Economic Optimisation of Typical Electrical Microgrids in Western Australian Industrial Zones

Submitted to the School of Engineering and Information Technology, Murdoch University in partial fulfilment of the requirements for the degree of Bachelor of Engineering Honours [BE(Hons)] Electrical Power, Industrial Computer Systems

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13 August 2018

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Author’s Declaration

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Abstract

The objective of this thesis is to examine the microgrid concept as a viable economic alternative to the centralised electrical network in Western Australia when applied to industrial loads. The key focus was on formulating an economic optimisation model as it is applied specifically to new Western Australian industrial developments. The Nambeelup Industrial Area, located approximately 9 km northeast of the city of Mandurah, is the electrical and thermal load considered for this task. Analysis was conducted to determine a range of technically viable microgrid configurations that display economically superior characteristics when compared to the benchmark. This benchmark is a proposed $31.1M infrastructure upgrade to supply the Nambeelup Industrial Area through the Meadow Springs Substation which is part of the South West Interconnected System. Using HOMER\(^1\) software and the acquired industry data, a range of distributed energy resources (DER), energy storage systems, thermal recovery systems and varying states of grid connection were modelled over a 25-year project life.

The studies show that the initial capital expenses of proposed microgrids were often many times the benchmark cost but had a decidedly lower project net present cost. Specifically, results revealed that increased DER penetration correlated with an average discounted savings of $350M over the project lifetime, which lead to an average payback period of less than three years when compared to the benchmark. Economically optimised architectures often featured combined heat and power (CHP) equipped gas-fired combustion generation with large-scale wind turbines. A final set of architectures were proposed based on their respective optimisation variables with a main featured configuration of a single 32 MVA CHP equipped gas turbine, an 18.15 MW wind farm and a 60 MWh vanadium redox flow battery bank installation. The featured system provides a more reliable and environmentally superior thermal and electrical energy source at a total net present cost of $411.6M which equates to a $47.97M per year project savings compared to the benchmark. Across the modelled topologies an average CO\(_2\) emissions improvement was observed of over 500 tonnes per year per every dollar invested. To financially quantify the

\(^1\) HOMER – Hybrid Optimisation of Multiple Energy Resources
environmental improvement brought about by this, a carbon tax was introduced to the optimisation model which shows that high DER penetration carries an economic benefit of over $2M per year due to decreased emissions. The economic and environmental findings underpin the microgrid concept as an advisable energy generation and distribution option for large-scale industrial and commercial energy requirements in Western Australia.

**Keywords** – Microgrid, Distributed Energy Resources, Optimisation, Sensitivity Analysis, Cost-Effectiveness Analysis, Net Present Cost, Levelised Cost of Energy, Combined Heat and Power
Acknowledgements

I would first like to thank my thesis supervisor Dr Ali Arefi for his guidance and support throughout this process. Throughout this endeavour he empowered me to achieve beyond what I expected. It was a privilege to have access to his knowledge in developing this work. I would also like to acknowledge and thank Dr Martin Anda, Dr Farhad Shahnia and Dr GM Shafiullah for their guidance during our meetings early in the project.

To my wife, Diana, for her tireless efforts in supporting me throughout this process. During this project she accepted an enormous additional load which I think was unfair at times, but she responded with a powerful optimism and boundless work ethic. There is no way this would have been achieved were it not for her strong values.

I would also like to thank Wolfgang for his support and friendship during this time. And, finally, a special mention to my mother, Nancy, for her love and support over the years.
Dedication

To Julian, Dahlia and Georgia – may your future world be awesome.

I hope this work can somehow make that more likely.

Love you – Papa
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<th>Description</th>
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<tbody>
<tr>
<td>AEMO</td>
<td>Australian Energy Market Operator</td>
</tr>
<tr>
<td>ARENA</td>
<td>Australian Renewable Energy Agency</td>
</tr>
<tr>
<td>AUD</td>
<td>Australian Dollars</td>
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<tr>
<td>CAPEX</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CO₂</td>
<td>Carbon Dioxide</td>
</tr>
<tr>
<td>CT</td>
<td>Combustion Turbine</td>
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<tr>
<td>CVBP</td>
<td>Canning Vale Business Park</td>
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<tr>
<td>DER</td>
<td>Distributed Energy Resource</td>
</tr>
<tr>
<td>DG</td>
<td>Diesel Generator</td>
</tr>
<tr>
<td>ER</td>
<td>Emissions Reduction</td>
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<tr>
<td>EUR</td>
<td>European Dollars</td>
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<td>GHG</td>
<td>Greenhouse Gas</td>
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<td>GT</td>
<td>Gas Turbine</td>
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<tr>
<td>HOMER</td>
<td>Hybrid Optimisation of Multiple Energy Resources</td>
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<tr>
<td>LA</td>
<td>Lead-Acid</td>
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<tr>
<td>LCOE</td>
<td>Levelised Cost of Energy</td>
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<tr>
<td>LI</td>
<td>Lithium-Ion</td>
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<tr>
<td>LPG</td>
<td>Liquified Propane Gas</td>
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<tr>
<td>MSS</td>
<td>Meadow Springs Substation</td>
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<td>NIA</td>
<td>Nambeelup Industrial Area</td>
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<td>NPC</td>
<td>Net Present Cost</td>
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<tr>
<td>O&amp;M</td>
<td>Operations and Maintenance</td>
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<td>OLTC</td>
<td>On-Load Tap Changer</td>
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<tr>
<td>OPEX</td>
<td>Operating Expenditure</td>
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<tr>
<td>poly-Si</td>
<td>Poly-Crystalline Silicon</td>
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<tr>
<td>PV</td>
<td>Photo-voltaic</td>
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<tr>
<td>RF</td>
<td>Renewable Fraction</td>
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<tr>
<td>RICE</td>
<td>Reciprocating Internal Combustion Engine</td>
</tr>
<tr>
<td>SAIDI</td>
<td>System Average Interruption Duration Index</td>
</tr>
<tr>
<td>SAIFI</td>
<td>System Average Interruption Frequency Index</td>
</tr>
<tr>
<td>SWIS</td>
<td>South West Interconnected System</td>
</tr>
<tr>
<td>USD</td>
<td>United States Dollars</td>
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<tr>
<td>VCR</td>
<td>Value for Customer Reliability</td>
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<tr>
<td>VRFB</td>
<td>Vanadium Redox Flow Battery</td>
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<tr>
<td>WA</td>
<td>Western Australia</td>
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<td>WT</td>
<td>Wind Turbine</td>
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## Key Units

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<td>A</td>
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<td>kAh</td>
<td>Kilo-Amp-Hours</td>
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<td>kT</td>
<td>Kilo-Tonnes</td>
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<tr>
<td>kV</td>
<td>Kilo-Volts</td>
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<td>kVA</td>
<td>Kilo-Volt-Amperes</td>
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<td>Kilo-Watts</td>
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<td>kWh</td>
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<td>m</td>
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<td>MVA</td>
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Chapter 1 Introduction

The expectations of electricity consumers have gone beyond reliability and security and now includes reduced environmental impact and improved social benefits [1]. However, consumer concerns alone have not been enough to standardise the adoption of renewable Distributed Energy Resources (DERs) in the design and development of industrial area electrical power infrastructure. Profitability is the most significant factor in any investment consideration. This principle would serve as the primary enabler in energy alternatives to the status quo [2]. As ageing infrastructure reaches its limits, significant decisions loom over the next evolution of electrical distribution networks in Australia. Stakeholders in this decision-making process are faced with the need to assess future network investments with a multi-objective approach.

Energy market conditions, coupled with the rising use of DERs, provide a unique opportunity for increased renewable penetration and disruptive technology uptake in industrial area development to offset overhead costs [3, 4]. These factors are giving rise to the smart grid concept, which is an electrical network that, among other things, facilitates an intelligent integration of DERs [2]. Deeper still are microgrids, which serve as the building blocks of the larger, more encompassing smart grids [2]. Microgrids are designed to address a multi-objective purpose, which includes enhanced reliability, increased renewable DER use and improved efficiencies through waste heat recovery [5]. The microgrid concept is fast becoming a large part of the Australian Renewable Energy Agency (ARENA) strategy to address renewable energy targets [6]. In 2016 the development plan for the Onslow DER microgrid was announced [7]. The project is the largest DER project in Australia with the aim to meet 50% of Onslow’s electricity needs through renewable sources and serves as a precedent for renewable penetration into residential and industrial zones. Although the Onslow project will act as a useful prototype of large-scale DER use, there is still a need to research on improving the investment profitability of microgrids in Australian industrial settings. If an economical microgrid configuration can be found, it can serve to promote more widespread dissemination of the concept among land developers.
Chapter 2  Project Background

The Western Australian State Government has established a range of regional development commissions, which serve to facilitate social and economic development among other responsibilities. The Peel Development Commission is one such statutory authority that tends to the needs of the Peel region approximately 75km from Perth, Western Australia. The Nambeelup Industrial Area (NIA) is located within the Peel region (Fig 2-2) and is the considered industrial area for this project.

![Fig 2-1. Nambeelup Location](image1)

![Fig 2-2. NIA Location](image2)

This project will form the electrical portion of a consolidated cross-faculty\(^2\) effort to develop a sustainable energy-water nexus concept for the NIA in collaboration with the Western Australian land authority, Landcorp. Landcorp owns approximately 120 hectares of the 1000-hectare Peel Business Park [9], located within the NIA.

2.1 Statement of Work

Motivations underpinning microgrid implementation can be argued in many ways. The most established benefit of microgrid operation is power reliability [10]. Reliability, however, is not a comparatively large concern for customers within the South West Interconnected System (SWIS).

\(^2\) In collaboration with the Environmental Engineering Department
From the 2016 Service Standard Performance Report issued by the SWIS network operator, Western Power, the system reliability indices were within the required performance benchmarks [11]. Of arguably greater social importance is the initiative to reach the Renewable Energy Target, which aims to reduce the national dependence on coal-fired power generation [12]. The dissemination of microgrid technology in industrial land development and construction will provide a significant boost to these efforts.

Pivotal to any project undertaking is the economic feasibility and return on investment. Consequently, it is necessary to uncover the most cost-effective configuration to act as an enabler to microgrid adoption in industrial areas throughout regional Australia. As part of the rationale behind this undertaking, gaining an understanding of the real costs of the current centralised network was a principal objective. Pepermans et al. make the argument that DER does not have the benefits of the economy of scale and, as a result, is significantly disadvantaged economically when compared to large-scale centralised distribution networks [13]. Byrnes et al. make a point that externalised costs artificially lower network connection and operation expenses, which underlines the need to understand the economics behind microgrid implementation [14]. A thorough discussion of the general benefits, opportunities and barriers is in Appendix A of this document.

The aspiration of this project is to understand renewable DER penetration and the effects of economic enablers (if any exist). To best achieve this aspiration, a detailed exploration is conducted into the impact of microgrid implementation applied to large-scale industrial energy requirements. An argument is posed that increased deployment of these concepts is economically superior to centralised energy generation, transmission and distribution. Finally, this project endeavours to find the optimal economic DER configuration for an industrial area in regional Western Australia.

2.2 Essential Concepts

It is essential to gain an appreciation of the factors and attributes that affect the viability of an investment in this technology. Objectives can be grouped into the categories of Environment,
Economy, Sustainability, Reliability and Modularity. A discussion on the opportunities and benefits of microgrid deployment are discussed later in Appendix A of this document. It is presumed that the person who reads this has a general understanding of renewable energy (RE), the microgrid concept and the ideas behind DER hybrid networks. However, for quick reference a brief explanation is provided, consider the following definitions:

- **Microgrid** – A local, distributed source network designed to supply a range of loads through a multi-objective control architecture\(^3\)
- **DER** – Energy generation resources attached directly to the associated power distribution network to satisfy local energy and local ancillary network services\(^7\)
- **RE** – An inexhaustible natural energy source that can be regularly replenished centrally or locally\(^5\)

Please see Appendix B for a more detailed summary and a list of well-known microgrid projects for reference.

---

**Fig 2-3. Typical Attributes of a Microgrid**

### 2.2.1 Economic Considerations

When performing microgrid economic feasibility analysis, it is essential to evaluate a variety of equipment configurations, system limitations and variable sensitivities to optimise returns on

---

\(^3\) Derived from [2, 15-20]

\(^4\) Derived from [21-23]

\(^5\) Derived from [24-26]
investment. Using various modelling packages, one can find a good summary of the economic considerations essential to the viability evaluation. From a range of literature, it is evident that the two primary financial factors are the net present cost (NPC) of the system and the levelised cost of energy (LCOE) when the system is in operation [27-34]. It is worth mentioning that a significant constraint on any project undertaking is the initial project capital investment (CAPEX) and ongoing project operating expenses (OPEX)\(^6\). This forms a meaningful evaluation metric in the assessment of viability. For a detailed explanation of NPC and LCOE, please refer to Appendix A.2 of this document.

### 2.2.2 Environmental Considerations

Arguably the prevailing objective in the deployment of microgrids is to establish a more ecologically friendly means of energy production and consumption. Metrics have been developed to govern and evaluate the level of positive environmental impact over a project lifecycle. Researchers have suggested that the crucial environmental performance indicators are the fraction of renewable DER to non-renewable DER within a system and the reduction in greenhouse gas emissions (GHG) [21, 28, 29, 36]. Although environmental metrics such as renewable fraction (RF) and emissions reduction form essential measures to assess system performance, the document scope does not permit a detailed assessment of these variables. An in-depth look at RF and emissions reduction calculations is in Appendix A.3 of this document.

### 2.2.3 Microgrid Modelling Packages

Numerous software packages can provide economic analysis of microgrids and DER systems. From research, it is clear that Hybrid Optimisation of Multiple Energy Resources (HOMER) is a widely used tool for general microgrid economic modelling and evaluation [37]. This was utilised for the primary modelling done in this project. Please see Appendix B.3 for a summary of other software packages.

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\(^6\) As defined in [35], not to be confused with Operations and Maintenance (O&M) costs
Chapter 3  The State of the Art

3.1  Analysis of Selected Case Studies

The following table presents a summary of chosen Australian research projects reviewed in this document. There were 10 research papers (11 case studies) that fit the selection criteria and were deemed to be of direct relevance to the project. Of the 11 studies listed in the table below, 2 were reviewed in this section. Further discussion around other studies can be found in Appendix A.3.

<table>
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<td>Orhan et al. [27]</td>
<td>Oct-14</td>
<td>Christmas Island, WA</td>
<td>0.6 – 100 kWa</td>
<td>DG-WT-PV-Batt</td>
<td>Diesel</td>
</tr>
<tr>
<td>Orhan et al. [27]</td>
<td>Oct-14</td>
<td>Kangaroo Island, SA</td>
<td>1.9 – 200 kWa</td>
<td>Grid-DG-WT-PV-Batt</td>
<td>Diesel</td>
</tr>
<tr>
<td>Kumar [36]</td>
<td>Oct-14</td>
<td>Geelong, VIC</td>
<td>4.2 kWp</td>
<td>Grid-PV-Batt</td>
<td>None</td>
</tr>
<tr>
<td>Franklin et al. [38]</td>
<td>Oct-13</td>
<td>Heron Island, QLD</td>
<td>169 kWp</td>
<td>DG-PV-Batt</td>
<td>Diesel</td>
</tr>
<tr>
<td>Jamal et al. [39]</td>
<td>Jul-17</td>
<td>Mid-West Region, WA</td>
<td>589 kWp</td>
<td>Grid-DG-PV-Batt</td>
<td>Diesel</td>
</tr>
<tr>
<td>Dalton et al. [40]</td>
<td>Jul-08</td>
<td>Gold Coast, QLD</td>
<td>900 kWp</td>
<td>Grid-DG-WT-PV-Batt</td>
<td>Diesel</td>
</tr>
<tr>
<td>Shafiullah et al. [33]</td>
<td>Mar-12</td>
<td>Generic Australian</td>
<td>14 kWp</td>
<td>Grid-WT-PV</td>
<td>None</td>
</tr>
<tr>
<td>Liu et al. [34]</td>
<td>Sep-12</td>
<td>Various Sites, QLD</td>
<td>3.1 kWp</td>
<td>Grid-PV-Batt</td>
<td>None</td>
</tr>
<tr>
<td>Kumar et al. [41]</td>
<td>Aug-14</td>
<td>Various Sites, VIC</td>
<td>100 kWp</td>
<td>Grid-OG-PV-Batt</td>
<td>Various 9</td>
</tr>
</tbody>
</table>

3.1.1  Christmas Island, WA [27]

Due to unavailable or unfeasible grid extensions, island communities are often forced to use stand-alone diesel generators. Orhan et al. postulate that, as a result, LCOE and emissions increase to the detriment of those communities [27]. A hybrid model was proposed and modelled with an LCOE of 0.314 $/kWh and an NPC of $3.66M to service a load of 100 kW average. The final topology was a 2.66 MW Diesel Generator, 40 kW Solar PV, 50x 7.5 kW Wind Turbines, 750x 6 V 1.16 kAh batteries and a 500 kW Power Rectifier / Inverter.

7 Abbreviations: kWa – Average Power in kilo-watts, kWp – Peak Power in kilo-watts
8 Abbreviations: Diesel Generator (DG), Other Generator (OG), Wind Turbine (WT), Solar Photo-Voltaic (PV) and Battery (Batt)
9 Ethanol, Diesel, Gasoline, Methanol, Natural Gas and Propane
3.1.2 Laverton, WA [30, 31]

Remote locations in Western Australia pose interesting challenges to the regional network service operator, Horizon Power. Edge-of-grid locations provide excellent opportunities for hybrid DER and microgrid implementation. Ali and Shahnia suggest that using HOMER software to assess the real demand data, an optimal LCOE could be found for the township of Laverton [30, 31]. Furthermore, an examination of the effects of load growth was conducted using a sensitivity analysis. A hybrid, standalone model was proposed and modelled with a final LCOE of 0.246 $/kWh and a project NPC of $10.4M to service a load of 415 kW average (1.35 MW peak). The final topology was a 700 kW Diesel Generator, 500 kW Solar PV, 5x 275 kW Wind Turbines, 300x 6 V 1.23 kAh batteries and a 500 kW Power Rectifier / Inverter.

3.2 Discussion and Knowledge Gaps

Throughout these studies, a collection of results was observed with a noticeable deviation based on location-specific causation. It was seen very clearly that there are significant opportunities economically and environmentally with the implementation of hybrid DER and microgrids. From review, there are many widespread practices and theories:

- HOMER software is the leading software package for economic / environmental assessment
- The four primary success criteria are LCOE, NPC, RF and emissions reduction
- In general, economic feasibility analysis is linearly scalable\textsuperscript{10,11}
- A hybrid Grid-DER topology is typical and often the most economically feasible\textsuperscript{12}
- Diesel is the most common fuel used with non-renewable DER

These prevailing practices and ideas are non-prohibitive and leave room for questioning and further analysis. Interrogating these dominant ideas introduces knowledge gaps that, in the opinion of the author, have not been satisfied to date. These deficiencies, considering the project scope, are listed below in no order:

\textsuperscript{10} e.g. studies on smaller loads can be scaled with a coefficient
\textsuperscript{11} The author believes that this is also acceptable due to the modularity of DER and the possibility of microgrid coupling
\textsuperscript{12} Often due to sell-back opportunities
• There is not a satisfactory amount of studies done relating to Western Australia\textsuperscript{13}
• In general, load sizes studied are smaller than what is considered in this project\textsuperscript{14}
• DER considered in most studies assume a homogenous generator fuel use\textsuperscript{15}
• DER considered does not appear to provide a significant energy-water nexus\textsuperscript{16,17}
• Considered studies have not developed a depth of knowledge about the tariff cost sensitivities
• Literature has mainly focussed on retrofit / brownfield type work\textsuperscript{18}
• Loads considered have been primarily residential or small commercial zoning\textsuperscript{19}
• Use of HOMER is the prevailing modelling technique\textsuperscript{20}

The author will endeavour to bridge these gaps by building in sufficient sensitivities based upon location-specific data and policy.

\textsuperscript{13} Although many generic studies provide high percentage accuracy of possible results, a more location-specific study is required
\textsuperscript{14} The linear scalability of models will assist in the endeavour; however, increasing load sizes lead to scaled capital costs. It has been shown that high capital costs are a prevailing barrier to microgrid proliferation.
\textsuperscript{15} There has been minimal research into alternative biofuels in Australian microgrid applications
\textsuperscript{16} There is a need to find possible interconnections between utility services
\textsuperscript{17} This was eventually deemed to be outside of project scope
\textsuperscript{18} There is a need for a more off-the-shelf model for greenfield developers
\textsuperscript{19} There is a need to assess the impact of industrial loads
\textsuperscript{20} There is a very limited understanding of other methods and alternative software review
Chapter 4  Model Development

A firm understanding of system attributes and the current state of the art must be ascertained to develop a robust model. Knowledge around the status-quo and emerging, decentralised approaches must be developed. The model development, testing and analysis methodology will follow the proposed sequence comprised of three sections:

1. Create a combined model and carry out complete system testing and analysis
   a. Define and input electrical and thermal load
   b. Define and input electrical network (Grid)
   c. Define and select the best conventional generation technology
   d. Define and select the best RE sources
   e. Define and select the best energy storage options
   f. Define and select suitable dispatch controllers

2. Conduct a sensitivity analysis on critical criteria
   a. Fuel
   b. Tariffs
   c. Load size

3. Combine all results and provide commentary and conclusion

After base system and sensitivity analysis, an overall results analysis was conducted with a discussion around the topology permutations and subsequent performance.

Unless otherwise stated, all dollar values have been converted to Australian dollars.

<table>
<thead>
<tr>
<th>Conversion Rates [42]</th>
</tr>
</thead>
<tbody>
<tr>
<td>AUD:EUR ( \rightarrow ) 1.61:1</td>
</tr>
<tr>
<td>AUD:USD ( \rightarrow ) 1.28:1</td>
</tr>
</tbody>
</table>

4.1  Model Building: Electrical and Thermal Load

Landcorp provided Murdoch university with electrical demand data for the Canning Vale Business Park (CVBP) covering the 2016 calendar year. A profile was generated and analysed as an analogous demand to what the NIA might require. The details of the CVBP load profile can
be found in Appendix F.3.1. A load was modelled for the NIA using the energy usage patterns observed in the CVBP. The NIA load demand was scaled up to a peak of 60 MW based on the Western Power Mandurah Load Area Non-Network Options Report [43]. Essential details are found in the table below.

![Table 4-1. NIA Load Attributes](image)

<table>
<thead>
<tr>
<th>Attributes</th>
<th>Nearest Substation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average kWh/d: 575,662.32</td>
<td>Meadow Springs (MSS) – Remaining Capacity: &lt;5 MVA</td>
</tr>
<tr>
<td>Average kW: 23,985.93</td>
<td>Main Feeder</td>
</tr>
<tr>
<td>Peak kW: 59,390.98</td>
<td>MSS504 – Tandure Cir – (22 kV, 324 A rated)</td>
</tr>
<tr>
<td>Load Factor: 0.4</td>
<td></td>
</tr>
<tr>
<td>Land Area: 120 ha</td>
<td></td>
</tr>
</tbody>
</table>

The Western Power forecast report suggests less than 5 MVA of available capacity through the Meadow Springs Substation. Furthermore, there is only one feeder with a maximum theoretical power delivery of 12 MVA meaning that the current infrastructure is grossly inadequate to service the NIA electrical load demand. Please see Fig 4-1.

![Fig 4-1. Averaged Power Demand NIA](image)

Defining and modelling NIA thermal demand is of importance to the selection of Combined Heat and Power (CHP) options with the conventional generation technologies assessed as part of the model. As there are no explicit thermal demand profiles for industrial estates of similar size and characteristics to the NIA, an assumption needed to be made as to the thermal load. Activities creating the most considerable thermal demand are space heating, water heating and cooking – all of which are anticipated tenant activities within the NIA. According to a 2008 Department of
Industry, Innovation and Science report [44] the trends in fuel energy consumption per household show an electricity to gas use ratio of approximately 25:17. Using this ratio to get an estimated value for the NIA thermal load we get the following:

- Annual Electrical Consumption – 210.12 GWh (24 MWa / 60 MWp)\(^{21}\)
- Annual Gas (Thermal) Consumption – 142.8 GWh (16.3 MWa / 30.5 MWp)

This assumption has also been limited to very traditional heating and cooking delivery types using natural gas as the primary fuel. The conventional generation models will include options for CHP as part of the value analysis based on the assumed thermal load.

A pattern of higher usage during the business hours is evident when looking at the hourly average electrical loads over the whole year. This pattern is consistent with typical industrial and commercial usage patterns. The figures below provide visibility into the hourly averages of both thermal and electrical loads. As mentioned earlier, the thermal load (gas water heating, cooking and ambient heating) was assumed to be a scale of 25:17 to the electrical load [44]. Furthermore, the average thermal usage was fit to a 4th order polynomial curve to represent a similar behaviour to the electrical usage.

21 MWp – Peak Power in units of Mega-Watts, MWa – Average Power in units of Mega-Watts
4.2 Model Building: Electrical Network

From the distribution system assessment and the projected increased load demand of the NIA, it is clear there is a significant electrical power shortfall predicted. Fig F-11 in Appendix F.3.2 provides data on the power requirements for the two loads.

The Mandurah Load Area Non-Network Options Report provides several network upgrade options to meet the growing demand in the Mandurah region over the next 5-10 years [43]. With the proposed NIA expansion, there is a need for a large enhancement to the distribution network or an embedded generation development to meet future demand. Options that have been provided within the report include the following:

1. Rebuild of Mandurah Substation and expand Meadow Springs Substation
   a. Total NPC: $35.7M
   b. Capacity Increase: 94.8 MVA

2. Rebuild of Mandurah Substation
   a. Total NPC: $30.7M
   b. Capacity Increase: 69.0 MVA

3. Expand Meadow Springs and build a new substation
   a. Total NPC: $42.4M
   b. Capacity Increase: 80.3 MVA

<table>
<thead>
<tr>
<th>Table 4-2. Load Comparisons</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
</tr>
<tr>
<td>------</td>
</tr>
<tr>
<td>Canning Vale Business Park</td>
</tr>
<tr>
<td>Nambeelup Industrial Area</td>
</tr>
</tbody>
</table>

As previously suggested, reliability is one of the most significant benefits gained from the installation of distributed generation [10]. It is therefore pertinent to accurately model outage frequency and include a reliability cost metric as part of the economic evaluation. Performance
indices such as the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are commonly used by network operators to assess the reliability of the system [45]. SAIFI provides an indicator of the mean frequency of electrical supply outages to customers in the network. SAIDI gives insight into the mean duration of outages which can be directly linked to the repair time needed to remediate the outage. Both indices are calculated with respect to the number of customers served in the network. However, for this project, the NIA is treated as a single consolidated customer.

