{1}{2\sigma^2}\left||x - \hat{y}|\right|^2\right) \tag{A.7}$$

Bayesian linear regression (BLR):

For BLR, the predicted value in the matrix form is defined as follows

$$\hat{y}_i = \boldsymbol{x}^{\boldsymbol{T}}\boldsymbol{W} + \eta_i \tag{A.8}$$

where η_i is bias value that sampled from the normal distribution $\eta_i \sim N(0, \sigma^2)$.

The BLR assumes that the parameter of model $\boldsymbol{W}$ has a prior distribution as follows:

$$P(\boldsymbol{W}) \sim N(M_o, S_o) \tag{A.9}$$

where M_o is the prior mean, and S_o is the prior covariance which is calculated during the training phase. The common approach to calculating M_o and S_o is by using the Maximum Likelihood Estimator (MLE).

Appendix B: Work Package 2 Methodology

The WP-2 methodology is shown in Figure B-1.

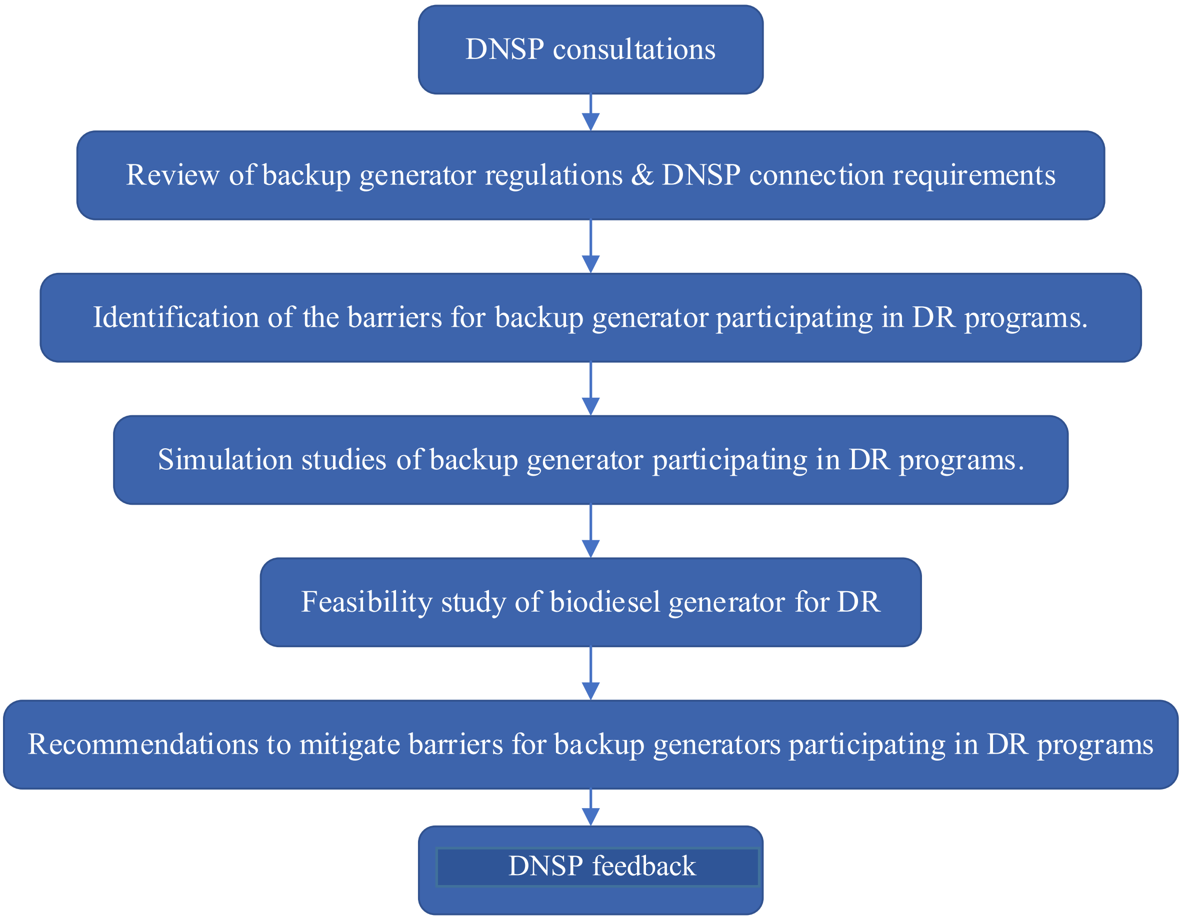


Figure B-1: Work package 2 methodology.

