# THE UNIVERSITY OF QUEENSLAND

## Bachelor of Engineering and Master of Engineering (BE/ME) Thesis

Analysis and Comparison of Energy Generation Technologies in Remote Australia

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# Analysis and Comparison of a Hybrid Energy Generation System in Remote Australia


## Abstract

Increased implementation of renewable technology for power generation is critical to achieving the emissions targets set by many countries, as well as delivering an economically viable method of providing power to isolated communities. This project set out to analyse and compare three technologies, namely Solar PV, Concentrating Solar Thermal with thermal storage and diesel generators, for deployment in remote Australian areas. In this paper, a detailed literature review of past projects involving renewable energy hybrid power generation systems has been completed. Thirty-six sources were chosen for the review based on criteria of recentness, relevance and peer review. Using these sources, this review has identified key areas of focus in the subsequent analysis as being the inclusion of solar thermal with thermal storage and a life-cycle analysis of GHG (embodied and emitted) and demonstrated the technical, economic and environmental feasibility of implementing hybrid energy systems worldwide and in Australia.

The information presented in the literature review has been used to guide the creation of an analysis code in the Python software package which analyses supplied weather and electric load data and identifies the optimum mixture of technologies in the hybrid system. The results of this analysis have shown that Port Augusta is the ideal site for implementation, with an optimum system containing 89% Concentrating Solar Thermal, 9% Diesel and 2% Solar PV and a total installed power of 8.9MW. This system has an LCOE of $0.203/kWh, a renewable fraction of 92% and results in an annual $CO_2$ reduction from a 100% diesel system of 13,412,749kgeq$CO_2$.

It is recommended for future projects in this area that weather and electric load data be gathered over several years at each site under analysis, preferably over the same period to allow for more accurate comparison. It may also be worthwhile to broaden the scope of future reviews to include wind turbines and battery technology in the analysis.

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# 1. Introduction

## 1.1 Context

Australia has access to some of the best solar resources in the world. Solar resources are generally assessed using the value of Direct Normal Irradiance (DNI) in the area of interest. “Australia has the highest average solar radiation per square metre of any continent in the world”, with “approximately 58 million petajoules (PJ), [or] approximately 10,000 times Australia's annual energy consumption…worth of solar radiation falling on Australia annually” [1]. Many of the areas that have extremely high DNI values in Australia, such as Western Australia and the Northern Territory (See Figure 15 in Appendix), have relatively low penetration of renewable technologies, particularly solar PV and solar thermal. These areas also have a large number of remote communities and mining sites which have medium to high energy requirements. For example, the ‘NT mining sector represents the largest electricity consumer within the unregulated network’ [2], which presents a significant opportunity for large-scale solar plants to provide power to these remote communities and mining sites. It is estimated that “Off-grid electricity generation accounted for…17 per cent of total generation in 2014–15” [3].

Currently, as shown in Figure 16 in the Appendix, the vast majority of off-grid energy generation is accounted for by fossil fuels. Many of these off-grid communities utilise diesel generators to supply power as evidenced by the high proportion of liquid fuels in the ‘Rest of off grid WA’ and ‘Rest of NT’ columns. To ensure affordable energy supply to residents in the Northern Territory “all domestic households and small to medium business customers paid the same retail tariffs, regardless of cost of supply and location. Large electricity customers using greater than 2 gigawatt hours per annum paid commercial tariffs negotiated with an electricity retailer of their choice” [4]. This method is costly to the government, harmful to the environment and particularly sensitive to any fluctuations in the price of diesel. While there has been a significant increase in small-scale (residential) solar PV installations in the city centres of Australia over the past two decades, with total capacity up from 516kW in 2001 to 5.44GW at the end of 2016 [5, 6], there is yet to be any significant deployment of large-scale solar generation technology. This is shown by the Clean Energy Australia Report (2015), wherein large-scale solar PV (> 1MW) is reported to have accounted for around 0.09% of total energy generation in Australia, while solar thermal accounted for 0.01%. Clearly then, there is the potential for a transition from the use of diesel generators to either large-scale (1-30MWe) solar PV or solar thermal to provide power to remote Australian sites.

## 1.2 Project Aim/Expected Outcome

This project will identify the optimum combination of three energy generation technologies to be deployed in a hybrid system, namely solar thermal with thermal storage, solar photovoltaic without storage and diesel generators, for power supply to a remote area in Australia. Economic analysis will be the primary metric for optimisation of the hybrid system with technical, environmental and social metrics being used to differentiate between economically similar systems. The method will be demonstrated on multiple selected sites for which meteorological data is available. The results will be presented in a way to facilitate further study into the feasibility of a hybrid energy generation system by remote communities, mining sites and other such operations that rely on independent sources of power.

## 1.3 Project Scope

The scope of the project has been limited to three technologies for power supply: Solar PV, Solar Thermal with thermal storage and Diesel Generators. Other technologies will not be included in the analysis. This projects analysis will focus solely on comparing and analysing systems in the Australian context.

During initial testing and analysis undertaken in HOMER, it was discovered that it would not be possible to accurately incorporate solar thermal with thermal storage into the hybrid system. This is a critical aspect of this project and represents a significant gap in the research that is currently available. The decision was made to switch to using Python software and develop a custom analysis program. The results from this program will be checked (where possible) against similar studies and results for the solar thermal component of the system will be checked against a SAM analysis.

## 1.4 Goals

The project will be focussed on one major goal and one minor goal, which can be further split into a series of sub-goals as below.

**Major Goal**: Identify the optimum mixture of solar thermal, solar photovoltaic and diesel generators, hereby referred to as the 'candidate technologies', for a representative sample of remote sites in Australia.

Sub goal: Present research findings on candidate technologies

Sub goal: Present research findings on hybrid renewable energy projects globally and in Australia

Sub goal: Develop economic, technological, environmental and social metrics to rank the mixtures of the candidate technologies

Sub goal: Identify the optimum mixture of the candidate technologies for the selected sites and present overall results for these sites

Sub goal: Identify the three most suitable sites in Australia for implementation of the candidate technologies based on meteorological data

Sub goal: Present detailed results for the three most suitable sites

**Minor Goal**: Produce a proposed layout for the solar thermal plant at one of the three proposed sites.

## 1.5 Key Software

Table 1 gives an indication of the software packages that will be utilised while completing the project.

Table 1 - Key Software

| Software | Project Application |
|---|---|
| **Python** | Used to develop analysis software for optimisation and comparison of hybrid systems |
| **SAM** | Used to design solar thermal plant layout and check key financial parameters |
| **HOMER** | Used for validation/checking of results where possible |

## 1.6 Risks

### 1.6.1 Identified Risks

Table 2 shows the risks associated with this project. This project will not involve any experimentation or hands-on work as the focus is on research, analysis and design, so physical risks to human safety have been assumed to be negligible.

Table 2 - Identified Risks

| No. | Risk | Potential Impact |
|---|---|---|
| **1** | Errors in developed Python analysis program | • Project outcomes will likely be delayed<br>• Project completion may be jeopardised<br>• Quality/accuracy of results may be reduced |
| **2** | HOMER software used for validation incorrectly | • Project outcomes may be delayed<br>• Quality/accuracy of results may be reduced |
| **3** | Cost/Energy production data for small-scale CST plants unavailable in required detail | • Project outcomes will likely be delayed or not achieved<br>• Quality of results may be reduced |
| **4** | Inaccuracies or bias in the weather data used for software analysis | • Reduced accuracy in developed model<br>• Reduced accuracy/certainty when comparing the three chosen sites |
| **5** | Issues with SAM or other design software | • Project outcomes will likely be delayed<br>• Quality of analysis/report may be reduced |

### 1.6.2 Risk Management Plan

The strategies to be used for the duration of the project to mitigate the risks identified in Table 2 have been listed in Table 3.

Table 3 - Risk Management Plan

| No. | Management Strategy |
|---|---|
| **1** | • Rigorously test/debug developed analysis software<br>• Compare obtained results with past literature<br>• If possible, validate results against those obtained using HOMER software (using an example hybrid system/systems that can be accurately modelled in both)<br>• Validate results for CST from analysis code using SAM software |
| **2** | • Compare obtained results with past literature<br>• Use tutorial/help resources available online to guide simulation methodology<br>• Liaise with supervisor regarding use of the software, check validity of results obtained |
| **3** | • Supervisor to provide references to useful research/examples<br>• Focus initial research primarily on CST technology, adjust scope of project accordingly |
| **4** | • Utilise trusted sources for data<br>• Use averaged data across multiple years if possible to reduce uncertainty<br>• Take values from similar timeframes across the analysed sites to ensure they are compared accurately |
| **5** | • Ensure familiarity with SAM or other design software well before they need to be used<br>• Follow online tutorials/help forums |

# 2 Literature Review

## 2.1 Scope of the Literature Review

It is important that this literature review have a well-defined scope focussed on areas most pertinent to this project. Table 4 below outlines what is deemed to be 'in-scope' and 'out-of-scope' for this review.

Table 4 - Literature Review Scope

| In-scope | Out-of-scope |
|---|---|
| Solar PV | Heating & power combined projects |
| Solar Thermal | |
| Thermal storage | |
| Diesel Generators | |
| Hybrid power generation projects (must involve some renewable component) | |

Please note that unless otherwise stated all prices shown in the literature review are in USD.

## 2.2 Criteria for Literature Selection

The focus of this report is on analysing prior art relevant to the area of study for the project. To ensure the credibility of conclusions drawn in this report, any sources used were screened using the following criteria:

- Recentness (sources from 2007-2017 were prioritised)
- Peer reviewed
- Relevance

## 2.3 Current State of Candidate Technologies

This project will analyse three technologies for feasibility of implementation in a hybrid system in the remote Australian context, namely solar thermal with thermal storage, solar PV and diesel. It is critical to the success of this project to have a detailed understanding of the operational characteristics of each of these technologies.

### 2.3.1 Diesel Generators

Diesel generators rely on the combustion of fossil fuel, namely diesel, to create power. Mechanical energy is generated by a diesel compression engine which is then used in an electric generator to create an electric current and therefore electrical power.

The primary application for diesel generators in Australia is in generating power for remote sites that are unable to connect to the main power grid. They are used for this purpose for the following reasons:

- Diesel generators are easy to deploy,
- simple to operate,
- can quickly scale power output to what is required (assuming generator was sized correctly)
- have a relatively low capital cost

While these advantages are useful in many scenarios, there are also several important drawbacks to using diesel generators for power generation, such as:

- High cost for diesel fuel
- High maintenance costs
- Significant GHG emissions
- Reduced efficiency at low loads

In a report prepared by AECOM on behalf of the Australian Renewable Energy Agency it is stated that "currently there is over 1.2GW of diesel generation capacity installed in off-grid Australia which supplies electricity to mines and communities at a cost of 240-450AUD/MWh in fuel only (excluding capital costs)" [7]. The fuel cost is generally assumed to be the primary cost when analysing diesel generators as capital cost and operation and maintenance (O&M) costs are typically much smaller in comparison. For example, based on the assumption of a 20 year operating life, Lazard calculated the capital cost of a diesel generator to be in the range of $650-$1050/kW and the O&M cost (Operation and Maintenance) to be $15/kW-year [8]. For a 2MW system with a capacity factor of 31%, the contribution to the levelized cost of energy from capital cost and O&M combined is approximately $25/MWh.

With regards to this project, diesel generators are expected to be deployed in an auxiliary/backup power generation role, meaning they will only be switched on when there are insufficient renewable resources to satisfy the load. While this is becoming a more common role for diesel generators to play, as in the following studies [9-13], there are still a high proportion of studies that implement a diesel generator as the primary source of power and use renewable technologies to support/reduce fuel consumption of this diesel generator, shown by [14-18].

### 2.3.2 Solar PV

Solar Photovoltaic panels are an energy generation technology that harnesses sunlight to create electricity. Sunlight is comprised of energy packets known as photons. When photons strike the semiconductor material in the solar panel, which is typically some form of silicon, movement of electrons is excited, thus causing the flow of electricity.

There has been considerable progress in the development of solar cell technology in the last 10-15 years and this development has led to three ‘generations’ of solar cells being defined. First generation solar cells are made of crystalline silicon (monocrystalline or polycrystalline) and are known as wafer-based cells. These cells currently make up the bulk of the commercial market, with a solar efficiency of 15-20% [19]. One of the most important advancements for solar PV technology was in the development of thin film solar cells, which are known as the second generation of solar cells. These cells typically have lower efficiencies, for example, amorphous silicon solar modules have an efficiency of only 6-8% [19], but are also much lower in cost and less energy intensive in manufacturing.

Third generation solar cells are mostly made up of organic materials “such as copper phthalocyanine, polyphenylene vinylene, and carbon fullerenes. These solar cells are less costly, have a high optical absorption coefficient, and the energy band gap can be tailored by changing the chain length of polymer. The energy-conversion efficiency of organic solar cells is low compared with inorganic solar cells. Lower stability, smaller life, and degradation are the major limitations of organic solar cells” [19]. Despite these limitations and negligible commercial deployment at this point in time, significant research and development efforts are being invested in third generation solar cells.

As discussed previously, most of the solar cells currently on the commercial market are first generation crystalline silicon cells. A feasibility study conducted by Ma, Yang & Lu identified the solar panel they used as being the SunTech STP210-18/Ud, which uses polycrystalline solar cell technology and has an efficiency of approximately 14.3% under standard test conditions [10]. Another study, carried out by Rehman et al, utilised the Sharp NU-U245P1 PV module which uses monocrystalline solar cell technology [20]. Based on these sources and industry standard practice for implementing solar PV technology, this project will make use of PV modules that are based on first generation solar cells.

Solar PV has mostly been deployed in a residential capacity in Australia, with rooftop PV installations (<100kW) accounting for 16.2% of Australia's renewable energy generation in 2015 [21]. The widespread deployment of Solar PV in Australian households has been driven by several advantages the technology possesses:

- Zero emissions of greenhouse gases (note: there are some embodied greenhouse gases related to the manufacturing of the panels)
- Easy to install
- Minimal operation and maintenance costs over the entire panel lifetime
- Relatively low cost per kWh

It should also be noted that significant reductions in the cost of PV panels in the last 5-10 years has contributed to the increased uptake of the technology. In a report published by the U.S Department of Energy it was estimated that from 2010 to 2015 the levelized cost of energy of solar PV dropped by up to 65%, with residential costs dropping from $6.2/W in 2010 to $3.1/W in 2015 [22]. The levelized cost of energy for commercial and utility scale solar PV dropped from $5/W to $2.2/W and $4.1/W to $1.8/W respectively between 2010 and 2015 [22].

Large-scale solar PV (>1MW) makes up approximately 0.6% of total renewable energy generation in Australia [21]. The primary reason the commercial and utilities sectors are lagging behind residential in terms of solar PV deployment is the intermittency of the power generated. For a power generation technology to be viable on a large scale, for example while providing power to the electricity network, it needs to be capable of supplying baseload power. ‘Baseload power’ refers to a technologies ability to supply power above a certain capacity factor. Solar PV relies on sunlight to generate electricity, and can therefore only work during daylight hours. This means that for solar PV to be capable of supplying power around the clock, some form of energy storage system, or auxiliary power generation system, must be used. Reducing the cost and increasing the efficiency of battery storage has, for this reason, been identified as the most critical factor in enabling the widespread deployment of large-scale solar PV.

### 2.3.3 Concentrating Solar Thermal with Thermal Storage

Concentrating solar thermal (CST), much like solar PV, harnesses sunlight to create electricity. CST technology achieves this using mirrors to focus the sun’s rays onto some form of collector. This heats a fluid which can then “produce electricity via a thermal energy conversion process similar to those used in conventional power plants” [23].

The three main types of CST are:

- Linear concentrating systems (i.e. parabolic troughs, linear Fresnel reflectors etc.)
- Power towers
- Dish/engine systems

The bulk of deployed CST technology is in parabolic troughs which accounted for about 96% of the 1300MW deployed worldwide at the end of 2010 [23]. Parabolic troughs are the only CST technology that has seen widespread deployment globally over the last 15-20 years, and are the only CST technology that is ‘mature’. Power towers, which accounted for 3% of deployed CST technology in 2010, “have the potential to achieve higher efficiency and lower-cost TES (thermal energy storage) compared with current trough technology” [23].

All three types of CST technology share similar advantages, namely:

- Zero greenhouse gas emissions (note: there are some embodied greenhouse gases related to the manufacturing of the components)
- Dispatchable power supply when used in conjunction with thermal storage
- Best suited technology to being oversized for excess generation due to efficiency of thermal storage

As mentioned above, power towers can achieve higher temperatures than traditional trough technologies such as linear Fresnel and can therefore obtain higher efficiencies. Given that Australia has access to world class solar resources, with areas such as Longreach in QLD receiving 2564kWh/$m^2$/year [24], there are many areas where high temperature power towers would be a viable power generation option. A study completed by Hinkley et al in 2013 concluded that "tower plants should be targeted for ongoing development and deployment in Australia" [24].

In the Australian context, the LCOE of both parabolic trough and power tower solar thermal technologies are estimated to be just over $0.2/kWh [24]. Globally, the LCOE of CST technology and thermal energy storage has been trending downwards with the assistance of various research initiatives and favourable political frameworks in some countries such as Spain and the US. It was noted by Dowling, Zheng and Zavala that while adding TES was found to increase LCOE by five "out of the six studies reviewed that compared CSP configurations with and without TES" [25], it also provided significant opportunities related to storage flexibility. In fact, "even if storage increased capital costs, it also increased revenue. In several cases, the revenue increases greatly outweighed the cost increases and resulted in shorter pay-back periods" [25].

In the scope of this project, it is somewhat difficult to separate parabolic trough and power tower technologies as they share similar advantages. They are both capable of operating at high temperatures (although power towers can go higher), have capacities in the range of 10-200MW (300MW upper limit for parabolic troughs) and similar ranges of efficiency, with parabolic trough ranging from 11-16% and power tower from 7-20% [26].

The CST technology that is chosen for implementation will be critical to the reliability of the hybrid systems energy supply due to its capability for TES. This TES, likely in conjunction with a diesel generator as mentioned above, will primarily be used to smooth out peaks and cover significant gaps in generation caused by a lack of renewable resources (i.e. night time). With regards to implementation of TES, Zhang et al propose that power tower technology is superior to parabolic troughs due to the higher temperatures that it can reach [27]. In addition, power towers “have the whole piping system…concentrated in the central area of the plant, which reduces the size of the piping system, and consequently reduces energy losses, material costs and maintenance”,  when compared to parabolic troughs [27]. For this reason, power tower technology has been identified as the most viable for use in this hybrid project. Choosing the heat transfer fluid for use in the TES system is also critical to the success of the plant. A review conducted by Tian and Zhao concluded that “Molten salts with excellent properties are considered to be the ideal materials for high-temperature thermal storage applications” [28].

## 2.4 Renewable Energy Hybrid Projects

### 2.4.1 Global Projects

#### *2.4.1.1 Technologies*

During this literature search, 30 hybrid energy generation projects have been reviewed. These studies were completed within the last eight years, with the earliest taking place in 2009 and the most recent being published in 2017. There are several observable trends that are present throughout these studies which have been identified and discussed below. Figure 1 shows the technologies considered by the reviewed feasibility studies.

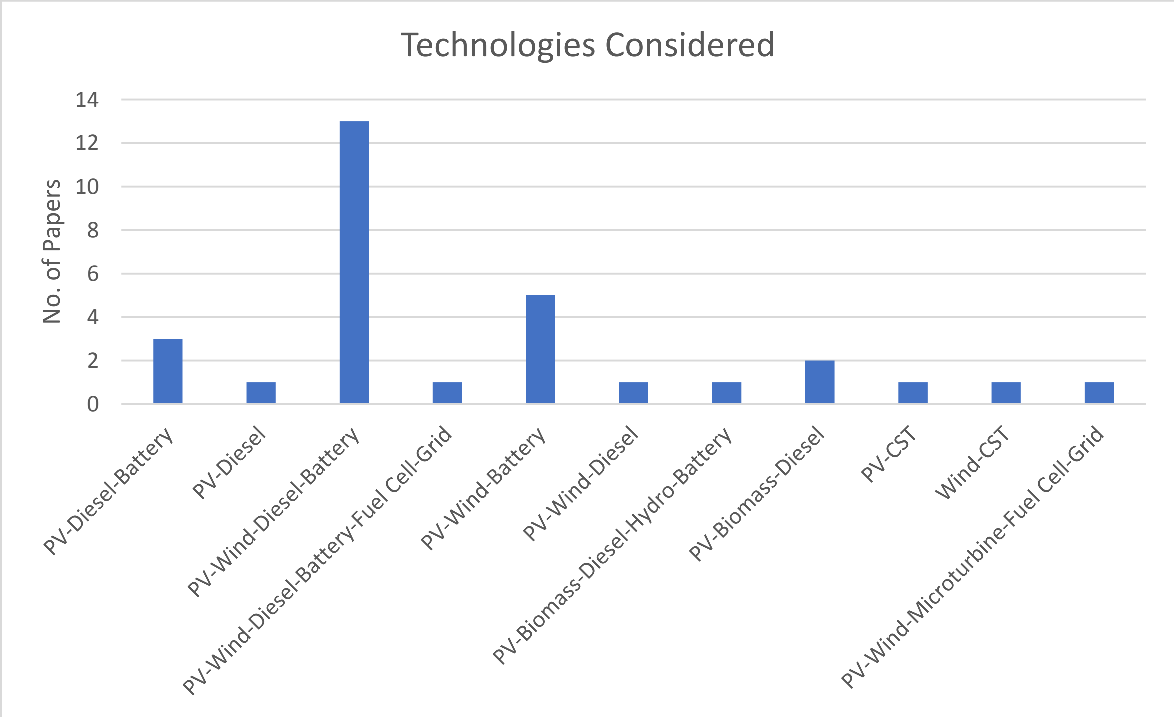


**Figure 1 - Statistics for Technologies Considered in Reviewed Studies [9-18, 20, 29-47]**

It is clear from Figure 1 that most of the studies looked at the feasibility of implementing some combination of solar photovoltaics, wind turbines, diesel generators and battery storage. Saheb-Koussa, Haddadi and Belhamel state that “Photovoltaic/wind/diesel hybrid systems are more reliable in producing electricity than photovoltaic-only/wind-only systems” [13]. The reason for this increased reliability is that solar PV and wind have complimentary power generation capabilities [14]. The maximum output of a solar PV panel is typically in the middle of the day, whereas wind turbines usually produce their maximum in the evening or later at night due to higher wind speeds. Combining these technologies means that as the output of one technology drops off, the output of the other will generally be increasing. This concept of higher reliability associated with hybrid renewable energy systems, along with a growing need for electricity in remote/off-grid regions, is cited as the primary motivator for studies [10-13, 15-17, 33, 35, 37-42, 47].