The SWIS boasts a very reliable electricity grid with SAIDI and SAIFI indices well above the industry benchmark [11]. The Western Power Service Standard Performance Report provides essential insights into the SWIS reliability performance [11]. Looking at the 2016 report, an analysis can be carried out on service standard benchmarks and targets which will provide insight into the SWIS reliability metrics to include in the model. Essential items that need to be contained within in the model include mean outage frequency (per year), mean repair time (hours) and repair time variability (%). The urban service performance reveals the following:

- **SAIFI** – 1.09 outages per year
- **SAIDI** – 103 minutes per outage (1.71667 hours)
- **Repair time variability** – 11.4 % (based on the last four years min/max range)

These values were entered in the model under the “scheduled rates” tab.

![Fig 4-4. Reliability data entry in HOMER](image-url)
As a “grid-only” scenario cannot be characterised as 100% reliable, it is necessary to financially quantify this capacity shortage as an additional cost in the final economic appraisal. This will assist in understanding the possible reliability benefits that DER technology can produce for the NIA. Finding a SWIS-specific cost per kWh of capacity shortage is quite a difficult task, and a general coefficient is assumed from two literature sources. In a 2016 network risk planning paper by Arefi et al. many values were used to associate a cost to network reliability [46]. In this paper, a value for customer reliability (VCR) was used from a 2014 Australian Energy Market Operator (AEMO) report which provides insight into the importance, and subsequent worth, of reliable energy to residential customers across most states in Australia [47]. However, it was noted that the charges used were based on the impact on residential customers. It was pointed out that the loss of power to an industrial client would likely be costlier. As such, an industrial reliability metric of $39.13 per kWh was used from the AEMO VCR application guide [48]. The VCR coefficient was used in the discounted reliability equation as shown in Appendix E.4.

Synergy is the government-owned corporation that serves as the primary electricity retailer to the SWIS. As the NIA resides within the SWIS network boundaries, an inspection of tariff pricing offered by Synergy is necessary [49]. There are many electricity pricing packages available to commercial and industrial operations. However, the most relevant tariff structures are the Synergy Business Plan Fifty (L3) and the Synergy Business Time of Use Fifty (R3). The model adopted the R3 time of use structure as it provides an opportunity to understand economic dispatch dynamics, details on these structures and decision rationale can be found in Appendix F.1.

### 4.2.1 Emissions Costs and Limits

As an addendum to the development of the electrical network attributes, it is relevant to include the project stance and basis on emissions. The NIA optimisation model will look at both carbon tax and emissions cap penalties as a means of appraising the benefits of cleaner generation.

In 2011, the Australian Labor Government led by Prime Minister Julia Gillard introduced the Clean Energy Act 2011 [50]. Within this act was a framework for penalising industries producing excess carbon emissions. The carbon pricing mechanism initially stipulated that the cost per unit
of carbon produced (where one “unit” is equal to one metric tonne) would be a fixed price of $23 per unit [51]. This was later increased to $24.15 per unit and then eventually repealed altogether under the Tony Abbott Liberal Government in July 2014 [52]. Although this scheme is no longer in place, it was included in the analysis due to its importance and relevance. Pricing was based on the 2014 pricing before the act being rescinded.

From Australia’s 2030 climate change target, a commitment has been made to reduce 2005 level emissions by 26-28 % [53]. Assuming this target is reached by a uniform reduction across all consumers, this criterion was used as the basis of the emissions limit sensitivity analysis. Under project baseline conditions the system would produce 182.15 kT/yr (from electrical and thermal generation). A sensitivity scenario was conducted with an emissions cap at 142.3 kT/yr (28 % decrease) using the 2030 target. Although a hard emissions cap will not be built into the model, this emissions limit was used in reflection after testing. By evaluating final topologies in this was the author hopes to provide insight as to whether the system topology can achieve the target as a microcosm of the broader national reductions objective. Please see Appendix F.8.1 for a summary of emissions metrics entered per fuel type and generation source.

### 4.3 Model Building: Conventional DER

For this project, “Conventional Generation” is defined as combustion type rotary devices that convert chemical potential energy into useful thermal, mechanical or electrical energy. This type of generation is dispatchable and typically a fixed installation. However, modular type microturbines will also be assessed as part of the analysis.

#### 4.3.1 Estimates and Assumptions

Although many fuel types could be assessed in the model, the practical options and availabilities within Western Australia should be used as a means of limiting the scope. As such, the following fuel types have been included in the scope as they are reasonably practicable to use within this area of the world:
Appendix F.5.1 provides the key metrics associated with each of these fuel types allowing for a quick comparison. It is evident from the fuel cost comparisons in Fig 4-6 and Table F-22 (Appendix F.5.1) that utilising natural gas would provide the best ongoing operation fuel cost. This economy will also need to be assessed against the capital and other operating and maintenance costs to get a complete picture of the cost-benefits of natural gas technology.

Based on the fuel types available an assessment was carried out on practicably installable options that could be considered as part of this project. The underlying technology was split into two groups of Combustion Turbines (CT) and Reciprocating Internal Combustion Engines (RICE). These groups were further delineated by fuel type and amenability to the proposed technology. Finally, each possibility was assessed under CHP and non-CHP scenarios.

Based on this assessment the ten possible conventional generation options were considered:

1. Natural Gas CT  
2. Natural Gas CT – CHP  
3. Natural Gas-fired RICE  
4. Natural Gas-fired RICE – CHP  
5. Diesel-fired RICE  
6. Diesel-fired RICE – CHP  
7. LPG-fired RICE  
8. LPG-fired RICE – CHP  
9. Biogas-fired RICE  
10. Biogas-fired RICE – CHP

---

22 LPG  
23 Cereal Straw gasification to Biogas – 60 % Methane  
24 Liquified Propane Vapour
In addition to this will also be an assessment on the viability of co-firing biogas with other fuel driven options. Although specific installation capacities would have an impact in a real commercial undertaking, for the purpose of this model an allowance was built in to scale all options up to 60 MW. It was seen early in the research that LPG technology would not be viable to this project as typical scales do not exceed 150 kW [54], so the assessment was reduced to eight options. Essential economic attributes that need to be considered to create an accurate model are:

- Capital Costs ($/kW equipment)
- Replacement Costs ($/kW fully replaced)
- Variable O&M Costs ($/kWh)
- Fixed O&M Costs ($/kW/year)
- Lifetime (Hours)
- Fuel Slope (m3/hr-kW output)
- Fuel Intercept (m3/hr-kW rated)
- Mean time between failure (MTBF) 25
- Mean time to repair (MTTR) 26
- Heat Recovery Ratio (%)

There are other inputs within the model that were deemed to be of lesser importance and as such were left to the default HOMER values. These inputs include minimum load ratio, minimum runtime and planned maintenance schedules. Please see key equations and calculation methods in Appendix E.3 – fuel calculations. Utilising these equations and available information, the fuel intercept and slopes were calculated. Using these values efficiencies were also calculated. In general, efficiencies were as shown in the Appendix F.5.1.

All cost calculations and subsequent assumptions can be found in Appendix F. A summary of all generator cost assumptions can be seen in Table 4-3 below. From Table F-24 (Appendix F.5.1), we can see fuel efficiency data relevant to each fuel and power generation technology. The data from the table has been captured in Fig 4-6 and Fig 4-7 below for ease of understanding. Upon inspection, it is evident that the RICE technology has better fuel efficiencies when compared to the CT. The most efficient machine is the diesel-fired RICE with a full load efficiency of 50 %, which is mostly explained by its lower fuel intercept and good energy density.

25 For the modelling of unplanned outage frequency.
26 For the modelling of unplanned outage duration.
27 If there is CHP capability.
Table 4-3 provides a summary of costs associated with the procurement, construction and operation of the various generation technologies.

![Generator Fuel Efficiencies](image)

Fig 4-6. Generator Fuel Efficiencies

![Fuel Curve Data](image)

Fig 4-7. Fuel Curve Data

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Gen Type</th>
<th>CHP</th>
<th>Capital Costs (A$/kW)</th>
<th>Replacement Costs (A$/kW)</th>
<th>Non-Fuel O&amp;M Costs (A$/kW-hr)</th>
<th>Operating Hours (hrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel</td>
<td>RICE N</td>
<td></td>
<td>$1,717.76</td>
<td>$1,370.88</td>
<td>$0.0125280</td>
<td>72000</td>
</tr>
<tr>
<td>Methane (Bio)</td>
<td>RICE N</td>
<td></td>
<td>$2,485.76</td>
<td>$2,138.88</td>
<td>$0.0125280</td>
<td>72000</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>RICE N</td>
<td></td>
<td>$1,717.76</td>
<td>$1,370.88</td>
<td>$0.0163680</td>
<td>100000</td>
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<tr>
<td>Natural Gas</td>
<td>CT N</td>
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<td>$1,564.20</td>
<td>$1,224.00</td>
<td>$0.0070370</td>
<td>100000</td>
</tr>
<tr>
<td>Diesel</td>
<td>RICE Y</td>
<td></td>
<td>$2,741.76</td>
<td>$1,717.76</td>
<td>$0.0189280</td>
<td>100000</td>
</tr>
<tr>
<td>Methane (Bio)</td>
<td>RICE Y</td>
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<td>$3,509.76</td>
<td>$2,485.76</td>
<td>$0.0189280</td>
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<tr>
<td>Natural Gas</td>
<td>RICE Y</td>
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<td>$2,741.76</td>
<td>$1,717.76</td>
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<tr>
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<td>CT Y</td>
<td></td>
<td>$1,941.10</td>
<td>$1,315.60</td>
<td>$0.0070370</td>
<td>100000</td>
</tr>
</tbody>
</table>

From the table, the Biogas RICE configuration has the highest capital and replacement expenses per kW. Whereas, the natural gas CT (both CHP/non-CHP) has lowest costs. In general, the CHP equipped generators are in the top 50% of capital cost. The exception being the natural gas CT (CHP), which sits in the middle of the cost hierarchy.

Non-fuel O&M costs varied across the fuel and technology types at a range of $0.007 to $0.025 per kW-hr. The natural gas-fired RICE (CHP) had the highest costs, where the natural gas CT (both CHP/non-CHP) had the lowest. Regarding lifecycle, once again the natural gas CT had the best performance metric of 100,000 operating hours before requiring a major overhaul or replacement.
4.3.2 Interim Model

An interim model was built within HOMER to assess and compare eight different conventional power generation options. The performance and cost metrics have been populated in line with the data presented in this report. Specifics of this assessment can be found in Appendix F.3.1.

After refining and sub-optimisation tests (found in Appendix F.4), the final conventional DER technologies to be assessed were determined. The conventional generation topology will reflect commonly available and suitable generators (seen in Fig 4-9). With this in mind, the gas turbine topology was modelled based on the GE TM2500 32 MVA rated mobile gas turbines (the NIA system requiring up to 2 turbines) [55]. The diesel RICE is based on Caterpillar CAT-C175-20 Prime rated to 5 MVA [56]. From this point onwards, any Natural Gas-fired CT will simply be referred to as gas turbines (GTs), and any Diesel RICE will be referred to as diesel generators (DG). Clear distinctions were made where CHP is enabled.

![Fig 4-8. Conventional Generation Topology for NIA optimisation model](image)

4.4 Model Building: Renewable DER

It is essential to understand and address the general background as well as the economic and technical attributes to build an accurate RE profile into the final model. Regarding the general background, the model considered the current state and trends of RE uptake within WA, available RE technologies, RE amenability to WA Industrial Zones and, finally, the locational advantages or disadvantages for each RE deployment in WA. Economic and technical attributes considered are as follows:
• Capital, Replacement, Operations and Maintenance costs associated with each RE technology
• Modularity, dispatchability, efficiency and lifecycle of each RE technology
• Environmental and sustainability impacts of using RE technology in comparison to incumbent methods

For this paper, the author will use the definition of renewable resources as defined by Twidell and Weir where they describe RE as energy obtained from naturally recurrent and sustained source of energy occurring in the local environment [26]. For further background, please refer to Appendix B.5.

Western Australia and Northern Territory are two of the bottom three producers of solar electricity (the other being Tasmania). This is despite the reality that these locations show the highest potential for Australian solar generation, emphasised in Fig 4-12, which provides a qualitative visual of solar potential in Australia. The figure below provides a breakdown of Electricity Generation in Western Australia. It is explicitly noted from initial inspection that natural gas is the most used fuel source for power generation (55.6% of the total generation share). Concerning electrical production from RE sources, wind is the most significant contributor with approximately 4.15% of the total generation share.

![Electricity Generation in WA](adapted from [57, 58])

Wind generation enjoys a significant uptake in Western Australia, underpinned by the notable potential for wind power in the Southwest parts of Australia (approximate mean 8 km/h). This fact is clearly shown in Fig 4-11 below [59].

28 Large-scale and Small-scale solar PV in this figure do not include distributed household rooftop PV installations
However, in contrast to historic investments into wind potential, there appears to be a comparatively unexploited source of energy in solar. From Fig 4-12 we can see that Western Australia has the potential to be a large producer of solar-derived electricity. It is also worth noting that the RE uptake trend is positive with many new projects announced annually. The scale of these projects is also trending upward as the costs and benefits begin to form a more favourable ratio. According to ARENA, there are over nine current major RE projects in WA ranging in project value from $420k to $39.4M (Cumulative value of current projects: $107.68M) [61].

From the ARENA major RE projects register [61], the following RE technologies have been installed (or are being installed) on a reasonably large-scale within WA:

- 10.6 MW Degrussa Solar Power Plant (Photovoltaic)
- 1 MW Carnegie CETO 6 Ocean Power (Wave Energy)
- 250 kW Alkimos Beach Residential Development (Photovoltaic)
- 2 MW Garden Island Microgrid (Photovoltaic / Wave Energy)
- 600 kW Rottnest WREN Project (Photovoltaic)
- 1 MW Karratha Airport Solar (Photovoltaic)
Beyond ARENA funded projects, the EMU downs wind farm (80 MW), Ord river hydropower station (30 MW) [62], EMU downs solar farm (20 MW) and Badgingarra wind farm (130 MW) are all notable projects in various stages of development [63, 64]. These projects join other fully completed wind farms such as the Collgar wind farm (206 MW) [65] and the Walkaway wind farm (89.1 MW) [66] as the largest RE generation facilities in WA.

Wind-driven RE comprises most established developments, despite the fact that WA enjoys consistent and energy dense solar radiation [60]. However, these stats can be very misleading as it only looks at large-scale, centralised projects. When it comes to solar uptake on an individual level, there is nearly 1,000 MW of installed capacity of PV in Western Australia [67].

WA has above-average national wind and solar resource availabilities, making these technologies a prime target for economic reasons. Furthermore, ocean technologies (both wave and tidal) are being investigated vigorously with qualitative evaluations indicating an excellent future opportunity. Conversely, both geothermal and hydro resources are not particularly advantaged in WA with a distinct lack of available, naturally occurring resources. Large-scale hydro (>10 MW) could only be considered around the Ord River region in Northern WA.

A non-exhaustive overview of available resources in WA can be found in Appendix B.5.3. This summary provides high-level selection criteria to govern RE generation choices for high profile and established RE technology. The following technologies have been examined and assessed according to natural resource opportunities and economic amenability utilising this approach:
Out of those technologies examined, only flat plate solar PV and wind technologies were included in the final economic assessment model. Please see Table B-6 in Appendix B.5.2 for a more detailed list of typically used renewable DER.

4.4.1 Estimates and Assumptions

Building on the essential costs and other economic variable assumptions was done through analysis and an amalgamation of data found in selected literature [27-34, 36, 41]. To build a viable model accurate and cross-checked economic data must be gathered and entered into the system. Apart from the capital and operating costs, these metrics include:

- Equipment Lifetime
- PV derating factors
- Solar ground reflectance
- Nominal PV operating cell temperature
- PV efficiency at standard test conditions
- Wind turbine hub height
- Wind turbine power curve
- Wind turbine losses
- Inverter efficiency
- Rectifier efficiency

Not all these items have been explicitly addressed in the selected literature. As such, assumptions are made based on findings from other sources. It has been recognised that it is best practice for cost estimates to be assessed alongside the availability of renewable energy resources. This would assist any future model developer in determining the suitability of deployment from a resource based and commercially based methodology. To see renewable energy resource data relevant to Western Australia please refer to appendix B.4.3.

There is a significant body of work around PV installations. From this, a wide range of costs can be assessed and used as part of the final cost assumption. Based on the collection of sources found in Appendix F.6.1, costs were set to 1,753.60 $/kW (capital) and 947.20 $/kW (replacement).
O&M costs were also updated based on more recent data than the averages found in Table F-29. The O&M cost assumptions of 16.20 $/kW-yr found in NREL report on PV cost modelling were used [68].

The derating factor was set to 82.5 % [30, 31, 36], ground reflectance set to 20 % [30, 31, 36] and nominal cell temperature set to $47 \, ^{\circ}C$ [30, 31] as an average of values found in selected literature. The primary Flat Plate PV module type considered was polycrystalline silicon (poly-Si) with an average efficiency under standard test conditions of 13 % [69], other types may be considered later as part of the sensitivity analysis. As there is widespread availability of a variety of PV panels, the assessment was done on generic type PV with location-specific inputs. There were no specific manufacturers considered outside of this scope.

The relevant works were not as comprehensive when it comes to wind technology costs. Regardless, there was a wide enough selection to provide an educated assumption of costs. Appendix F.6.2 provides the primary wind technology cost estimates built into the model. The final pricing and technical assumptions are as follows:

- Rated Power (at 12 m/s): 1650 kW
- Rotor Blade Diameter: 82 m
- Hub height: 82.5 m
- Capital Costs: 2180.10 $/kW
- Replacement Costs: 1638.91 $/kW
- O&M Costs: 65.79 $/kW-yr
- Lifetime: 22 years

Sensitivity analysis was carried out on the capital and operating expenses to understand the effects on future deployment. From this point in the document, wind turbines are to be referred to by the acronym “WT”.

---

32 $3,597,165.00 per turbine
33 $2,704,199.80 per turbine
34 $108,553.50 per turbine per year
Power converter settings appear to be not much more than an afterthought to most of the examples found in the body of knowledge. Irrespective of this perception, data has been summarised in Appendix F.6.3 with a rounded average produced to form the following model parameters:

- Capital Costs: 700 $/kW
- O&M Costs: 6 $/MW-hr
- Replacement Costs: 700 $/kW
- Lifetime: 15 years

Both inverter and rectifier efficiencies have been set to 93% as an average of values found in selected literature [30, 31, 36]. The relative capacity of the rectifier has been left at the default setting of 100%. No specific power converter manufacturer was considered, all assessments were done on a generic type with the specifications populated from Table F-31 (Appendix F.6.3).

### 4.4.2 Interim Model

In conclusion, the following renewable generation devices were included in the final system optimisation model:

- Flat Plate poly-Si Photovoltaic Panels\textsuperscript{35}
- 225 kW Wind Turbines\textsuperscript{37}
- 1.65 MW Wind Turbines\textsuperscript{36}
- Generic Power Converter\textsuperscript{38}

Concentrating solar thermal, large-scale hydroelectric, hydrokinetic (wave and tidal) generation and geothermal formed other energy sources that were assessed but deemed not amenable to the strategy. The discrimination between different technologies was carried out based on commercial viability and locational availability. The updated interim system optimisation model can be seen in Fig F-13 found in Appendix F.1. It is also worth noting that after further system boundary refinement that the 225 kW wind turbines were excluded from the scope as they added no additional benefit to the optimisation tests. The justifications for this can be found in Appendix F.4.1.

\textsuperscript{35} No minimum increment, up to 70 MW capacity  
\textsuperscript{36} Based on the Vestas V82  
\textsuperscript{37} Based on the Vestas V27  
\textsuperscript{38} Up to 70 MW capacity
4.5 Model Building: Energy Storage

In Sabihuddin et al. [70], there is a clear overview of various energy storage technologies that are amenable to the DER philosophy proposed in this paper. From Sabihuddin et al., the general idea behind the proliferation of such technologies is to disassociate the direct link from generation to consumption, allowing for more dynamic and planned use of energy. There are many options to select from depending on the scale and application of the energy storage device. For this project, the extent of the power delivery capacity should be defined as a medium scale (10 – 100 MW) for use in bridging power or energy management applications (requiring a peak load storage duration >1 hour as a minimum). Table B-7 in Appendix B.6.1 summarises energy storage technologies considered as part of the NIA project. It is worth noting that liquid metal batteries, molten salt batteries, metal-air batteries, fuel cells and sensible heat storage technologies are still in stages of commercialisation and development that make them less economically feasible to the NIA project [70]. As a result, they were not considered in the assessment.

After consideration, the primary energy storage technology to be used in the NIA model are chemical batteries (both lead-acid and lithium-ion). This was not only based on the maturity levels but also on research generated from essential contributors to the microgrid and DER body of knowledge. Specific cost and technical attributes were populated within HOMER based on this research (see Appendix F.7 for further information).
As a final addition, chemical flow batteries are of interest to the project, so a generic flow battery based on the Vanadium Redox Flow technology was added to the optimisation model.

### 4.5.1 Estimates and Assumptions

Based on the data found throughout literature (see Appendix F.7.1), a generic Lead-Acid (LA) battery model was developed that allowed for full scalability with the following final assumptions:

- Capital costs: 1600 $/Unit
- Replacement costs: 1600 $/Unit\(^{40}\)
- O&M costs: 15 $/Unit-yr\(^{41}\)
- Nominal Capacity: 4.92 kWh\(^{42}\)
- Max Capacity: 7.5 kWh\(^{43}\)
- Max Power: 1.67 kW\(^{44}\)
- Lifetime throughput: 10 MWh \([73]\)
- Voltage: 6 V \([73]\)
- String Size: 8\(^{45}\)
- State of Charge: 40% minimum

Finally, an average float life of 11.2 years was used based on assumptions made by selected authors \([27, 30, 31, 73]\).

Until very recently, the costs of Lithium-Ion (LI) batteries were prohibitive for microgrid type applications \([74]\). However, the trend is changing rapidly with this technology set to overtake other electrochemical storage options in just about every key category \([75]\). In the Australian context, a notable large-scale LI installation in South Australia was successfully spearheaded in 2017 by the well-known global entrepreneur, Elon Musk \([76]\). With these in mind, it was deemed necessary to consider LI technology (both small and large-scale) in the NIA optimisation model.

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\(^{39}\) DG – refers to distributed generation which is synonymous with DER

\(^{40}\) Replacement costs are the same as capital cost due to the assumption that maximum economic reductions have been realised. This idea is backed up in literature \([71]\).

\(^{41}\) This is based on an average from \([27, 30, 31, 72]\)

\(^{42}\) Derived from 820Ah at the 20 hours rate operating at nominal voltage (6V) \([73]\)

\(^{43}\) Derived from 1156Ah at the 100 hours rate operating at nominal voltage (6V) \([73]\)

\(^{44}\) Derived from 279A (1 hour average rate) at nominal voltage (6V) \([73]\)

\(^{45}\) Assuming a DC bus voltage of 48 V
In the development of generic LI battery models, many sources were accessed and utilised in both
technical and cost assumptions. Please see Appendix F.7.2 for a summary of LI batteries and
manufacturers assessed. General costs and technical specifications associated are as follows:

- Capital costs: 8000 $/Unit [77]
- Replacement costs: 3,033.70 $/Unit\textsuperscript{46}
- O&M costs: 8.33 $/Unit-yr [77]
- Nominal Capacity: 13.5 kWh [78]
- Lifetime throughput: 37.8 MWh [77]
- Round trip efficiency: 91.8 % [78]
- Voltage: 350 V [78]
- State of Charge: 0 % minimum [78]

Alongside its LA counterpart, this LI model is generic and fully scalable allowing for a simplified
optimisation assessment. A float life of 15 years was used based on the average float life in Sarre
et al. [79] and the predicted life in Broussely et al. [80].

Research has indicated that Vanadium Redox Flow Battery (VRFB) banks are very suitable to
DER and microgrid type applications [81]. At the discretion of the project this technology has
been added to the optimisation model with the following key model attribute assumptions:

- Nominal Voltage: 400 V
- Nominal Capacity: 400 kWh
- Capital cost: 145,776.00 $/Unit\textsuperscript{47}
- Replacement cost: 89,887.64 $/Unit\textsuperscript{48}
- O&M cost: 10,204.00 $/Unit-yr\textsuperscript{49}
- Depth of discharge: 100 %
- Round trip efficiency: 93 %
- Lifetime throughput: 8,670 MWh [82]
- Float Life: 20 years [84]

Fundamental assumptions and literature backing up the VRFB economic and technical
assumptions can be found in Appendix F.7.3.

\textsuperscript{46} Calculated based on the concepts of future economic improvements suggested in [71]
\textsuperscript{47} Pricing derived from [82, 83]
\textsuperscript{48} Calculated based on the concepts of future economic improvements suggested in [71]
\textsuperscript{49} Pricing derived from [82, 83]
4.5.2 Interim Model

In summary, it was seen that of all storage types available chemical battery technology was the most applicable to the NIA project (apart from vanadium flow). Within this category, LA and LI provide the best economic and technical attributes leading to their selection in the final NIA optimisation model. Furthermore, an assessment was conducted on a generic chemical flow battery based on the VRFB technology. Fig F-14 in Appendix F.1 provides an updated topology of all the considered generation and energy storage equipment in the NIA model.

4.6 Model Building: Dispatch Control

As discussed in previous sections, there is a vast spectrum of generation and storage combinations that can be employed within a microgrid or DER framework. In addition to the physical installation of DER is the framework in which to control the energy dispatch. In the pursuit of economic optimisation, it is essential to understand that an energy flow control structure can significantly affect the fuel and lifecycle costs of a DER system.

When specifying or developing a control strategy, it is most important to consider the main optimisation objective. Optimisation objectives include economic, environmental or technical efficiencies. When the optimisation objective is defined, an algorithm can be developed or chosen based on how it addresses pertinent questions. These questions can include:

1. What is the hierarchal order of energy demands?
2. From which generation sources shall energy demands be met?
3. To what extent will the chosen generation sources be utilised?
4. Will the control mechanism rely on feedback or predictive data?

Proposed algorithms were assessed upon how proficiently it addresses these questions considering the primary objective.
Dispatch control has a great deal of relevance to a project with an objective to economically optimise a generation topology. There were four types of algorithms considered in this project:

- Generator Order (GO)
- Load-Following (LF)
- Cycle-Charging (CC)
- Combined Dispatch (CD)

More detail on these algorithms can be found in Appendix B.7. The NIA project would greatly benefit from an in-depth analysis of the effects that different control structures have on essential commercial and technical metrics. From high-level examination into the presented control structures, it has been determined that CC, LF and CD would be controllers of most interest for the NIA economic optimisation with the GO option ruled out due to its incompatibility with CHP and renewable generation sources [85]. However, due to scope constraints, the CD controller will not be assessed in this paper. As a recommendation, an investigation should be made into the CD algorithm and the possibility of developing a specific custom controller for loads like the NIA. For more detail on the control algorithm study and associated literature, refer to Appendix B.7.