As the first step, the project team has carried out meeting with the Victorian DNSPs to better understand their guidelines on backup generator connections and participation of C&I customers in demand response programs. Also, the project team has reviewed the literature and the DNSP guidelines and standards on backup generator connections and demand response. Next, the team has investigated the barriers for backup generator participating in demand response, which includes three aspects: location-based barriers, network-based barriers, and time-based barriers. For each barrier, the team has conducted comprehensive simulation studies following DNSP guidelines to investigate the impact of backup generators on power grids. Moreover, the team has carried out the feasibility study of biodiesel generators for demand response, which covers the advantages and barriers of using biodiesel generation. After carefully analysing the simulation results, the project team has proposed several recommendations to mitigate barriers for backup generator participating in demand response schemes. Finally, the project team obtained feedback from DNSPs on project recommendations and discuss the implementation roadmap for recommendations.

Simulation Methodology

In this chapter, the barriers to backup generator utilisation in demand response schemes are investigated using simulation studies. Three types of barriers are investigated here: 1) network barriers, 2) location-based barriers, and 3) time-based barriers. Load-flow studies are carried out to explore the barriers regarding network and backup generator location. Time-based barriers are investigated with quasi-dynamic simulations and short-circuit calculations to identify the export limit of the backup generators. The simulation studies are summarised in Figure B-2.