Figure 1 also indicates that there have been very few studies conducted with the goal of hybridising solar thermal technology with other power generation technologies. This presents a potential gap in the research which this project is aiming to cover in its analysis.

While it has not been included in the studies reviewed for Figure 1, Modi et al note in their report that in Danish climatic conditions, i.e. extremely cold, it is both economically and environmentally feasible to include concentrating solar thermal in a hybrid system with natural gas or biomass for combined heating and power generation [48]. In the Australian context heating is not a significant issue, so although this study confirms that CST can be effectively used in a hybrid system it does not validate its inclusion in a hybrid system used solely for power generation. An example of a CST hybrid system used for power generation has been presented by Vick and Moss, in whose report the addition of CST technology to existing wind farms in Texas was assessed [34]. Vick and Moss concluded that adding CST significantly increases the capacity factor of the system and allows far better load matching than the wind-only plant. It should be noted, however, that adding CST also increased the LCOE of the system from $64/MWh (wind-only) to approximately $108/MWh (wind-CST) [34].

#### 2.4.1.2 Initial Assumptions

Site specific assumptions and meteorological data for the chosen area of study are critical to the accuracy of the feasibility analysis. Additionally, the nature of the country in which the study takes place also gives some insight into the reason the study was conducted. Figure 2 shows that, of the 30 studies reviewed in this report, 17 were completed for areas in India, Algeria, Saudi Arabia and Iran.

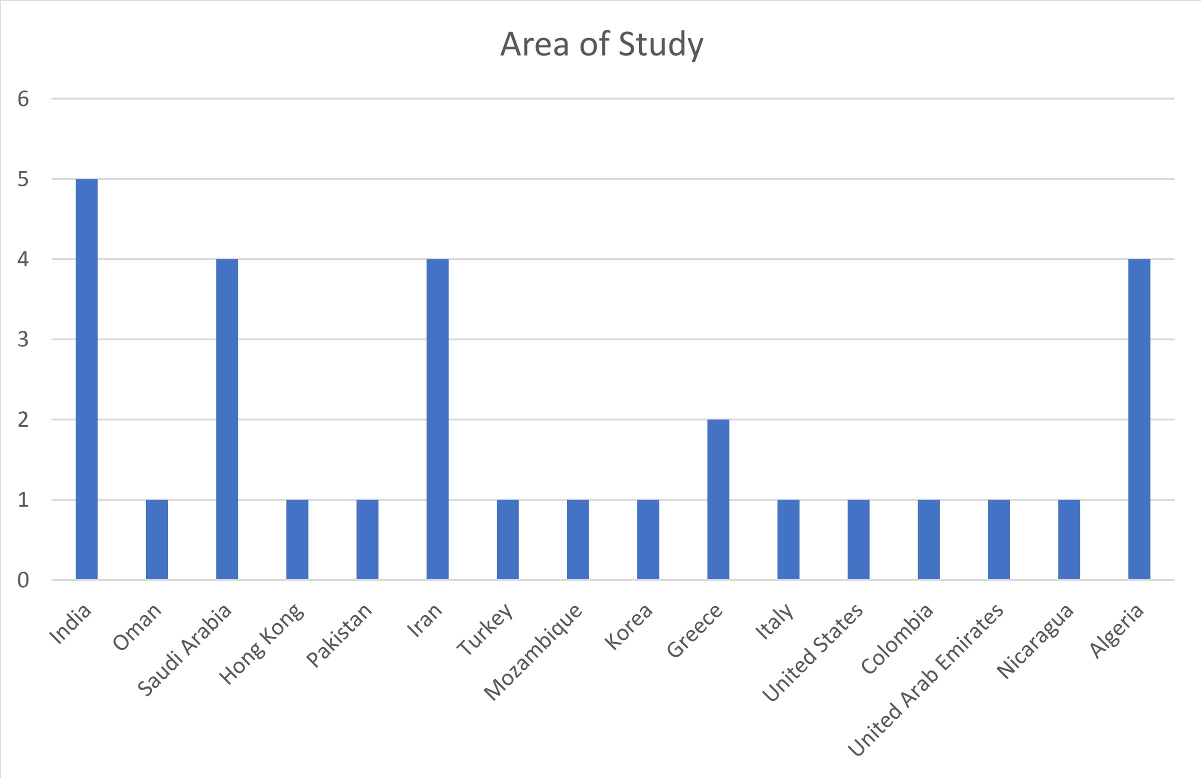


**Figure 2 - Area of Study [9-18, 20, 29-47]**

The common theme among these four areas is that they are all developing, or in the case of Saudi Arabia, semi-developed, countries. This implies that there may still be a sizeable proportion of their populations who have limited or no access to power. Developing countries also generally depend heavily on fossil fuel for power generation expansion, which for a remote community usually means deploying a diesel generator. Rezzouk and Mellit note that using a diesel generator in remote areas in the north of Algeria is not ideal due to a "lack of road infrastructures to deliver fuel, high costs of fuel transportation depending on the site location, and frequent maintenance required" [17]. These drawbacks are likely to be experienced in most, if not all, of the other countries/areas that were analysed in the 30 studies reviewed.

There are several possible approaches to modelling a load profile for the site under investigation. Rezzouk and Mellit used monthly average electrical consumption for a community in the area under study for the year 2012 as published by UDES, a research unit located in Bou-Ismail [17]. This load profile yielded a daily average load of 509kWh and showed that the highest consumption occurred between 0830 and 1630 each day, coinciding with office hours.

Al Sharafi et al take a typical daily load profile of a residential house in the area of study and include an aspect of randomness by “specifying daily and hourly noise inputs” [47]. This approach is also used by Rehman et al, except that they take it one step further by splitting the energy usage of various household items into summer and winter loads, resulting in two separate load profiles for summer and winter [20]. There is a distinct contrast between the load profiles for a residential household and a community, with two peaks observable in the household profiles presented by Rehman et al and Al Sharafi et al from 0500 to 0900 and 1600 to 2100. Based on the assumption of 5 to 6 people per household and 100 households in the community, Rehman et al used a daily average load of 205kWh with a peak load of 47kW [20].

Dursun et al developed their load profile using HOMER software and assumed that “since the hottest months are June, July, and August, the load requirement is high for these months” [39], primarily due to increased cooling requirements. The study undertaken by Dursun et al was based on an area in Turkey, which has a similar climate to Australia. By implementing day-to-day and time step-to-time step variability factors of 2%, Dursun et al found that the daily average load for a region containing 50 households was 1853kWh/day [39]. This project will implement a similar method to that of Dursun et al by setting the peak load month to January, the middle of summer in Australia, and exporting a load profile generated by the HOMER software.

It is worth noting that the accuracy of the load profile is important for the feasibility of the hybrid system that is designed, as a key drawback to using renewable energy is usually a mismatch between resource availability and peak load requirements.

Following on from modelling the load profile of the site in question, characterising the available renewable resources is the next critical step in setting up a model. Many of the reviewed studies, such as [9-12, 14-18, 20, 29-32, 37-41, 44, 45], used published NASA data available through the HOMER software to achieve this. Some of these studies, such as [20], used NASA data for solar radiation and data from their respective meteorological department for wind speed. This project will make use of weather data, including hourly DNI and GHI levels, at a variety of sites across Australia provided by Professor Hal Gurgenci.

#### *2.4.1.3 Technologies Chosen*

The technologies chosen to be used in the hybrid systems by the reviewed studies generally followed the trends in Figure 1. By observing Figure 3, however, some minor differences can be discerned.

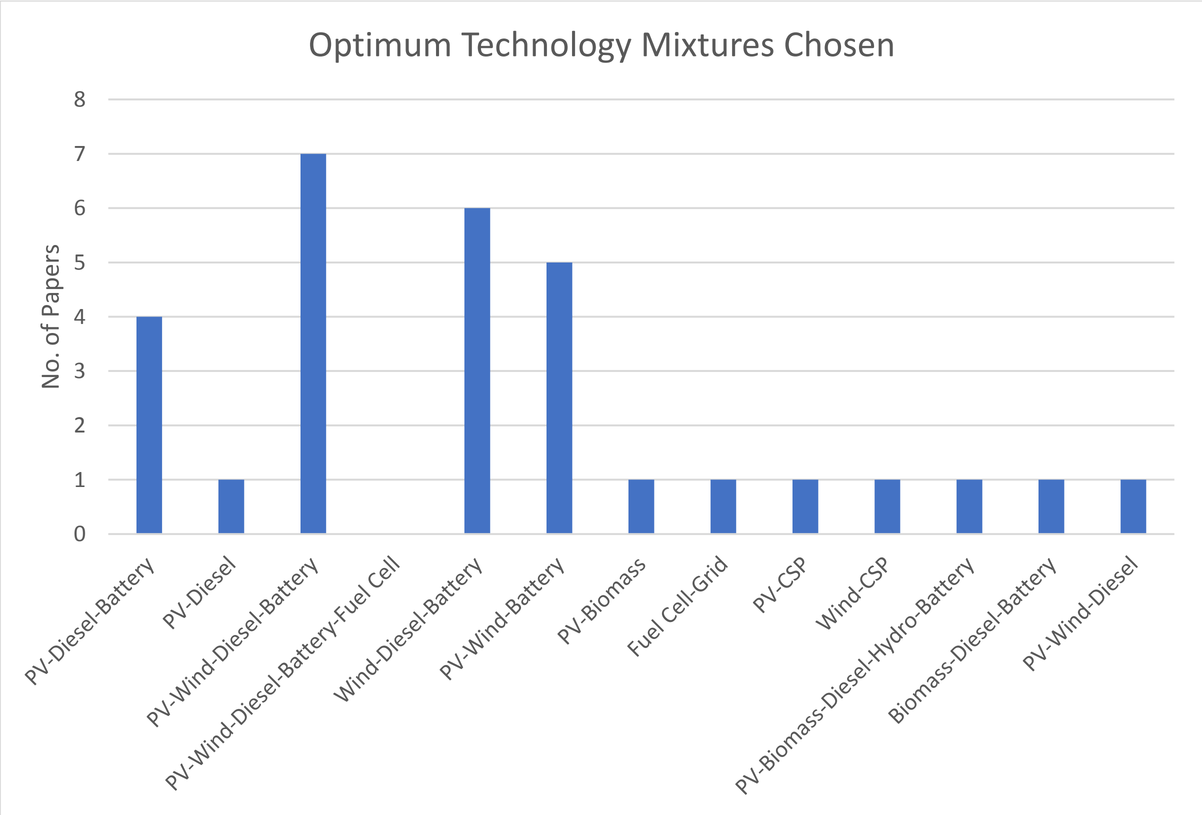


**Figure 3 - Technologies Chosen for Optimised Hybrid System [9-18, 20, 29-47]**

One such difference is the reduction in hybrid systems that utilise solar photovoltaics, wind, diesel and batteries in one system. This reduction is likely to be mostly related to renewable resources specific to the region under study. An example of this is given by Saheb-Koussa, Haddadi and Belhamel when they conclude that “The hybrid system configurations which meet the desired load depend largely on the renewable energy potential quality. For the high speed wind potential sites, more than half of the total energy production of the optimal system configuration is provided by the wind generator such as in the case of Adrar site, while at low wind speed potential regions, the wind power contribution represents 0% of total energy production such as in the case of Tamenrasset site" [13]. This is reflected in the breakdown of the technologies used to satisfy the load requirements at each of the sites, with 24 PV modules and a diesel generator used at Tamenrasset versus 7 PV modules, 2 1kW wind turbines and a diesel generator at Adrar.

Mamaghani et al showed that the optimal hybrid system varies for different sites across Colombia. With an assumed load of 180kWh/day and a peak load of 38kW at a site in Unguia, Colombia, it was found that the wind potential was too low to be feasible for inclusion in a hybrid system. The optimum economic system had a total installed power of 125kW, with 100kW of Solar PV panels and a 25kW diesel generator. The renewable fraction in this case was 0.98. Conversely, at a site in Puerto Estrella with a load of 379kWh/day (88kW peak), the optimum composition of the hybrid system was found to be "500 PV panels (320 W each), 1 Aeolos 10 kW wind turbine, diesel generator of 25 kW, 250 Surrette batteries s4ks25p, and inverter of 80 kW" [32]. While this system includes a portion of wind power generation, the bulk of the load is still covered by the Solar PV array.

As discussed in 2.4.1.2 Initial Assumptions, Dursun et al assumed a load of 1853kWh/day for a site in Turkey. The renewable resources at this site were reasonably good for both wind and solar, with an average annual solar radiation value of 4.322kWh/m$^2$/day and an average annual wind speed at 10m of 4.54m/s. Based on these values, Dursun et al concluded that the optimal hybrid system has a total installed power of 445kW, with 4 50kW Wind Turbines, a 125kW Diesel Generator, a 120kW Solar PV array, a 100kW converter and 96 batteries (approximately 666kWh of storage) [39].

#### 2.4.1.4 Analysis Tools

The majority of studies reviewed, as shown by Figure 4, made use of HOMER software for optimisation of their hybrid system.

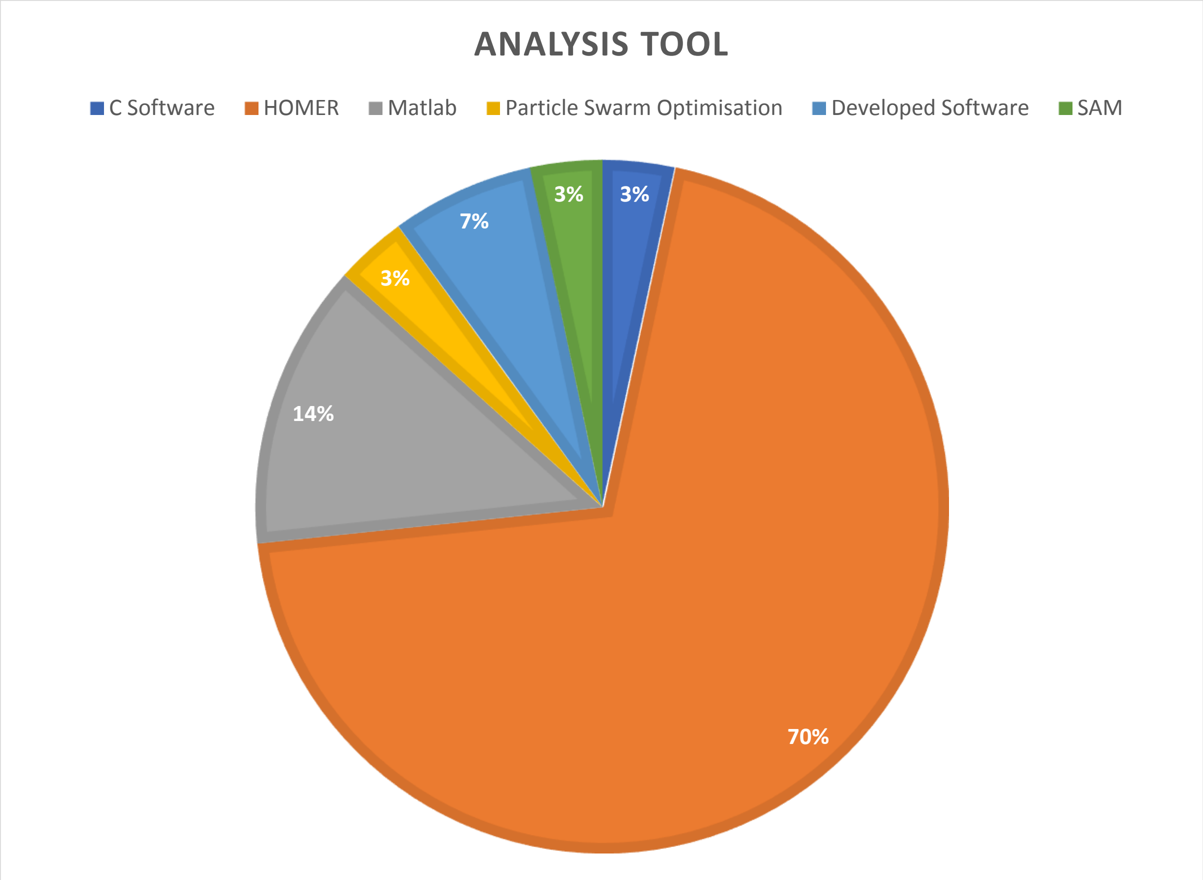


Figure 4 - Analysis Tool Used [9-18, 20, 29-47]

HOMER is generally considered to be an excellent choice for analysing the optimum combination of technologies for a hybrid power generation system, however, there are some drawbacks to implementing this software. Rajbongshi et al noted that HOMER assumes a 100% reliable grid, which is not the case in many developing countries, such as India [31]. To allow the inclusion of an unreliable grid in their model, Rajbongshi et al used the proxy generator scheduling method in HOMER [31], although this solution also had some minor issues with setting the sell/buy-back price of electricity. While this is not expected to be an issue in this project, as the primary focus is on off-grid hybrid system applications, it provides some insight into why some studies opt for software packages other than HOMER. For example, the studies conducted by Mohamed et al and Mokheimer et al designed and implemented their own analysis software using Matlab, citing a lack of flexibility in HOMER as their primary reason for doing so [42, 43]. While using their own software as the primary optimisation tool, both [42] and [43] validated their results against those achieved using HOMER software with the same components and assumptions.

The method used by Mohamed et al and Mokheimer et al is expected to be the one employed in this project. For this project, HOMER does not allow sufficient flexibility in component design to achieve the desired hybrid system as it is not possible to accurately integrate thermal storage within the solar thermal system. Despite this, it does give a good platform for sanity checking results obtained with other software packages and will therefore still be implemented in this way.

#### 2.4.1.5 Metrics of Feasibility

The feasibility of a renewable energy hybrid project is entirely dependent on the metrics used for assessing this feasibility. 26 of the 30 studies that were reviewed for this report found their optimal hybrid system to be a feasible replacement/addition, albeit generally under a specific set of conditions.

The study conducted by Rehman and Al-Hadhrami was the only study that found a diesel-only solution to be more affordable for power generation in an off-grid community. Their results indicated that the diesel-only system had an LCOE of $0.19/kWh with the capital cost of a diesel generator at $1521/kW and the diesel fuel price at $0.2/l [16]. The closest renewable hybrid system to this was a system with 21% solar PV penetration and 300 batteries for storage which resulted in an LCOE of $0.219/kWh [16]. They concluded that the diesel-only system would be the most economically feasible system below a diesel fuel cost of $0.6/l.

The assumed price of diesel fuel is perhaps one of the most critical factors in a feasibility study of a hybrid system. This price is highly sensitive and tends to fluctuate over the life of a project. Diesel fuel price is also highly dependent on the area of study, which can contribute to the different prices used in different projects. However, the range of diesel fuel price from $0.2/litre to $0.6/litre in which Rehman and Al Hadhrami found diesel-only generation to be most economical is lower than the assumed price for many of the other reviewed studies. Mamaghani et al used world bank data to set the diesel fuel price of their study, conducted in Colombia, at $1.1/litre. Fazelpour et al conducted a study in Oman, Iran using a diesel fuel price of \$0.32/litre, which given the rich supplies of oil in this area is reasonable. Despite this extremely low diesel fuel price, Fazelpour et al found that "due to Iran's energy conservation program for removing fossil fuel subsidy… [and] in considering the penalty costs of environmental emission in the calculations, wind-diesel hybrid system with battery storage is the best economic system and has a minimum NPC of\$8,516,000 and a COE of 0.339\$/kW, followed by the diesel-battery system (NPC of \$8,667,000 and COE of 0.339\$/kWh)" [14]. This wind-diesel hybrid system has a renewable fraction of approximately 15%, with 100kW worth of wind turbines and a 600kW diesel generator. Bhatt et al used a diesel fuel price of \$0.94/litre for a remote area in Uttarakhand, India and showed a number of sensitivity graphs assessing the effect of increasing diesel fuel price on LCOE of the system. While hybrid systems with a high renewable energy fraction were found to be much less susceptible to increases in diesel fuel price when compared to systems with more dependence on diesel generators, increased diesel fuel price was still found to increase LCOE. In a system with an 87% renewable energy fraction, Bhatt et al showed that increasing the diesel fuel price from \$0.94/litre to \$1.08/litre at a fixed interest rate of 7% lead to an increase in LCOE from \$0.195/kWh to \$0.203/kWh [11]. Similarly, Roy and Kulkarni demonstrated the effect of increasing diesel fuel price cost on PV penetration and overall cost of energy (See Figure 20 in the Appendix). Figure 20 shows that when diesel fuel price increases from 60-80 Rupees/litre (0.93-1.24USD/litre) to 90 Rupees/litre (1.4USD/litre), the optimal solar PV penetration increases from 30% to 40% [15].