### 4.7 Final Model Boundaries

From earlier sections, an NIA optimisation model topology was developed based on best cost and technical metrics. This interim topology can be seen in Fig F-14 found in Appendix F.1. Before defining the final boundaries, optimisation tests a refinement exercise was conducted to ensure targeted results. The details of model refinement tests can be referred to in Appendix F.4.
After further fine-tuning, the scope of the model testing was bound by primary thermal and electrical energy source constraints (e.g. grid-connected/islanded, and CHP enabled/disabled).

Table 4-4 below provides a summary of the proposed methodology of varying the system topology.

<table>
<thead>
<tr>
<th>Topology Iteration</th>
<th>Grid State</th>
<th>Turbine Cogeneration</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Connected</td>
<td>Thermal and Electrical</td>
</tr>
<tr>
<td>2</td>
<td>Islanded</td>
<td>Thermal and Electrical</td>
</tr>
<tr>
<td>3</td>
<td>Connected</td>
<td>Electrical Only</td>
</tr>
<tr>
<td>4</td>
<td>Islanded</td>
<td>Electrical Only</td>
</tr>
</tbody>
</table>

Furthermore, a range of sensitivities is included per scenario to ensure a thorough understanding of the uncertainties around crucial project drivers. These sensitivity variables will consist of:

- Emissions Penalties (On / Off)
- Reliability Penalties (On / Off)
- Electrical Load Changes (±10 %)
- Thermal Load Changes (±10 %)
- Fuel Cost Changes (±30 %)
- Tariff Changes (±10 %)

The final system topology is shown in Fig 4-17 below. It is worth noting that this will still be subject to change depending on challenges and limitations found during the final testing phase.

![Fig 4-16. Final NIA Optimisation Topology](image-url)
The NIA project has several global economic and technical settings that govern all test cases. The assumptions that the parameters are primarily based on reviewed literature and practical assessments. Global values are set to the quantities as found in Table F-15 in Appendix F.1.
Chapter 5 Testing

From the recommendations put forward in section 4.7, the testing procedure and methodology is best carried out in four decoupled cases. These cases divided as per Table 4-4 in section 4.7 are as follows:

Case 1. Grid-Connected, CHP enabled generators
Case 2. Islanded, CHP enabled generators
Case 3. Grid-Connected, no CHP
Case 4. Islanded, no CHP

The considered technology was refined as per the modelling process outlined in section 4.7 can be seen in Fig 4-17. Utilising the testing scope and procedure described in section 4.7 a set of tests were executed facilitating an examination into a microgrid development as part of the NIA development. The testing will explore and search for the lowest instances of the three crucial economic optimisation variables CAPEX, OPEX\(^{50}\) and NPC. Ultimately, a small set of systems are highlighted based on optimised total project NPC. This set of systems were subjected to scrutiny based on their performance against the other essential optimisation variables. It is worth noting that the LCOE variable and NPC are proportionally linked to one another. As a result, they will be used interchangeably at specific discussion points upon author discretion. After final critique, the best economic options are proposed for the NIA and, more broadly, Western Australian industrial zones like the NIA. Each topology henceforth will be referred to in its shortened ID. For example, Case 1 Architecture 1 is to be referred to as “C1A1”.

5.1 Base Case (Grid Only)

The base case of comparison for the other iterations is a grid infrastructure upgrade and network connection for the NIA through the Meadow Springs Substation (MSS) which is part of the SWIS. Thermal demand was met through a purely conventional boiler system fired with natural gas. The

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\(^{50}\) OPEX is distinct from Operation and Maintenance (O&M) in that it includes all costs and incomes outside of the initial capital expenses, following the definition provided by HOMER [35]. Please refer to section 2.2.1 for a definition of OPEX and CAPEX.
grid CAPEX is set to $31.1M based on the western power non-network options report for the Mandurah load area [43]. The hypothetical upgrade will be sufficient enough to supply the NIA at current capacity, however any increase in demand will lead to further network expansion considerations. All additional cases were assessed against this benchmark to understand its performance. Sensitivity was built in to refine the testing and understand capabilities and potential of each topology.

Fig 5-1. Base Case Topology

<table>
<thead>
<tr>
<th>Base Case Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>• LCOE: 0.346 $/kWh</td>
</tr>
<tr>
<td>• NPC: $1,127.28M</td>
</tr>
<tr>
<td>• CAPEX: $31.1M</td>
</tr>
<tr>
<td>• OPEX: $73.48M</td>
</tr>
<tr>
<td>• CO₂ Emissions: 182.15 kT/yr</td>
</tr>
<tr>
<td>• Capacity Shortage: 126.61 MWh/yr</td>
</tr>
<tr>
<td>• Grid Energy: 210.01 GWh</td>
</tr>
<tr>
<td>• RF: 0 %</td>
</tr>
</tbody>
</table>

Sensitivity analysis was carried out according to the scope outlined in section 4.7. As anticipated with increased electrical load comes an increased NPC due to an elevated OPEX burden. However, the LCOE shows a minor reduction (0.617 %) as the load grows due to an improved ratio between the total annualised costs and the total electrical load served. The OPEX costs do not increase in direct proportion to the load due to the economics of scale. The thermal load changes only had a marginal effect on financial and emissions metrics. Changes to tariffs lead to a linear response in all economic metrics.

Applying the $24.15 per tonne emissions tax resulted in an additional $4.4M in nominal annual costs. This works out to be an additional $65.7M to the project NPC. A reliability penalty of $39.13 per kWh of capacity shortage was applied which adds a nominal cost of $4.95M per year. This leads to an additional $73.9M of NPC over the project. With emissions and reliability penalties in the settings, an additional cost of $9.35M per year is incurred to the project resulting in an extra 0.0306 $/kWh (8.86 %) to the system LCOE.

51 NB – Nambeelup Boiler System
5.2 Case 1: Grid-Connected, CHP Enabled

Case 1 is subject to all global values as mentioned in the introduction to testing section. This case will consider the arrangement and technologies as structured in Appendix C.1.1. Table C-8 provides a summary of results.

This case features three distinct configurations to suit the three economic optimisation variables. Table C-8 in the Appendix provides the generation and energy resource composition for each optimised variable scenario. Interestingly, wind turbine technology is specified in two-thirds of the optimised variable scenarios suggesting a strong standing in the final topology. Another unexpected result is the variation of total installed DER capacity per scenario with a range of 0 to 71.76 MW (DC sources limited by power electronic converter rating). As anticipated, the least reliable systems all feature heavy dependence on the SWIS.

### Best NPC Architecture (C1A1)

- 11x V82 Vestas Wind Turbines (Rated Capacity: 18.2 MW)
- 1x TM2500 GE CHP Gas Turbine (Rated Capacity: 32 MVA)
- 1x Grid upgrade and connection to MSS Substation (< 70 MW capacity)
- Dispatch Algorithm: Cycle Charging or Load Following

### System Performance Metrics

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>LCOE</td>
<td>0.0948 $/kWh</td>
</tr>
<tr>
<td>Total NPC</td>
<td>$340.5M</td>
</tr>
<tr>
<td>CAPEX</td>
<td>$132.8M</td>
</tr>
<tr>
<td>OPEX</td>
<td>$14.9M/yr</td>
</tr>
<tr>
<td>RF</td>
<td>10.8 %</td>
</tr>
<tr>
<td>CO₂ Emissions</td>
<td>91.7 kT/yr</td>
</tr>
<tr>
<td>Cap Shortage</td>
<td>0 MWh/yr</td>
</tr>
<tr>
<td>Grid Energy</td>
<td>6.9 GWh/yr</td>
</tr>
</tbody>
</table>

The best performing LCOE and NPC configurations intersected as shown in Table C-8 (Case 1, Architecture 1). Scenarios where a low initial capital expenditure (CAPEX) was observed corresponded with a high NPC over the lifetime of the project. This link is strongly correlated with an increased amount of purchased energy from the grid. As expected, a low renewable
penetration was noted in these instances leading to increased ongoing tariff or fuel-related operating costs. Sensitivity analysis can be found in Appendix C.1.1.

Fig 5-3. Annualised NPC Breakdown C1A1

Table 5-1. Case 1 Economic Results

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Optimised System Variables</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>LCOE NPC</td>
<td>CAPEX ($)</td>
</tr>
<tr>
<td>Architecture ID</td>
<td>C1A1</td>
<td>C1A2</td>
</tr>
<tr>
<td>Topology</td>
<td>WT GT(c) Grid</td>
<td>Grid</td>
</tr>
<tr>
<td>LCOE ($/kWh)</td>
<td>0.095</td>
<td>0.346</td>
</tr>
<tr>
<td>Total NPC ($M)</td>
<td>340.49</td>
<td>1127.28</td>
</tr>
<tr>
<td>OPEX ($M/yr)</td>
<td>13.92</td>
<td>73.48</td>
</tr>
<tr>
<td>CAPEX ($M)</td>
<td>132.78</td>
<td>31.1</td>
</tr>
<tr>
<td>Capacity Shortage (MWh/yr)</td>
<td>0</td>
<td>126.61</td>
</tr>
<tr>
<td>Grid Energy (GWh)</td>
<td>6.87</td>
<td>210.01</td>
</tr>
</tbody>
</table>

For more detail please see Table C-8 in the appendices
For grid-connected scenarios the initial capital optimisation is the same as the benchmark
OPEX is annualised, includes carbon tax and reliability penalties
Over a 25-year lifespan

Fig 5-4. Case 1 Annual Electrical Production by Source Type (GWh/yr)
5.3  Case 2: Islanded, CHP Enabled

Case 2 is identical to Case 1 excluding the grid connection (islanded topology). This case will consider the arrangement and technologies as structured in Appendix C.2.1. Table C-9 provides a summary of findings from the case 2 optimisation model.

**Best NPC Architecture (C2A1)**

- 2x TM2500 GE CHP Gas Turbine (Rated Capacity: 32 MVA)
- 1x CAT175-20 Prime Diesel Generator set (Rated Cap.: 5 MVA)
- Dispatch Algorithm: Cycle Charging or Load Following

**System Performance Metrics**

- LCOE: 0.099 $/kWh
- Total NPC: $354.99M
- CAPEX: $144.47M
- Total OPEX: $14.11M/yr
- RF: 0 %
- CO2 Emissions: 121.32 kT/yr
- Cap Shortage: 0 MWh/yr
- Grid Energy: 0 GWh/yr

There are three distinct topologies with the installed DER capacity featuring a wide range (69 MW – 246.23 MW) between recommended arrangements (shown in Table C-9 in Appendix C.1.1). Outside of these tests, it is worth mentioning that lowest emissions and highest renewable penetration come with an enormous capital expenditure in battery (both LA and VRFB) capacity. Under these scenarios, high CAPEX and replacement costs lead to a prohibitive LCOE. From a purely economic standpoint, installing two 32MW GTs with cogeneration technology and a backup DG is a great option (LCOE: 0.099 $/kWh), but is closely challenged economically with a more diverse DER configuration (C2A3). Operating expenses were the best under the varied DER arrangement of C2A3. Battery banks were utilised primarily in environmentally optimised scenarios. As with case 1, wind was also a strong performer featuring in optimised architectures.

From Fig 5-6 it is evident that the most significant contributors to C2A1 NPC are the CAPEX and ongoing fuel expenses for the generators. By way of comparison, C2A3 had a significantly reduced fuel component, but the CAPEX more than made up for the reduced fuel usage leading to a larger system NPC. Conventional generation featured in four out of the five optimised topologies. Finally, the advantage of dispatchable generation is very clearly highlighted with GT-
based configurations leading to the best reliability (and lowest reliability penalties). Sensitivity analysis can be found in Appendix C.2.1.

Table 5-2. Case 2 Economic Results

<table>
<thead>
<tr>
<th>System</th>
<th>Architectures ID</th>
<th>Optimised System Variables</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>C2A1</td>
<td>LCOE NPC</td>
<td></td>
</tr>
<tr>
<td></td>
<td>C2A2</td>
<td>0.099</td>
<td></td>
</tr>
<tr>
<td></td>
<td>C2A3</td>
<td>Total NPC ($M)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>354.99</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>OPEX ($M/yr)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>14.11</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>CAPEX ($M)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>144.47</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Capacity Shortage (MWh/yr)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Purchased Energy (GWh)</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>0</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Grid</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

For more detail please see Table C-9 in the appendices.

56 For grid-connected scenarios the initial capital optimisation is the same as the benchmark.

57 OPEX is annualised, includes carbon tax and reliability penalties.

58 Over a 25-year lifespan.
5.4 Case 3: Grid-Connected, No CHP

Case 3 removes the CHP equipped gas turbines from the optimisation model and replaces them with simple turbines with no ability to cogenerate or utilise waste heat. Prior to testing there was a notable CAPEX difference per kW installed between these options. However, it was unknown what differences may arise outside of this comparison. This case will consider the arrangement and technologies as structured in Appendix C.3.1. A summary of results for case 3 is found in Table C-10 (Appendix C.2.1).

Three distinct topologies were found per the corresponding optimisation variable. Lowest OPEX, Best RF and Lowest Emissions scenarios shared the same architecture with approximately 68.3 MW of installed DER generation capacity (plus 70 MW from the SWIS). Like case 1, wind turbines featured in most optimisation scenarios.

<table>
<thead>
<tr>
<th>Best NPC Architecture (C3A1)</th>
</tr>
</thead>
<tbody>
<tr>
<td>- 16x V82 Vestas Wind Turbines (Rated Capacity: 26.4 MW)</td>
</tr>
<tr>
<td>- 1x TM2500 GE Gas Turbine (Rated Capacity: 32 MVA)</td>
</tr>
<tr>
<td>- 1x Grid upgrade and connection to MSS Substation (&lt; 70 MW capacity)</td>
</tr>
<tr>
<td>- Dispatch Algorithm: Cycle Charging / Load Following</td>
</tr>
</tbody>
</table>

**System Performance Metrics**

| LCOE: 0.101 $/kWh | RF: 27.37% |
| Total NPC: $360.21M | CO₂ Emissions: 105.4 kt/yr |
| CAPEX: $138.71M | Cap Shortage: 0 MWh/yr |
| Total OPEX: $14.85M/yr | Grid Energy: 7.2 GWh/yr |

The installed DER capacity ranges from 0 and 68.3 MW with wind and gas turbine technology featuring most commonly. CAPEX varied widely with the highest among the selected architectures being nearly 5.5 times the benchmark. Project NPC values across case 3 all performed better than the benchmark. Furthermore, improved reliability, renewable penetration and emissions reduction were observed. Annual operating expenses across the case 3 architectures were around five times less on average.
Table 5-3. Case 3 Economic Results

<table>
<thead>
<tr>
<th>System</th>
<th>Quantity</th>
<th>Optimised System Variables</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Architecture ID</td>
<td>C3A1</td>
<td>C3A2</td>
</tr>
<tr>
<td></td>
<td>Topology</td>
<td>WT</td>
<td>GT</td>
</tr>
<tr>
<td></td>
<td>LCOE ($/kWh)</td>
<td>0.101</td>
<td>0.346</td>
</tr>
<tr>
<td></td>
<td>Total NPC ($M)</td>
<td>360.21</td>
<td>1127.28</td>
</tr>
<tr>
<td></td>
<td>OPEX ($M/yr)</td>
<td>14.85</td>
<td>73.48</td>
</tr>
<tr>
<td></td>
<td>CAPEX ($M)</td>
<td>138.71</td>
<td>31.10</td>
</tr>
<tr>
<td></td>
<td>Capacity Shortage (MWh/yr)</td>
<td>0</td>
<td>126.61</td>
</tr>
<tr>
<td></td>
<td>Purchased Energy (GWh)</td>
<td>7.20</td>
<td>210.01</td>
</tr>
</tbody>
</table>

Fig 5-9. Annualised NPC Breakdown C3A1

The NPC breakdown of C3A1 shows (Fig 5-9) that CAPEX forms the primary cost category of the project with OPEX and fuel costs following closely behind. From Fig 5-10 diverse DER production leads to a superior economic model. Sensitivity analysis can be found in Appendix C.3.1.

---

60 For more detail please see Table C-9 in the appendices
61 For grid-connected scenarios the initial capital optimisation is the same as the benchmark
62 OPEX is annualised, includes carbon tax and reliability penalties
63 Although C3A3 features the same DER technology as C3A1 it utilises 10 MW more installed WT in the topology with a higher RF and improved emissions performance
64 Over a 25-year lifespan
5.5 Case 4: Islanded, No CHP

Because case 4 is the islanded topology of case 3, it will contain all generation and storage options barring the SWIS connection. This case will consider the arrangement and technologies as structured in Appendix C.4.1. Table C-11 provides a summary of results for case 4. Three distinct topologies were found per the corresponding economic optimisation variable. Outside of the primary scope it was noted that many intersection points existed between RF and emissions optimisation variables which indicates that this case could be a strong environmental performer.

C4A1 features two GTs and a backup DG, identical to the best NPC topology of case 2 – C2A1 (apart from CHP capability). A 52 MWh LI installation featured in C4A3, but with an energy autonomy of 2.17 hours, a state of charge (SoC) typically around 61.43 % and a modest throughput, it is safe to assume that the LI banks were primarily used for power quality applications. CAPEX for the best environmental performers was prohibitive and would need further concessions to be economically feasible (details on these architectures can be found in Chapter 6).

Installed DER capacity varied extensively with a range of 64 MW to 159.82 MW. C4A1 performed quite well across most technical and economic metrics but offered very little regarding renewable penetration or emissions reductions. Other architectures in case 4 provided substantial environmental benefits but with a significant cost that would surely exclude these options from...
actual implementation. Lastly, PV featured heavily within optimised high RF and low emissions architectures but was neglected in economically optimised topologies. Sensitivity analysis can be found in Appendix C.4.1.

### Table 5-4. Case 4 Economic Results

<table>
<thead>
<tr>
<th>System</th>
<th>Optimised System Variables</th>
<th>Quantity</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Architecture ID</td>
<td>C4A1</td>
<td>C4A2</td>
<td>C4A3</td>
</tr>
<tr>
<td>Topology</td>
<td>GT</td>
<td>GT</td>
<td>DG</td>
</tr>
<tr>
<td>LCOE ($/kWh)</td>
<td>0.101</td>
<td>0.102</td>
<td>0.114</td>
</tr>
<tr>
<td>Total NPC ($M)</td>
<td>359.43</td>
<td>362.63</td>
<td>399.62</td>
</tr>
<tr>
<td>OPEX ($/yr)</td>
<td>16.81</td>
<td>17.6</td>
<td>12.39</td>
</tr>
<tr>
<td>CAPEX ($M)</td>
<td>108.7</td>
<td>100.11</td>
<td>214.82</td>
</tr>
<tr>
<td>Capacity Shortage (MWh/yr)</td>
<td>0</td>
<td>14.42</td>
<td>1.47</td>
</tr>
<tr>
<td>Purchased Energy (GWh)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

![Fig 5-12. Annualised NPC Breakdown C4A1](image)

![Fig 5-13. Case 4 Annual Electrical Production by Source Type (GWh/yr)](image)

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65 For more detail please see Table C-9 in the appendices
66 For grid-connected scenarios the initial capital optimisation is the same as the benchmark
67 OPEX is annualised, includes carbon tax and reliability penalties
68 Over a 25-year lifespan
5.6 Case Study Findings

In general, it was observed that hybrid DER systems produced greatly reduced NPC with featured systems often consisting of an even conventional and renewable source component. Furthermore, initial observations show a strong correlation between grid reliance and capacity shortage, which is indicative of possible reliability benefits to utilising diverse DER in a given system. Further evaluation can be found in Chapter 6.
Chapter 6  Analysis and Discussion

The general system evaluation produced 17 distinct configurations optimised to a variety of optimisation variables (12 topologies optimised to economic variables and five topologies optimised to environmental variables). Results were bundled up into their respective optimised variable and shown in Fig 6-1. This figure displays the optimised annual electrical energy production (GWh), DER elements and total project NPC for each of the 17 configurations. As mentioned in Chapter 5, the prime focus was on systems that are optimised to the best possible NPC. Table 6-2 provides details on the topologies that yield the lowest total project NPC. See section 6.2 below for in-depth analysis and commentary on each system NPC.

![Fig 6-1. Installed Capacity (MW) of 17 Distinct Optimised Topologies](image)

![Fig 6-2. NPC optimised configuration assessment and comparison](image)
6.1 Observations: Comparison to literature

The analysis results were compared to the body of knowledge used throughout this project, and the comparable results are shown in Fig 6-3 below. In this study, the lowest NPC was $340.49M, and subsequent lowest LCOE was $0.0948/kWh (C1A1). This LCOE is on the lower side of the spectrum with only [28] and [29] achieving lower values. However, it is noted that this seems consistent with the trend of lower costs for larger systems as shown in Table 6-1. This is also consistent with general knowledge of economies of scale.

![Fig 6-3. LCOE comparisons to literature](image)

<table>
<thead>
<tr>
<th>Literature</th>
<th>Lowest LCOE ($/kWh)</th>
<th>Load Demand (GWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lu et al. [29]</td>
<td>0.09</td>
<td>2300</td>
</tr>
<tr>
<td>Blokers et al. [28]</td>
<td>0.093</td>
<td>205000</td>
</tr>
<tr>
<td>C1A1</td>
<td>0.0948</td>
<td>210.11</td>
</tr>
<tr>
<td>C2A1</td>
<td>0.0994</td>
<td>210.11</td>
</tr>
<tr>
<td>C4A1</td>
<td>0.1008</td>
<td>210.11</td>
</tr>
<tr>
<td>C3A1</td>
<td>0.1010</td>
<td>210.11</td>
</tr>
<tr>
<td>Shafiullah et al. [33]</td>
<td>0.136</td>
<td>0.0365</td>
</tr>
<tr>
<td>Kumar et al. [40]</td>
<td>0.191</td>
<td>0.57</td>
</tr>
<tr>
<td>Ali and Shahnia [30, 31]</td>
<td>0.246</td>
<td>3.64</td>
</tr>
<tr>
<td>Orhan et al. [27]</td>
<td>0.314</td>
<td>0.0055</td>
</tr>
<tr>
<td>Shafiullah and Carter [32]</td>
<td>0.433</td>
<td>3.03</td>
</tr>
</tbody>
</table>

From this comparison, it is evident that the results from this study stack up well against the current body of knowledge. Differences can be easily explained through the variation of load demand served by the DER combination.

6.2 Observations: Net Present Cost

The total system NPC is used as the primary means to optimise systems within HOMER. This is partly because total NPC captures all the essential economic considerations such as CAPEX, OPEX, replacement costs, fuel costs and salvage profits. Furthermore, the NPC calculation puts system costs into “real” terms which represent the value of future expenditure in present terms by considering currency inflation and borrowing costs. For this reason, the author recognises that, although CAPEX for DER implementation is high, the total NPC reflects the “true” cost to the
proponent. By using NPC, the proposed systems are shortlisted for more in-depth evaluation. Table 6-2 provides insight into the best topologies optimised to total system NPC.

As seen in earlier sections, the specification of diverse DER leads to a higher project CAPEX when compared to the benchmark (grid only). This is greatly offset however by a generally improved total project NPC and LCOE. The highlighted system architectures have a mean LCOE of 0.214 $/kWh which is ~38 % less than the benchmark. The reasons for this are mostly linked to lower ongoing tariff reliance. However, improved reliability and emissions performance reduce associated penalties, leading to a better NPC.

### Table 6-2. Best NPC Systems

<table>
<thead>
<tr>
<th>Performance Metrics</th>
<th>Total Project NPC</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quantity</td>
<td>CA1</td>
<td>CA1</td>
</tr>
<tr>
<td>Architecture</td>
<td>WT-GT(c)-Grid</td>
<td>GT(c)-DG</td>
</tr>
<tr>
<td>LCOE ($/kWh)</td>
<td>0.095</td>
<td>0.099</td>
</tr>
<tr>
<td>Total NPC ($M)</td>
<td>340.49</td>
<td>354.99</td>
</tr>
<tr>
<td>OPEX ($M/yr)</td>
<td>13.92</td>
<td>14.11</td>
</tr>
<tr>
<td>CAPEX ($M)</td>
<td>132.78</td>
<td>144.47</td>
</tr>
<tr>
<td>RF (%)</td>
<td>10.76</td>
<td>0</td>
</tr>
<tr>
<td>Capacity Shortage (MWh/yr)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>CO₂ Emissions (kT/yr)</td>
<td>91.67</td>
<td>121.32</td>
</tr>
<tr>
<td>Grid Energy (GWh)</td>
<td>6.87</td>
<td>0.00</td>
</tr>
</tbody>
</table>

---

69 GT(c) – CHP Gas Turbine, GT – Gas Turbine, PV – Photovoltaic, WT – Wind Turbine, Batt - Battery
C1A1 is the NPC optimised configuration in the grid-connected CHP enabled scenario. C2A1 is the islanded counterpart to C1A1 also featuring CHP enabled generation. From the analysis, it is evident that the total project NPC is approximately 33% of the benchmark NPC. As stated earlier, this can be explained by the lower ongoing tariff costs (contained within OPEX) for the architectures containing more DER penetration. Although some DER technologies still require continuing fuel or maintenance costs, they tend to be a sizable portion less than the system tariff burden. The required capital expenses to implement these systems are still high in comparison to the benchmark, but it is worth considering what was mentioned in section A.2.3 regarding the externalised costs of connecting to the grid and the way it deceptively lowers grid connection costs [14].

Fig 6.5. Case 1,2 Best NPC Topology

Fig 6.6. Case 3,4 Best NPC Topology
6.3 Observations: Capital Expenditure

For grid-connected systems, capital expenditure is lowest under the network upgrade and connection scenario (shown in Case 1 and 3). In an islanded configuration running dual gas turbines provides the lowest initial cost option. However, this topology still carries a CAPEX at least three times higher than the grid connection option. The dual gas turbine topology also varies substantially with the inclusion of CHP capabilities. Case 2 CAPEX is nearly $36M more for installed cogeneration capabilities (albeit with a total NPC reduction of approximately $5M).

The mean CAPEX of the 17 distinct optimised topologies was $221.37M which was approximately seven times that of the benchmark scenario and had a standard deviation of $320.8M indicative of the vast range of values. There was an observed correlation between low CAPEX and increased emissions which are easily explained by the fact that renewable generation technology tends to incur a higher CAPEX. This cost trend can be seen in Fig 6-7 below which demonstrates that higher renewable and battery penetration leads to more substantial CAPEX requirements.