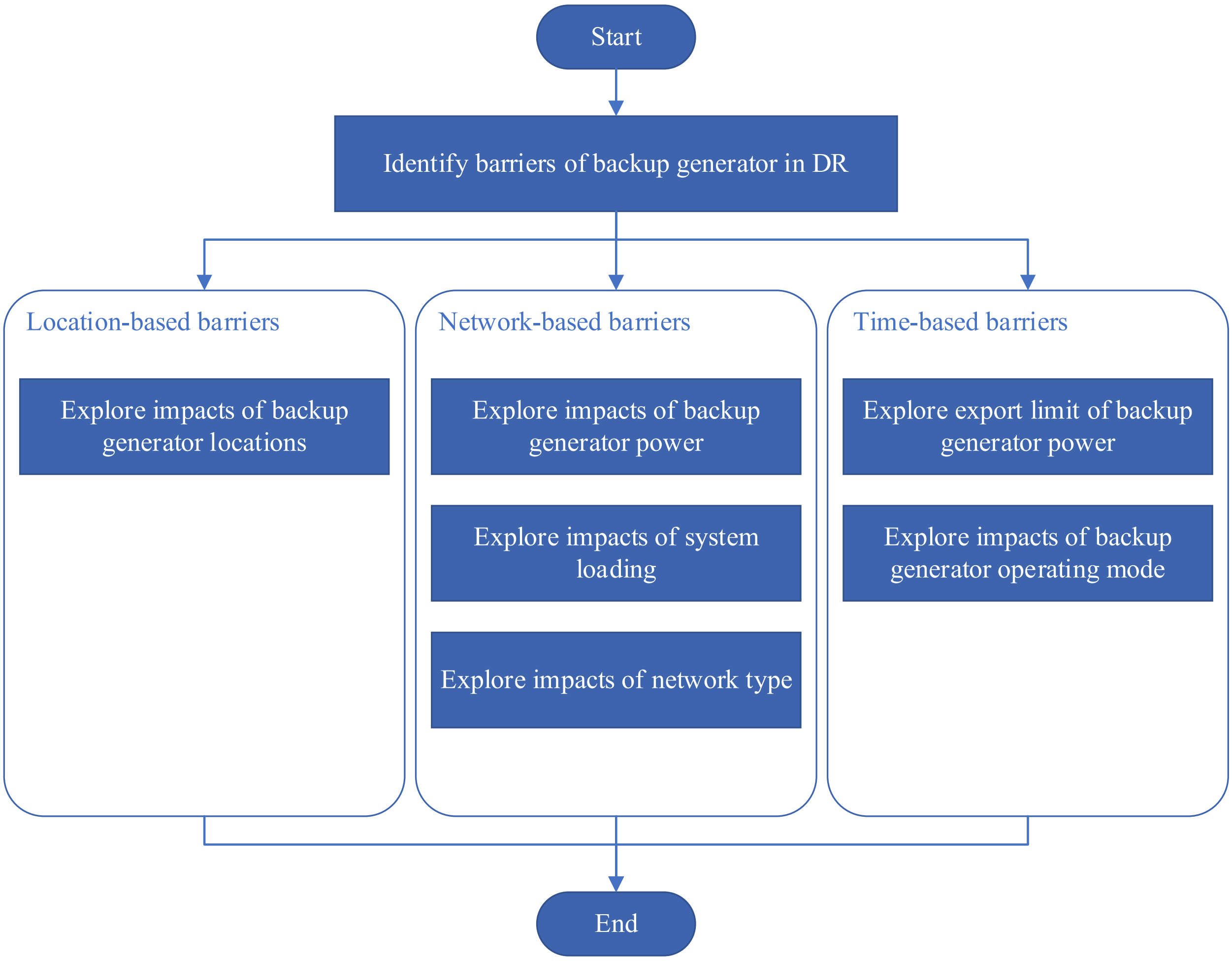


Figure B-2: The simulation methodology.

Appendix C: DNSP Consultations and Feedback

The project team had four DNSP consultation meetings with AusNet Services, Jemena, Powercor and United Energy. The noteworthy comments from these meetings are summarised below:

Meeting with the AusNet Services Team (Date: 18th November 2021)

1. Embedded generator export limit depends on the network type, and where the embedded generator is situated within the network; for example, the export limits are based on whether the embedded generator units are located in urban, semi-urban or rural feeders.
2. Export limits are determined during the network studies stage and are a function of network topology, asset type, voltage limitations and existing installed embedded generation on the feeder (among other factors).
3. The embedded generation connection guide provides further details regarding embedded generator connections to the AusNet services network: https://www.ausnetservices.com.au/en/Electricity/Connections/Apply-for-Solar-and-Other-Generation

Meeting with the Jemena Team (Date: 7th February 2022)

1. Generally, the connection requirements are the same as if it is a permanent arrangement for backup generators with a 'make-before-break' transfer. Depending on the type, size and synchronisation time with the grid, we may consider exemptions to certain performance standards and modelling requirements. Note that only standby generators with a 'make-before-break' transfer require a connection agreement. For 'break-before-make' transfer, an interlock will break the grid connection supply before connecting the alternative supply.
2. Generally, backup generator export is limited to zero. It will only be allowed as a temporary connection to transfer a customer's supply back to the grid. A parallel generator connection with the distribution network will be limited to a maximum time. A timer shall be installed to disconnect the generator from the distribution network if this time is exceeded in cases where there is a 'make-before-break' transfer.
3. Unless requested by the connection applicant, no evaluation will be done to determine the export limit of the backup generator.
4. The same methodology is used for determining the constraints for backup generators as for other generators with a permanent connection.
5. Jemena follows the national electricity rules (NER) Chapter 5A process for generators (non-IES) less than 5MVA which generally takes up to 65 business days to assess an application and make an offer. The timeframe to be brought online will depend on the extent of the connection works required and the customer's generator work to fully commission the generator. Only standby generators with a 'make-before-break' transfer require a connection agreement.
6. The only communication protocol that can be used with Jemena Host supervisory control and data acquisition (SCADA) is DNP3. A Jemena remote terminal unit (RTU) with Distributed

Network Protocol 3 (DNP3) slave connection to SCADA Host at one end and communication connection to embedded generator RTU/controller at the other end could be looked at, depending upon the application

7. Standby generators are not supposed to connect to the grid beyond a temporary connection timeframe to allow customer's supply to be transferred back to the grid.