When assessing the overall running cost of a diesel generator, it is also important to consider the fuel consumption. Rohani et al published a diesel generator fuel curve in their study which shows the fuel consumption in litres per hour for a range of output powers from 0 to 1000kW (See Figure 19 in the Appendix) [30]. This fuel curve clearly describes a linear relationship between output power and fuel consumption, and this linear relation has been given by Roy and Kulkarni as:

$$Fuel\ Consumption = A \times Power_{DG} + B \times P_{DG_{Rated}}$$

Where A and B are constants of the fuel curve expressed in litres/kWh and have been found to be 0.2088 and 0.01841 respectively. Using either the curve shown in Figure 19 or the linear relation expressed above, the total fuel cost of a diesel generator at any load can be expressed accurately and its contribution to LCOE determined. While running costs are known to be the largest cost associated with diesel generators, capital cost is the most critical factor when including renewable technologies such as solar PV in a hybrid system.

In their study, Rehman and Al-Hadhrami used a solar PV panel capital cost of $5000/kW, which in 2010 was an accurate estimate for commercial deployment of solar PV systems [22]. [22] shows us that as of 2015 the LCOE of PV systems in a commercial framework had dropped to $2200/kW and is likely to continue dropping as deployment/production increases worldwide. This is a significant reduction in price and it is thought that if this analysis were to be completed with today's price it would find a PV-diesel-battery hybrid system to be cheaper than diesel-only. Another assumption that may have contributed to the feasibility conclusion reached by the study is the O&M cost of PV panels per year, which Rehman and Al-Hadhrami took to be $50/kW-year. This seems too high and, given that it contributed approximately 10% of the annualised cost of the hybrid system, it would have had a significant impact on the overall LCOE. Studies such as [14], [11], [30] and [40] used annual solar PV O&M costs of $25/kW, $19.38/kW, $20/kW and $22.5/kW respectively. There were even studies, such as those completed by Ma, Yang and Lu and Rezzouk and Mellit, that assumed a solar PV panel O&M cost of $0/kW i.e. negligible compared to other costs [10, 17]. Depending on the size of the solar system in question, it seems to be most logical to assume that there is some O&M cost associated with the solar PV panels, albeit relatively minor compared to their capital cost. It was concluded by Rehman and Al-Hadhrami that despite the diesel-only system being the most economical choice, the 21% solar penetration system resulted in significant reduction in C02 emissions and was technically capable of supplying the power requirements of the town.

Broadly speaking, the technological feasibility of a renewable energy hybrid project is assessed based on the system's ability to supply power when it is required by the end user. While reliability of supply is often seen as the most critical technological issue, it is also important to consider the other side of this issue as well, which is how best to avoid oversizing the hybrid system that is deployed.

In the study conducted by Rehman and Al-Hadhrami, which examined a PV-diesel-battery hybrid system and set the annual capacity shortage to 0%, it was shown that there is a correlation between increased renewable penetration in a hybrid system and increased excess power generation [16]. With 79% of power supplied by the diesel generators and 21% by the solar PV system, excess generation was approximately 0.67% of the total production. Increasing the solar PV penetration to 30% lead to excess generation of 3.48% and 42% penetration resulted in 9.94%. To identify when and why this excessive generation occurs, the system configuration, load profile and assumptions must be examined in greater detail. In the optimal system configuration there are four diesel generators with capacities of 1250kW, 750kW, 2250kW and 250kW respectively. There are also 300 batteries (2280kWh total capacity), a 3000kW inverter and 2000kW of solar panels. The minimum load ratio of the generators is 30% which means that the lowest allowable output of the 4 generators combined is 1,350kW. During summer months the average daily load is approximately 3.3MW and the peak occurs around 14:00 [16]. It is difficult to draw any meaningful conclusions from this, but it can be assumed that the load is large enough across the entire day to prevent significant excess generation. The average daily winter load profile tells a different story, with the peak load of 1800kW occurring at 18:00 and an average load likely in the vicinity of 1500kW [16]. Even at the minimum load ratio of 30%, the diesel generators will satisfy 90% of this load, leaving a significant amount of solar generation flowing into the batteries. There is also a sizeable gap between the peak energy generation of the solar PV system and the peak energy demand of the village during the winter months. This combination of factors is almost certain to contribute to excess generation through the winter months as the batteries will quickly be fully charged.

Ma, Yang and Lu in 2013 analysed a solar-wind-battery hybrid system and concluded that setting the annual capacity shortage to 0% (i.e. power requirements met at all times) resulted in 100,883 kWh (48.6% of the total production) of wasted energy due to “timing mismatch between power demand and generation” [10]. This is significant, as oversizing the system to meet energy demands has negatively impacted on both the economic and environmental aspects of the system by producing far more energy than is required. Excess generation could be avoided by increasing the amount of energy storage available, however, “for stand-alone applications, [battery] storage cost still represents the major economic restraint” [42]. While increasing the amount of battery storage is not economically feasible, it has been shown by Roy and Kulkarni that “It is practically not possible to operate a DG PV system without battery. A small battery is essential for achieving a smooth changeover from DG to PV mode or reverse” [15]. Although Roy and Kulkarni explicitly mention battery storage as being critical to the technical feasibility of their PV-diesel hybrid system, this statement also justifies the inclusion of solar thermal in this project. As has been mentioned previously, thermal storage is one of the biggest advantages of solar thermal for power generation, and given that battery storage is not part of this project’s analysis it will no doubt be critical to the technical feasibility of the optimised system to have some form of energy storage available.

Consistent with the methods applied in the feasibility studies reviewed for this report, the economics of each system are what will primarily be used to find the optimum configuration. Nearly 90% of these studies used the levelized cost of energy (LCOE) as the basis for optimisation of their hybrid system [9-15, 17, 18, 20, 29-37, 39-46]. For example, Al Saadi and Krarti found that implementing a diesel-only system on Masirah Island, Oman, resulted in an LCOE of $0.273/kWh versus $0.154/kWh for the optimised hybrid system of 8.25MW of wind turbines, 3MW diesel generator and 45.6MWh of battery storage [40]. Al Saadi and Krarti also present two options for carbon neutral hybrid power generation systems (i.e. renewable penetration of 100%), with option 1 utilising 0.5MW of PV, 24.75MW of wind turbines and 68.4MWh of battery storage and option two using 22MW of wind turbines and 114MWh of battery storage. Option 1 and 2 resulted in LCOE’s of $0.181/kWh and $0.18/kWh respectively [40]. Based on these results, it was recommended that implementing a hybrid system could save the government a significant amount of money that was going towards subsidising the high price of diesel-only power generation.

Bentouba and Bourouis found that implementing a 96% renewable penetration hybrid system of solar PV-wind-diesel was the most economic option for supplying 100% of the energy demand of Timiaouine in the south of Algeria. This system was reported to have an LCOE of $0.176/kWh [45].

Garrido et al compared a PV-diesel-battery hybrid system to a PV-biomass-battery hybrid system for energy supply in Nampula, Mozambique and found that the most economic option was PV-biomass-battery with an LCOE of $0.35/kWh (27% less than the LCOE for PV-diesel-battery). While the LCOE was significantly lower, they noted in their report that excess energy generated by the PV-biomass-battery system was far higher than that of the PV-diesel-battery system, with 4.4MWh and 0.7MWh produced annually respectively. The most likely reason for this discrepancy is the increased quantity of battery storage used in the PV-diesel-battery system.

The issue of environmental impact is at the core of any proposed hybrid system which incorporates renewable energy technology. Rezzouk and Mellit showed that increasing solar PV penetration in a hybrid system with a diesel generator is directly correlated to decreasing annual GHG emissions as shown in Figure 17 in the Appendix [17]. An environmental analysis was also completed by Rohani and Nour, who showed that a 500kW hybrid system with 45% renewable penetration reduces annual GHG emissions by 37%. When Rohani and Nour modelled a 1MW hybrid system with 64% renewable penetration "the amount of CO2 emission…changes from 5,936,315 kg/year for conventional system to 3,185,242 kg/year for hybrid system, thus hybrid system leads to 46% emission reduction" [30]. Studies such as [15, 29] also analysed the environmental impact of a hybrid system and concluded that higher renewable penetration results in significant reductions in GHG emissions per year. While these studies give an excellent indication of the potential for reduction in total emissions by reducing dependence on fossil fuels, this project aims to take a similar approach to that employed by Agarwal et al. In their report, Agarwal et al analyse the "Life-cycle carbon dioxide emissions" for all the components included in their hybrid system [46]. This is a more accurate approach when considering the total GHG emissions related to a component, as technologies such as solar PV panels are known to have a particularly high embodied energy (high GHG emissions involved in manufacturing of panels).

### 2.4.2 Australian Projects

As this project will be based in the Australian context, six feasibility studies that analysed renewable hybrid power generation systems in various locations throughout Australia have been reviewed. The study completed by Byrnes et al looked at the potential for deployment of renewable technologies in three remote indigenous communities in Western Australia that currently rely on diesel generators for power, and the reasons why this deployment has not already happened. Through research and analysis, Byrnes et al found that the LCOEs for solar thermal, solar PV and diesel generators in these areas were approximately $200/MWh-$350/MWh, $120/MWh-$470/MWh and $420/MWH-$700/MWh respectively. These LCOE results were achieved based on the following assumptions:

- Capital costs of solar thermal central receiver (also known as power tower) and solar PV fixed-tilt of $7929/kW and $2456/kW respectively
- "The capital maintenance rate [of diesel generators] is (14.29%) to reflect the need for total replacement of generators" [49] every 7 years.
- Solar thermal central receiver variable O&M costs and fixed O&M costs set at $28.45/kW/year and $71.37/kW/year respectively
- Solar PV fixed-tilt variable O&M costs and fixed O&M costs set at $13.4/kW/year and $25/kW/year respectively

While a hybrid system was not explicitly proposed, this showed that "deployment of renewable energy in remote communities can help overcome many social challenges while providing direct financial benefits to stakeholders" [49]. Despite the obvious advantages, Byrnes et al also identified a number of key qualitative and financial barriers that have been frustrating renewable deployment in remote Australian communities, citing issues such as a lack of capital, inadequate access to/understanding of information, a lack of follow-through from external parties, institutional barriers related to communication between federal and state governments and limited resources available for administrative capacity/governance of the communities in question.

Studies [50-52] utilised HOMER software to assess feasibility of hybrid systems, with Ali and Shahnia and Dalton et al both finding that incorporating renewable components was technically and economically feasible. Ali and Shahnia showed that a diesel-only power generation system had an LCOE of 0.358AUD/kWh versus the optimum hybrid systems LCOE of 0.238AUD/kWh [52]. This hybrid system included 545kW of solar PV, 1375kW of wind turbines, a 700kW diesel generator and 2MWh of battery storage (Renewable fraction of 73%). For reference, the customers of the town are currently charged 0.257AUD/kWh, which is lower than the estimated LCOE for the diesel-only power generation system [52].
Hyland concluded in his study that diesel-only generation was more economically viable in a remote community than a system that included diesel, solar PV and battery storage [50]. This is an interesting result, as the overwhelming majority of studies reviewed for this report, particularly those conducted more recently (within the last two years), found that hybrid systems with some renewable penetration provided a more economical and environmentally friendly solution than diesel-only. The assumptions made in the report appear to be valid, with capital/O&M costs of equipment matching up to values used in other sources. It is possible that the discount rate of 12% is too high, which for a capital-intensive technology such as solar PV or battery storage could have a significant impact on the economic feasibility. Ali and Shahnia conducted a sensitivity analysis using a range of discount rate values from 5-9% and a range of inflation rate values from 1-4%, and concluded that the optimum hybrid system detailed above was the best system for any combination of inflation and discount rates [52]. Similarly, Byrnes et al assumed a Risk-Free Rate of Return (similar concept to discount rate) of 6% [49]. Hyland also presented evidence from a report completed by Ondrazcek et al which stated that a typical range for the discount rate in a developed country with high solar resources is 5-10% [50, 53]. Based on the assumptions of these studies, it would seem that 12% is an overly conservative discount rate for the Australian market.

Even with a lower discount rate of 6%, however, sensitivity analysis conducted by Hyland showed that solar PV did not become a feasible inclusion unless the price of diesel fuel increased or the cost of solar PV panels was reduced to approximately 80% of its current cost [50]. On that note, the diesel fuel prices used of 0.4AUD/litre for mining and 0.804AUD/litre for the community case seem to be too low. Ali and Shahnia used a diesel fuel price of 1.1AUD/litre and Dalton et al used a base diesel fuel price of 1AUD/litre [51, 52]. Dalton et al also completed a sensitivity analysis for increasing diesel fuel price which showed that the optimised hybrid system was significantly less affected by variations in diesel fuel price. For example, “tripling of the fuel price [from 1AUD/litre to 3AUD/litre] leads to an increase in NPC for genset-only configurations of a factor of 2–2.5, while for the RES/hybrid, NPC increases by a factor of 1.5–2” [51]. Hyland also mentions some difficulties with obtaining accurate meteorological data for the sites analysed which may have had some influence on the result.

Two of the reviewed Australian studies used HOMER in conjunction with another piece of software. Hessami et al initially used “collected data in order to produce a spreadsheet model for the analysis of the energy and power requirements of the French Island community. At any given half hour interval, wind speed, solar radiation and power required by the community were determined” [54]. Hessami et al note that system optimisation using this spreadsheet model was “impractical and time-consuming” [54], so at this point they switched over to utilising HOMER software. This study concluded that the most economically feasible system was the hybrid wind-diesel-battery system at just over $0.21/kWh. A grid-connected system had a lower LCOE than this at just over $0.1/kWh, but due to the location of the site in question this option was ruled out.

Shafiullah also used HOMER to conduct the techno-economic analysis of the potential hybrid systems, but found that the software “does not consider transport, installation, tax and insurance and other socio-economic costs required to setup an energy generation facility” [55]. For this reason, Shafiullah decided to use RETScreen in addition to HOMER to ensure that all costs were accurately captured in the analysis. This resulted in an “optimised wind-solar PV-grid-connected hybrid system developed for the Cooee Bay, Tanby substation [with Net Present Cost (NPC) of] 18,238,478 [AUD and LCOE of] 0.316AUD/kWh respectively. On the other hand, NPC and LCOE for the grid-connected only system are 18,525,184 AUD and 0.321AUD/kWh respectively” [55].

Three of the six Australian studies reviewed for this report considered the environmental impact of their proposed hybrid power generation systems, namely [52, 54, 55]. Their findings were much the same as those of the reviewed global studies, with Shafiullah stating that “with the increased penetration of PV and wind energy, CO2 emissions are reduced significantly” [55]. There appears to be a gap in the research in terms of Australian projects in the field of life-cycle carbon dioxide emissions, as none of the studies that were reviewed considered the embodied energy in each of the renewable components.

## 2.5 Summary

A total of 36 studies have been reviewed and presented in this report to demonstrate an understanding of published literature on the topic of feasibility analysis for hybrid power generation systems. This review has found that the overwhelming majority of published studies agree that renewable technology integration into hybrid power generation systems is technically, economically and environmentally feasible. Remote communities with no access to grid-connection have been identified as the ideal case for implementation of renewable hybrid systems, particularly in areas with excellent renewable resources.
Based on the methodology applied in these studies, LCOE has been identified as the most accurate economic metric for assessment of feasibility. The key variables to focus on when determining the LCOE, based on the assumptions made and methodologies implemented in the reviewed studies, have been identified as diesel fuel price and the capital cost of solar thermal technology. While Solar PV capital cost is an important contributor to the LCOE, it is regarded by most of the studies as a ‘mature’ technology in Australia and is therefore less likely to fluctuate.

Technical feasibility is not as easily quantifiable, but can be assessed by analysing the system’s ability to supply the required energy demand without generating significant excess energy. Environmental analysis has been identified as one area that is often not considered in enough detail, and the findings in this review have provided motivation to conduct a thorough life-cycle carbon dioxide assessment of any components used in the proposed hybrid system.

The most noteworthy finding of this review is that there is a gap in research when it comes to including solar thermal with thermal storage in renewable hybrid power generation systems, particularly in the Australian context, and this area will therefore be covered in detail in this projects analysis.

# 3 Methodology

## 3.1 Critical Assumptions

### 3.1.1 Studied Areas

As outlined in the introduction to this project, the focus of this study was on analysis and comparison of energy generation technologies in a remote Australian context. The areas of study were chosen such that this goal could be achieved while also showing the feasibility of renewable energy hybrid systems across a wide range of sites in Australia. While several of the areas used in this project are not classified as 'remote', they provide an indication of the available resources and typical loads in every state of mainland Australia.

### 3.1.2 Renewable Resources

Weather files containing data for Global Horizontal Irradiance (GHI) and Direct Normal Irradiance (DNI) in watts per metre squared corresponding to each hour of a year have been supplied by Professor Hal Gurgenci for use in this project. For brevity, these files have not been included in the report, however, the areas with weather data files available (and the year the data was collected) are listed below:

- Alice Springs (2000)
- Chinchilla (2011)
- Cobar (2010)
- Halls Creek (2012)
- Kalgoorlie (2011)
- Longreach (2010)
- Mildura (2010)
- Newman (2006)
- Port Augusta (2012)
- Tennant Creek (2010)
- Wagga Wagga (2006)
- Woomera (2009)

Figure 24 to Figure 35 in the appendix show the average GHI and DNI for each of these locations across the 12 months of the year. It should be noted that these weather files are not all from the same year across the sites studied. While this is not ideal, it is not expected that this will have a significant impact on the results as the primary focus of the project is identifying the optimum combination of technologies to supply power to remote sites. Errors introduced by using weather data from different years across sites may influence which 3 sites are chosen as the 'ideal candidates' for implementation of the hybrid power system, but should have no quantifiable impact on the overall outcomes and conclusions of the project.

### 3.1.3 Load Profile

The load profiles used in the analysis were based on the assumption of 5 people per household. Household annual average consumption was found using Energy Made Easy [56]. Using the population for each town/city (sourced from the Australian Bureau of Statistics) that had weather data, it was possible to assume an average daily energy usage in kWh for the town/city in question. A synthetic load profile was created using HOMER software with the following assumptions:

- 'Community' load profile
- Peak load in January (Summer in Australia)
- Day-to-day random variability set to 10%
- Timestep-to-timestep random variability set to 10%
- Timestep size of 60 minutes

This synthetic load profile was then scaled to the appropriate size using the average daily energy usage found above. Table 5 shows the key assumptions and values associated with the load profile for the sites investigated in this project.

Table 5 - Assumed Values for Load Profile

| Site | Household Annual Average Consumption (kWh/day) [56] | Population (people) [57] | Total Daily Energy Consumption (kWh/day) |
|---|---|---|---|
| **Alice Springs** | 31.3 | 27,972 | 175,105 |
| **Chinchilla** | 20 | 7,000 | 28,000 |
| **Cobar** | 32 | 5,120 | 32,768 |
| **Halls Creek** | 22.9 | 3,338 | 15,288 |
| **Kalgoorlie** | 22.9 | 33,000 | 151,140 |
| **Longreach** | 25 | 3,703 | 18,515 |
| **Mildura** | 16.3 | 55,000 | 179,300 |
| **Newman** | 22.9 | 5,500 | 25,190 |
| **Port Augusta** | 17.4 | 15,000 | 52,200 |
| **Tennant Creek** | 31.3 | 3,600 | 22,536 |
| **Wagga Wagga** | 32 | 60,000 | 384,000 |
| **Woomera** | 17.4 | 150 | 522 |

Figure 21 and Figure 22 in the appendix show the daily load profile and the seasonal load profile respectively for an indicative 1000kWh/day. The actual load profiles used in the analysis match the trends shown in Figure 21 and Figure 22, but use the Total Daily Energy Consumption shown in Table 5 as the scaled annual average load. See also Figure 23 in the Appendix for the full electric load tab used in this project as shown in HOMER.

In this project, the annual capacity shortage has been set to 0%, indicating that the implemented system can meet the required load at all times.

### 3.1.4 Financial

There were three key assumptions made with regards to the financial calculations in the analysis. The first assumption was that 100% of the capital required for the project was borrowed from investors (government or private). This meant that the most influential factor to consider when calculating financial parameters was the discount rate. As discussed in the literature review, the discount rate for similar projects to this in Australia typically lies somewhere in the range of 5-10%. The annual report from the 2015-2016 period published by the Clean Energy Finance Corporation stated that the target Portfolio Benchmark Return Target was 5.95%-6.95% [58]. Similarly, the 2013-2014 report named a key portfolio performance metric as being a project yield of approximately 7% [59]. With these figures in mind, a base discount rate of 7% was assumed in this project, with a sensitivity analysis conducted to assess the impact of changing this value in the range of 4-12%.

The third financial assumption was with regards to the calculation of LCOE implemented in the analysis. To do this, equivalent annual cost was calculated using the following equation.

$$EAC = \frac{NPV}{A_{t,r}}$$

$$where: A_{t,r} = \frac{1 - \frac{1}{(1+r)^t}}{r}$$

$$r = discount\ rate$$

$$t = number\ of\ years$$

$$NPV = Net\ Present\ Value\ of\ project$$

The LCOE can then be calculated by dividing the total EAC by the annual energy production.

### 3.1.5 Diesel Generator

Table 6 shows the assumed values for the critical parameters related to the implementation of a diesel generator into a hybrid system.

Table 6 - Diesel Generator Cost Assumptions

| Item | Cost |
|---|---|
| **Capital Cost** | 850 (AUD/kW) |
| **O&M Cost** | 0.05 (AUD/kW/hour of operation) |
| **Fuel Cost** | 1.0 (AUD/litre) |
| **Replacement Cost** | 850 (AUD/kW) |
| **Generator Life** | 60,000 (hours) [52] |

The fuel use of the diesel generator has been calculated using the relationship discussed in the literature review, given by the following equation:

$$Fuel\ Use = (A \times load) + (B \times generator\ capacity)$$

$$Where\ A = 0.2088$$

$$B = 0.01841$$

It has been assumed that whenever the diesel generator is required it runs at the average generator load, which was calculated using the total contribution from the diesel generator over the year divided by the number of operating hours in that year.