![Fig 6-7. CAPEX per Optimised Topology](image)

Finally, a thought-provoking observation can be seen in Fig 6-8 where CAPEX optimised systems tend to be above average regarding emissions. This trend is entirely expected as there is no
specified renewable DER in these configurations. However, it is interesting that case 2 CAPEX optimised system (C2A2) can reduce CO₂ emissions low enough to exceed the emissions reduction target. This result is entirely linked to CHP capabilities built into the generators allowing for reduced reliance on other thermal production mechanisms thus reducing fuel usage.

The specification of DER sources will carry a higher initial cost when compared to the heavily subsidised network options. It is recommended that any future research into DER economics is carried out with an awareness of the true cost of network infrastructure implementation.

6.4 Observations: Operating Expenditure

The economic performance metrics for OPEX optimised systems were very positive. From each case winning topologies respectively featured a mean LCOE and NPC over three times less than the benchmark. Furthermore, the OPEX in each optimised topology was approximately 17% of the benchmark. In islanded scenarios grid reliance was offset by the inclusion of PV generation (33 MW average) and LI battery storage (50 MWh average) as seen in C2A3 and C4A3. Wind-based power generation featured strongly in all topologies with an average of 28 MW of installed wind turbine capacity.

Throughout the model permutations, there is a detected link between the combination of gas turbines and wind turbines and a lower system OPEX. A qualititative convergence appears where CAPEX and OPEX fall within a similar band in comparison to each variable high point. This
meeting happens approximately when 100% of electrical production comes from conventional DER (C4A1, C4A2).

However, the best OPEX scenarios tend to feature a higher than average CAPEX. This observation leads to the conclusion that to reduce ongoing operating expenses; one must spend more initially (particularly on renewable DER). This relationship can be seen in Fig 6-12 where higher CAPEX approximately corresponds with lower OPEX with CAPEX peaks around high renewable DER configurations. In general, it was noted that the NPC for optimised OPEX configurations were generally low (compared to average). However, C1A3 featured a very low NPC and subsequent LCOE.

Fig 6-10. OPEX per Optimised Topology
Fig 6-11. OPEX Topology Emissions Performance

Fig 6-11 demonstrates that OPEX optimised topologies feature DER that emit far less CO₂ than the incumbent power network approach. The reason for this is apparent with the annual electrical production coming from a very diverse DER combination with a high renewable penetration. When examining this metric, a major benefit of DER use is the reduced ongoing costs compared to conventional models due to the removal of fuel requirements. It is recommended that any future research considers system-wide effects of this reduction (e.g. – To what extent does reduced fuel costs improve the cost-effectiveness of flow batteries?).

6.5 Observations: Environmental Metrics

As previously mentioned, the scope of this paper is on the economic attributes of using DER to supply industrial type electrical and thermal loads. However, the usage of renewable DER comes with the intrinsic link of positive environmental impact. It was noted that where renewable DER, cogeneration or battery usage was used increasingly, there was a notable reduction of CO₂ emissions produced while meeting the NIA demand.

All DER systems were regularly able to reduce emissions to below the grid-only benchmark of 182.15 kT/yr. Furthermore, over 75 % of topology permutations produced systems that were under the hypothetical emissions cap of 142.3 kT/yr. The best performing system (C2A4) was able to achieve emissions as low as 15.37 kT/yr which is a mere 8.3 % of the benchmark. This architecture features 107 wind turbines (176.55 MW installed capacity) and 1639.6 MWh of
installed VRFB banks. However, as anticipated, the lowest emissions systems tend to exhibit prohibitively high economic metrics. The best emissions architecture, C2A4 also has a total system NPC of $2.1B which is nearly double that of the benchmark and is over three times the average NPC across all permutations. An interesting observation when examining Fig 6-13 is that the emissions reduction contribution from RE sources is not as significant as the contribution from CHP enabled generation sources. This suggests that thermal generation accounts for a large portion of emissions and a further strategies utilising RE thermal sources would be recommended.

![Fig 6-13. Emissions Metrics by Production Source](image)

From Fig 6-13 the reader can see the relationship between electrical production sources and the reduction of emissions compared to the benchmark. As anticipated, systems with the highest renewable DER fraction tended to produce the least amount of CO$_2$ emissions. However, the total system NPC was often prohibitively expensive in these high RF cases as evidenced in Fig 6-1. From Fig 6-14 it is evident that renewable DER is not the only way to curtail excess emissions. Through the proliferation of CHP equipped GTs some of the best environmental performance systems featured more than 50% conventional generation.

This knowledge served as an impetus for the author to define an economic metric that captures best environmental value for an investment. These cost-effectiveness metrics were defined as tonnes of reduced CO$_2$ when compared to the benchmark per CAPEX or NPC [tonne-reduced/$]. The CAPEX metric helps to understand the environmental impact per dollar initially invested where the NPC metric helps define the environmental impact per dollar spent across the project lifetime (including all ongoing costs). Fig 6-15 shows that a combination of CHP enabled GTs
and WTs provides the best emissions reduction per dollar initially invested. This combination also yields marked environmental benefits per project NPC. This result is valuable from the perspective of looking for ways to enable the environmental benefits of DER proliferation without the common cost dissuasions.

Fig 6-14. Impact of CHP on CO₂ Emissions

Fig 6-15. Emissions Reduction per Dollar Invested

It is evident from the analysis that as the systems tend to adopt elevated levels of any DER, the emissions performance greatly benefits. To obtain the highest levels of cost-effective emissions reductions, a system with an approximately equal share of CHP equipped GT, and WT electrical

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70 Non-CHP conventional generation includes grid supplied energy
71 CHP conventional generation is only gas turbine generating sets equipped with CHP apparatus
production is the best. Where practicable, the system should only rely on a minimal amount of grid-purchased energy.

A system without heat recovery systems was also assessed to gain an understanding of the effects of CHP on the economic metrics. C3A1 and C4A1 are the grid-connected and islanded topologies that yielded the best total project NPC (seen in Fig 6-6). These systems displayed similar performance characteristics to C1A1 and C2A1 but with slightly worse economic and environmental metrics. This shows that heat recovery provides a significant commercial advantage in addition to the environmental benefits. Furthermore, HOMER does not offer the ability to scale back the size of the boiler in a dynamic fashion to offset the inclusion of CHP thermal energy. If this capability were included there would be an even more considerable benefit of using CHP over non-CHP options (although the non-fuel boiler costs are marginal as shown in Appendix F.5.7). Finally, the most substantial advantage of CHP is the reduction in emissions due to the reduced fuel usage by the boiler to meet the thermal demand. As described in section 6.5, it is evident that CHP has the second largest impact on emissions behind only renewable technology.

Fig 6-16. Cost-Effective Emissions General Reduction Trend

6.6 Observations: Effects of Cogeneration

Note that not all islanded systems present large emissions reductions, this diagram just provides the general trend.
Fig 6-17. CHP Emissions and NPC Differences

Fig 6-17 shows that there is a very slight average NPC increase across all non-CHP based topologies. This seems counter-intuitive at first due to the higher CAPEX cost of CHP equipped generators. However, considering the addition of the carbon tax and the reduced boiler fuel usage, this is logical. The average CO₂ emissions of CHP equipped systems is 32.39 kT/yr less than the non-CHP counterpart. With the carbon tax applied this equates to an NPC increase of $19.56M which almost entirely explains the average difference between the two scenarios. This suggests that any addition to the carbon tax would tip the scales entirely in favour of CHP technology (both financially and environmentally).

6.7 Observations: Effects of Islanding

A notable development of islanded systems is the significant increase in installed capacity in specific optimised scenarios (C2A4, C2A5, C4A4). This elevated capacity correlated with an increase in electricity production, particularly from renewable sources. Wind turbines featured heavily in both grid-connected and islanded configurations. However, a notable increase in wind turbine capacity and production was noted in islanded configurations. Furthermore, the largest proliferation of battery technology was found amongst islanded systems. This makes sense as the storage of energy helps to underpin the reliability of the system in the place of the network.

Fig 6-18. Grid Connection Type and NPC Differences
Table 6-3. Network Connection Type and Battery Proliferation

<table>
<thead>
<tr>
<th>Network Connection Type</th>
<th>LA (MWh)</th>
<th>VRFB (MWh)</th>
<th>LI (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Islanded</td>
<td>2858.43</td>
<td>1639.60</td>
<td>99.78</td>
</tr>
<tr>
<td>Grid-Connected</td>
<td>0.00</td>
<td>56.80</td>
<td>0.00</td>
</tr>
</tbody>
</table>

Interestingly, of the increased battery proliferation lithium-ion batteries featured in a much smaller capacity when compared to its counterparts. However, this is misleading as most of the capacity specifications for VRFB and LA are in systems optimised for RF or emissions whereas LI is specified into systems optimised for OPEX (C2A3, C4A3). This leads to the conclusion that LI is currently the economically preferred battery technology, primarily when used in small capacities to underpin islanded systems. However, regarding versatility and applicability, the VRFB features more prominently in diverse systems. This, coupled with cost trends, leads the author to conclude that VRFB technology is the most amenable economic and technical option to WA DER projects. For a battery analysis summary, refer to Appendix D.1.

Finally, it was noted that the average CO₂ emissions for NPC optimised islanded systems was slightly more than grid-connected scenarios. This is a somewhat unexpected result; however, it makes sense considering the observation earlier that best emissions reduction per NPC can include a small amount of grid-purchased energy as a reserve. The alternative for islanded systems would be a battery bank of some sort which hurts the project NPC. This would skew configuration preference to systems that are less costly at the expense of environmental benefits. The suggestion from this observation is that a small amount of centralised grid use could be more environmentally beneficial in the near term.

### 6.8 Observations: Investment Commentary

Optimised systems were assessed relative to the benchmark scenario (grid-only). The results were generally positive with 14 out of 17 systems displaying superior economic performance. As mentioned earlier, CAPEX costs for DER hybrid systems were universally higher than the benchmark, but payback periods average 2.1 years across positive difference systems. The best economically performing system (C1A1) has a discounted payback period of just 1.77 years with
annualised project savings after that point of $52.7M/yr. This data suggests that many of the optimised scenarios modelled in this paper would be an attractive economic option for future developers.

An argument can be made, however, that carbon tax and reliability penalties may skew the data in favour of DER hybrid systems. From a reliability analysis, the average capacity shortage of all optimised DER systems are 72.74 MWh/yr better than the benchmark. Furthermore, the average CO₂ emissions across the systems is 84.77 kT/yr less than the benchmark. Calculating the effect of these penalties equates to $4.89M per year. When considering the average annualised project savings is $23.6M per year across all optimised DER systems it is evident that emissions and reliability penalties make up a small portion of the economic difference between DER and the benchmark system.

Table D-12 in Appendix D.1 provides a summary of essential economic attributes per architecture. Although it is misleading to use the term “return on investment” in a similar fashion to investments that produce revenue, the investment performance metrics in Table D-12 captures a very strong rate of savings for invested dollar. It is necessary also to note that the expense is required regardless and any savings on a compulsory outlay is seen in a similar light to business revenue. As Lysons and Farrington pointed out, a 4 % cost saving is comparable to a 20 % increase in revenue [86]. In summary, high DER penetration systems are, on average, economically superior to the status-quo.
6.9 Observations: Technical Commentary

As much of modelling has been carried out using HOMER there has been a distinct focus on economic attributes. This economic focus is in line with the scope of the project however it is necessary to perform a rudimentary feasibility analysis on the technical attributes of suggested topologies. A load flow analysis was executed to gain understanding on bus voltages and network stability. This will also be useful in understanding the type of local power equipment required to enable grid-connected and islanded switching. The technical commentary will focus on the C1A1 architecture modelled in Power World simulator. There are four situations that need to be assessed:

Test 1. Maximum wind production, maximum load demand
Test 2. Maximum wind production, minimum load demand
Test 3. Minimum wind production, maximum load demand
Test 4. Minimum wind production, minimum load demand

The gas turbine was used as the dispatchable DER energy source to make up for shortfalls with the purchased grid power as the last option. The following model assumptions were used:

- Power factor: 0.9
- Maximum Load: 60 MW / 29 MVAR (0.6 + j0.29 per unit)
- Minimum Load: 5.8 MW / 2.8 MVAR (0.058 + j0.028 per unit)
- Load Voltage: 415 V
- Distribution Network Voltage to Nearest Substation (MSS): 22 kV [43]
- Gas Turbine max power output: 32 MVA (11.5 kV / 50 Hz) [87]
- Wind Turbine max power output: 18.15 MW (700 V) [88]
- Distribution feeder and local cable impedance: 0.063 + j0.097 ohm/km [89]
- Feeder length to the nearest substation: 9.5 km
Finally, a discussion was held around technical sensitivities such as load growth and redundancy. This was combined with economic sensitivity analysis around fuel costs, tariff costs, sell back availability and carbon tax policy.

From this analysis, the economically preferred option (C1A1) has shown technical deficiencies that would make it infeasible to specify as the NIA electrical supply. In two of the tests carried out voltage violations were noted (test 2 and 3). This is even with the local gas turbine being used to inject reactive power into bus 2 to maintain bus voltage at 1.0 per unit. This problem can be solved using transformer On-Load Tap Changing (OLTC) or using power injection at the load.
bus. To provide the reader with a visualisation of an example solution based on economic optimisation and technical feasibility a single line diagram of a hypothetical DER system is presented in Fig 6-24.

Fig 6-24. Modified C1A1 Architecture

To ensure the system can handle the intermittency of the wind turbine installation it is recommended that a sizeable VRFB bank is installed to support the load bus during times of low local DER generation. After a final load flow analysis, it was seen that a VRFB bank installation of 30 MW / 60 MWh would best support the system at its most extreme points. The utilisation of OLTC at nearby transformers could account for any additional voltage regulation requirements at the load bus. Fig 6-24 provides a diagram of the modified architecture and associated performance metrics. Findings show that this proposed system can achieve a dramatic reduction in project NPC and emissions at a CAPEX of approximately six times that of the benchmark. Furthermore, this system exhibits a negligible capacity shortage indicating 100 % reliability. From this, it is recommended that any future industrial developments strongly consider the use of DER systems from an economic and technical perspective.

6.10 Proposed Topologies

Table 6-4 provides a summary of best general DER configurations. There is not a single preferred or absolute recommendation due to the multi-objective nature of the project. However, a robust
proposed architecture can be seen in the figure below which represents the C1A1 architecture with an additional VRFB bank to help support the network when required.

As an overall observation, it was noted that gas turbines and wind turbines were consistently featured throughout most of the permutations. These technologies are well suited to the NIA location and can serve multiple variables to great effect.

<table>
<thead>
<tr>
<th>Optimisation Variable</th>
<th>Recommended Configuration</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPC</td>
<td>Grid-GT-WT</td>
<td>Dual GT’s perform well in islanded mode but adding a WT creates a more versatile system at a small cost.</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Grid only</td>
<td>Significantly lower than DER options, however no option to island.</td>
</tr>
<tr>
<td>OPEX</td>
<td>WT-GT-LI</td>
<td>Could connect to grid if further reliability required, but the grid adds a lot to OPEX. These topologies featured a small installation of lithium-ion banks.</td>
</tr>
<tr>
<td>RF</td>
<td>WT-Li or Grid</td>
<td>Minimal amounts of grid energy required in times of low wind. If islanding is desired, a lithium-ion installation is the recommended economical choice to reduce stability issues.</td>
</tr>
<tr>
<td>Emissions</td>
<td>WT-GT-VRFB</td>
<td>Like the OPEX scenario but with VRFB reliability, grid connection not required due to battery storage.</td>
</tr>
<tr>
<td>Overall</td>
<td>Grid-GT-WT-VRFB</td>
<td>70 % WT, 30 % GT with small VRFB battery storage. Grid connection is optional in cases of need or if grid sales become an option.</td>
</tr>
</tbody>
</table>

It was also noted that VRFB technology is a strong option when reliability or environmental objectives become a prevailing motivation behind the project. This form of storage allows for the most significant renewable penetration due to its ability to handle substantial power flow and energy storage with an excellent economy. The combination of gas turbines and VRFB is a minimum essential if the system is to be run in islanded mode at any stage. Finally, cogeneration adds a small additional initial cost to the project but brings excellent environmental and reliability advantages that make it very attractive (with an overall better project NPC). As a result, all gas turbines are recommended to be equipped with CHP capabilities.
Chapter 7 Conclusion and Future Work

This thesis explored the economic outcomes of utilising microgrid style local DER networks in Western Australian industrial areas with a focus on the proposed NIA development (featuring an electrical demand of 60 MW peak). Knowledge gaps around the locality, load scale, tariff structures and development types were addressed utilising a range of examination techniques. System analysis was conducted using HOMER software to help understand the economic attributes of proposed microgrid configurations when compared to just connecting a load to the SWIS. This investigation included research into the effects of CHP installed to conventional DER to meet local thermal demands. Four cases were explored which involved two states of grid-connection and two states of CHP proliferation.

Results revealed that CAPEX costs were many times that of a simple grid connection, but the observed average project NPC was significantly lower in DER systems. Increased DER penetration into the NIA was seen to correlate with lower total project NPC with an average discounted savings of $350M over a 25-year period. A high prevalence of wind and gas turbines was observed in NPC optimised DER configurations. Configurations featuring strong wind and gas generation technology also carried a robust environmental advantage with an observed 685.94 tonne per year CO₂ emission reduction for every dollar of CAPEX invested when compared to the benchmark.

The highest emissions were observed in systems with the highest central network reliance. As a result, calculations were conducted on the effects of emissions and reliability penalties to gain understanding on the externalised costs of using the centralised electricity network. It was found that DER systems created a more reliable system and the value of this increased reliability $2.85M per year. Furthermore, DER systems also produced an environmental improvement of 84.77 kT per year of reduced emissions with a value of $2.05M per year. The introduction of these policies quantifies the added worth of microgrids in the energy marketplace where many indirect costs are obscured due to lack of performance attribute pricing.
The investigation into unique DER technologies such as VRFB banks and CHP equipped generators gave insight into locally novel ways to improve system performance economically and environmentally. The utilisation of CHP equipped conventional generation correlated with a stronger economic and environmental performance. Economically optimised CHP topologies displayed a mean project NPC of $347.74M which is only 30.8% of the benchmark. CHP equipped DER topologies also produced 34.39 kT/yr less annual CO\textsubscript{2} emissions. VRFB technology featured in many environmentally optimised configurations, but it also carries an economic advantage compared to other energy storage options with a battery energy cost 25% less than LI and LA technologies utilised (~0.03 $/kWh). Furthermore, VRFB can handle high power throughput making it an ideal choice to replace grid reliance.

Finally, a feasibility evaluation was done with the help of Power World Simulator to determine the technical viability of proposed architectures in servicing the electrical and thermal needs of the NIA. It was found that the lowest technically feasible NPC architecture features 11 large-scale wind turbines rated at 1.65 MW each, a single CHP equipped 32 MVA gas-fired combustion turbine and a 60 MWh VRFB bank capable of delivering 30 MW of power. This system would have an optional coupling to the SWIS but would operate in an islanded mode in most cases. The installation and operation of this proposed microgrid would carry a CAPEX of $175.7M and project NPC of $411.6M. The annual savings of $47.97M per year would allow for a payback period of just 2.62 years. This delivers a reliable indicator that microgrid proliferation to meet the energy demands of Western Australian industrial loads is a robust financial option that would likely outperform current electrical power network developments.

7.1 Future Work

Referring to section 3.2, this paper has addressed several identified knowledge gaps. But there are still several items that necessitate further exploration to advance the understanding of future energy distribution networks. From the economic perspective, this study has utilised best available pricing information from literature and other sources. However, it would be advantageous to engage industry leaders in this field of work directly to refine commercial
knowledge. Environmentally, it has been seen that DER considered in most studies assume a homogenous generator fuel use with minimal research into alternative biofuels in Australian microgrid applications. Understanding biofuels could lead to sizeable environmental performance enhancements with DER or microgrid systems. Furthermore, DER considered does not appear to provide a significant energy-water nexus. There is a need to find possible interconnections between utility services to build a more robust and sustainable municipal provision.

Although it is clear from this paper that capital costs for non-network solutions tend to be less economically competitive there is a clear benefit to proliferation if viewed from a total project timeline perspective. The environmental benefits of increased RE penetration and CHP utilisation are well known with this paper serving to underline these principles. Furthermore, many researchers have pointed to the hidden costs of network solutions and the need to refurbish old assets will expose many hidden costs in the near term. Coupled with that knowledge, there are indicators showing economic metrics associated with DER improving as deployment increases. These developments suggest that the economic gap between network and non-network (DER) solutions may be narrowed soon.
Bibliography


[135] ABB Pty Ltd, "Capturing solar energy to deliver 'microgrid' power to remote towns in Western Australia," ed: ABB Pty Ltd, 2018.


[136] ABB Pty Ltd, "Capturing solar energy to deliver 'microgrid' power to remote towns in Western Australia," ed: ABB Pty Ltd, 2018.


[192] V. Gandarillas, "Feasibility of small scale energy storage technologies in rural areas," MS thesis, Department of Mechanical and Aerospace Engineering, Faculty of Engineering,


Appendices

Appendix A  Microgrid Rationale

A.1  Microgrids: Benefits and Opportunities

The common motivations for microgrid proliferation were discussed briefly in section 2.1. Of great importance is the initiative to reach the emissions targets, which aims to reduce GHG emissions 20% by 2020 (from 2005 GHG levels) [14, 90]. The International Energy Agency has predicted that at current trajectory with no significant policy changes, fossil fuels will still account for approximately 90% of world energy production [91]. The dissemination of microgrid technology in industrial land development and construction will provide a significant boost to these efforts.

The reviewed literature has provided a multitude of reasons why microgrid dissemination is needed to tackle the range of social, environmental and market challenges facing the Australian energy sector. Balcombe et al. [92] have produced an excellent paper on the motivators and challenges met in the promotion of DER technologies. A principal argument in favour of DER is lower GHG emissions during operation. Although, in two separate papers, Pepermans et al. and Allan et al. argue that this cannot be generalised for all DER and more research is required before conclusive statements are made [13, 93]. Nonetheless, it is evident that a growing section of DER is based on renewable technologies that will substantially contribute to the reduction of GHG production.

The research in Balcombe et al. also argued that current central generation may not be optimal. Daly and Morrison support this idea and suggest that DER opens up the opportunity for diversification of generation techniques and fuels which would theoretically lead to more reliability and keep costs low [94]. For better or worse, DER use has a very large local impact. Not only would localised heat and fuels be readily available, but the inherent flexibility in DER deployment would allow for quicker and localised reactions to energy market pricing. Microgrid
control systems with market pricing objectives have been researched and trialled. An example of this is found in Sinha et al. [95], where the central controller algorithm included objectives related to market price decisions.

It is evident that the current central infrastructure is ageing, and DER could play a role in avoiding costly network replacements and repairs. As recently as 2017, Western Power has been looking for hybrid DER solutions to prevent costly network refurbishments in edge-of-grid locations [96]. And while these DER trials are taking place, it has already been established, through Jenkins et al. [23], that DER technology could currently be used as a provider of grid support and ancillary services to significant effect.

### A.2 Microgrids: Barriers to Proliferation

Although there are established and emerging benefits to the use of DER and microgrid technology, many barriers exist that hinder the growth in this field. The difficulties can be categorised into three primary categories:

- Social
- Technical
- Economic

Although many of these barriers are becoming less prohibitive as advancements in expertise and materials transpire, they still constitute a formidable hindrance to widespread DER usage. Furthermore, Australia particularly faces numerous unique barriers that require tailored resolutions.

#### A.2.1 Social Barriers

Worldwide, the propagation DER and microgrid technologies are hindered by various institutional, market and policy barriers. Australia is not free from its challenges where conventional power generation proponents have historically lobbied for reduced network access to non-primary generation companies. Byrnes et al. make mention of lengthy regulatory
approvals, costly and non-transparent grid-connection procedures, sudden policy changes, and government support for incumbent generation practices [14]. Furthermore, the paper demonstrates that there is a false economy for conventional generation as the costs of emissions and land have been externalised. Nonetheless, the Australian government has recently commissioned the ARENA to address institutional resistance to RE uptake.

In another paper, Byrnes and Brown mention community acceptance and uncertain government policies as other significant social barriers [97]. One area of policy prone to uncertainty is the governance surrounding retail and consumer pricing in Australia. Historically the Australian energy market has been regulated, but even as a transition occurs to a more decentralised structure, consumers will not enjoy consistent pricing. Simshauser and Whish-Wilson suggest that pricing fluctuations will require concrete and sophisticated regulatory efforts to ensure welfare to the consumer [98].

### A.2.2 Technical Barriers

Microgrid and DER technologies are well established and have been used in many applications. However, many papers have cited issues associated with power flow, protection, network control and planning being among the technical deterrents to widespread adoption [13, 91, 94, 99, 100]. Many of the technical issues cited have a more profound effect on less established power infrastructure. Western Australia possesses one of the most stable and reliable power networks in the world. SWIS reliability indices, which are used to evaluate the performance of the network, show that benchmarks for 2016 have been met in all but one area [11]. This indicates that the SWIS would be an ideal network for the trialling of DER and microgrid technologies.

### A.2.3 Economic Barriers

Affordability is a principal driver in all major projects, and it can be argued that this is the largest deterrent to the microgrid concept becoming a convention in power infrastructure. The capital costs associated with DER have historically been high, and when compared to utilising available networks most developers are prone to abandon non-conventional approaches. Pepermans et al. makes the argument that DER does not have the benefits of the economy of scale and, as a result,
is significantly disadvantaged economically [13]. The point made by Byrnes et al. regarding externalised costs artificially lowering grid costs is especially poignant in this situation [14]. Although initial investment costs have been a significant barrier, there are indications that DER is becoming more affordable with lower prices being cited in literature over time [28-30, 94, 101]. Furthermore, Alfred Cavallo suggests in his paper that coupling of specific technologies, such as wind and compressed air energy storage (CAES), may lead to cost benefits [102].

Operations and maintenance costs form another key consideration in the economic feasibility analysis of any undertaking. Once more, the argument about externalised costs of centralised generation becomes important. In addition to this, the “uniform pricing structure” of the electricity tariffs in Western Australia hides the true cost of energy served to edge-of-grid communities that would otherwise be prime locations for microgrid pilots such as the hybrid trial mentioned previously [96]. Fig A-1 provides a basic diagram of the uniform pricing structure in Western Australia. The selection of research in the following section shows an assortment of economic feasibility results. It is evident that the viability of a project is dependent upon factors that are locational, institutional and technical. Nonetheless, these papers show that viability is achievable and payback periods are no longer prohibitive.

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1 DG refers to “distributed generation” in this figure.
2 This is an original diagram which is an adaptation of [2]
A.3 Analysis of Additional Case Studies

Liu et al. [34] and Kumar et al. [41] provide further intriguing studies into hypothetical DER system implementation in Australia. A brief discussion is contained in this appendix. Furthermore, a review of relevant international studies was reviewed as key parts of the body of knowledge.