Meeting with the Powercor/ United Energy Teams (Date 20-05-2022)

- As soon as a plant is going to export, the Powercor treats that as a generator. The requirements are depending on the capacity of the generation plant,
  - Below 5 MW – Powercor performance standards should be met.
  - Above 5 MW – NER Chapter 2 rules will apply. Generators need to meet the NER technical standards and the AEMO would be involved in the connection process.
- For network augmentation and non-network solutions – invite proponent to come with a fee payable to the demand responder.
- The export capability depends on where the backup generator is connected to the network, network conditions and generator capacity. If there is an embedded generator on the feeder, there may not be enough headroom to allow any more capacity. If it requires network augmentation, then it may not be worth to connect the backup/ embedded generator.
- Also, there is no blanket export limit for backup/ embedded generators – it will depend on network conditions and size of the generator. There is a framework for the connection process. The criteria are consistently applied across all backup/ embedded generator connections; however, Powercor assesses each generator connection case-by-case basis.
- Also, it depends on how weak the network is at the generator connection point – need to adhere to voltage and thermal limits of the feeder, and high fault level limits may also be a constraint (Powercor design limit - 13.1 kA (ultimate capacity) – it is depending on switchgear and some may have a lower rating (i.e. old switchgear)). Some limits are from the DNSP code of practice, and some are from asset rating.
- All DNSPs have a similar approach for determining export limits for generators, but different assessment criteria may be applied.
- There are no 'standards' to stipulate how quickly to synchronise. It will depend on the generator size and the impact of the synchronisation activity.
- C&I customers must get an approval from the DNSP on synchronisation period. Make-before-break always synchronise; they may export or stay at zero export.
- Backup generators may export for a minimum number of hours - only use when there is a disruption.
- In break-before-make connection, back-up generators only connect when there is a disruption to the main network. Under break-before-make generation, the interlock prevents from exporting or connecting to the grid.
- In break-before-make, first synchronise with the grid and then export. There is a restriction on how frequent and how often they can export.
- Communication protocol for backup generators is DNP3.

- There is no specific communication protocol requirement for inter-tripping. A range of technologies are recommended.

Powercor/ United Energy Criteria for generator connection

- Preliminary enquiry – export capacity request
- Powercor will respond with available capacity or if an augmentation is required
- Customer to make a decision yes / no – status assessment
- If continuing, Powercor to provide network data- customer must do voltage / thermal studies – to check for any negative impacts
- Next step is to check whether there are no negative impacts for the customer, then to complete a dynamic assessment
- Then a study based on the PSSE model – Powercor will do a study based on standards
- Once all requirements are satisfied, then a connection can be made (e.g., voltage, thermal, fault level study and impact assessment). Power quality assessment includes voltage limits, and flicker etc.
- Commissioning testing will be carried out to ensure agreed performance standards are met.

Meeting with the AusNet Services – (Date 14/07/2022 and via email communications)

- AusNet services assess the generator connections below 5 MW under two categories:
  1. Lower than 1.5MW, customer will need to follow the connection guidelines
  2. Larger than 1.5MW will be assessed by the AusNet team by using guidelines in the following document

  https://www.ausnetservices.com.au/Electricity/Connections/Apply-for-Solar-and-Other-Generation/Large-complex-connections
  https://www.ausnetservices.com.au/en/Electricity/Connections/Apply-for-Solar-and-Other-Generation/Embedded-Generation-Connection-1500-to-5000-kW
- The export limit imposed on the generator depends on the connection type;
  1. Residential/ Commercial/ Industrial solar connections – Export limit up to 5kW per phase or up to 3.5 kW for SWER, and for the inverter energy system (IES) up to 10 kW/phase installed capacity with the basic model standing offer (MSO)
  2. Large solar PV systems (capacity > 30kW) are subjected to AusNet assessment and approval
  3. For community BESS export (for both HV and LV) – Subject to AusNet approval as it depends on the size and LV conductor limitations

     PV/BESS >30 kW subjects to AusNet assessment
- *For generators (non-IES) less than 5MVA, how quickly must the generators be brought online?*

  Depends on the synchronisation technology employed at the backup generator
- *Are there any preferred communication protocols other than "DNP3.0" for SCADA* communication in embedded generators?

Based on SOP 11-16
Various communication requirements are currently under consideration/discussion.