The price of diesel fuel has been determined using information provided by the Australian Institute of Petroleum and the Australian Competitor and Consumer Commission. The AIP estimated that the national average terminal gate price for diesel fuel in Australia from the year 2004-2016 was 124.8 cents/litre [60]. Given that the focus of this project is on power generation for remote areas, it is important to note that it is not necessary to pay the fuel excise tax of 0.396AUD/litre on this diesel fuel [50]. However, there will likely be significant transport costs which will increase the price of the diesel fuel. With these factors in mind, the diesel fuel price for this project has been assumed to be 1AUD/litre.

### 3.1.6 Concentrating Solar Thermal

There were several assumptions made with relation to the sizing of the concentrating solar thermal plant implemented to satisfy the desired load, namely:

- Total storage capacity was based on the storage hours required by the following relationship – Total storage amount = Annual average hourly load * Required storage hours * Storage buffer
    - Where the storage buffer was assumed to be 1.2
- The solar multiple (solar multiple of 1 indicates that the mirror area is sufficient to run the solar thermal plant at nameplate capacity) was set at 1.5
- The time required for the storage to be filled was set to 5 hours
- The mirror field efficiency was set to 48% [27]
- The plant efficiency was set to 40% [27]
- Losses from TES (Thermal Energy Storage) due to dissipation of heat (radiation from receiver, piping and tank losses) were assumed to be negligible (Zhang et al estimate that the losses from these sources are less than 1% [27])

Table 7 displays the assumed values for the costs associated with implementing a concentrating solar thermal plant.

Table 7 - CST Cost Assumptions

| Item | Cost |
|---|---|
| **Capital Cost** | 7929 (AUD/kW) [49] |
| **O&M Cost** | 50 (AUD/kW/year) |
| **Plant Life** | 25 years |

### 3.1.7 Solar PV

To calculate the contribution made by solar PV it was assumed that the solar panels are tilted at the latitude of the location under study. This has been identified by two suppliers of solar panels in Australia as being the optimal tilt angle to maximise the annual yield of a panel [61, 62]. To calculate the effect of tilting the solar panels, formulas and methods from [19, 63] were used in the analysis code. As Australia is in the Southern Hemisphere, the optimal orientation of the panels has been shown by these suppliers to be true north [61, 62]. Table 8 shows the critical specifications for the solar panel that has been used in this project, as well as a summary of key assumptions related to tilt and orientation.

Table 8 - Solar PV Panel Technical Assumptions

| Designation | Sunpower E20-435-COM |
|---|---|
| **Nominal Power** | 435W |
| **Average Panel Efficiency** | 20.3% |
| **Product Warranty (Guaranteed life)** | 25 years |
| **Panel Tilt** | Latitude of Location |
| **Panel Orientation** | North |

Following on from the technical assumptions made for the solar PV panels, it was also necessary to make assumptions regarding the associated costs, as shown in Table 9.

Table 9 - Solar PV Cost Assumptions

| **Item** | **Cost** |
|---|---|
| **Capital Cost** | 1500 (AUD/kW) |
| **O&M Cost** | 20 (AUD/kW/year) [11, 14, 30, 40] |

### 3.1.8 Sensitivity Analysis

The range of discount rates was used to set the parameters for the other critical variables in the sensitivity analysis. For example, to capture the full range of possible discount rates it was necessary to implement a range of 4-12%. A discount rate of 4% is 43% less than the base rate of 7%, and a discount rate of 12% is 71% higher than the base rate. A base value was set for each critical variable and they were then varied through the range defined by the discount rate. Table 16 in the appendix displays the values used for each variable in the sensitivity analysis, as well as numerical results.

## 3.2 Developed Python Analysis Code

The analysis code that was developed for this project has not been included in its entirety in this report, however, the following is a description of how the code works (pseudo code) and what is required to run it. The overall composition of the code is that of a two-variable optimisation analysis, with PV power and CST storage hours being the two variables under investigation.

1. Import required modules, namely
    a. Xlrd (module to allow manipulation of excel files)
    b. Math (allows the use of simple mathematical functions)
    c. Numpy (allows the use of numpy arrays)
    d. Matplotlib (used to produce plots of critical data)
    e. Timeit
    f. CSV
    g. itertools
2. A class was created to keep track of information related to the solar thermal plant such as:
    a. Total storage capacity which is defined by the number of storage hours required and the average load in the provided load profile
    b. Field capacity and mirror area. These are set based on the total storage capacity and the required 'fill time' for the thermal storage
    c. Plant capacity, which is based on the field capacity divided by the solar multiple and then multiplied by the assumed efficiency of the solar thermal power plant
    d. Three functions related to the stored thermal energy, one of which returns the current amount of energy available, one which is used to add storage and one which is used to subtract storage
    e. Two functions related to the excess generated by the plant. When the 'add storage' function is run, it checks to see if there is enough room for the energy to be stored. If there is not, this is taken to be excess energy and is

added to the excess energy tally using the 'add excess' function. The other function returns the total amount of excess energy at any given point.

3. A function to calculate the effect of the tilt of the solar panels was implemented using equations referenced from [19, 63].
4. The main simulation function of the code runs through the following steps:
    a. Takes the load file, weather file, size of the PV plant and number of storage hours as arguments
    b. Opens the weather and load files and extracts key information from them such as average load and average DNI/GHI
    c. Opens the weather and load file again, then loops through the following process for each hour of the year:
        i. Storage corresponding to the DNI value for this hour is added to the CST plant
        ii. Checks whether solar PV can cover the entire load in that hour. If it is, adds the load to the total contribution from PV
        iii. If solar PV cannot cover the entire load, checks to see whether solar PV and CST together can cover the load. If they can, the contributions from solar PV and CST are updated accordingly.
        iv. If both solar PV and CST are insufficient to satisfy the load requirement in this hour, the diesel generator kicks in and covers the remaining load. Total contributions from each technology are updated accordingly.
    d. The function returns:
        i. The total contribution (kWh) and the peak load (kW) from each of the three technologies
        ii. The number of hours the diesel generator was required (total runtime)
        iii. The nominal capacity of the CST plant
        iv. The excess energy generated by PV and CST
5. Three functions have then been implemented to complete a financial analysis and identify the optimum hybrid system

a. The primary financial function takes the following as arguments:
    i. Load file
    ii. Weather file
    iii. Diesel fuel cost
    iv. Solar PV capital cost
    v. CST capital cost
    vi. Discount Rate
    vii. Minimum Solar PV to be implemented
    viii. Maximum Solar PV to be implemented
    ix. Minimum Storage Hours to be implemented
    x. Maximum Storage Hours to be implemented
b. The primary function then runs through and tests each possible combination of systems according to the ranges supplied for PV and CST using the main simulation function defined above.
    i. The equivalent annual cost is found for each system and divided by the yearly output gives the LCOE (AUD/kWh)
    ii. The function returns the optimum system within the supplied range based on LCOE
c. The other two functions are used to calculate the diesel fuel use based on the generator size required and the equivalent annual cost respectively

6. Two functions have been created which use the primary financial function to complete further analysis:
    a. The first function runs the primary financial function for all supplied load and weather files and returns a sorted list of the areas analysed (according to LCOE)
    b. The second function is used for sensitivity analysis and varies the following critical parameters:
        i. Diesel fuel cost
        ii. Solar PV capital cost
        iii. CST capital cost

iv. Discount Rate

## 3.3 Life-Cycle GHG Emissions Analysis

The primary source of information for GHG emissions analysis in this report was a study completed by Nugent and Sovacool. In this study, Nugent and Sovacool "screened 153 lifecycle studies of greenhouse gas equivalent emissions for wind turbines and solar panels to identify a subset of the 41 most relevant, current, peer-reviewed, original, and complete assessments" [64]. In this case, 'complete assessments' refers to studies which analysed the full spectrum of greenhouse gases generated by each technology, not just carbon dioxide. This is an important criterion as things like the manufacturing of solar panels and the operation of a diesel generator can also produce significant levels of other greenhouse gases.

This study also published values for GHG emissions linked to solar thermal, but based this on research pertaining to parabolic trough technology not power tower technology. Despite this, it has been assumed that the value of equivalent $CO_2$ emissions per kWh given in the report published by Nugent and Sovacool is sufficiently accurate for use in this report.
As per the study by Nugent and Sovacool, Table 10 shows the assumed values for equivalent $CO_2$ emissions for each of the technologies.

Table 10 - Assumed Values for GHG Analysis [64]

| Technology | Mean (g $CO_2$ eq/kWh) |
|---|---|
| **Solar PV** | 49.9 |
| **Solar Thermal** | 13 |
| **Diesel** | 778 |

# 4 Results

## 4.1 Overall Results

The following results have been generated using the Python analysis code discussed in the methodology section of the report. For the full table of results for all 12 sites see Table 17 in the Appendix. Table 11 and Figure 5 display the overall results of the analysis that has been undertaken.

Table 11 - Analysis Results across 12 Sites

| Site | LCOE ($/kWh) | NPV ($ Millions) | Renewable Fraction (%) | Total Installed Power (MW) |
|---|---|---|---|---|
| **Port Augusta** | $0.203 | 97.3 | 92% | 8.9 |
| **Halls Creek** | $0.204 | 28.6 | 91% | 2.8 |
| **Woomera** | $0.205 | 0.98 | 92% | 0.09 |
| **Newman** | $0.21 | 48.4 | 89% | 4.6 |
| **Wagga Wagga** | $0.211 | 745.5 | 89% | 62.9 |
| **Tennant Creek** | $0.211 | 43.5 | 87% | 3.8 |
| **Alice Springs** | $0.22 | 355 | 86% | 32 |
| **Mildura** | $0.23 | 372.2 | 86% | 32 |
| **Kalgoorlie** | $0.23 | 317.6 | 82% | 27 |
| **Cobar** | $0.23 | 69.7 | 85% | 5.8 |
| **Longreach** | $0.24 | 40.1 | 86% | 3.6 |
| **Chinchilla** | $0.25 | 64.3 | 79% | 5 |

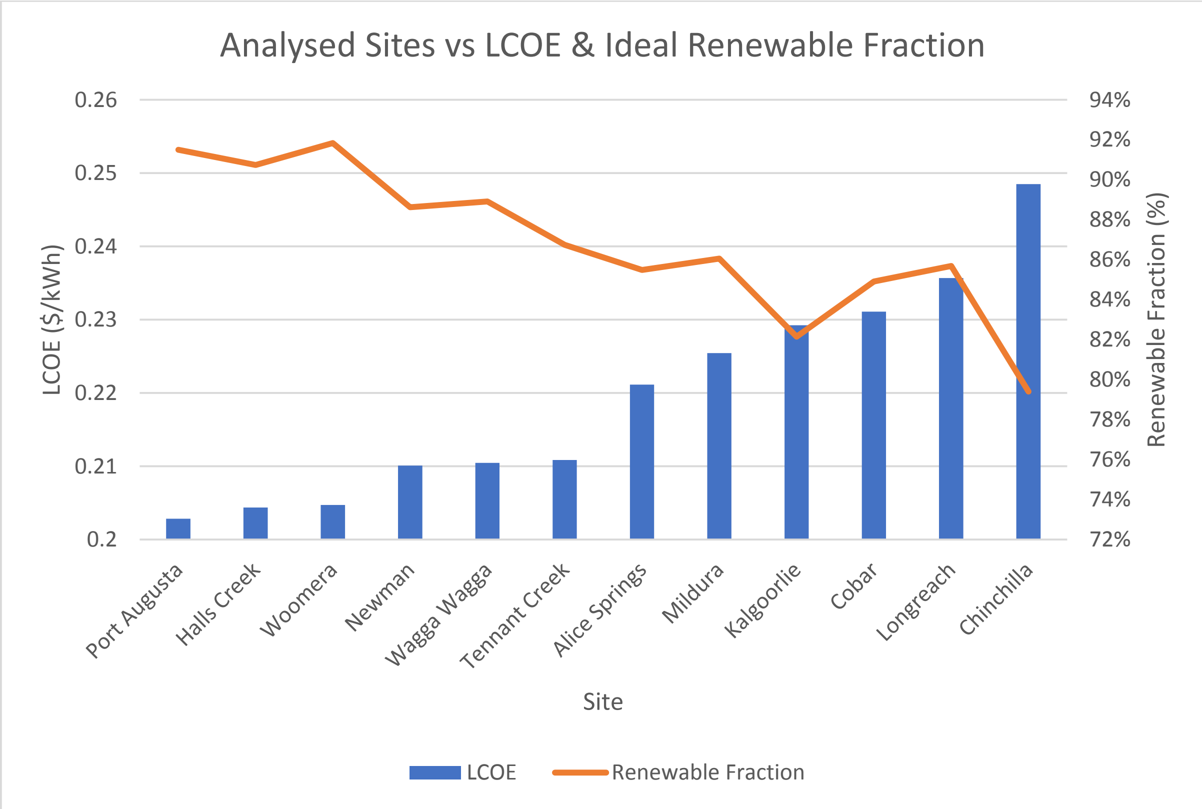


Figure 5 - Graphical Analysis Results across 12 Sites

The results shown in Table 11 and Figure 5 indicate that the top 3 site locations based on LCOE are Port Augusta, Halls Creek and Woomera. Table 11 also shows the total installed power at each site. The total installed power for Woomera is small enough that it may invalidate some of the assumptions made for CST and as such this result will be excluded. The top three sites are therefore Port Augusta, Halls Creek and Newman, all of which have a moderate sized system installed (between 2MW and 9MW). Further analysis has been undertaken on these sites as indicated by the results below.

## 4.2 Detailed Results for Top 3 Sites

Detailed results for the top 3 sites are shown in Table 12.

Table 12 - Detailed Results for Top 3 Sites

| | | | Generated Power | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Location** | **PV Power (kW)** | **CST Storage (Hours)** | **PV Total (MWh)** | **CST Total (MWh)** | **DG Total (MWh)** | **DG Peak (kW)** | **DG Run Time (Hours)** | **PV Excess (MWh)** | **CST Plant Capacity (MW)** | **CST Excess (MWh)** |
| **Port Augusta** | 200 | 12 | 441.2 | 17113.1 | 1630.8 | 5059.8 | 1643 | 0 | 3.5 | 41250 |
| **Halls Creek** | 150 | 11 | 329.2 | 4750.4 | 518.7 | 1703.7 | 1752 | 0 | 0.93 | 10919 |
| **Newman** | 300 | 11 | 662.5 | 7509.3 | 1048.7 | 2698.3 | 1908 | 0 | 1.54 | 18306 |

Figure 6 gives an indication of the technology breakdown for each of the ideal systems implemented across the top 3 sites.

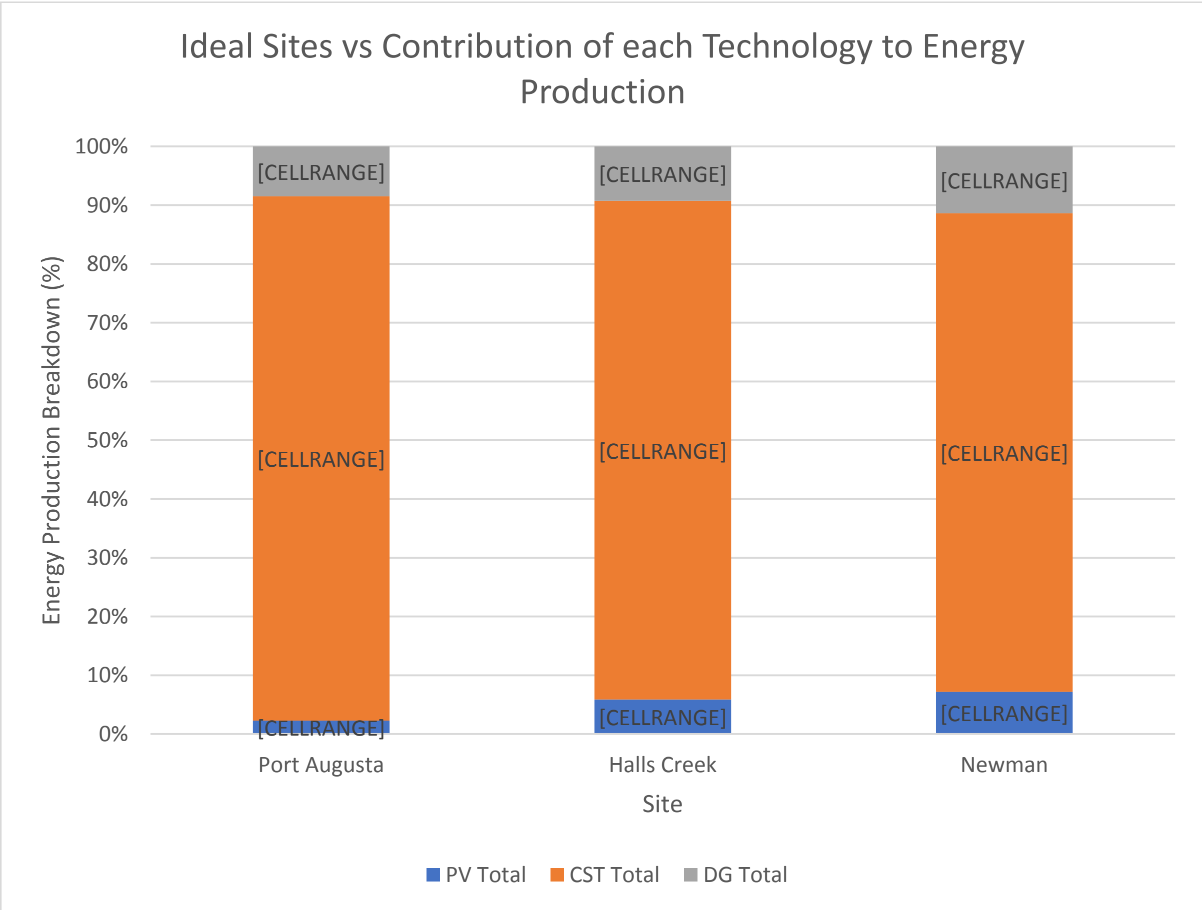


Figure 6 - Breakdown of Contribution to Energy Production by each Technology

Figure 7 shows the excess energy generated by the systems at each of the three ideal sites.

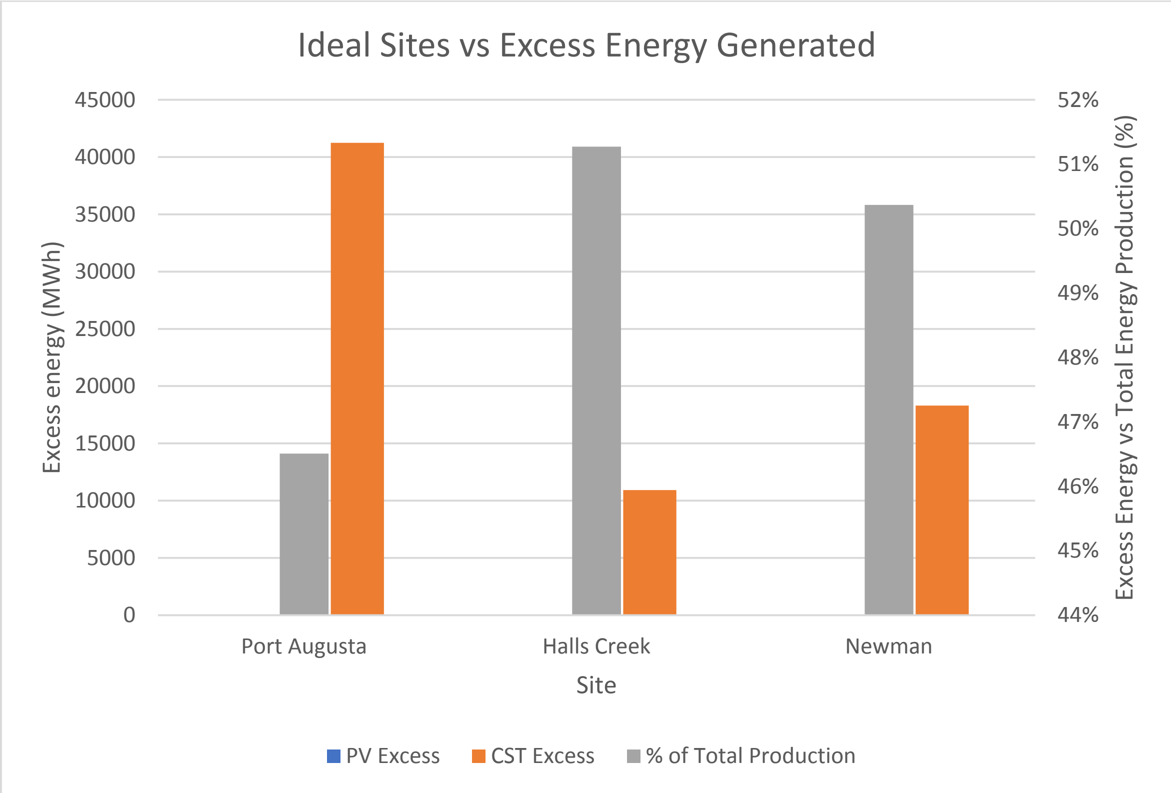


Figure 7 - Excess Energy Generated at Ideal Sites

Table 13 shows the equivalent annual $CO_2$ emissions for the optimum hybrid system at each of the top three sites.