A.3.1 Various Sites, QLD [34]

In this study, Liu et al. [34] investigate the performance of residentially embedded solar PV from a technical, environmental and economic standpoint. It was demonstrated in the paper that PV hybrid systems conserve costs and reduce emissions while meeting the customer demands. The investigation was conducted at eleven different sites in Queensland with a variety of results. With the inclusion of grid-sales, the LCOE across these sites were exceptionally low with Townsville recording a negative LCOE (indicating a profit per kWh). The downside is the unpredictability of energy buyback rates offered by electricity retailers.

A.3.2 Various Sites, VIC [41]

Kumar et al. [41] spend time focusing on alternative fuels in the implementation of hybrid DER topologies. Furthermore, this study performed analysis across nine different towns and cities in Victoria. The load sizes and hybrid topology were standardised throughout these nine sites with the generator fuel type being the primary variable, ahead of the secondary variables of wind speed and solar irradiation specific to each location. Furthermore, an analysis was carried out on the effects of the different electricity retailers and tariff structures have on the LCOE. In conclusion, it was seen that with an ethanol-fuelled generator coupled with PV key metrics could be achieved. In the end, an LCOE of 0.191 $/kWh, NPC of $1.43M and RF of 94 % was realised. This study was incredibly useful from the perspective of biofuel utilisation.

A.3.3 Cue, WA [32]

Shafiullah and Carter [32] reinforce the notion that stand-alone generator systems typically have a higher LCOE when compared to grid-connected systems. Shafiullah and Carter explore the solar
PV potential and hypothesise that it could lead to enormous savings potential. The topology considered has four diesel generators rated between 100-200 kW each. The study showed that the inclusion of 500 kW of solar PV could not only meet customer demand but lower the LCOE from 0.514 $/kWh to 0.433 $/kWh while increasing the RF from 0 to 27 %.

### A.3.4 International Studies

The following table gives a summary of selected international research projects reviewed in this document. Five research papers fit the selection criteria and were deemed to be of key relevance to the project.

<table>
<thead>
<tr>
<th>Literature</th>
<th>Date of Publication</th>
<th>Location</th>
<th>Load Size</th>
<th>Sources (^3)</th>
<th>Fuels Used</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ma et al. [103, 104]</td>
<td>May-14</td>
<td>Hong Kong, China</td>
<td>30 kWp</td>
<td>PV-W-B-PHES</td>
<td>None</td>
</tr>
<tr>
<td>Papaioannou et al. [105]</td>
<td>Jan-14</td>
<td>Athens, Greece</td>
<td>80 kWp</td>
<td>Grid-G-W-PV-B</td>
<td>Diesel</td>
</tr>
<tr>
<td>Shoeb et al. [106]</td>
<td>Dec-16</td>
<td>Bhola, Bangladesh</td>
<td>150 kWp</td>
<td>G-PV-B</td>
<td>Diesel</td>
</tr>
<tr>
<td>Nazir et al. [107]</td>
<td>Jan-13</td>
<td>Padang, Indonesia</td>
<td>166 kWp</td>
<td>Grid-Hyd-PV-B</td>
<td>None</td>
</tr>
</tbody>
</table>

Papaioannou et al. [105] conducted a case study on microgrids in varied connection modes at the pilot site of Meltemi near Athens. The results support the use of further DER in island-based communities. In two related papers, Ma et al. [103, 104] assessed the impact of varied energy storage technologies. There was a comparison between BESS and Pumped Hydro Energy Storage (PHES) systems on a remote island in Hong Kong. The studies showed that the lifecycle and energy costs of PHES outperformed BESS providing an intriguing argument for the dissemination of this technology in other systems, particularly on islands, in support of the Papaioannou et al. paper.

Concerning non-residential loads, the studies of Shoeb et al. [106], Nazir et al. [107] and Anastasopoulou et al. [108] provides excellent examples of more diverse requirements. Shoeb et al. focus on addressing power needs in agricultural settings in Bangladesh, while Anastasopoulou et al. provides a fascinating study on using DER to support the power requirements of large

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\(^3\) Abbreviations: Generator (G), Wind (W), Solar (PV), Pumped Hydro Energy Storage (PHES), Hydro (Hyd) and Battery (B)
chemical plants in Africa. The study carried out by Anastasopoulou et al. is of interest to the author as it gives a precedent for industrial DER modelling with MW-scale loads.

Appendix B  Background Material

B.1  Essential Definitions

B.1.1  Microgrid Concept

There is a variety of beliefs about the microgrid concept, and this idea is subject to change as technology and research continue to unearth new possibilities. An assortment of definitions from well-known writers and associations in the field can be found in many key sources [2, 15-20]. After inspecting these prevailing definitions, despite the differences in how researchers limit or define the concept, there are prevailing themes that persist, these can be seen in Table B-2.

Table B-2. Consistent Microgrid Elements

<table>
<thead>
<tr>
<th>LOCALITY</th>
<th>CONTROL</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sources need to be located near the loads they are servicing</td>
<td>Microgrids are characterised by the ability to apply a multi-objective control architecture to both source and demand</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>DISTRIBUTED GENERATION</th>
<th>MULTI-MODE OPERATION</th>
</tr>
</thead>
<tbody>
<tr>
<td>Microgrids facilitate the aggregation of a range of intermittent and dispatchable energy sources (not just electrical) into a network</td>
<td>Microgrids are designed with the capacity to operate either independently or interconnected with the main electricity network (grid)</td>
</tr>
</tbody>
</table>

Table B-3. The State of the Art - Significant Microgrid Projects

<table>
<thead>
<tr>
<th>Project Name</th>
<th>Location</th>
<th>Load Served</th>
<th>Ref.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Garden Island Microgrid + CETO 6 Wave Generation</td>
<td>Garden Island, WA</td>
<td>2MW+3MW</td>
<td>[109]</td>
</tr>
<tr>
<td>Rottnest Island Water and Renewable Energy Nexus (WREN)</td>
<td>Rottnest Island, WA</td>
<td>&gt;1.2MW</td>
<td>[110]</td>
</tr>
<tr>
<td>Chevron Energy - Santa Rita Jail CERTS Microgrid Demo</td>
<td>United States of America</td>
<td>2.8MW</td>
<td>[17, 111, 112]</td>
</tr>
<tr>
<td>SDG&amp;E - Borrego Springs Microgrid</td>
<td>United States of America</td>
<td>4.6MW</td>
<td>[111, 113, 114]</td>
</tr>
<tr>
<td>Coober Pedy Renewable-Diesel Hybrid</td>
<td>Coober Pedy, SA</td>
<td>&gt;9MW</td>
<td>[115]</td>
</tr>
<tr>
<td>Illinois Institute of Technology: Perfect Power Prototype</td>
<td>United States of America</td>
<td>9MW</td>
<td>[111, 116, 117]</td>
</tr>
<tr>
<td>DeGrussa Solar Project</td>
<td>DeGrussa Minesite, WA</td>
<td>&gt;10.6MW</td>
<td>[118]</td>
</tr>
<tr>
<td>Kennedy Energy Park</td>
<td>Hughenden, QLD</td>
<td>&gt;56MW</td>
<td>[119]</td>
</tr>
</tbody>
</table>

4 Indicates the electrical load that is served through the hybrid DER or microgrid system
In general, the definition of a microgrid could be condensed into a local, distributed source network designed to supply a range of loads through a multi-objective control architecture. The following table provides examples of well-known microgrid case studies and testbeds that form part of the review of the state of the art. This list is non-exhaustive; however, these have been curated based upon its relevance to the project. Earlier in this document, a detailed examination of selected international and Australian studies is provided to underpin and complement this list. It is worth noting that an excellent resource with a more exhaustive category of pilot sites can be found in chapter 6 of Microgrids: architectures and control [111].

B.1.2 Distributed Energy Resources

From the definition of a microgrid provided in section B.1.1, DERs form an essential part of the microgrid concept. As with microgrids, there isn't a universal consensus on all of the vital attributes behind the DER concept [21]. However, also like the microgrid concept, some common themes characterise the idea and thus form a qualitative definition. In Distributed Generation: a definition by Ackermann, et al., there is a useful breakdown of some of the key attributes among the varied definitions of DER [21]. From Ackermann et al. [21], it is stated that "Distributed generation is an electric power source connected directly to the distribution network or on the customer side of the meter."

Other definitions (see Moskovitz et al. [22]) support this description, so it is possible to formulate a meaning in basic terms. That is, DER can be classified as energy generation resources attached directly to the associated power distribution network to satisfy local energy and local ancillary network services. One can define “ancillary network services” as per the definition found in Jenkins et al. [23], which when paraphrased posits that ancillary network services are Voltage Regulation, Frequency Regulation, Load Following, Reserve and Black-Start facilities. For further discussion on the types of DER available please refer to Appendix B in this document.
B.1.3 Renewable Energy Sources

RE is ubiquitous, and the use of the RE technology is only growing as developments in the field continue to mount. RE can be defined as an inexhaustible natural energy source that can be regularly replenished centrally or locally. This paraphrased definition is taken from many leading writers in the field [24-26]. Renewable resources typically fall within the categories of Wind, Marine, Solar, Hydro, Geothermal and Bioenergy [24].

B.2 DER Technology Types

There is a comprehensive catalogue of DER technology found in selected literature [21, 120-122], a basic list includes:

- Gas Turbines (Open Cycle, Closed Cycle and Micro)
- Internal Combustion Engines (“Generating Sets” or “Generators”)
- Hydro (Large, Small and Micro)
- Wind Turbines
- Solar Photovoltaic Arrays (PV)
- Solar Thermal
- Biomass/Biofuel
- Fuel Cells
- Geothermal
- Ocean Energy (Wave and Tidal)
- Energy Storage (Chemical Battery, Fly-wheels and Compressed Air)

These resources are typically used in a hybrid format in conjunction with the broader electrical network.

B.3 Microgrid Modelling Software

Many software applications provide economic/technical analysis. To date the following software packages have been identified as applicable to this project:
From research, it is clear that HOMER is the best tool for general microgrid economic modelling and evaluation [37]. In fact, the majority of details regarding financial considerations were derived from the HOMER Energy Glossary [123], which is an exhaustive dictionary of relevant terms.

### B.4 RE Resources

In *Renewable Energy Resources* by Twidell and Weir, they describe RE as energy obtained from naturally repetitive and persistent flows of energy occurring in the local environment [26]. From this, and other definitions ([25, 124]), we can generalise RE as an inexhaustible energy source that can be regularly replenished centrally or locally. Further to this, we can also infer that RE is derived from one of three energy categories:

- Solar (direct or indirect)
- Planetary
- Geothermal

Renewable resources typically fall into the following categories [124]:

- Wind Energy
- Marine Energy
- Solar Energy
- Hydro-Energy
- Geothermal Energy
- Bioenergy
Although it is often the case, it is probably worth noting that the terms “Renewable” and “Sustainable” should not be used interchangeably. RE speaks to the attribute of the energy source to replenish itself organically/naturally. Sustainable energy, however, addresses the ability to supply energy in excess to demand and at a reduced negative collateral impact on the environment [125]. Sustainable energy techniques can be deployed in Renewable or Conventional power generation scenarios. An example of a non-renewable sustainable energy methodology would be a combined cycle gas turbine where waste heat is captured and used to improve the sustainability of the process.
B.4.1 National RE Deployment Trends

Looking at the Australian Department of Environment and Energy report titled *Australian Energy Update 2017* [57] we can find key RE statistics for the 2015/2016 across Australia. For the sake of getting a broader image of the deployment and trends over a larger time span, the *Australian Energy Update 2016* [126] is also a good reference. Australian Energy Statistics (AES) *Table O* is provided as an appendix to the 2017 update, which provides clear statistics per state and territory [58]. The table below provides some quick links to Australian Energy Update reports for the last seven years. It is worth noting that the current Department of Environment and Energy was previously known as the Department of Industry, Innovation and Science.

### Table B-4. Quick links to AES Reports

<table>
<thead>
<tr>
<th>Source</th>
<th>Comment</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Department of Environment and Energy</td>
<td>Aus. Energy Update Reports from 2017 onwards</td>
<td>[127]</td>
</tr>
<tr>
<td>Department of Environment and Energy</td>
<td>Aus. Energy Statistics, Table O (appendix to 2017 Report)</td>
<td>[129]</td>
</tr>
</tbody>
</table>

Table B-5 below is an adaptation of information found in Table O [58]. The table provides several important data points that offer insight into overall electricity generation in Australia (for the 2014-2015 year). Some of the key takeaways are highlighted in the table for clarity but are also summarised as follows:

- Queensland generates the largest amount of electrical energy (27.28 % of Australian generation)
- Black coal is the most utilised fuel source in Australian electricity generation (42.65 % of total national generation)
- New South Wales is the largest consumer of black coal for electricity generation purposes (48.83 % of national black coal use)
• Northern Territory has the highest percentage of non-renewable electricity generation (98.52 % non-renewable)

• Queensland has the highest actual non-renewable electricity generation (~64000 GWh)

• Tasmania has the highest percentage of renewable electricity generation (98.32 % renewable - based on >85 % hydro-electric generation)

• New South Wales has the highest actual renewable electricity generation (6937 GWh)

• South Australia accounts for >37 % of all wind power generation in Australia

• Queensland generates the most RE from bagasse and wood (1550 GWh) and solar (1920 GWh)

• Hydro-Electricity is the most utilised renewable fuel source (38.9 % of all renewable generation in Australia)

• Western Australia does not lead in any RE metric, however, it generates the highest natural gas derived electricity

**Table B-5. Electricity Generation by Australian State/Territory (adapted from [58])**

<table>
<thead>
<tr>
<th>Non-renewable fuels</th>
<th>NSW (GWh)</th>
<th>VIC (GWh)</th>
<th>QLD (GWh)</th>
<th>WA (GWh)</th>
<th>SA (GWh)</th>
<th>TAS (GWh)</th>
<th>NT (GWh)</th>
<th>AUS (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black coal</td>
<td>52562.20</td>
<td>0.00</td>
<td>44553.80</td>
<td>10523.40</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>107639.40</td>
</tr>
<tr>
<td>Brown coal</td>
<td>0.00</td>
<td>48336.80</td>
<td>0.00</td>
<td>0.00</td>
<td>2633.60</td>
<td>0.00</td>
<td>0.00</td>
<td>50970.40</td>
</tr>
<tr>
<td>Natural gas</td>
<td>4528.40</td>
<td>2190.90</td>
<td>18248.50</td>
<td>20146.00</td>
<td>5003.80</td>
<td>143.60</td>
<td>18.90</td>
<td>52462.60</td>
</tr>
<tr>
<td>Oil products</td>
<td>284.30</td>
<td>126.30</td>
<td>1197.20</td>
<td>4223.50</td>
<td>1078.30</td>
<td>18.90</td>
<td>2201.40</td>
<td>6798.80</td>
</tr>
<tr>
<td>Total non-renewable</td>
<td>57374.90</td>
<td>50654.00</td>
<td>63999.50</td>
<td>34893.00</td>
<td>7834.70</td>
<td>162.50</td>
<td>2952.70</td>
<td>217871.20</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Renewable fuels</th>
<th>NSW (GWh)</th>
<th>VIC (GWh)</th>
<th>QLD (GWh)</th>
<th>WA (GWh)</th>
<th>SA (GWh)</th>
<th>TAS (GWh)</th>
<th>NT (GWh)</th>
<th>AUS (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bagasse, wood</td>
<td>551.10</td>
<td>15.90</td>
<td>1550.30</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>2117.30</td>
</tr>
<tr>
<td>Biogas</td>
<td>472.10</td>
<td>672.20</td>
<td>91.10</td>
<td>126.90</td>
<td>84.90</td>
<td>34.60</td>
<td>9.00</td>
<td>1490.80</td>
</tr>
<tr>
<td>Wind</td>
<td>1376.00</td>
<td>3067.80</td>
<td>32.50</td>
<td>1643.20</td>
<td>4291.90</td>
<td>1055.10</td>
<td>0.00</td>
<td>11466.50</td>
</tr>
<tr>
<td>Hydro</td>
<td>3113.70</td>
<td>1170.90</td>
<td>649.10</td>
<td>206.10</td>
<td>10.80</td>
<td>8294.40</td>
<td>0.00</td>
<td>13445.00</td>
</tr>
<tr>
<td>Solar PV</td>
<td>1424.20</td>
<td>957.20</td>
<td>1920.20</td>
<td>683.30</td>
<td>845.50</td>
<td>102.00</td>
<td>35.30</td>
<td>5967.70</td>
</tr>
<tr>
<td>Geothermal</td>
<td>0.00</td>
<td>0.00</td>
<td>0.60</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.60</td>
</tr>
<tr>
<td>Total renewable</td>
<td>6937.00</td>
<td>5884.00</td>
<td>4243.90</td>
<td>2659.60</td>
<td>5233.10</td>
<td>9486.10</td>
<td>44.30</td>
<td>34487.90</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>All fuel types</th>
<th>NSW (GWh)</th>
<th>VIC (GWh)</th>
<th>QLD (GWh)</th>
<th>WA (GWh)</th>
<th>SA (GWh)</th>
<th>TAS (GWh)</th>
<th>NT (GWh)</th>
<th>AUS (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total</td>
<td>64311.90</td>
<td>56538.00</td>
<td>68243.40</td>
<td>37552.50</td>
<td>13067.90</td>
<td>9648.60</td>
<td>2997.00</td>
<td>252359.30</td>
</tr>
<tr>
<td>Percent renewable</td>
<td>10.79%</td>
<td>10.41%</td>
<td>6.22%</td>
<td>7.08%</td>
<td>40.05%</td>
<td>98.32%</td>
<td>1.48%</td>
<td>13.67%</td>
</tr>
<tr>
<td>Percent non-renewable</td>
<td>89.21%</td>
<td>89.59%</td>
<td>93.78%</td>
<td>92.92%</td>
<td>59.95%</td>
<td>1.68%</td>
<td>98.52%</td>
<td>86.33%</td>
</tr>
</tbody>
</table>
B.4.2 Typical Renewable DER

Table B-6 is a non-exhaustive list of typically deployed RE sources throughout the world. It is important to note that a significant deterrent to uptake has been the intermittent nature of many RE sources. However, with the growth in viable energy storage options this problem is being minimised. For the purposes of this section, all energy storage devices are omitted from the comparisons as this will be covered in other sections.

<table>
<thead>
<tr>
<th>Technology</th>
<th>Dispatch Type</th>
<th>Typical Flexibility Type</th>
<th>Typical available size per module</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small hydro (with reservoir)</td>
<td>Dispatchable</td>
<td>Fixed</td>
<td>1MW - 100MW</td>
</tr>
<tr>
<td>Micro-hydro (with reservoir)</td>
<td>Dispatchable</td>
<td>Fixed</td>
<td>25kW - 1MW</td>
</tr>
<tr>
<td>Wind turbine</td>
<td>Intermittent</td>
<td>Fixed or Modular</td>
<td>200W - 3MW</td>
</tr>
<tr>
<td>Photovoltaic arrays</td>
<td>Intermittent</td>
<td>Modular</td>
<td>20W - 100kW</td>
</tr>
<tr>
<td>Solar thermal, central receiver</td>
<td>Intermittent</td>
<td>Modular</td>
<td>1MW - 10MW</td>
</tr>
<tr>
<td>Solar thermal, Lutz system</td>
<td>Intermittent</td>
<td>Modular</td>
<td>10MW - 80MW</td>
</tr>
<tr>
<td>Geothermal</td>
<td>Dispatchable</td>
<td>Fixed</td>
<td>5MW - 100MW</td>
</tr>
<tr>
<td>Ocean energy (Wave)</td>
<td>Semi-Dispatchable</td>
<td>Fixed or Modular</td>
<td>100kW - 1MW</td>
</tr>
<tr>
<td>Ocean energy (Tidal)</td>
<td>Semi-Dispatchable</td>
<td>Fixed or Modular</td>
<td>100kW - 1MW</td>
</tr>
<tr>
<td>Ocean energy (Thermal)</td>
<td>Semi-Dispatchable</td>
<td>Fixed or Modular</td>
<td>100kW - 10MW</td>
</tr>
<tr>
<td>Stirling engine</td>
<td>Dispatchable</td>
<td>Modular</td>
<td>2kW - 10kW</td>
</tr>
<tr>
<td>Battery Energy storage</td>
<td>Dispatchable</td>
<td>Modular</td>
<td>500kW - 5MW</td>
</tr>
<tr>
<td>Fly-Wheel Energy Storage</td>
<td>Dispatchable</td>
<td>Modular</td>
<td>1kW - 100kW</td>
</tr>
<tr>
<td>Compressed Air Energy Storage (CAES)</td>
<td>Dispatchable</td>
<td>Modular</td>
<td>1kW - 300MW</td>
</tr>
</tbody>
</table>

Incluing selected non-electrical sources
**B.4.3 Renewable Energy Resources in WA**

In Fig B-4 it is evident that the Nambeelup area has access to a greater solar irradiance the other major population centres throughout the country. Furthermore, from Fig B-5, Nambeelup has a clear locational advantage in terms of wind resources, out-performing all the assessed major population centres. It is clear from these performance metrics that introducing solar PV and wind turbines to the model would provide interesting and worthwhile economic results. Concentrating and solar tracking PV options are interesting as the monthly average solar direct normal irradiance (DNI) data for Nambeelup suggests a significant thermal opportunity (Fig B-3).

However, there is not enough commercially proven examples to warrant inclusion in this project [130].
There are no known geothermal resources available within the southwest region of Australia. As such, this technology will not be included in the model. However, hydrokinetic options are something that could be considered for the model as south-west Australia is a hotbed for wave and tidal technologies [109, 131]. However, as the technology is still in its very early stages and the maximum deployment in Australia is <2 MW in capacity it is seen as not economically advantageous to hydrokinetic technologies included in the current model.

Lastly, in offset to the unique wind and solar advantages, the NIA is not privileged with significant hydropower opportunities. In Fig B-6, the NIA location is depicted with a distance measurement to the nearest significant waterbody. The North Dandalup river has the greatest potential with an existing dam in place built by Water Corporation [132].

However, with a maximum elevation of 250 m (producing low hydraulic head) and the vastly expensive costs of hydro installation [133], it was deemed to not worthwhile to pursue large-scale hydro as part of the model.

Fig B-6. Nambeelup area waterbodies
### B.5 Energy Storage Systems

#### B.5.1 Energy Storage

Table B-7. Energy Storage Technologies Considered (adapted from [30, 70, 134-139])

<table>
<thead>
<tr>
<th>Category</th>
<th>Technology</th>
<th>MW Capacity</th>
<th>Typical Application</th>
<th>Commercial Maturity</th>
<th>Australian Projects</th>
<th>Selected</th>
<th>Selection Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mechanical</td>
<td>PHES</td>
<td>10 – 8000</td>
<td>EM</td>
<td>FC</td>
<td>Tumut 3 Power Station</td>
<td>No</td>
<td>Not widely used in Australia</td>
</tr>
<tr>
<td></td>
<td>CAES</td>
<td>0.01 – 3000</td>
<td>EM</td>
<td>C</td>
<td>No-known major deployment</td>
<td>No</td>
<td>Not fully commercialised</td>
</tr>
<tr>
<td></td>
<td>FES</td>
<td>0.001 – 10</td>
<td>PQ</td>
<td>C</td>
<td>Nullagine &amp; Marble Bar Power Stns</td>
<td>No</td>
<td>Storage Capacity Low</td>
</tr>
<tr>
<td>Chemical Battery</td>
<td>ZnAg</td>
<td>0 - 0.25</td>
<td>EM</td>
<td>FC</td>
<td>No known major deployment</td>
<td>No</td>
<td>No precedent in Australian DER</td>
</tr>
<tr>
<td></td>
<td>ZnMn</td>
<td>0 - 0.001</td>
<td>EM</td>
<td>FC</td>
<td>No known major deployment</td>
<td>No</td>
<td>No precedent in Australian DER</td>
</tr>
<tr>
<td></td>
<td>Pb-Acid</td>
<td>0 - 50</td>
<td>EM</td>
<td>FC</td>
<td>King Island RE Project</td>
<td>Yes</td>
<td>Relevant maturity / precedent</td>
</tr>
<tr>
<td></td>
<td>Li-Ion</td>
<td>0 - 100</td>
<td>EM</td>
<td>FC</td>
<td>Hornsdale Power Reserve</td>
<td>Yes</td>
<td>Relevant maturity / precedent</td>
</tr>
<tr>
<td></td>
<td>NiMH</td>
<td>0.01 - 3</td>
<td>EM</td>
<td>FC</td>
<td>No known major deployment</td>
<td>No</td>
<td>No precedent in Australian DER</td>
</tr>
<tr>
<td></td>
<td>NiCd</td>
<td>0 - 50</td>
<td>EM</td>
<td>FC</td>
<td>Storage Capacity Low</td>
<td>No</td>
<td>No precedent in Australian DER</td>
</tr>
<tr>
<td>Electromagnetic</td>
<td>Supercapcit</td>
<td>0 - 5</td>
<td>PQ</td>
<td>C</td>
<td>No known major deployment</td>
<td>No</td>
<td>Storage Capacity Low</td>
</tr>
<tr>
<td>Chemical Flow Battery</td>
<td>VRBF</td>
<td>0 - 20</td>
<td>EM</td>
<td>C</td>
<td>Busselton Tree Farm</td>
<td>Yes</td>
<td>Not fully commercialised</td>
</tr>
<tr>
<td></td>
<td>ZnBrF</td>
<td>0.001 - 20</td>
<td>EM</td>
<td>D</td>
<td>Base64 Business Complex</td>
<td>No</td>
<td>Not fully commercialised</td>
</tr>
</tbody>
</table>

---

6 From selected literature found in [70]  
7 EM – Energy Management, PQ – Power Quality. From selected literature found in [70]  
8 FC – Fully Commercialised, C – Commercialising, D – Developing. Adapted from selected literature found in [70]  
10 From [134]  
11 From [135]  
12 ZnAg: Zinc Silver Oxide, ZnMn: Alkaline, Pb-Acid: Lead-Acid, Li-Ion: Lithium-Ion, NiMH: Nickel Metal Hydride, NiCd: Nickel Cadmium  
13 From [7]  
14 From [139]  
15 From [137]  
16 From [139]  
17 VRBF: Vanadium Redox Flow, ZnBrF: Zinc Bromine Flow  
18 From [140]  
19 From [136]
An in-depth discussion of the tabled energy storage system technologies can be found in Appendix 0.

B.5.2 Energy Storage Category: Mechanical

Technology: Flywheel Energy Storage (FES)

Flywheel technologies are very promising, particularly for small to medium scale power quality applications (requiring less than 1 min worth of storage capacity) [70]. However, at this stage, it is not technically or commercially viable for the NIA project.