- *What are inter-tripping and communication link requirements for back-up generators and how these requirements are determined?* Is there any flexibility on the communication protocol requirements? Based on SOP 11-16

A Summary of DNSP consultation meetings

Following conclusions can be drawn from the DNSP consultation meetings

- DNSPs have their own guidelines/ methodologies for generator export limit assessment. However, all DNSPs ensure they comply with the NER, existing voltage standards and thermal limits.
- The generator export limit is depending on the network type and the location of the customer, however there is no time-based assessment done for generators.
- There are no consistent requirements for inter-tripping across the four DNSPs in Victoria and each DNSP provides their own requirements for inter-tripping. In particular, there is no consistent technical specification for communication protocol for inter-tripping. Some DNSPs specify costly fibre optic links while the some DNSPs do not have any specific communication requirement for inter-tripping.
- The differences also relate to the threshold of generator capacity above which inter-tripping is required. This means for example that a large energy user with sites spread across the different DNSPs will face different requirements for different sites. It is not possible at the moment to apply a uniform approach and commercial assessment across all of Victoria.

DNSP Feedback Workshop (AusNet Services, Jemena, PowerCor, United Energy)

A feedback workshop was organised by the C4NET on 3rd March 2023 to obtain feedback on the WP2 recommendations. A summary from the feedback workshop is given below:

- All DNSPs have confirmed the benefits of having dynamic export limits for C&I customer backup generators. Also, they have indicated that the dynamic export limit is consistent with the flexible export trial in LV network.
- The study found that the faut level does not affect the export limit. However, AusNet Services has highlighted the fact that the fault level could be an issue for embedded generators connected to underground CBD network. Since study team did not consider the CBD underground network that issue was not captured in the study, but it is not relevant as the study scope include only C&I customers connected to the Urban, Semi-Urban and Rural networks.
- DNSPs have recommended to include more benefits having flexible operating more for backup generators, so that they can consider that option during the connection studies.

Appendix D: Work Package 3 Methodology

The methodology, shown in Figure D-1, has been followed in WP-3 to demonstrate the work package objectives.

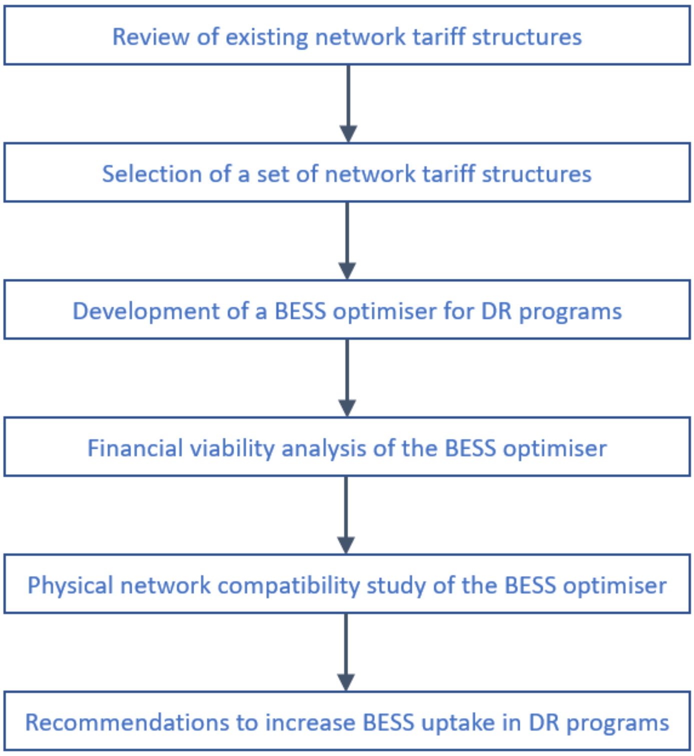


Figure D-1: Work package-3 methodology.