Table 13 - GHG Emissions Analysis Results

| Site | Total Annual Emissions (kgCO2eq/year-MWh) | Total Annual Emissions (kgCO$_2$eq/year) | PV Emissions (kgCO$_2$eq/year) | CST Emissions (kgCO$_2$eq/year) | Diesel Emissions (kgCO$_2$eq/year) | Diesel System Emissions (kgCO2eq/year) | Diesel System Emissions (kgCO2eq/year-MWh) | Difference (%) |
|---|---|---|---|---|---|---|---|---|
| **Port Augusta** | 78.9 | 1513235.9 | 22015.6 | 222470.2 | 1268750.1 | 14925984.5 | 778 | 163% |
| **Halls Creek** | 86 | 481702.2 | 16429.4 | 61755.6 | 403517.2 | 4355505.7 | | 160% |
| **Newman** | 102.7 | 946544.2 | 33057.7 | 97621.23 | 815865.3 | 7173528.5 | | 153% |

Figure 8 shows the emissions contributed by each technology at each of the top 3 sites. Note that the percentage shown above each bar is the relative contribution of that technology to the total GHG emissions.

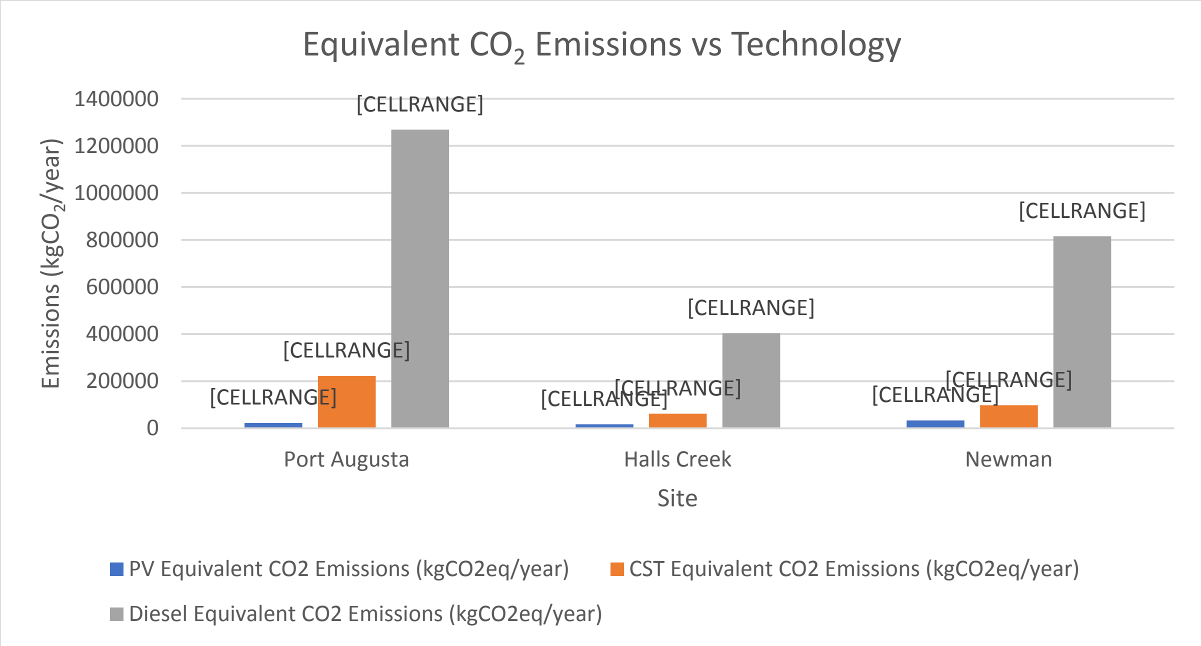


**Figure 8 - Equivalent $CO_2$ Emissions vs Technology in Optimum Hybrid System**

Figure 9 displays the difference between the optimum hybrid system at each site versus a 100% diesel system at each site as well as the reduction in emissions due to the implementation of the hybrid system.

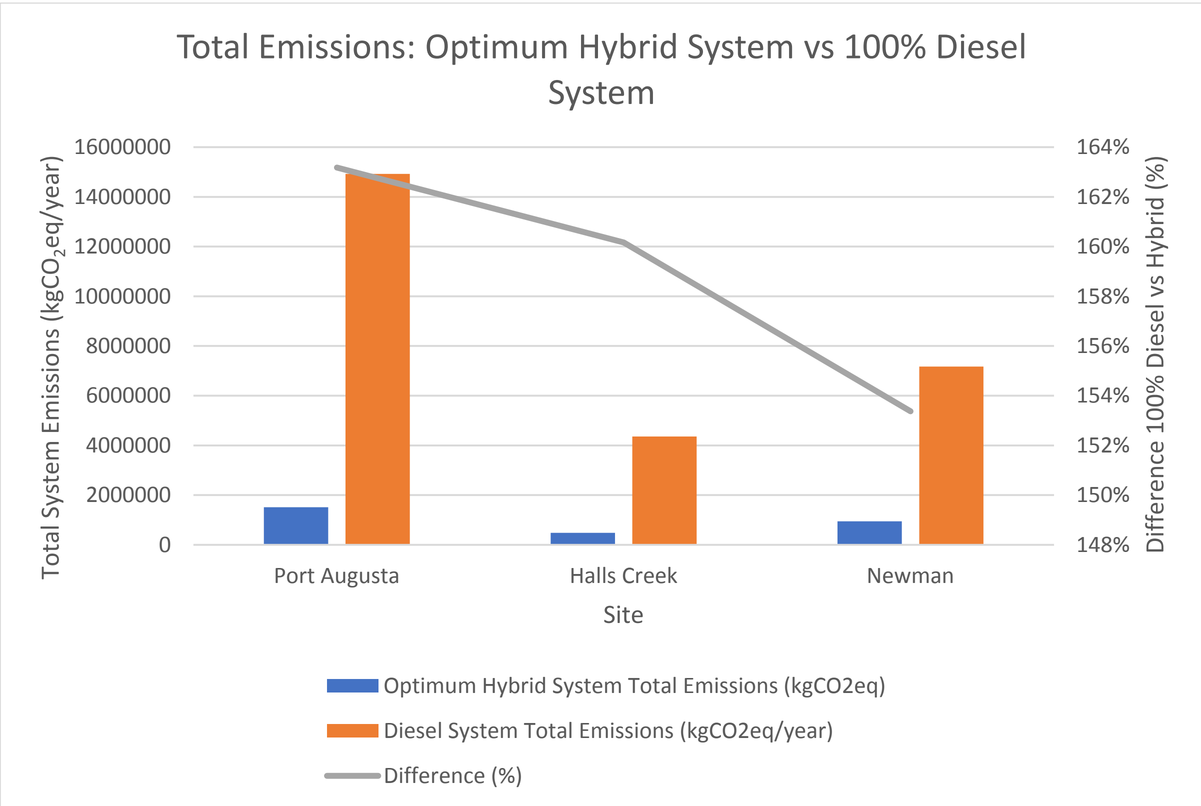


**Figure 9 - Optimum Hybrid System vs 100% Diesel System Total Emissions**

## 4.3 Sensitivity Analysis Results for Top 3 Sites

Figure 10, Figure 11 and Figure 12 show the results of the sensitivity analysis that was conducted on the critical parameters related to LCOE for each of the top 3 sites. See Table 16 in the Appendix for the values used in this sensitivity analysis and the detailed results.

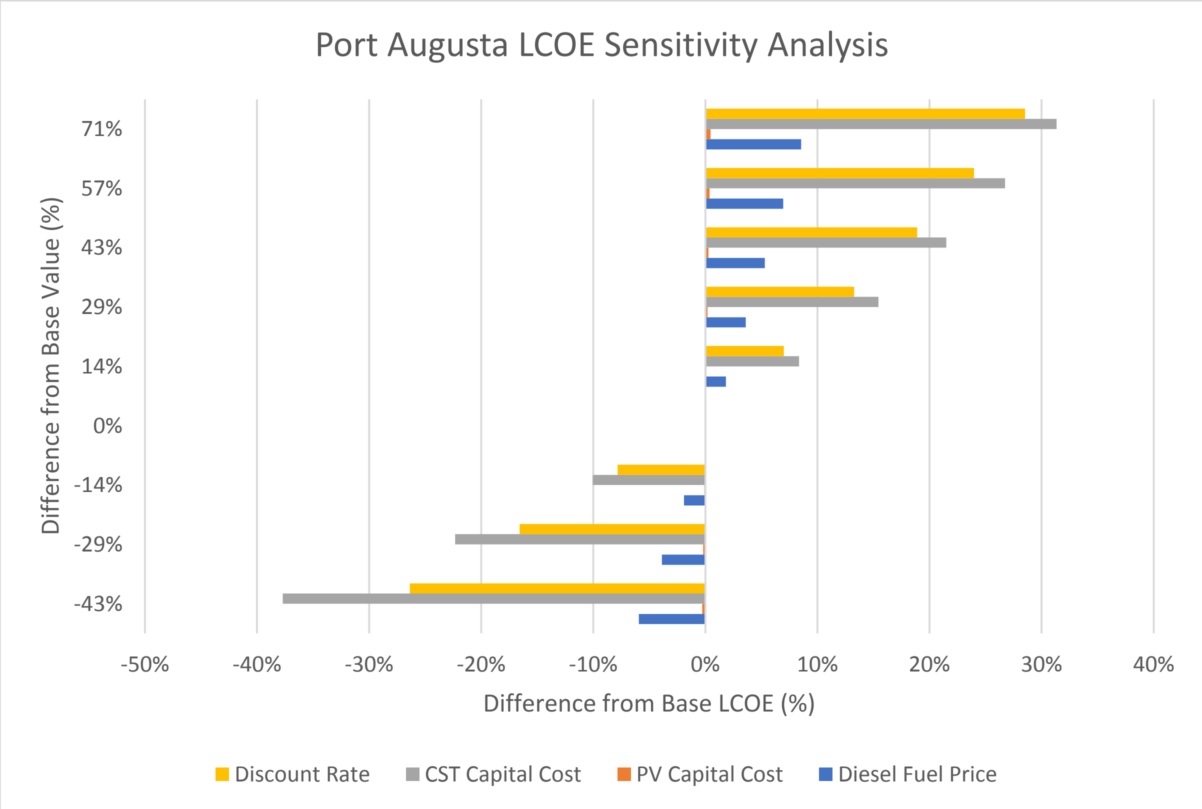


Figure 10 - Port Augusta LCOE Sensitivity Analysis

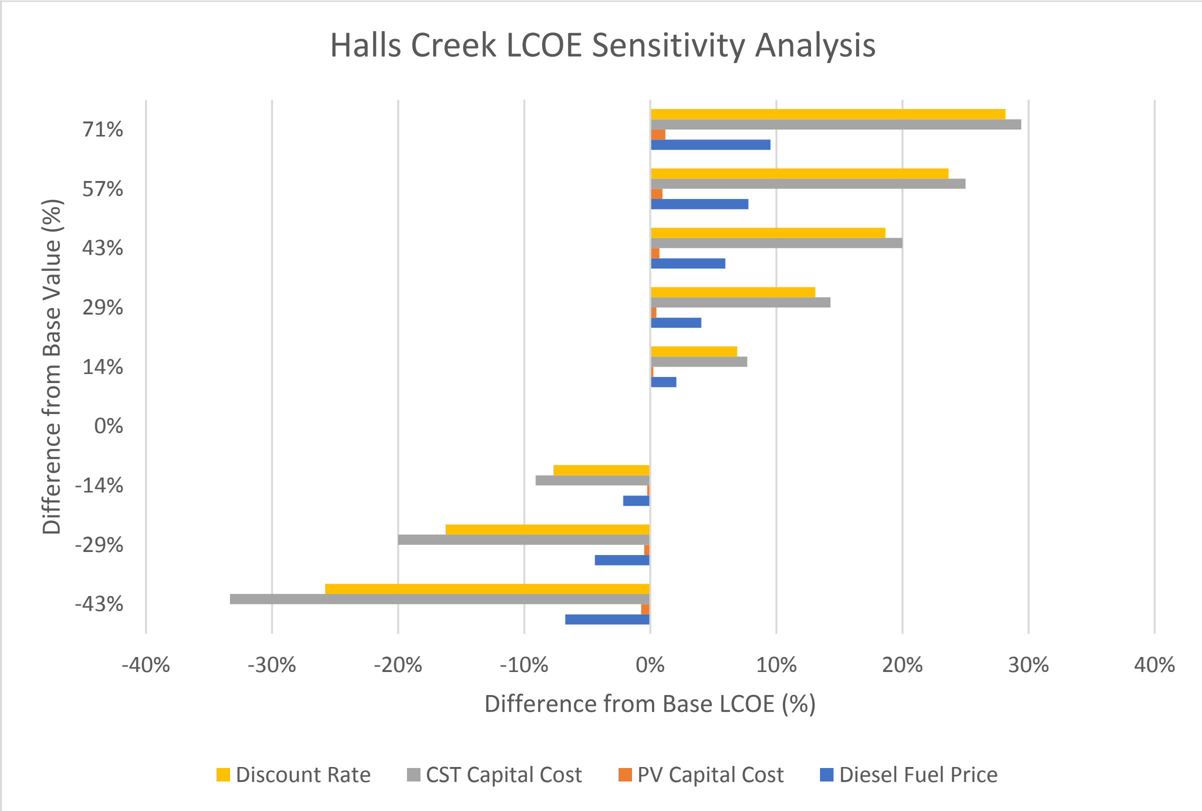


Figure 11 - Halls Creek LCOE Sensitivity Analysis

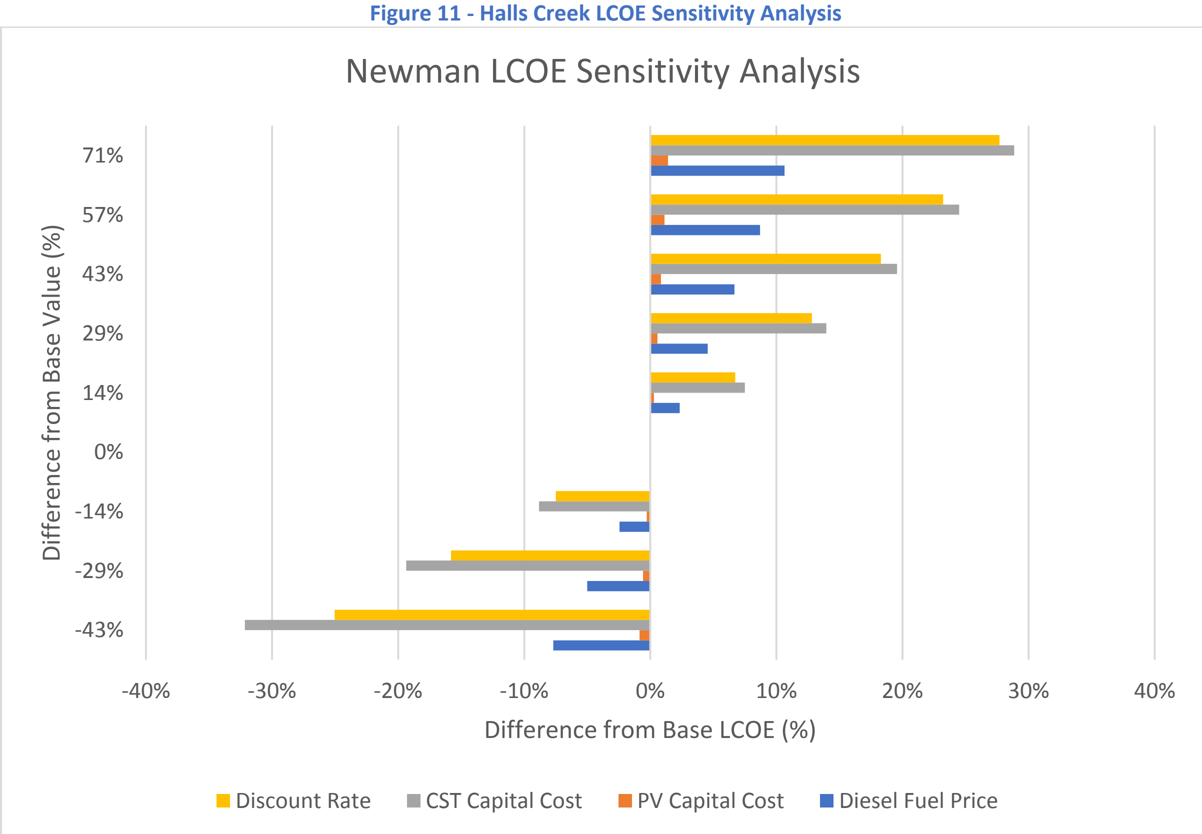


Figure 12 - Newman LCOE Sensitivity Analysis

# 5 Design and Implementation of Solar Thermal Plant at Port Augusta

## 5.1 SAM Analysis

An analysis has been undertaken using the System Advisory Model software to obtain the required size of the CST plant to be installed at the optimum site (i.e. Port Augusta). While SAM has not been used as a primary means of generating financial results for this project, the results found from this SAM analysis have been used to sanity check assumptions in the developed analysis code, as well as the results given by this code.

### 5.1.1 Assumptions

Figure 13 shows the assumptions that were made in the SAM software to accurately model the CST system:

- Note: weather file for Port Augusta was uploaded to software

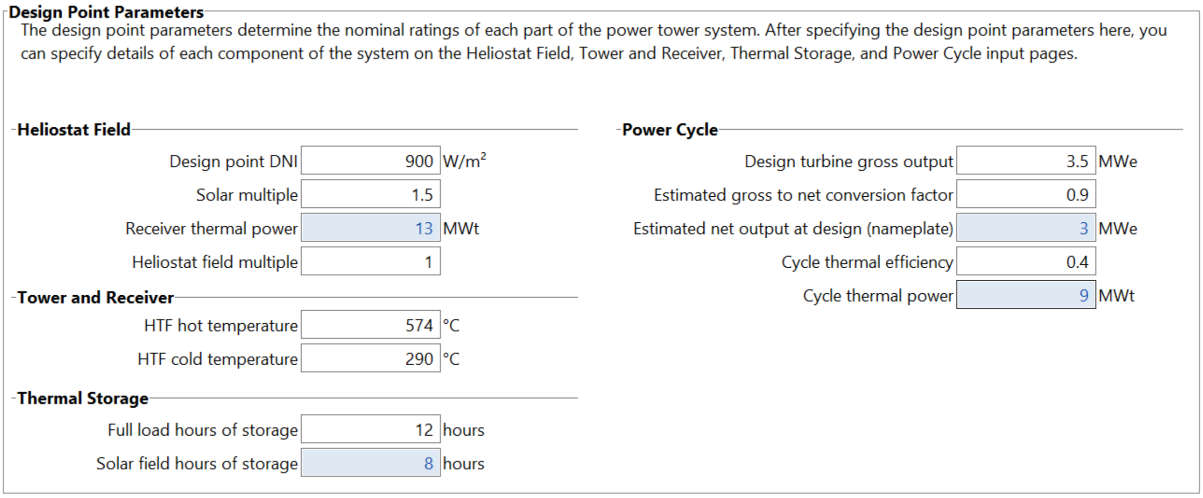


**Figure 13 - Design Point Parameters for CST Plant in SAM**

As shown in Figure 13, the design point DNI was set to 900W/m$^2$. While this value is higher than the average DNI's shown in Figure 32 for Port Augusta, there are generally at least 3-4 hours per day (around midday) that achieve this value throughout the year. The solar multiple, design turbine gross output and the full load hours of storage were both set according to assumptions made in the analysis code for the CST plant. The cycle thermal efficiency was set to 0.4 and the HTF hot temperature and HTF cold temperature were left at the values generated by SAM.

### 5.1.2 Results

The following results were achieved using the assumptions listed above. Figure 14 shows the optimised heliostat field layout.

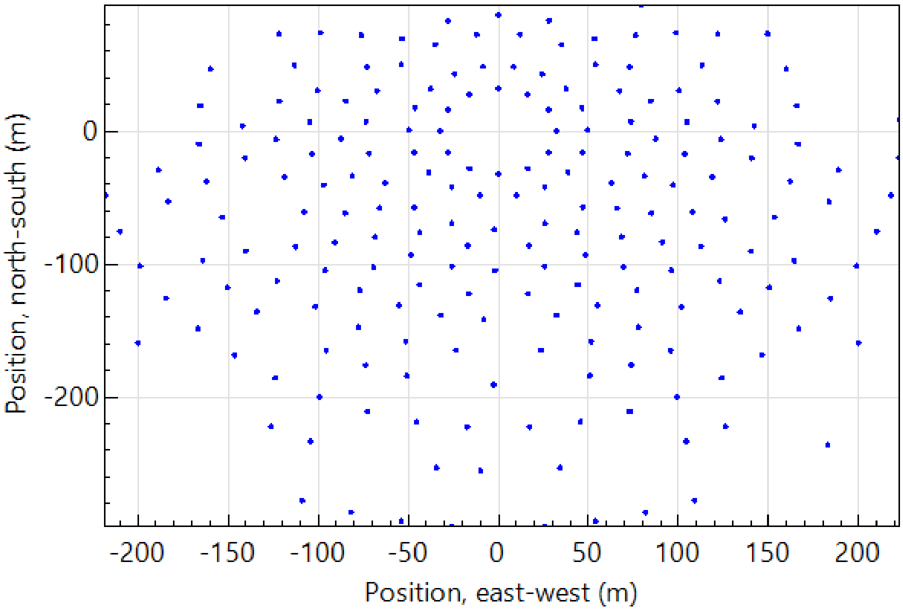


Figure 14 - Optimised Heliostat Field Layout for CST Plant

Table 14 displays the critical results from the SAM analysis.

Table 14 – Critical Results from SAM Analysis

| Parameter | Value |
|---|---|
| **Total no. of heliostats** | 208 |
| **Total reflective area** | 30,030m$^2$ |
| **Total land area used by field** | 319,702m$^2$ |
| **Tower height** | 43m |
| **Estimated water requirements for washing** | 1.4ML/year |

The results shown in Table 15 have been included in this report for validation purposes only and do not replace those achieved with the analysis code.