Technology: Pumped Hydroelectric Energy Storage (PHES)

The Tumut 3 power station showcases Australian PHES technology [134]. There are no other known major installations, but leading researchers indicate that dissemination of the technology could lead to a truly viable 100% renewable system [28, 134]. This is because both the power and energy storage capacities are capable of being deployed in very large scales. Still, the maturity and commercial viability of the technology does not satisfy the criteria of NIA selection.

Technology: Compressed Air Energy Storage (CAES)

Although there are no known Australian examples, there is a promising growth market for CAES technology, particularly coupled with wind power [141, 142]. This is partially due to wide scalability, long life and negligible self-discharge rate (making very long-term storage viable) [70]. Regardless, without further maturity, this technology does not meet the NIA selection criteria.

B.5.3 Energy Storage Category: Electromagnetic

Technology: Supercapacitors

The use of supercapacitors integrated with DER installations is beginning to gain popularity especially as a means of addressing problems associated with renewable DER transient network dynamics [143]. This typical application of addressing power quality only requires a small amount
of energy storage capacity thus limiting its utilisation in RE management deployments [70]. As a result, this technology was not included in the final NIA model. No other electromagnetic technologies were considered.

**B.5.4 Energy Storage Category: Chemical Battery**

**Technology: Lead-Acid Battery**

Lead-acid battery technology is the oldest and most mature of all assessed chemical battery technologies [144]. This demonstrated technical history has led to a great deal of applied knowledge which underpins its maturity. There are many local and international examples of commercial-scale use within DER installations which assures its viability to the NIA modelling [138, 144].

**Technology: Lithium-Ion Battery**

Lithium-Ion proliferation is trending upward particularly in renewables capacity firming applications [145]. Though this technology is not as historically proven as its lead-acid counterpart, the rapid commercial uptake and technical developments are indicative of a product on the rise. Due to the profile of recent Australian projects, it was a necessity to include in the NIA model [139].

**Other Chemical Batteries**

Zinc Silver Oxide, Alkaline, Nickel Metal Hydride and Nickel Cadmium were also judged against assessment criteria to determine its inclusion within the model. Based on various commercial and technical metrics they were excluded.

**B.5.5 Energy Storage Category: Chemical Flow Battery**

**Technology: Vanadium Flow Battery**

Research has indicated that vanadium flow batteries (VRFB) are very suitable to DER and microgrid type applications [81]. Although there is a very local example of its application at the
Busselton Tree Farm [30], there is a lack of technical and commercial maturity in Australia makes it difficult to select for the NIA model. However, at the discretion of the project, this technology has been added to the optimisation model.

**Technology: Zinc-Bromine Flow Battery**

Like its Vanadium counterpart, a lack of commercial viability and precedent within the Australian market has excluded Zinc-Bromine Flow batteries from consideration within the NIA model.

### B.5.6 Battery State of Charge Comparisons

![Fig B-7. State of charge Lead-Acid](image1.png) ![Fig B-8. State of charge Vanadium Redox Flow](image2.png) ![Fig B-9. State of charge Lithium-Ion](image3.png)

### B.6 Dispatch Control

Control processes and structures can range in degrees of complication, with a clear correlation between complexity and the cost to implement. The simplest of approaches is a static generation ordering (GO) routine which dispatches fixed power outputs from a predetermined hierarchy of generators [85]. As the gains in simplicity are greatly offset by economic and technical inefficiencies, this strategy is rarely utilised as a deliberate approach. However, according to Barley and Winn [146], there are two rudimentary dispatch tactics that can adequately rival sophisticated predictive control algorithms in most optimisation aims.
The first of these systems is called “Load Following” (LF) and emphasises running the main generator only to the extent that the primary net load demands it (plus any spinning reserve requirements) [147]. Under LF control, energy storage devices are charged exclusively by renewable resources, making it well suited to diverse generation topologies. The second strategy is termed “Cycle Charging” (CC), and it places priority on running the generator at rated power regardless of the net load demand [148]. With CC control, excess generation from the primary generation source was used to meet lower priority demands such as deferrable loads and energy storage devices. Barley and Winn comment on the fact that CC control is great for enhancing generator fuel performance as it dispatches generators at rated power for most time steps [146].

However, arguments against both strategies are known. LF control is often characterised as a mid-priced option more suited to peaking plants rather than baseload situations due to increased fuel cycle costs [149] and a reduction of load factor [149, 150]. These arguments against LF control generally only carry weight in scenarios where large-scale, centralised generation is being utilised, such as Nuclear power. Criticisms against CC control usually are related to increased battery costs like wear costs and conversion losses [146]. Furthermore, with the generator supplying most of the charging current, there is a diminished opportunity to store energy from sustainable renewable sources [146].

As a means of addressing the problems arising in both LF and CC strategies, a merged algorithm could be beneficial. This concept has been looked at by Homer Energy as an additional controller module within the HOMER software package. The “Combined Dispatch” (CD) strategy utilises key aspects of both LF and CC controllers [151]. The priorities start with attempting to meet load requirements with the energy storage devices first, and if required the second priority would resemble a CC generation ramp up to charge storage and meet load. If necessary, the final approach is an LF controller style dynamic minimal generation to meet demand hierarchies.
Appendix C  Optimisation Test Results

C.1  Case 1 (Grid-connected, CHP Generators)

C.1.1  Inputs

This case will consider the following arrangement and technologies as specific case variables:

- SWIS Network Connection (Limit: Always Connected-70 MW capacity)
- CHP enabled TM2500 gas turbine (Limit: 0-2 units rated at 32 MW each)
- CAT-C175-20 Prime diesel generator (Limit: 0-1 units rated at 5 MW each)
- Vestas V82 wind turbine (Limit: nil at 1.65 MW each)
- Generic Flat Plate poly-Si PV (Limit: nil)
- Generic Power Electronic Inverter/Rectifier (Limit: nil)

All the pre-selected battery types were included in the topology. The dispatch controller will consider both cycle charging and load following algorithms. The AC connected, generic thermal load controller is not included in any optimisation calculations and merely facilitates the CHP thermal output to the thermal load.

C.1.2  Results

Table C-8. Case 1 Optimisation

<table>
<thead>
<tr>
<th>Quantity</th>
<th>LCOE</th>
<th>NPC</th>
<th>CAPEX</th>
<th>OPEX</th>
<th>Emissions</th>
<th>RF</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Architecture ID</td>
<td>C1A1</td>
<td>C1A2</td>
<td>C1A3</td>
<td>C1A4</td>
<td>C1A5</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>Topology</td>
<td>WT GT(c) Grid</td>
<td>Grid</td>
<td>PV WT GT(c) DG Grid</td>
<td>PV WT Batt Grid</td>
<td>WT Grid</td>
<td>Grid</td>
<td></td>
</tr>
<tr>
<td>PV (MW)</td>
<td>0</td>
<td>0</td>
<td>3.75</td>
<td>43.90</td>
<td>0</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>WT (MW)</td>
<td>18.15</td>
<td>0</td>
<td>33.00</td>
<td>44.55</td>
<td>66.00</td>
<td>-</td>
<td></td>
</tr>
<tr>
<td>GT (MW)</td>
<td>32.00</td>
<td>0</td>
<td>32.00</td>
<td>0</td>
<td>0</td>
<td>-</td>
<td></td>
</tr>
</tbody>
</table>

1 Optimisation is set to find the best performing topology for each system variable
2 For grid-connected scenarios the initial capital optimisation is the same as the benchmark
3 Annualised
4 This is the highest technically feasible RF
5 This is the best overall Total NPC Architecture and lowest LCOE
6 This is the best annual OPEX Architecture
C.1.3 Sensitivity Analysis

No significant changes were noted with electrical load fluctuations barring the need to supplement the grid with generators to handle increased load. With a 10% load increase, a diesel generator was included in the architecture 1 configuration. No notable configuration changes were recommended under thermal load variance.

As tariffs rise an expected drop in grid purchases follows. The energy is directed through DER installations at a higher degree. An interesting result is that renewable sources were relied upon less under high tariff scenarios and conventional generation specified into the system. The reasoning behind this is believed to be the comparative flexibility advantage of diesel generators to be installed with little CAPEX and replacement considerations.

Inversely to higher tariff rates, higher fuel rates led to a greater dependence upon the SWIS. LCOE remained steady throughout as purchase decisions were funnelled to the most economical options under each scenario.

---

7 CC – Cycle Charging, LF – Load Following, CC/LF – The same result was achieved with both algorithms
8 Over a 25-year lifespan
With the introduction of an emissions cap the only effected topology would be architecture 2. With the addition of a gas turbine to this topology a reduced grid demand would ensue with reduced emissions as a result. In C1A1 the total costs due to emissions penalties was A$2.2M per year.

C.2 Case 2 (Islanded, CHP Generators)

C.2.1 Inputs

This case will consider the following arrangement and technologies as specific case variables:

- CHP enabled TM2500 gas turbine (Limit: 0-2 units rated at 32 MW each)
- CAT-C175-20 Prime diesel generator (Limit: 0-1 units rated at 5 MW each)
- Vestas V82 wind turbine (Limit: nil at 1.65 MW each)
- Generic Flat Plate poly-Si PV (Limit: nil)
- Generic Power Electronic Inverter/Rectifier (Limit: nil)

All the pre-selected battery types were included in the topology. All controller settings and options (including thermal) will remain the same as case 1.

C.2.2 Results

Table C-9. Case 2 Optimisation

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Optimised System Variables</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Topology</td>
<td>GT(c)</td>
<td>GT(c) DG</td>
</tr>
<tr>
<td>PV (MW)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>WT (MW)</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>GT (MW)</td>
<td>64.00</td>
<td>64.00</td>
</tr>
</tbody>
</table>

Optimisation is set to find the best performing topology for each system variable
For grid-connected scenarios the initial capital optimisation is the same as the benchmark
Annualised
This is the highest technically feasible RF
This is the best overall Total NPC Architecture and lowest LCOE
This is the best annual OPEX Architecture
### Performance Metrics

<table>
<thead>
<tr>
<th></th>
<th>LCOE (A$/kWh)</th>
<th>Total NPC (A$M)</th>
<th>OPEX (A$M/yr)</th>
<th>CAPEX (A$M)</th>
<th>RF (%)</th>
<th>Capacity Shortage (MWh/yr)</th>
<th>CO₂ Emissions (kT/yr)</th>
<th>Grid Energy (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
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<td>0.099</td>
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<td>0.649</td>
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<td>15.37</td>
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<td>0.607</td>
<td>1944.71</td>
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<tr>
<td></td>
<td>0.346</td>
<td>1127.28</td>
<td>73.48</td>
<td>31.1</td>
<td>82.33</td>
<td>182.15</td>
<td>0</td>
<td>-</td>
</tr>
</tbody>
</table>

**C.2.3 Sensitivity Analysis**

This case was analysed under the load growth and contraction scenarios outlined in section 4.7. Under electrical load contraction (-10%) a similar topology was observed with the point of difference being the battery type (LI rather than VRFB). The LI banks had an average SoC of 84.67%, when compared to the VRFB SoC of 36.87% under normal load conditions it is evident that LI did not have the same level of energy input into the system. The load growth scenario (+10%) lead to a dramatic reduction of renewables in the DER topology with a simple islanded dual gas turbine configuration. This scenario lead to a lower LCOE but with higher fuel costs and greater emissions.

---

15 CC – Cycle Charging, LF – Load Following, CC/LF – The same result was achieved with both algorithms
16 Over a 25-year lifespan
Typical economic behaviour was exhibited under the fuel sensitivity analysis. With patterns clearly showing higher conventional generation uptake as fuel prices dropped for respective generators. With the gas turbines typically making up a larger percentage of installed capacity the natural gas fluctuations have a greater impact.

All optimised configurations fell under the emissions cap of 142.3 kT/yr. This is due to the applied carbon tax with C2A1 incurring over A$2.93M/yr of emissions tax annualised present costs alone. As the reliability penalty increases, intermittent sources (primarily renewable DER) are specified at a lower rate.

C.3 Case 3 (Grid-connected, Non-CHP Generators)

C.3.1 Inputs

This case will consider the following arrangement and technologies as specific case variables:

- SWIS Network Connection (Limit: Always Connected-70 MW capacity)
- Simple TM2500 gas turbine (Limit: 0-2 units rated at 32 MW each)
- CAT-C175-20 Prime diesel generator (Limit: 0-1 units rated at 5 MW each)
- Vestas V82 wind turbine (Limit: nil at 1.65 MW each)
- Generic Flat Plate poly-Si PV (Limit: nil)
- Generic Power Electronic Inverter/Rectifier (Limit: nil)

All preselected battery types were used in this case. All controller settings and options (including thermal) will remain the same.
C.3.2 Results

Table C-10. Case 3 Optimisation

<table>
<thead>
<tr>
<th>Quantity</th>
<th>Optimised System Variables</th>
<th>Benchmark</th>
</tr>
</thead>
<tbody>
<tr>
<td>Architecture ID</td>
<td>C3A1&lt;sup&gt;21&lt;/sup&gt; C3A2 C3A3&lt;sup&gt;22&lt;/sup&gt;</td>
<td>-</td>
</tr>
<tr>
<td>Topology</td>
<td>WT GT Grid Grid WT GT Grid Grid</td>
<td></td>
</tr>
<tr>
<td>PV (MW)</td>
<td>0 0 0</td>
<td>-</td>
</tr>
<tr>
<td>WT (MW)</td>
<td>26.40 0 36.30</td>
<td>-</td>
</tr>
<tr>
<td>GT (MW)</td>
<td>32.00 0 32.00</td>
<td>-</td>
</tr>
<tr>
<td>DG (MW)</td>
<td>0 0 0</td>
<td>-</td>
</tr>
<tr>
<td>LA (MWh)</td>
<td>0 0 0</td>
<td>-</td>
</tr>
<tr>
<td>VRFB (MWh)</td>
<td>0 0 0</td>
<td>-</td>
</tr>
<tr>
<td>SWIS (MW)</td>
<td>70.00 70.00 70.00 70</td>
<td></td>
</tr>
<tr>
<td>Power Converter (MW)</td>
<td>0 0 0</td>
<td>-</td>
</tr>
<tr>
<td>LCOE (A$/kWh)</td>
<td>0.101 0.346 0.102 0.346</td>
<td></td>
</tr>
<tr>
<td>Total NPC (A$M)&lt;sup&gt;18&lt;/sup&gt;</td>
<td>360.21 1127.28 364.58 1127.28</td>
<td></td>
</tr>
<tr>
<td>OPEX (A$M/yr)</td>
<td>14.85 73.48 13.69 73.48</td>
<td></td>
</tr>
<tr>
<td>CAPEX (A$M)</td>
<td>138.71 31.10 160.29 31.1</td>
<td></td>
</tr>
<tr>
<td>RF (%)</td>
<td>27.37 0 36.56 0</td>
<td></td>
</tr>
<tr>
<td>Capacity Shortage (MWh/yr)</td>
<td>0 126.61 0 126.61</td>
<td></td>
</tr>
<tr>
<td>CO₂ Emissions (kT/yr)</td>
<td>105.40 182.15 91.35 182.15</td>
<td></td>
</tr>
<tr>
<td>Grid Energy (GWh)</td>
<td>7.20 210.01 6.54 210.01</td>
<td></td>
</tr>
</tbody>
</table>

Optimisation is set to find the best performing topology for each system variable
For grid-connected scenarios the initial capital optimisation is the same as the benchmark
Annualised
This is the highest technically feasible RF
This is the best overall Total NPC Architecture and lowest LCOE
This is the best annual OPEX Architecture
CC – Cycle Charging, LF – Load Following, CC/LF – The same result was achieved with both algorithms
Over a 25-year lifespan
C.3.3 Sensitivity Analysis

As the electrical load increases the system tends to specify more conventional generation. This sample size is quite small and will require further analysis into correlations. Wind turbines are most viable at -10 % and at standard load conditions. Grid reliance decreases at +10 % by significant factor due to increased utilisation of conventional DER. +10 % enjoyed a better LCOE as a result.

Fitting with expectation, grid reliance decreases as tariffs increase. Conventional generation (GT and/or DG) is the preferred DER technology when grid prices become prohibitive. CO₂ emissions increase as conventional DER reliance increases.

Natural gas prices appear to have one of the largest effects on LCOE. As fuel prices go up grid reliance increases. As expected, as fuel prices increase emissions decrease. This is due to reduced operating hours of the GT. With a diesel price around 0.84 $/L it is advantageous to include a 5 MW DG into the topology. A GT is always specified regardless of the fuel fluctuations, although usage notably varies.

The only optimised configuration effected by an emissions cap is C3A2 (lowest CAPEX). The other configurations sit comfortably within the limit. The carbon tax costs incurred by C3A1 is around $2.55M per year.

C.4 Case 4 (Islanded, Non-CHP Generators)

C.4.1 Inputs

This case will consider the following arrangement and technologies as specific case variables:

- Simple TM2500 gas turbine (Limit: 0-2 units rated at 32 MW each)
- CAT-C175-20 Prime diesel generator (Limit: 0-1 units rated at 5 MW each)
- Vestas V82 wind turbine (Limit: nil at 1.65 MW each)
- Generic Flat Plate poly-Si PV (Limit: nil)
- Generic Power Electronic Inverter/Rectifier (Limit: nil)
All preselected battery types were used in this case. All controller settings and options (including thermal) will remain the same.

C.4.2 Results

Table C-11. Case 4 Optimisation

<table>
<thead>
<tr>
<th>Installed Capacity</th>
<th>Quantity</th>
<th>Optimised System Variables</th>
<th>Performance Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>Architecture ID</td>
<td>C4A1 29</td>
<td>C4A2</td>
<td></td>
</tr>
<tr>
<td>Topology</td>
<td>GT GT DG</td>
<td>GT GT</td>
<td></td>
</tr>
<tr>
<td>PV (MW)</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>WT (MW)</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>GT (MW)</td>
<td>64.00</td>
<td>64.00</td>
<td></td>
</tr>
<tr>
<td>DG (MW)</td>
<td>5.00</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>LA (MWh)</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>VRFB (MWh)</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>LI (MWh)</td>
<td>0</td>
<td>52.03</td>
<td></td>
</tr>
<tr>
<td>SWIS (MW)</td>
<td>0</td>
<td>0</td>
<td>70</td>
</tr>
</tbody>
</table>

| Power Converter (MW) | 0 | 0 | 35.05 | 50.27 | - |

<table>
<thead>
<tr>
<th>Optimised System Variables</th>
<th>LCOE (A$/kWh)</th>
<th>NPC</th>
<th>CAPEX (A$M)</th>
<th>OPEX (A$M/yr)</th>
<th>RF (%)</th>
<th>Capacity Shortage (MWh/yr)</th>
<th>CO₂ Emissions (kT/yr)</th>
<th>Grid Energy (GWh)</th>
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</thead>
<tbody>
<tr>
<td>Architecture ID</td>
<td>0.101</td>
<td>0.102</td>
<td>0.114</td>
<td>0.321</td>
<td>0.346</td>
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<td>PV (MW)</td>
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<td>24.20</td>
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<td>126.61</td>
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<td></td>
</tr>
<tr>
<td>WT (MW)</td>
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<td>690.08</td>
<td>182.15</td>
<td>126.61</td>
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<td></td>
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<td>GT (MW)</td>
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<td>67.55</td>
<td>0</td>
<td>126.61</td>
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<td></td>
</tr>
<tr>
<td>DG (MW)</td>
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<td>14.42</td>
<td>1.47</td>
<td>209.00</td>
<td>0</td>
<td>126.61</td>
<td></td>
<td></td>
</tr>
<tr>
<td>LA (MWh)</td>
<td>154.77</td>
<td>156.16</td>
<td>85.34</td>
<td>48.09</td>
<td>182.15</td>
<td>126.61</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

25 Optimisation is set to find the best performing topology for each system variable
26 For grid-connected scenarios the initial capital optimisation is the same as the benchmark
27 Annualised
28 This is the highest technically feasible RF
29 This is the best overall Total NPC Architecture and lowest LCOE
30 This is the best annual OPEX Architecture
31 CC – Cycle Charging, LF – Load Following, CC/LF – The same result was achieved with both algorithms
32 Over a 25-year lifespan
C.4.3 Sensitivity Analysis

Regardless of the changes to the electrical load the same dual GT topology was specified for the best LCOE/NPC optimisation. The LCOE improves by approximately 10 % as the load grows 20 %, however this sample size is insufficient in identifying a broad-spectrum correlation. All other indicators behaved as anticipated.

As with the load changes, the ±30 % fuel variations did not lead to any topology changes. The system consistently specified a dual GT topology with no variation to generator operational hours.

C4A1 would be affected by an emissions cap as it just exceeds the future emissions limit by 13.86 kT/yr. The costs due to carbon tax reach A$3.7M/yr in C4A1. Lastly, C4A1 did not have any capacity shortage, therefore no penalties would be incurred.
### Appendix D  Analysis and Discussion

#### D.1  Observations: Investment Commentary

<table>
<thead>
<tr>
<th>Architecture</th>
<th>Topology</th>
<th>Optimised Variable</th>
<th>Present worth ($)</th>
<th>Annual worth ($/yr)</th>
<th>Return on investment (%)</th>
<th>Internal rate of return (%)</th>
<th>Simple payback (yr)</th>
<th>Discounted payback (yr)</th>
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<tbody>
<tr>
<td>C1A1</td>
<td>WT GT(c) Grid</td>
<td>NPC</td>
<td>$786,787,500</td>
<td>$52,739,400</td>
<td>54.6</td>
<td>60.2</td>
<td>1.66</td>
<td>1.77</td>
</tr>
<tr>
<td>C1A2</td>
<td>Grid</td>
<td>CAPEX</td>
<td>$0</td>
<td>$0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
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<td>C1A3</td>
<td>PV WT GT(c) DG Grid</td>
<td>OPEX</td>
<td>$772,283,500</td>
<td>$51,767,170</td>
<td>37.2</td>
<td>41.8</td>
<td>2.39</td>
<td>2.59</td>
</tr>
<tr>
<td>C1A4</td>
<td>PV WT Batt Grid</td>
<td>Emissions</td>
<td>$573,428,200</td>
<td>$38,437,640</td>
<td>21</td>
<td>25.2</td>
<td>3.94</td>
<td>4.43</td>
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<tr>
<td>C1A5</td>
<td>WT Grid</td>
<td>RF</td>
<td>$513,433,600</td>
<td>$34,416,120</td>
<td>26.7</td>
<td>31</td>
<td>3.22</td>
<td>3.55</td>
</tr>
<tr>
<td>C2A1</td>
<td>GT(c) GT(c) DG</td>
<td>NPC</td>
<td>$772,291,100</td>
<td>$51,767,680</td>
<td>48.7</td>
<td>53.5</td>
<td>1.87</td>
<td>1.99</td>
</tr>
<tr>
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<td>GT(c) GT(c)</td>
<td>CAPEX</td>
<td>$768,898,200</td>
<td>$51,540,250</td>
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<td>1.74</td>
<td>1.85</td>
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<tr>
<td>C2A3</td>
<td>PV WT GT(c) Batt</td>
<td>OPEX</td>
<td>$736,443,200</td>
<td>$49,364,750</td>
<td>29.7</td>
<td>34.6</td>
<td>2.88</td>
<td>3.15</td>
</tr>
<tr>
<td>C2A4</td>
<td>WT Batt</td>
<td>Emissions</td>
<td>$762,068,100</td>
<td>$51,417,580</td>
<td>50.5</td>
<td>55.6</td>
<td>1.8</td>
<td>1.92</td>
</tr>
<tr>
<td>C2A5</td>
<td>WT DG Batt</td>
<td>RF</td>
<td>$767,068,100</td>
<td>$51,417,580</td>
<td>50.5</td>
<td>55.6</td>
<td>1.8</td>
<td>1.92</td>
</tr>
<tr>
<td>C3A1</td>
<td>WT GT Grid</td>
<td>NPC</td>
<td>$767,068,100</td>
<td>$51,417,580</td>
<td>50.5</td>
<td>55.6</td>
<td>1.8</td>
<td>1.92</td>
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<tr>
<td>C3A2</td>
<td>Grid</td>
<td>CAPEX</td>
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<td>$0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>C3A3</td>
<td>WT GT Grid</td>
<td>OPEX / Em / RF</td>
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<td>$51,124,680</td>
<td>42.4</td>
<td>47.1</td>
<td>2.12</td>
<td>2.28</td>
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<tr>
<td>C4A1</td>
<td>GT GT DG</td>
<td>NPC</td>
<td>$767,848,100</td>
<td>$51,469,860</td>
<td>69.5</td>
<td>74.7</td>
<td>1.34</td>
<td>1.42</td>
</tr>
<tr>
<td>C4A2</td>
<td>GT GT</td>
<td>CAPEX</td>
<td>$764,653,300</td>
<td>$51,255,710</td>
<td>77.3</td>
<td>83.2</td>
<td>1.2</td>
<td>1.27</td>
</tr>
<tr>
<td>C4A3</td>
<td>PV WT GT Batt</td>
<td>OPEX</td>
<td>$727,661,100</td>
<td>$48,776,080</td>
<td>29.3</td>
<td>34.1</td>
<td>2.92</td>
<td>3.2</td>
</tr>
<tr>
<td>C4A4</td>
<td>PV WT GT</td>
<td>Em / RF</td>
<td>$736,443,200</td>
<td>$49,364,750</td>
<td>29.7</td>
<td>34.6</td>
<td>2.88</td>
<td>3.15</td>
</tr>
</tbody>
</table>

**Average**

- $352,655,994
- $23,638,993
- 31.14
- 42.74
- 1.93
- 2.10

### D.2  Observations: Effects of Battery Technology

From section 4.5, three battery storage technologies were selected as part of this project. Key economic assumptions can be found in that section. These attributes feed into the concept of

---

33 As defined in [152], this represents the difference between compared systems NPC
34 This is the annualised present worth
35 Based on the calculation as defined in [152]
36 As defined in [152]
37 As defined in [152]
38 As defined in [152]
battery wear cost which defines the cost of cycling produced electrical energy through these devices [153]. HOMER gives a simple equation to calculate this measure. After calculation it was noted that VRFB technology has a wear cost that is less than 10% of the others (see Table D-13 for wear costs). As a result, VRFB technology was consistently cycled to a greater depth of discharge throughout many permutations.