In the first step, the project team reviewed a number of existing network tariff structures. Then, a set of network tariff structures, namely Evo Energy, Essential Energy, SA Network, and AusGrid tariff structures were selected in consultation with AGL. In particular, two aspects of these tariff structures were considered: 1) standard tariff (without BESS trial), and 2) BESS trial tariff. Next, four selected C&I customers, whose profiles were provided by AGL, were chosen, and the project team developed a BESS optimiser for these customers. Afterwards, financial viability analysis was conducted by the project team to explore how the consideration of different BESS sizes and network tariff structures can impact C&I customers financially. Specifically, each C&I customer has been tested with five financial scenarios, such as the consideration of unvaried existing tariff structures, reduction in tariff structures to receive the target PBP, reduction in CapEx to attain the target PBP, increase in the BESS C rating with decreased capacity, and decrease in the BESS C rating with increased capacity. Besides, the project team has performed the distribution network compatibility study of the developed BESS optimiser to demonstrate its operational impacts on network voltages and line loading. Finally, after carefully analysing the simulation results, the project team proposed several recommendations to expedite the uptake of batteries in DR programs.

Appendix E: Network Tariff Structures

Network tariff structures of four DNSPs are selected, namely Evo Energy, Essential Energy, SA Network, and AusGrid. In particular, two aspects of these network tariff structures are considered: 1) standard network tariff (without BESS trial), and 2) BESS trial network tariff. While standard network structures represent the business as usual (BAU) rates assigned for C&I customers, BESS trial network tariff structures denote reduced rates introduced to encourage them to install batteries at their premises.

Table E.1 provides the tariff structure of Evo Energy without and with BESS trial. According to the standard network tariff, peak (from 7 am to 5 pm), off-peak (from 10 pm to 7 am), and shoulder (from 5 pm to 10 pm), ToU rates are 8.85 ¢/kWh, 3.32 ¢/kWh, and 5.31 ¢/kWh, respectively. The FiT rate, demand charge, capacity charge, and supply charge are capped at 4.1 ¢/kWh, 21.22 ¢/kW/day, 21.22 ¢/kW/day, and 59.818 ¢/day, respectively. While ToU prices, FiT rate, and supply charge remain the same in the BESS trial tariff, both demand charge and capacity charge are reduced to 18.95 ¢/kW/day and 18.29 ¢/kW/day, respectively.

Table E.1: Tariff structure of Evo Energy without and with BESS trial.

Tariff component	Without BESS trial	With BESS trial
ToU prices	8.85 ¢c/kWh (peak: 7 am to 5 pm) 3.32 ¢/kWh (off peak: 10 pm to 7 am) 5.31 ¢/kWh (shoulder: 5 pm to 10 pm)	8.85 ¢/kWh (peak: 7 am to 5 pm) 3.32 ¢/kWh (off peak: 10 pm to 7 am) 5.31 ¢/kWh (shoulder: 5 pm to 10 pm)
FiT rate	4.1 ¢/kWh	4.1 ¢/kWh
Demand charge	21.22 ¢/kW/day	18.95 ¢/kW/day
Capacity charge	21.22 ¢/kW/day	18.29 ¢/kW/day
Supply charge	59.818 ¢/day	59.818 ¢/day

The tariff structure of Essential Energy without and with BESS trial is illustrated in Table E.2. In both cases, peak (from 5 pm to 8 pm), off-peak (from 10 pm to 7 am), and shoulder (from 8 pm to 10 pm, from 7 am to 10 am, and 2 pm to 5 pm) rates are considered as 4.41 ¢/kWh, 2.785 ¢/kWh, and 3.79 ¢/kWh, respectively. However, the BESS trial tariff allows C&I customers to charge BESS from the power grid (also includes load demand consumption) free of charge between 10 am and 2 pm whilst without the BESS trial, the rate is 4.195 ¢/kWh. Besides, both tariffs consider the same rates for FiT and supply charge, figuring at 4.76 ¢/kWh and 15.808 AU$/day, respectively. Furthermore, three rates of demand charges are applied in both tariffs (rates are the same without and with BESS trial) throughout a day. For instance, peak, off peak, and shoulder demand charges (subject to the same periods as ToU) are capped at 33.634 ¢/kW/day, 7.585 ¢/kW/day, and 30.430 ¢/kW/day, respectively.

Table E.2: Tariff structure of Essential Energy without and with BESS trial.