Table 15 – CST Plant Financial Costs SAM Results vs Analysis Code

| Parameter | SAM Analysis Value | Analysis Code Value | Difference (%) |
|---|---|---|---|
| **Total installed cost ($)** | 29,114,408 | 32,125,500 | 10 |
| **Estimated total installed cost per net capacity ($/kW)** | 9,243 | *9,179 | 1 |

*Value reached by adding $7929/kW (assumed capital cost of CST) to the O&M cost of $50/kW/year, which for a project life of 25 years this becomes $1250/kW

# 6 Discussion and Conclusions

## 6.1 Discussion

### 6.1.1 Discussion of Overall Results

The results displayed in Table 11 and Figure 5 reveal several important trends in the data. One such trend from Table 11 is how tightly grouped the LCOE values are for the 12 sites considered, ranging from $0.2/kWh at Port Augusta to $0.25/kWh at Chinchilla. This is a maximum difference in LCOE of less than 20% and, given how widely spread the sites are across Australia, is an interesting result. On this note, it is also evident that in general a higher renewable fraction, which is in itself indicative of superior renewable resources, leads to a lower LCOE. For example, the top six sites have an average renewable fraction of 90% versus the bottom six sites average of 84%. While this may not seem like a significant difference, there is also a difference in the variation of LCOE's between the top six sites and the bottom six. The top six sites vary from an LCOE of $0.203/kWh to an LCOE of $0.211/kWh, which is a difference of approximately 4%, whereas the bottom six sites vary from $0.22/kWh to $0.25/kWh, corresponding to a difference of 12%. From this it can be deduced that the quality of renewable resources, and as a result the renewable fraction in the hybrid system, play a critical role in both the overall cost of the system as well as the stability of this cost.

It would be expected that a study with large distances between analysed sites would yield results that varied widely in composition and cost of energy. While this may usually be the case, the results obtained in this project are not entirely unexpected. The solar resources available in Australia are among the best in the world and, although they are exceptionally high in central Australia, there are very few regions in the country that would be considered to have 'poor' solar resources. This undoubtedly contributed to the consistency of the LCOE results shown in Table 11. It has also been noted that there are some unusual trends in the DNI data for some of the sites analysed. Figure 24 through to Figure 35 show the average GHI and DNI for all 12 sites across all months of the year. Of particular interest is that, with the possible exception of Mildura, Port Augusta and Woomera, most of the sites have unusually high average DNI through the winter months of the year with no noticeable peak in the summer months. This is concerning, as it implies that the weather data used in this project may have some inaccuracies. Regardless of whether the data is inaccurate or not, however, the consistently high DNI levels across all months of the year for most of the sites analysed would have played a significant role in the LCOE values achieved and the ideal system composition. The amount of CST in each system and, by extension, the renewable fraction, would have been influenced most by this. Table 11 also shows a significant variation in the size of the system required at each of the analysed sites. This was to be expected given the methodology applied for setting the load at each of the sites. It should be acknowledged that this may also have had some influence on the composition of the ideal system at each site, as this method essentially removes NPV as a useful comparison tool given that NPV is linked to the total installed power of the system. By using only the LCOE of each system to assess its viability, it is likely that some bias was introduced towards CST given that it is the most capital-intensive technology assessed in this project with the lowest cost per kWh over its lifetime. While NPV is not particularly useful for comparison between sites in this case, if the size of the system was set to a constant value it would then be a viable alternative to LCOE as the primary optimisation parameter.

In addition, the CST plant capacities chosen for most of the ideal systems are on the lower end of what is typically recommended for implementation. The analysis code did not impose any restrictions on the plant capacity of CST and, while this method should still be valid for a technological comparison project such as this, it may be important to revisit or revise this assumption if conducting a feasibility study concerned with actually implementing a system.

### 6.1.2 Discussion of Detailed Results

The detailed results for the top three sites that are shown in Table 12, namely Port Augusta, Halls Creek and Newman, give a clear indication of the composition of the ideal system at each of these sites. As expected from information gathered in the literature review, the CST plant is responsible for the majority of the energy generation at each of the top three sites. Figure 6 shows that CST supplies 81% of the energy requirements in Newman, 85% in Halls Creek and 89% in Port Augusta. Once again referring to Table 12, it can also be seen that a higher proportion of CST leads to lower diesel generator requirements, as evidenced by the lower diesel generator run time of 1643 hours in Port Augusta, where there is 12 hours of CST storage, versus 1752 hours in Halls Creek and 1908 hours in Newman, which both have 11 hours of CST storage. Solar PV is shown by Table 12 and Figure 6 to be a necessary component of the ideal hybrid system at all three sites, although it is worth noting that more solar PV is deployed in systems with lower CST contributions. For example, Port Augusta has the highest CST contribution at 89% but the lowest Solar PV contribution at 2%, whereas Newman has the lowest CST contribution at 81% and the highest Solar PV contribution at 7%. The contribution of diesel remains steady at 9% in Port Augusta and Halls Creek, with a slight increase at Newman to 11%. This indicates that the renewable resources at Newman are likely to be the poorest of the top three sites.

The relatively low contributions of Solar PV and, to a lesser extent, diesel generators, are quite surprising. Conventional wisdom dictates that hybrid systems would generally rely primarily on Solar PV during the day and a combination of CST and diesel generators at night. In this case, it seems that the primary function of PV in the ideal system was to shave some energy off the peak load throughout the day, allowing CST to cover the remainder. The diesel generator seems to have performed a similar function to Solar PV at night, albeit based on the peak load required of diesel shown in Table 12 there were clearly some nights that CST had insufficient storage to cover the majority of the electric load. As discussed above, the weather data almost certainly influenced the overall composition and renewable fraction of the systems at each of the sites, but given that the average GHI shown in Figure 24 to Figure 35 follows similar trends to the average DNI it cannot be concluded with any certainty that the weather data played a specific role in reducing the contribution of Solar PV. The assumed capital cost for solar PV used in this project has been verified against many sources and as such should not be the cause of the low contribution. It is possible that the solar panel tilt calculations produced an incorrect result. While it has been checked that the tilt angle produces an increase in Solar PV production throughout the year when compared to horizontal panels, it could not be verified whether this increase was accurate. The low contribution of diesel generators to the system can most likely be attributed to the storage capability of CST. As mentioned above and in the literature review, diesel generators have seen widespread deployment because they are reliable and able to be switched on and generating power at short notice. In hybrid systems that use Solar PV, wind or other fluctuating energy sources, diesel generators must be used to supply baseload power. In the ideal systems found through this projects analysis, the thermal storage available as part of the CST plant allows it to supply reliable baseload power. It should also be noted that in the analysis code the technologies are checked for their ability to satisfy the current load in the order:

1. Solar PV
2. Solar PV and CST
3. Solar PV, CST and Diesel

Checking the technologies in this order was necessary given that the diesel generator was assumed to be auto sized to whatever load was required of it, however, this method relies on the accuracy of the assumption that if a renewable energy source can supply the energy requirements then it should be prioritised over diesel.

Excess energy was raised as an important consideration in many of the reviewed studies and the results shown in Table 12 and Figure 7 display the excess energy generated by each technology at each of the top three sites. It is interesting to note that Solar PV does not produce any excess energy at all, probably because the generation capacity of Solar PV is relatively low compared to the load at each site. Figure 7 reveals that, despite having the highest total for excess energy generated, Port Augusta has the lowest percentage of total production of the top three sites, with excess energy equivalent to 47% of its total production. In comparison, Figure 7 shows that Halls Creek and Newman produce 51% and 50% of their total production in excess energy respectively. A reduction in excess energy generation could be achieved by increasing the amount of storage capacity relative to the capacity of the solar field. It is worth noting that the reason this was not done in this project was due to the layout of the analysis code. To ensure that the analysis was kept as a two-variable optimisation problem, the storage capacity of the CST plant was linked to the solar field capacity and the output capacity of the CST plant in the code. While this did result in a significant reduction in the complexity of the problem, it also meant that the size of the storage tank used for the analysis could not be de-linked from the solar field capacity and therefore the excess energy generated could not be reduced. The large quantity of excess energy generated at all three sites may not be ideal for some projects, but it does introduce some interesting opportunities for increasing the value of the project. With average excess energy of approximately 50% of the total production of the plant, there is potentially scope to sell this excess energy on to a client or feed it back into the grid to further reduce the LCOE of the system. This project has focussed on remote sites in Australia, so it should be assumed that feeding the excess energy back into the grid is not an option, however, residual value could still be extracted from this excess energy through methods such as hydrogen production via electrolysis. If this method or similar were implemented in the system, it would contribute to lowering both the LCOE of the system and the GHG emissions per MWh of energy produced as not all the excess energy would be wasted.

It is clear from Table 13 that Port Augusta has the lowest annual emissions per MWh of energy produced at 78.9kg$CO_2$eq/MWh-year, whereas Halls Creek and Newman produced 86kg$CO_2$eq/MWh-year and 102.7kg$CO_2$eq/MWh-year respectively. Given the increased contribution of diesel at the Newman site as shown in Figure 6 it was to be expected that there would be increased equivalent $CO_2$ emissions comparative to the other two sites. It is interesting, however, that there is an 8% difference between the emissions of Port Augusta and Halls Creek given that the renewable fraction at these two sites is very similar. This discrepancy in emissions is likely caused by the difference in the contribution of CST at Port Augusta and Halls Creek. As discussed above, Figure 6 shows that CST contributes 89% of the total production at Port Augusta versus only 85% at Halls Creek. While the contribution from Solar PV at Halls Creek is larger than that at Port Augusta, the reduced relative size of the CST plant leads to increased usage of the diesel generator at night time and therefore results in increased $CO_2$ emissions. Table 12 confirms that the run time of the diesel generator at Halls Creek is approximately 109 hours longer per year than the run time of the diesel generator at Port Augusta.

Table 13 and Figure 8 show the relative contributions of each technology to the total $CO_2$ emissions at each of the top three sites. Despite the relatively low contribution that diesel makes to overall energy production, diesel features prominently in $CO_2$ emissions at all three sites, with contributions of 84%, 84% and 86% at Port Augusta, Halls Creek and Newman respectively. Solar PV contributes the least to $CO_2$ emissions at all three sites, which is to be expected given the low overall contribution of the technology to energy production and the low $CO_2$ emissions related to manufacturing and operating the technology. Also shown in Table 13 and Figure 9 are the $CO_2$ emissions produced by a 100% diesel system and the significant reduction in emissions that is brought about by implementing the hybrid system. The reduction in emissions is highest at Port Augusta, where the hybrid system $CO_2$ emissions are 163% lower than the 100% diesel system. The reduction in $CO_2$ emissions is shown to be only slightly lower at Halls Creek and Newman, with results of 160% and 153% respectively.

The sensitivity analyses shown for the three sites in Figure 10, Figure 11 and Figure 12 reveal a few important trends in the data. It is clear from these figures that the two factors with the greatest influence are CST capital cost and the discount rate. Figure 10 shows that increasing the CST capital cost by 71% from the base value of 7929AUD/kWh results in an LCOE increase of approximately 31% at Port Augusta. Similarly, a reduction in CST capital cost of 43% at Port Augusta results in an LCOE that is approximately 38% lower than the base value. This result follows logically from the fact that CST is a highly capital-intensive technology and each of the systems at the three sites uses a high proportion of CST to cover the load requirements. Discount rate has a slightly lower impact on changes in LCOE when compared to CST capital cost, as evidenced by Figure 10, Figure 11 and Figure 12, with an increase of 71% from the base value leading to an increase in LCOE of approximately 28% for all three sites.

It is interesting to note that in the case of Newman, the sensitivity of the LCOE to diesel fuel price is higher than in the case of Port Augusta and Halls Creek. An increase of 71% to the diesel fuel price produces an 8% increase in LCOE at Port Augusta, a 9% increase in LCOE at

Halls Creek and an 11% increase in LCOE at Newman. As with the variations in sensitivity to CST capital cost at each of the three sites, this difference is due to the composition of the ideal hybrid system. Higher reliance on diesel generators at Newman compared to Halls Creek and Port Augusta means more sensitivity to fluctuations in the price of diesel fuel but less sensitivity to fluctuations in CST capital cost. Similarly, a higher contribution from Solar PV at Halls Creek means increased sensitivity to Solar PV capital cost but reduced sensitivity to CST capital cost. Despite the differences in composition between the ideal systems at each of the three sites, they all primarily use capital intensive technology to satisfy their load demands and as such are influenced by fluctuations in the discount rate to a similar extent.

Based on the results obtained from the sensitivity analysis, it was evident that the major results of the analysis, namely system composition and LCOE, are highly sensitive to changes in CST capital cost. It is therefore important to ensure there is minimal uncertainty in the assumed value. While this project has made use of several reputable sources to decide on a CST capital cost value, a further check to increase confidence was completed via a SAM analysis. This analysis was conducted both for this reason and to develop an example of the heliostat field required at Port Augusta for a 3.5MW CST plant. Figure 14 and Table 14 show the primary results of the SAM analysis undertaken. The total land area taken up by the heliostat field of 319,702m$^2$ in Table 14 gives a clear indication of why systems utilising this technology are ideally placed in regional or remote areas. The SAM analysis, as shown in Table 14, also estimated the annual water usage of the CST plant for washing mirrors at 1.4 mega litres/year. This is a significant water requirement and should be a consideration for any project looking to implement a hybrid system similar to those found to be ideal in this report. As an interesting aside, some of the water being brought in to wash the solar mirrors could also be used to enable hydrogen production via electrolysis with the excess energy generated by the plant.

Table 15 displays the financial results of the SAM analysis, and while these are not intended to be rigorous or used in place of the results from the analysis code, they do increase confidence in the accuracy of this report's analysis. Table 15 shows that SAM returned a value of $29,114,408 for the total installed cost of the CST plant and the analysis code returned a value of $32,125,500. This result, which displays a difference of approximately 10% between the outputs of the two different methods, reinforces the validity of the assumptions made with regards to CST technology. Similarly, the estimated total installed cost per net capacity is shown by Table 15 to have a difference of only 1% between the SAM analysis result of $9,243/kW and the analysis code result of $9,179/kW. Clearly then, despite the acknowledged uncertainty in CST capital cost and the fact that it is an immature technology in the Australian context, the analysis conducted in this report has produced reasonable results.

## 6.2 Conclusions

The focus of this project has been on the analysis and comparison of three energy generation technologies for deployment in the remote Australian context. This has been achieved by developing an analysis code that makes use of synthetic load profiles and supplied weather data to identify the ideal hybrid energy system at each site. The results have shown that the optimum systems all incorporate significant renewable fractions and primarily rely on Concentrating Solar Thermal for baseload power supply. Port Augusta has been identified as the ideal site for deployment, with both the highest renewable fraction at 92% and the lowest LCOE, at $0.203/kWh, of the sites analysed. The system at Port Augusta was found to be optimised with 89% of total production from CST, 9% from diesel and 2% from Solar PV, resulting in an annual $CO_2$ reduction from a 100% diesel system of 13,412,749kgeq$CO_2$. Based on information gathered in the literature review, it has been concluded that these results are reasonable and demonstrate the feasibility of such a hybrid system in the remote Australian context.

## 6.3 Future Work and Recommendations

While the results of this project have aligned well with similar studies and expectations based on theory, there are several key recommendations that could be implemented in any future work to improve the analysis.

The primary recommendations for future work in this area are as follows:

- Use weather data over a period of more than one year at each site under analysis
    - Ideally, weather data for each site would be from the same time period to give a more accurate comparison
- Use actual electric load data from the sites under analysis rather than a synthetic load profile
- The solar PV panel tilt calculations should be studied in greater detail and checked more rigorously for accuracy
- More thorough analysis of the minimum size requirements for CST plants to be viable
- Look for ways to de-link the CST storage capacity from the field capacity

Similarly, there are a couple of areas that have not been covered in this project which may warrant more extensive study.

- The inclusion of other renewable energy sources such as wind turbines to broaden the scope of the analysis
- The inclusion of a battery system for Solar PV may result in an increased contribution to overall production from this technology

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# 7 Appendix

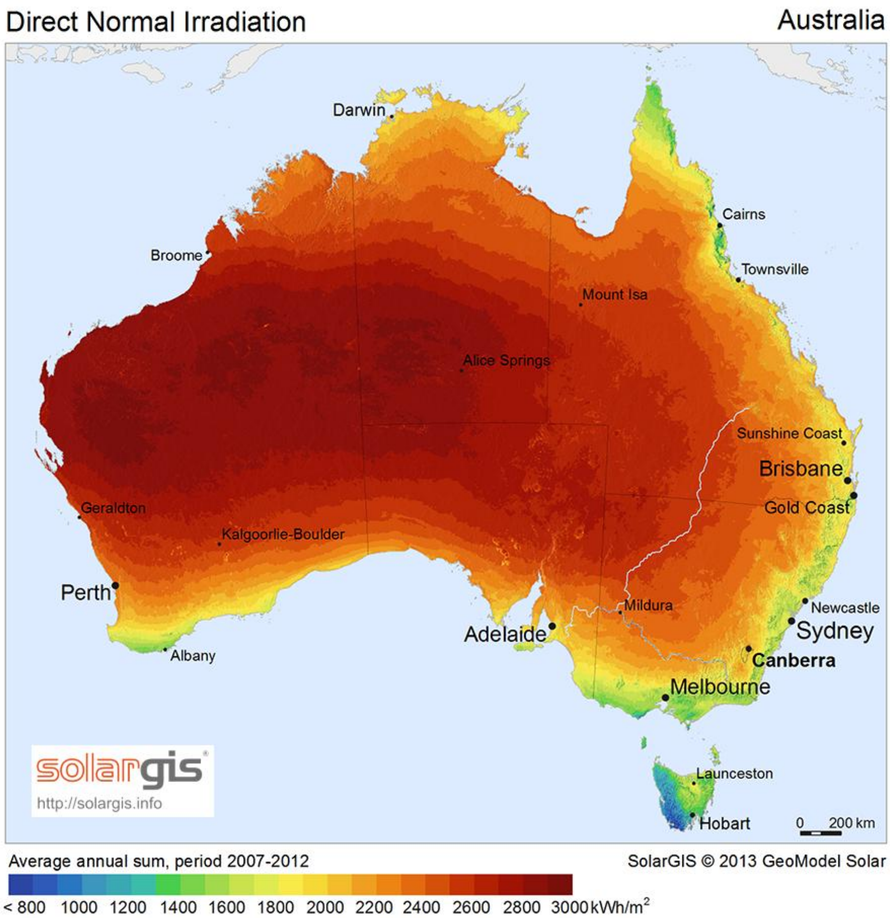


Figure 15 -Australian Direct Normal Irradiation Map [65]