<table>
<thead>
<tr>
<th>Metric</th>
<th>LI</th>
<th>LA</th>
<th>VRFB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Replacement Cost ($k)</td>
<td>8.0</td>
<td>1.6</td>
<td>145.8</td>
</tr>
<tr>
<td>Lifetime Throughput (MWh)</td>
<td>38</td>
<td>10</td>
<td>8670</td>
</tr>
<tr>
<td>Efficiency (pu.)</td>
<td>0.92</td>
<td>0.80</td>
<td>0.93</td>
</tr>
<tr>
<td>Battery Wear Cost ($/kWh)</td>
<td>0.221</td>
<td>0.179</td>
<td>0.017</td>
</tr>
</tbody>
</table>

See Appendix B.6.6 for a visual into the average state of charge throughout the year for comparable system configurations. An increased level of battery throughput in systems with renewable DER can create a reduced reliance on conventional generation if the system dispatch algorithm manages the system accordingly. This reduced conventional reliance creates an incentive to increase renewable penetration and, by default, reduce emissions. From Fig D-10 it is very clear that vanadium redox tends to add a significantly lower energy cost to the system (approximately 25% less than the other technologies). Once again this is attributed to the lower wear cost that VRFB attracts. This result suggests the VRFB would best provide the necessary technical attributes to a hybrid DER system at the best economic performance.

![Fig D-10. Battery energy cost over the year](image)
Appendix E  Derivations and Equations

E.1 Economic Metrics

E.1.1 Net Present Cost

NPC can be expressed as all of the costs and incomes that transpire within the duration of the project, with the future cash flows discounted to the present [154]. The NPC includes all capital costs, replacement costs, operation and maintenance (O&M) costs. It is expressed by the following equation:

\[
C_{\text{npc,tot}} = C_0 + \sum_{N=1}^{R_{\text{proj}}} \frac{C_i - S_i}{(1 + i)^N}
\]

where \( N = \) number of years [yr], \( i = \) real discount rate, \( C_0 = \) initial capital costs [\$], \( C_i = \) ongoing costs [\$], \( R_{\text{proj}} = \) the project lifetime [yr] and \( S_i = \) salvage value [\$]. The HOMER Energy Glossary [123] provides excellent definitions of economic terms mentioned.

E.1.2 Cost of Energy

The Cost of Energy (COE) is a useful metric to evaluate the performance of energy generation systems. It is expressed in units of dollars per kilowatt-hour [\$/kWh]. Even more useful of a metric is the Levelised Cost of Energy (LCOE), which provides the COE over the lifetime of a project. In very a basic description, the LCOE is the average discounted costs divided by the average useful energy production over the life of the project [123]. These costs include capital, O&M and decommissioning expenses (or, inversely, salvage revenues) discounted to the present value [155]. LCOE can be expressed using the following equation:

\[
LCOE = \frac{\sum_{N=1}^{R_{\text{proj}}} C_{\text{Tot}}(N)}{\sum_{N=1}^{R_{\text{proj}}} E_{\text{TOT}}(N)}
\]

where \( C_{\text{Tot}}(N) = \) total costs in year \( N = \) capital + O&M + fuel [\$], \( E_{\text{TOT}}(N) = \) electricity generation in year \( N [\text{kWh}], i = \) real discount rate and \( R_{\text{proj}} = \) lifetime of the project [yr].
E.2 Environmental Metrics

E.2.1 Renewable Fraction

As mentioned before, the Renewable Fraction (RF) is the ratio of renewable generation to non-renewable generation deployed in a microgrid. RF can be expressed using the following equation [41, 123]:

\[
RF = \frac{E_{\text{ren}} + H_{\text{ren}}}{E_{\text{TOT}} + H_{\text{TOT}}}
\]  
(3)

where \(E_{\text{ren}}\) = renewable energy production [kWh], \(H_{\text{ren}}\) = renewable thermal production [kWh], \(E_{\text{TOT}}\) = total electrical production [kWh] and \(H_{\text{TOT}}\) = total thermal production [kWh].

E.2.2 Emissions Reduction

From Liu et al. [34] it was suggested that GHG emissions could be calculated using the following method:

\[
EM = \frac{Q \cdot EF}{1000}
\]  
(4)

where \(EM\) = greenhouse gas emissions [kg], \(Q\) = electricity used [kWh] and \(EF\) = emission factors of Australian grid electricity [g/kWh]. These emissions factors can be found on page 16 of Australian Energy Market Operator Emissions Factors Report [156]. This approach is insufficient in that it only considers the emissions from the grid. A more general approach can be seen in Zou et al. [157], which sums emissions by generator fuel type consumed.

\[
EM = \sum_{N=1}^{R_{\text{proj}}} (\sigma_{\text{CO}_2} + \sigma_{\text{CO}} + \sigma_{\text{HC}} + \sigma_{\text{NO}} + \sigma_s)V_{\text{fuel}}(N)
\]  
(5)

where \(\sigma_{\text{CO}_2}, \sigma_{\text{CO}}, \sigma_{\text{HC}}, \sigma_{\text{NO}}, \sigma_s\) = the coefficients of different pollutants [kg/L] and \(V_{\text{fuel}}(N)\) = the fuel consumption of the \(N\)th year [L/yr]. Relevant emissions coefficients and factors can be found in the Department of the Environment National Greenhouse Accounts Report for 2016 [158].
E.3 Fuel Calculations

For all arrangements, a fuel slope was calculated using equations 5 and 6 in combination with the appropriate fuel consumption charts. The fuel slope was then derived from the following equation:

\[ S_{fuel} = \frac{C_{100\%} - C_{25\%}}{P_{100\%} - P_{25\%}} \]  

(5)

Where \( C_{100\%} \) is the fuel consumption at 100 % rated load in m\(^3\)/hr, \( C_{25\%} \) is the fuel consumption at 25 % rated load in m\(^3\)/hr, \( P_{100\%} \) is the electrical power output at 100 % rated load in kW, \( P_{25\%} \) is the electrical power output at 25 % rated load in kW and \( S_{fuel} \) is the fuel slope in m\(^3\)/hr/kW electrical output.

The fuel intercept was also found looking at fuel consumption charts [159, 160] and calculating as per equation 6 below. This was cross-checked against data sheets for well-known diesel and gas generators [161, 162].

\[ I_{fuel} = \frac{C_{25\%} - P_{25\%} \cdot S_{fuel}}{P_{rated}} \]  

(6)

Where \( C_{25\%} \) is the fuel consumption at 25 % rated load in m\(^3\)/hr, \( P_{25\%} \) is the electrical power output at 25 % rated load in kW, \( S_{fuel} \) is the fuel slope in m\(^3\)/hr/kW electrical output, \( P_{rated} \) which is the full nominal power rating for the generator/turbine in kW rated and \( I_{fuel} \) is the fuel intercept in m\(^3\)/hr/kW rated.

Finally, power generation efficiency curves were produced using equation 7 with key calculated values from equations 5 and 6 substituted in.

\[ \eta_{gen} = \frac{3600 \cdot P_{gen}}{\rho_{fuel} \cdot LHV_{fuel} \cdot (I_{fuel} + S_{fuel} \cdot P_{gen})} \]  

(7)

Where \( P_{gen} \) is the relative fraction of power output to rated power in p.u., \( LHV_{fuel} \) is the lower heating value of the fuel in MJ/kg, \( I_{fuel} \) is the fuel intercept in m\(^3\)/hr/kW rated, \( S_{fuel} \) is the fuel
slope in m3/hr/kW electrical output and $\eta_{gen}$ is the power generation efficiency as a function of $p_{gen}$ in p.u.

Note that when liquid fuels are assessed all volumetric values are converted from cubic meters (m3) to litres (L). This is the case with Diesel and LPG (propane). All values have been used to populate the HOMER model, screenshots available in the appendices.

E.4 Reliability Penalty

$$CRP = \sum_{k=0}^{25} \left( \frac{\beta_R \lambda_{sk}}{(1 + i)^k} \right)$$

where $CRP =$ Discounted Reliability Penalty [$\], $\beta_R =$ Penalty Cost Coefficient [$/kWh], $\lambda_{sk} =$ Annual Capacity Shortage [kWh] and $i =$ Real Discount Rate [pu.]. Under the base case scenario, the annual capacity shortage is 126.6 MWh/y (including 15 % operating generation reserve) and the discounted reliability penalty over the lifetime of the project is $73,903,646.83 (at $39.13 per kWh of capacity shortage).

Appendix F Model Input Parameters

F.1 Tariff Structures

- Synergy Business Plan Fifty (L3) Tariff
  - Flat Rate with a staged cost structure
    - $0.353197 per kWh for the first 1650 kWh per day
    - $0.318798 per kWh for additional usage
- Synergy Business Time of Use Fifty (R3) Tariff
  - Time of Use (ToU) tariff
    - $0.46677 per kWh during peak hours
    - $0.143697 per kWh during off-peak hours
    - Peak times are weekdays from 9am – 10pm
Using the energy consumption profile for the NIA, an analysis was carried out to define the most cost-effective tariff to use for the modelling exercise. From the analysis it was found that the L3 “Flat Rate” tariff was most the cheapest as modelled usage falls largely within peak times (69% peak usage). However, the R3 ToU tariff allowed for businesses to make dynamic load adjustments. As a result, the R3 tariff was put into the model as the grid tariff structure. Another advantage of using the R3 tariff is that it will provide visibility into the behaviours of dispatchable generation during peak and off-peak periods.

<table>
<thead>
<tr>
<th>Tariff</th>
<th>Averaged Cost per kWh</th>
<th>Annual Usage (GWh)</th>
<th>Annual Electricity Cost ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>R3 (ToU)</td>
<td>0.3337</td>
<td>210.12</td>
<td>70.12</td>
</tr>
<tr>
<td>L3 (Flat Rate)</td>
<td>0.3189</td>
<td>210.12</td>
<td>67.01</td>
</tr>
</tbody>
</table>

F.2 Model Global Settings

<table>
<thead>
<tr>
<th>Location Based Metrics</th>
<th>Load and Network Metrics</th>
<th>General Economic Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Project Location: Nambeelup WA 6207,</td>
<td>• Annual Ave. Electrical Demand: 575.66 MWh/d</td>
<td>• Project Lifetime: 25 years</td>
</tr>
<tr>
<td>Australia (32°31’20”S 115°49’38”E)</td>
<td>• Peak Electrical Load: 59.4 MW</td>
<td></td>
</tr>
<tr>
<td>• Solar GHI annual average: 5.51 kWh/m2/d</td>
<td>• Load factor: 0.4039</td>
<td></td>
</tr>
<tr>
<td>• Wind annual average: 7.48 m/s @ 50m</td>
<td>• Peak Thermal Load: 23.7 MW (380 MWh/d annual ave.)</td>
<td></td>
</tr>
<tr>
<td>• Diesel Fuel Price: 1.2 $/L</td>
<td>• Spinning Reserve: 15 %</td>
<td></td>
</tr>
<tr>
<td>• Natural Gas Fuel Price: 0.125 $/m3</td>
<td>• Reliability Penalties on ($39.13 per kWh of capacity shortage)</td>
<td></td>
</tr>
</tbody>
</table>

Environmental Metrics

• Max allowable capacity shortage: 0.0571 % (Current SWIS Capacity Shortage)
F.3 Interim Modelling

F.3.1 CVBP Load Profile

Essential details of the load are as follows:

<table>
<thead>
<tr>
<th>Nearest Substations</th>
<th>Attributes</th>
<th>Main Feeders</th>
</tr>
</thead>
<tbody>
<tr>
<td>Canning Vale (CVE)</td>
<td>Average kWh/d: 200,919.58</td>
<td>WLN504 – Modal RMU – (22 kV, 324 A rated)</td>
</tr>
<tr>
<td></td>
<td>Average kW: 8,371.65</td>
<td>WLN505 – Modal 3 RMU – (22 kV, 324 A rated)</td>
</tr>
<tr>
<td></td>
<td>Peak kW: 20,762.10</td>
<td>WLN507 – Treetop – (22 kV, 324 A rated)</td>
</tr>
<tr>
<td></td>
<td>Load Factor: 0.4</td>
<td>CVE513 – Magnet Rd East – (22 kV, 324 A rated)</td>
</tr>
<tr>
<td></td>
<td>Land Area: 15 ha</td>
<td></td>
</tr>
</tbody>
</table>

The Western Power forecast report suggests over 35 MVA available capacity through the CVE and WLN substations to feed the load. Furthermore, with 4 large HV feeders available to the business park there is a maximum theoretical power delivery of 49 MVA. This does not consider the other customers on those circuits, but electrical distribution infrastructure is not a limitation for future expansion. Please see Fig F-11.
F.3.2 Conventional Generation

Due to the number of simulations the model optimisation calculations were split into three parts:

1. Test all non-CHP options (four generators) at full search space: Natural Gas CT, Natural Gas RICE, Diesel RICE and Biogas RICE.

2. Test all CHP options (four generators) at full search space: Natural Gas CT CHP, Natural Gas RICE CHP, Diesel RICE CHP and Biogas RICE CHP

3. Test top non-CHP against top CHP options (two generators) at full search space. Test 3 will include some sensitivity analysis around fuel costs.

All generators were given an assessment range of 0 – 60000 kW in 5000 kW steps. Detailed model results can be found in Appendix 0. Summarised conventional generation testing conclusions can be seen in Table F-17. As anticipated from the initial cost estimates, the natural gas-fired CT provided the best cost benefit. However, an interesting result came about when both CHP and non-CHP options were tested against one another. The early expectation was that the CHP would provide enough thermal benefits to offset the additional capital and operating costs. This was not the case as shown in test 3 results. Given the option, the optimisation algorithm relegated the CHP equipped turbine to less than half of the generation capacity (37.9 %). Despite the efficiency shortfalls the optimum arrangement includes a high percentage of natural gas-fired turbines. The suggested conventional DER combination is 50 MW installed capacity of natural gas-fired CTs...
and 5 MW installed capacity of diesel-fired RICE. The comparison between CHP and non-CHP CT technology was reassessed once emissions penalties are introduced.

Table F-17 provides insight into fuel price fluctuations that were built in as model sensitivities. Three different diesel prices and two different gas prices were used reflective of the price range found over the last 5 years [163, 164]. Interestingly, regardless of a doubling of price in either direction the architecture remained the same. This suggests that this is a robust combination going forward.

Table F-17. Fuel Sensitivity Scenarios (Conventional Gen)

<table>
<thead>
<tr>
<th>Sensitivities</th>
<th>Architectures</th>
<th>Economics</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Gas Turbine (MW)</td>
<td>CHP Gas Turbine (MW)</td>
</tr>
<tr>
<td>1.200</td>
<td>0.125</td>
<td>30.00</td>
</tr>
<tr>
<td>1.200</td>
<td>0.250</td>
<td>30.00</td>
</tr>
<tr>
<td>1.800</td>
<td>0.125</td>
<td>30.00</td>
</tr>
<tr>
<td>1.800</td>
<td>0.250</td>
<td>30.00</td>
</tr>
<tr>
<td>2.400</td>
<td>0.125</td>
<td>30.00</td>
</tr>
<tr>
<td>2.400</td>
<td>0.250</td>
<td>30.00</td>
</tr>
</tbody>
</table>

Interim Model: Conventional DER

Fig F-12. Interim Model: Initial Conventional DER Combination
F.3.3 Renewable Generation

Interim Model: Renewable DER

F.3.4 Energy Storage

Interim Model: Energy Storage

F.4 Model Refinement

For a focused analysis it is important to create working boundaries for the project. These boundaries were developed through two mechanisms:
- Scope Restrictions around primary energy sources (electrical/thermal)
- Sub-Optimisation (where possible)

With the use of these methods a refined set of scenarios would be defined which would then be subject to uncertainty analysis based on essential sensitivity variables. Upon inspection of current optimization scenarios, the following system variables were identified:

1. Grid (States: Connected / Islanded)
2. Thermal Load (States: on / off)
3. GT CHP Capability (States: on / off)
4. DG (States: on / off)
5. WT (States: 1.65 MW / 225 kW)
6. LI Banks (States: on / off)
7. LA Banks (States: on / off)
8. VRFB Banks (States: on / off)

With these eight variables included in the model there was a possible set of 256 topology iterations prior to any size optimizations or controller development. Using the built in HOMER optimization time estimator (Fig F-15), the reader can see the need for further refinement to produce a coherent and concise set of results.

Fig F-15. Interim HOMER Schematic and Estimated Simulation Time
F.4.1 Sub-Optimisation

To further assist in refining the test focus areas, a set of sub-optimization tests will occur where possible to create a greater number of fixed constraints. For this to be done, the following sub-optimization tests were to occur:

- Test 1 - Define best generator
- Test 2 - Define best wind turbine

Only one option from these refinement tests was selected and carried into the final optimization model. The selection criteria will primarily be economic in nature including metrics like LCOE, NPC, Capital and O&M costs. Upon identifying the ideal options, a set test topology was defined and subjected to the scope restrictions outlined in Section 4.7.

The framework for test 1 is very simple as CHP is not being considered. The electrical load will remain fixed and no thermal load was included. The aim is to confirm the need to include a diesel RICE option in the final optimization model. The comparison scenarios were as follows:

- Scenario 1: Up to 70 MW Natural Gas CT only
- Scenario 2: Up to 70 MW Natural Gas CT and Diesel RICE at optimized ratio

A comparison will take place on the key economic metrics as well as emissions indicators to determine the most refined conventional generation options. The search space within the optimization model allows for increments of 5 MW per generator to find a reasonably specific generation capacity per type. The results from these scenario tests can be seen in Table F-18 below.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Diesel RICE Capacity (MW)</th>
<th>Gas Turbine Capacity (MW)</th>
<th>LCOE ($/kWh)</th>
<th>NPC ($M)</th>
<th>O&amp;M ($M)</th>
<th>Initial Capital ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 (W/ Diesel RICE)</td>
<td>10</td>
<td>45</td>
<td>0.0887893</td>
<td>278.2958</td>
<td>13.25213</td>
<td>80.5952</td>
</tr>
<tr>
<td>2 (W/O Diesel RICE)</td>
<td>0</td>
<td>55</td>
<td>0.0929778</td>
<td>291.4242</td>
<td>14.33892</td>
<td>77.5104</td>
</tr>
</tbody>
</table>
Contrary to expectations, the optimization results of the conventional generation reduction tests yielded a ratio including diesel at small capacities. As a means of gaining understanding, sensitivity analysis on fuel prices, fuel efficiencies, operating lifecycles and load size was carried out.

Interestingly, even under the scenario with the least favourable variables, the diesel RICE was prescribed at its minimum of 5 MW. This suggests that fuel or efficiency isn’t the entire story behind the inclusion in the model results. Comparisons between the scenarios show that operating costs is the differentiator providing the marginal improvement of the mixed generation topology (seen in Table F-19).

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Replacement Costs ($M)</th>
<th>O&amp;M Costs ($M)</th>
<th>Fuel Costs ($M)</th>
<th>Salvage Profit ($M)</th>
<th>Total Operating Cost ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 (With Diesel)</td>
<td>3.41</td>
<td>2.88</td>
<td>8.14</td>
<td>-1.17</td>
<td>13.25</td>
</tr>
<tr>
<td>2 (Without Diesel)</td>
<td>4.16</td>
<td>3.39</td>
<td>7.95</td>
<td>-1.16</td>
<td>14.34</td>
</tr>
</tbody>
</table>

In Table F-19, there are improvements to both annual replacement and annual O&M under the mixed generation topology. Fig F-18 shows the generator utilization against the typical load on the 16th of March. From the figure the DS RICE is being utilized as a

---

59 Annual operating cost is the sum of replacement, O&M and fuel with salvage profits subtracted
fast dispatch peaking plant to supplement the base generation being provided by the gas turbine plant.

Initially, it was thought that including a supplementary peaking generator to support the base generator would be unnecessary and possibly economically inferior. However, the results indicate that it increases the operating life of the base plant to the point that the peaking plant costs are outweighed by the economic benefit. As a result of this analysis it has been determined that it is essential to include small-scale (approximately 5-10 MW) Diesel RICE capacity within the optimisation model to ensure that this peaking capability is considered.

Test 2 was very simple and consisted of the NIA electrical load, a scalable LI battery bank, a power converter and two types of wind turbines as developed in earlier sections. This test is to determine the most applicable wind turbine to the NIA load. Analysis was carried out on the effects of load size and the applicability of each turbine to scale.

Table F-20 provides the outcome of each wind turbine scenario. From these results, there is a need to include small-scale wind turbines in the event of a high wind penetration topologies to avoid over capacity issues with an additional 1.65 MW wind turbine. However, for the purposes of refining the model the 1.65 MW wind turbine was used in the initial optimisation iteration. Both types were used only in refining a topology with a high wind penetration recommended.

### Table F-20. Test 2 Scenario Results

<table>
<thead>
<tr>
<th>Scenario</th>
<th>1.65 MW Wind Turbines</th>
<th>225 kW Wind Turbines</th>
<th>LCOE ($/kWh)</th>
<th>NPC ($M)</th>
<th>Operating cost ($M)</th>
<th>Initial capital ($M)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 (Both)</td>
<td>109</td>
<td>8</td>
<td>0.5532</td>
<td>1733.09</td>
<td>18.39</td>
<td>1458.81</td>
</tr>
<tr>
<td>2 (Large-Scale)</td>
<td>113</td>
<td>0</td>
<td>0.5582</td>
<td>1748.76</td>
<td>18.82</td>
<td>1467.98</td>
</tr>
</tbody>
</table>

40 Battery Bank fixed at 120,000 Lithium-Ion Batteries
41 Power Converter fixed at 145,000 kW capacity
The fine-tuning of the topology yielded interesting results. With an absence of all the required delineations, the project was refined further based upon practical limitations and assumptions. Two development tests were conducted to determine the best generator combination and best wind turbine technology to use. It was determined that dual options be used for these categories with a dominant (primary) and an auxiliary technology. The auxiliary technology was employed only when a high percentage penetration of the dominant technology has been recommended and further enhancement is required. The table below offers a review of the findings of the tests.

<table>
<thead>
<tr>
<th>Test</th>
<th>Subject</th>
<th>Dominant Technology</th>
<th>Auxiliary Technology</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Conventional Generation</td>
<td>Natural Gas CT</td>
<td>Diesel RICE</td>
</tr>
<tr>
<td>2</td>
<td>Wind Turbine Technology</td>
<td>1.65MW Turbine</td>
<td>225kW Turbine</td>
</tr>
</tbody>
</table>
F.5 Conventional DER Cost Assumptions

F.5.1 Fuel and Efficiency Attributes

Essential fuel pricing data can be found in the table below.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Type</th>
<th>Density (kg/m³)</th>
<th>LHV (MJ/kg)</th>
<th>Cost ($/ltr)</th>
<th>Cost (A$/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel</td>
<td>Liquid</td>
<td>846</td>
<td>42.6</td>
<td>120.00</td>
<td>11.99</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>Gas</td>
<td>0.777</td>
<td>47.1</td>
<td>0.01252</td>
<td>1.23</td>
</tr>
<tr>
<td>LPG</td>
<td>Gas</td>
<td>0.498</td>
<td>46.4</td>
<td>0.07654</td>
<td>11.92</td>
</tr>
<tr>
<td>Biogas</td>
<td>Gas</td>
<td>0.72</td>
<td>30</td>
<td>0.0922</td>
<td>15.36</td>
</tr>
</tbody>
</table>

The following section outlines the process of fuel and engine efficiency development.

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Type</th>
<th>Density (kg/m³)</th>
<th>LHV (MJ/kg)</th>
<th>Intercept (Vol/hr/kW)</th>
<th>Slope (Vol/hr/kW)</th>
<th>Full Load Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel</td>
<td>RICE</td>
<td>846.00</td>
<td>42.60</td>
<td>0.07222222</td>
<td>0.27555556</td>
<td>0.28722399</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>CT</td>
<td>0.7770</td>
<td>47.10</td>
<td>0.09886364</td>
<td>0.30000000</td>
<td>0.24662445</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>RICE</td>
<td>0.7770</td>
<td>47.10</td>
<td>0.08787879</td>
<td>0.26666667</td>
<td>0.27745251</td>
</tr>
<tr>
<td>Methane (Bio)</td>
<td>RICE</td>
<td>0.7200</td>
<td>30.00</td>
<td>0.14646465</td>
<td>0.44444444</td>
<td>0.28205128</td>
</tr>
</tbody>
</table>

It was evident upon calculation that the efficiency values did not reflect established knowledge around generator and turbine efficiencies [168]. Consequently, it was best practice to scale the efficiencies to known values and maintain the relative difference between the technologies as a means of differentiation. Using the US Department of Energy report, the efficiency of diesel RICE was scaled up to 0.5 and that scaling factor was applied to all others to maintain relative difference. The results are summarised in Table F-24.

---

42 Density values sourced from Engineering Toolbox [165]
43 Lower Heating Values sourced from Engineering Toolbox [165]
44 Calculated based on density, LHV and cost per litre
45 Fuel Watch Diesel Terminal Gate Pricing Dec 2017 [166]
46 Natural Gas Spot Price Dec 2017 [167]
47 Liquified Propane Vapour
48 BP Autogas prices [55]
49 60 % Methane gas
50 Calculated at 60 % of Methane LHV
51 Calculated from page 43, IRENA document on Biogas gasifier levelized cost of energy [56]
Table F-24. Scaled Fuel Intercepts and Slopes

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Type</th>
<th>Density (kg/m³)</th>
<th>LHV (MJ/kg)</th>
<th>Intercept (Vol/hr/kW)</th>
<th>Slope (Vol/hr/kW)</th>
<th>Full Load Efficiency (Scaled)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Diesel</td>
<td>RICE</td>
<td>846.00</td>
<td>42.60</td>
<td>0.04148791</td>
<td>0.15829233</td>
<td>0.5</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>CT</td>
<td>0.7770</td>
<td>47.10</td>
<td>0.05679202</td>
<td>0.17233439</td>
<td>0.42932425</td>
</tr>
<tr>
<td>Natural Gas</td>
<td>RICE</td>
<td>0.7770</td>
<td>47.10</td>
<td>0.05048179</td>
<td>0.15318613</td>
<td>0.48298979</td>
</tr>
<tr>
<td>Methane (Bio)</td>
<td>RICE</td>
<td>0.7200</td>
<td>30.00</td>
<td>0.08413632</td>
<td>0.25531021</td>
<td>0.49099534</td>
</tr>
</tbody>
</table>

Note: MTBF and MTTR values were only applied to the final preferred generators. Values can be found in Appendix F.5.9.

F.5.2 Cost Attributes: Natural Gas-fired turbine

From the 2016 United States Energy Information Administration report on the Capital Costs of Utility Scale Electricity Generating Plants [169], a number of useful estimates are found. These capital, O&M and replacement cost metrics were used to model the CT and RICE options within the model. The lifetime of the turbines was selected to be 100,000 operating hours based on a Siemens AG gas turbine life extension report written in 2006 [170]. Cost assumptions were developed using the EIA report, US DoE report and the Siemens maintenance recommendations, are as found in Table F-25.