Tariff component	Without BESS trial	With BESS trial
ToU prices	4.41 ¢/kWh (peak: 5 pm to 8 pm) 2.785 ¢/kWh (off peak: 10 pm to 7 am) 3.79 ¢/kWh (shoulder: 8 pm to 10 pm and 7 am to 5 pm)	4.41 ¢/kWh (peak: 5 pm to 8 pm) 2.785 ¢/kWh (off peak: 10 pm to 7 am) 3.79 ¢/kWh (shoulder: 8 pm to 10 pm 7 am to 10 am, and 2pm to 5 pm)
FiT rate	4.76 ¢/kWh	4.76 ¢/kWh
Demand charge	33.634 ¢/kW/day (peak) 7.585 ¢/kW/day (off peak) 30.430 ¢/kW/day (shoulder)	33.634 ¢/kW/day (peak) 7.585 ¢/kW/day (off peak) 30.430 ¢/kW/day (shoulder)
Supply charge	15.808 AU$/day	15.808 AU$/day

Table E.3: Tariff structure of SA Network without and with BESS trial.

Tariff component	Without BESS trial	With BESS trial
ToU prices	5.33 ¢/kWh (peak: 7 am to 9 pm) 3.9 ¢/kWh (off peak: 9 pm to 7 am)	5.33 ¢/kWh (peak: 7 am to 9 pm) 3.9 ¢/kWh (off peak: 9 pm to 7 am)
FiT rate	5 ¢/kWh	5 ¢/kWh
Demand charge	9.589 c/kW (5 pm to 9 pm) 85.855 ¢/day (fixed)	4.795 ¢/kWh (5 pm to 9 pm) 42.927 ¢/day (fixed)
Supply charge	2.739 AU$/day	2.739 AU$/day

The tariff structure of SA network without and with BESS trial is depicted in Table E.3. In this tariff structure (with and without the BESS trial), C&I customers are charged at 5.33 ¢/kWh and 3.9 ¢/kWh during peak period (from 7 am to 9 pm) and off-peak period (from 9 pm to 7 am), respectively. The same supply charge and FiT rate are also applied with and without the BESS trial, figuring at 2.739 AU$/day and 5 ¢/kWh, respectively. Besides, the SA network tariff structure contains two components of demand charge, such as fixed (applicable everyday) and varying (applicable from 5 pm to 9 pm). Each of the demand charge component is cut down by 50% in the BESS trial tariff.

Table E.4 demonstrates the tariff structure of AusGrid. In the standard tariff structure, 15.33 ¢/kWh, 2.078 ¢/kWh, and 4.52 ¢/kWh are imposed on C&I customers during peak (from 2 pm to 8 pm), off-peak (from 10 pm to 7 am), and shoulder (from 7 am to 2 pm, and from 8 pm to 10 pm) periods, respectively. Also, C&I customers pay 4.769 ¢/kW/day and 146.973 ¢/day as demand and supply charges. They receive FiT at 5 ¢/kWh for excess solar export. On the contrary, in the community BESS trail tariff, 1.6 ¢/kWh and 141 ¢/kWh are added, along with same standard ToU prices, for charging BESS during off-peak and peak periods, respectively. Moreover, 0.75 ¢/kWh is paid to the C&I customers for exporting BESS discharge into the power grid during peak hours while completely calling off the demand charge and keeping the supply charge unvaried.

Table E.4: Tariff structure of AusGrid without and with BESS trial.

Tariff component	Without BESS trial	With BESS trial
ToU prices	15.33 ¢/kWh (peak: 2pm to 8 pm) 2.078 ¢/kWh (off peak: 10 pm to 7 am) 4.52 ¢/kWh (shoulder: 7 am to 2 pm and 8 pm to 10 pm)	15.33 ¢/kWh (peak: 2pm to 8 pm) 2.078 ¢/kWh (off-peak: 10 pm to 7 am) 4.52 ¢/kWh (shoulder: 7 am to 2 pm and 8 pm to 10 pm) 1.6 ¢/kWh (off-peak charge) 141 ¢/kWh (peak demand charge)
FiT rate	5 ¢/kWh	5 ¢/kWh 0.75 ¢/kWh (peak discharge)
Demand charge	4.769 ¢/kW/day	0 ¢/kW/day
Supply charge	146.973 ¢/day	146.973 ¢/day