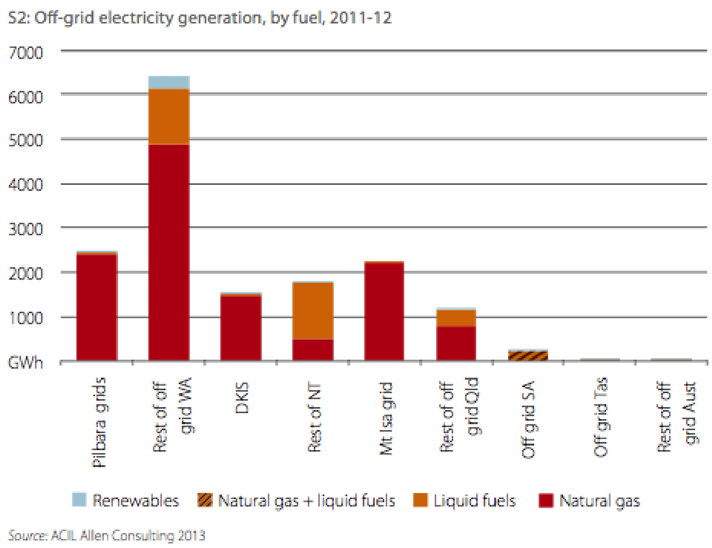


Figure 16 - Off-Grid Electricity Generation by Fuel

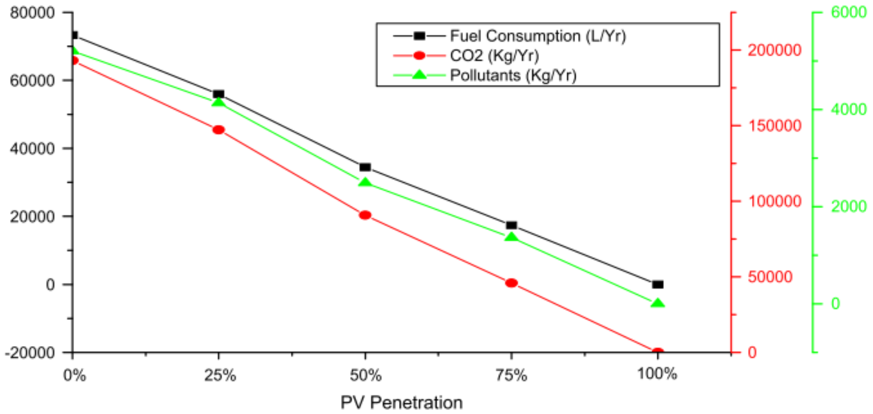


**Fig. 15.** Effect of increasing the PV penetration on fuel consumption and GHG saving.

**Figure 17 - Relationship between PV Penetration and GHG Emissions [17]**

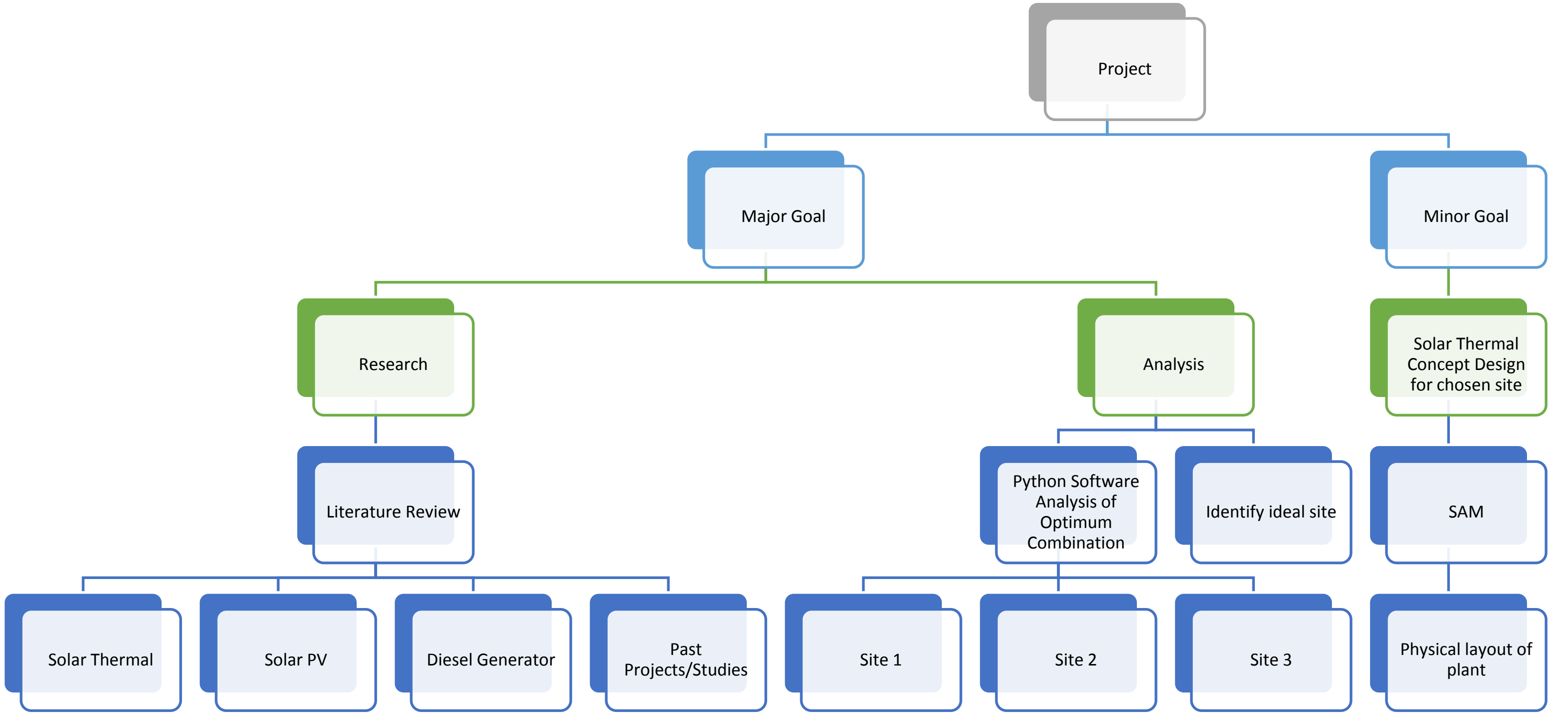


Figure 18 - Major Tasks and Work Flow Plan

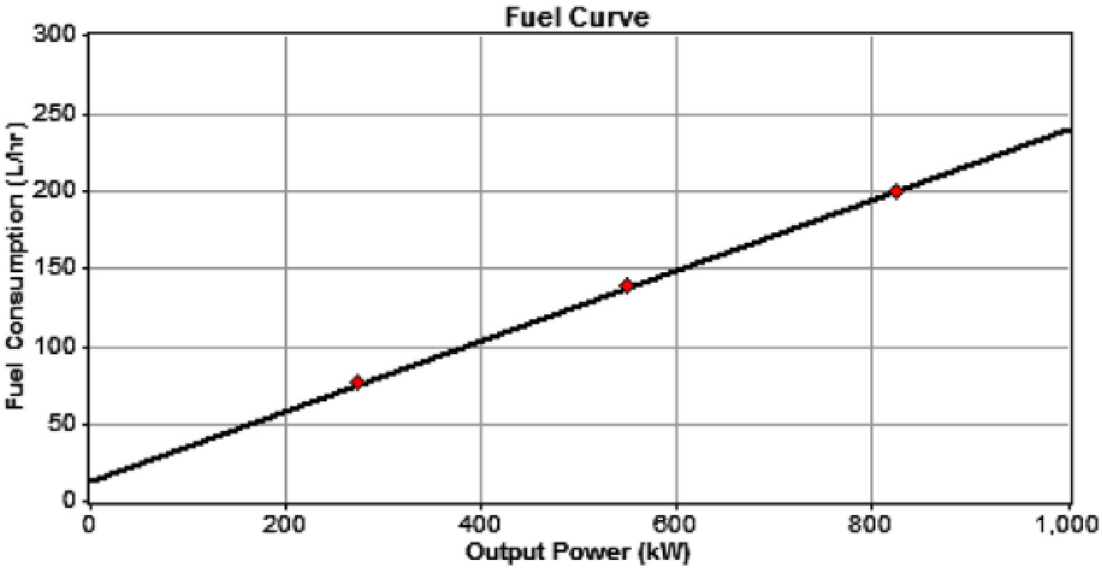


Figure 19 - Diesel Generator Output Power vs Fuel Consumption [30]

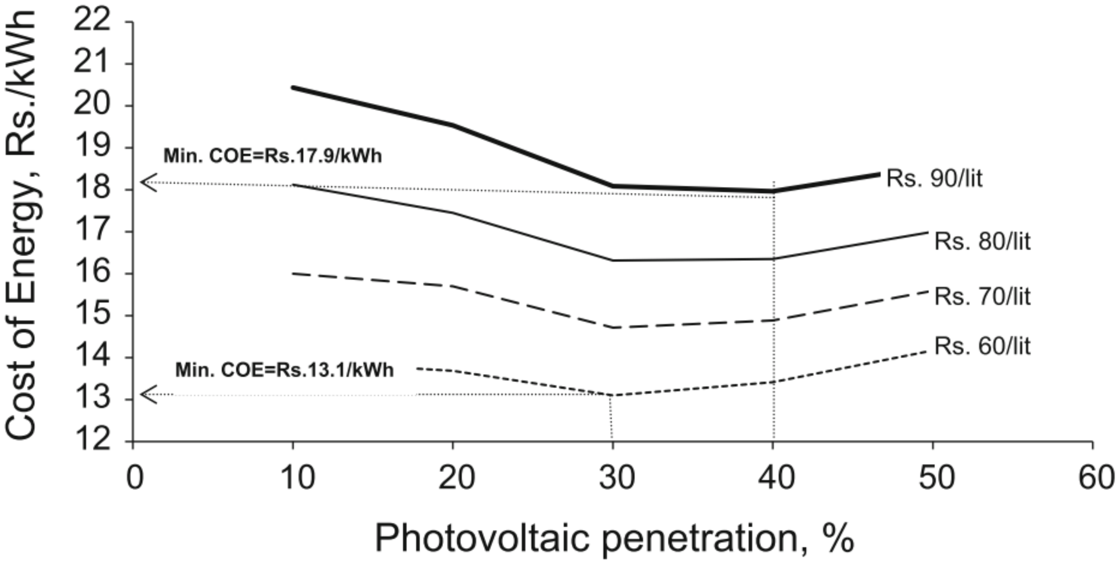


Figure 20 - Sensitivity of Optimum PV Penetration to Diesel Cost [15]

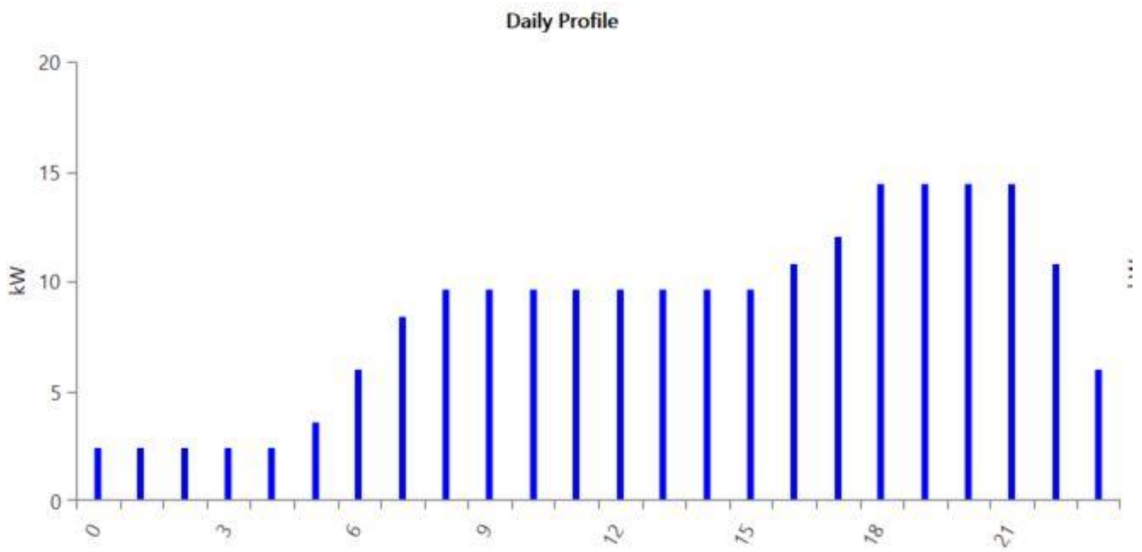


Figure 21 - Unscaled Daily Load Profile

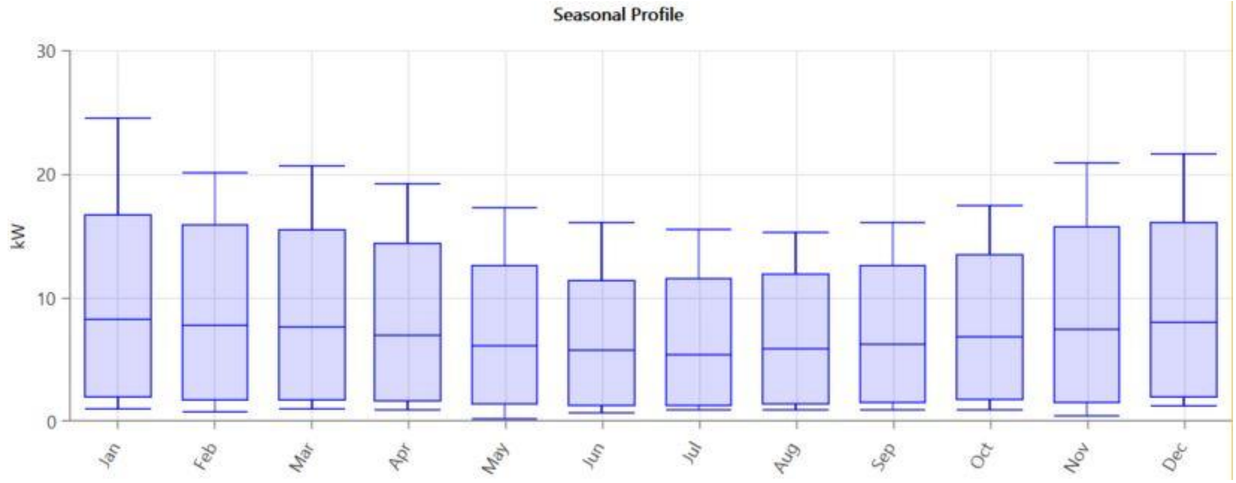


Figure 22 - Unscaled Seasonal Load Profile (Peak shown in January)