Table F-25. Natural Gas CT Cost and Fuel Assumptions

<table>
<thead>
<tr>
<th>Natural Gas CT</th>
<th>Natural Gas CT (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Capital Costs: A$1564.20/kW</td>
<td>• Capital Costs: A$1941.10/kW</td>
</tr>
<tr>
<td>• Replacement Costs: A$1224.00/kW</td>
<td>• Replacement Costs: A$1315.60/kW</td>
</tr>
<tr>
<td>• Operating Hours prior to overhaul: 100,000hrs</td>
<td>• Operating Hours prior to overhaul: 100,000hrs</td>
</tr>
<tr>
<td>• Variable O&amp;M Costs: A$0.00448/kW-hr</td>
<td>• Variable O&amp;M Costs: A$0.00448/kW-hr</td>
</tr>
<tr>
<td>• Fixed O&amp;M Costs: A$0.002557/kW-hr</td>
<td>• Fixed O&amp;M Costs: A$0.002557/kW-hr</td>
</tr>
<tr>
<td>• Combined O&amp;M: A$0.007037/kW-hr</td>
<td>• Combined O&amp;M: A$0.007037/kW-hr</td>
</tr>
</tbody>
</table>

Fuel Metrics

<table>
<thead>
<tr>
<th>Natural Gas CT</th>
<th>Natural Gas CT (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Heat Recovery Ratio: 58 %</td>
<td>• Scaled Fuel Slope: 0.172334 m3/hr-kW output</td>
</tr>
<tr>
<td>• Fuel Intercept: 0.0879 m3/hr-kW rated</td>
<td>• Scaled Fuel Intercept: 0.0568 m3/hr-kW rated</td>
</tr>
<tr>
<td>• Fuel Slope: 0.2667 m3/hr-kW output</td>
<td>• Full-Load Efficiency: 42.93 %</td>
</tr>
</tbody>
</table>
The EIA report did not provide clear cost estimates for the fitting of heat recovery systems. However, useful data was located within two United States Department of Energy papers on CHP [168, 171]. These provide estimates on the additional costs associated with a CHP installation to both CT and RICE applications. Note that one of the documents was written in 1999 and costs will have improved since then, however the data in Table F-25 provides a conservative valuation.

From equation 5 in Appendix E, the fuel slope was calculated to be 0.2667 m³/hr-kW output. For natural gas CT and RICE options the fuel intercept calculated was 0.0879 m³/hr-kW rated. For the CHP enabled turbine, the heat recovery ratio was set to 58%, in line with system 1 in the United States Department of Energy report on CHP [171]. After scaling the efficiency, the fuel metrics were re-derived and can be found in Table F-25.

### F.5.3 Natural Gas-fired RICE

From sourced literature, mentioned in earlier parts of this document, cost estimates were developed for the model and summarised within the table below.

<table>
<thead>
<tr>
<th>Natural Gas RICE</th>
<th>Natural Gas RICE (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Capital Costs: A$1717.76/kW [169]</td>
<td>• Capital Costs: A$2741.76/kW [168, 169]</td>
</tr>
<tr>
<td>• Replacement Costs: A$1370.88/kW [169]</td>
<td>• Replacement Costs: A$1717.76/kW [168, 169]</td>
</tr>
<tr>
<td>• Operating Hrs before overhaul: 72,000hrs [172]</td>
<td>• Operating Hrs before overhaul: 66,000hrs [168, 172]</td>
</tr>
<tr>
<td>• Variable O&amp;M Costs: A$0.01536/kW-hr [171]</td>
<td>• Variable O&amp;M Costs: A$0.02432/kW-hr [168, 171]</td>
</tr>
<tr>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
</tr>
<tr>
<td>• Combined O&amp;M: A$0.016368/kW-hr</td>
<td>• Combined O&amp;M: A$0.025328/kW-hr</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fuel and Heat Metrics</th>
<th>Fuel and Heat Metrics</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Heat Recovery Ratio: 58%</td>
<td>• Scaled Fuel Intercept: 0.05048 m³/hr-kW rated</td>
</tr>
<tr>
<td>• Fuel Intercept: 0.0879 m³/hr-kW rated</td>
<td>• Scaled Fuel Slope: 0.1531 m³/hr-kW output</td>
</tr>
<tr>
<td>• Fuel Slope: 0.2667 m³/hr-kW output</td>
<td>• Full Load Efficiency: 48.29%</td>
</tr>
</tbody>
</table>
F.5.4 Diesel-fired RICE

The cost estimate data for both the natural gas and diesel RICE options was very similar. Capital and replacement costs were alike, O&M and operating hours had variation. From sourced literature, mentioned in earlier parts of this document, cost estimates were developed for the model and summarised within the table below.

**Table F-27. Diesel RICE Cost and Fuel Assumptions**

<table>
<thead>
<tr>
<th>Diesel RICE</th>
<th>Diesel RICE (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Capital Costs: A$1717.76/kW [169]</td>
<td>• Capital Costs: A$2741.76/kW [168, 169]</td>
</tr>
<tr>
<td>• Replacement Costs: A$1370.88/kW [169]</td>
<td>• Replacement Costs: A$1717.76/kW [168, 169]</td>
</tr>
<tr>
<td>• Operating Hrs before overhaul: 72000hrs [172]</td>
<td>• Operating Hrs before overhaul: 51,000hrs [168, 172]</td>
</tr>
<tr>
<td>• Variable O&amp;M Costs: A$0.01152/kW-hr [113]</td>
<td>• Variable O&amp;M Costs: A$0.01792/kW-hr [113, 168]</td>
</tr>
<tr>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
</tr>
<tr>
<td>• Combined O&amp;M: A$0.012528/kW-hr</td>
<td>• Combined O&amp;M: A$0.018928/kW-hr</td>
</tr>
</tbody>
</table>

**Fuel and Heat Metrics**

<table>
<thead>
<tr>
<th>Diesel RICE</th>
<th>Diesel RICE (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Heat Recovery Ratio: 58 %</td>
<td>• Scaled Fuel Intercept: 0.041487 m³/hr-kW rated</td>
</tr>
<tr>
<td>• Fuel Intercept: 0.0722 L/hr-kW rated</td>
<td>• Scaled Fuel Slope: 0.15829 m³/hr-kW output</td>
</tr>
<tr>
<td>• Fuel Slope: 0.2755 L/hr-kW output</td>
<td>• Full Load Efficiency: 50 %</td>
</tr>
</tbody>
</table>

F.5.5 LPG-fired RICE

Upon research it was seen that LP-vapour-fired generators are generally not used for applications larger than 150kW. As a result, LPG options were removed from consideration.

F.5.6 Biogas-fired RICE

From the US EPA report on CHP technologies [172], section 2.4.7.3 provides estimates on the use of biogas in RICE generation technology. The report estimates a flat rate USD $600/kW addition to the capital and replacement costs of other RICE technology. O&M costs will replicate the costs of other fuel-fired RICE generation technology. Cost estimates are as follows:
### Table F-28. Biogas RICE Cost and Fuel Assumptions

<table>
<thead>
<tr>
<th>Biogas (60 % Methane) RICE</th>
<th>Biogas (60 % Methane) RICE (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Capital Costs: A$2485.76/kW [169, 172]</td>
<td>• Capital Costs: A$3509.76/kW [168, 169, 172]</td>
</tr>
<tr>
<td>• Replacement Costs: A$2138.88/kW [169, 172]</td>
<td>• Replacement Costs: A$2485.76/kW [168, 169, 172]</td>
</tr>
<tr>
<td>• Operating Hrs before overhaul: 72000hrs [172]</td>
<td>• Operating Hrs before overhaul: 51,000hrs [168, 172]</td>
</tr>
<tr>
<td>• Variable O&amp;M Costs: A$0.01152/kW-hr [113]</td>
<td>• Variable O&amp;M Costs: A$0.01792/kW-hr [113, 168]</td>
</tr>
<tr>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
<td>• Fixed O&amp;M Costs: A$0.001008/kW-hr [169]</td>
</tr>
<tr>
<td>• Combined O&amp;M: A$0.012528/kW-hr</td>
<td>• Combined O&amp;M: A$0.018928/kW-hr</td>
</tr>
</tbody>
</table>

#### Fuel and Heat Metrics

<table>
<thead>
<tr>
<th>Biogas (60 % Methane) RICE</th>
<th>Biogas (60 % Methane) RICE (CHP)</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Heat Recovery Ratio: 58 %</td>
<td>• Scaled Fuel Intercept: 0.084136 m3/hr-kW rated</td>
</tr>
<tr>
<td>• Fuel Intercept: 0.1465 m3/hr-kW rated</td>
<td>• Scaled Fuel Slope: 0.2553 m3/hr-kW output</td>
</tr>
<tr>
<td>• Fuel Slope: 0.4444 m3/hr-kW output</td>
<td>• Full Load Efficiency: 49.09 %</td>
</tr>
</tbody>
</table>

### F.5.7 Boiler Costs

HOMER does not allow for the inclusion of boiler capital costs into the system model. The only direct economic variable associated with the boiler is the fuel price. Indirect costs include the emissions and efficiency inputs [173]. As a result, there is a reduced benefit afforded to CHP systems within the HOMER model because in a normal scenario an increased installation of CHP technology would lead to a scaled down boiler size. Due to the scale of the thermal load, the most comparable concept in practice would be a small sized district heat-only boiler (HOB) system (0.5MW – 20MW) as described in Sandvall et al. [174]. From Sandvall et al. the specific investment cost of a natural gas-fired HOB can reach 0.13€/kW\textsubscript{heat} installed. Furthermore, an additional O&M cost of 2% of investment cost per year applies over the lifetime of the project [174].
Using an EUR:AUD currency conversion rate of 1.61:1 the total installed CAPEX of the NIA boiler at full capacity (30.5MW\text{peak}) is approximately A$6,400.00. The ongoing non-fuel OPEX for the boiler at full capacity would by A$127.67/yr. The assumed life cycle is 35 years based on Sandvall et al. meaning replacement costs and salvage revenues would not apply in the assessment. Utilising equation 1 in Appendix E to calculate the NPC at the real discount rate of 4.44 % the maximum non-fuel impact the boiler has on the total system NPC is A$8,432.30. With the addition of fuel costs at maximum usage the contribution to the system NPC escalates dramatically to A$32.06M. Using this knowledge, it is fair to assume that the boiler capital and non-fuel operating costs are negligible and can be ignored in the economic assessment.

![Fig F-20. Total Boiler NPC Contributions](image-url)

| Fuel NPC | $32,051,378.58 |
| Non-Fuel NPC | $8,432.30 |
F.5.8 Generator Refinement Test Detailed Results

It would be ideal to run the optimisation simulation with all eight generators at full search space. However, this led to an unmanageable amount of possible simulations. As a result, the modelling was split into three calculations each taking around 15 minutes.

**INTERIM CONVENTIONAL DER TEST 1: NON-CHP OPTIONS**

Results based on lowest cost of energy:

- 35 MW Natural Gas CT (servicing 75.9 % of electrical load)
- 15 MW Natural Gas RICE (servicing 24 % of electrical load)
- 5 MW Diesel RICE (servicing 0.145 % of electrical load)

**LCOE**: 0.07832 $/kWh  
**Total NPC**: $288,005,600.00  
**Operating Cost**: $13,696,820.00

*NOTE: These economic metrics do not include reliability penalties, emissions penalties, emissions cap and built in maintenance programs. As a result the NPC is artificially lower than what would be found in the final model. These metrics are for interim purposes only.*

*Fig F-21. Cost Breakdown (Conventional Gen Test 1)*
INTERIM CONVENTIONAL DER TEST 2: CHP OPTIONS

Results based on lowest cost of energy:

- 35 MW Natural Gas CT (servicing 78.7 % of electrical load)
- 15 MW Natural Gas RICE (servicing 20.9 % of electrical load)
- 5 MW Diesel RICE (servicing 0.401 % of electrical load)

**LCOE**: 0.09691 $/kWh  
**Total NPC**: $346,281,500.00  
**Operating Cost**: $14,127,620.00

**NOTE**: These economic metrics do not include reliability penalties, emissions penalties, emissions cap and built in maintenance programs. As a result the NPC is artificially lower than what would be found in the final model. These metrics are for interim purposes only.

![Fig F-22. Cost Breakdown (Conventional Gen Test 2)](image)

This test also provides some insight into the thermal recovery from the CHP enabled generators. The following observations were noted:

- Natural Gas CT serviced 158 MWh/yr thermal demand (70.3 %)
- Natural Gas RICE serviced 28.6 MWh/yr thermal demand (12.7 %)
- Diesel RICE serviced 1 MWh/yr thermal demand (0.466 %)
- The natural gas boiler made up the difference, servicing 37 MWh/yr thermal demand (16.5 %)
INTERIM CONVENTIONAL DER TEST 3: FINAL OPTIONS WITH SENSITIVITIES

Results based on lowest cost of energy:

- 30 MW Natural Gas CT (servicing 57.2% of electrical load)
- 15 MW Natural Gas CT (CHP) (servicing 37.9% of electrical load)
- 5 MW Natural Gas RICE (servicing 4.78% of electrical load)
- 5 MW Diesel RICE (servicing 0.145% of electrical load)

**LCOE**: 0.07237 $/kWh  
**Total NPC**: $269,382,900.00  
**Operating Cost**: $11,753,990.00

*NOTE: These economic metrics do not include reliability penalties, emissions penalties, emissions cap and built in maintenance programs. As a result the NPC is artificially lower than what would be found in the final model. These metrics are for interim purposes only.*

![Cost Breakdown Graph](image)

**Fig F-23. Cost Breakdown (Conventional Gen Test 3)**

Like test 2, test 3 provides thermal recovery figures from the CHP enabled generators. The following observations were noted:

- Natural Gas CT (CHP) serviced 63.5 MWh/yr thermal demand (32.3%)
- The natural gas boiler made up the difference, servicing 133.5 MWh/yr thermal demand (67.7%)

In conclusion, it is proposed that the best conventional generation arrangement to take into the wider optimisation problem is ~30 MW Natural Gas-fired CT, ~20 MW Natural Gas-fired CT with CHP, ~5 MW of Diesel RICE and a Thermal Boiler (see Fig F-12 in Appendix 0).
F.5.9 Gas Turbine and Diesel Generator Unplanned outages

Based on the methodology used in Calabro [175] and the MTBF and MTTR values for both types of generators a reliability metric was considered. From literature the following MTBF and MTTR values were assumed for each type of generator:

- $MTBF_{GT} = 6500 - 30000$ hours (derived from [176-178])
- $MTTR_{GT} = 88 - 96$ hours (derived from [177, 178])
- $MTBF_{DG} = 1251$ hours (derived from [176, 179])
- $MTTR_{DG} = 54$ hours (derived from [179])

The service application manual for gas turbine generators developed by Thomas Ekstrom in conjunction with the American Society of Mechanical Engineers (ASME) was used to help understand the importance of outages per generator duty type [177]. From this an assumed maintenance line was added to the generators as follows:

- GT Maintenance ($M_{GT}$) → every 8675 operational hours for 88 hours of planned outage
- DG Maintenance ($M_{DG}$) → every 1251 operational hours for 54 hours of planned outage

This was input into the HOMER generator maintenance tab.

F.6 Renewable DER Cost Assumptions

F.6.1 Photovoltaic DER

From selected literature Table F-29 has been populated. A rounded average was initially calculated and utilised in the system model.

<table>
<thead>
<tr>
<th>Literature</th>
<th>Publication Date</th>
<th>Capital (A$/kW)</th>
<th>Replacement (A$/kW)</th>
<th>O&amp;M (A$/kW-yr)</th>
<th>Lifetime (yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhan et al. [27]</td>
<td>2014</td>
<td>2300</td>
<td>2300</td>
<td>10</td>
<td>20</td>
</tr>
<tr>
<td>Ali and Shahnia [30, 31]</td>
<td>2016</td>
<td>1300</td>
<td>1300</td>
<td>40</td>
<td>25</td>
</tr>
<tr>
<td>Kumar [36]</td>
<td>2014</td>
<td>1000</td>
<td>800</td>
<td>50</td>
<td>25</td>
</tr>
<tr>
<td>Shafiullah et al. [33]</td>
<td>2012</td>
<td>3300</td>
<td>3300</td>
<td>0</td>
<td>Not stated</td>
</tr>
</tbody>
</table>
Upon further review, it was noted that manufacturing advances across many renewable technologies is creating a notable downward pricing slope [180]. As this project is assessed over a 25-year period it would be negligent to not build these considerations into the model. This has since been reflected in the HOMER model.

### F.6.2 Wind DER

The table below provides a summary of wind turbine related cost assumptions in literature.

<table>
<thead>
<tr>
<th>Literature</th>
<th>Publication Date</th>
<th>Capital (A$/kW)</th>
<th>Replacement (A$/kW)</th>
<th>O&amp;M (A$/kW-yr)</th>
<th>Lifetime (yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhan et al. [27]</td>
<td>2014</td>
<td>4267</td>
<td>3133</td>
<td>27</td>
<td>Not stated</td>
</tr>
<tr>
<td>Ali and Shahnia [30, 31]</td>
<td>2016</td>
<td>1273</td>
<td>1273</td>
<td>5</td>
<td>20</td>
</tr>
<tr>
<td>Shafiullah et al. [33]</td>
<td>2012</td>
<td>4267</td>
<td>3133</td>
<td>0</td>
<td>Not stated</td>
</tr>
<tr>
<td>Lu et al. [29]</td>
<td>2017</td>
<td>2300</td>
<td>2300</td>
<td>35</td>
<td>20</td>
</tr>
<tr>
<td>Blakers et al. [28]</td>
<td>2017</td>
<td>2300</td>
<td>2300</td>
<td>35</td>
<td>25</td>
</tr>
<tr>
<td><strong>Rounded Average</strong></td>
<td></td>
<td>2900</td>
<td>2500</td>
<td>21</td>
<td>22</td>
</tr>
</tbody>
</table>

For the generic turbine, all settings were to be initially based on the Vestas V82 – 1.65 MW turbine which was used in the Emu Downs wind farm [181]. As a point of difference, the Vestas V27 – 225 kW turbine was also assessed as it was utilised in the Ten Mile Lagoon wind farm in Esperance, WA [182]. The Vestas V82 settings come from the V82 datasheet [88] and the Vestas V27 settings come from the V27 datasheet [183]. Turbine electrical losses were set to 0.8 % based on a 2017 case study in large-scale wind [184]. Pricing was initially based on the selected literature in Table F-30. However, these initial assumptions have been found to be inadequate as
it fails to consider the international standards associated with rotor diameters and the recent cost improvements of wind turbines.

According to the International Electrotechnical Commission standard governing wind turbines (IEC 61400), average wind speeds play a large part of the sizing of wind turbines [185, 186]. The NIA has an annual average wind speed of 7.475 m/s which places it between wind class III and class IV. As the NIA wind speed is classified in a lower category, the rotor sizes would need to be larger and the hub height higher than a class II designed turbine to generate the same amount of power [187]. This needs to be considered in setting hub heights and selecting rotor sizes as this will directly affect the capacity factor [188].

The author has initiated discussions with Mr Jonathan King, a wind turbine engineer working for Senvion Australia Pty Ltd in Melbourne, which have anecdotally indicated that wind turbine installed prices could soon reach A$1M per MW installed [189]. This was built into a sensitivity analysis to see the effect on the DER topology under this scenario. In the present moment however, prices can be approximated based on costs structures analysed throughout European wind farm installations [190]. But even more applicable is the recent data generated by the National Renewable Energy Laboratory in the United States. The data found in a 2015 report indicates that fully installed capital costs are around A$2,180.10 per kW [188]. This is offset by a higher operating expenditure, with cited O&M costs at A$65.79 per kW-year [188].

Like the conventional generators selected for the final model, wind turbines have moving parts that are subject to unplanned failures which effects its ability to deliver constantly reliable power to the system. Using the reliability calculation method found in Calabro [175] and the MTBF and MTTR values associated with typical wind turbines a planned annual maintenance outage input was added to the HOMER model. That maintenance variable, $M_{WT}$ was set to 8688 calendar hours and a 72-hour duration.
F.6.3 Power Converter

The following table provides a summary of costs associated with the installation and operation of a power converter.

### Table F-31. Cost Assumptions for Power Converter

<table>
<thead>
<tr>
<th>Literature</th>
<th>Publication Date</th>
<th>Capital ($/kW)</th>
<th>Replacement ($/kW)</th>
<th>O&amp;M ($/MW-hr)</th>
<th>Lifetime (yrs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhan et al. [27]</td>
<td>2014</td>
<td>800</td>
<td>700</td>
<td>2</td>
<td>Not stated</td>
</tr>
<tr>
<td>Ali and Shahnia [30, 31]</td>
<td>2016</td>
<td>1000</td>
<td>1000</td>
<td>25</td>
<td>10</td>
</tr>
<tr>
<td>Kumar [36]</td>
<td>2014</td>
<td>200</td>
<td>170</td>
<td>Not stated</td>
<td>15</td>
</tr>
<tr>
<td>Shafiullah and Carter [32]</td>
<td>2015</td>
<td>800</td>
<td>700</td>
<td>0</td>
<td>20</td>
</tr>
<tr>
<td>Shafiullah et al. [33]</td>
<td>2012</td>
<td>800</td>
<td>700</td>
<td>0</td>
<td>Not stated</td>
</tr>
<tr>
<td>Liu et al. [34]</td>
<td>2012</td>
<td>800</td>
<td>800</td>
<td>0</td>
<td>15</td>
</tr>
<tr>
<td>Kumar et al. [41]</td>
<td>2014</td>
<td>200</td>
<td>180</td>
<td>Not stated</td>
<td>Not stated</td>
</tr>
<tr>
<td><strong>Rounded Average</strong></td>
<td></td>
<td>700</td>
<td>700</td>
<td>6</td>
<td>15</td>
</tr>
</tbody>
</table>

F.7 Other DER Cost Assumptions

F.7.1 Lead-Acid Energy Storage

There is a significant body of knowledge around flooded deep cycle LA batteries modelled within HOMER. Table F-32 provides used characteristic data from selected literature.

### Table F-32. Lead-Acid modelling characteristics used in selected literature

<table>
<thead>
<tr>
<th>Literature</th>
<th>Mfr</th>
<th>Model</th>
<th>Max Cap (kWh/unit)</th>
<th>Capital ($/Unit)</th>
<th>Replacement ($/Unit)</th>
<th>O&amp;M ($/Unit-yr)</th>
<th>Life (yrs)</th>
<th>Throughput (MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Orhan et al. [27]</td>
<td>Surrette</td>
<td>6 CS 25P</td>
<td>6.936</td>
<td>1250</td>
<td>1250</td>
<td>2</td>
<td>20</td>
<td>9.645</td>
</tr>
<tr>
<td>Ali and Shahnia [30, 31]</td>
<td>Trojan</td>
<td>IND17-6V</td>
<td>7.212</td>
<td>1500</td>
<td>1500</td>
<td>30</td>
<td>20</td>
<td>9.579</td>
</tr>
<tr>
<td>Liu et al. [34]</td>
<td>Surrette</td>
<td>4 KS 25P</td>
<td>7.6</td>
<td>170</td>
<td>130</td>
<td>-</td>
<td>2</td>
<td>10.5517</td>
</tr>
<tr>
<td>Kumar et al. [41]</td>
<td>Surrette</td>
<td>4 KS 25P</td>
<td>7.6</td>
<td>170</td>
<td>130</td>
<td>-</td>
<td>12</td>
<td>10.5517</td>
</tr>
</tbody>
</table>

It is evident from literature that there is a wide range of assumptions used, particularly with cost estimates. This has created a need to develop a specific set of cost metrics for batteries modelled...
within the NIA project. Based on precedence within selected literature, the three LA battery models and manufacturers were:

- Surrette 6 CS 25P
- Surrette 4 KS 25P
- Trojan IND17-6V

These batteries are well-known with easily accessible cost data. After review, the final cost estimates can be seen in the table below.

<table>
<thead>
<tr>
<th>Battery</th>
<th>Capital ($/Unit)</th>
<th>Replacement ($/Unit)</th>
<th>O&amp;M ($/Unit-yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Surrette - 6 CS 25P</strong></td>
<td>1600</td>
<td>1600</td>
<td>15</td>
</tr>
<tr>
<td><strong>Trojan - IND17-6V</strong></td>
<td>1500</td>
<td>1500</td>
<td>15</td>
</tr>
<tr>
<td><strong>Surrette - 4 KS 25P</strong></td>
<td>1700</td>
<td>1700</td>
<td>15</td>
</tr>
</tbody>
</table>

**F.7.2 Lithium-Ion Energy Storage**

The following is a summary of locally available batteries that were looked at as part of the LI model cost assumptions:

- Manufacturer: LGChem | Model: LG RESU 10 | Specifications: 48 V / 8.5 kWh / 5 kW
- Manufacturer: Discover AES | Model: 12-48-6650 | Specifications: 48 V / 6.6 kWh / 3 kW
- Manufacturer: Ampetus | Model: ASL100-60 | Specifications: 48 V / 2.7 kWh / 1.5 kW
- Manufacturer: Tesla | Model: Powerwall 2 | Specifications: 240 V / 12.5 kWh / 5 kW

After research, the most fit for purpose battery specifications was deemed to be based on the Tesla Powerwall 2 (DC Coupled).

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53 Averaged cost based on information from various online retailers
54 Averaged cost based on information from various online retailers
55 Converted to AUD (1.6 to 1) from Zakeri and Syri [72]
F.7.3 Vanadium Redox Flow Battery Banks

Assumptions that formed the VRFB model are general and broadly based on web-based sales data pertaining to the Gildemeister Cellecube FB 200-400 model [82]. However, a flow battery cost comparison study by Zawodzinski et al. was utilised as a cross reference [83]. Other technical and economic assumptions were found in selected literature [82, 84, 191, 192].

It is worth noting that VRFB technology may be more technically amenable to large-scale energy storage installations like the NIA project. This is due to the condition that a project only needs to replace the electrolyte solution after lifetime throughput has been reached (avoiding a costly full replacement of battery structures). Additionally, from a safety perspective, initial studies indicate that VRFB banks are not subject to thermal runaway events like its chemical battery counterparts [193, 194].

F.8 HOMER Setup

F.8.1 HOMER Emissions Settings

Using carbon dioxide emissions data from various sources the following emissions metrics were input into the HOMER model [195, 196]:

<table>
<thead>
<tr>
<th>Fuels</th>
<th>Grid (SWIS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas Carbon Content: 75 %</td>
<td>Carbon Dioxide 700g/kWh</td>
</tr>
<tr>
<td>Diesel Carbon Content: 88 %</td>
<td>Sulfur Dioxide 2.74g/kWh</td>
</tr>
<tr>
<td>All other pollutants left at default values</td>
<td>Nitrogen Oxides 1.34g/kWh</td>
</tr>
<tr>
<td>Generator emissions set to default</td>
<td>All other pollutants left at default values</td>
</tr>
</tbody>
</table>

The system emissions were capped at 190 kT/yr under most scenarios with a post testing analysis carried out at 142.3 kT/yr. Carbon pricing was set to a rate of $24.15 per tonne of produced carbon dioxide.