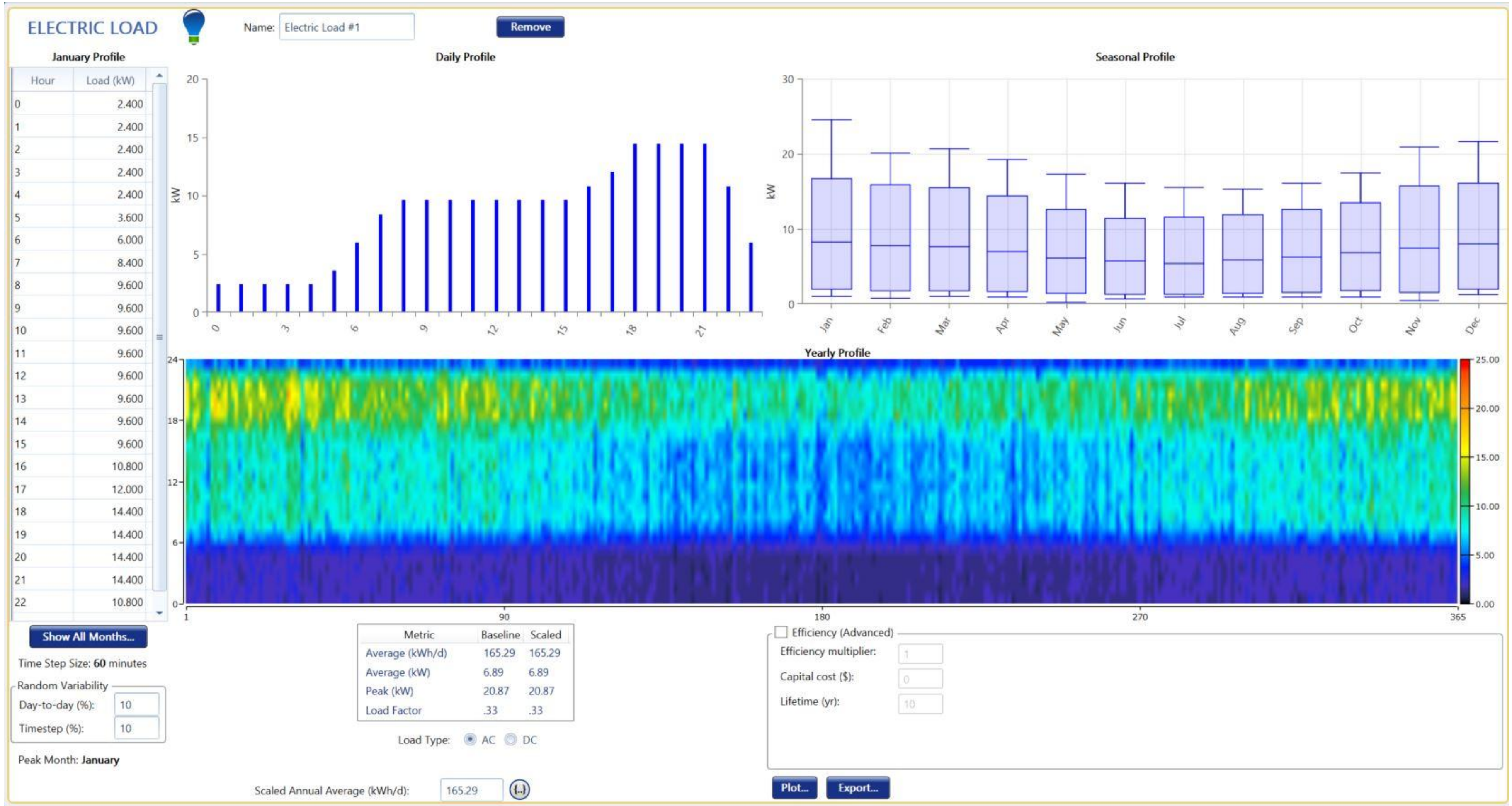


Figure 23 - Unscaled Load Tab from HOMER

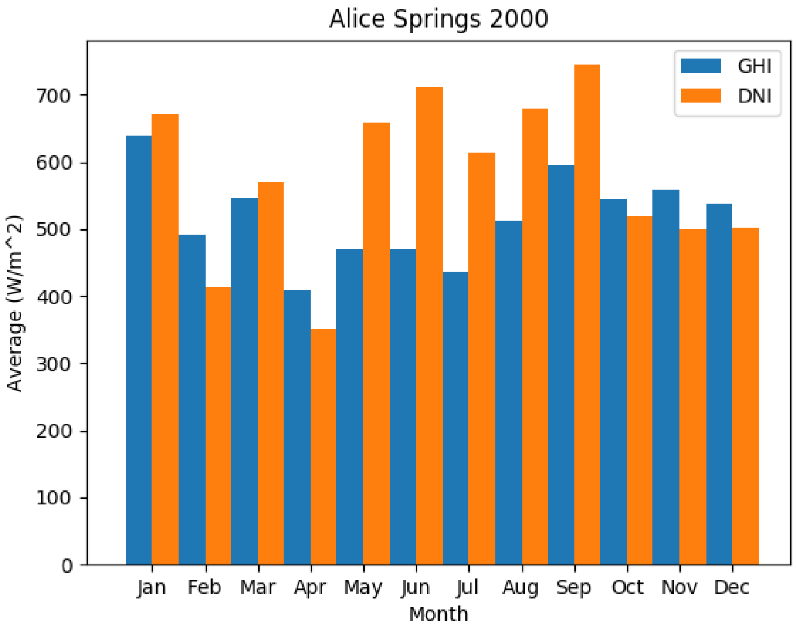


**Figure 24 - Alice Springs (2000) Average Monthly GHI and DNI**

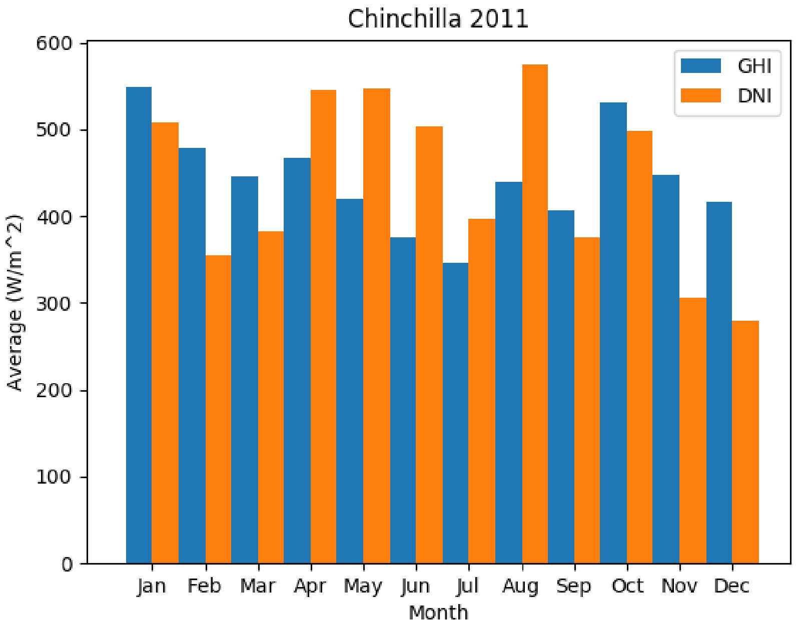


**Figure 25 - Chinchilla (2001) Average Monthly GHI and DNI**

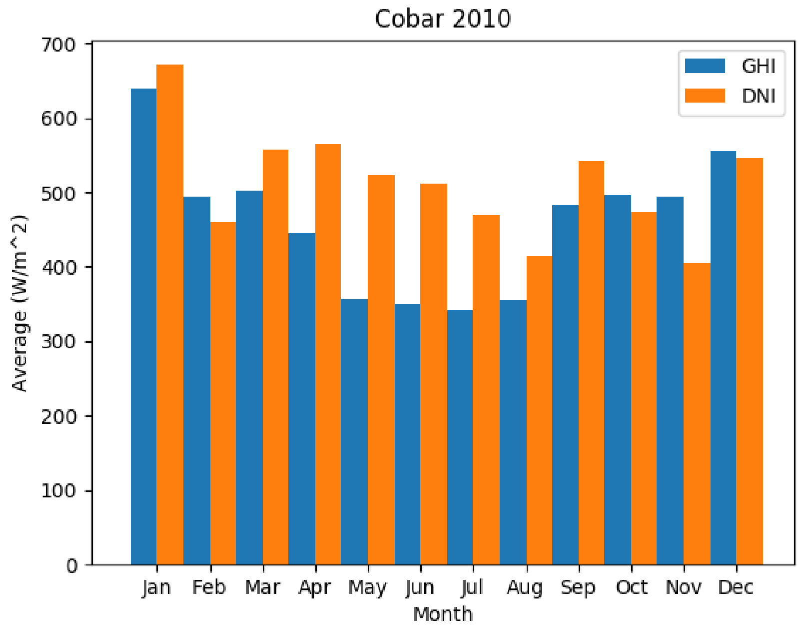


Figure 26 - Cobar (2010) Average Monthly GHI and DNI

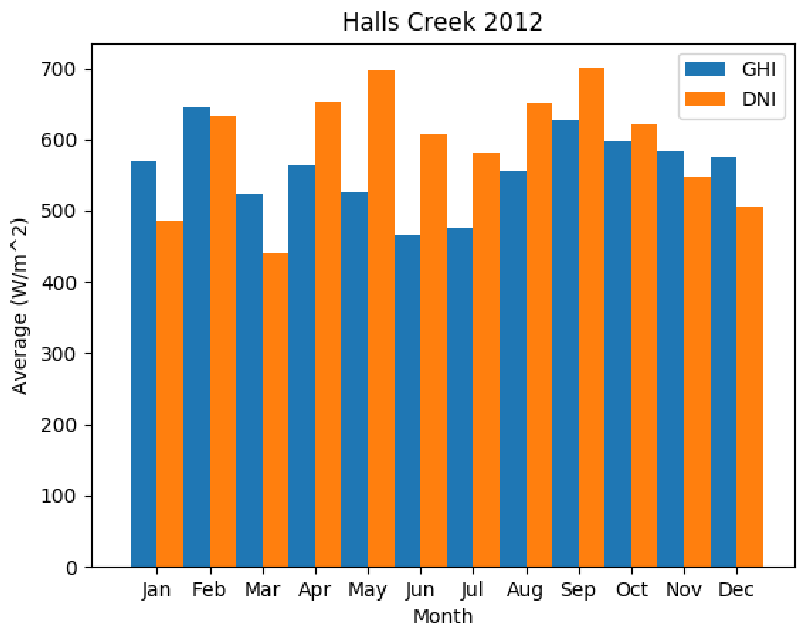


Figure 27 - Halls Creek (2012) Average Monthly GHI and DNI

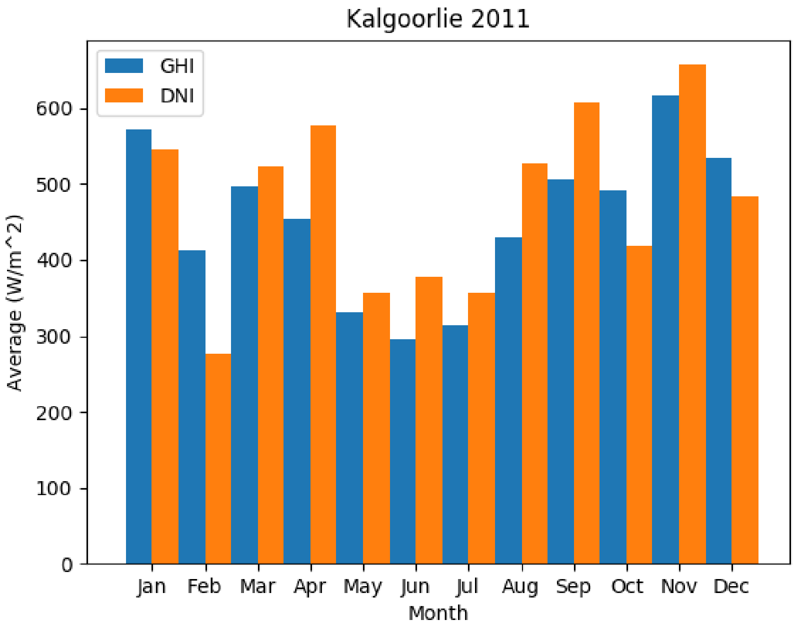


Figure 28 - Kalgoorlie (2011) Average Monthly GHI and DNI

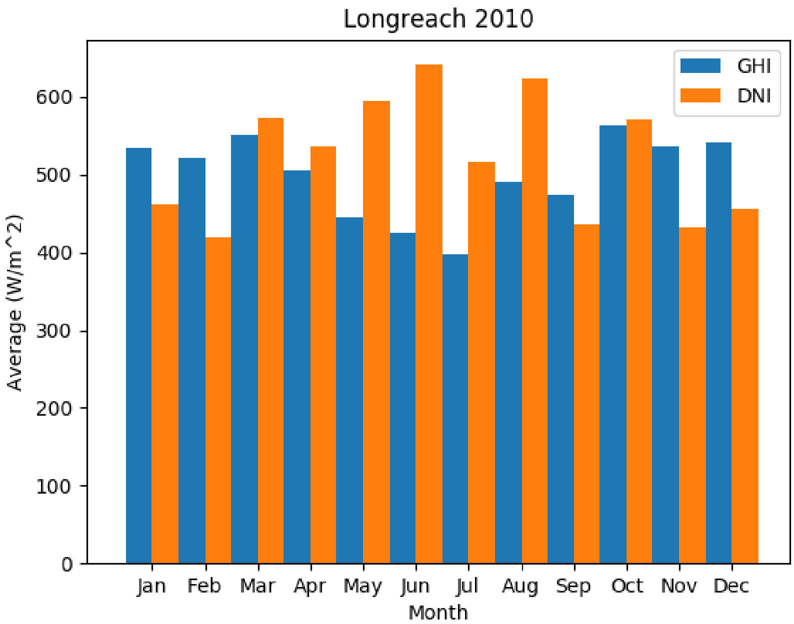


Figure 29 - Longreach (2010) Average Monthly GHI and DNI

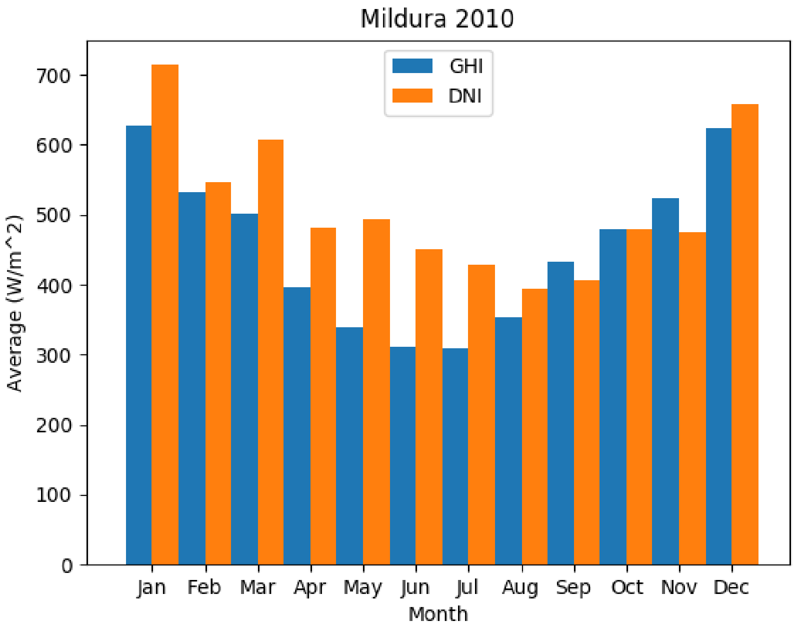


Figure 30 - Mildura (2010) Average Monthly GHI and DNI

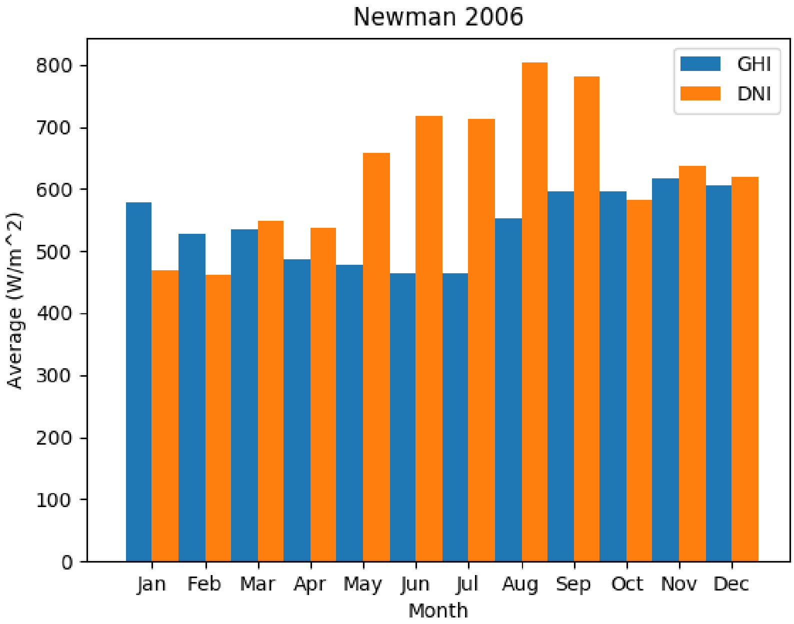


Figure 31 - Newman (2006) Average Monthly GHI and DNI

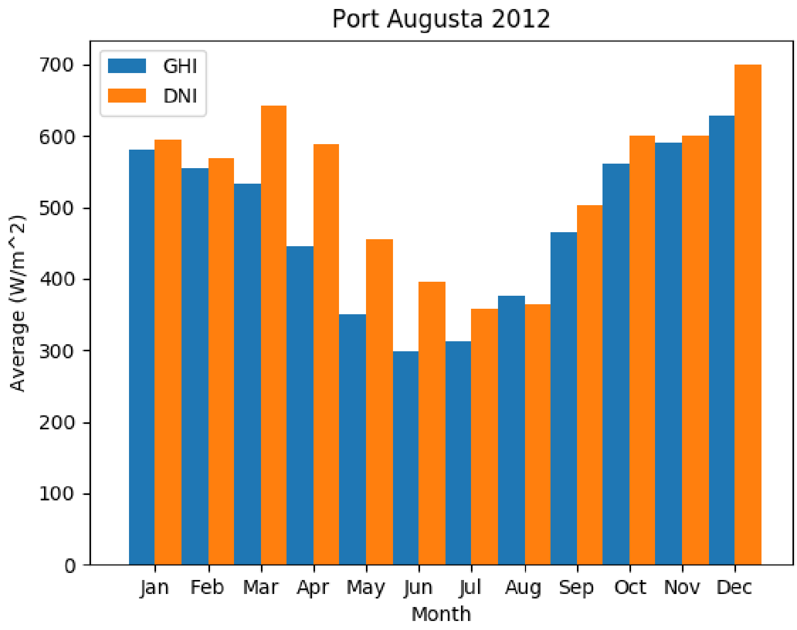


Figure 32 - Port Augusta (2012) Average Monthly GHI and DNI

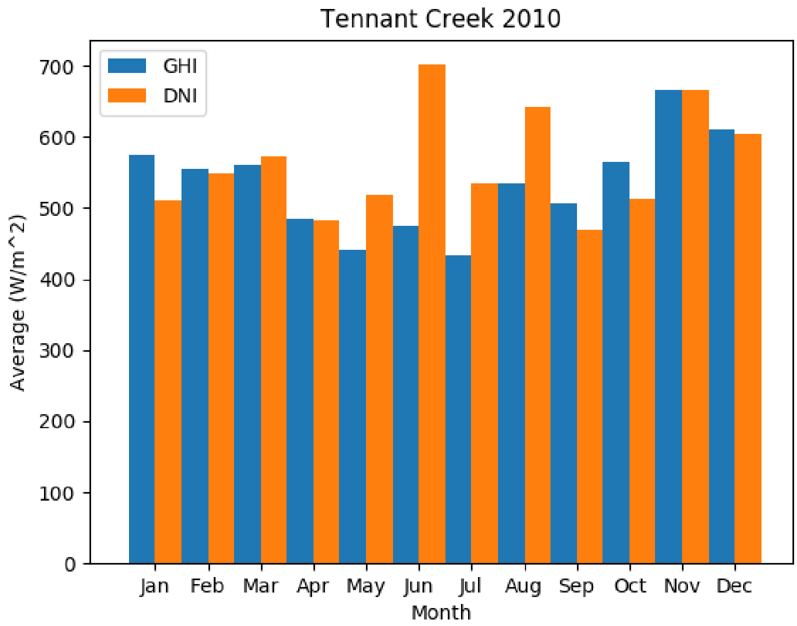


Figure 33 - Tennant Creek (2010) Average Monthly GHI and DNI

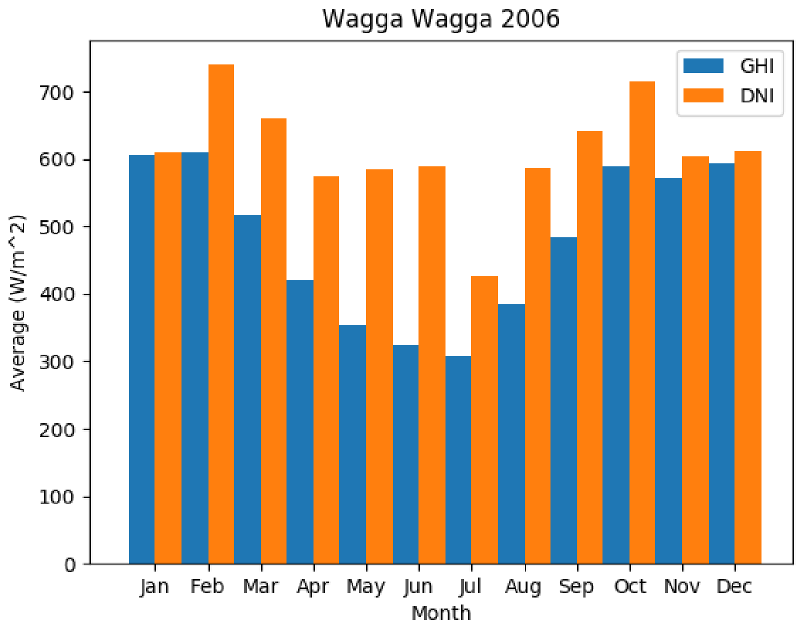


Figure 34 - Wagga Wagga (2006) Average Monthly GHI and DNI

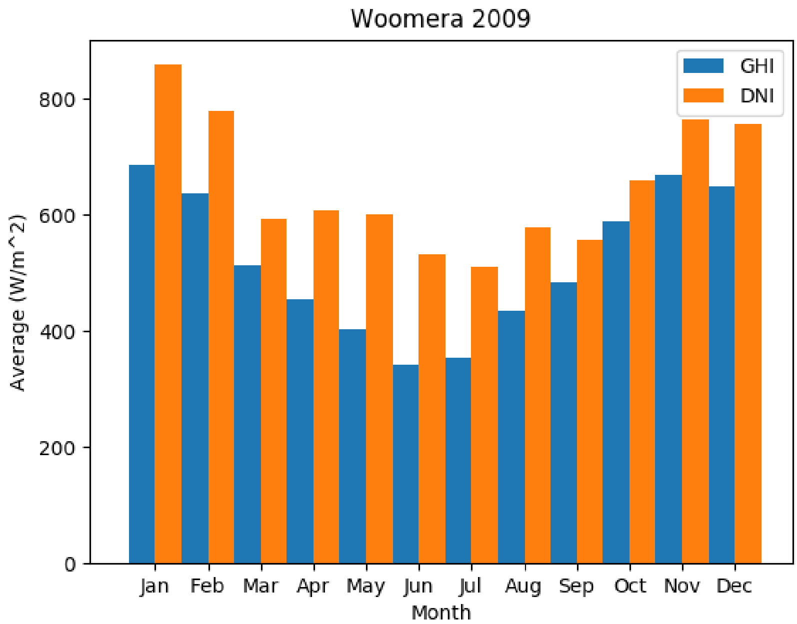


Figure 35 - Woomera (2009) Average Monthly GHI and DNI

Table 16 - Sensitivity Analysis Numerical Results

| Actual LCOE Values | | | | | | | | | | % Difference from base LCOE | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Port Augusta | | | | | | | | | | Port Augusta | | | | | | | | |
| Range | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** |
| Diesel Fuel | 0.191 | 0.195 | 0.199 | 0.203 | 0.207 | 0.210 | 0.214 | 0.218 | 0.222 | -5.9% | -3.9% | -1.9% | 0.0% | 1.8% | 3.6% | 5.3% | 7.0% | 8.5% |
| PV Capital | 0.202 | 0.202 | 0.203 | 0.203 | 0.203 | 0.203 | 0.203 | 0.204 | 0.204 | -0.3% | -0.2% | -0.1% | 0.0% | 0.1% | 0.2% | 0.3% | 0.4% | 0.5% |
| CST Capital | 0.147 | 0.166 | 0.184 | 0.203 | 0.221 | 0.240 | 0.258 | 0.277 | 0.295 | -37.7% | -22.3% | -10.0% | 0.0% | 8.4% | 15.4% | 21.5% | 26.7% | 31.3% |
| Discount Rate | 0.161 | 0.174 | 0.188 | 0.203 | 0.218 | 0.234 | 0.250 | 0.267 | 0.284 | -26.4% | -16.6% | -7.8% | 0.0% | 7.0% | 13.3% | 18.9% | 24.0% | 28.5% |
| Halls Creek | | | | | | | | | | | | | | | | | | |
| Range | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** |
| Diesel Fuel | 0.191 | 0.196 | 0.200 | 0.204 | 0.209 | 0.213 | 0.217 | 0.222 | 0.226 | -6.7% | -4.4% | -2.2% | 0.0% | 2.1% | 4.0% | 5.9% | 7.8% | 9.5% |
| PV Capital | 0.203 | 0.203 | 0.204 | 0.204 | 0.205 | 0.205 | 0.206 | 0.206 | 0.207 | -0.7% | -0.5% | -0.2% | 0.0% | 0.2% | 0.5% | 0.7% | 1.0% | 1.2% |
| CST Capital | 0.153 | 0.170 | 0.187 | 0.204 | 0.221 | 0.238 | 0.255 | 0.273 | 0.290 | -33.3% | -20.0% | -9.1% | 0.0% | 7.7% | 14.3% | 20.0% | 25.0% | 29.4% |
| Discount Rate | 0.162 | 0.176 | 0.190 | 0.204 | 0.220 | 0.235 | 0.251 | 0.268 | 0.285 | -25.8% | -16.2% | -7.7% | 0.0% | 6.9% | 13.1% | 18.6% | 23.6% | 28.2% |
| Newman | | | | | | | | | | | | | | | | | | |
| Range | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** | **-43%** | **-29%** | **-14%** | **0%** | **14%** | **29%** | **43%** | **57%** | **71%** |
| Diesel Fuel | 0.195 | 0.200 | 0.205 | 0.210 | 0.215 | 0.220 | 0.225 | 0.230 | 0.235 | -7.7% | -5.0% | -2.4% | 0.0% | 2.3% | 4.6% | 6.7% | 8.7% | 10.6% |
| PV Capital | 0.208 | 0.209 | 0.210 | 0.210 | 0.211 | 0.211 | 0.212 | 0.212 | 0.213 | -0.9% | -0.6% | -0.3% | 0.0% | 0.3% | 0.6% | 0.8% | 1.1% | 1.4% |
| CST Capital | 0.159 | 0.176 | 0.193 | 0.210 | 0.227 | 0.244 | 0.261 | 0.278 | 0.295 | -32.2% | -19.4% | -8.8% | 0.0% | 7.5% | 14.0% | 19.6% | 24.5% | 28.9% |
| Discount Rate | 0.168 | 0.181 | 0.195 | 0.210 | 0.225 | 0.241 | 0.257 | 0.274 | 0.291 | -25.0% | -15.8% | -7.5% | 0.0% | 6.7% | 12.8% | 18.3% | 23.2% | 27.7% |

**Table 17 - Full Analysis Code Numerical Results**

| Location | LCOE | NPV | PV Power | Storage Hours | PV EAC | CST EAC | DG EAC | DG Fuel Cost | PV Total | CST Total | CST Peak | DG Total | DG Peak | DG Hours | PV Excess | CST Plant Capacity | CST Excess | Renewable Fraction | Total Installed Power (kW) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Port Augusta | $0.203 | $97,293,133 | 200 | 12 | $29,743 | $2,669,156 | $1,192,826 | $508,861 | 441195 | 17113091.12 | 3480 | 1630784 | 5060 | 1643 | 0 | 3480 | 41249982.16 | 91.5% | 8864 |
| Halls Creek | $0.204 | $28,604,758 | 150 | 11 | $22,307 | $716,581 | $405,302 | $168,741 | 329246 | 4750431.131 | 934 | 518660 | 1704 | 1752 | 0 | 934 | 10918609.14 | 90.7% | 2820 |
| Woomera | $0.205 | $978,392 | 0 | 12 | $- | $26,692 | $12,444 | $5,015 | 0 | 175571.6695 | 35 | 15600 | 55 | 1566 | 0 | 35 | 408059.0574 | 91.8% | 90 |
| Newman | $0.210 | $48,431,294 | 300 | 11 | $44,615 | $1,180,709 | $711,928 | $323,223 | 662478 | 7509325.314 | 1540 | 1048670 | 2698 | 1908 | 0 | 1540 | 18306295.36 | 88.6% | 4645 |
| Wagga Wagga | $0.210 | $745,454,360 | 0 | 12 | $- | $19,635,169 | $10,183,006 | $4,754,902 | 0 | 125975824.7 | 25603 | 15703258 | 37283 | 1955 | 0 | 25603 | 303387331.3 | 88.9% | 62886 |
| Tennant Creek | $0.211 | $43,542,494 | 200 | 11 | $29,743 | $1,056,311 | $655,646 | $323,473 | 426614 | 6738474.675 | 1377 | 1094644 | 2186 | 2144 | 0 | 1377 | 16358608.64 | 86.7% | 3824 |
| Alice Springs | $0.221 | $354,979,522 | 1250 | 11 | $185,895 | $8,207,547 | $5,805,739 | $2,811,409 | 2676646 | 52209182.7 | 10702 | 9319927 | 19513 | 2190 | 0 | 10702 | 127255442.6 | 85.5% | 31984 |
| Mildura | $0.225 | $372,249,149 | 700 | 12 | $104,101 | $9,168,192 | $5,617,673 | $2,746,529 | 1488298 | 55346697.32 | 11955 | 9211253 | 18846 | 2157 | 0 | 11955 | 145122622.4 | 86.1% | 32017 |
| Kalgoorlie | $0.229 | $317,639,207 | 1875 | 11 | $278,842 | $7,084,256 | $5,342,470 | $2,845,170 | 3794164 | 41738332.82 | 9237 | 9892729 | 15084 | 2552 | 0 | 9237 | 113164551.7 | 82.2% | 27332 |
| Cobar | $0.231 | $69,723,316 | 0 | 12 | $- | $1,675,534 | $1,113,398 | $548,148 | 0 | 10247475.63 | 2185 | 1820760 | 3588 | 2312 | 0 | 2185 | 26391512.74 | 84.9% | 5772 |
| Longreach | $0.236 | $40,091,492 | 0 | 12 | $- | $946,732 | $656,928 | $303,681 | 0 | 5830156.252 | 1234 | 974003 | 2338 | 2119 | 0 | 1234 | 14872080.1 | 85.7% | 3572 |
| Chinchilla | $0.248 | $64,254,250 | 0 | 12 | $- | $1,431,731 | $1,138,439 | $611,953 | 0 | 8213189.389 | 1867 | 2130060 | 3120 | 2646 | 0 | 1867 | 23094540.26 | 79.4% | 4987 |